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France

France is one of the world's largest nuclear power producers, but has very limited fossil fuel resources. The 1999 merger of its top two oil companies formed the fourth largest oil company in the world.

The information in this report is the best available as of January 2002 and is subject to change.



BACKGROUND

One of the world's largest economies, France is a founding member of the European Union (EU) and a member of the Group of Seven (G-7) industrialized nations, the General Agreement on Tariffs and Trade (GATT)/World Trade Organization (WTO), the International Energy Agency (IEA), and the International Atomic Energy Agency (IAEA). France joined the common European currency, the euro, on January 1, 1999.

France's economy has had stronger growth than that of many of its neighbors in recent years, having experienced a cyclical upturn since late 1997 that is now winding down. France's economy grew 3.4% in 2000, but growth is estimated to have declined to 2.1% in 2001. France's economy in 2002 will closely track the eurozone as whole, where growth for 2002 is forecast at 1.4%. Euro coins and bills were introduced beginning January 1, 2002, though the French franc has been pegged to the euro since 1999.

Traditionally, the role of the state has been stronger in France than in other Western European countries. France is one of the most centralized countries in Europe with a strong history of state ownership in the aviation, telecommunications, and energy industries. However, the role of the government now is changing. Important economic and political changes in France include widespread privatization and increasingly frequent mergers and acquisitions (M&As) and hostile corporate takeovers, once virtually

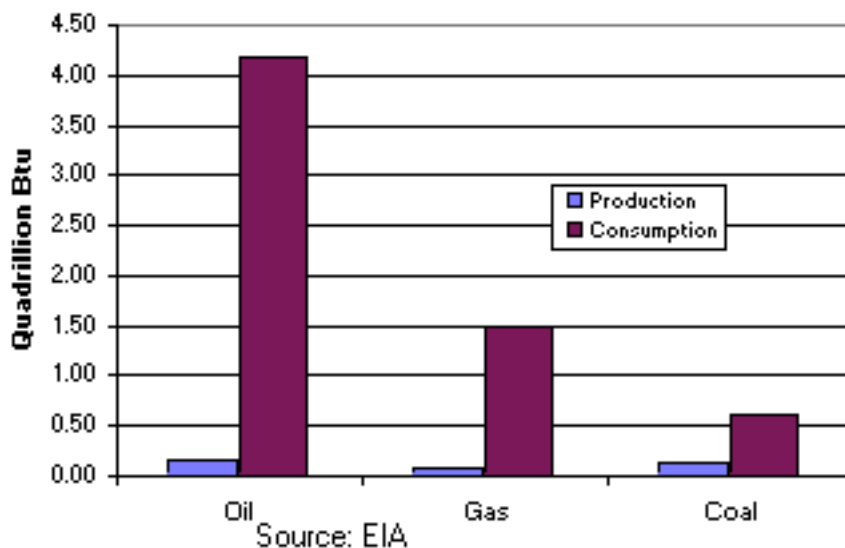
unheard of in France.

International pressures of globalization and more direct pressure from the EU are behind the current trend away from government involvement in industry. The French government is headed by the moderate socialist prime minister, Lionel Jospin, and the Gaullist president, Jacques Chirac, under the French system of governmental "cohabitation." The divided government has moved very slowly toward privatization of the country's energy industry, despite an EU directive that calls for member states to relinquish control of their energy companies to the private sector. This has caused friction between France and other EU members, particularly in regard to acquisitions by Electricite de France (EdF).

ENERGY

French energy policy has been relatively consistent in recent decades, with the main objectives including: securing energy supply, achieving international competitiveness, and protecting the environment. The focus on energy security has led France to become one of the world's top producers and consumers of nuclear power. France's production of primary energy rose by 2.1% in 2000, to about 5.04 quadrillion Btu. France's energy demand rose by 1.1% to about 10.3 quadrillion Btu. However, France's total energy bill rose by 102% in 2000, to 155.2 billion French francs (FFR).

French Fossil Fuel Energy Production and Consumption, 1999 (2000 for Oil)



OIL

About 1.9 million barrels per day (bbl/d) of France's approximate 2 million bbl/d oil consumption are imported. France has reserves totaling only 140 million barrels. Exploration increased in 2000-2001 because of higher oil prices, and France's proven reserves increased in 2000,

though they are still extremely small, and fell slightly in 2001. France's domestic crude oil production comes from numerous wells producing very small amounts of oil. Because of France's limited domestic fossil fuel energy sources, security of supply historically has been a major concern.

Despite France's limited domestic reserves and production, the French oil industry is an important actor in world energy markets. Major oil assets of French oil companies are located in the North Sea, Africa, and Latin America. French imports come primarily from Saudi Arabia and Norway, followed by the United Kingdom (UK), Iraq, Iran, Nigeria, and Russia. In July 2001, the Iraqi government stated that it would reconsider oil projects with French companies and no longer give French companies "priority" due to France's support of the U.S.-British "Smart Sanctions" proposal at the United Nations Security Council. Iraq has letters of intent with TotalFinaElf that would take effect when sanctions are lifted.

In early 1999, French oil company Total merged with Belgian oil company Petrofina to create TotalFina, the world's sixth-largest oil company and the third-largest oil company in Europe. Only months later, TotalFinaElf was formed by TotalFina's acquisition of Elf Aquitaine. After the deal was completed in 2000, TotalFinaElf became the fourth-largest publicly listed oil company in the world, after ExxonMobil, Royal Dutch/Shell, and BP. TotalFinaElf has proven reserves of about 10.8 billion barrels of oil equivalent and production of about 2.1 million bbl/d. TotalFinaElf has very little crude oil production in North America or Asia (outside of the Middle East), unlike the other super majors. The company claims to have raised hydrocarbon output by 6% in 2001 and plans to raise production by 9% in 2002 as major new resources come on stream. TotalFinaElf owns more than 50% of the refinery capacity in France, and is the seventh-largest refiner in the world.

Downstream

France's crude oil refining capacity is 1.9 million bbl/d. The country's largest refinery is TotalFinaElf's refinery at Gonfreville l'Orcher with a capacity of

323,643 bbl/d. Increasingly strict EU environmental regulations for refineries are in large measure behind recent upgrades in the French refining sector. The regulations will become considerably more strict in 2005, and substantial investment in the refining sector will be necessary to meet these new mandatory targets. ExxonMobil has begun adapting its Port Jerome refinery to 2005 EU specifications.

Because oil security has been such a concern for French energy policy-makers, there is a French law allowing the French government to refuse to close a refinery if it believes its supply or price security is at risk. Essentially, this gives the French government veto power over EU legislation regarding refineries. This could become an important issue as the EU's environmental standards are strengthened further.

NATURAL GAS

France has very limited natural gas resources and therefore imports almost all of the natural gas it consumes. Natural gas consumption increased 3.6% in 2000, and the share of natural gas in the French energy market rose to 14.5%. Industry's share of consumption rose from 44% to 48% year-on-year 1999-2000, but household use declined from a 39% share to a 36% share year-on-year 1999-2000.

The French natural gas industry is run by Gaz de France (GdF), the state-held company with a monopoly on importation and distribution of natural gas in France. By 2003, Gaz de France aims to possess sufficient reserves to produce at least 15% of the natural gas it sells. The company's annual production capacity stands at more than 70 billion cubic feet (Bcf). GdF also has the largest underground storage capacity in western Europe, with 318 Bcf, about 3 months supply. In November 2001, the French government decided to privatize the country's natural gas transport network, allowing the operators, GdF and a subsidiary of TotalFinaElf, to purchase it. However, Communist members of parliament blocked the plan in December, though it seems likely that a version will take effect sometime in 2002. France is the only EU country that owns a franchised natural gas network. GdF has increased

substantially its holdings in North Sea natural gas over the past few years, including interests in Norway's Snoehvit and Njord fields. The company acquired holdings in twelve exploration licences in the UK North Sea with an average equity of 21% from Texaco in June 2001. GdF supplies about a fifth of total French consumption from its holdings in France and abroad. Norway is France's top natural gas imports supplier, followed by Russia and Algeria. Natural gas imports from Russia have been declining in recent years, while imports from Algeria have been rising. However, there has been discussion of a new pipeline to connect Russian natural gas to France. The Netherlands is a smaller source of French natural gas imports. GdF also imports liquefied natural gas (LNG) to its two terminals. In addition to long-term contracts, GdF buys natural gas on the spot market or with short-term contracts from the UK's North Sea.

France is the only country in the EU that has not yet enacted any legislation adopting the rules of the EU's 1998 Gas Directive. However, there have been some changes in France's natural gas market since 1998. The EU directive required that 20% of member countries' natural gas markets become competitive. Without a legal basis, GdF nonetheless opened its grid to third-party access in August 2000. About 100 of the country's largest industrial consumers now are able to choose their suppliers. The companies allowed to choose other suppliers and use GdF's network are limited to 20% of the market, the minimum prescribed in the directive. However, no progress has yet been made on plans to change the status of GdF from a wholly-owned state enterprise to a joint stock company, that could then be partially privatized. Because France has been one of the slower countries to pave the way for competition, it has come under harsh criticism from the EU and fellow member countries. In September 2000, the European Commission (EC, the executive body of the EU) sent a formal warning letter to France for failure to notify the EC of national laws enacted to ensure implementation of the 1998 Natural Gas Directive. Although France adopted draft legislation in May 2000, the full national parliament has not yet passed a law to open the market, and is not likely to do so until after the parliamentary and presidential elections in the spring of 2002.

GdF is establishing France as a hub for Western European natural gas. In October 1998, France for the first time became linked via pipeline to a foreign production field. The NorFra pipeline linked Norway's Troll gas field in the North Sea to the French natural gas grid. The pipeline is 840 kilometers (521 miles) long, and is the longest undersea natural gas pipeline in the world. About half of the natural gas from the pipeline will transit through France to points in Italy and Spain, while the other half will be consumed in France. By 2005, the Norwegian pipeline is expected to supply one-third of France's total natural gas consumption. GdF is increasing its trading activities in partnership with Societe Generale, a French Bank. GdF's trading affiliate, Gaselys, carried out 600 transactions in 2000, six times the volume of 1999. GdF has invested abroad heavily, and owns distribution networks in several countries. However, France's lack of liberalization may cause problems with GdF's business in other EU countries. In 2001, Spain's Enagas refused access to its pipelines to GdF on the grounds that there is a "lack of reciprocity with France." In addition, this has prevented GdF from entering partnerships that have cross-ownership with foreign companies, such as Statoil.

GdF is constructing the Les Marches du Nord-Est pipeline in two parts. The first 124-mile part went operational in October 2001, and the second 186-mile part is expected to go operational in October 2002. GdF has signed a 25-year contract with Italy's Snam for delivery of 6 billion cubic meters (Bcm, or 212 Bcf) of Norwegian natural gas through the pipeline. GdF plans to spend \$2.5 billion 2001-2003 on developing its pipeline network and installations in France.

Liquefied Natural Gas

GdF has two liquefied natural gas (LNG) terminals: the 159-Bcf-per-year capacity facility at Fos-sur-Mer near Marseille and the 353-Bcf-per-year capacity facility at Montoir-de-Bretagne, near Nantes. Increasing France's importance as a transit center, GdF receives Nigerian LNG at its Montoir-de-Bretagne terminal that is swapped out to Italy's Enel. The terminal receives 4 Bcm (141 Bcf) annually, 3.5 Bcm (124 Bcf) under the Italian contract and 0.5

Bcm (18 Bcf) under a contract signed by GdF.

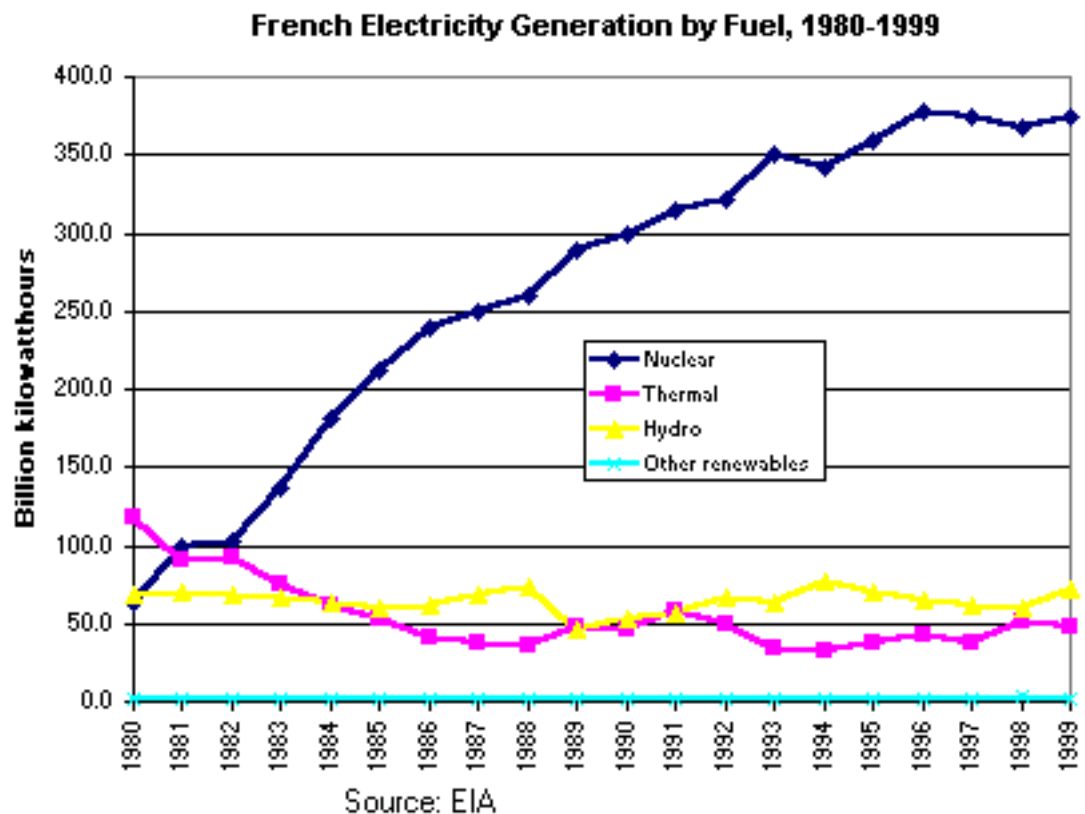
COAL

France has very limited coal reserves and neither produces nor consumes significant amounts of coal. Coal-fired electricity has been mostly replaced by nuclear power. Coal imports come from Australia, the United States, and South Africa.

The French government has supported the coal industry since the 1994 National Coal Pact between Charbonnages de France (CdF), the state coal company, and French coal miners unions. According to the agreement, the industry would receive state support as it gradually phased out the industry all together. All French coal mines are slated to be shut down by 2005. In May 2001, the EC authorized France to pay EUR 991 million in state aid to the coal industry. The number of mine workers is to have been reduced to 2,800 at the end of 2001 and production to just 2.2 million short tons, according to the government's plan.

ELECTRICITY

France is the second-largest electricity market in Europe (behind Germany). France's electricity sector is dominated by the state-held monopolist, Electricite de France (EdF), which produces, transports, and distributes over 95% of electricity in France. EdF is the last major state-run



electricity monopolist in the EU, as most of France's neighbors have privatized their electricity companies. However, there has been partial liberalization of some aspects of France's electricity sector.

A 1996 EU directive required that at least 26% of electricity sales in member countries be opened to competition, beginning in February 1999. This requirement increased to 28% in February 2000 and will increase further to 33% in 2003. In February 2000, a full year after the first EU deadline, France passed legislation that began the electricity sector's liberalization. Since that time, about 1,800 large industrial and commercial consumers (those using more than 16 million kilowatthours per year) comprising about 30% of the market have been able to choose their electricity supplier (although few of these consumers actually have changed suppliers). There has been criticism that the February 2000 law's requirement of three-year contracts is an obstacle to the real establishment of a free market.

Another step toward liberalization has been the creation of the Electricity Transmission Network (Reseau de Transport d'Electricite, RTE) that owns the country's high tension transmission network. RTE's mission is to assure all clients fair access to the network. The single tariff for international electricity transport proposed by RTE was given a positive reception by the European council of energy ministers in May 2001. In addition, an energy regulatory body has been established to oversee the deregulation process. The Commission for the Regulation of Electricity (CRE), which also will oversee natural gas deregulation when the time comes, has four main purposes: (1) advising the government in nearly all matters relating to electricity, (2) the close monitoring of the rules governing the access to the networks and compliance therewith, (3) the auditing of EdF's unbundled accounts, and (4) sanctions against infringements in certain cases, mainly in relation to network access. CRE is gradually taking on more responsibility as liberalization continues.

In late November 2001, the Powernext electricity trading market was launched in France. Powernext auctions standard hourly contracts for physical

delivery of electricity to business customers under responsibility of the RTE and guaranteed by Clearnet, a subsidiary of the Euronext stock exchange. Powernext aims to trade 10% of the French market by 2003-2004, and also to act as a price reference for the electricity market. In an additional liberalizing step, in accordance with the terms of EdF's acquisition of a controlling stake in Germany's EnBW, EdF sold 1200 megawatts (MW) of virtual power capacity to some 20 competitors (generators, traders, etc.), French and foreign, in 2001.

There are currently only two companies of any size in France that may be able to compete on a limited basis with EdF in the future. France's second-largest electricity group is Compagnie Nationale de Rhone (CNR), which produces about 3% of France's electricity, mostly from hydroelectric plants. In August 2001, a company for the commercialization of CNR's production was created by CNR and Electrabel of Belgium that is called Energie du Rhone. It will also market electricity produced by Electrabel. The French government has made EdF divest itself from its small holding in CNR in an effort to liberalize the market. The other producer is SNET, a subsidiary of French coal utility Charbonnages de France. In an effort to get into the French market, ENDESA of Spain has purchased about 30% of SNET. Because of interconnectors, other foreign companies are also attempting to get a foothold in the French electricity market. So far, EnBW (34.5% owned by EdF) and RWE, both of Germany, have attracted a small amount of industrial customers.

EdF has come under criticism and scrutiny from member EU countries, the European Commission (EC), and others on several counts. One is that liberalization around the world, and in the EU in particular, has made many electricity assets available abroad while EdF's assets (which are about 95% of the market) are unavailable. Hence, EdF can purchase foreign companies, but foreign companies cannot purchase assets in France. Another charge is that EdF's status as a state-owned monopoly has made it easier for it to purchase and outbid competitors abroad. EdF allegedly enjoys a lower cost of capital than private-sector rivals and a management that can focus on expansion rather than domestic competitors. In addition, it is alleged that taxpayers

finance the expansion while the company does not have to justify its expansion to shareholders as would be necessary in a private sector company. In June 2001, the EC launched an investigation into EdF to see whether the company has benefitted from illegal state aid such as tax breaks or certain financial guarantees.

In any event, EdF has made many large foreign purchases in the past few years, such that 25% of EdF's 2000 revenues of EUR 34.4 billion came from assets in 19 foreign countries. The contract between the French government and EdF for 2001-2003 plans for EUR 19 billion in purchases abroad by 2005. In response, Spain and Italy passed laws or adopted regulations that make it difficult for EdF to purchase their electricity assets. Spain compromised October by allowing the takeover of part of Hidrocantabrico in return for France increasing the interconnection between the two countries from 1,000 MW to 4,000 MW by 2006. In terms of Italy's law, the EC ruled in June 2001, that capital flows may not be restricted merely because of varying degrees of liberalization. However, the initial privatization sale may be restricted, but such restrictions can only be in place for a limited period, after which the privatized companies can be resold to state-owned companies.

In December 2001, Laurent Fabius, Minister for Finance and the Economy, stated his opposition to a proposed 5% increase in electricity rates by EdF in 2002. EdF raised rates 1% in November 2001.

Nuclear

France is the world's largest nuclear power generator on a per capita basis, and ranks second in total installed nuclear capacity (behind the United States). Because of France's extremely limited domestic energy sources, energy supply security and reliance on imports are major issues in France.

Government policy has promoted a dramatic increase in nuclear power generation over the past three decades. Currently, about 75% of French electricity comes from France's 57 nuclear power plants. This represents a dramatic change from 1973, when fossil fuels accounted for more than 80% of French power generation. The government nuclear regulator is DSIN, and

EdF operates the plants. In July 2001, France and the United States signed an accord to jointly fund U.S.-French research on advanced reactors and fuel cycle development.

France is now seen to be retreating slowly from its staunchly pro-nuclear position. Previously, the government planned to have nuclear power reach 100% of electricity generation. Environmental objections have increased in recent years. Germany's decision to phase out nuclear power started a public debate within France about the future of its own industry, and public opinion polls showed that a growing percentage of the public favors an end to nuclear power.

France now must decide whether to replace obsolete nuclear plants with more modern nuclear plants, or to begin phasing out nuclear power. Since 1997, the ruling government of Prime Minister Jospin has included members of the Green Party, *Les Verts*. The government has generally come to the conclusion that the volume of nuclear capacity exceeds its economically efficient contribution to the electricity market. Nevertheless, costs will fall when plants continue functioning past their 30-year capital amortisation periods, though how much longer they can function past thirty years is an open question.

In July 2001, the reorganization of the French nuclear sector commenced with the nomination of a management committee for a new holding company, Topco, that will preside over the country's major nuclear enterprises. Its nuclear operations will include mining, fuels, treatment, recycling, decontamination and engineering. As part of a restructuring program announced in Nov 2000, CEA-Industrie, Cogema and Framatome announced plans to merge Framatome with a company holding Cogema's stakes in Framatome, Eramet, TotalFinaElf and Cogera. CEA-Industrie is the holding company for the state's Commissariat à l'Energie Atomique. The capital of the new company - Topco - eventually would be open to industrial partners and the amount of stock available on the market would be increased over time. The EC required this new structure in order to approve the merger of Framatome's nuclear business with that of Siemens of Germany that was

approved in February 2001. EdF divested itself of Framatome, and EdF will now be able to have competitive bidding for nuclear services and supplies that formerly had been exclusively sourced from Framatome.

France is one of the few countries in the world with a nuclear reprocessing plant. Cogema's La Hague facility received authorization from DSIN to start operations of two new facilities, hull and end-pieces compacting and plutonium purification and conditioning, in January 2002.

ENVIRONMENT

In terms of environmental issues, France is noted for using nuclear energy that results in less greenhouse gases, but this creates other environmental concerns. The country's lack of fossil fuel resources, in addition to making France keenly aware of the importance of energy security, paradoxically has made France rely on cleaner energy sources. However, air pollution, especially in Paris, remains a pertinent environmental issue to urban dwellers.

In general, however, most energy-related environmental trends in France appear to be headed for greater efficiency and less environmental impact. The country's rate of energy consumption is holding steady, and France's energy and carbon intensity are on the decline. In addition, France has announced an extensive 10-year plan to curb its carbon emissions in order to meet its commitments under the Kyoto Protocol--one of the first countries to do so.

As part of this plan, France has reiterated its need to develop renewable energy sources to maintain its energy self-sufficiency. Although nuclear energy has helped to provide France with the energy independence the country desires, objections to nuclear energy are increasing. In the 21st century energy efficiency measures in all sectors of the economy likely will be needed in order to make further environmental improvement a realistic proposition.

Sources for this report include: CIA World Factbook; Dow Jones News Wire

service; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Petroleum Economist; Petroleum Intelligence Weekly; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

President: Jacques Chirac (since May 1995)

Prime Minister: Lionel Jospin (since June 1997)

Independence: 486 (unified by Clovis)

Population (July 2001E): 59.6 million

Location/Size: Western Europe, bordering the Bay of Biscay and English Channel, between Belgium and Spain southeast of the UK; bordering the Mediterranean Sea, between Italy and Spain/547,030 sq km (slightly less than twice the size of Colorado)

Language: French 100%, rapidly declining regional dialects and languages (Provençal, Breton, Alsatian, Corsican, Catalan, Basque, Flemish)

Ethnic groups: Celtic and Latin with Teutonic, Slavic, North African, Indochinese, Basque minorities

Religions: Roman Catholic 90%, Protestant 2%, Jewish 1%, Muslim (North African workers) 3%, unaffiliated 4%

Defense (8/98): Army 203,200; Air Force 78,100; Navy 63,300

ECONOMIC OVERVIEW

Economy, Finance, and Industry Minister: Laurent Fabius

Currency: Euro (EUR)

Exchange Rate (1/10/02): 1 U.S. Dollar = EUR 1.12

Gross Domestic Product (GDP, 2001E): \$1.21 trillion

Real GDP Growth Rate (2001E): 2.1% **(2002F):** 1.1%

Inflation Rate (consumer prices, 2001E): 1.7% **(2002F):** 1.3%

Unemployment Rate (2001E): 8.9% **(2002F):** 9.8%

Exports of Goods and Services (2001E): \$294.3 billion

Imports of Goods and Services (2001E): \$295.3 billion

Major Trading Partners: Germany, Italy, Belgium, the United Kingdom, the United States

Major Export Products: Machinery and transport equipment, agricultural

products, chemical products

Major Import Products: Machinery and transport equipment, agricultural products, chemical products, and energy

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 140 million barrels

Oil Production (2001E): 78,000 barrels per day (bbl/d), of which 28,000 bbl/d is crude oil

Oil Consumption (2001E): 2 million bbl/d

Net Oil Imports (2001E): 1.9 million bbl/d

Crude Oil Refining Capacity (1/1/02E): 1.9 million bbl/d

Natural Gas Reserves (1/1/02E): 403 billion cubic feet (Bcf)

Natural Gas Production (1999E): 0.07 trillion cubic feet (Tcf)

Natural Gas Consumption (1999E): 1.35 Tcf

Net Natural Gas Imports (1999E): 1.28 Tcf

Coal Reserves (12/31/96E): 128 million short tons (Mmst)

Coal Production (1999E): 6 Mmst

Coal Consumption (1999E): 26 Mmst

Electric Generation Capacity (1/1/99E): 108 gigawatts

Electricity Generation (1999E): 497 billion kilowatthours (bkwh), 75% nuclear, 14% hydro, 10% thermal, less than 1% other renewables

Electricity Consumption (1999E): 399 bkwh

Net Electricity Exports (1999E): 98 bkwh

ENVIRONMENTAL OVERVIEW

Minister of Regional Development and Environment: Yves Cochet

Total Energy Consumption (1999E): 10.3 quadrillion Btu* (2.7% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 108.6 million metric tons of carbon (1.7% of world carbon emissions)

Per Capita Energy Consumption (1999E): 173.5 million Btu (vs. U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 1.8 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)

Energy Intensity (1999E): 7,324 Btu/ \$1990 (vs U.S. value of 12,638 Btu/ \$1990)**

Carbon Intensity (1999E): 0.08 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (40.0%), Residential (23.8%), Transportation (20.7%), Commercial (15.5%)

Sectoral Share of Carbon Emissions (1998E): Transportation (38.7%), Industrial (34.4%), Commercial (10.7%), Residential (16.2%)

Fuel Share of Energy Consumption (1999E): Oil (40.8%), Natural Gas (14.5%), Coal (5.9%)

Fuel Share of Carbon Emissions (1999E): Oil (66.4%), Natural Gas (19.7%), Coal (13.9%)

Renewable Energy Consumption (1998E): 1,161 trillion Btu* (2% increase from 1997)

Number of People per Motor Vehicle (1998): 1.9 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified March 25th, 1994). Signatory to the Kyoto Protocol (April 29th, 1998)- not yet ratified.

Major Environmental Issues: Some forest damage from acid rain; air pollution from industrial and vehicle emissions; water pollution from urban wastes and agricultural runoff.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Climate Change-Kyoto Protocol.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International

Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

****GDP based on EIA International Energy Annual 1999.**

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January 2002

France

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BACKGROUND

One of the world's largest economies, France is a founding member of the [European Union \(EU\)](#) and a member of the Group of Seven (G-7) industrialized nations, the General Agreement on Tariffs and Trade (GATT)/World Trade Organization (WTO), the International Energy Agency (IEA), and the International Atomic Energy Agency (IAEA). France joined the common European currency, the euro, on January 1, 1999. France's economy has had stronger growth than that of many of its neighbors in recent years, having experienced a cyclical upturn since late 1997 that is now winding down. France's economy grew 3.4% in 2000, but growth is estimated to have declined to 2.1% in 2001. France's economy in 2002 will closely track the eurozone as whole, where growth for 2002 is forecast at 1.4%. Euro coins and bills were

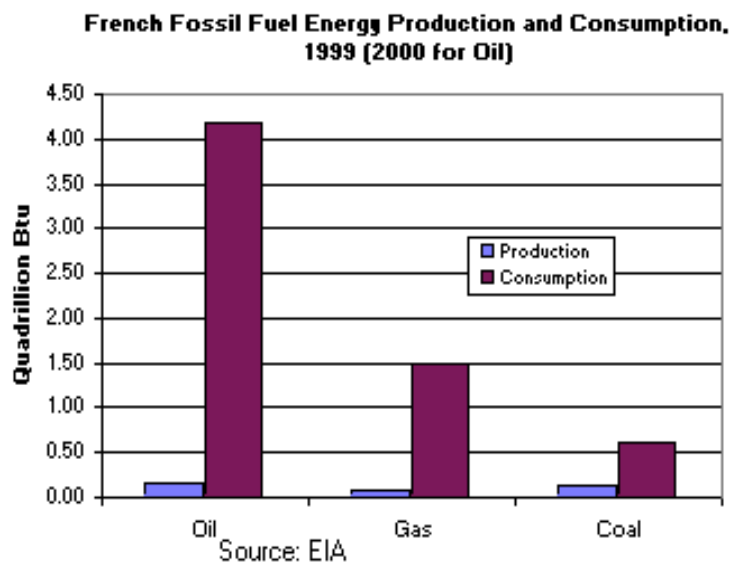
introduced beginning January 1, 2002, though the French franc has been pegged to the euro since 1999.

Traditionally, the role of the state has been stronger in France than in other Western European countries. France is one of the most centralized countries in Europe with a strong history of state ownership in the aviation, telecommunications, and energy industries. However, the role of the government now is changing. Important economic and political changes in France include widespread privatization and increasingly frequent mergers and acquisitions (M&As) and hostile corporate takeovers, once virtually unheard of in France.

International pressures of globalization and more direct pressure from the EU are behind the current trend away from government involvement in industry. The French government is headed by the moderate socialist prime minister, Lionel Jospin, and the Gaullist president, Jacques Chirac, under the French system of governmental "cohabitation." The divided government has moved very slowly toward privatization of the country's energy industry, despite an EU directive that calls for member states to relinquish control of their energy companies to the private sector. This has caused friction between France and other EU members, particularly in regard to acquisitions by Electricite de France (EdF).

ENERGY

French energy policy has been relatively consistent in recent decades, with the main objectives including: securing energy supply, achieving international competitiveness, and protecting the environment. The focus on energy security has led France to become one of the world's top producers and consumers of nuclear power. France's production of primary energy rose by 2.1% in 2000, to about 5.04 quadrillion Btu. France's energy demand rose by 1.1% to about 10.3 quadrillion Btu. However, France's total energy bill rose by 102% in 2000, to 155.2 billion French francs (FFR).



OIL

About 1.9 million barrels per day (bbl/d) of France's approximate 2 million bbl/d oil consumption are imported. France has reserves totaling only 140 million barrels. Exploration increased in 2000-2001 because of higher oil prices, and France's proven reserves increased in 2000, though they are still extremely small, and fell slightly in 2001. France's domestic crude oil production comes from numerous wells producing very small amounts of oil. Because of France's limited domestic fossil fuel energy sources, security of supply historically has been a major concern.

Despite France's limited domestic reserves and production, the French oil industry is an important actor in world energy markets. Major oil assets of French oil companies are located in the North Sea, Africa, and Latin America. French imports come primarily from Saudi Arabia and Norway, followed by the United Kingdom (UK), Iraq, Iran, Nigeria, and Russia. In July 2001, the Iraqi government stated that it would reconsider oil projects with French companies and no longer give French companies "priority" due to France's support of the U.S.-British "Smart Sanctions" proposal at the United Nations Security Council. Iraq has letters of intent with TotalFinaElf that would take effect when sanctions are lifted.

In early 1999, French oil company Total merged with Belgian oil company Petrofina to create TotalFina, the world's sixth-largest oil company and the third-largest oil company in Europe. Only months later, TotalFinaElf was formed by TotalFina's acquisition of Elf Aquitaine. After the deal was completed in 2000, TotalFinaElf became the fourth-largest publicly listed oil company in the world, after ExxonMobil, Royal Dutch/Shell, and BP. TotalFinaElf has proven reserves of about 10.8 billion barrels of oil equivalent and production of about 2.1 million bbl/d. TotalFinaElf has very little crude oil production in North America or Asia (outside of the Middle East), unlike the other super majors. The company claims to have raised hydrocarbon output by 6% in 2001 and plans to raise production by 9% in 2002 as major new resources come on stream. TotalFinaElf owns more than 50% of the refinery capacity in France, and is the seventh-largest refiner in the world.

Downstream

France's crude oil refining capacity is 1.9 million bbl/d. The country's largest refinery is TotalFinaElf's refinery at Gonfreville l'Orcher with a capacity of 323,643 bbl/d. Increasingly strict EU environmental

regulations for refineries are in large measure behind recent upgrades in the French refining sector. The regulations will become considerably more strict in 2005, and substantial investment in the refining sector will be necessary to meet these new mandatory targets. ExxonMobil has begun adapting its Port Jerome refinery to 2005 EU specifications.

Because oil security has been such a concern for French energy policy-makers, there is a French law allowing the French government to refuse to close a refinery if it believes its supply or price security is at risk. Essentially, this gives the French government veto power over EU legislation regarding refineries. This could become an important issue as the EU's environmental standards are strengthened further.

NATURAL GAS

France has very limited natural gas resources and therefore imports almost all of the natural gas it consumes. Natural gas consumption increased 3.6% in 2000, and the share of natural gas in the French energy market rose to 14.5%. Industry's share of consumption rose from 44% to 48% year-on-year 1999-2000, but household use declined from a 39% share to a 36% share year-on-year 1999-2000.

The French natural gas industry is run by Gaz de France (GdF), the state-held company with a monopoly on importation and distribution of natural gas in France. By 2003, Gaz de France aims to possess sufficient reserves to produce at least 15% of the natural gas it sells. The company's annual production capacity stands at more than 70 billion cubic feet (Bcf). GdF also has the largest underground storage capacity in western Europe, with 318 Bcf, about 3 months supply. In November 2001, the French government decided to privatize the country's natural gas transport network, allowing the operators, GdF and a subsidiary of TotalFinaElf, to purchase it. However, Communist members of parliament blocked the plan in December, though it seems likely that a version will take effect sometime in 2002. France is the only EU country that owns a franchised natural gas network. GdF has increased substantially its holdings in North Sea natural gas over the past few years, including interests in Norway's Snoehvit and Njord fields. The company acquired holdings in twelve exploration licences in the UK North Sea with an average equity of 21% from Texaco in June 2001. GdF supplies about a fifth of total French consumption from its holdings in France and abroad. Norway is France's top natural gas imports supplier, followed by Russia and Algeria. Natural gas imports from Russia have been declining in recent years, while imports from Algeria have been rising. However, there has been discussion of a new pipeline to connect Russian natural gas to France. The Netherlands is a smaller source of French natural gas imports. GdF also imports liquefied natural gas (LNG) to its two terminals. In addition to long-term contracts, GdF buys natural gas on the spot market or with short-term contracts from the UK's North Sea.

France is the only country in the EU that has not yet enacted any legislation adopting the rules of the EU's 1998 Gas Directive. However, there have been some changes in France's natural gas market since 1998. The EU directive required that 20% of member countries' natural gas markets become competitive. Without a legal basis, GdF nonetheless opened its grid to third-party access in August 2000. About 100 of the country's largest industrial consumers now are able to choose their suppliers. The companies allowed to choose other suppliers and use GdF's network are limited to 20% of the market, the minimum prescribed in the directive. However, no progress has yet been made on plans to change the status of GdF from a wholly-owned state enterprise to a joint stock company, that could then be partially privatized. Because France has been one of the slower countries to pave the way for competition, it has come under harsh criticism from the EU and fellow member countries. In September 2000, the European Commission (EC, the executive body of the EU) sent a formal warning letter to France for failure to notify the EC of national laws enacted to ensure implementation of the 1998 Natural Gas Directive. Although France adopted draft legislation in May 2000, the full national parliament has not yet passed a law to open the market, and is not likely to do so until after the parliamentary and presidential elections in the spring of 2002.

GdF is establishing France as a hub for Western European natural gas. In October 1998, France for the first time became linked via pipeline to a foreign production field. The NorFra pipeline linked Norway's Troll gas field in the North Sea to the French natural gas grid. The pipeline is 840 kilometers (521 miles) long, and is the longest undersea natural gas pipeline in the world. About half of the natural gas from the pipeline will transit through France to points in Italy and Spain, while the other half will be consumed in France. By

2005, the Norwegian pipeline is expected to supply one-third of France's total natural gas consumption. GdF is increasing its trading activities in partnership with Societe Generale, a French Bank. GdF's trading affiliate, Gaselys, carried out 600 transactions in 2000, six times the volume of 1999. GdF has invested abroad heavily, and owns distribution networks in several countries. However, France's lack of liberalization may cause problems with GdF's business in other EU countries. In 2001, Spain's Enagas refused access to its pipelines to GdF on the grounds that there is a "lack of reciprocity with France." In addition, this has prevented GdF from entering partnerships that have cross-ownership with foreign companies, such as Statoil.

GdF is constructing the Les Marches du Nord-Est pipeline in two parts. The first 124-mile part went operational in October 2001, and the second 186-mile part is expected to go operational in October 2002. GdF has signed a 25-year contract with Italy's Snam for delivery of 6 billion cubic meters (Bcm, or 212 Bcf) of Norwegian natural gas through the pipeline. GdF plans to spend \$2.5 billion 2001-2003 on developing its pipeline network and installations in France.

Liquefied Natural Gas

GdF has two liquefied natural gas (LNG) terminals: the 159-Bcf-per-year capacity facility at Fos-sur-Mer near Marseille and the 353-Bcf-per-year capacity facility at Montoir-de-Bretagne, near Nantes. Increasing France's importance as a transit center, GdF receives Nigerian LNG at its Montoir-de-Bretagne terminal that is swapped out to Italy's Enel. The terminal receives 4 Bcm (141 Bcf) annually, 3.5 Bcm (124 Bcf) under the Italian contract and 0.5 Bcm (18 Bcf) under a contract signed by GdF.

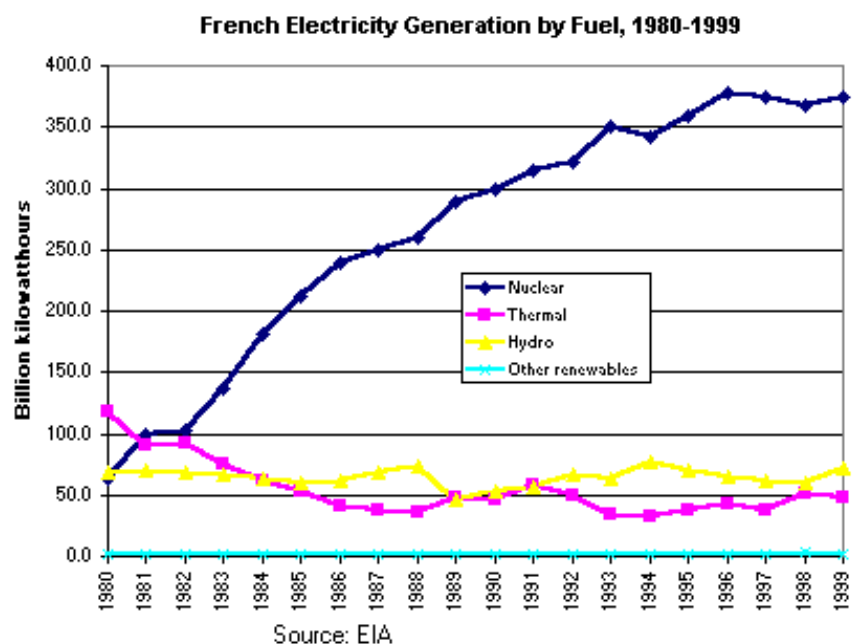
COAL

France has very limited coal reserves and neither produces nor consumes significant amounts of coal. Coal-fired electricity has been mostly replaced by nuclear power. Coal imports come from Australia, the United States, and South Africa.

The French government has supported the coal industry since the 1994 National Coal Pact between Charbonnages de France (CdF), the state coal company, and French coal miners unions. According to the agreement, the industry would receive state support as it gradually phased out the industry all together. All French coal mines are slated to be shut down by 2005. In May 2001, the EC authorized France to pay EUR 991 million in state aid to the coal industry. The number of mine workers is to have been reduced to 2,800 at the end of 2001 and production to just 2.2 million short tons, according to the government's plan.

ELECTRICITY

France is the second-largest electricity market in Europe (behind Germany). France's electricity sector is dominated by the state-held monopolist, Electricite de France (EdF), which produces, transports, and distributes over 95% of electricity in France. EdF is the last major state-run electricity monopolist in the EU, as most of France's neighbors have privatized their electricity companies. However, there has been partial liberalization of some aspects of France's electricity sector.



A 1996 EU directive required that at least 26% of electricity sales in member counties be opened to competition, beginning in February 1999. This requirement increased to 28% in February 2000 and will

increase further to 33% in 2003. In February 2000, a full year after the first EU deadline, France passed legislation that began the electricity sector's liberalization. Since that time, about 1,800 large industrial and commercial consumers (those using more than 16 million kilowatthours per year) comprising about 30% of the market have been able to choose their electricity supplier (although few of these consumers actually have changed suppliers). There has been criticism that the February 2000 law's requirement of three-year contracts is an obstacle to the real establishment of a free market.

Another step toward liberalization has been the creation of the Electricity Transmission Network (Reseau de Transport d'Electricite, RTE) that owns the country's high tension transmission network. RTE's mission is to assure all clients fair access to the network. The single tariff for international electricity transport proposed by RTE was given a positive reception by the European council of energy ministers in May 2001. In addition, an energy regulatory body has been established to oversee the deregulation process. The Commission for the Regulation of Electricity (CRE), which also will oversee natural gas deregulation when the time comes, has four main purposes: (1) advising the government in nearly all matters relating to electricity, (2) the close monitoring of the rules governing the access to the networks and compliance therewith, (3) the auditing of EdF's unbundled accounts, and (4) sanctions against infringements in certain cases, mainly in relation to network access. CRE is gradually taking on more responsibility as liberalization continues.

In late November 2001, the Powernext electricity trading market was launched in France. Powernext auctions standard hourly contracts for physical delivery of electricity to business customers under responsibility of the RTE and guaranteed by Clearnet, a subsidiary of the Euronext stock exchange. Powernext aims to trade 10% of the French market by 2003-2004, and also to act as a price reference for the electricity market. In an additional liberalizing step, in accordance with the terms of EdF's acquisition of a controlling stake in Germany's EnBW, EdF sold 1200 megawatts (MW) of virtual power capacity to some 20 competitors (generators, traders, etc.), French and foreign, in 2001.

There are currently only two companies of any size in France that may be able to compete on a limited basis with EdF in the future. France's second-largest electricity group is Compagnie Nationale de Rhone (CNR), which produces about 3% of France's electricity, mostly from hydroelectric plants. In August 2001, a company for the commercialization of CNR's production was created by CNR and Electrabel of Belgium that is called Energie du Rhone. It will also market electricity produced by Electrabel. The French government has made EdF divest itself from its small holding in CNR in an effort to liberalize the market. The other producer is SNET, a subsidiary of French coal utility Charbonnages de France. In an effort to get into the French market, ENDESA of Spain has purchased about 30% of SNET. Because of interconnectors, other foreign companies are also attempting to get a foothold in the French electricity market. So far, EnBW (34.5% owned by EdF) and RWE, both of Germany, have attracted a small amount of industrial customers.

EdF has come under criticism and scrutiny from member EU countries, the European Commission (EC), and others on several counts. One is that liberalization around the world, and in the EU in particular, has made many electricity assets available abroad while EdF's assets (which are about 95% of the market) are unavailable. Hence, EdF can purchase foreign companies, but foreign companies cannot purchase assets in France. Another charge is that EdF's status as a state-owned monopoly has made it easier for it to purchase and outbid competitors abroad. EdF allegedly enjoys a lower cost of capital than private-sector rivals and a management that can focus on expansion rather than domestic competitors. In addition, it is alleged that taxpayers finance the expansion while the company does not have to justify its expansion to shareholders as would be necessary in a private sector company. In June 2001, the EC launched an investigation into EdF to see whether the company has benefitted from illegal state aid such as tax breaks or certain financial guarantees.

In any event, EdF has made many large foreign purchases in the past few years, such that 25% of EdF's 2000 revenues of EUR 34.4 billion came from assets in 19 foreign countries. The contract between the French government and EdF for 2001-2003 plans for EUR 19 billion in purchases abroad by 2005. In response, Spain and Italy passed laws or adopted regulations that make it difficult for EdF to purchase their

electricity assets. Spain compromised October by allowing the takeover of part of Hidrocantabrico in return for France increasing the interconnection between the two countries from 1,000 MW to 4,000 MW by 2006. In terms of Italy's law, the EC ruled in June 2001, that capital flows may not be restricted merely because of varying degrees of liberalization. However, the initial privatization sale may be restricted, but such restrictions can only be in place for a limited period, after which the privatized companies can be resold to state-owned companies.

In December 2001, Laurent Fabius, Minister for Finance and the Economy, stated his opposition to a proposed 5% increase in electricity rates by EdF in 2002. EdF raised rates 1% in November 2001.

Nuclear

France is the world's largest nuclear power generator on a per capita basis, and ranks second in total installed nuclear capacity (behind the United States). Because of France's extremely limited domestic energy sources, energy supply security and reliance on imports are major issues in France. Government policy has promoted a dramatic increase in nuclear power generation over the past three decades. Currently, about 75% of French electricity comes from France's 57 nuclear power plants. This represents a dramatic change from 1973, when fossil fuels accounted for more than 80% of French power generation. The government nuclear regulator is DSIN, and EdF operates the plants. In July 2001, France and the United States signed an accord to jointly fund U.S.-French research on advanced reactors and fuel cycle development.

France is now seen to be retreating slowly from its staunchly pro-nuclear position. Previously, the government planned to have nuclear power reach 100% of electricity generation. Environmental objections have increased in recent years. Germany's decision to phase out nuclear power started a public debate within France about the future of its own industry, and public opinion polls showed that a growing percentage of the public favors an end to nuclear power.

France now must decide whether to replace obsolete nuclear plants with more modern nuclear plants, or to begin phasing out nuclear power. Since 1997, the ruling government of Prime Minister Jospin has included members of the Green Party, *Les Verts*. The government has generally come to the conclusion that the volume of nuclear capacity exceeds its economically efficient contribution to the electricity market. Nevertheless, costs will fall when plants continue functioning past their 30-year capital amortisation periods, though how much longer they can function past thirty years is an open question.

In July 2001, the reorganization of the French nuclear sector commenced with the nomination of a management committee for a new holding company, Topco, that will preside over the country's major nuclear enterprises. Its nuclear operations will include mining, fuels, treatment, recycling, decontamination and engineering. As part of a restructuring program announced in Nov 2000, CEA-Industrie, Cogema and Framatome announced plans to merge Framatome with a company holding Cogema's stakes in Framatome, Eramet, TotalFinaElf and Cogera. CEA-Industrie is the holding company for the state's Commissariat a l'Energie Atomique. The capital of the new company - Topco - eventually would be open to industrial partners and the amount of stock available on the market would be increased over time. The EC required this new structure in order to approve the merger of Framatome's nuclear business with that of Siemens of Germany that was approved in February 2001. EdF divested itself of Framatome, and EdF will now be able to have competitive bidding for nuclear services and supplies that formerly had been exclusively sourced from Framatome.

France is one the few countries in the world with a nuclear reprocessing plant. Cogema's La Hague facility received authorization from DSIN to start operations of two new facilities, hull and end-pieces compacting and plutonium purification and conditioning, in January 2002.

ENVIRONMENT

In terms of [environmental issues](#), France is noted for using nuclear energy that results in less greenhouse gases, but this creates other environmental concerns. The country's lack of fossil fuel resources, in addition

to making France keenly aware of the importance of energy security, paradoxically has made France rely on cleaner energy sources. However, [air pollution](#), especially in Paris, remains a pertinent environmental issue to urban dwellers.

In general, however, most energy-related environmental trends in France appear to be headed for greater efficiency and less environmental impact. The country's rate of [energy consumption](#) is holding steady, and France's [energy and carbon intensity](#) are on the decline. In addition, France has announced an extensive 10-year plan to curb its [carbon emissions](#) in order to meet its commitments under the Kyoto Protocol—one of the first countries to do so.

As part of this plan, France has reiterated its need to develop [renewable energy sources](#) to maintain its energy self-sufficiency. Although [nuclear energy](#) has helped to provide France with the energy independence the country desires, objections to nuclear energy are increasing. In the [21st century](#) energy efficiency measures in all sectors of the economy likely will be needed in order to make further environmental improvement a realistic proposition.

Sources for this report include: CIA World Factbook; Dow Jones News Wire service; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Petroleum Economist; Petroleum Intelligence Weekly; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

President: Jacques Chirac (since May 1995)

Prime Minister: Lionel Jospin (since June 1997)

Independence: 486 (unified by Clovis)

Population (July 2001E): 59.6 million

Location/Size: Western Europe, bordering the Bay of Biscay and English Channel, between Belgium and Spain southeast of the UK; bordering the Mediterranean Sea, between Italy and Spain/547,030 sq km (slightly less than twice the size of Colorado)

Language: French 100%, rapidly declining regional dialects and languages (Provençal, Breton, Alsatian, Corsican, Catalan, Basque, Flemish)

Ethnic groups: Celtic and Latin with Teutonic, Slavic, North African, Indochinese, Basque minorities

Religions: Roman Catholic 90%, Protestant 2%, Jewish 1%, Muslim (North African workers) 3%, unaffiliated 4%

Defense (8/98): Army 203,200; Air Force 78,100; Navy 63,300

ECONOMIC OVERVIEW

Economy, Finance, and Industry Minister: Laurent Fabius

Currency: Euro (EUR)

Exchange Rate (1/10/02): 1 U.S. Dollar = EUR 1.12

Gross Domestic Product (GDP, 2001E): \$1.21 trillion

Real GDP Growth Rate (2001E): 2.1% **(2002F):** 1.1%

Inflation Rate (consumer prices, 2001E): 1.7% **(2002F):** 1.3%

Unemployment Rate (2001E): 8.9% **(2002F):** 9.8%

Exports of Goods and Services (2001E): \$294.3 billion

Imports of Goods and Services (2001E): \$295.3 billion

Major Trading Partners: Germany, Italy, Belgium, the United Kingdom, the United States

Major Export Products: Machinery and transport equipment, agricultural products, chemical products

Major Import Products: Machinery and transport equipment, agricultural products, chemical products, and energy

ENERGY OVERVIEW

Proven Oil Reserves (1/1/02E): 140 million barrels

Oil Production (2001E): 78,000 barrels per day (bbl/d), of which 28,000 bbl/d is crude oil

Oil Consumption (2001E): 2 million bbl/d

Net Oil Imports (2001E): 1.9 million bbl/d

Crude Oil Refining Capacity (1/1/02E): 1.9 million bbl/d

Natural Gas Reserves (1/1/02E): 403 billion cubic feet (Bcf)

Natural Gas Production (1999E): 0.07 trillion cubic feet (Tcf)

Natural Gas Consumption (1999E): 1.35 Tcf

Net Natural Gas Imports (1999E): 1.28 Tcf

Coal Reserves (12/31/96E): 128 million short tons (Mmst)

Coal Production (1999E): 6 Mmst

Coal Consumption (1999E): 26 Mmst

Electric Generation Capacity (1/1/99E): 108 gigawatts

Electricity Generation (1999E): 497 billion kilowatthours (bkwh), 75% nuclear, 14% hydro, 10% thermal, less than 1% other renewables

Electricity Consumption (1999E): 399 bkwh

Net Electricity Exports (1999E): 98 bkwh

ENVIRONMENTAL OVERVIEW

Minister of Regional Development and Environment: Yves Cochet

Total Energy Consumption (1999E): 10.3 quadrillion Btu* (2.7% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 108.6 million metric tons of carbon (1.7% of world carbon emissions)

Per Capita Energy Consumption (1999E): 173.5 million Btu (vs. U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 1.8 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)

Energy Intensity (1999E): 7,324 Btu/ \$1990 (vs U.S. value of 12,638 Btu/ \$1990)**

Carbon Intensity (1999E): 0.08 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (40.0%), Residential (23.8%), Transportation (20.7%), Commercial (15.5%)

Sectoral Share of Carbon Emissions (1998E): Transportation (38.7%), Industrial (34.4%), Commercial (10.7%), Residential (16.2%)

Fuel Share of Energy Consumption (1999E): Oil (40.8%), Natural Gas (14.5%), Coal (5.9%)

Fuel Share of Carbon Emissions (1999E): Oil (66.4%), Natural Gas (19.7%), Coal (13.9%)

Renewable Energy Consumption (1998E): 1,161 trillion Btu* (2% increase from 1997)

Number of People per Motor Vehicle (1998): 1.9 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified March 25th, 1994). Signatory to the Kyoto Protocol (April 29th, 1998)- not yet ratified.

Major Environmental Issues: Some forest damage from acid rain; air pollution from industrial and vehicle emissions; water pollution from urban wastes and agricultural runoff.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Climate Change-Kyoto Protocol.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Links

For more information from EIA on France, please see:

[EIA - Country Information on France](#)

Links to other U.S. Government sites:

[CIA World Factbook - France](#)

[U.S. Department of Energy on French Nuclear Sector](#)

[U.S. State Department Consular Information Sheet - France](#)

[U.S. Department of Commerce Country Commercial Guide - France](#)

[U.S. State Department Background Notes on France](#)

[U.S. Embassy in France](#)

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[French Embassy in the United States](#)

[French Embassy in the United States, Office for Nuclear Affairs](#)

[French Agency for Environment and Energy Management \(ADEME\)](#)

[Gaz de France](#)

[Charbonnages de France](#)

[Electricite de France](#)

[TotalFinaElf](#)

[International Energy Agency on France](#)

[European Commission Directorate General XVII \(Energy\)](#)

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Regional Indicators: European Union (EU)

The European Union, with increasingly integrated economies and energy sectors, is the world's second-largest energy consumer (behind the United States). EU members include: [Austria](#), [Belgium](#), [Denmark](#), [Finland](#), [France](#), [Germany](#), [Greece](#), [Ireland](#), [Italy](#), [Luxembourg](#), [the Netherlands](#), [Portugal](#), [Spain](#), [Sweden](#), and the [United Kingdom](#).

Note: Information contained in this report is the best available as of October 2001 and is subject to change.

BACKGROUND

The European Union (EU) was founded as the European Economic Community (EEC) by the Treaty of Rome in 1957 to promote economic and political integration in Europe. The founding of the EEC followed the creation of the European Coal and Steel Community, established after World War II as a means of promoting integration among former enemies. The EEC has expanded from its original six members (Belgium, France, the Federal Republic of Germany, Italy, Luxembourg, and the Netherlands) to include the United Kingdom, Ireland, and Denmark in 1973; Greece in 1981; Spain and Portugal in 1986; and Austria, Finland, and Sweden (former members of the European Free Trade Association) in 1995. The Treaty on European Union (known as the Maastricht Treaty) ushered in a new stage in European history when it entered into force on November 1, 1993. Maastricht renamed the community (now known as the EU), created European citizenship, strengthened the power of the European Parliament, laid out plans for Economic and Monetary Union (EMU), and committed members to negotiate for expansion of the EU to include Central and Eastern European countries. In 2000, EU members were estimated to account for 29% of world economic activity (see [Table 1](#)), a share that remained about constant during the 1990s. The United States has extensive trade relations with the EU. In 2000, 22% of U.S. exports (\$152 billion) went to EU members, and 19% of U.S. imports (\$195 billion) originated in EU countries.



As part of EMU, 11 EU member countries (Belgium, France, Germany, Italy, Spain, Portugal, Finland, Austria, the Netherlands, Ireland and Luxembourg) adopted a new common European currency, called the "euro," on January 1, 1999. The European Central Bank (ECB) is housed in Frankfurt, Germany. This means that a single monetary policy for the 12 participating countries is elaborated at the ECB. Euro banknotes and coins are scheduled to begin circulating in all participating countries no later than January 1, 2002, and the euro is to replace completely all participating countries' national currencies by July 1, 2002. Most countries' banks have already been frontloaded with coins and banknotes, starting in September 2001.

Greece was the only EU member country that applied but was denied entry to EMU at its introduction; in June 2000, Greece's application was accepted and Greece became a member of the euro-zone on January 1, 2001. The

United Kingdom and Denmark opted out and Sweden purposely did not meet requirements. The euro-zone represents about 80% of the EU's GDP. The euro currently functions as a base currency for the currencies of all the countries participating in the euro; they are all fixed to the euro, and although the euro is not used as banknotes or coinage, the euro is the only currency that fluctuates in value with other currencies, including the U.S. dollar. The euro fell in value initially against the dollar, from being worth \$1.18 in January 1999, to about \$1.00 by the end of 1999, and \$0.85 in October 2000, before rising again to \$0.93 in January 2001. Since then, the euro has stabilized at between \$0.93 and \$0.85, being valued most recently at \$0.91.

In 2001, the Treaty of Nice was signed by member governments. This treaty changes the way the institutions of the EU operate in order to make possible the admission of new member states in the future. Central and Eastern European EU applicants expected to join in the next phase of EU expansion include Poland, Hungary, the Czech Republic, Estonia, Slovenia and Cyprus. Some EU members are calling for a target date by which these applicants will be admitted officially. No date has been set, but membership is expected to extend to these six countries by about 2005. Slovakia, Bulgaria, Romania, Latvia, Lithuania, Turkey and Malta also have begun discussions of accession.

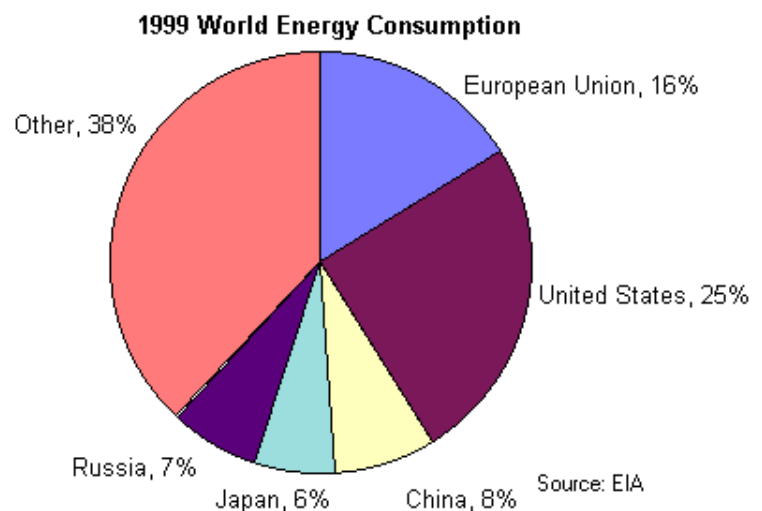
EU legislation has played a significant role in member countries' domestic energy policies. The [EU Directive on Electricity](#) was passed in January 1997 and required members to begin opening up their electricity markets to competition within two years (Greece, Belgium and Ireland were granted waivers). The [EU Natural Gas Directive](#) was passed in June 1998 (Greece, Belgium, and Ireland again were granted waivers), requiring the opening of EU members' gas markets. The Gas Directive has also affected Norway, as it is a member of the European Economic Area (EEA).

ENERGY CONSUMPTION

In 1999, EU countries consumed 62.7 quadrillion British thermal units (Btu) of energy (16% of the world's total) and generated 915 million metric tons of energy-related carbon emissions (15% of the world's total). Oil is the dominant fuel (see [Table 2](#)), accounting for 44% of 1999 total energy consumption in the region, followed by natural gas at 22%. In 1999, EU members consumed about 34% of the world's nuclear power, 18% of the world's oil, 16% of the world's natural gas, and over 10% of the world's coal. Over the past decade, natural gas has been the fastest growing fuel source in the EU, mainly at the expense of coal, whose share has declined sharply. This is in part due to environmental

considerations, but also due to increased availability of natural gas supplies because of pipelines from Algeria, Norway, and Russia. Nuclear power generation has grown only slightly over the past decade. Nuclear power is gradually being phased out in Germany over the next twenty years, so its share of EU energy consumption is likely to drop. Hydroelectric power generation has remained about constant over the past decade. Other "renewables" (geothermal, biomass, solar, wind) doubled between 1992 and 1999, from a relatively small base level. Renewable energy and natural gas are expected to be the two fastest growing fuels in the EU over the next 20 years.

The combined economies of the EU are similar in size to the U.S. economy (\$8.5 trillion gross domestic product for the EU in 2000 and \$10 trillion for the United States), and the EU population of 379 million exceeds the U.S. population of 278 million. However, EU total energy consumption for 1999 of 63 quads is less than the U.S.



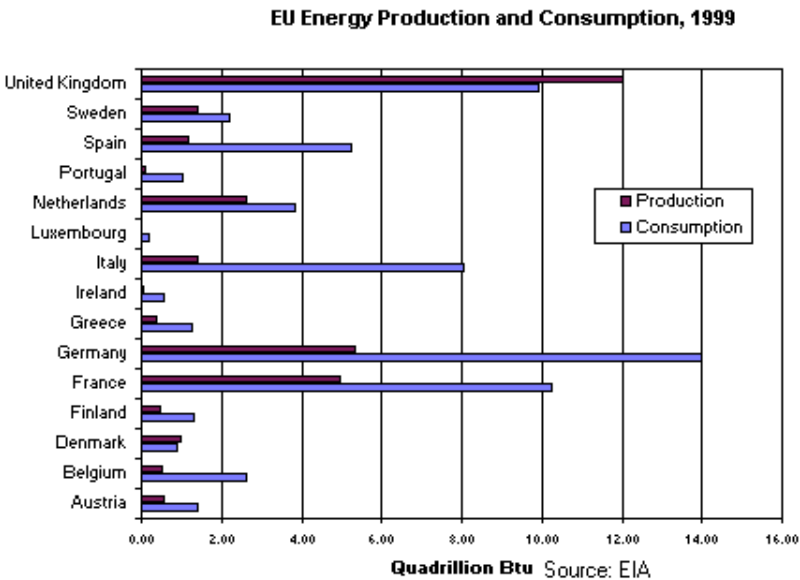
consumption of 97 quads.

ENERGY RESOURCES AND SUPPLY

EU members possess only about 0.7% of the world's proven reserves of oil and 2.2% of the world's natural gas reserves (see [Table 3](#)). However, they have 7.4% of proven coal reserves, 16% of the world's capacity for refining crude oil into petroleum products, and 16% of the world's electric generating capacity. In 1999, they produced 5% of the world's crude oil, 9% of the world's natural gas, and 8% of the world's coal.

IMPORT DEPENDENCY

The EU region is a net importer of energy. In 1999, while the EU's 15 members consumed 16% of the world's energy, they produced only 8%. Import dependency varies by fuel and individual country, with an overall import dependency for the entire EU of around 50%. In 1999, the EU was a net importer of coal (8% of world production in terms of tonnage vs. 11% of consumption in terms of tonnage); natural gas (9% of world production vs. 16% of consumption); and oil (5% of world production vs. 18% of consumption). Germany, Italy, and France are the EU's largest net importers of energy; the United Kingdom is the only significant net exporter. EU oil is imported primarily from Russia, the Persian Gulf region, Norway, and North Africa.



ENERGY USE AND CARBON EMISSIONS

The 15 EU countries collectively emitted 915 million metric tons (Mmt) of carbon from the consumption of fossil fuels in 1999. This accounted for 15% of world carbon emissions in that year. Of the EU countries, Germany emitted the most carbon (230 Mmt), followed by the United Kingdom (152 Mmt), Italy (121 Mmt) and France (109 Mmt). Overall, the EU emitted 2.4 metric tons of carbon per person in 1999, compared to a U.S. average of 5.6 metric tons per person. Under the December 1997 Kyoto Protocol, the EU is obligated to reduce its greenhouse gas emissions 8% from 1990 levels (in that year, the EU emitted 913 Mmt of carbon) by 2008-2012. All EU member states signed the Kyoto Protocol on April 29, 1998. On June 17, 1998, the EU agreed on how it would meet the 8% reduction. Under this agreement, different EU member states are assigned varying degrees of emission cuts, ranging from a 4% increase in the case of Sweden, to a reduction of 28% in the case of Luxembourg, with other countries somewhere in between.

Table 1. Economic and Demographic Indicators for EU Countries

Table 1. Economic and Demographic Indicators for EU Countries					
	Gross Domestic Product (GDP) (purchasing power parity)				Population, 2001E (Millions)
	2000E (Billions of U.S. Dollars)	Real GDP Growth Rate		Per Capita, 2000E(U.S. Dollars)	
		2000 Estimate	2001 Projection		

Austria	\$203	3.1%	2.6%	\$25,000	8.2
Belgium	\$259.2	4.1%	2.5%	\$25,300	10.3
Denmark	\$136.2	2.8%	2.2%	\$25,500	5.4
Finland	\$118.3	5.6%	4%	\$22,900	5.2
France	\$1,448	3.1%	2.7%	\$24,400	59.6
Germany	\$1,936	3%	2.4%	\$23,400	83
Greece	\$181.9	3.8%	3.9%	\$17,200	10.6
Ireland	\$81.9	9.9%	8.4%	\$21,600	3.8
Italy	\$1,273	2.7%	2.5%	\$22,100	57.7
Luxembourg	15.9	5.7%	5.5%	\$36,400	0.4
Netherlands	\$388.4	4%	3.2%	\$24,400	16
Portugal	\$159	2.7%	2.8%	\$15,800	10
Spain	\$720.8	4%	4.4%	\$18,000	40
Sweden	\$197	4.3%	2.8%	\$22,200	8.9
United Kingdom	\$1,360	3%	2.4%	\$22,800	59.6
Total	\$8,478.6	3.3%	2.8%	\$22,446	378.7

Source: CIA, WEFA World Economic Outlook.

Table 2. Energy Consumption and Carbon Emissions in EU Countries, 1999

	Energy Consumption								Carbon Emissions (Million metric tons)
	Total (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Renewable Electricity	Net Electricity Imports	
Austria	1.39	39%	22%	9%	0%	30%	1%	-1%	18

Belgium	2.61	46%	23%	12%	18%	0.1%	0.4%	0.3%	38
Denmark	0.89	53%	23%	22%	0%	0.03%	5%	-3%	17
Finland	1.31	34%	11%	11%	17%	10%	8%	9%	13
France	10.26	41%	14%	6%	38%	7%	0.2%	-6%	109
Germany	13.98	41%	21%	23%	12%	1%	1%	0.1%	230
Greece	1.28	63%	4%	29%	0%	4%	0.3%	0.1%	26
Ireland	0.56	62%	23%	12%	0%	2%	0.5%	0.4%	10
Italy	8.04	51%	30%	6%	0%	6%	1%	5%	121
Luxembourg	0.19	49%	15%	2%	0%	2%	0.4%	31%	2
Netherlands	3.85	45%	40%	8%	1%	0.03%	1%	5%	64
Portugal	1.02	68%	8%	15%	0%	7%	1%	-1%	17
Spain	5.23	57%	11%	14%	11%	5%	1%	1%	82
Sweden	2.20	34%	1%	4%	30%	33%	1%	-4%	16
United Kingdom	9.92	35%	35%	16%	11%	1%	1%	%	152
Total	62.73	44%	22%	13%	14%	5%	1%	0.4%	915

Source: Energy Information Administration *Note: Percentages may not add to 100% due to independent rounding.*

Table 3. Energy Supply Indicators--EU Countries

	Fossil Fuel Proved Reserves			Fossil Fuel Production, 1999			Electric Generating Capacity, 1/1/99 (Million kilowatts)	Crude Oil Refining Capacity, 1/1/01 (Thousand barrels/day)
	Crude Oil, 1/1/01 (Million barrels)	Natural Gas, 1/1/01 (Trillion cubic feet)	Coal (Billion short tons)	Oil (Crude, liquids, and processing gain; Thousand barrels/day)	Natural Gas (Trillion cubic feet)	Coal (Million short tons)		

Austria	86	0.9	0.0	21	0.1	1.3	14	209
Belgium	0	0.0	0.0	12	0.0	0.4	13	768
Denmark	1,069	3.4	0.0	304	0.3	0.0	13	176
Finland	0	0.0	0.0	0	0.0	0.0	16	200
France	145	0.5	0.1	80	0.1	6.3	108	1,895
Germany	380	11.5	73.9	132	0.8	226.1	108	2,259
Greece	10	0.0	3.2	4	0.0	67.2	9	407
Ireland	0	0.7	0.0	1	0.0	0.0	4	71
Italy	622	8.1	0.0	147	0.6	0.0	66	2,359
Luxembourg	0	0.0	0.0	0	0.0	0.0	0	0
Netherlands	107	62.5	0.5	114	2.6	0.0	14	1,204
Portugal	0	0.0	0.0	2	0.0	0.0	10	304
Spain	21	0.0	0.7	20	0.0	26.7	45	1,294
Sweden	0	0.0	0.0	0	0.0	0.0	33	423
U.K.	5,003	26.8	1.7	2,967	3.5	40.9	70	1,771
Total	7,443	114.4	80.1	3,804	8.0	368.9	523	13,340

Sources: Energy Information Administration, *Oil & Gas Journal*.

Sources for this report include: Energy Information Administration, International Energy Agency; European Union; Oil and Gas Journal.

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United States Energy Information Administration

May 2000

France: Environmental Issues

Introduction

After being hard hit by the oil shocks of the 1970s, France dedicated itself to attaining energy independence and improving its environment. With few fossil energy resources and only small opportunities for increasing electricity generation using hydropower, however, France imported almost all of the oil and gas it used at that time. Since the late 1970s, however, and despite its lack of fossil fuel resources, France has reduced its energy import dependence, largely by developing and expanding its domestic nuclear power program.

In addition to reducing energy imports, France's nuclear program has become a critical component of the country's environmental protection efforts, which began in earnest with the establishment of the French Ministry of the Environment in 1971. By developing and enhancing nuclear energy options, France has been able to adhere to the goals stated in the Environment Ministry's mission: monitor the environment, protect nature, prevent, reduce, or totally eliminate pollution and other nuisances, and enhance the quality of life. The Ministry has carried out its mission in two main ways -- by preserving and protecting spaces and species, and by developing research to improve environmental knowledge.

In addition to the use of nuclear energy, which has reduced pollution from carbon emissions and other greenhouse gases, significant efforts by the French government to improve energy efficiency and promote conservation have resulted in a relatively low level of energy intensity. However, while the overall trends have been very positive for France's environment, several recent events have had negative impacts and resulted in significant environmental damage.

Recent Problems

***Erika* Oil Spill**

On December 12, 1999, the Maltese-registered oil tanker *Erika* broke in two and sank in stormy seas off the Brittany coast of France, spilling nearly 90,000 barrels of heavy oil into the Bay of Biscay. Although the oil spill occurred over 50 miles from shore, stormy weather and easterly winds conspired against cleanup efforts, and on Christmas Day part of the 14-mile oil slick began washing up on the French coastline, killing tens of thousands of birds and endangering fishing grounds, and eventually covering a 250-mile stretch of coastline. Total Fina Elf, the French-Belgian oil company that chartered the *Erika* from an Italian management company, at first pledged \$85 million to clean up the spill, then vowed to make a larger financial contribution, as well as agreeing to fund directly the pumping of some 150,000 barrels of fuel oil remaining in the sunken hull of the ship. France also sought emergency funds from the European Union to clean up the pollution, as well as funding for a European oil spill monitoring service.



In response to the *Erika* disaster--which occurred because of corrosion in a bulkhead, creating structural weakness that caused the ship to break in two--the European Parliament passed a resolution urging member states to impose tougher shipping laws. French President Jacques Chirac has called for stricter ship inspections, and the French government has vowed to make shippers pay for damage caused by their products--France is likely to push this agenda when it holds the rotating presidency of the EU during the second half of 2000. Chirac also called for tougher controls on ships flying so-called "flags of convenience" from countries with less stringent environmental legislation and regulation.

Natural Disasters: Storms

Unfortunately for France, environmental damage from the *Erika* spill was exacerbated by a series of storms that ripped through France in late December 1999. In addition to hindering cleanup of oil along the coastline, the unprecedented storms devastated large parts of France, destroying between 260 million and 300 million trees and causing major damage to Electricité de France's transmission system, which left 3.4 million customers without power for up to several days. Officials have estimated that the total cost of the storms could run to \$12 billion.

Nitrate-Polluted Water

The European Union recently began legal proceedings against France for failure to respect EU

environmental protection laws. France was admonished for "non-respect" of the EU's Nitrates Directive, which aims to curb the introduction of excessive levels of nitrates into surface waters, groundwater, and marine waters from fertilizers and waste. Excessive nitrate levels cause harmful algal blooms and have adverse public health implications. The EU cited France for failing to identify nitrate-polluted or threatened waters in accordance with the criteria set down in the Directive, noting that France has not chosen to apply the Directive throughout its territory, instead designating specific vulnerable zones.

Air Pollution

Pollution from transportation has become the main cause of air pollution in France. According to a European Commission report, over 50% of emissions of polluting agents such as nitrogen oxides (NOx) or carbon monoxide come from road transport vehicles. A European Commission survey found that 70% of Europeans were more worried in 1999 than they were in 1994 about air quality. In addition, the survey found that air pollution was at the top of Europeans' list of environmental concerns, with traffic being blamed as the number one culprit.

In Paris, about 3 million cars enter the capital daily, and the resulting smog that engulfs the city causes health problems like asthma and chronic coughing, filling emergency rooms with people suffering from bronchial ailments. The French tourist industry is becoming worried that visitors to Paris will depart with memories of clogged streets, hazy skies, and pictures of the Eiffel Tower shrouded in smoke. France is also the biggest emitter of dioxins in Europe.

To control its air pollution problem, the French Environment and Energy Control Agency (ADEME) is attempting to equip the country with a monitoring system that meets the requirements of the national Air Pollution Act. The International Energy Agency (IEA) has recommended that France increase its air quality monitoring and emission reduction efforts, as well as formulate and implement measures to enhance the use of environmentally sound fuels in order to tackle urban pollution problems. In addition to supporting investments to clean up industrial processes, ADEME is stepping up its work in the transport sector, attempting to change individuals' behavior by encouraging the use of public transport.

In that vein, European Car-Free Day is scheduled for September 22, 2000. Environmentalists are hoping this "day without cars," which is being held for the third time, will force drivers to think about pollution and their role in creating it. On September 22, 1999, 66 French towns (almost twice as many as in 1998) participated in the car-free day. In areas where air quality was monitored, pollution directly linked to automobile traffic dropped considerably--between 20 and 50% depending on the pollutants and the towns.

In addition, in July 1999 BP Amoco announced the introduction of a range of cleaner fuels for motorists in the Paris region, which should lead to a significant reduction in automobile and transport emissions. The new Ultra Low Sulfur Diesel (ULSD), which was launched in Paris in September 1999, reduces emissions by 90% on all diesel vehicles, without any detrimental impact on performance and at no extra cost. BP claims that ULSD also reduces other emissions substantially and enables new particulate reduction technology to be fitted on buses and other

transport vehicles

Energy Consumption

France's total energy consumption in 1998 was 10 quadrillion Btu, 2.6% of the world's total energy consumption. After holding steady for most of the 1980s, French energy consumption, which was 8.5 quads in 1980, rose significantly in the early 1990s. (The upward trend now has slowed.) Even with this increase, 1998 per capita energy consumption in France, at 170 million Btu, was less than half the level of the United States (350.7 million Btu per capita energy consumption).

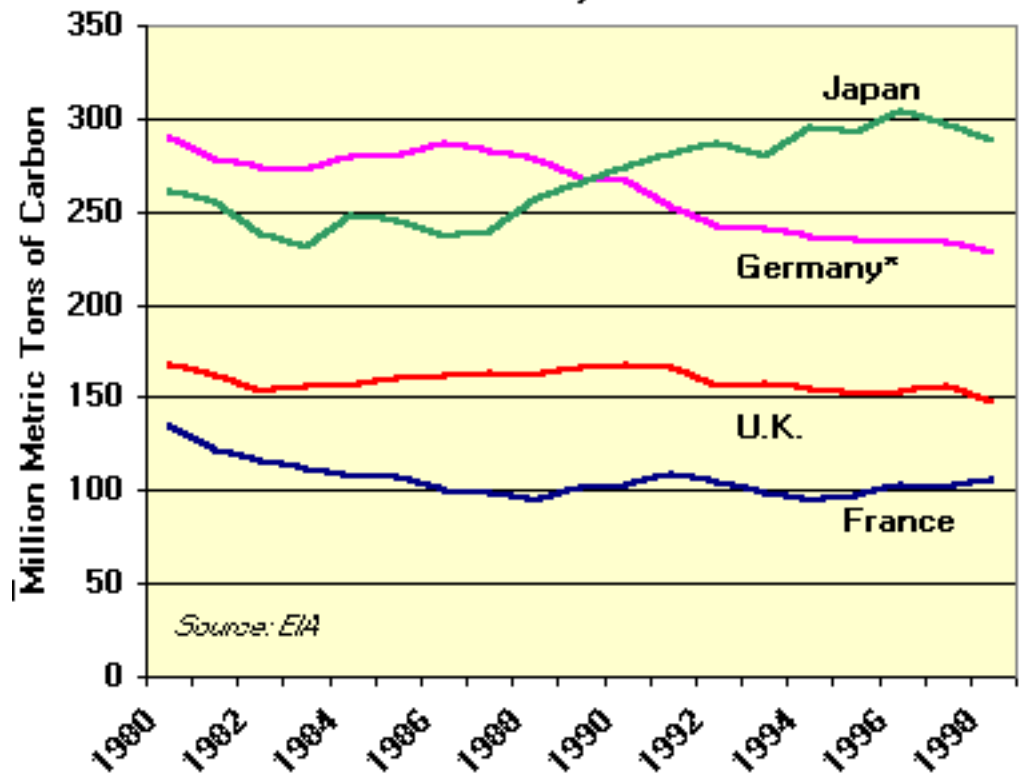
Industrial consumption accounted for 40.3% of France's total energy consumption in 1997, with residential at 23.8%, transportation at 20.3%, and commercial at 15.6%. The transportation sector increase its overall energy consumption by 3.5% in 1998, following a 2.4% boost in 1997, and transportation may soon overtake residential as the number two energy-consuming sector in France.

On January 19th, the French government released its plan to discourage consumption of fossil fuels while relaunching France's energy management policy. The program seeks to discourage consumption through the use of ecological tax measures, targeting corporations as well as individuals by taxing polluting behavior while rewarding "ecologically useful conduct" with reductions in the value-added tax.

Carbon and Energy-Related Emissions

In 1998, France emitted 106.6 million metric tons of carbon compared to 147.4 million metric tons of carbon in the United Kingdom, 227.5 million metric tons in Germany, 288.5 million in Japan, and 1,494.6 million in the United States. The 4.7% increase in France's carbon emissions between 1997 and 1998--partly in response to a decline in production of nuclear and hydropower (which emit no carbon), forcing the country to rely on more imported oil and gas--confirmed the government's view that the nuclear option is unavoidable if the country is to meet its international

Energy-Related Carbon Emissions, 1980-1998



*Germany data includes statistics for East and West Germany until 1990, unified Germany from 1991-1998

environmental obligations. Over the past 20 years, France's nuclear energy program has allowed the power sector to reduce its carbon dioxide emissions per kilowatt-hour by a factor of nine. Additionally, the country's per capita carbon emissions (1.8 metric tons of carbon) are substantially lower than in other developed countries (for example, carbon emissions in the United States in 1998 were 5.5 metric tons of carbon per capita) due to France's preferred use of nuclear power rather than fossil fuels for energy.

Under the Kyoto Protocol, France is an Annex I country and has pledged to reduce its carbon emissions to 1990 levels (a 0% change from 1990). Although France has not yet ratified the Protocol, in January 2000 the French government unveiled an extensive and detailed plan for the next ten years to curb carbon emissions. France was the first country to announce such measures to meet its commitments under Kyoto. The 96-point plan includes a carbon tax, which will take effect in 2001 at \$23 to \$30 per metric ton of carbon emitted, rising to about \$75 by 2010. The tax will be applied to the General Tax on Polluting Activities, an ecology tax that was introduced in 1999, which will be gradually extended to energy consumption by businesses and by electricity producers.

According to the Inter-Ministerial Greenhouse Effect Mission, the government body which drew up the January 2000 program, the plan was necessary for France to meet its obligations under the climate change protocol. Although France is currently emitting carbon levels slightly above the country's 1990 level, increased economic activity and energy consumption have threatened to increase France's carbon emissions even more. Thus, the recently announced program became necessary so that France would avoid that increase in emissions in its attempt to maintain 1990 emissions levels.

An independent report has stated that most of the burden of reducing France's greenhouse gas emissions will fall onto French industry, even though it is responsible for only 34% of total French emissions. The report notes that, in order to meet Kyoto commitments, French industry will need to make a 20%-30% emission reduction. In comparison, the January 2000 program aims to stabilize (at 40 million tons) by 2020 carbon emissions from the transportation sector, which accounts for 39% of France's carbon emissions.

In conjunction with the announcement of measures to meet its Kyoto commitments, France also stated that it is ready to consider tradable carbon emission permits in an international context that includes stringent regulation. The government has set guidelines for creating a market in carbon, involving industries that are large energy consumers and that sign a voluntary agreement to limit emissions of greenhouse gases.

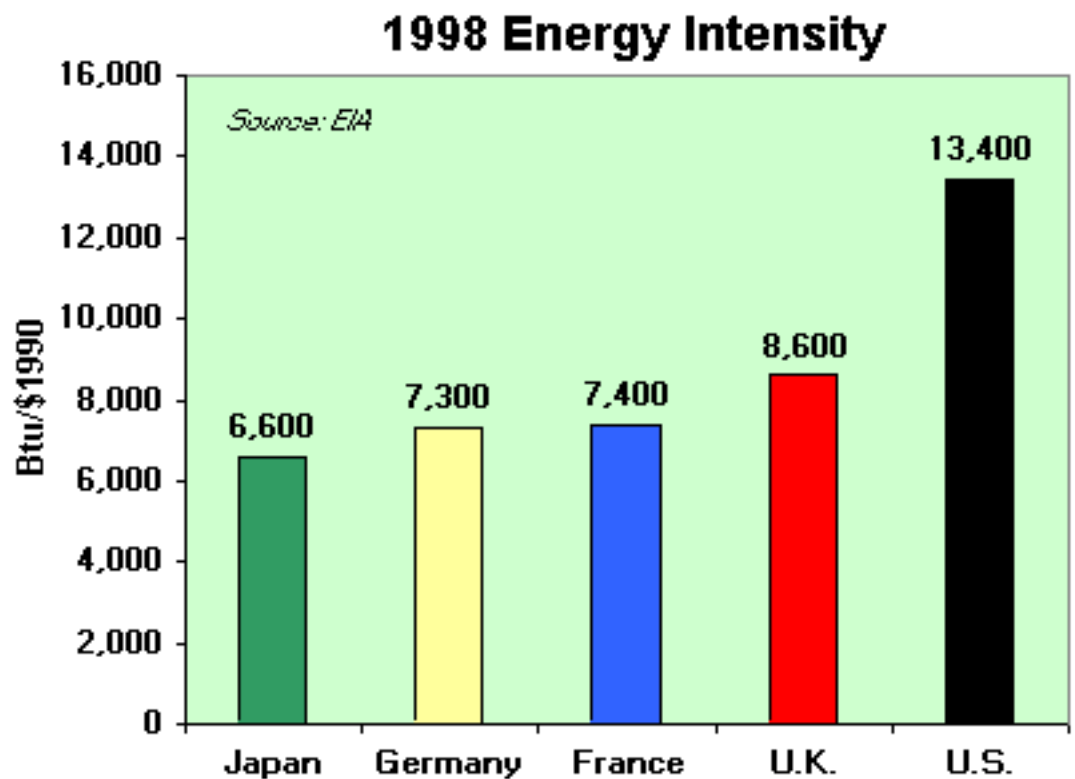
France's statement on trading of carbon emissions permits marks a potentially major shift in French policy, which until now had opposed the tradable permits scheme, arguing that it was ineffective and unenforceable. However, details of the plan still need to be worked out, and Environment Minister Dominique Voynet has said that she believes the public will view carbon permits as "pollution permits" for rich companies, rather than as a way to reduce carbon emissions. The French government has emphasized that, in order to be effective, similar permit

plans must eventually be taken on a European scale.

Energy and Carbon Intensity

France's preference for nuclear power over coal, oil, and gas has allowed it to maintain relatively low levels of fossil energy intensity and carbon intensity. In 1998, France's overall energy intensity, at 7,400/Btu \$1990, was slightly higher than that of Japan (6,600 Btu/\$1990) and Germany (7,300 Btu/\$1990), but below the U.K.'s level of 8,600 Btu/\$1990, and considerably lower than the U.S.'s energy intensity of 13,400 Btu/\$1990. To reduce its energy intensity further, France is undertaking a major effort at energy management. This effort, especially in research, will focus on transport, new buildings, household equipment, and innovations in small- and medium-sized industries employing industrial processes that are energy efficient and clean.

In terms of carbon intensity, France's move away from fossil fuels such as coal is clear. France's 1998 carbon intensity was 0.08 metric tons of carbon/thousand \$1990, with Japan following at 0.09 metric tons of carbon/thousand \$1990, Germany (0.12), the United Kingdom (0.13), and the United States (0.21). After Sweden, France has the lowest emissions of carbon dioxide in relation to its GDP in all of Europe.



Renewable Energy

Because of its lack of indigenous natural resources, France's energy self-sufficiency depends to a great extent on conserving energy and developing renewable energy sources. However, France has little in the way of hydropower, and little potential. In addition, renewable energy consumption in France in 1997 actually decreased by 2%, to 1,133 trillion Btu.

Recognizing that something must be done to spur the growth of renewable energy, the French government, in its January 2000 plan to meet its Kyoto commitments, included several long-term structural measures to encourage the use of renewable energy resources. The government's aim is to achieve a market "breakthrough" for renewable energy sources while consolidating the market

share of wood and hydroelectricity. In addition, greater use of renewable energy resources would help reduce carbon emissions. ADEME is a major participant in the development of research into alternative engines and fuel (electric, gas, bio-fuel vehicles), but it is likely that renewable energy use will not see a real surge until the French government removes market barriers (such as subsidies for other energy sources) that inhibit the use of renewables for electricity and heat production.

Nuclear Energy

When France initiated its nuclear energy program in the early 1970s, environmental protection issues did not generate the concern that they do today in Western countries. Although domestic opposition has been increasing, France has maintained its position that nuclear energy, because it does not pollute the same way that coal, oil, or natural gas do, contributes to the preservation of the environment. Since nuclear energy does not release nitrogen, sulfur, carbon, or dust into the atmosphere, France has argued that nuclear power is one of the best responses to demands for environmental protection.

Between 1980, when nuclear energy provided just 15% of France's electricity, and 1993, when the share of nuclear-generated electricity rose to 75%, France has recorded sizeable reductions in emissions of harmful pollutants from energy generation. During that 13-year time period, sulfur dioxide emissions, which to a large degree are responsible for acid rain, decreased by 70%, reductions in nitrous oxides that contribute to smog were 12%, and dust emissions were reduced by 52%. According to the Ministry of Industry, French nuclear power plants prevent the emission of 1.7 million tons of sulfur dioxide and 890,000 tons of nitrous oxides each year. The French government has announced that the January 2000 "ecotax" will not apply to France's nuclear industry. The tax actually could encourage an increase in France's use of nuclear energy.

In a recent public opinion survey on nuclear power, the share of French citizens who said that nuclear power was less harmful to the environment than other sources stood at 33%, up slightly from 30% in 1992. The



government pointed to these results as evidence that public perceptions of nuclear power have improved. Since France has a good nuclear safety record, and since power produced by French nuclear plants is one of the least expensive forms of energy in the EU, nuclear energy is a natural export market for France.

France's unilateral decision in 1995 to resume nuclear weapons testing in the South Pacific, which came despite the condemnation of European ecologists, "green" politicians, and anti-nuclear pressure groups all across the globe, angered many of its neighbors who do not share France's commitment to the nuclear option. The French government, which stands by its decision to test nuclear weapons, did acknowledge, however, the shifting attitudes towards nuclear power in February 1998 when it decided that the fast breeder reactor Super-Phénix, located at Creys-Malville in the Lyon area, would be shut down permanently.

France in the 21st Century

Despite entering the new century suffering from the twin blows of the *Erika* oil spill and the devastating storms of December 1999, France's environmental outlook appears positive. France has taken the initiative in pushing Europe to honor its climate change commitments, and the country has demonstrated its willingness to cut its carbon emissions to 1990 levels. With ADEME seeking solutions to reduce energy consumption in the medium- and long-term (in order to make progress towards sustainable development), combined with France's strong commitment to nuclear energy, France may very well meet those emission reduction levels.

On the other hand, the IEA has chastised France because progress in promoting energy efficiency has stalled during the last 10 years, mainly due to low energy prices and a slackening of government efforts. Government subsidies for energy efficiency investments and funding for research and development programs have experienced a sizeable reduction. In addition, France is under pressure from the European Union to liberalize its energy sector.

According to the IEA, France can boost its energy efficiency simply by fully implementing existing regulations in the industrial, commercial, government, and residential sectors. By continuing to monitor and evaluate the cost-effectiveness of energy efficiency programs, France should be able to determine which programs are the most beneficial. However, the IEA believes that France must institute a major new program of energy efficiency measures across all end-use sectors--only then will the country be able to harness its significant energy savings potential.

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International Energy Outlook

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Preface

This report presents international energy projections through 2020, prepared by the Energy Information Administration, including outlooks for major energy fuels and issues related to electricity, transportation, and the environment.

The *International Energy Outlook 2002* (IEO2002) presents an assessment by the Energy Information Administration (EIA) of the outlook for international energy markets through 2020. The report is an extension of the EIA's *Annual Energy Outlook 2002* (AEO2002), which was prepared using the National Energy Modeling System (NEMS). U.S. projections appearing in the IEO2002 are consistent with those published in the AEO2002. IEO2002 is provided as a statistical service to energy managers and analysts, both in government and in the private sector. The projections are used by international agencies, Federal and State governments, trade associations, and other planners and decisionmakers. They are published pursuant to the Department of Energy Organization Act of 1977 (Public Law 95-91), Section 205(c). The IEO2002 projections are based on U.S. and foreign government policies in effect on October 1, 2001.

Projections in IEO2002 are displayed according to six basic country groupings (Figure 1). The industrialized region includes projections for nine individual countries—the United States, Canada, Mexico, Japan, France, Germany, Italy, the Netherlands, and the United Kingdom—plus the subgroups Other Europe and Australasia, which is defined as Australia, New Zealand, and the U.S. Territories (Guam, Puerto Rico, and the U.S. Virgin Islands). The developing countries are represented by four separate regional subgroups: developing Asia, Africa, Middle East, and Central and South America. China, India, and South Korea are represented in developing Asia; Brazil is represented in Central and South America; and Turkey is represented in the Middle East.

The nations of Eastern Europe and the former Soviet Union (EE/FSU) are considered as a separate country grouping. The EE/FSU nations are further separated into Annex I and non-Annex I member countries participating in the Kyoto Climate Change Protocol on Greenhouse Gas Emissions. These groupings are used to assess the potential role of Annex I EE/FSU countries in reaching the Annex I emissions targets of the Kyoto Climate Change Protocol.

The report begins with a review of world trends in energy demand. The historical time frame begins with data from 1970 and extends to 1999, providing readers

with a 29-year historical view of energy demand. The IEO2002 projections cover a 21-year period.

High economic growth and low economic growth cases were developed to depict a set of alternative growth paths for the energy forecast. The two cases consider alternative growth paths for regional gross domestic product (GDP). The resulting projections and the uncertainty associated with making international energy projections in general are discussed in the first chapter of the report. The status of environmental issues, including global carbon emissions, is reviewed. Comparisons of the IEO2002 projections with other available international energy forecasts are included in the first chapter.

The next part of the report is organized by energy source. Regional consumption projections for oil, natural gas, coal, nuclear power, and renewable energy (hydroelectricity, geothermal, wind, solar, and other renewables) are presented in the five fuel chapters, along with a review of the current status of each fuel on a worldwide basis. Chapters on energy consumed by electricity producers and energy use in the transportation sector follow. The report ends with a discussion of energy and environmental issues, with particular attention to the outlook for global carbon emissions.

Appendix A contains summary tables of the IEO2002 reference case projections for world energy consumption, gross domestic product (GDP), energy consumption by fuel, electricity consumption, carbon emissions, nuclear generating capacity, energy consumption measured in oil-equivalent units, and regional population growth. The reference case projections of total foreign energy consumption and consumption of oil, natural gas, coal, and renewable energy were prepared using EIA's World Energy Projection System (WEPS) model, as were projections of net electricity consumption, energy consumed by fuel for the purpose of electricity generation, and carbon emissions. In addition, the National Energy Modeling System's (NEMS) Coal Export Submodule (CES) was used to derive flows in international coal trade, presented in the coal chapter. Nuclear *consumption* projections for the reference case were derived from the International Nuclear Model, PC Version (PC-INM). Nuclear *capacity* projections for the reference case were based on analysts' knowledge of the nuclear programs in different countries.

Appendix B and C present projections for the high and low economic growth cases, respectively. Nuclear *capacity* projections for the high and low growth cases were based on analysts' knowledge of nuclear programs. Nuclear *consumption* projections for both cases were derived from WEPS. Appendix D contains summary tables of projections for world oil production capacity and oil production in the reference case and two alternative cases: high oil price and low oil price. The projections were derived from WEPS and from the U.S. Geological Survey. Appendix E presents regional forecasts of transportation energy use in the reference case, derived from the WEPS model. Appendix F describes the WEPS model. Appendix G presents comparisons of historical data with the projections published in previous *IEOs*.

The six basic country groupings used in this report (Figure 1) are defined as follows:

- **Industrialized Countries** (the industrialized countries contain 18 percent of the 2001 world population): Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, the United Kingdom, and the United States.

- **Eastern Europe and the Former Soviet Union (EE/FSU)** (7 percent of the 2001 world population):

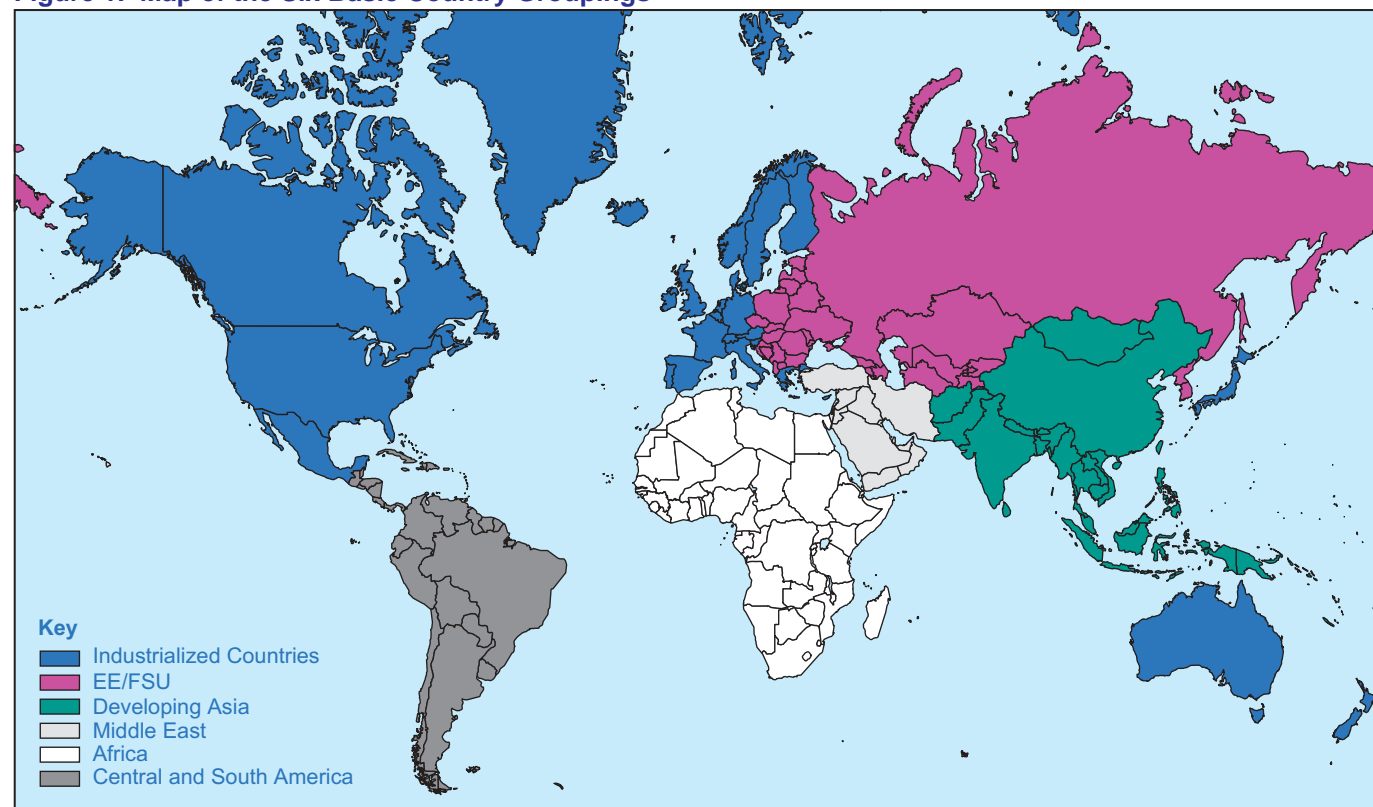
- **Eastern Europe:** Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Macedonia, Poland, Romania, Slovakia, Slovenia, and Yugoslavia.

- **Former Soviet Union:** Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

- **Developing Asia** (55 percent of the 2001 world population): Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), China, Fiji, French Polynesia, Hong Kong, India, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, South Korea, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.

- **Middle East** (4 percent of the 2001 world population): Bahrain, Cyprus, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, Turkey, the United Arab Emirates, and Yemen.

Figure 1. Map of the Six Basic Country Groupings



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

- **Africa** (10 percent of the 2001 world population): Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo (Brazzaville), Congo (Kinshasa), Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Ivory Coast, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, St. Helena, Sudan, Swaziland, Tanzania, Togo, Tunisia, Uganda, Western Sahara, Zambia, and Zimbabwe.

- **Central and South America** (6 percent of the 2001 world population): Antarctica, Antigua and Barbuda, Argentina, Aruba, Bahama Islands, Barbados, Belize, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama Republic, Paraguay, Peru, St. Kitts-Nevis, St. Lucia, St. Vincent/Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, and Venezuela.

In addition, the following commonly used country groupings are referenced in this report:

- **Annex I Countries** (countries participating in the Kyoto Climate Change Protocol on Greenhouse Gas Emissions): Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany,

Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, and the United Kingdom.¹

- **European Union (EU):** Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden, and the United Kingdom.

- **Mercosur Trading Block:** Argentina, Brazil, Paraguay, and Uruguay. Chile and Bolivia are Associate Members.

- **North American Free Trade Agreement (NAFTA) Member Countries:** Canada, Mexico, and the United States.

- **Organization for Economic Cooperation and Development (OECD):** Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

- **Organization of Petroleum Exporting Countries (OPEC):** Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

- **Pacific Rim Developing Countries:** Hong Kong, Indonesia, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.

- **Persian Gulf:** Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates.

Objectives of the *IEO2002* Projections

The projections in *IEO2002* are not statements of what will happen, but what might happen given the specific assumptions and methodologies used. These projections provide an objective, policy-neutral reference case that can be used to analyze international energy markets. As a policy-neutral data and analysis organization, EIA does not propose, advocate, or speculate on future legislative and regulatory changes. The projections are based on current U.S. and foreign government policies. Assuming current policies, even knowing that changes will occur, will naturally result in projections that differ from the final data.

Models are abstractions of energy production and consumption activities, regulatory activities, and producer and consumer behavior. The forecasts are highly dependent on the data, analytical methodologies, model structures, and specific assumptions used in their development. Trends depicted in the analysis are indicative of tendencies in the real world rather than representations of specific real-world outcomes. Even where trends are stable and well understood, the projections are subject to uncertainty. Many events that shape energy markets are random and cannot be anticipated, and assumptions concerning future technology characteristics, demographics, and resource availability cannot be known with certainty.

¹Turkey and Belarus are Annex I nations that have not ratified the Framework Convention on Climate Change and did not commit to quantifiable emissions targets under the Kyoto Protocol. In 2001, the United States withdrew from the Protocol, and Kazakhstan requested that it be added to the list of Annex I countries.

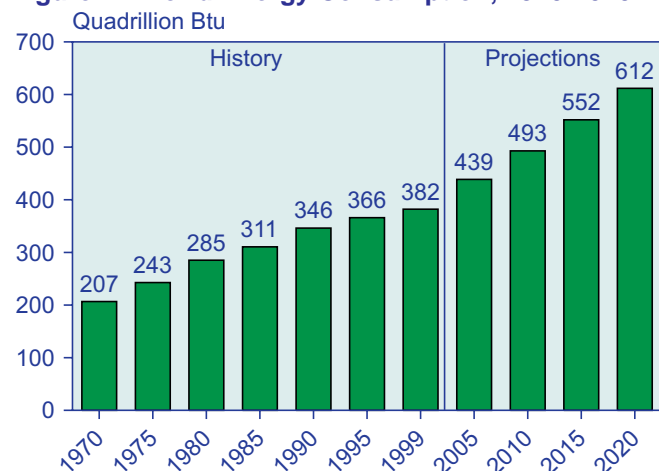
Highlights

World energy consumption is projected to increase by 60 percent from 1999 to 2020. Much of the growth in worldwide energy use is expected in the developing world in the IEO2002 reference case forecast.

In the reference case projections for the *International Energy Outlook 2002 (IEO2002)*, world energy consumption is projected to increase by 60 percent over a 21-year forecast horizon, from 1999 to 2020. Worldwide energy use grows from 382 quadrillion British thermal units (Btu) in 1999 to 612 quadrillion Btu in 2020 (Figure 2). Energy markets were influenced by a host of developments in 2001, including high world oil prices that persisted from 2000 into the first part of 2001 and then weakened substantially in the third quarter of the year; a global economic slowdown led by a mild recession in the United States; and the aftermath of the terrorist attacks on the United States on September 11, 2001.

Despite the events of the past year, much of the growth in worldwide energy use is still expected in the developing world, as it has been in past editions of this outlook (Figure 3). In particular, energy demand in developing Asia and Central and South America is projected to more than double between 1999 and 2020. Both of these regions are expected to sustain energy demand growth of about 4 percent annually throughout the forecast, accounting for about half of the total projected increment in world energy consumption and 83 percent of the increment for the developing world alone.

Figure 2. World Energy Consumption, 1970-2020

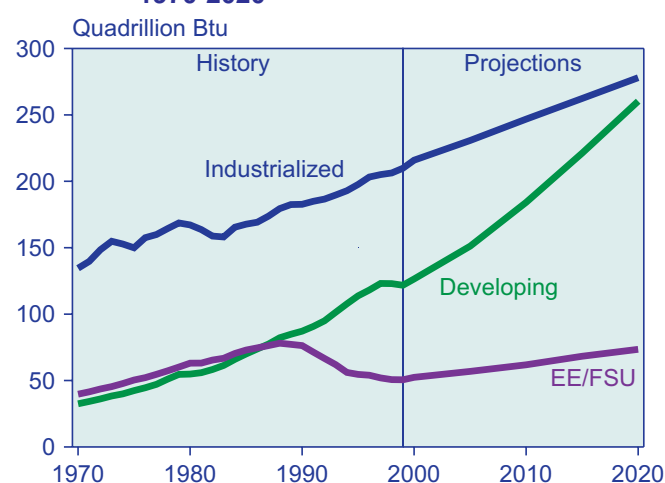


Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

High world oil prices carried into 2001 from the previous year, and for the first half of the year they remained within—and, during day trading, occasionally spiked above—the \$22 to \$28 per barrel price band that the Organization of Petroleum Exporting Countries (OPEC) has defined as its preferred range. Although prices spiked initially after the September 11 terrorist attacks launched on the United States, oil demand weakened substantially in the weeks and months that followed the attacks, and OPEC found it difficult to hold prices much above the \$22 per barrel mark. Even after three production quota cuts amounting to 3.5 million barrels per day were made in 2001, prices did not strengthen. At the end of 2001, OPEC entered into a protracted negotiation with key non-OPEC producers aimed at reducing oil exports enough to shore up the world market price. OPEC members (excluding Iraq) agreed to cut 1.5 million barrels of production, and non-OPEC producers Angola, Norway, Mexico, Oman, and Russia agreed to take a combined 462,500 barrels per day out of the export market beginning in January 2002.

The U.S. refiner acquisition cost of imported crude oil fell from \$27.72 per barrel in 2000 to an estimated \$22.05 per barrel in 2001 (nominal dollars). The *IEO2002*

Figure 3. World Energy Consumption by Region, 1970-2020



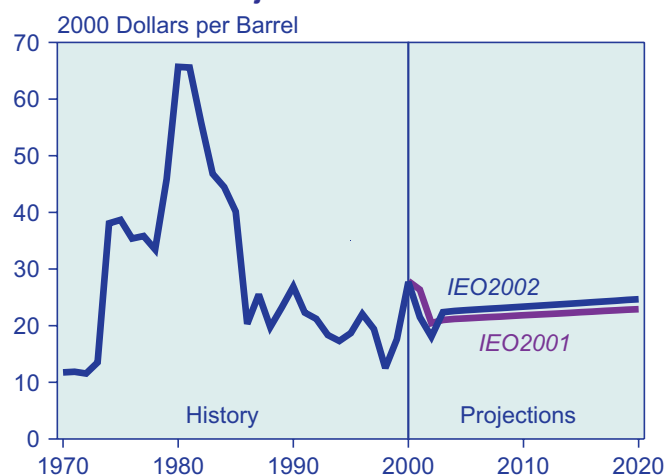
Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

reference case expects world oil prices to moderate in 2002 and return to the price trajectory anticipated in last year's outlook for the mid-term. World oil prices are expected to reach \$25 per barrel in 2000 dollars (\$42 per barrel in nominal dollars) at the end of the projection period. This year's projection for world oil prices is slightly higher than last year's projection (Figure 4), reflecting the successes OPEC had in managing oil production cutbacks to raise oil prices in 2000, along with a more optimistic mid-term outlook for demand in the world's developing countries.

Outlook for World Energy Demand

Much of the industrialized world experienced economic slowdown in 2001, led by what is estimated to have been a recession in the United States since March 2001. The lowered economic activity in the industrialized world will have short-term impacts on the rest of the world as demand for products and services from developing countries slows in response. Lowered demand for computer equipment has already nudged high-tech exporters South Korea and Taiwan into recession. The mid-term forecast assumes that the recession will not be protracted in the United States, and that gross domestic product (GDP) growth and energy demand growth will rebound and will largely resume the trend projected in last year's outlook. The *IEO2002* reference case expects that energy consumption in the industrialized world will grow by 1.3 percent per year between 1999 and 2020, slightly higher than the 1.2 percent per year projected in last year's report.

Figure 4. Comparison of 2001 and 2002 World Oil Price Projections



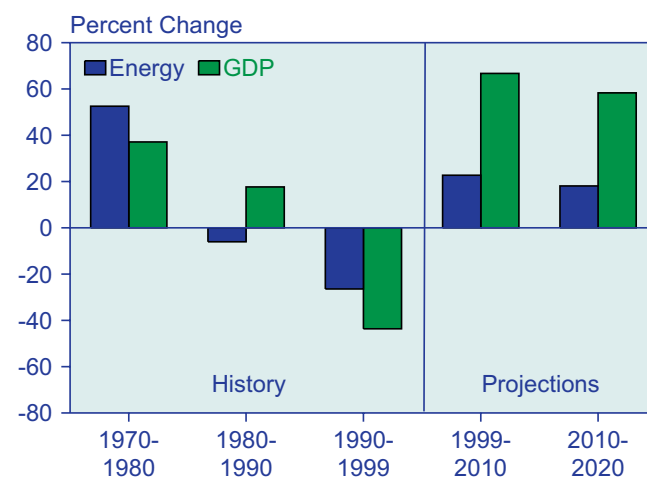
Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, July 2001). **IEO2001:** EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001). **IEO2002:** 1999-2002—EIA, *Short-Term Energy Outlook*, on-line version (February 7, 2002), web site www.eia.doe.gov/emeu/steo/pub/contents.html. 2003-2020—EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001).

One of the few bright spots among the world's regional economies in 2001 was the former Soviet Union (FSU), where GDP registered a second year of positive growth for every nation in the region. High oil prices and a devalued ruble helped Russia—the region's largest economy—post strong economic gains by boosting performance in the country's industrial sector. As the ruble regained value in 2001, the manufacturing sector slowed somewhat (as imported goods once again could compete with domestic goods), but high world oil prices in the first three quarters of the year helped Russia return to a GDP growth rate of 5.3 percent.

Ukraine, the second largest economy in the FSU, also reported positive economic growth in 2001—only its second year of positive GDP since the dissolution of the Soviet Union in 1989. Ukraine is a net importer of oil, and the high world oil prices did not benefit its economy. Instead, fiscal reform and strong growth in industrial output, construction activity, agriculture, and exports, along with fast-paced growth in domestic consumption and investment, helped to fuel Ukraine's economic growth. The improving economic outlook for Russia and the rest of the FSU suggests a more sustained period of growth for the region and is expected to result in energy demand growth for the region of 1.8 percent per year between 1999 and 2020, reaching 57 quadrillion Btu at the end of the forecast (Figure 5).

Worldwide, oil consumption rose by less than 100,000 barrels per day in 2001, divided evenly among the industrialized (mainly Western Europe) and developing (mainly Central and South America) nations. Demand is expected to begin to recover in 2002 as the world economies begin to recover from the slowdown in 2001, and

Figure 5. Percent Change in Energy Consumption and GDP in the Former Soviet Union



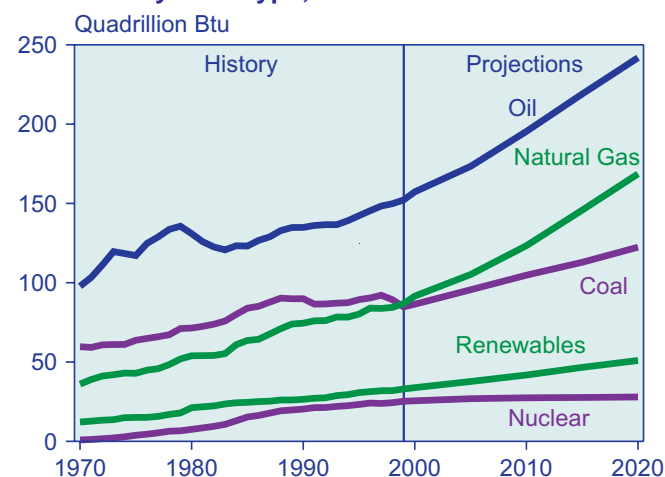
Sources: DRI-WEFA World Economic Outlook 2001, Third Quarter; Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001); and EIA, World Energy Projection System (2002).

global oil demand is projected to expand by about 600,000 barrels per day in 2002. The increases in worldwide oil use projected in the reference case would require an increment of almost 44 million barrels per day over current productive capacity. OPEC producers are expected to be the major beneficiaries of increased production requirements, but non-OPEC supply is expected to remain competitive, with major increments of supply coming from offshore resources, especially in the Caspian Basin, Latin America, and deepwater West Africa. Deepwater exploration and development initiatives are generally expected to be sustained worldwide, with the offshore Atlantic Basin emerging as a major future source of oil production in both Latin America and Africa.

World Energy Consumption by Energy Source

Throughout the past several decades, oil has been the world's dominant source of primary energy consumption, and it is expected to remain in that position with a 40-percent share of total energy consumption over the 1999-2020 period (Figure 6). The oil share of the world energy pie does not increase in the forecast because countries in many parts of the world are expected to switch from oil to natural gas and other fuels, particularly for electricity generation. Its share of total energy consumption is expected to remain constant because of its predominance in the transportation sector, where energy use is projected to grow robustly over the next two decades. World oil consumption is projected to increase by 2.2 percent annually over the 21-year projection period, from 75 million barrels per day in 1999 to 119 million barrels per day in 2020.

Figure 6. World Energy Consumption by Fuel Type, 1970-2020

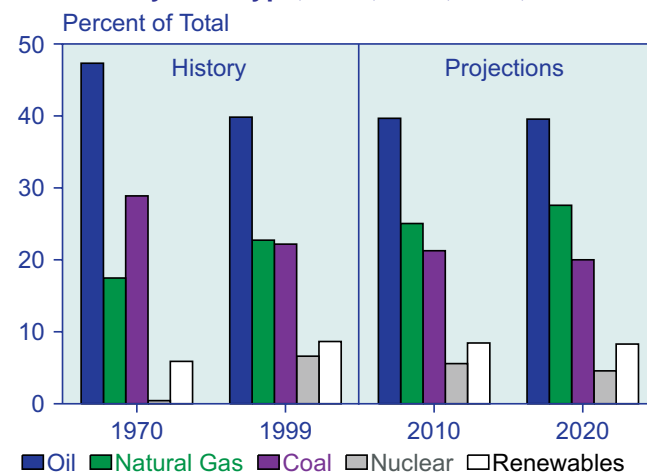


Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Although the nations of the industrialized world continue to consume more of the world's petroleum products than do those of the developing world, the gap is projected to narrow considerably over the forecast period. In 1999, developing nations consumed 58 percent of the amount of oil consumed in the industrialized world, but by 2020 they are expected to consume almost 90 percent as much oil as the industrialized world. The increase in oil use in the industrialized world is expected to occur predominantly in the transportation sector, where there are presently few economically competitive alternatives to oil. In the developing world, oil demand is projected to grow in all end-use sectors. As the energy infrastructures of emerging economies improve, people are turning from traditional fuels like wood burning for heating and cooking to electricity, and additional petrochemical feedstocks are being used for industry.

The fastest growing source of energy consumption in the *IEO2002* reference case is projected to be natural gas. Over the 1999-2020 forecast period, gas use is projected to nearly double in the reference case, reaching 162 trillion cubic feet in 2020. Natural gas use surpassed coal use (on a Btu basis) for the first time in 1999, and by 2020 it is expected to exceed coal use by 38 percent (Figure 7). The natural gas share of total energy consumption is projected to increase from 23 percent in 1999 to 28 percent in 2020, and natural gas is expected to account for the largest increment in electricity generation (increasing by 33 quadrillion Btu and accounting for 43 percent of the total increment in energy use for electricity generation). Much of the projected growth in natural gas consumption throughout the world is in response to rising demand for natural gas to fuel efficient new gas turbine

Figure 7. World Energy Consumption Shares by Fuel Type, 1970, 1999, 2010, and 2020



Sources: **1970 and 1999:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, World Energy Projection System (2002).

power plants. Gas use is increasing for a number of additional reasons, including price, environmental concerns, fuel diversification and/or energy security issues, market deregulation (for both gas and electricity), and overall economic growth.

In the industrialized world, natural gas is expected to make a greater contribution to incremental energy consumption among the major fuels, increasingly becoming the choice for new power generation because of its environmental and economic advantages. In the developing countries, increments in gas use are expected to supply both power generation and industrial uses. The *IEO2002* reference case projects particularly robust growth in natural gas use in the developing world, averaging 5.3 percent per year between 1999 and 2020, reflecting the growing popularity of the fuel, as well as the expectation that the relatively immature gas markets of emerging countries will develop quickly over the coming years.

World coal use has been in a period of generally slow growth since the 1980s, and the trend is expected to continue through the projection period. The projected slow growth in coal consumption, averaging 1.7 percent per year through 2020, suggests that coal will account for a shrinking share of world energy consumption. In 1999, coal provided 22 percent of world primary energy consumption, down from 27 percent in 1985. In the *IEO2002* reference case, the coal share of total energy consumption is projected to fall to 20 percent by 2020. The expected decline in coal's share of energy use would be even greater were it not for large increases in energy use projected for developing Asia, where coal continues to dominate many fuel markets, especially in China and India. As very large countries in terms of both population and land mass, China and India are projected to account for 83 percent of the total expected increase in coal use worldwide (on a Btu basis).

Coal consumption is heavily concentrated in the electricity generation sector. Almost 65 percent of the world's coal use is for electricity generation, and power generation accounts for virtually all the projected growth in coal consumption worldwide. One exception is China, where coal continues to be the main fuel in a rapidly growing industrial sector, reflecting the country's abundant coal reserves and limited access to other sources of energy. Consumption of coking coal is projected to decline slightly in most regions of the world as a result of technological advances in steelmaking, increasing output from electric arc furnaces, and continuing replacement of steel by other materials in end-use applications.

Although past editions of this report have projected declines in nuclear electricity consumption, higher capacity utilization and fewer expected retirements of existing plants have resulted in a revision to the expectations for a decline in consumption. Extensions of operating licenses (or the equivalent) for nuclear power plants

are expected to be requested and granted among the countries of the industrialized world. With more of the existing nuclear power plants expected to remain in operation, the projected decline in nuclear generation is slowed. In the *IEO2002* reference case, world nuclear capacity is projected to rise from 350 gigawatts in 2000 to 363 gigawatts in 2010 before falling to 359 gigawatts in 2020.

The highest growth in nuclear generation is projected for the developing world, where consumption of electricity from nuclear power is projected to increase by 4.7 percent per year between 1999 and 2020. In particular, developing Asia is expected to see the greatest expansion in new nuclear generating capacity. The nations of developing Asia account for half the reactors currently under construction worldwide, including eight in China, four in South Korea, two in India, and two in Taiwan.

Renewable energy use is expected to increase by 53 percent between 1999 and 2020, but its current 9-percent share of total energy consumption is projected to drop slightly to 8 percent by 2020. Over the forecast horizon, growth in renewable energy resources is expected to continue to be constrained by relatively moderate fossil fuel prices. Renewable energy consumption is expected to be driven by new, large-scale hydroelectric projects, particularly in China, India, Malaysia, and other developing Asian countries. In 2001, construction on mega-hydro projects like China's 18,200-megawatt Three Gorges Dam and Malaysia's 2,400-megawatt Bakun continued amidst criticism of their environmental impacts and concerns about the welfare of the people being relocated to accommodate the projects.

The world's use of electricity is projected to increase by two-thirds over the forecast horizon, from 13 trillion kilowatthours in 1999 to 22 trillion kilowatthours in 2020. The strongest growth rates in electricity consumption are projected for developing Asia, where electricity consumption is expected to grow by 4.5 percent per year as robust economic growth increases the demand for electricity to run newly purchased air conditioners, refrigerators, stoves, space heaters, and water heaters. In the industrialized world, electricity consumption is expected to grow at a more modest pace. Slower population and economic growth, along with the market saturation of certain electronic appliances (such as air conditioners) and efficiency gains from electrical appliances help to explain the expected slower growth of electricity use in the industrialized nations, although growing computer usage and the introduction of new electronic devices could moderate that trend somewhat in the future.

There have been two important developments in the electricity sector in recent years that may affect the way the industry works in the future. The first is the

increasing role of foreign direct investment in the developing regions of the world. Greater access to foreign investment in the electricity sector has allowed developing nations to construct the infrastructure needed for substantial increases in access to electricity, a particular problem for many developing nations. A second important component of the electric industry's evolution over the past several years is electricity reform. Many developing countries have implemented reforms to the rules governing electricity generation and distribution in an effort to secure the foreign direct investment they need to modernize and improve the electricity infrastructure. In industrialized countries, many nations have undertaken electricity reforms to introduce greater competition in domestic markets in an effort to reduce the costs of electricity to consumers.

Outlook for Transportation Energy Use

The past year saw a reversal of the high prices and tight markets that characterized the energy industry in 2000. Transportation demand growth in 2001 is likely to be the lowest in several years, with slowing economic growth moderating growth in world oil demand even before the September 11 terrorist attacks on the United States. Despite the recent pressure on transportation fuels from oil prices that hit 10-year highs in 2000, transportation energy use is expected to continue robust growth over the next two decades, especially in the developing world, where relatively immature transportation infrastructures are expected to grow rapidly as national and regional economies expand. In the *IEO2002* reference case, energy use for transportation is projected to increase by 3.8 percent per year in the developing world, compared with average annual increases of 1.7 percent for the industrialized countries, where transportation

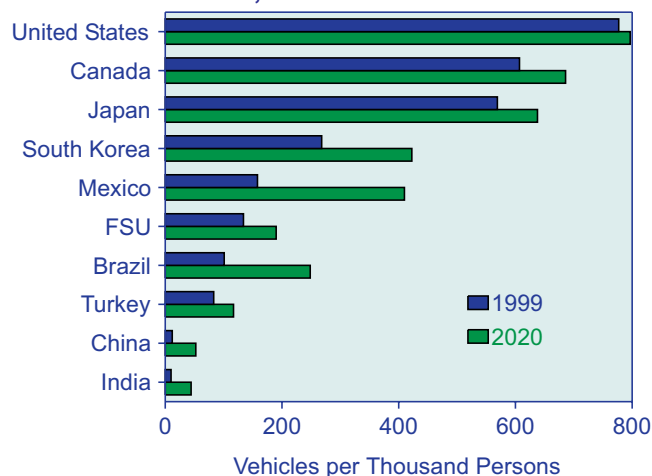
systems are largely established and motorization levels (per capita vehicle ownership) are, in many nations, expected to reach saturation levels over the 21-year forecast horizon.

In urban centers of the developing world, car ownership is often seen as one of the first symbols of emerging prosperity. Per capita motorization in much of the developing world is projected to more than double between 1999 and 2020, although population growth is expected to keep motorization levels low relative to those in the industrialized world. For example, the U.S. per capita motorization level in 2020 is projected at 797 vehicles per thousand persons, but in China—where motorization is expected to grow fivefold over the forecast horizon—the projected motorization level in 2020 is only 52 vehicles per thousand persons (Figure 8).

Carbon Dioxide Emissions

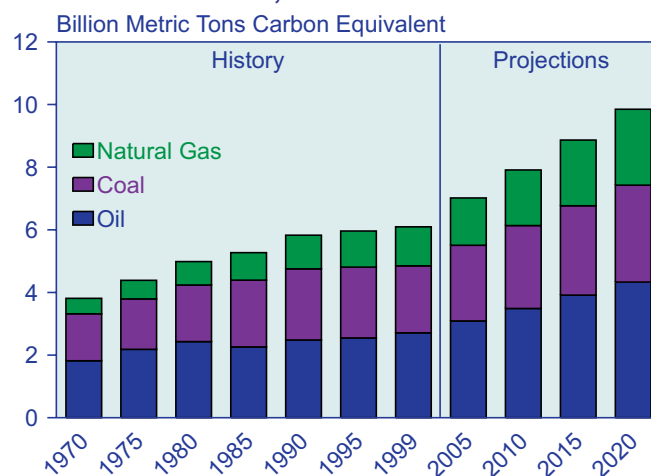
Because estimates indicate that approximately 80 percent of all human-caused carbon dioxide emissions currently come from fossil fuel combustion, world energy use has emerged at the center of the climate change debate. In the *IEO2002* reference case, world carbon dioxide emissions are projected to rise from 6.1 billion metric tons carbon equivalent in 1999 to 7.9 billion metric tons per year in 2010 and to 9.9 billion metric tons in 2020 (Figure 9). Much of the projected increase in carbon dioxide emissions is expected to occur in the developing world, where emerging economies are expected to produce the largest increases in energy consumption. Developing countries alone account for 77 percent of the projected increment in carbon dioxide emissions between 1990 and 2010 and 72 percent between 1990 and 2020. Continued heavy reliance on coal and other fossil

Figure 8. Motorization Levels in Selected Countries, 1999 and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, *World Energy Projection System* (2002).

Figure 9. World Carbon Dioxide Emissions by Fossil Fuel, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *World Energy Projection System* (2002).

fuels, as projected for the developing countries, would ensure that even if the industrialized world undertook efforts to reduce carbon dioxide emissions, worldwide carbon dioxide emissions would still grow substantially over the forecast horizon.

Energy Intensity

The *IEO2002* projections, like all forecasts, are accompanied by a measure of uncertainty. One way to quantify the uncertainty is to consider the relationship between energy consumption and growth in gross domestic product (that is, energy intensity) over time. In the industrialized countries, history shows the link between energy consumption and economic growth to be a relatively weak one, with growth in energy demand lagging behind economic growth. In the developing countries, the two have been more closely correlated, with energy demand growing in parallel with economic expansion.

In the *IEO2002* forecast, energy intensity in the industrialized countries is expected to improve (decrease) by 1.3 percent per year between 1999 and 2020, about the same rate of improvement observed in the region between 1970 and 1999. Energy intensity is also projected to improve in the developing countries—by 1.2 percent per year—as their economies begin to behave more like those of the industrialized countries as a result of improving standards of living that accompany the projected economic expansion (Figure 10). For more than three decades, the EE/FSU has maintained a much higher level of energy intensity than either the industrialized or developing countries. Over the forecast

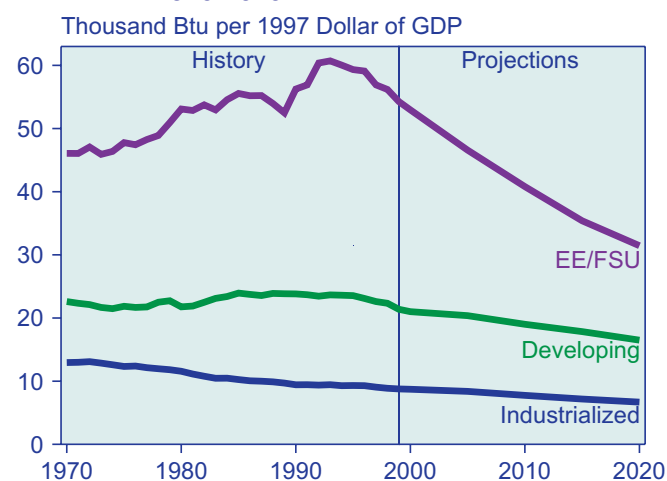
horizon, energy intensity is expected to improve in the EE/FSU region in concert with expected recovery from the economic and social declines of the early 1990s; however, it is still expected to be twice as high as in the developing world and five times as high as in the industrialized world.

Carbon Intensity

Carbon intensity—the amount of carbon dioxide emitted per dollar of GDP—is also projected to improve throughout the world over the next two decades (Figure 11). The most rapid improvements are, for the most part, projected for the transitional economies of the EE/FSU. In the FSU, economic recovery from the upheaval of the 1990s is expected to continue throughout the forecast. The FSU nations are also expected to replace old and inefficient capital stock and increasingly use less carbon-intensive natural gas for electricity generation and other end uses in place of more carbon-intensive oil and coal.

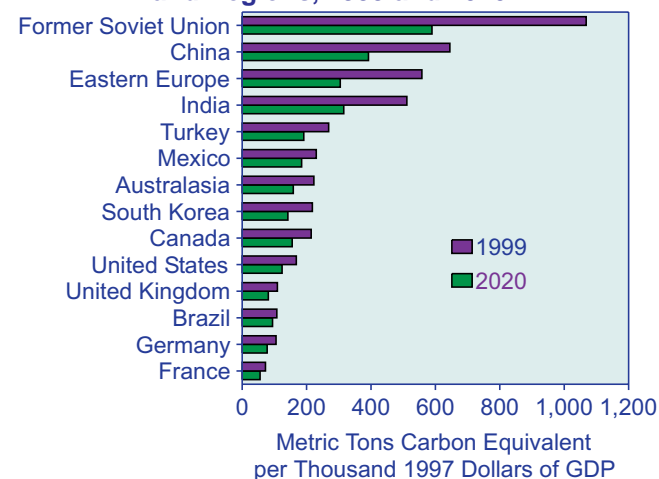
In developing Asia, China and India are also expected to see fairly rapid improvements in carbon intensity over the projection period, primarily as a result of rapid economic growth rather than a switch to less carbon-intensive fuels. Both China and India are expected to continue their heavy dependence on fossil fuels, especially coal, in the *IEO2002* reference case forecast, but their combined annual GDP growth is projected to average 6.6 percent, compared with an expected 4.4-percent annual rate of increase in fossil fuel use from 1999 to 2020.

Figure 10. World Energy Intensity by Region, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 11. Carbon Intensity in Selected Countries and Regions, 1999 and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

World Energy Consumption

The IEO2002 projections indicate continued growth in world energy use, including large increases for the developing economies of Asia and South America. Energy resources are thought to be adequate to support the growth expected through 2020.

The *International Energy Outlook 2002* (IEO2002) presents the Energy Information Administration (EIA) outlook for world energy markets to 2020. Current trends in world energy markets are discussed in this chapter, followed by a presentation of the IEO2002 projections for energy consumption by primary energy source and for carbon emissions by fossil fuel. Uncertainty in the forecast is highlighted by an examination of alternative assumptions about economic growth and their impacts on the IEO2002 projections and how future energy intensity trends could influence the reference case projections. The chapter ends with a comparison of the IEO2002 projections with forecasts available from other organizations.

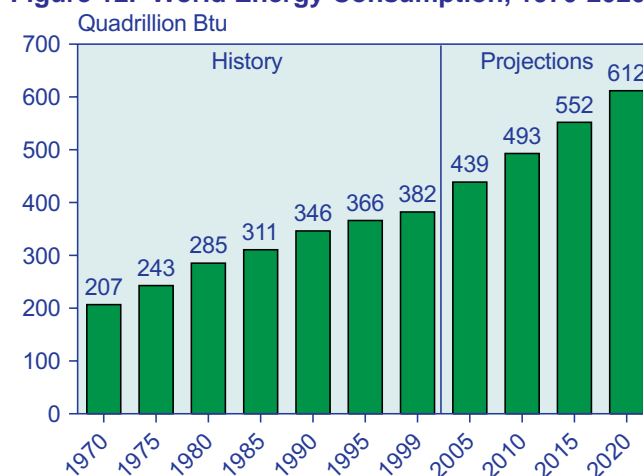
Current Trends in World Energy Demand

Between 1999 and 2020, total world energy use is projected to grow from 382 quadrillion British thermal units (Btu) to 612 quadrillion Btu (Figure 12 and Table 1)—a 60-percent increase—in the IEO2002 reference case projection. Energy markets in 2001 were affected by a host of developments and events, including high world oil prices that continued from 2000 into the first half of the year and then weakened substantially toward the end of the year; a global economic slowdown led by the United States; and the aftermath of the terrorist attacks on the United States on September 11, 2001.

For much of 2001, world oil prices remained in the news, with prices within or slightly above the price range of

\$22 to \$28 per barrel that the Organization of Petroleum Exporting Countries (OPEC) considers optimal (Figure 13). After September 11, oil prices initially spiked, but a substantial lowering of demand in the weeks and months that followed made it difficult for OPEC to hold prices much above the \$22 per barrel level [1]. An OPEC meeting on September 26-27 did not result in an anticipated oil production cut to shore up prices, which were beginning to fall even before the terrorist attacks.

Figure 12. World Energy Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Table 1. World Energy Consumption and Carbon Dioxide Emissions by Region, 1990-2020

Region	Energy Consumption (Quadrillion Btu)				Carbon Dioxide Emissions (Million Metric Tons Carbon Equivalent)			
	1990	1999	2010	2020	1990	1999	2010	2020
Industrialized Countries	182.7	209.7	246.6	277.8	2,849	3,129	3,692	4,169
EE/FSU	76.3	50.4	61.8	73.4	1,337	810	978	1,139
Developing Countries	87.2	121.8	184.1	260.3	1,641	2,158	3,241	4,542
Asia	51.0	70.9	113.9	162.2	1,053	1,361	2,139	3,017
Middle East	13.1	19.3	26.3	34.8	231	330	439	566
Africa	9.3	11.8	15.7	20.3	179	218	287	365
Central and South America	13.7	19.8	28.3	43.1	178	249	377	595
Total World	346.2	381.9	492.6	611.5	5,827	6,097	7,910	9,850

Sources: **1990 and 1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

OPEC experienced some difficulties in trying to maintain its desired price band both before and after the September attacks. The slowing U.S. economy had already reduced the demand for oil, and the cartel reduced oil production quotas by a combined 3.5 million barrels per day in three separate instances before the terrorist attacks [2]. In mid-November 2001, the OPEC member nations met again to discuss ways to boost sagging oil prices that had fallen to as low as \$18 per barrel and had dipped even lower in day trading. OPEC announced it would cut production by another 1.5 million barrels per day, beginning in January 2002, but only on condition that key non-OPEC oil suppliers, Mexico, Oman, Russia, and Norway, would also cut production. Angola and Kazakhstan also indicated a willingness to consider cutting exports [3]. OPEC wanted non-OPEC suppliers to remove a combined 500,000 barrels per day from the market.

The degree of compliance among the OPEC and non-OPEC members who struck the December 2001

With the terrorist attacks and the ensuing war launched in Afghanistan against the Al Qaeda terrorist network and the ruling Taliban regime, the short-term outlook for world economic and energy growth is fraught with even more uncertainty than normal. The mid-term outlook will also be affected by developments in the American-led anti-terrorist actions, an outlook that is difficult to assess in early 2002.

Developing countries as a whole are projected to account for 60 percent of the increment in total energy

Dollars per Barrel

OPEC's "Optimal" Price Range

Date	Oil Price (Dollars per Barrel)
Jan 1996	17.0
Jul 1996	20.0
Jan 1997	23.0
Jul 1997	18.0
Jan 1998	12.0
Jul 1998	11.0
Jan 1999	15.0
Jul 1999	22.0
Jan 2000	28.0
Jul 2000	31.0
Jan 2001	24.0
Jul 2001	19.0

The bar chart displays projected energy consumption in Quadrillion Btu for five regions from 1970 to 2020. The Y-axis ranges from 0 to 100 in increments of 20. The X-axis shows the years 1970, 1980, 1990, 1999, 2010, and 2020. The legend identifies the regions by color: China (green), Other Developing Asia (purple), Central and South America (dark blue), Middle East (light green), and Africa (pink).

Year	China	Other Developing Asia	Central and South America	Middle East	Africa
1970	12	8	7	4	3
1980	18	14	11	7	7
1990	27	24	14	13	10
1999	32	39	20	20	12
2010	55	58	28	27	16
2020	85	78	43	35	20

Energy Information Administration / International Energy Outlook 2002

use over the projection period, compared with the industrialized world's 30 percent (Figure 15). The emerging, transitional economies of Eastern Europe and the former Soviet Union (EE/FSU) account for the remainder.

Even before the events of September 11, the U.S. economy was showing signs of slipping, and many analysts believe the attacks in September virtually ensured that the country would be pushed into recession. In fact, the National Bureau of Economic Research declared in late November that a recession had begun in the United States as early as March 2001 [8]. Recession in the United States clearly has implications for international markets and, in turn, the demand for energy worldwide. Slowing markets in the United States mean a lowered demand for imports. The technology sector, spurred by a spate of computer upgrades because of Y2K-related fears in 1999, had slowed dramatically by 2001, resulting in slower economic growth for many Asian, technology-exporting countries, such as South Korea and Taiwan, which provide much of the computer equipment for the United States and other parts of the industrialized world [9].

The negative impact of the slowing U.S. economy on the markets of the developing world is expected to be made even worse because of the persistent Japanese recession and a slowing of the economies of Western Europe. With virtually all of the industrialized world slowing, or already in full recession, it will be difficult for the developing world to resist an economic turndown as well. Japan's economy was stagnant or in decline for much of 2001, and many analysts feel that the country is in yet another of a series of recessions that have plagued it for

the past several years. Deflation continues to be problematic for Japan, as it has been since 1996, and consumers are reluctant to spend while the true value of their assumed debt continues to expand [10]. Thus far, Prime Minister Koizumi's efforts to shift government fiscal policy away from public works projects and toward economic reforms have not been successful.

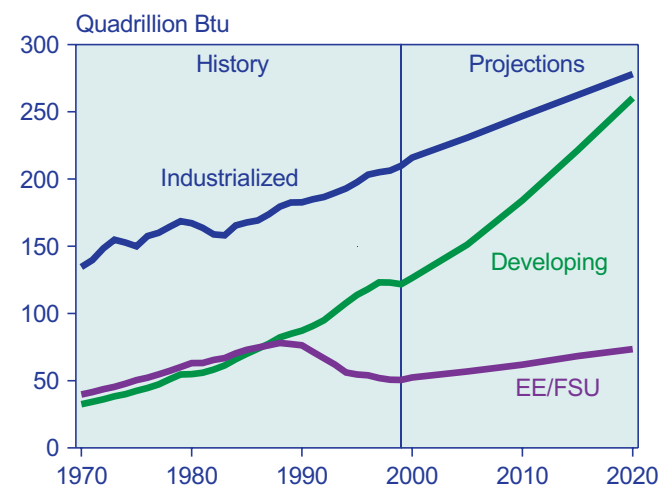
The Western European economies also began to show signs of recession or of economic slowdown in 2001. The European Central Bank (ECB) resisted cutting interest rates for the first quarter of 2001, but as the slowing economic performance became clear, the Governing Council agreed to cut interest rates by a total of 150 basis points between May and November in four separate instances. Two of the cuts were made after September 11, and the ECB Governing Council stated that its cut on September 17 was being made because the terrorist acts on the United States would be likely to "weigh adversely on confidence in the euro arena, reducing the short-term outlook for domestic growth" and to increase inflationary risks [11].

In Germany, Western Europe's largest economy, gross domestic product (GDP) growth fell to 0.8 percent in 2001, from 3.2 percent in 2000. Even before the September 11 terrorist attacks, the German economy showed signs of weakening, with year-to-year growth slowing from 1.8 percent in the first quarter of 2001 to 0.6 percent in the second quarter and 0.3 percent in the third [12]. Analysts speculated that the country would soon be in a recession. Tax cuts in 2001 helped to soften the impact of Germany's slowing economy in 2001, and the government is considering moving up the time frame for implementing further cuts originally scheduled for the period 2003 to 2005, in an attempt to stimulate economic recovery.

Other countries in Western Europe were also showing signs of weakening. Tax cuts helped to boost consumer spending in France in the first part of 2001, but weakening manufacturing output related to lowered export demand after the terrorist attacks in the United States is expected to make it difficult for France to maintain its pace of economic growth into 2002 [13]. Modest growth was reported in Italy and the United Kingdom, but export growth slowed substantially after September in both countries [14].

Developing Asia (outside of China and India) is particularly vulnerable to fluctuations in the economies of the industrialized world, because many Asian countries largely depend on revenues from exports to industrialized countries. In particular, the United States is the largest export market for most Asian countries, and the U.S. recession has already had adverse impacts on the Asian markets. Singapore and Taiwan have suffered income contractions, and Hong Kong and Malaysia are near

Figure 15. Energy Consumption by Region, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

recession, with South Korea, Thailand, and Indonesia reporting slowing economic growth [15].

Exports from the developing Asian countries have uniformly declined. The demand for electronic technologies has not rebounded from the declines in 2000, which has hurt the economies of technology producers South Korea, Taiwan, Singapore, and Malaysia, resulting in a 20-percent decline in exports at the end of 2001. Even China and Indonesia—countries that are less dependent on technology-oriented exports—have suffered from the global economic slowdown in 2001. China's exports grew by 4 percent in the third quarter of 2001, compared with 25 percent during the same period in 2000. In Indonesia, exports declined by 10 percent in the third quarter of 2001, compared with 25-percent growth in the third quarter of 2000.

Not surprisingly, the terrorist attacks have made the economic situation in developing Asia even worse. With expectations that the U.S. recession will be prolonged and growth in exports will not revive quickly, the economic slowdown in developing Asia is expected to continue well into 2002. Moreover, international tensions are likely to have an adverse impact on tourism which will further harm the economies of Hong Kong, Singapore, and Thailand, where tourism accounts for more than 6 percent of GDP in each country [16]. Amidst worries of prolonged recessions among the developing Asian nations, domestic consumer demand has weakened as well, adding to the problems of the regional economies.

China has fared better than its neighbors, mostly because of the large state-sector investment expansion and stable private-sector consumption growth. Between 1998 and 2000, the Chinese government issued \$43 billion worth of special bonds to finance investment in the public infrastructure and indicated that it may issue another \$18 billion in 2001 and 2002 to ensure that economic growth continues [17]. China's GDP increased by 7.6 percent in the first three quarters of 2001, and it is expected to slip only slightly in 2002, to 7.2 percent. That said, China's accession into the World Trade Organization at the end of 2001 is expected to result in a short-term adverse impact on the economy, with fears that foreign competition may test China's often inefficient state-owned firms [18].

India has also thus far weathered the global economic slowdown fairly well, reporting higher than expected increments in income in 2001. At present, there are increasing signs of a slowdown in India as the growth in exports continues to decline and consumer spending also begins to falter. Passenger car sales in India fell by 22 percent between September 2000 and September 2001, and sales of commercial vehicles fell by 6 percent over the same time frame [19].

The slowdown in the industrialized countries' economies has affected the performance of economies in Central and South America. However, in two of the larger economies of the region, Brazil and Argentina, other circumstances have exacerbated the short-term economic risk. In Brazil, the largest economy of South America and the world's sixth largest economy, a persistent drought continued in 2001, leading to reduced industrial output as the government imposed a 20-percent cut in power use as part of its rationing program, in an effort to avoid blackouts [20]. Brazil's plan to diversify the electricity mix of the country by increasing thermal generation, particularly in terms of natural-gas-fired capacity, took on more urgency in 2001, partly in response to the ongoing threat of drought in a country that normally generates more than 80 percent of its electricity from hydropower. Reservoir levels fell 28 percent below capacity in key consuming regions of the country in the fall of 2001.

In 2001, the vulnerability of Brazil's electricity supply, in consort with the slowing industrial economies, led to reduced foreign investment, which had been a key contributor to the success of the nation's economy in 2000. With substantial support of foreign direct investment, the Brazilian government was able to handle a large current account deficit and was given a fair amount of latitude in the way it conducted monetary policy [21]. The central bank of Brazil increased interest rates in an attempt to limit the depreciation of the Brazilian real, but Brazil's benchmark interest rate (known as Selic) reached 19 percent in early 2002. With substantially lower exports in the face of the U.S. and world economic slowdown that began in 2001, growth in Brazil's GDP was only 1.5 percent in 2001 and is expected to be only 1.9 percent in 2002, compared with 4.5 percent in 2000 [22].

Argentina is another key economy of the Central and South America region, but it has also experienced several difficult economic years. When the Brazilian real was devalued in 1999, the close economic relationship between the two countries resulted in recessionary problems for the U.S. dollar-pegged Argentine currency. In fact, the country remained in the recession it has now been struggling with for more than 4 years. In early September 2001, the International Monetary Fund (IMF) lent assistance to Argentina, approving an increase of the country's available credit to \$22 billion in an attempt to stabilize the economy and to help attract investment and improve output [23]. Subsequently, however, the IMF decided to withhold some \$1.26 billion in payments to Argentina in December when it became concerned that the country had not implemented sufficient austerity measures [24].

The Argentine financial situation deteriorated so much that President de la Rúa resigned in December 2001, and three new presidents were sworn in and resigned in

quick succession until Eduardo Duhalde took the office [25]. Duhalde announced a devaluation of the Argentine peso which would no longer be pegged to the U.S. dollar. The country also defaulted on a \$28 million payment on a 2007 Italian lira bond—one of the largest defaults on record. There are worries that the default will make it nearly impossible to attract foreign investment into the country and that the new government may be turning away from the free-market policies it has implemented over the past decade in favor of more government control.

One bright spot among the economies of the world is the positive economic growth that continues in the countries of the former Soviet Union (FSU). In 2000, high world oil prices and a devalued ruble helped Russia—the region's largest economy—post its strongest year of economic growth, 8.3 percent, since the dissolution of the Soviet regime [26]. With the devaluation of the ruble making it difficult for consumers in the former Soviet republics to purchase imported products, domestic manufacturers began to increase production strongly. As the ruble regained value in 2001, the manufacturing sector slowed somewhat (as imported goods once again were able to compete with domestic goods), but relatively high world oil prices in the beginning of the year helped to keep economic growth positive in Russia, and its GDP grew by 5.3 percent in 2001.

The other FSU republics benefited from the improving Russian economy. In 2000, Ukraine posted its first increase in GDP since 1989, 5.8 percent, and an even stronger growth rate of 8.5 percent followed in 2001 [27, 28]. The country is a net importer of oil, and the high world oil prices did not benefit the Ukrainian economy. Instead, fiscal reform and strong growth in industrial output, construction activity, agriculture, and exports, along with fast-paced growth in domestic consumption and investment, helped to fuel Ukraine's economic growth. The government has managed to balance the state budget, cut expenditures, and begin the process of privatizing the energy sector as well as restructuring the country's banking sector. The international financial community has been encouraged by these changes and, in late September 2001, the IMF and the World Bank resumed their financing programs for Ukraine by releasing funds that had been on hold since 2000.

Another large FSU economy, Kazakhstan, has also performed well over the past 2 years, with GDP increasing by 9.6 percent in 2000 and 11.6 percent in 2001 [29]. Unlike Ukraine, Kazakhstan is an oil exporter, and much of its growth can be attributed to increased oil production. The government also supported private-sector growth by implementing tax cuts in 2001. With a banking sector that has been privatized and is widely considered to be among the best in the FSU, foreign direct

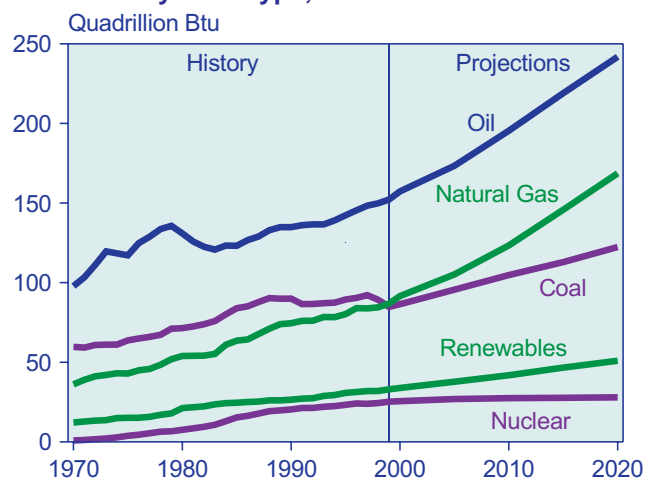
investment has increased strongly over the past few years and is further encouraging the country's economic growth.

Outlook for Primary Energy Consumption

The *IEO2002* reference case projects that consumption of every primary energy source will increase over the 21-year forecast horizon (Figure 16). Most of the increment in energy consumption in the reference case is in the form of fossil fuels (oil, natural gas, and coal), because it is expected that fossil fuel prices will remain relatively low, and that the cost of generating energy from non-fossil fuels will not be competitive. It is possible, however, that as environmental programs or government policies—particularly those designed to limit or reduce greenhouse gas emissions—are implemented, the outlook might change, and non-fossil fuels (including nuclear power and renewable energy sources such as hydroelectricity, geothermal, biomass, solar, and wind power) might become more attractive. The *IEO2002* projections assume that government policies or programs in place as of October 1, 2001, will remain constant over the forecast horizon.

Oil is expected to remain the dominant energy fuel throughout the forecast period (maintaining a 40-percent share of total energy use between 1999 and 2020), as it has for decades. In the industrialized world, increases in oil use are projected primarily in the transportation sector, where there are currently no available fuels to compete significantly with oil products. The *IEO2002* reference case projects declining oil use for

Figure 16. World Energy Consumption by Fuel Type, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

electricity generation, with other fuels (mostly natural gas) expected to be more favorable alternatives to oil-fired generation.

In the developing world, oil consumption is projected to increase for all end uses. In some countries where non-commercial fuels have been widely used in the past (such as fuel wood for cooking and home heating), diesel generators are now sometimes being used to dissuade rural populations from decimating surrounding forests and vegetation, most notably in Sub-Saharan Africa, Central and South America, and Southeast Asia [30]. Because the natural gas infrastructure necessary to expand its use has not been as widely established in the developing world as it has in the industrialized world, natural gas use is expected to grow in the developing world, but not enough to accommodate all of the increase in demand for energy.

Natural gas is projected to be the fastest growing primary energy source worldwide, maintaining growth of 3.2 percent annually over the 1999-2020 period, more than twice the rate of growth for coal use. Natural gas consumption is projected to rise from 84 trillion cubic feet in 1999 to 162 trillion cubic feet in 2020, particularly for electricity generation. Gas is increasingly seen as the desired option for electric power, given the efficiency of combined-cycle gas turbines relative to coal- or oil-fired generation, and the fact that it burns more cleanly than either coal or oil, making it a more attractive choice for countries interested in reducing greenhouse gas emissions.

Coal use worldwide is projected to increase by 2.0 billion short tons (at a rate of 1.7 percent per year) between 1999 and 2020. Substantial declines in coal use are projected for Western Europe and the EE/FSU countries, where natural gas is increasingly being used to fuel new growth in electric power generation, and for other industrial and building sector uses (Figure 17). In the developing world, however, even larger increases are projected for China and India, where coal supplies are plentiful. Together these two countries account for 85 percent of the projected rise in coal use in the developing world over the forecast period.

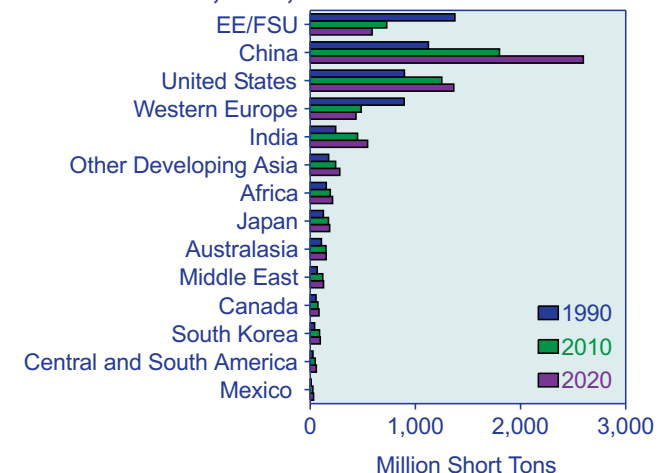
Worldwide, consumption of electricity generated from nuclear power is expected to increase from 2,396 billion kilowatthours in 1999 to 2,667 billion kilowatthours in 2020. Although past editions of this report have projected declines in nuclear electricity consumption toward the end of the forecast horizon, higher capacity utilization and fewer expected retirements of existing plants have resulted in a revision to the expectations for a decline in consumption. Extensions of operating licenses (or the equivalent) for nuclear power plants are expected to be granted among the countries of the

industrialized world, slowing the decline in nuclear generation. In many of the industrialized countries, extending the operating life of a nuclear power plant is a decision left primarily to the owner and thus is an economic decision. In the *IEO2002* reference case, world nuclear capacity is projected to rise from 350 gigawatts in 2000 to 361 gigawatts in 2015 before falling to 359 gigawatts in 2020.

The highest growth in nuclear generation is projected for the developing world, where consumption of electricity from nuclear power is projected to increase by 4.7 percent per year between 1999 and 2020. In particular, developing Asia is expected to see the greatest expansion in new nuclear generating capacity. The nations of developing Asia account for half of the 33 reactors currently under construction worldwide, including 8 in China, 4 in South Korea, 2 in India, and 2 in Taiwan.

Consumption of electricity from hydropower and other renewable energy sources is projected to grow by 2.1 percent annually in the *IEO2002* forecast. With fossil fuel prices projected to remain relatively low in the reference case, renewable energy sources are not expected to be widely competitive, and the renewable share of total energy use is expected to decline from 9 percent in 1999 to 8 percent in 2020. In the developing world, particularly in countries of developing Asia, such as China, India, Malaysia, and Vietnam, much of the growth in renewable energy use is driven by the installation of large-scale hydroelectric power plants. In the industrialized world, nonhydroelectric renewable energy sources are projected to predominate, particularly wind power in Western Europe and biomass and geothermal power in the United States.

Figure 17. World Coal Consumption by Region, 1990, 2010, and 2020



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Outlook for Carbon Dioxide Emissions

If fossil fuel consumption grows to the levels projected in the *IEO2002* reference case, carbon dioxide emissions are expected to rise to 7.9 billion metric tons carbon equivalent in 2010 and to 9.9 billion metric tons by 2020 (Figure 18). Much of the increase is expected in the developing countries, where emerging economies are expected to produce the largest increases in energy consumption, and carbon dioxide emissions are projected to grow by an average of 3.6 percent per year between 1999 and 2020. Developing countries alone account for 77 percent of the projected increment in world carbon emissions between 1990 and 2010 and 72 percent between 1990 and 2020 (Figure 19). Continued heavy reliance on coal and other fossil fuels projected for the developing countries is expected to drive the growth in carbon dioxide emissions over the forecast period.

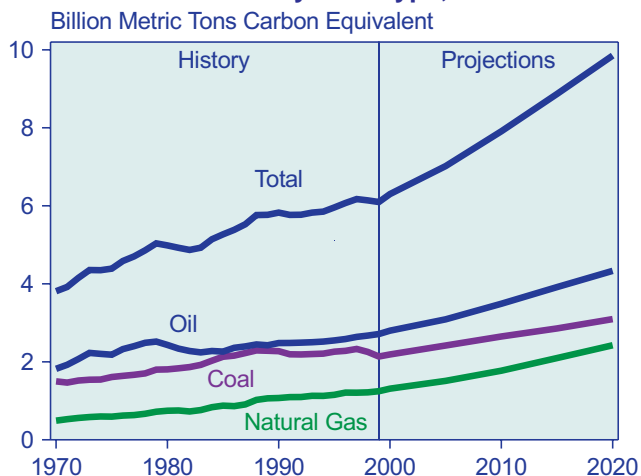
In November 2001, participating member countries of the United Nations' seventh Conference of Parties (COP-7) met in Marrakesh, Morocco, and reached final agreement for the procedures and institutions needed to make the Kyoto Protocol fully operational. Although the

United States was present at COP-6 in Bonn and at COP-7, it did not take an active role in the negotiations. In March 2001, the United States announced that it would not support the Kyoto Protocol. As of March 2002, 83 countries and the European Community had signed the treaty.² It was ratified by 49 signatories, only two of which (the Czech Republic and Romania) are among the Annex I countries³ that would be required to limit or reduce their greenhouse gas emissions relative to 1990 levels under the terms of the Protocol.

On March 4, 2002, the European Union (EU) voted to ratify the Protocol, committing its 15 member countries to reductions in greenhouse gas emissions as specified in the accord [31]. All the EU members are expected to ratify the Kyoto Protocol formally by June 1, 2002. No agreement has been reached among the EU member countries, however, with regard to the individual emission reductions that will be required. Denmark has argued that it was given a disproportionate share of the EU's total reduction burden.

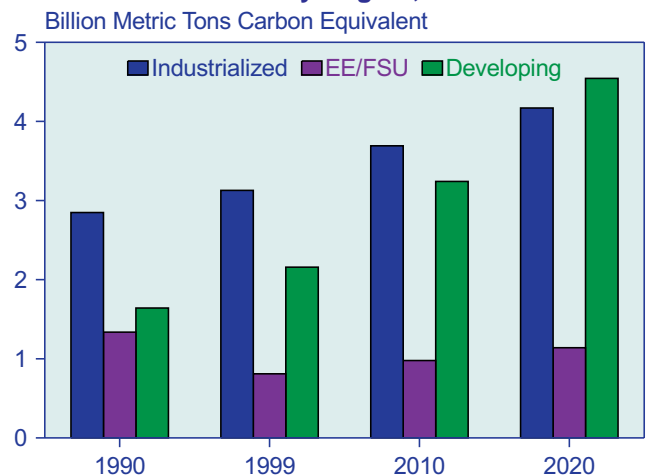
The Kyoto Protocol enters into force 90 days after it has been ratified by at least 55 Parties to the United Nations Framework Climate Change Convention (UNFCCC),

Figure 18. World Energy-Related Carbon Dioxide Emissions by Fuel Type, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 19. World Energy-Related Carbon Dioxide Emissions by Region, 1990-2020



Sources: **1990 and 1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

²The following 49 Parties to the Convention have ratified, accepted, acceded, or approved the Protocol as of March 6, 2002: Antigua and Barbuda, Argentina, Azerbaijan, Bahamas, Bangladesh, Barbados, Benin, Bolivia, Burundi, Colombia, Cook Islands, Cyprus, Czech Republic, Dominican Republic, Ecuador, El Salvador, Equatorial Guinea, Fiji, Gambia, Georgia, Guatemala, Guinea, Honduras, Jamaica, Kiribati, Lesotho, Malawi, Maldives, Malta, Mauritius, Mexico, Micronesia, Mongolia, Morocco, Nauru, Nicaragua, Niue, Palau, Panama, Paraguay, Romania, Samoa, Senegal, Trinidad and Tobago, Turkmenistan, Tuvalu, Uruguay, Uzbekistan, and Vanuatu.

³Turkey and Belarus, which are represented under Annex I of the UNFCCC, do not face quantified emission targets under the Kyoto Protocol. The Kyoto Protocol includes emission targets for 4 countries not listed under Annex I—namely, Croatia, Liechtenstein, Monaco, and Slovenia. Collectively, the 39 Parties facing specific emissions targets under the Kyoto Protocol are commonly referred to as “Annex B Parties,” because their targets were specified in Annex B of the Protocol. In addition, Kazakhstan proposed an amendment to the Marrakesh agreement, requesting that its name be added to the list of Annex I countries.

including a representation of Annex I countries accounting for at least 55 percent of the total 1990 carbon dioxide emissions from the Annex I group. Although the United States had the largest share of Annex I emissions in 1990 at 35 percent, even without U.S. participation the Protocol could enter into force for the other signatories.

Oil consumption is projected to account for the largest increment in worldwide carbon dioxide emissions. In 2020, emissions related to oil use are projected to be 1.9 billion metric tons carbon equivalent higher than the 1990 level. Emissions from natural gas use are expected to be 1.4 billion metric tons above 1990 levels in 2020 and emissions from coal 0.8 billion metric tons above 1990 levels. Although natural gas use is expected to increase at a faster rate than oil use, it is a less carbon-intensive fuel.

If the Kyoto Protocol became effective and the industrialized Annex I countries tried to reduce emissions solely by cutting fossil fuel consumption, reductions in energy use between 30 and 60 quadrillion Btu would be necessary (depending on the mix of fossil fuels used to achieve the reduction because of the relative differences in carbon intensity among the fossil fuels).⁴ It is more likely, however, that most countries would attempt to reduce greenhouse gas emissions through alternative strategies, such as fuel switching, conservation measures, reforestation, emissions trading, and others.

Because there were no binding agreements to reduce or limit greenhouse gas emissions at the time this report was prepared, the *IEO2002* reference case projections do not account for the impact of any potential policy. Carbon dioxide emissions in the industrialized Annex I countries alone (i.e., excluding the transitional Annex I countries of the EE/FSU) are projected to grow to 3,527 million metric tons carbon equivalent in 2010 and 3,938 million metric tons in 2020, from 2,765 million metric tons in 1990. Approximately 43 percent of the expected increment is attributed to natural gas consumption, because many of the industrialized Annex I countries are increasingly turning to natural gas for new electricity generation because of its relative efficiency and low carbon dioxide emissions. Total Annex I emissions are projected to grow to 4,359 million metric tons carbon equivalent in 2010 and 4,900 million metric tons in 2020 from 3,897 million metric tons in 1990.

Oil accounts for 44 percent of the projected increase in carbon dioxide emissions in the industrial Annex I countries, which rely heavily on oil for transportation and, at present, have few economical alternatives. Only 12 percent of the projected increase in carbon dioxide emissions for the region are attributed to coal use. Projected

decreases in coal consumption in Western Europe and moderate increases in the other industrialized countries account for coal's smaller portion of rising emissions.

Carbon dioxide emissions fell by 527 million metric tons in the transitional economies of the EE/FSU between 1990 and 1999, from 1,337 million metric tons to 810 million metric tons carbon equivalent. Emissions in the EE/FSU countries are expected to rise to 978 million metric tons carbon equivalent in 2010 and to 1,139 million metric tons in 2020, remaining below their 1990 level even at the end of the forecast horizon.

IEO2002 projects that the Annex I EE/FSU countries could provide 318 million metric tons of potential emissions allowances for the Annex I emissions reduction effort in 2010. Without allowance trading, the industrialized Annex I countries (including the United States) would have to reduce their emissions by a combined 948 million metric tons (or 27 percent) relative to the reference case projection for 2010. Because the EE/FSU Annex I countries are projected to emit about 318 million metric tons less than their Protocol targets, however, Annex I member countries as a whole would need to reduce their combined emissions by only 630 million metric tons (or 14 percent) in 2010 relative to the baseline projection. Removing the United States from the computations (given the country's announcement that it will not participate in this program), the 318 million metric tons of potential carbon dioxide emissions trading equivalents would mean that the remaining Kyoto Protocol participants would have to reduce their emissions by only 53 million metric tons—2 percent below the *IEO2002* reference case baseline in 2010.

Alternative Growth Cases

A major source of uncertainty in the *IEO2002* forecast is the expected rate of future economic growth. *IEO2002* includes a high economic growth case and a low economic growth case in addition to the reference case. The reference case projections are based on a set of regional assumptions about economic growth paths—measured by GDP—and energy elasticity (the relationship between changes in energy consumption and changes in GDP). The two alternative growth cases are based on alternative assumptions about possible economic growth paths (Figure 20).

For the high and low economic growth cases, different assumptions are made about the range of possible economic growth rates among the industrial, transitional EE/FSU, and developing economies. For the industrialized countries, one percentage point is added to the reference case GDP growth rates for the high economic

⁴This range was calculated by removing consumption of the most carbon-intensive fuel possible, coal, and the least carbon-intensive fossil fuel possible, natural gas, with the understanding that it probably would be impractical to reduce consumption of coal only, and a combination of fossil fuels would have to be reduced.

growth case and one percentage point is subtracted from the reference case GDP growth rates for the low economic growth case. Outside the industrialized world and excluding China and the EE/FSU, reference case GDP growth rates are increased and decreased by 1.5 percentage points to provide the high and low economic growth case estimates.

Because China experienced particularly high, often double-digit growth in GDP throughout much of the 1990s, it has the potential for a larger downturn in economic growth. In contrast, the EE/FSU region suffered a severe economic collapse in the early part of the decade and has been trying to recover from it with mixed success. The EE/FSU nations have the potential for substantially higher economic growth if their current political and institutional problems moderate sufficiently to allow the recovery of a considerable industrial base. As a result of these uncertainties, 3.0 percentage points are subtracted from the reference case GDP assumptions for China to form the low economic growth case, and 1.5 percentage points are added to the reference case to form the high economic growth case. For the EE/FSU region, 1.5 percentage points are subtracted from the reference case assumptions to derive the low economic growth case, and 3.0 percentage points are added for the high economic growth case.

The *IEO2002* reference case shows total world energy consumption reaching 612 quadrillion Btu in 2020, with the industrialized world projected to consume 278 quadrillion Btu, the transitional EE/FSU countries 73 quadrillion Btu, and the developing world 260 quadrillion Btu. In the high economic growth case, total world

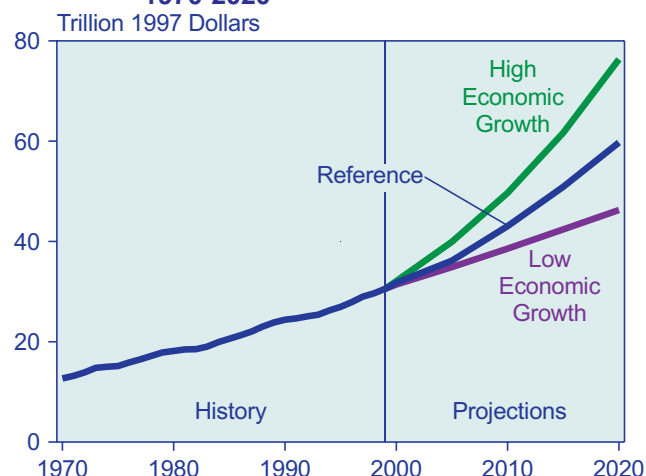
energy use in 2020 is projected to be 728 quadrillion Btu, 117 quadrillion Btu higher than in the reference case (Figure 21). Under the assumptions of the low economic growth case, worldwide energy consumption in 2020 would be 88 quadrillion Btu lower than in the reference case (or 524 quadrillion Btu). Thus, there is a substantial range of 205 quadrillion Btu, or one-third of the total consumption projected for 2020 in the reference case, between the projections in the high and low economic growth cases. Corresponding to the range of the energy consumption forecasts, carbon dioxide emissions in 2020 are projected to total 8,365 million metric tons carbon equivalent in the low economic growth case (1,485 million metric tons less than the reference case projection) and 11,781 million metric tons carbon equivalent in the high economic growth case (1,930 million metric tons higher than the reference case projection).

Trends in Energy Intensity

Another way of quantifying the uncertainty surrounding a long-term forecast is to consider the relationship of energy use to GDP over time. Economic growth and energy demand are linked, but the strength of that link varies among regions and their stages of economic development. In industrialized countries, history shows the link to be a relatively weak one, with energy demand lagging behind economic growth. In developing countries, demand and economic growth have been more closely correlated in the past, with energy demand growth tending to track the rate of economic expansion.

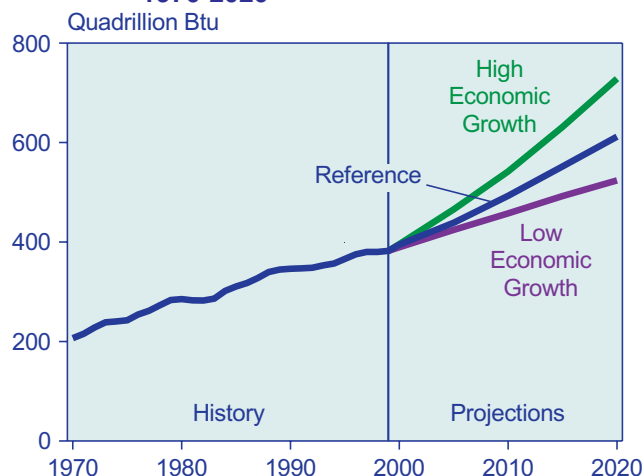
The historical behavior of energy intensity in the FSU is problematic. Since World War II, the EE/FSU economies

Figure 20. World Gross Domestic Product in Three Economic Growth Cases, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** DRI-WEFA, *World Economic Outlook*, Vol. 1 (Lexington, MA, Third Quarter 2001); and EIA, World Energy Projection System (2002).

Figure 21. World Energy Consumption in Three Economic Growth Cases, 1970-2020



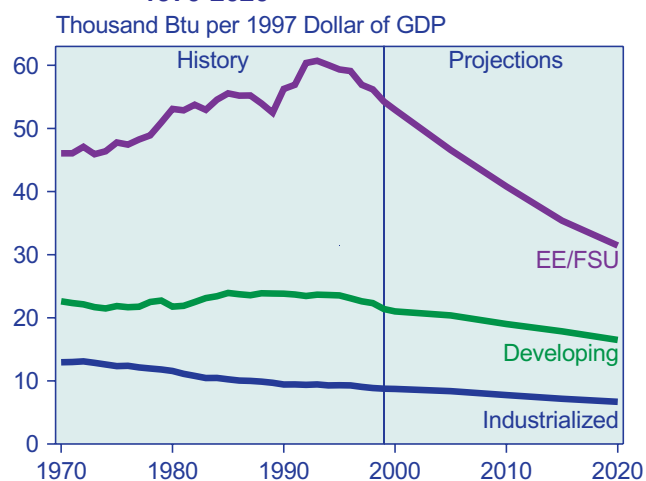
Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

have had higher levels of energy intensity than either the industrialized or the developing countries. In the FSU, however, energy consumption grew more quickly than GDP until 1990, when the collapse of the Soviet Union created a situation in which both income and energy use were declining, but GDP fell more quickly and, as a result, energy intensity increased. Over the forecast horizon, energy intensity is expected to decline in the region as the EE/FSU nations continue to recover from the economic and social problems of the early 1990s. Still, energy intensity in the EE/FSU is expected to be almost double that in the developing world and five times that in the industrialized world in 2020 (Figure 22).

The stage of economic development and the standard of living of individuals in a given region strongly influence the link between economic growth and energy demand. Advanced economies with high living standards have relatively high energy use per capita, but they also tend to be economies where per capita energy use is stable or changes very slowly, and increases in energy use tend to correlate with employment and population growth.

In the industrialized countries, there is a high penetration rate of modern appliances and motorized personal transportation equipment. To the extent that spending is directed to energy-consuming goods, it involves more often than not purchases of new equipment to replace old capital stock. The new stock is often more efficient than the equipment it replaces, resulting in a weaker link between income and energy demand. In developing countries, standards of living, while rising, tend to be low relative to those in more advanced economies.

Figure 22. World Energy Intensity by Region, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Changing growth patterns of energy intensity could have dramatic impacts on energy consumption in the projection period, particularly among the developing countries. For instance, if energy intensities in each of the developing countries are assumed to improve (decline) annually by a percentage equal to the single greatest annual improvement recorded between 1990 and 1999, energy intensity in the developing world as a whole would fall by 69 percent between 1999 and 2020. Historically, the average of the largest single-year improvements in energy intensity for each of the developing nations has been 6 percent, and the single-year improvements for individual developing countries have ranged from 15 percent (China) to 3 percent (Brazil). If energy intensity in each of the developing countries were to improve annually over the forecast period at the highest historical rate of improvement recorded for the country in a single year, their combined energy consumption in 2020 would be 103 quadrillion Btu, as compared with the reference case projection of 260 quadrillion Btu.

If, on the other hand, energy intensity in each of the developing countries were to change annually at the lowest historical rate of improvement (or the highest rate of worsening) recorded for a single year from 1990 to 1999, energy intensity in the developing world as a whole would increase (worsen) by 120 percent between 1999 and 2020. Historically, the average of the largest single-year increases in energy intensity for each of the developing nations (including the smallest historical decreases in countries where energy intensity has improved every year) has been 4 percent, ranging from an increase of 10 percent (South Korea) to a decrease of 4 percent (China). If energy intensity in each of the developing countries were to worsen (increase) annually over the forecast period at the highest historical rate recorded for the country in a single year (or to improve by the lowest rate recorded for countries where energy intensity has improved every year), their combined energy consumption in 2020 would climb to 744 quadrillion Btu in 2020—almost three times the reference case projection.

Forecast Comparisons

Another way to examine the uncertainty associated with the *IEO2002* projections is to compare them with those offered by other forecasters. Four organizations provide forecasts comparable to those in *IEO2002*. The International Energy Agency (IEA) provides “business as usual” projections to the year 2020 in its *World Energy Outlook 2000*. DRI-WEFA also provides energy forecasts by fuel to 2020 in its *World Energy Service: World Outlook 2000*. Petroleum Economics, Ltd. (PEL) and Petroleum Industry Research Associates (PIRA) publish world energy forecasts to the year 2015. For this comparison, 1997 is used as the base year for all the forecasts, because IEA does not publish data for any other historical years.

Regional breakouts among the forecasting groups vary, complicating the comparisons. For example, *IEO2002* includes Mexico in North America, but all the other forecasts include Mexico in Latin America. As a result, for purposes of this comparison, Mexico has been removed from North America in the *IEO2002* projections and added to Central and South America to form a “Latin America” country grouping that matches the other series. DRI-WEFA and PIRA include only Japan in industrialized Asia, whereas industrialized Asia in the *IEO2002* forecast comprises Japan, Australia, New Zealand, and the U.S. Territories. DRI-WEFA and *IEO2002* include Turkey in the Middle East, but IEA includes Turkey, as well as the Czech Republic, Hungary, and Poland, in “OECD Europe” (which is designated as “Western Europe” for this comparison). PEL also places Turkey in Western Europe but includes the Czech Republic, Hungary, and Poland in Eastern Europe, as does *IEO2002*. Although most of the differences involve fairly small countries, they contribute to the variations among the forecasts.

All the forecasts provide projections out to the year 2010 (Table 2). The growth rates for energy consumption among the reference case forecasts for the 1997-2010 time period are similar, ranging between 2.0 and 2.1 percent per year. All the forecasts for total energy consumption fall well within the range of variation defined by the

IEO2002 low and high economic growth cases; in fact, all are within a range of 0.1 percentage point around the *IEO2002* reference case.

The regions for which the largest variations are seen among the forecasts are developing Asia, Latin America, and the EE/FSU. For developing Asia the projected average annual growth rates vary by 1.0 percentage point among the forecasts. DRI-WEFA projects the lowest growth in energy demand in the region at 3.1 percent per year between 1997 and 2010. However, DRI-WEFA only reports a projection for all of Asia, and lower expected growth rates in the industrialized countries of that region (i.e., Australia, Japan, and New Zealand) may be dampening the growth expected in the entire region. PEL projects the highest average growth for developing Asia in the 1997-2010 period, at 4.1 percent per year. *IEO2002* expects energy demand in developing Asia to grow by 3.3 percent annually over this time period.

Among the nations of developing Asia, the widest variations in the energy consumption forecasts are seen for China. PEL projects a growth rate of 4.6 percent per year, higher than projected in the *IEO2002* high economic growth case (4.1 percent per year). The *IEO2002* reference case projection for China defines the lower range of the forecasts, at 3.2 percent per year between 1997 and 2010.

Table 2. Comparison of Energy Consumption Growth Rates by Region, 1997-2010
(Average Annual Percent Growth)

Region	<i>IEO2002</i>			<i>IEO2001</i>	DRI-WEFA	IEA	PIRA	PEL
	Low Growth	Reference	High Growth					
Industrialized Countries	1.0	1.3	1.6	1.3	1.3	1.2	1.0	1.1
United States and Canada	1.4	1.6	1.8	1.5	1.5	1.1	1.3	1.3
Western Europe	0.7	1.1	1.5	1.1	1.1	1.3	0.7	0.9
Asia	0.3	1.0	1.3	0.8	—	1.1	0.3 ^a	0.5
EE/FSU	0.6	1.4	2.0	1.1	1.1	1.4	2.1	0.9
Developing Countries	2.4	3.2	4.5	3.2	2.7	3.6	3.6	3.7
Asia	2.3	3.3	4.7	3.3	3.1 ^c	3.9	3.6	4.1
China	1.5	3.2	4.1	3.2	—	3.6	4.1	4.6
Other Asia ^b	3.1	3.4	5.2	3.3	—	4.2	3.3	3.8
Middle East	2.1	2.8	3.9	3.0	3.6	2.7	3.4	3.3
Africa	1.7	2.4	3.4	2.6	2.5	2.9	2.9	2.8
Latin America	2.9	3.6	4.9	3.6	3.7	3.3	2.6	2.8
Total World	1.4	2.0	2.8	2.0	2.1	2.1	2.0	1.8

^aJapan only.

^bOther Asia includes India and South Korea.

^cIncludes Japan, Australia, and New Zealand.

Sources: *IEO2002*: Energy Information Administration (EIA), World Energy Projection System (2002). *IEO2001*: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. *DRI-WEFA*: DRI-WEFA, *World Energy Service: World Outlook 2000* (Lexington, MA, January 2001). *IEA*: International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), pp. 364-418. *PIRA*: PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001), Tables II-4, II-6, and II-7. *PEL*: Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001), Table 1.

The lower projection for China's energy consumption in the *IEO2002* forecast reflects a precipitous drop in energy use in China between 1997 and 1999, the historical year on which the *IEO2002* forecast is based. Consumption in China fell by 13 percent from 1997 to 1999, attributable to a 24-percent (6 quadrillion Btu) reduction in coal use. As a result, while *IEO2002* projects 5.1-percent annual growth in China's energy use between 1999 and 2010, the higher historical level in 1997 results in a lower growth projection for the 1997-2010 period. The other forecasts were based either on 1997 historical data (IEA) or on the expectation that energy use in China would increase between 1997 and 1999 (PIRA, for instance, estimated a 15-percent increase in energy use over the 2-year period).

Projections for the EE/FSU differ by a range of 1.2 percentage points, varying from 0.9 percent annual growth in energy demand between 1997 and 2010 (PEL) to 2.1 percent per year (PIRA). *IEO2002* projects that energy use in the EE/FSU will increase by 1.4 percent per year over the period. Energy consumption growth rates projected by PIRA fall outside the range defined by the *IEO2002* high and low economic growth cases, demonstrating the great uncertainties among the forecasts about how rapidly the economic recovery might progress over the next decade.

Latin America is another region for which large differences among the forecasts are evident. The projected

growth rates for energy demand from 1997 to 2010 range from 2.6 percent per year (PIRA) to 3.7 percent (DRI-WEFA). The *IEO2002* reference case projects a growth rate of 3.6 percent per year for Latin America. Both PEL and PIRA projections fall below the lower bound of 2.9 percent per year defined by the *IEO2002* low economic growth case, reflecting different expectations of how several key economies of the region (notably, Brazil, Argentina, and Venezuela) may fare over the next several years.

IEO2002, PIRA, and PEL provide forecasts for energy use in 2015, the end of the PEL and PIRA forecast horizons (Table 3), and their projections for worldwide growth in energy consumption between 1997 and 2015 are similar, ranging from 1.9 percent per year (PEL) to 2.1 percent per year (*IEO2002* and PIRA). Regionally, however, there are some differences in the expectations for growth in energy demand. *IEO2002*, and to an even greater degree, PIRA, expect a much faster pace of recovery for the EE/FSU over the 1997-2015 period (1.5 and 2.2 percent per year, respectively) than does PEL (0.9 percent per year). *IEO2002* and PEL project similar annual growth rates for energy consumption in the countries of Eastern Europe between 1997 and 2015, with most of the variation in the EE/FSU forecasts resulting from their different expectations for the FSU. (PIRA does not publish a separate forecast for Eastern Europe and the FSU.) *IEO2002* expects much more robust recovery for energy use in the FSU, projecting an

Table 3. Comparison of Energy Consumption Growth Rates by Region, 1997-2015
(Average Annual Percent Growth)

Region	<i>IEO2002</i>			<i>IEO2001</i>	PIRA	PEL
	Low Growth	Reference	High Growth			
Industrialized Countries	0.9	1.3	1.6	1.2	0.9	0.4
United States and Canada.	1.3	1.5	1.8	1.4	1.1	1.1
Western Europe.	0.6	1.0	1.4	1.0	0.7	0.8
Asia	0.3	1.0	1.3	0.9	0.5	0.3
EE/FSU	0.8	1.5	2.4	1.4	2.2	0.9
Former Soviet Union	0.9	1.7	2.5	1.5	—	0.7
Eastern Europe	0.5	1.1	2.0	1.2	—	1.5
Developing Countries	2.4	3.3	4.6	3.4	3.4	3.5
Asia	2.4	3.4	4.8	3.4	3.7	3.9
China	1.8	3.6	4.5	3.6	4.1	4.1
Other Asia ^a	2.9	3.3	5.0	3.3	3.3	3.6
Middle East	2.2	2.9	4.0	3.1	3.2	3.1
Africa	1.7	2.5	3.6	2.6	2.9	2.6
Latin America.	2.8	3.8	4.9	3.7	2.7	2.8
Total World.	1.5	2.1	2.9	2.1	2.1	1.7

^aOther Asia includes India and South Korea.

Sources: *IEO2002*: Energy Information Administration (EIA), World Energy Projection System (2002). *IEO2001*: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. **PIRA**: PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001), Tables II-4, II-6, and II-7. **PEL**: Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001).

average increase of 1.7 percent per year, than does PEL (0.7 percent per year).

There is also a significant difference among the three forecasts for the industrialized world over the 1997-2015 time period. The expected average annual growth in energy consumption for the industrialized nations ranges from 0.4 percent for PEL to 1.3 percent in the *IEO2002* reference case. The *IEO2002* projections are higher than PEL's and PIRA's for each of the three regions of the industrialized world. Higher expectations for developing Asia in the PEL and PIRA forecasts, however, offset the more pessimistic outlook for the industrialized nations.

IEO2002, IEA, and DRI-WEFA provide energy consumption projections for 2020. Table 4 provides a comparison of growth rates between 1997 and 2020 by region for the three forecasts. Again, the expectations for growth in total world energy consumption are similar, ranging from 2.0 percent per year (IEA) to 2.1 percent per year (DRI-WEFA and *IEO2002*). There are also relatively large differences among the forecasts for the EE/FSU, with growth rate projections ranging from 1.3 percent per year (DRI-WEFA) to 1.6 percent per year (IEA), with *IEO2002* at 1.5 percent per year.

There are some differences among the three forecasts for energy demand growth in the industrialized region

from 1997 to 2020. IEA is less optimistic about growth in the United States and Canada (0.9 percent per year) than is DRI-WEFA (1.1 percent per year) or *IEO2002* (1.3 percent per year). DRI-WEFA, however, does not distinguish between industrialized and developing Asia in its forecast, and so it is difficult to assess what the expectations for Australia, Japan, and New Zealand may have meant for the DRI-WEFA industrialized world growth forecasts during this time period. Both *IEO2002* and IEA project that energy demand in Western Europe and the industrialized Asian countries will grow by 1.0 percent per year between 1997 and 2020.

Energy consumption projections for the developing world also vary in the three forecasts. While all three project the lowest growth rates among the developing world to be in Africa, *IEO2002* expects only a 2.5-percent average annual increase in energy consumption in the region, compared with DRI-WEFA's 2.6 percent and IEA's 2.8 percent. For the Middle East, IEA and *IEO2002* project average annual growth of 2.8 percent, whereas DRI-WEFA projects a 3.4-percent average annual increase over the forecast horizon. Both *IEO2002* and IEA also expect the highest growth in energy consumption to occur in developing Asia (including China); however, because Japan, Australia, and New Zealand cannot be disaggregated from DRI-WEFA's Asia consumption forecast, projected growth is dampened (3.0 percent per year).

Table 4. Comparison of Energy Consumption Growth Rates by Region, 1997-2020
(Average Annual Percent Growth)

Region	<i>IEO2002</i>			<i>IEO2001</i>	DRI-WEFA	IEA
	Low Growth	Reference	High Growth			
Industrialized Countries	0.9	1.2	1.5	1.1	1.1	0.9
United States and Canada.	1.2	1.4	1.7	1.3	1.2	0.9
Western Europe.	0.6	1.0	1.3	1.0	0.9	1.0
Asia	0.3	1.0	1.3	0.9	—	1.0
EE/FSU	0.8	1.5	2.4	1.4	1.3	1.6
Former Soviet Union	0.9	1.6	2.5	1.5	1.4	—
Eastern Europe	0.6	1.2	2.1	1.3	0.9	—
Developing Countries	2.3	3.3	4.5	3.4	2.7	3.4
Asia	2.3	3.4	4.7	3.4	3.0	3.7
China	1.8	3.7	4.6	3.7	—	3.4
Other Asia ^a	2.7	3.2	4.8	3.2	—	4.0
Middle East	2.2	2.8	4.1	3.1	3.4	2.8
Africa	1.6	2.5	3.5	2.6	2.6	2.8
Latin America.	2.6	3.8	4.7	3.7	3.5	3.1
Total World	1.4	2.1	2.9	2.1	2.1	2.0

^aOther Asia includes India and South Korea.

Sources: *IEO2002*: Energy Information Administration (EIA), World Energy Projection System (2002). *IEO2001*: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. *DRI-WEFA*: DRI-WEFA, *World Energy Service: World Outlook 2000* (Lexington, MA, January 2001). *IEA*: International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), pp. 364-418.

Finally, the projections vary not only with respect to levels of total energy demand but also with respect to the composition of primary energy inputs. All the forecasts provide energy consumption projections by fuel in 2010 (Table 5). DRI-WEFA does not provide a breakout of nuclear and other sources of electricity generation but instead provides a single forecast for “primary electricity.”

In terms of oil consumption, all the forecasts expect similar growth worldwide between 1997 and 2010. Oil demand is projected to increase by between 1.7 percent per year (PIRA) and 2.1 percent per year (DRI-WEFA and *IEO2002*). All the forecasts expect natural gas use to grow more rapidly than other fuels between 1997 and 2010. *IEO2002* expects slower growth in coal use over the 13-year period than do the other forecasts. *IEO2002* projects a 1.0-percent average annual growth rate for coal use, as compared with a range of 1.5 percent per year (PEL) to 1.8 percent per year (PIRA and DRI-WEFA) in the other forecasts.

IEO2002 is more optimistic about the prospects for nuclear electricity generation, projecting average growth of 1.1 percent per year between 1997 and 2010, as compared with the range of 0.6 percent per year (PEL) to 0.8 percent per year (IEA and PIRA) projected in the other forecasts. This optimism reflects the expectations that nuclear generators in the United States and other parts of the industrialized world and in the EE/FSU will not be retired as quickly as expected in prior outlooks.

PEL, PIRA, and *IEO2002* provide world energy consumption projections by fuel for 2015 (Table 6). The three forecasts reflect different views about expected growth by fuel between 1997 and 2015. *IEO2002* expects strong growth in natural gas use to result in slow growth in coal consumption, particularly for electric power generation. PEL expects natural gas use to grow more slowly and coal use to grow more rapidly than projected in *IEO2002*. PIRA expects faster growth in natural gas and coal use but slower growth for nuclear power and renewables than projected in *IEO2002*. Moreover,

Table 5. Comparison of World Energy Consumption Growth Rates by Fuel, 1997-2010
(Average Annual Percent Growth)

Fuel	<i>IEO2002</i>			<i>IEO2001</i>	DRI-WEFA	IEA	PIRA	PEL
	Low Growth	Reference	High Growth					
Oil	1.6	2.1	2.9	2.1	2.1	2.0	1.7	1.6
Natural Gas	2.5	3.0	3.8	3.1	3.4	2.8	3.4	1.5
Coal	0.2	1.0	1.7	0.8	1.8	1.7	1.8	2.9
Nuclear	0.7	1.1	1.5	1.0	— ^a	0.8	0.8	1.9
Renewable/Other	1.6	2.1	2.9	2.2	— ^a	2.5	1.8	0.6
Total	1.4	2.0	2.8	2.0	2.1	2.1	2.0	1.8
Primary Electricity	1.2	1.7	2.3	1.7	1.5	1.5	1.3	1.3

^aDRI-WEFA reports nuclear and hydroelectric power together as “primary electricity.”

Sources: *IEO2002*: Energy Information Administration (EIA), World Energy Projection System (2002). *IEO2001*: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. **DRI-WEFA**: DRI-WEFA, *World Energy Service: World Outlook 2000* (Lexington, MA, January 2001). **IEA**: International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), pp. 364-418. **PIRA**: PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001), Table II-8. **PEL**: Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001).

Table 6. Comparison of World Energy Consumption Growth Rates by Fuel, 1997-2015
(Average Annual Percent Growth)

Fuel	<i>IEO2002</i>			<i>IEO2001</i>	PIRA	PEL
	Low Growth	Reference	High Growth			
Oil	1.6	2.2	3.0	2.2	1.7	1.7
Natural Gas	2.5	3.1	3.9	3.1	3.4	1.3
Coal	0.3	1.1	1.9	1.0	1.8	2.7
Nuclear	0.4	0.8	1.2	0.8	0.6	1.8
Renewable/Other	1.5	2.1	2.9	2.1	1.9	0.2
Total	1.5	2.1	2.9	2.1	2.1	1.7
Primary Electricity	1.0	1.6	2.2	1.6	1.3	1.3

Sources: *IEO2002*: Energy Information Administration (EIA), World Energy Projection System (2002). *IEO2001*: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. **PIRA**: PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001), Table II-8. **PEL**: Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001).

IEO2002 projects much higher growth in nuclear power use (0.8 percent per year) than does PEL (0.2 percent per year).

IEO2002, IEA, and DRI-WEFA are the only forecasts that provide projections for 2020 (Table 7). The three forecasts show similar expectations for growth in oil and natural gas use but different expectations for coal and nuclear power. In the *IEO2002* reference case, coal use is projected to increase by 1.2 percent per year, whereas

the IEA and DRI-WEFA projections are considerably higher, at 1.7 and 1.9 percent per year, respectively. Much of the future coal use in the *IEO2002* projection is offset by a more robust forecast for nuclear power than in either of the other two forecasts. *IEO2002* expects primary electricity use (nuclear power and renewable energy) to increase by 1.5 percent per year, compared with 1.0 percent per year in the IEA and DRI-WEFA forecasts.

Table 7. Comparison of World Energy Consumption Growth Rates by Fuel, 1997-2020
(Average Annual Percent Growth)

Fuel	<i>IEO2002</i>			<i>IEO2001</i>	DRI-WEFA	IEA
	Low Growth	Reference	High Growth			
Oil	1.5	2.1	3.0	2.2	2.1	1.9
Natural Gas	2.5	3.1	3.9	3.1	3.2	2.7
Coal	0.3	1.2	2.0	1.0	1.9	1.7
Nuclear	0.2	0.7	1.1	0.5	— ^a	0.0
Renewable/Other	1.3	2.1	2.8	2.0	— ^a	2.3
Total	1.4	2.1	2.9	2.1	2.1	2.0
Primary Electricity	0.9	1.5	2.1	1.4	1.0	1.0

^aDRI-WEFA reports nuclear and hydroelectric power together as "primary electricity."

Sources: **IEO2002**: Energy Information Administration (EIA), World Energy Projection System (2002). **IEO2001**: EIA, *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001), Table A1, p. 169. **DRI-WEFA**: DRI-WEFA, *World Energy Service: World Outlook 2000* (Lexington, MA, January 2001). **IEA**: International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), pp. 364-418.

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World Oil Markets

In the IEO2002 forecast, periodic production adjustments by OPEC members are not expected to have a significant long-term impact on world oil markets. Prices are projected to rise gradually through 2020 as the oil resource base is expanded.

Throughout the last quarter of 2001, crude oil prices were below the range preferred by Organization of Petroleum Exporting Countries (OPEC) producers (\$22 to \$28 per barrel for the OPEC basket price). Three factors contributed to the softening of prices late in 2001. First, there was only a loose adherence by some OPEC producers to announced cutbacks in production. Second, the long-anticipated increase in non-OPEC production brought about by the high price environment of 2000 and 2001 began to materialize. Third, world demand growth continued to be extremely sluggish.

World oil prices are expected to show some recovery in 2002, assuming disciplined adherence by OPEC producers to their stated cutback intentions as well as additional supply reductions by several key non-OPEC producers. Russia, Norway, Mexico, Oman, and Angola all have committed to production cutbacks in order to firm up prices. It remains to be seen, however, whether such a coalition of OPEC and non-OPEC producers can demonstrate the restraint necessary to manage the market. Despite evidence that OPEC has achieved some of its price goals in recent years, production cutback strategies traditionally had only sporadic success.

World oil consumption in 2001 rose by less than 100 thousand barrels per day, scattered evenly among the industrialized nations (mainly Western Europe) and developing nations (mainly Latin America). Although the developing Asian economies are no longer in recession, their current growth is modest by comparison with their rapid economic expansion during the early and mid-1990s. Latin American oil demand has also experienced only modest growth since 1999. In the former Soviet Union (FSU), where oil demand grew in 2000 for the first time in more than a decade, there was a slight decline in demand in 2001. Global oil demand in 2002 is expected to grow by about 600,000 barrels per day [1].

OPEC members (not including Iraq) have agreed to cutbacks that will reduce current production levels by about 1.7 million barrels per day, in response to indications of price weakness in the near-term market. It is anticipated that the cutbacks will keep the world oil price (U.S. refiner acquisition cost for imports) commensurate with the lower end of the OPEC target range for the basket price of \$22 to \$28 per barrel throughout 2002,

although additional production corrections are certainly possible. Iraq's oil production and export volumes have been continuing at the sanction levels dictated by the United Nations Security Council. Those levels are assumed to remain in effect throughout all of 2002.

Historically, OPEC's market management strategies have often ended in failure. OPEC's recent successes have been the result of tight market conditions and disciplined participation by OPEC members. Currently, spare production capacity worldwide—with the exception of two or three Persian Gulf members of OPEC—is negligible, making OPEC's consensus building easier as a result. Non-OPEC production is expected to show significant increases in the near future, however, and several members of OPEC have announced plans to expand production capacity over the next several years. In an oil market environment with substantial spare production capacity, it will be more difficult for OPEC to achieve unanimity among its members.

Although non-OPEC producers have been somewhat slow in reacting to higher oil prices, there remains significant untapped production potential worldwide, especially in deepwater areas. Although the lag between higher prices and increases in drilling activity seems to have increased in the aftermath of the low price environment of 1998 and 1999, non-OPEC production increased by 1.1 million barrels per day in 2000 and by an additional estimated 700 thousand barrels per day in 2001, and it is expected to increase by another 1 million barrels per day in 2002. Almost one-half of the worldwide non-OPEC production increase over the next 2 years is expected to come from the FSU. The remainder of the expected increase is evenly divided between producers in industrialized nations and those in developing economies.

Incorporating the recent price turbulence into the construction of an intermediate- and long-term oil market outlook is difficult and raises the following questions: Will prices return to OPEC's preferred range in response to production cutback strategies, or will the anticipated increase in non-OPEC production temper the price rise? Will sustained and robust economic growth in developing countries return in the aftermath of the severe setback to the Asian economies in 1997-1999? Will

technology guarantee that oil supply development will move forward even if a low world oil price environment returns?

Although oil prices more than doubled in real terms from 1998 to 1999 and have softened considerably since then, such developments are not indicative of the trend in the *International Energy Outlook 2002 (IEO2002)* reference case. In the short term, oil prices are expected to decline slightly until agreed-upon OPEC production cutbacks are put into place along with some non-OPEC cooperation early in 2002. From their anticipated level in 2002, oil prices are expected to increase gradually to 2020. When the economic recovery in Asia is complete, demand growth in developing countries throughout the world is expected to be sustained at robust levels. Worldwide oil demand is projected to reach almost 119 million barrels per day by 2020, requiring an increment to world production capability of almost 44 million barrels per day relative to current capacity. OPEC producers are expected to be the major suppliers of increased production requirements, but non-OPEC supply is expected to remain highly competitive, with major increments to supply coming from offshore resources, especially in the Caspian Basin, Latin America, and deepwater West Africa.

Over the past 25 years, oil prices have been highly volatile. In the future, one can expect volatile behavior to recur principally because of unforeseen political and economic circumstances. It is well recognized that tensions in the Middle East, for example, could give rise to serious disruptions of normal oil production and trading patterns. On the other hand, significant excursions from the reference price trajectory are not likely to be long sustained. High real prices deter consumption and encourage the emergence of significant competition from marginal but large sources of oil and other energy supplies. Persistently low prices have the opposite effects.

Limits to long-term oil price escalation include substitution of other fuels (such as natural gas) for oil, marginal sources of conventional oil that become reserves (i.e., economically viable) when prices rise, and nonconventional sources of oil that become reserves at still higher prices. Advances in exploration and production technologies are likely to bring down prices when such additional oil resources become part of the reserve base. The *IEO2002* low and high world oil price cases suggest that the projected trends in growth for oil production are sustainable without severe oil price escalation. There are oil market analysts, however, who find this viewpoint to be overly optimistic, based on what they consider to be a significant overestimation of both proven reserves and ultimately recoverable resources (see box on page 25).

Highlights of the *IEO2002* projections for the world oil market are as follows:

- The reference case oil price projection shows an increase of more than \$4 per barrel over current prices out to 2003, followed by a modest 0.6-percent average annual increase from 2003 to 2020.
- Deepwater exploration and development initiatives are generally expected to be sustained worldwide, with the offshore Atlantic Basin emerging as a major future source of oil production in both Latin America and Africa. Technology and resource availability can sustain large increments in oil production capability at reference case prices. The low price environment of 1998 and early 1999 did slow the pace of development in some prospective areas, especially the Caspian Basin region.
- Economic development in Asia is crucial to long-term growth in oil markets. The projected evolution of Asian oil demand in the reference case would strengthen economic ties between Middle East suppliers and Asian markets.
- Although OPEC's share of world oil supply is projected to increase significantly over the next two decades, competitive forces are expected to remain strong enough to forestall efforts to escalate real oil prices significantly. Competitive forces operate within OPEC, between OPEC and non-OPEC sources of supply, and between oil and other sources of energy (particularly natural gas).
- The uncertainties associated with the *IEO2002* reference case projections are significant. The international war on terrorism, uncertain economic recovery in developing Asia and Japan, the success of China's economic reforms and its political situation, Brazil's impact on other Latin American economies, and economic recovery prospects for the FSU all increase the risk of near-term political and policy discontinuities that could lead to oil market behavior quite different from that portrayed in the projections.

World Oil Prices

The near-term price trajectory in the *IEO2002* reference case is somewhat different from that in *IEO2001*. In last year's reference case price path, only modest relief was expected in 2001 from the high oil prices of late 1999 and 2000, primarily because of OPEC's demonstrated ability to adhere to announced production cutbacks. This year's reference case price path shows prices falling to \$21.55 per barrel in 2001, based on weak demand, less-than-anticipated non-OPEC supply, some cheating by OPEC members in their market management strategies, and

Oil Resources in the 21st Century: What Shortage?

In the late 1990s it became fashionable to warn the world of a looming shortage in worldwide oil supplies. Much of the pessimistic speculation was related to a disbelief in the estimates of oil reserves, especially those claimed by OPEC nations throughout the 1980s. Although the controversy regarding oil reserves has dissipated somewhat, there has been much evidence that the long-term production potential of oil resources is healthy. This is true for both conventional oil and nonconventional resources.

The U.S. Geological Survey, in its most recent assessment of oil's long-term production potential, identified at least 3 trillion barrels (mean estimate) of ultimately recoverable conventional oil worldwide.^a Because history has shown that only about one-fourth of the oil estimated to be "ultimately recoverable" has actually been produced, rough calculations would place the likely peak in worldwide conventional oil production at some point beyond 2020.

No one doubts that fossil fuels are subject to depletion, and that depletion leads to scarcity, which in turn leads to higher prices. Resources are defined as nonconventional when they cannot be produced economically at today's prices and technology. With higher prices, the gap between conventional oil and nonconventional resources narrows. Ultimately, a combination of escalating prices and technological enhancements will transform the nonconventional into the conventional. Much of the pessimism about oil resources has been focused entirely on conventional resources. However, the decade of the 1990s saw technological advances that helped bring down the cost of producing liquid fuels from several nonconventional sources, including heavy oils, tar sands, and natural gas.

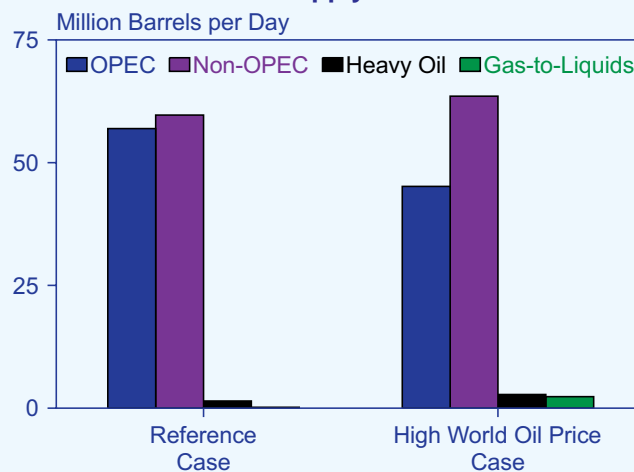
Heavy oils typically have an API gravity of less than 24 degrees and will not flow on their own at standard reservoir temperatures. Tar sands are similar, but with more viscous oil and located closer to the surface. More than 3.3 trillion barrels (oil in place) of heavy oil and tar sands is estimated worldwide, with Canada and Venezuela having the most significant deposits. There are two distinct methodologies for recovering these resources from the ground. For deposits close enough to the surface, mining is feasible. For deeper deposits, steam injection can be used to heat the oil, allowing it to flow more like conventional oil. Once the oil has been retrieved, it still must be cleaned and upgraded before it will behave more like conventional refinery

feedstocks.^b The reference case in *IEO2002* shows development of almost 900 thousand barrels per day in heavy oils and tar sands production capacity over the forecast period. The high world oil price case shows an increase of almost 2.2 million barrels per day of production capacity by 2020. All of the new capacity is expected to be built in Canada and Venezuela. It is assumed that this production capacity could be economically developed and produced at prices in the range of \$23 to \$25 per barrel.

Significant portions of the world's natural gas resources lie in remote locations or are found in small accumulations. Development of such projects usually is discouraged, because delivery via pipeline or LNG tanker is often uneconomical. Using an updated version of a technology that has existed since World War II (Fischer-Tropsch), natural gas molecules can be recombined as liquid synthetic petroleum products. Gas-to-liquids (GTL) technology is an attractive marketing option, because the infrastructure for petroleum products is already in place. The GTL technology also has enough versatility to accommodate smaller gas deposits economically. In addition, GTL offers a number of environmental advantages that may enhance its economic attractiveness.^c

A few GTL projects are expected to be built in the *IEO2002* reference case because of convenient access to
(continued on page 26)

Projected OPEC, Non-OPEC, and Nonconventional Oil Supply in 2020



Source: Energy Information Administration, World Energy Projection System (2002).

^aU.S. Geological Survey, *World Petroleum Assessment 2000*, web site <http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60>.

^bNational Energy Board, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (Calgary, Alberta, October 2000), p. 22.

^cEnergy Information Administration, *International Energy Outlook 2000*, DOE/EIA-0484(2000) (Washington, DC, March 2000), p. 59.

Oil Resources in the 21st Century: What Shortage? (Continued)

distribution infrastructure. In the high world oil price case, an increase of more than 2.3 million barrels per day is projected over the forecast period, including projects in Latin America, the Pacific Rim, the Middle East, the former Soviet Union, and the United States. It is assumed that this production capacity could be economically developed and produced at prices in the range of \$26 to \$28 per barrel. The figure below compares the supply-side response in the *IEO2002* high world oil price case with that in the reference case.

In the *IEO2002* high world oil price case, heavy oil, tar sands, and GTL are the only nonconventional oil supplies that are economically viable. It is conceivable, however, that oil prices could be substantially higher. For example, if the OPEC producers adopt a conservative capacity expansion strategy, prices could more than double in real terms over the forecast period. Such a steady diet of high oil prices would further alter the supply side of the market in ways even beyond those suggested by heavy oil, tar sands, and GTL. For

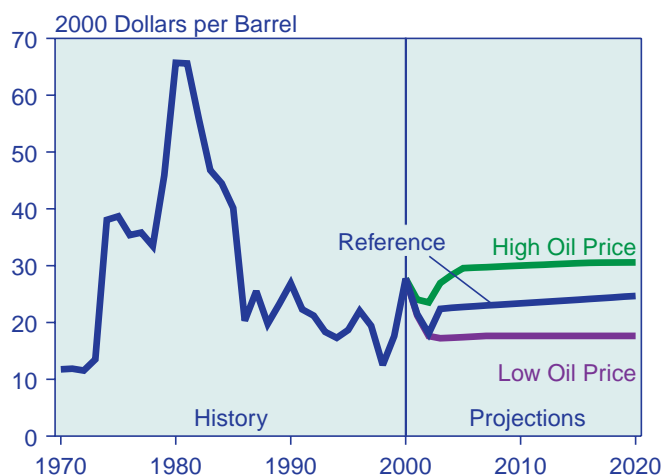
example, other nonconventional liquids might begin to make inroads into such a market. Coal-to-liquids technologies and even shale oil (with enormous worldwide reserves that dwarf those of conventional oil) might be introduced into the supply mix.

Any long-term strategy that has as an objective the achievement of sustained high prices is unlikely to be successful, given the feasibility of making nonconventional supplies economical at those prices. The inability to predict accurately the diminishing costs of current technologies or the enhanced capabilities of new technologies could make a long-term high price strategy a risky one for OPEC. Reasonable arguments can be made that any artificial (non-market) means of production management might achieve short-term objectives but are unlikely to optimize revenues or stabilize market share in the long run. It is anticipated that nonconventional oil resources will act as a buffer against prolonged periods of high oil prices well into the middle of this century, and perhaps well beyond.

Saudi Arabia's decision to postpone production cutbacks in the aftermath of the September 11, 2001, terrorist attacks on the United States. In both outlooks, the price trajectory in the reference case beyond 2005 shows a gradual increase of about 0.5 percent per year to 2020. Three possible long-term price paths are shown in Figure 23. In the reference case, projected prices reach \$24.68 in 2020 (all prices in 2000 dollars unless otherwise

noted). In nominal dollars, the reference case price is expected to exceed \$42 in 2020. In the low price case, prices are projected to reach \$17.41 by 2005 and to remain at about that level out to 2020. In the high price case, prices are projected to reach \$30.50 by 2015 and to remain at about that level out to 2020. The projected leveling off in the high price case is due to the market penetration of alternative energy supplies that could become economically viable at that price.

Figure 23. World Oil Prices in Three Cases, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, July 2001). **Projections:** 2000-2002—EIA, *Short-Term Energy Outlook*, on-line version (January 8, 2002), web site www.eia.doe.gov/emeu/steo/pub/contents.html. 2003-2020—EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383 (2002) (Washington, DC, December 2001).

In all the *IEO2002* oil price cases, oil demand is expected to rise significantly over the projection period. In the high and low world oil price cases, the projected rise in oil consumption ranges from a low of 39 million barrels per day to a high of 50 million barrels per day, respectively. There is widespread agreement that resources are not a key constraint on world demand to 2020. Rather more important are the political, economic, and environmental circumstances that could shape developments in oil supply and demand.

World Oil Demand

Over the next two decades, oil is projected to remain the dominant fuel in the world energy mix, accounting for 40 percent of total energy consumption worldwide throughout the forecast period. Total world oil demand is expected to grow by 2.2 percent annually, rising from 74.9 million barrels per day in 1999 to 118.6 million barrels per day in 2020 (Figure 24). In the industrialized world, oil use grows much more slowly than the world average, at 1.3 percent per year, as oil markets reach saturation levels in all end use sectors except electric

power. Oil use in the industrialized world is expected to decline as natural gas becomes the fuel of choice for new electricity generation capacity.

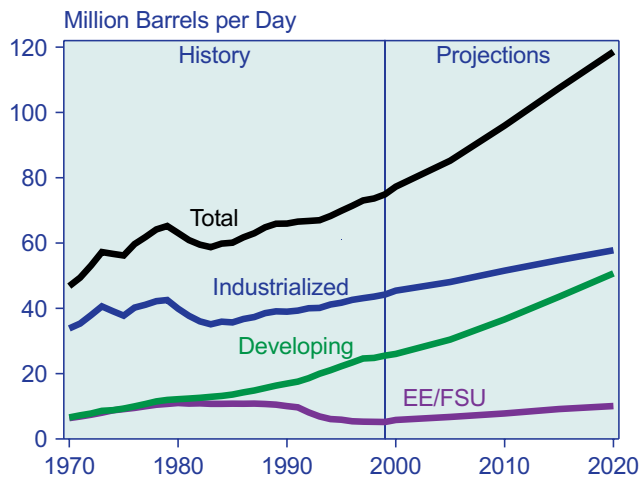
The highest growth in oil demand is projected for developing Asia, at 3.7 percent per year and accounting for 35 percent of the increment in oil consumption in the forecast period (Figure 25). Oil intensity is projected to remain high in developing countries relative to that in the industrial world (Figure 26). Industrial processes continue to require large amounts of fuel relative to

output. Even in the transportation sector, the motor vehicle fleets in developing countries burn large amounts of gasoline or diesel fuel relative to their size, power, and capacity, as is the case in China. Relatively high levels of oil intensity are expected to contribute to the fast-paced growth of oil use in the region as a whole [2].

World oil demand increased modestly in 2001, by 100 thousand barrels per day [3]. Early in 2001 the world oil market was extremely tight. Prices were high and there was concern that there might be shortages in supply. In the last quarter of 2001, however, prices eased considerably as a result of the economic slowdown in the United States and a sharp decrease in jet fuel demand after the September terrorist attacks. The current global economic slowdown is expected to have only short-term effects on oil demand. As the world economy recovers, oil demand is expected to resume an upward trend in the *IEO2002* reference case projection. In general, disruptions in oil demand have historically been short-lived. For instance, in 1990 and 1991 many economies were in recession, and air travel fell sharply in reaction to the Gulf War. As the global economy recovered, however, oil demand returned to its upward trend.

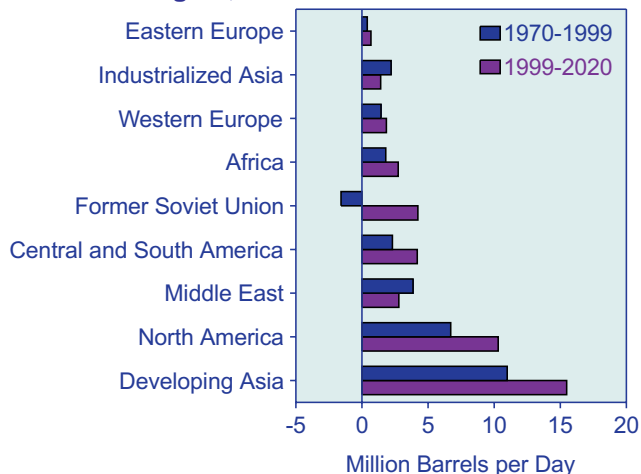
The transportation sector is expected to account for much of the worldwide increase in oil use over the projection period. By 2020, transport is projected to account for 55 percent of world oil demand, based on expectations that there will be no economically viable substitutes for oil as a transportation fuel, and that private ownership of motor vehicles will continue to expand in most of the developing countries.

Figure 24. World Oil Consumption by Region, 1970-2020



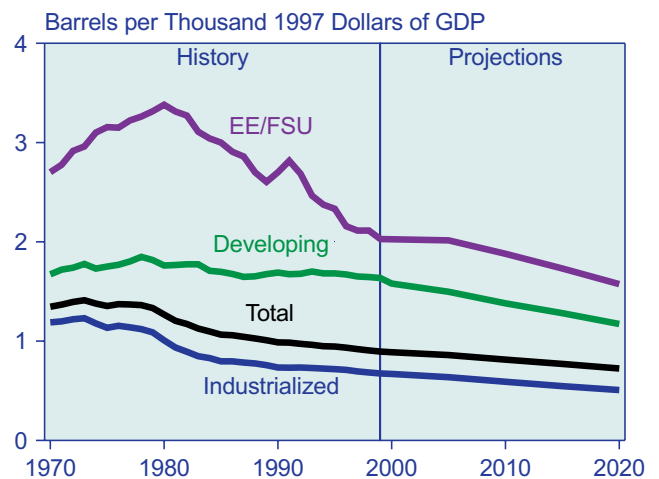
Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 25. Increments in Oil Consumption by Region, 1970-1999 and 1999-2020



Sources: **1970 and 1999:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

Figure 26. Oil Intensity by Region, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

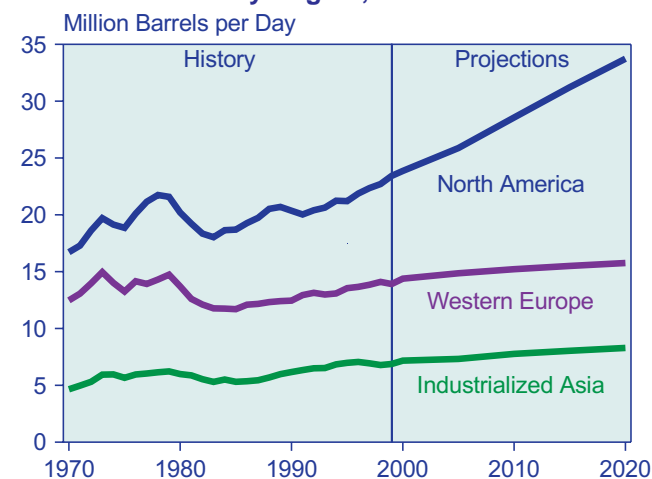
North America

Petroleum product consumption in North America is projected to increase by 10.3 million barrels per day from 1999 to 2020, at an average annual growth rate of 1.8 percent. This is by far the largest expected increase among the industrialized regions (Figure 27).

The effects of the slowing global economy and the recession in the United States are expected to affect demand for all petroleum products in North America. In the short term, the largest expected reduction in oil demand is in the jet fuel market. U.S. jet fuel demand declined by almost 4 percent in 2001 and is expected to be down by 10 percent in the first half of 2002 [4]. Over the past year, high jet fuel prices, the largest component of airline costs, contributed to the slowdown of air passenger travel and air cargo shipments [5]. The slowdown became steeper after the September 11 terrorist attacks. Most airlines in North America announced significant reductions in flight schedules, averaging 20 to 25 percent from normal levels [6]. There is considerable uncertainty in the short term about the pace of recovery of North American airline travel and jet fuel demand.

The United States is the largest consumer of oil in the world, accounting for more than one-fourth of total world demand. The *IEO2002* reference case projects that primary consumption of oil in the United States will increase by 1.5 percent annually from 1999 to 2020, and that oil's share in the U.S. energy mix will increase slightly, from 39.4 percent in 1999 to 39.7 percent in 2020, totaling 26.7 million barrels per day.

Figure 27. Oil Consumption in the Industrialized World by Region, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

The economic slowdown that started in late 2000 and the terrorist attack on the United States in September 2001 have worsened the short-term demand outlook not only for jet fuel but for all other petroleum products. Distillate fuel use in the United States fell between April and June 2001, when lower natural gas prices led most industrial sector consumers and electric utilities to switch back to natural gas from distillates. Faltering consumer spending and business investment also slowed the growth in demand for petrochemicals and for liquefied petroleum gas (LPG) and naphtha feedstocks as well.

Over the next 20 years, the expected trend of moderate oil prices should facilitate growth in U.S. oil demand, centering on the transportation fuels. The growing penetration of relatively high-consumption sports utility vehicles will support higher oil demand in this sector. It is not expected that diesel will surpass or substitute for gasoline as the primary passenger fuel, as it has in Western Europe. Oil use in the electric power sector is expected to continue its long-term decline as natural-gas-fired generating capacity gains market share. Industrial oil demand is also expected to rise at a modest rate of 1.1 percent per year, reflecting slower growth in industrial output and a continuing structural shift toward less energy-intensive manufacturing and services [7].

In Canada, virtually all the increase in oil consumption expected from 1999 to 2020, estimated at 0.5 million barrels per day, is expected to occur in the transportation sector. Canada's extensive hydroelectric and natural gas resources are widely used for power generation and for industrial and commercial uses. The trend in transport fuel demand is similar to that in the United States. Gasoline is the preferred vehicle fuel in the Canadian market, and sales of sport utility vehicles are rising.

In Mexico, total demand for oil is expected to rise by 4.1 percent per year from 1999 to 2020, sustained by an upsurge in the consumption of oil products in all economic sectors, except for power generation. Transportation is expected to remain the largest consumer of oil products, accounting for 50 percent of total petroleum demand in 2020. Total demand for oil is expected to more than double over the forecast period, rising from 2.0 million barrels per day in 1999 to 4.6 million barrels per day in 2020, due mainly to economic growth and a rapidly expanding population.

Western Europe

Oil is the largest energy source in Western Europe; however, the growth in demand projected for the region is the lowest in the *IEO2002* forecast. Oil use in Western Europe is projected to increase by about 0.6 percent per year, from 13.9 million barrels per day in 1999 to 15.8

million barrels per day in 2020. Most of the incremental demand is expected in the transportation sector.

The oil share of the electricity generation market is expected to continue to decline with the rapid penetration of natural gas in the power sector. At current oil prices, heavy fuel oil is too expensive for normal baseload generation, and its main use is in delivering power at peak periods from existing oil-fired boilers. Because cheaper natural gas has become available in the Southern part of Europe through the Trans-Mediterranean pipeline from North Africa (completed in 1983) and the Algerian Bazoduc Maghreb-Europe pipeline to Spain (completed in 1996) [8], oil's share of the power generation market is expected to continue to decline [9].

Jet fuel demand in Western Europe has increased by 40 percent since 1990, and demand for diesel fuel has risen by more than one-third. Over the same period, gasoline demand has barely changed, mainly because it continues to be more highly taxed than are other fuels, and tax differentials have encouraged consumers to purchase diesel-fueled cars. In addition, the steady growth in road freight is expected to boost diesel demand, assuming that diesel fuel continues to be taxed less heavily than gasoline.

Industrialized Asia

All the countries of industrialized Asia (Japan, Australia, and New Zealand) are net importers of oil. Japan, which imports all the oil it uses, accounts for 81 percent of the total demand in the region. Oil demand in industrialized Asia is projected to increase by an average of 0.9 percent per year, from 6.9 million barrels per day in 1999 to more than 8.3 million barrels per day in 2020. Relative to other fuels, oil use is expected to grow slowly. Oil's share in the region's energy mix is declining steadily with a continuing shift toward other fuels, particularly to natural gas in the power sector. Oil use produces 18 percent of Japan's electricity, and its share has been declining. Australia's use of oil for electricity generation is marginal, and New Zealand uses none [10].

Most of the demand for oil in industrialized Asia is for transportation. In Japan, demand for gasoline continues to rise, in large part because of deregulation of the market. Retail gasoline prices in 2001, on average, remained below the levels of 1996, when the Japanese market was liberalized and competition intensified [11].

Eastern Europe and the Former Soviet Union

After the collapse of the Soviet Union in 1991 oil demand fell steadily, from 8.3 million barrels per day to approximately 3.7 million barrels per day in 1999. However, economic prospects in the region have improved since 2000,

and economic growth is expected for the countries of the FSU in the near future. FSU oil consumption is expected to increase at an annual average rate of 3.7 percent from 1999 to 2020, reaching 8.0 million barrels per day at the end of the forecast period—still well below the region's peak use of 9.0 million barrels per day in 1987.

All the FSU economies began to show positive economic growth in 2000, many of them at high rates. Economic growth in the region is expected to average 4.7 percent per year from 1999 to 2020, but improved industrial efficiencies and fuel switching in favor of natural gas for power generation are projected to result in somewhat slower increases in oil demand, averaging 3.7 percent per year over the forecast.

Oil demand in Eastern Europe is expected to grow by an average of 1.8 percent per year, from 1.5 million barrels per day in 1999 to 2.1 million barrels per day in 2020. Given the expectations for continued economic growth and the accompanying rise in personal income levels, most of the growth in East European oil use is expected to occur in the transportation sector, particularly in the region's largest economies—Poland, Hungary, and the Czech Republic—which are close to Western European markets and are members of the Organization for Economic Cooperation and Development (OECD).

Motorization levels in Eastern Europe (the number of vehicles per thousand persons) are expected to rise from 217 in 1999 to 284 in 2020. Growth in demand for transportation fuels is expected to be led by diesel, as is also expected for the neighboring countries of the European Union. In fact, as part of their drive to join the European Union and meet its fuels standards, major Eastern European refiners such as Poland's PKN Orlen and the Czech Republic's Ceska Rafinerska are continuing to invest heavily in improvements aimed at achieving fuel standards required by the European Union. PKN Orlen, for example, is planning to invest \$250 million at its Plock refinery to improve gasoline and diesel quality to meet 50 parts per million sulfur specifications before 2005. This investment is on top of the \$2 billion spent on a major refinery upgrade project in 2000 [12].

Developing Asia

China

Developing Asia remains the focus of expectations for future growth in world oil demand. In less than 10 years, China is expected to become the largest oil consumer in Asia, surpassing Japan as the world's second largest oil consumer after the United States. With the transportation sector accounting for most of the increase, oil use in China is expected to grow by 4.3 percent per year, from 4.3 million barrels per day in 1999 to 10.5 million barrels per day in 2020 (as compared with 6.4 million barrels per day projected for Japan in 2020).

Currently, the transportation sector is the smallest final energy consumer in China among the major economic sectors, accounting for 14 percent of total energy use. Within the transportation sector, motor fuels consumption accounts for around 70 percent [13]. Vehicle ownership, still relatively low in China at less than 12 cars per thousand persons in 1999, is projected to reach 52 per thousand by 2020. As per capita income rises, the demand for cars, and therefore for transport fuel, is expected to increase dramatically. The Chinese government has allocated more resources to expand and upgrade the highway network in anticipation of this growth. By 2020, demand for transportation fuels is projected to make up 56 percent of total oil demand in China. Increasing personal wealth and higher average incomes in China are expected to outweigh high retail prices for transportation fuels, which still are set by the Chinese government but increasingly have reflected global market prices.

Outside the transportation sector, oil demand in China is projected to increase by an average of 2.4 percent per year, as compared with the average growth rate of 0.5 percent per year projected for nontransportation oil use in the industrialized countries. In the 1970s, China consumed a large volume of crude oil directly in various industries, especially for power generation. In the late 1970s, when crude oil production became stagnant, the government moved to restrict the use of oil in the electric power sector and to convert as many oil-fired power plants to coal firing as possible [14]. Consumption of petroleum products in China grew by 3.2 percent per year on average during the 1980s and by 6.5 percent per year from 1990 to 1999.

India

India is projected to be among the world's fastest growing economies over the forecast period, and its oil consumption is projected to grow by 4.6 percent per year on average from 1999 to 2020, to nearly 4.9 million barrels per day. The country depends on oil for about 33 percent of its total energy needs and imports about 1.3 million barrels per day or two-thirds of its crude oil requirement.

The transportation sector is expected to be the main source of the increase in India's oil demand over the next two decades. Fuel use for road travel is heavily weighted toward diesel fuel, and approximately 80 percent of motor vehicles in India run on diesel (compared to 15 percent in China). Despite substantial increases in crude oil prices from 2000 through early 2001, diesel remains less than half as expensive as gasoline. India's domestic price deregulation will likely support growth in gasoline demand if it proceeds as scheduled in 2002, with prices expected to fall to import parity levels.

India's agricultural sector is a large consumer of oil products, mainly distillate, although droughts like the one experienced in 1999 have tended to dampen oil demand. Assuming normal precipitation in India, agricultural activity is expected to increase, leading to faster growth in demand for oil in this sector.

Other Developing Asia

Although demand for oil products in developing Asia recovered more rapidly than many analysts expected after the economic crisis of 1997-1999, it is anticipated that, over the long term, oil demand will increase at a slower and more sustainable rate than the high growth rates recorded during the 1990s. The short-term economic outlook and oil demand growth remain mixed, given the current weakness of the export-oriented economies such as South Korea, Taiwan, Singapore, Malaysia, Thailand, Indonesia, and the Philippines. Recovery is expected to be in line with the U.S. economy in the next few quarters.

In 2001, naphtha demand increased rapidly as sizable expansions in naphtha-cracking ethylene production capacities took place in Taiwan and Singapore. To meet this growing demand, ExxonMobil constructed an 800,000 metric ton per year ethylene production unit in Singapore, which became fully operational at the end of 2001. In addition, a combined increment of 280,000 metric tons per year in capacity was scheduled for completion in Singapore and Thailand by the end of 2001 [15].

Demand for residual fuel is expected to remain sluggish among the countries of other developing Asia. Power generation and industrial plants are likely to continue shifting away from residual fuel in favor of natural gas. The shutdown of Indonesia's natural gas fields in North Aceh in response to domestic insurgency, however, increased concerns over the stability of the natural gas supply to industries that have switched from oil and have become highly dependent on liquefied natural gas (LNG). South Korea, which currently imports about 42 percent of its LNG from Indonesia [16], would be particularly vulnerable to a disruption of LNG supplies.

Total oil demand in South Korea is projected to grow from 2.0 million barrels per day in 1999 to 3.0 million barrels per day in 2020—an average annual rate of 1.9 percent—led by growth in the transportation and industrial sectors. The rate of increase in oil demand is expected to be much slower than it was over the past two decades. Oil demand grew by more than 8 percent per year between 1980 and 1999, as transportation energy use increased rapidly. The main factors that are expected to slow the growth of oil use in the future are moderating economic growth, industrial restructuring, and energy demand saturation in some sectors, particularly transportation. As the Korean economy moves from

energy-intensive industrial activities to service industries, energy intensity is also projected to decline [17].

Central and South America

Oil consumption in Central and South America is projected to increase from 4.7 million barrels per day in 1999 to 8.8 million barrels per day in 2020. At present, oil consumption in Central and South America accounts for about 48 percent of total primary energy demand. However, oil's share of the energy mix has been steadily declining, mainly in the power generation and industrial sectors due to substitution of hydroelectricity, natural gas, and coal. Continued declines in oil's share in these sectors are expected to be offset by growth in the transportation sector.

Oil consumption for transportation in Central and South America is expected to increase at an average rate of 3.1 percent per year, from 2.6 million barrels per day in 1999 to 4.9 million barrels per day in 2020. The number of vehicles per thousand people is projected to increase from 100 in 1999 to 236 by 2020.

Brazil is the largest economy in Central and South America, accounting for 42 percent of the region's total oil demand. Brazil's oil consumption in 1999 is estimated to have been 2.0 million barrels per day, the same as India's, and it is projected to grow at an annual average rate of 3.3 percent to 3.9 million barrels per day in 2020.

Brazil's electricity capacity shortage in 2000—caused by a persistent drought that reduced hydroelectric reservoir levels substantially—led to rationing in June 2001. In response to the lack of hydroelectric capacity available, some industrial consumers began to use backup diesel generation to avoid shutting down plants. Brazil's state-owned oil company, Petrobras, announced that it would increase oil imports by 20 percent, from 115,000 barrels per day to 140,000 barrels per day, in order to keep up with the new power-related demand [18].

Middle East

Oil dominates the energy mix because of its abundance in the Middle East. After the collapse of oil prices in 1998, economic activities and energy demand in the region were constrained. Low oil prices reduced economic growth in most of the region, particularly Iran and the United Arab Emirates. Saudi Arabia's economy managed to expand but at a slow pace. The impact of lower world oil prices in mid- to late 2001, combined with the economic slowdown led by the United States, kept oil use from expanding in 2001, and demand in the region is expected to be flat in 2002. However, as the world's economies recover and oil demand returns in the industrialized world, so too should growth in Middle East oil use. Oil consumption in the Middle East is projected to grow by 2.1 percent per year, from 5.0

million barrels per day in 1999 to 7.8 million barrels per day in 2020.

Oil demand growth in the Middle East is driven by the transportation sector, particularly in countries with large populations, such as Turkey and Iran. The growing petrochemical sectors of Saudi Arabia and the United Arab Emirates are another explanation for the increase in oil use in the region.

Africa

Oil currently supplies 44 percent of Africa's total energy needs. Demand for oil in the region is projected to grow by 3.6 percent per year, from 2.5 million barrels per day in 1999 to 5.3 million barrels per day in 2020. The transportation and electric power sectors, and to a lesser degree the residential sector, account for most of the region's oil consumption. About 47 percent of Africa's total oil use in 1999 was for transportation, and oil demand in the region's transportation sector is expected to grow by an average of 3.1 percent per year, to 2.2 million barrels per day in 2020.

Oil is widely used for electricity generation in Africa, with the exception of South Africa which has huge domestic coal deposits. In the second half of the forecast period, natural gas is expected to start to make some inroads in the electricity sector as African countries develop natural gas infrastructures [19]. In addition, oil is still important for agricultural activities in many African economies.

The impact of the high oil price environment in 2000 and at the beginning of 2001 was lower demand in South Africa, the largest economy in the region, as well as in many small, oil-importing countries. However, most of the continent's key economies, including Egypt, Nigeria, Algeria, and Libya, export oil and continue to boost their revenues and consequently economic growth and oil use [20].

The Composition of World Oil Supply

In the *IEO2002* reference case, world oil supply in 2020 is projected to exceed the 2000 level by 41 million barrels per day. Increases in production are expected for both OPEC and non-OPEC producers; however, only about one-third of the total increase is expected to come from non-OPEC areas. Over the past two decades, the growth in non-OPEC oil supply has resulted in an OPEC market share substantially under its historic high of 52 percent in 1973. New exploration and production technologies, aggressive cost-reduction programs by industry, and attractive fiscal terms to producers by governments all contribute to the outlook for continued growth in non-OPEC oil production.

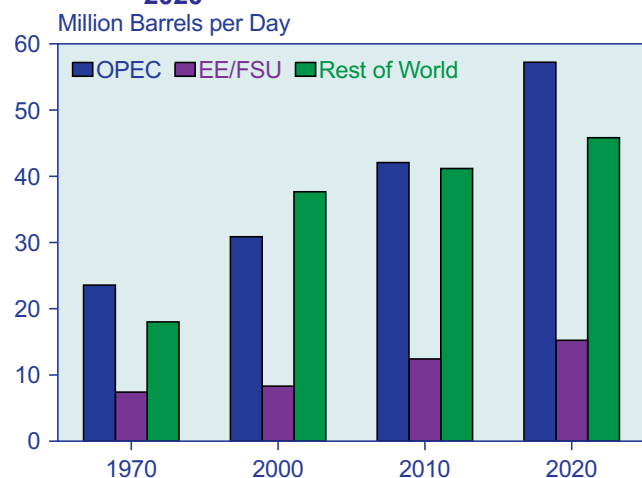
While the long-term outlook for non-OPEC supply remains optimistic, the low oil price environment of 1998 and early 1999 had a definite impact on exploration and development activity. By the end of 1998, drilling activity in North America had fallen by more than 25 percent from its level a year earlier. Worldwide, only the Middle East region registered no decline in drilling activity during 1998. In general, onshore drilling fell more sharply than offshore drilling. Worldwide, offshore rig utilization rates were generally sustained at levels better than 80 percent of capacity [21].

The reference case projects that about two-thirds of the increase in petroleum demand over the next two decades will be met by an increase in production by members of OPEC rather than by non-OPEC suppliers. OPEC production in 2020 is projected to be more than 26 million barrels per day higher than it was in 2000 (Figure 28). The *IEO2002* estimates of OPEC production capacity to 2005 are slightly less than those projected in *IEO2001*, reflecting a shift toward non-OPEC supply projects in the recent high price environment. Some analysts suggest that OPEC might pursue significant price escalation through conservative capacity expansion decisions rather than undertake ambitious production expansion programs; however, the low and high world oil price forecasts in this outlook do not assume such suggestions.

Reserves and Resources

Table 8 shows estimates of the conventional oil resource base by region out to the year 2025, based on the *World Petroleum Assessment 2000* by the U.S. Geological Survey (USGS). The oil resource base is defined by three

Figure 28. World Oil Production in the Reference Case by Region, 1970, 2000, 2010 and 2020



Sources: **History:** Energy Information Administration (EIA), *International Petroleum Monthly*, DOE/EIA-0520(2001/11) (Washington, DC, November 2001). **Projections:** EIA, World Energy Projection System (2002).

categories: remaining reserves (oil that has been discovered but not produced); reserve growth (increases in reserves resulting mainly from technological factors that enhance a field's recovery rate); and undiscovered (oil that remains to be found through exploration). The information in Table 8 is derived from the USGS mean estimate, an average assessment over a wide range of uncertainty for reserve growth and undiscovered resources. The *IEO2002* oil production forecast is based on the USGS mean assessment.

Expansion of OPEC Production Capacity

It is generally acknowledged that OPEC members with large reserves and relatively low costs for expanding production capacity can accommodate sizable increases in petroleum demand. In the *IEO2002* reference case, the production call on OPEC suppliers is projected to grow at a robust annual rate of 3.3 percent through 2020 (Table 9 and Figure 29). OPEC capacity utilization is expected to increase sharply after 2000, reaching 95 percent by 2015 and remaining there for the duration of the projection period.

Table 8. Estimated World Oil Resources, 2000-2025
(Billion Barrels)

Region and Country	Proved Reserves	Reserve Growth	Undiscovered
Industrialized			
United States	30.48	76.03	83.03
Canada	15.46	12.48	32.59
Mexico	35.48	25.63	45.77
Japan	0.15	0.09	0.31
Australia/New Zealand . .	4.34	2.65	5.93
Western Europe	23.77	19.32	34.58
Eurasia			
Former Soviet Union . . .	63.56	137.70	170.79
Eastern Europe	2.40	1.46	1.38
China	24.00	19.59	14.62
Developing Countries			
Central and South America	99.86	90.75	125.31
India	6.24	3.81	6.78
Other Developing Asia . .	16.51	14.57	23.90
Africa	80.46	73.46	124.72
Middle East	702.69	252.51	269.19
Total	1,105.41	730.05	938.90
OPEC	863.29	395.57	400.51
Non-OPEC	242.12	334.48	538.39

Note: Resources include crude oil (including lease condensates) and natural gas plant liquids.

Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site <http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60>.

Iraq's role in OPEC in the next several years will be of particular interest. In 1999, Iraq expanded its production capacity to 2.8 million barrels per day in order to reach the slightly more than \$5.2 billion in oil exports allowed by United Nations Security Council resolutions. The expansion was required because of the low price environment of early 1999. In the *IEO2002* reference case, Iraq is assumed to maintain its current oil production capacity of 3.1 million barrels per day into 2002, and its exports are assumed to generate revenues no greater than those allowed by the United Nations Security Council sanctions. Iraq has indicated a desire to expand its production capacity aggressively, to about 6 million barrels per day, once the sanctions are lifted. Preliminary discussions of exploration projects have already been held with potential outside investors, including France, Russia, and China. Such a significant increase in Iraqi oil exports would offset a significant portion of the price stimulus associated with current OPEC production cutbacks.

Given the requirements for OPEC production capacity expansion implied by the *IEO2002* estimates, much attention has been focused on the oil development, production, and operating costs of individual OPEC producers. With Persian Gulf producers enjoying a reserve-to-production ratio that exceeds 86 years, substantial capacity expansion clearly is feasible.

Production costs in Persian Gulf OPEC nations are less than \$2 per barrel, and the capital investment required to increase production capacity by 1 barrel per day is less than \$5,500 [22]. Assuming the *IEO2002* low price trajectory, total development and operating costs over the entire projection period, expressed as a percentage of gross oil revenues, would be less than 23 percent. Thus, Persian Gulf OPEC producers can expand capacity at a

cost that is a relatively small percentage of projected gross revenues.

For OPEC producers outside the Persian Gulf, the cost to expand production capacity by 1 barrel per day is considerably greater, exceeding \$12,000 in some member nations; yet those producers can expect margins in excess of 32 percent on investments to expand production capacity over the long term, even in the low price case [23]. Venezuela has the greatest potential for capacity expansion and could aggressively increase its production capacity by more than 1.1 million barrels per day, to 4.2 million barrels per day by 2005. It is unclear, however, whether the current political climate will support the outside investment required for any substantial expansion of production capacity. Tables D1-D6 in Appendix D show the ranges of production potential for both OPEC and non-OPEC producers.

The reference case projection implies aggressive efforts by OPEC member nations to apply or attract investment capital to implement a wide range of production capacity expansion projects. If those projects were not undertaken, world oil prices could escalate; however, the combination of potential profitability and the threat of competition from non-OPEC suppliers argue for the pursuit of a relatively aggressive expansion strategy.

In the *IEO2002* forecast, OPEC members outside the Persian Gulf are expected to increase their production potential substantially, despite their higher capacity expansion costs. There is much optimism regarding Nigeria's offshore production potential, although it is unlikely to be developed until the middle to late part of this decade. In addition, increased optimism about the

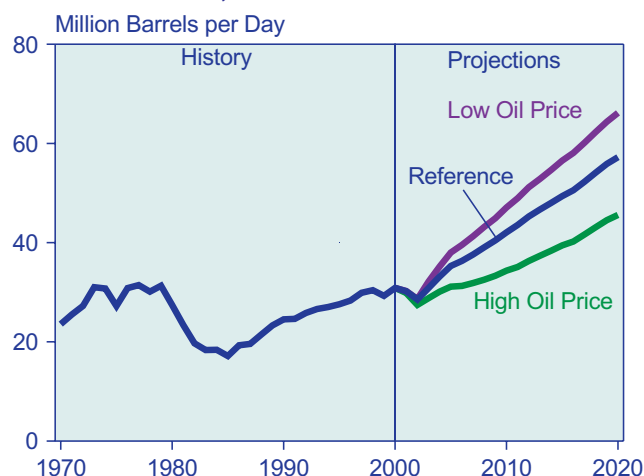
Table 9. OPEC Oil Production, 1990-2020
(Million Barrels per Day)

Year	Reference Case	High Oil Price	Low Oil Price
History			
1990	24.5	—	—
2000	30.9	—	—
Projections			
2005	35.3	31.1	38.0
2010	42.1	34.3	47.1
2015	49.4	39.4	56.5
2020	57.2	45.6	66.2

Note: Includes the production of crude oil, natural gas plant liquids, refinery gain, and other liquid fuels.

Sources: **History:** Energy Information Administration (EIA), *International Petroleum Monthly*, DOE/EIA-0520(2001/11) (Washington, DC, November 2001), Table 1.4. **Projections:** EIA, World Energy Projection System (2002).

Figure 29. OPEC Oil Production in Three Oil Price Cases, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *International Petroleum Monthly*, DOE/EIA-0520(2001/11) (Washington, DC, November 2001). **Projections:** EIA, World Energy Projection System (2002).

production potential of Algeria, Libya, and Venezuela supports the possibility of reducing the world's dependence on Persian Gulf oil.

Non-OPEC Supply

The growth in non-OPEC oil supplies played a significant role in the erosion of OPEC's market share over the past two decades, as non-OPEC supply became increasingly diverse. North America dominated non-OPEC supply in the early 1970s, the North Sea and Mexico evolved as major producers in the 1980s, and much of the new production in the 1990s has come from the developing countries of Latin America, West Africa, the non-OPEC Middle East, and China. In the *IEO2002* reference case, non-OPEC supply from proven reserves is expected to increase steadily, from 46.0 million barrels per day in 2000 to 61.1 million barrels per day in 2020 (Table 10).

There are several important differences between the *IEO2002* production profiles and those published in *IEO2001*:

- The U.S. production decline is considerably less severe in the *IEO2002* projections as a result of higher oil price paths, technological advances yielding higher recovery rates, and lower costs for deep exploration and production in the Gulf of Mexico.
- The estimated peak for North Sea production is delayed by a year to 2006 in the *IEO2002* forecast, and the expected decline in production to 2020 is slightly tempered, due to higher oil price paths coupled with enhanced subsea and recovery technologies.
- Resource development in the Caspian Basin region was expected to be delayed significantly in the *IEO2001* forecast due to significant geopolitical

challenges and an expected lower price environment. In the *IEO2002* projections, Caspian output is expected to rise to almost 3 million barrels per day by 2005 and to increase steadily thereafter. There still remains a great deal of uncertainty about export routes from the Caspian Basin region.

- *IEO2001* anticipated moderate delays in the exploration and development of deepwater projects worldwide. Significant output from such projects was not anticipated until oil prices returned to and remained in the range of \$22 to \$28 per barrel for a significant period of time. With higher world oil price assumptions, output from deepwater projects in the U.S. Texas Gulf, the North Sea, West Africa, the South China Sea, Brazil, Colombia, and the Caspian Basin is accelerated in the *IEO2002* forecast by 2 to 3 years (see box on page 35).

In the *IEO2002* forecast, North Sea production reaches a peak in 2006, at almost 6.7 million barrels per day. Production from Norway, Western Europe's largest producer, is expected to peak at about 3.4 million barrels per day in 2004 and then gradually decline to about 3.0 million barrels per day by the end of the forecast period with the maturing of some of its larger and older fields. The United Kingdom sector is expected to produce about 2.7 million barrels per day by the middle of this decade, followed by a decline to 2.5 million barrels per day by 2020.

Two non-OPEC Persian Gulf producers are expected to increase output gradually for the first half of this decade. Enhanced recovery techniques are expected to increase current output in Oman by more than 180,000 barrels per day, with only a gradual production decline anticipated after 2005. Current oil production in Yemen is expected to increase by at least 110,000 barrels per day within the next couple of years, and those levels should show little decline throughout the forecast period. Syria is expected to hold its production flat through the first half of this decade, but little in the way of new resource potential will allow anything except declining production volumes.

Oil producers in the Pacific Rim are expected to increase their production volumes significantly as a result of enhanced exploration and extraction technologies. India is expected to show some modest production increase early in this decade and only a modest decline in output thereafter. Deepwater fields offshore from the Philippines have resulted in an improved reserve picture. By the middle of this decade, production is expected to reach almost 240,000 barrels per day. Vietnam is still viewed with considerable optimism regarding long-term production potential, although exploration activity has been slower than originally hoped. Output levels from Vietnamese fields are expected to exceed 425,000 barrels per day by 2020.

Table 10. Non-OPEC Oil Production, 1990-2020
(Million Barrels per Day)

Year	Reference Case	High Oil Price	Low Oil Price
History			
1990	42.2	—	—
2000	46.0	—	—
Projections			
2005	49.6	51.7	48.9
2010	53.6	58.1	52.2
2015	57.8	63.7	55.7
2020	61.1	68.2	58.7

Note: Includes the production of crude oil, natural gas plant liquids, refinery gain, and other liquid fuels.

Sources: **History:** Energy Information Administration (EIA), *International Petroleum Monthly*, DOE/EIA-0520(2000/11) (Washington, DC, November 2001), Table 1.4. **Projections:** EIA, World Energy Projection System (2002).

The 21st Century's First Non-OPEC Surprise: The Atlantic Basin

Non-OPEC oil production has always shown amazing resiliency in the face of overt pessimism. Words such as "decline" and "stagnation" have frequently been associated with forecasts of long-term non-OPEC supply potential. However, the year 2000 saw non-OPEC producers achieve output volumes of almost 46 million barrels per day after two decades of steady growth that averaged 1.1 percent annually.^a Two factors are generally given credit for non-OPEC's dependable growth. First, the evolution of exploration and recovery technologies dramatically reduced costs and allowed the exploitation of more hostile environments. 3-D seismic, horizontal drilling, floating platforms, and sub-sea completion systems are just some of the technologies that have made important contributions. Second, a few non-OPEC surprises have always seemed to surface every decade. Over the past 25 years, the Alaskan North Slope, Mexico, the North Sea, and the Caspian Basin all have qualified as surprises, with oil production potential exceeding expectations.

A rebound in oil prices from the extremely low levels of 1998 and early 1999 ushered in the new century. The increased drilling activity brought about by higher prices produced an obvious candidate for the first non-OPEC surprise of the 21st century. The Atlantic Basin, featuring Brazil and Argentina along coastal Latin America and the countries from Mauritania to Namibia along coastal West Africa, was experiencing oil finds that were both frequent and sizable. As with many of the non-OPEC surprises of the past, most of this oil was being found in hostile environments. In this case, it was offshore fields in water depths that tested exploration and recovery technologies to their limits.

Most of the interest in the Latin American offshore sector is focused on Brazil. Many of the significant developments in deepwater exploration and production have evolved in Brazil. As early as the 1970s, Brazil recognized the need to concentrate its exploration efforts in offshore areas. The initial production from an offshore basin started in 1977. Its ventures into ultra-deep projects have claimed several world records. Brazil has also realized that two-thirds of the prospective global offshore basins lie in extremely deep water. It is estimated that 75 percent of Brazil's total reserves could come from ultra-deepwater projects, exceeding 3,000 feet. Industry experts expect that water depths exceeding 8,000 feet will most likely be feasible for production purposes within 5 years.

In 1997, Brazil enacted legislation that allowed private-sector participation in oil exploration, production, refining, and distribution. As a result of this decision and the resulting diversity and expertise of the investors in Brazil's oil sector,^b the country's long-term oil exploration and production outlook is viewed with optimism. In the *IEO2002* forecast, Brazil's oil production is expected to increase to 2.8 million barrels per day by 2010, more than doubling current levels. By 2020, production is projected to reach 4.1 million barrels per day. It is expected that the entirety of Brazil's oil production will be consumed domestically, leaving only a modest requirement for imports.

Most of the non-OPEC interest in the West African offshore sector is centered on Angola. Over the past 3 years, the success rate of exploration wells in Angola's deepwater blocks has been stunning, and the field sizes are proving to be astonishing. More than a dozen fields, each with reserves totaling more than 500 million barrels, are being readied for near- to mid-term development. Capital investment in the Angolan oil sector has eclipsed even OPEC member Nigeria's investment draw. In 2000, the offshore sector provided 40 percent of Angola's gross domestic product.

The prolific nature of Angola's oil field discoveries has brought the region to the forefront as the cutting edge for new deepwater technologies. As with many of the West African states, Angola offers attractive terms and conditions with less costly operations than other offshore provinces.^c *IEO2002* projects that Angola's oil production will increase to levels of 2.1 million barrels per day by 2010, almost tripling current levels, and to 3.3 million barrels per day by 2020. There is a long-term strategic value to Angolan crude oil supplies that should not be underestimated. Many West African streams are lighter, higher-valued crude oils that are tailor-made for U.S. East Coast markets and are able to offer an alternative to Middle Eastern supply sources.

While Brazil and Angola are the Atlantic Basin's predominant non-OPEC oil producers, other emerging economies are also positioned to capture a slice of the deepwater action. In Latin America, Argentina is projected to become a 1 million barrel per day producer by the end of this decade with the development of its offshore sector. In Africa, just about every West African country is either conducting its own search for hydrocarbons or attempting to attract outside investors for licensing agreements. Those countries displaying a

(continued on page 36)

^aEnergy Information Administration, *International Petroleum Monthly*, DOE/EIA-0520(2001/12) (Washington, DC, December 2001).

^b"Deepwater at the Double," *Hart's E&P*, Vol. 73, No. 10 (October 2000), p. 40.

^c"World Focus on West Africa," *Hart's E&P*, Vol. 74, No. 1, Supplement (January 2001), p. 3.

Australia has made significant recent additions to its proven reserves, and it is possible that Australia will become a million barrel per day producer by the middle of this decade. Malaysia shows little potential for any significant new finds, and its output is expected to peak at around 800,000 barrels per day early in this decade and then gradually decline to 650,000 barrels per day by 2020. Papua New Guinea continues to add to its reserve posture and is expected to achieve production volumes approaching 200,000 barrels per day by the middle of this decade, followed by only a modest decline over the remainder of the forecast period. Exploration and test-well activity have pointed to some production potential for Bangladesh and Mongolia, but significant output is not expected until late in this decade.

Oil producers in Central and South America have significant potential for increasing output over the next decade. Brazil became a million barrel per day producer in 1999, with considerable production potential waiting to be tapped. Brazil's production is expected to rise throughout the forecast period and to top 2.5 million barrels per day by 2020. Colombia's current economic downturn and civil unrest have delayed its bid to join the relatively short list of worldwide million barrel per day producers, but its output is expected to top a million barrels per day within the decade and show modest decline for the remainder of the forecast period. In both countries, the oil sector would benefit significantly from the creation of a favorable climate for foreign investment.

Argentina is expected to increase its production volumes by at least 150,000 barrels per day over the next 2 years, and by the middle of the decade it is likely to become a million barrel per day producer. Although the current political situation in Ecuador is in transition, there is still optimism that Ecuador will increase production by more than 300,000 barrels per day within the next couple of years.

Several West African producers (Angola, Cameroon, Chad, Congo, Gabon, and Ivory Coast) are expected to reap the benefits of substantial exploration activity, especially considering the recent rebound in oil prices. Angola is expected to become a million barrel per day producer early in this decade. Given the excellent exploration results, Angola could produce volumes of up to 2 million barrels per day well into the later years of the forecast period. The other West African producers with offshore tracts are expected to increase output by up to 360,000 barrels per day for the duration of the forecast.

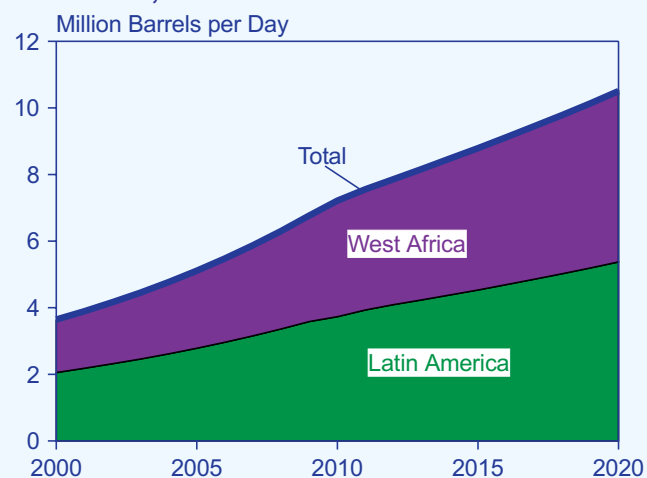
North African producers Egypt and Tunisia produce mainly from mature fields and show little promise of adding to their reserve posture. As a result, their production volumes are expected to decline gradually throughout the forecast. Sudan and Equatorial Guinea are expected to produce modest volumes early in this decade. Eritrea, Somalia, and South Africa also have some resource potential, but they are not expected to produce significant amounts until after 2005.

The 21st Century's First Non-OPEC Surprise: The Atlantic Basin (Continued)

particular interest in deepwater projects include the Ivory Coast, Sierra Leone, Equatorial Guinea, Congo, Namibia, and Gabon. The figure at right presents the oil production forecast for Atlantic Basin non-OPEC producers out to 2020.

There is one particularly attractive aspect of the deepwater component of the oil industry: it is a sector that is still in its infancy. Of the deepwater oil that has been discovered, only 20 percent has been developed and produced. Excursions into water depths over 5,000 feet are still relatively rare and are considered on the edge of feasibility. However, such barriers are softening with the willingness and confidence of oil companies in tackling deepwater projects. Companies are beginning to realize that the deepwater sector is likely to mature over a substantial number of years, and it therefore represents an integral part of their future business for a long time to come. With the exception of Nigeria, most deepwater areas are outside OPEC boundaries. This can only be considered an unexpected but welcome bonus for the deepwater niche of the non-OPEC world oil market.

Projected Atlantic Basin Non-OPEC Oil Production, 2000-2020



Source: Energy Information Administration, World Energy Projection System (2002).

In North America, moderately rising U.S. output is expected to be complemented by significant production increases in Canada and Mexico. Canada's output is expected to increase by more than 200,000 barrels per day over the next 2 years, mainly from Newfoundland's Hibernia oil project, which could produce more than 155,000 barrels per day at its peak sometime in the next several years. Canada is projected to add an additional 700,000 barrels per day in output from a combination of frontier area offshore projects and oil from tar sands. Higher expected oil prices, technological advances, and lower costs for deepwater exploration and production in the Gulf of Mexico enhance the long-term U.S. production profile. Mexico is expected to adopt energy policies that encourage the efficient development of its vast resource base. Expected production volumes in Mexico exceed 4.1 million barrels per day by the end of the decade and remain near that level through 2020.

With assumed higher oil prices, oil production in the FSU is expected to reach 10.0 million barrels per day by 2005—a level that could be somewhat higher if the outlook for investment in Russia were not so pessimistic. The long-term production potential for the FSU is still regarded with considerable optimism, especially for the resource-rich Caspian Basin region. The *IEO2002* reference case shows FSU output exceeding 14.8 million barrels per day by 2020, implying export volumes exceeding 6.9 million barrels per day. In China, oil production is expected to decline by nearly 3.0 million barrels per day by 2020. China's import requirements are expected to be as large as its domestic production by 2010 and to continue growing as its petroleum consumption increases.

The estimates for non-OPEC production potential presented in this outlook are based on such parameters as numbers of exploration wells, finding rates, reserve-to-production ratios, advances in both exploration and extraction technologies, and the sensitivity to changes in the world oil price. A critical component of the forecasting methodology is the constraint placed on the exploration and development of non-OPEC undiscovered resources. For the purpose of the three *IEO2002* price cases, no more than 15, 25, and 35 percent of the mean United States Geological Survey estimate of non-OPEC undiscovered oil is assumed to be developed over the forecast period in the low, reference, and high price cases, respectively. In all price cases, OPEC producers are assumed to be the source of the required residual supply. Tables D1-D6 in Appendix D show the ranges of production potential for both OPEC and non-OPEC producers.

The expectation in the late 1980s and early 1990s was that non-OPEC production in the longer term would stagnate or decline gradually in response to resource

constraints. The relatively insignificant cost of developing oil resources within OPEC countries (especially those in the Persian Gulf region) was considered such an overwhelming advantage that non-OPEC production potential was viewed with considerable pessimism. In actuality, however, despite a relatively low price environment, non-OPEC production has risen every year since 1993, adding more than 5.2 million barrels per day between 1993 and 2000.

It is expected that non-OPEC producers will continue to increase output, producing an additional 7.6 million barrels per day by 2010. Three factors are generally given credit for the impressive resiliency of non-OPEC production: development of new exploration and production technologies, efforts by the oil industry to reduce costs, and efforts by producer governments to promote exploration and development by encouraging outside investors with attractive fiscal terms.

Worldwide Petroleum Trade in the Reference Case

In 2000, industrialized countries imported 15.8 million barrels of oil per day from OPEC producers. Of that total, 9.9 million barrels per day came from the Persian Gulf region. Oil movements to industrialized countries represented more than 70 percent of the total petroleum exported by OPEC member nations and almost two-thirds of all Persian Gulf exports (Table 11). By the end of the forecast period, OPEC exports to industrialized countries are estimated to be about 6.2 million barrels per day higher than their 2000 level, and more than half the increase is expected to come from the Persian Gulf region.

Despite such a substantial increase, the share of total petroleum exports that goes to the industrialized nations in 2020 is projected to be almost 14 percent below their 2000 share, and the share of Persian Gulf exports going to the industrialized nations is projected to fall to about 40 percent. The significant shift expected in the balance of OPEC export shares between the industrialized and developing nations is a direct result of the robust economic growth anticipated for the developing nations of the world, especially those of Asia. OPEC petroleum exports to developing countries are expected to increase by more than 17.0 million barrels per day over the forecast period, with more than half of the increase going to the developing countries of Asia. China, alone, is likely to import about 7.2 million barrels per day from OPEC by 2020, virtually all of which is expected to come from Persian Gulf producers.

North America's petroleum imports from the Persian Gulf are expected to almost double over the forecast period (Figure 30). At the same time, more than one-half

of total North American imports in 2020 are expected to be from Atlantic Basin producers and refiners, with significant increases expected in crude oil imports anticipated from Latin American producers, including Venezuela, Brazil, Colombia, and Mexico. West African producers, including Nigeria and Angola, are also expected to increase their export volumes to North America. Caribbean Basin refiners are expected to account for most of the increase in North American imports of refined products.

With a moderate decline in North Sea production, Western Europe is expected to import increasing amounts from Persian Gulf producers and from OPEC member nations in both northern and western Africa. Substantial

imports from the Caspian Basin are also expected. Industrialized Asian nations are expected to increase their already heavy dependence on Persian Gulf oil. The developing countries of the Pacific Rim are expected to more than double their total petroleum imports between 2000 and 2020.

Worldwide crude oil distillation refining capacity was about 81.5 million barrels per day at the beginning of 2000. To meet the projected growth in international oil demand in the reference case, worldwide refining capacity would have to increase by more than 50 million barrels per day by 2020. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and especially in the Asia Pacific region.

Table 11. Worldwide Petroleum Trade in the Reference Case, 2000 and 2020
(Million Barrels per Day)

Exporting Region	Importing Region							
	Industrialized				Nonindustrialized			
	North America	Western Europe	Asia	Total	Pacific Rim	China	Rest of World	Total
2000								
OPEC								
Persian Gulf	2.6	3.2	4.1	9.9	2.7	0.7	1.5	4.9
North Africa	0.3	2.0	0.0	2.3	0.0	0.0	0.1	0.1
West Africa	0.9	0.5	0.0	1.4	0.1	0.0	0.1	0.2
South America	1.6	0.2	0.0	1.8	0.1	0.0	0.8	0.9
Asia	0.1	0.0	0.3	0.4	0.2	0.0	0.0	0.2
Total OPEC	5.4	5.9	4.5	15.8	3.2	0.7	2.5	6.4
Non-OPEC								
North Sea	0.6	4.7	0.0	5.3	0.0	0.0	0.0	0.0
Caribbean Basin	1.8	0.2	0.0	2.1	0.3	0.0	2.2	2.5
Former Soviet Union	0.0	1.6	0.0	1.7	0.2	0.0	0.1	0.3
Other Non-OPEC	2.9	1.3	0.9	5.1	1.9	0.4	1.1	3.4
Total Non-OPEC	5.3	7.8	1.0	14.1	2.4	0.4	3.4	6.2
Total Petroleum Imports	10.7	13.7	5.4	29.9	5.6	1.1	5.9	12.5
2020								
OPEC								
Persian Gulf	4.9	3.5	5.0	13.4	8.7	7.1	4.3	20.1
North Africa	0.5	2.3	0.0	2.7	0.1	0.0	0.4	0.6
West Africa	0.9	0.9	0.2	2.0	0.1	0.0	0.9	1.0
South America	3.3	0.3	0.1	3.7	0.1	0.0	1.4	1.5
Asia	0.1	0.0	0.1	0.2	0.2	0.1	0.0	0.3
Total OPEC	9.7	6.9	5.5	22.0	9.3	7.2	7.0	23.4
Non-OPEC								
North Sea	0.5	3.9	0.0	4.4	0.1	0.0	0.0	0.1
Caribbean Basin	3.4	0.4	0.1	3.9	0.2	0.0	1.5	1.6
Former Soviet Union	0.4	3.1	0.5	4.0	1.4	0.1	0.2	1.7
Other Non-OPEC	4.2	1.3	0.4	5.9	2.2	0.3	1.2	3.7
Total Non-OPEC	8.4	8.8	1.0	18.2	3.9	0.4	2.9	7.2
Total Petroleum Imports	18.2	15.6	6.5	40.3	13.1	7.6	9.9	30.6

Notes: Totals may not equal sum of components due to independent rounding.

Sources: **2000:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **2020:** EIA, Office of Integrated Analysis and Forecasting, IEO2002 WORLD Model run IEO2002.B20 (2002).

Refiners in North America and Europe, while making only modest additions to their distillation capacity, are expected to continue improving product quality and enhancing the usefulness of the heavier portion of the barrel through investment in downstream capacity. Likewise, future investments by developing countries

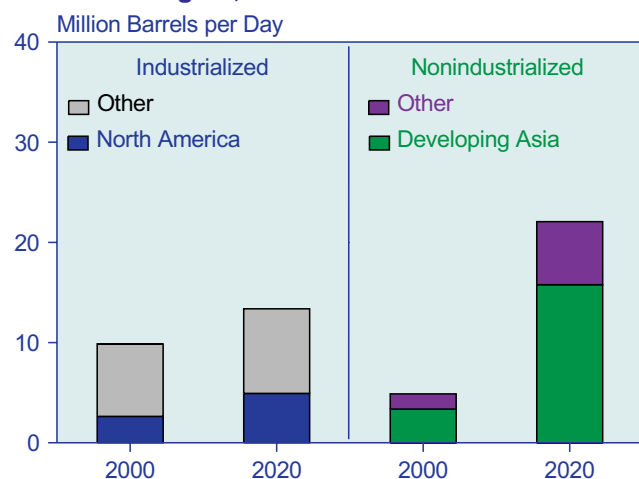
are also expected to include more advanced configurations designed to meet the anticipated increase in demand for lighter products, especially transportation fuels.

Other Views of Prices and Production

Several oil market analysis groups produce world oil price and production forecasts. Table 12 compares the *IEO2002* world oil price projections with similar forecasts from the International Energy Agency (IEA), Petroleum Economics, Ltd. (PEL), Petroleum Industry Research Associates (PIRA), the Gas Research Institute (GRI), Natural Resources Canada (NRCan), DRI-WEFA, and Deutsche Banc Alex.Brown (DBAB).

The collection of forecasts includes a wide range of price projections, based on the volatility of the world oil markets. In particular, oil prices have fluctuated widely since the late 1990s, first tumbling as a result of the Asian economic recession of 1997-1998, then sent upward by the region's subsequent recovery. High oil prices followed the ability of OPEC to maintain production quotas in 2000, which supported sustained high prices throughout the year. Finally, oil prices collapsed in mid-to late 2001 as a result of decreases in demand that accompanied the global economic slowdown and the aftermath of the September 11 terrorist attacks.

Figure 30. Imports of Persian Gulf Oil by Importing Region, 2000 and 2020



Sources: **2000:** Energy Information Administration (EIA), *International Petroleum Monthly*, DOE/EIA-0520(2001/11) (Washington, DC, November 2001). **2020:** EIA, Office of Integrated Analysis and Forecasting, *IEO2002 WORLD Model* run IEO2002.B20 (2002).

Table 12. Comparison of World Oil Price Projections, 2005-2020
(2000 Dollars per Barrel)

Forecast	2005	2010	2015	2020
<i>IEO2002</i>				
Reference Case	22.73	23.36	24.00	24.68
High Price Case	29.56	30.01	30.44	30.58
Low Price Case	17.41	17.64	17.64	17.64
DRI-WEFA (October 2001)	19.39	20.32	21.81	23.12
IEA (November 2000)	20.41	20.41	—	27.83
PEL (June 2001)	13.53	14.77	13.38	—
PIRA (October 2001)	24.31	24.21	27.75	—
GRI (March 2001)	18.70	18.70	18.70	18.70
NRCan (April 1997)	21.79	21.79	21.79	21.79
DBAB (December 2001)	17.68	17.58	17.95	18.30

Notes: *IEO2001* projections are for average landed imports to the United States. S&P, GRI, WEFA, and DBAB projections are for composite refiner acquisition prices. PEL projections are for Brent crude oil. PIRA projections are for West Texas Intermediate crude oil at Cushing.

Sources: **IEO2002:** Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001). **DRI-WEFA:** DRI-WEFA, *U.S. Energy Outlook, Spring/Summer 2001* (Lexington, MA, October 2001), p. 49. **IEA:** International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), p. 39. **PEL:** Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001), p. 10. In the 2001 edition of this report, PEL declared two possible oil price projections in 2010 and 2015 (neither of which was identified as a "base case"). In 2010, either 13.53 or 18.06 and in 2015, either 13.38 or 16.35 depending on OPEC behavior. **PIRA:** PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001), Table II-3. **GRI:** Gas Research Institute, *Baseline Projection Data Book 2001 Edition*, Volume I, p. SUM-21 (March 2001), crude oil (refiner acquisition). **NRCan:** Natural Resources Canada, *Canada's Energy Outlook, 1996-2020*, Annex C2 (Ottawa, Ontario, Canada, April 1997) (reaffirmed in January 2000). **DBAB:** Deutsche Banc Alex.Brown, Inc., "World Oil Supply and Demand Estimates," e-mail from Adam Sieminski (December 14, 2001).

Given the uncertainties of the current world situation, there is a spread of more than \$10 per barrel among the forecasts for oil prices in 2005, as compared with the spread of only \$6 per barrel among the forecasts available last year. The current oil price projections for 2005 range from PEL's \$13.53 per barrel (constant 2000 U.S. dollars) to PIRA's \$24.21 per barrel. The NRCan and IEA forecasts are the earliest: NRCan's projection was formulated in 1997 (but reaffirmed in 2000) and IEA's in November 2000. Nevertheless, those forecasts fall well within the range defined by the other forecasts. Two of the forecasts, PEL and DBAB, fall below the range defined by the *IEO2002* high and low world oil price scenarios in 2005, again demonstrating the wide range of projections in the early years of the forecast.

IEO2002 expects oil prices to rise to \$23.15 in 2005. This projection leans somewhat toward the higher end of the forecasts: only PIRA projects higher world oil prices in 2005. Recent forecasts from DRI-WEFA, DBAB, and GRI all expect that prices will be in the range of \$18 to just under \$20 per barrel in 2005.

The entire PEL price forecast series may be considered an outlier relative to the rest of the forecasts. PEL's price projections fall consistently below those of the *IEO2002* low price path through 2015, when the PEL time series ends. If the PEL series is omitted, the range of prices among the remaining series is much smaller in 2015, \$10 per barrel, with PIRA at the high end of the range (\$27.75 per barrel) and DBAB at the low end (\$17.95 per barrel). At the end of the forecast period, the uncertainty among forecasters as measured by the difference between highest and lowest expected prices remains about the same at \$9.53 per barrel in 2020.

IEO2002 prices are the highest of any of the series across the 2005-2020 time period, with the exception of PIRA between 2005 and 2015 and IEA in 2020. It should be noted that IEA did not publish a price projection for 2015 in its *World Energy Outlook 2000*; however, it states that "between 2010 and 2020, the price increases steadily," from \$20.41 per barrel to \$27.83 per barrel. A simple interpolation results in an oil price in 2015 of about \$24.12 per barrel, placing the IEA price very close to (but still below) the *IEO2002* estimate of \$24.45 per barrel.

The price forecasts are influenced by differing views of the projected composition of world oil production. Two factors are of particular importance: (1) expansion of OPEC oil production and (2) the timing of a recovery in EE/FSU oil production. All the forecasts agree that the recovery of EE/FSU production will be fairly slow, although most are somewhat more optimistic about EE/FSU production development than they were last year.

Higher world oil prices in 2000 and the early part of 2001, along with accelerating economic recovery in Russia, currently the largest oil producer in the region, no doubt have influenced the production forecasts for the EE/FSU. Nevertheless, only DBAB projects that the share of EE/FSU production will rise above 13 percent over the course of the projection period. DBAB estimates that EE/FSU production will rise to 16 percent of the world total supply by 2020 (Table 13). DRI-WEFA is the least optimistic about recovery in the region, and its projected share for the EE/FSU remains at 9 percent throughout the 2005-2020 time period. *IEO2002* and PIRA are also optimistic about production in the region. Both forecasts expect the EE/FSU share of world oil production to climb from 12 percent in 2005 to 13 percent in 2010, where it remains for the remainder of the limits of the forecasts (that is, 2015 for PIRA and 2020 for *IEO2002*).

The forecasts that provide projections through 2020 (*IEO2002*, DRI-WEFA, DBAB, and IEA) all expect OPEC to provide incremental production of between 20 and 33 million barrels per day between 1999 and 2020 (Table 13). There is more variation in expectations among these four forecasts for the "other" non-OPEC suppliers. DRI-WEFA expects a substantial increase of 14.3 million barrels per day of supply from other suppliers, whereas IEA expects a decline of 3.4 million barrels per day in production from other non-OPEC sources. IEA projects that the "other" share of world oil production will fall to 29 percent by 2020 while the OPEC share increases to 54 percent. In contrast to DRI-WEFA, *IEO2002* expects more moderate growth in other non-OPEC supply, at 8.6 million barrels per day from 1999 to 2020; DBAB expects growth of 3.3 million barrels per day.

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Table 13. Comparison of World Oil Production Forecasts

Forecast	Percent of World Total			Million Barrels per Day			
	OPEC	EE/FSU	Other Non-OPEC	OPEC	EE/FSU	Other Non-OPEC	Total
History							
1999	39	10	50	29.1	7.6	37.2	73.9
Projections							
2005							
<i>IEO2002</i>	42	12	46	35.3	10.3	39.8	84.9
DRI-WEFA ^a	39	9	48	33.3	7.5	40.9	85.4
PEL	39	10	48	32.9	8.8	40.4	84.0
PIRA	36	12	52	30.3	10.0	43.4	83.7
DBAB	40	13	45	32.3	10.6	36.9	81.1
2010							
<i>IEO2002</i>	44	13	43	42.1	12.4	41.2	95.7
DRI-WEFA ^a	39	9	48	37.0	8.8	45.2	90.3
IEA ^b	46	11	38	44.1	10.3	36.6	95.9
PEL	43	10	44	40.2	9.4	41.1	92.8
PIRA	38	13	49	35.0	12.1	45.1	92.2
DBAB	42	15	41	38.0	13.2	36.9	90.3
2015							
<i>IEO2002</i>	46	13	41	49.4	14.0	43.8	107.2
DRI-WEFA ^a	41	9	47	42.7	9.8	49.1	104.9
PEL	51	10	37	52.4	9.8	37.7	102.2
PIRA	41	13	46	41.0	13.3	45.7	100.0
DBAB	44	15	39	43.4	15.3	38.4	99.5
2020							
<i>IEO2002</i>	48	13	39	57.2	15.3	45.8	118.3
DRI-WEFA ^a	43	9	44	50.6	10.8	51.5	117.2
IEA ^b	54	11	29	61.8	12.3	33.8	114.7
DBAB	45	16	37	49.4	17.7	40.5	110.3

^aIn the DRI-WEFA projections, EE/FSU includes only Russia.

^bIEA total supply numbers include processing gains and unconventional oil. As a result, regional percentages do not add to 100.

Note: IEA, DRI-WEFA, PEL, and DBAB report processing gains separately from regional production numbers. As a result, the percentages attributed to OPEC, EE/FSU, and Other Non-OPEC do not add to 100.

Sources: **IEO2002**: Energy Information Administration, World Energy Projection System (2002). **DRI-WEFA**: DRI-WEFA, *Oil Market Outlook: Long Term Focus, Second Quarter 2000* (Lexington, MA, 2000), p. 14. **IEA**: International Energy Agency, *World Energy Outlook 2000* (Paris, France, November 2000), p. 77. **PEL**: Petroleum Economics, Ltd., *Oil and Energy Outlook to 2015* (London, United Kingdom, June 2001). **PIRA**: PIRA Energy Group, *Retainer Client Seminar* (New York, NY, October 2001). **DBAB**: Deutsche Banc Alex.Brown, fax from Adam Sieminski (December 14, 2001).

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Natural Gas

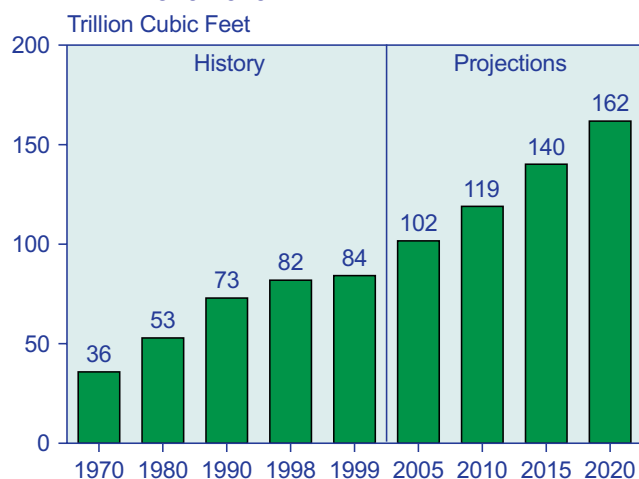
Natural gas is the fastest growing primary energy source in the IEO2002 forecast. The use of natural gas is projected to nearly double between 1999 and 2020, providing a relatively clean fuel for efficient new gas turbine power plants.

Natural gas is expected to be the fastest growing component of world energy consumption in the *International Energy Outlook 2002 (IEO2002)* reference case. Natural gas consumption in 2020 is projected to total 162 trillion cubic feet, nearly double the 1999 total of 84 trillion cubic feet (Figure 31), and its share of total energy consumption is projected to increase from 23 percent in 1999 to 28 percent in 2020. The growth of natural gas consumption in developing countries (Figure 32) is expected to be significantly greater than in the rest of the world, averaging 5.3 percent per year, as compared with 2.4 percent per year in the industrialized countries, 2.3 percent per year in Eastern Europe and the former Soviet Union (EE/FSU), and 3.2 percent globally. In the developing countries, annual natural gas consumption is projected to almost triple over the forecast period. By comparison, nuclear electricity consumption in the developing countries is projected to grow at a rate of 4.7 percent per year, oil and coal at 3.2 percent per year, and renewable energy (primarily hydropower) at 3.0 percent per year. The largest increments in natural gas use are expected in developing Asia and North America, and the smallest increments are expected in Africa and the Middle East (Figure 33).

Much of the projected growth in natural gas consumption throughout the world is in response to rising demand for natural gas to fuel efficient new gas turbine power plants. In the *IEO2002* reference case, the projections for natural gas consumption by electricity generators show more rapid growth than the projections for any other fuel. Natural gas consumption for electricity generation is projected to grow by 4.0 percent per year in the industrialized countries, compared with -0.1 percent for oil and 0.9 percent for coal, accounting for 56.3 percent of the projected increase in total energy used to generate electricity. World gas consumption for electricity generation more than doubles in the forecast, from 27.2 trillion cubic feet in 1999 to 58.9 trillion cubic feet in 2020, and consumption in the developing countries is projected to triple, from 5.9 trillion cubic feet in 1999 to 17.7 trillion cubic feet in 2020.

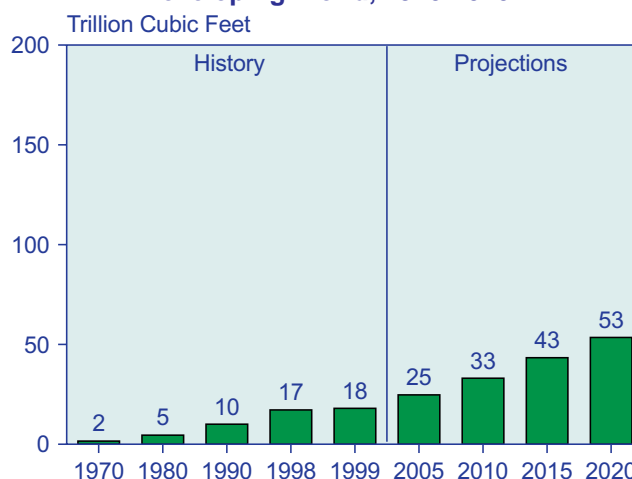
Although coal is expected to remain the predominant fuel used for power generation, natural gas is projected to capture 24 percent of the power generation market in the industrialized countries and 21 percent in the developing countries in 2020, up from 14 percent and 13 percent, respectively, in 1999. The natural gas market share

Figure 31. World Natural Gas Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 32. Natural Gas Consumption in the Developing World, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

of total world energy consumption for electricity generation in 2020 is projected to be 26 percent, compared with coal's 32 percent.

The use of natural gas is increasing for a variety of reasons, including price, environmental concerns, fuel diversification and/or energy security issues, market deregulation (for both gas and electricity), and overall economic growth. In many countries, governments hold equity in natural gas companies, and this can be used as a policy instrument. Examples include Kogas (Korea), Petronas (Malaysia), Pertamina (Indonesia), China National Petroleum Corporation, Gazprom (Russia), Pemex (Mexico), Oman LNG, Adgas (subsidiary of Abu Dhabi National Oil Company), National Iranian Oil Company, Sonatrach (Algeria), Nigerian National Petroleum Corporation, Egyptian General Petroleum Company, and Mossgas in South Africa. Most of these governments are fostering the expansion of their respective natural gas markets.

The amount of natural gas traded across international borders continues to grow, increasing from barely 20 percent of the world's consumption in 1999 to 22 percent in 2000 [1]. Pipeline exports grew by 8 percent and liquefied natural gas (LNG) trade grew by 10.3 percent between 1999 and 2000. Numerous international pipelines are either planned or already under construction. Projected increases in world natural gas consumption will require bringing new gas resources to market. The fact that many sources of natural gas are far from

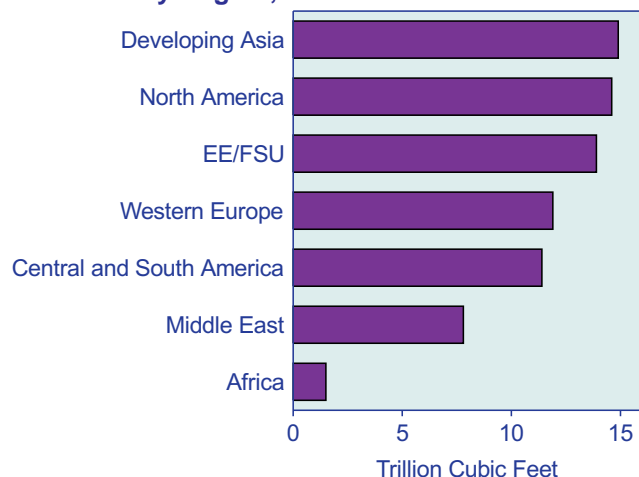
demand centers, coupled with cost decreases throughout the LNG chain, has made LNG more economical, contributing to the expectation of strong worldwide growth for LNG.

The economics of transporting natural gas to demand centers currently depend on the market price, and the pricing of natural gas is not as straightforward as the pricing of oil. More than 50 percent of the world's oil consumption is traded internationally, whereas natural gas markets tend to be more regional in nature, and prices can vary considerably from country to country. In Asia and Europe, for example, LNG markets are strongly influenced by oil and oil product markets rather than by natural gas prices. As the use and trade of natural gas continue to grow, it is expected that pricing mechanisms will continue to evolve, facilitating international trade and paving the way for a global natural gas market.

Reserves and Resources

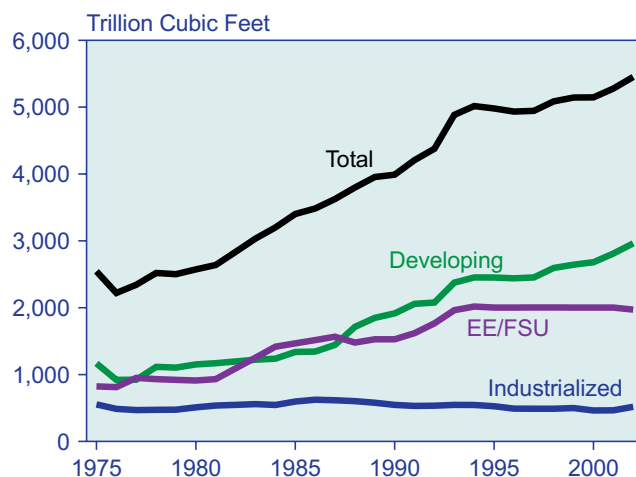
Since the mid-1970s, world natural gas reserves have in general increased each year (Figure 34). As of January 1, 2002, proved world natural gas reserves,⁵ as reported by *Oil & Gas Journal*, were estimated at 5,451 trillion cubic feet, 173 trillion cubic feet more than the estimate for 2001. Most of the increase is attributed to developing countries, where gas reserves have increased by 152 trillion cubic feet since last year's survey. Natural gas reserves in the industrialized countries also increased

Figure 33. Increases in Natural Gas Consumption by Region, 1999-2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

Figure 34. World Natural Gas Reserves by Region, 1975-2002



Sources: **1975-1993:** "Worldwide Oil and Gas at a Glance," *International Petroleum Encyclopedia* (Tulsa, OK: PennWell Publishing, various issues). **1994-2002:** *Oil & Gas Journal* (various issues).

⁵Proved reserves, as reported by the *Oil & Gas Journal*, are estimated quantities that can be recovered under present technology and prices. Figures reported for Canada and the former Soviet Union, however, include reserves in the probable category. Natural gas reserves reported by the *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect the most recent changes. Significant gas discoveries made during 2001 are not likely to be reflected in the reported reserves.

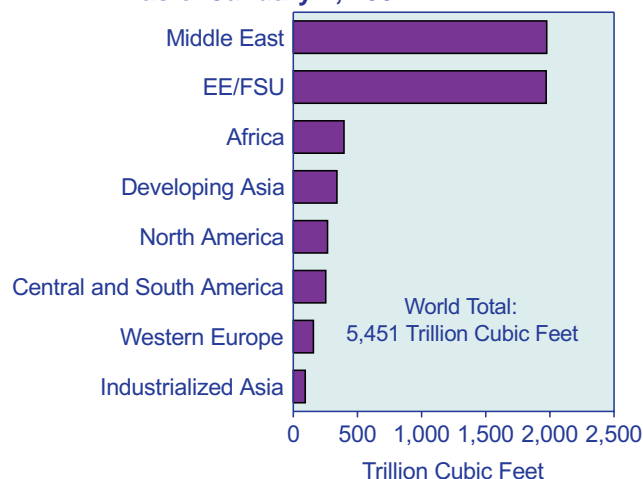
between 2001 and 2002, by 52 trillion cubic feet. EE/FSU reserves declined by 31 trillion cubic feet—mostly as a result of lowered estimates for Russia and for the East European countries Hungary and Romania, where reserves were halved over the past year.

The majority (about 72 percent) of the world's natural gas reserves are located in the Middle East and the FSU (Figure 35). Russia and Iran together account for almost one-half of the world's natural gas reserves (Table 14). Reserves in the rest of the world are fairly evenly distributed on a regional basis.

Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 60.0 years [2]. Central and South America has a reserves-to-production ratio of 71.8 years, the FSU 79.6 years, and Africa 86.2 years. The Middle East's reserves-to-production ratio exceeds 100 years.

The largest expansion in natural gas reserves between 2001 and 2002 occurred in the Middle East, where 120 trillion cubic feet was added to the region's reserve base. Of that amount, 115 trillion cubic feet was attributed to revised estimates of Qatar's reserves by officials of Qatargas and Rasgas [3]. Developing Asia also saw an increase in reserves of 23 trillion cubic feet over the past year. Among the developing Asian countries, the greatest increase in proven reserves was in Indonesia, where reserves grew by 20 trillion cubic feet. Pakistan and Papua New Guinea, and to a lesser extent the Philippines and Thailand, also saw modest increases in gas reserves. Malaysia was the only developing Asian country with a notable decline in reserves, from 82 trillion cubic feet in 2001 to 75 trillion cubic feet in 2002.

Figure 35. World Natural Gas Reserves by Region as of January 1, 2002



Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 99, No. 52 (December 24, 2001), pp. 126-127.

In the industrialized world, reserves have remained fairly stable for much of the past 20 years. In both North America and industrialized Asia, reserves increased from 2001 to 2002. In North America, an increment of 10 trillion cubic feet in U.S. natural gas reserves offset declines in Canada and Mexico. In industrialized Asia, Australia's reserves increased by 45 trillion cubic feet, more than doubling its reserve estimate from 2001.

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids). According to the most recent USGS estimates, released in the *World Petroleum Assessment 2000*, a significant volume of natural gas remains to be discovered. The mean estimate for worldwide undiscovered gas is 5,196 trillion cubic feet (Figure 36), which is approximately double the worldwide cumulative consumption forecast in *IEO2002*. Reserves plus resources are four times the cumulative consumption forecast.

Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 3,660

Table 14. World Natural Gas Reserves by Country as of January 1, 2002

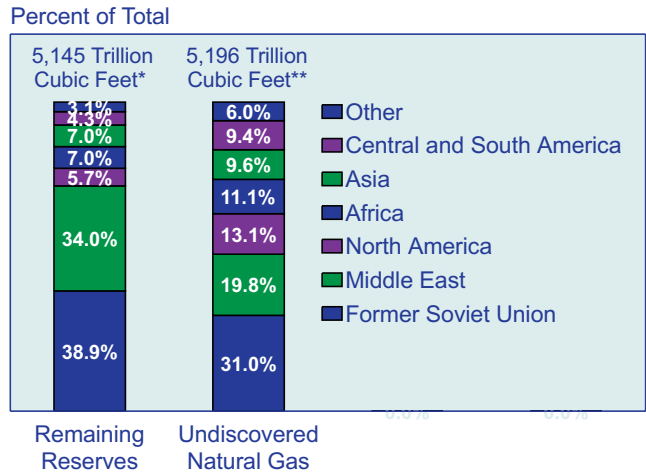
Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	5,451	100.0
Top 20 Countries	4,863	89.2
Russia	1,680	30.8
Iran	812	14.9
Qatar	509	9.3
Saudi Arabia	219	4.0
United Arab Emirates	212	3.9
United States	177	3.3
Algeria	160	2.9
Venezuela	148	2.7
Nigeria	124	2.3
Iraq	110	2.0
Turkmenistan	101	1.9
Indonesia	93	1.7
Australia	90	1.7
Malaysia	75	1.4
Uzbekistan	66	1.2
Kazakhstan	65	1.2
Netherlands	63	1.1
Canada	60	1.1
Kuwait	52	1.0
China	48	0.9
Rest of World	588	10.8

Source: "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 99, No. 52 (December 24, 2001), pp. 126-127.

trillion cubic feet. More than one-half of the mean undiscovered gas estimate is expected to come from the former Soviet Union, the Middle East, and North Africa, and an additional 1,169 trillion cubic feet is expected to come from a combination of North, Central, and South America. It is estimated that about one-fourth of the undiscovered natural gas reserves worldwide are in undiscovered oil fields.

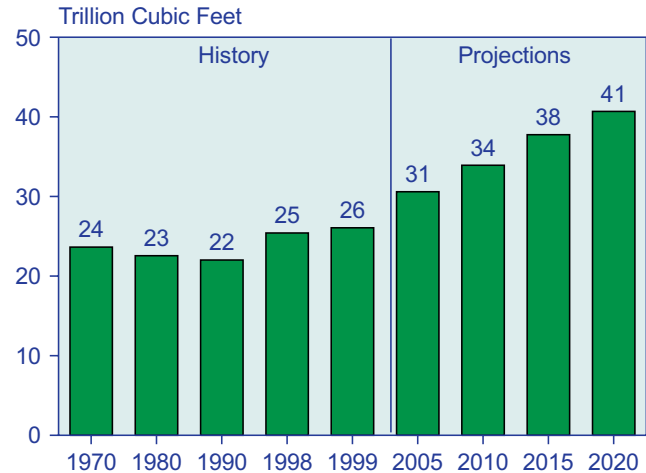
Although the United States has produced more than 40 percent of its total estimated natural gas endowment and carries less than 10 percent as remaining reserves, in

Figure 36. World Natural Gas Resources by Region, 2000



*As of January 1, 2000.
 **Through 2025.
 Source: U.S. Geological Survey, *World Petroleum Assessment 2000*, web site <http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60>.

Figure 37. Natural Gas Consumption in North America, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

the rest of the world reserves have been largely unexploited. Outside the United States, the world has produced less than 10 percent of its total estimated natural gas endowment and carries more than 30 percent as remaining reserves.

Regional Activity

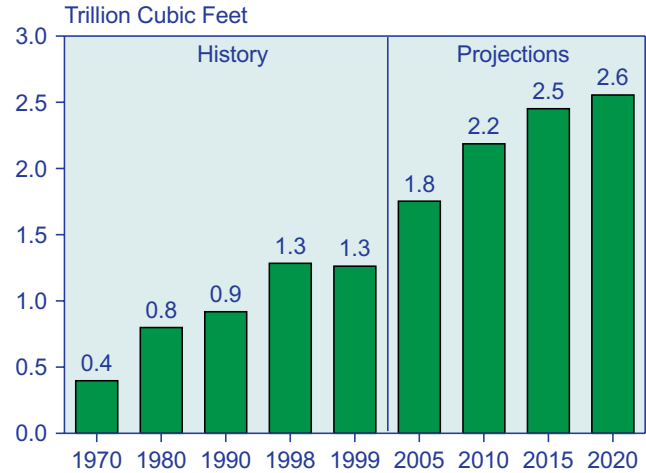
North America

Natural gas consumption in the *IEO2002* forecast for North America is projected to grow at a rate of 2.1 percent per year between 1999 and 2020 (Figure 37). Demand for gas is projected to increase in all three countries of the region (United States, Canada, and Mexico), but the most rapid growth rates are projected for Mexico, where the present immature gas infrastructure is expected to expand over the forecast period (Figure 38). The North American region is rapidly moving toward becoming an integrated gas market, and a substantial increase in the movement of natural gas between the United States, Canada, and Mexico is expected in the future.

United States and Canada

The United States currently is the dominant consumer of natural gas in North America, and it is expected to remain in that position throughout the projection period. Total U.S. natural gas consumption is projected to increase from 22 trillion cubic feet in 1999 to 34 trillion cubic feet in 2020 (compared with Canada's projected 4 trillion cubic feet in 2020 and Mexico's 3 trillion cubic feet). Much of the increment in U.S. gas use is expected in the electricity sector, where electricity generators (excluding cogenerators) are projected to account for 55

Figure 38. Natural Gas Consumption in Mexico, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

percent of total U.S. natural gas consumption by 2020, according to the Energy Information Administration's *Annual Energy Outlook 2002 (AEO2002)* [4]. Electricity generation is expected to surpass the industrial sector as the largest consumer of natural gas in the United States, with lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions favoring natural-gas-fired generation over coal-fired generation.

Natural gas accounts for 25 percent of Canada's total energy consumption, and its share is not expected to change substantially over the projection period. Because the country already relies on its ample supply of cheap hydroelectric power to provide more than one-half of its electricity supply, natural-gas-fired generating capacity is not expected to expand as dramatically as in the United States. As a result, much of Canada's natural gas production is expected to be exported to the United States, where increasing demand will be greatest. Record high prices for natural gas in the United States in 2000 underscored the potential benefits to Canadian gas exporters. Canada's natural gas exports provided significant increases in revenues to producers, accounting for close to two-thirds of the country's 2000 trade surplus. It is estimated that Canadian gas revenues reached \$13.8 billion, compared with estimated 1999 revenues of \$7.3 billion [5].

As the U.S. demand for natural gas increases, the country will come to rely more heavily on imports, particularly from Canada (Figure 39). Over the past several years, the United States has experienced a widening gap between production and consumption, and in 2000 it consumed 18.0 percent more than it produced. The

difference was made up with pipeline imports from Canada and Mexico and LNG imports from numerous sources, including Algeria, the United Arab Emirates, Australia, Qatar, Trinidad and Tobago, Malaysia, Nigeria, Oman, and Indonesia. Canada accounted for 93.8 percent of U.S. natural gas imports in 2000, LNG 5.9 percent, and Mexico 0.3 percent.

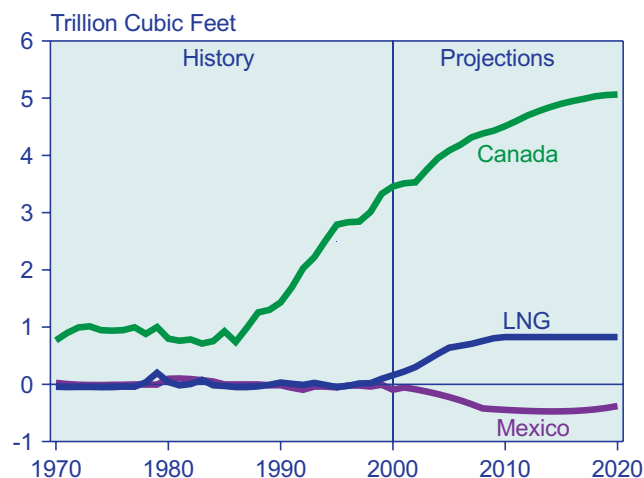
Imports into the United States from Canada in 2000 were 5.2 percent higher than in 1999, and during the first 9 months of 2001 they were 10 percent higher than over the same period in 2000 (2.9 trillion cubic feet vs. 2.6 trillion cubic feet) [6]. Over the past several years, cross-border pipeline capacity has increased considerably between the two countries. Most recently, the Alliance Pipeline was completed in December 2000, allowing 1,325 million cubic feet per day of natural gas from western Canada to be moved through North Dakota and into Chicago.

Although recent pipeline additions have provided significant increases in cross-border capacity between western Canada and the United States, there are pipeline bottlenecks within Canada that prevent some new supplies from reaching U.S. markets. There are several projects underway to alleviate this problem. Canadian Natural Resources (CNR), for example, has received approval to construct a pipeline from Ladyfern (where a discovery in 2000 is estimated to be one of the most prolific gas discoveries in western Canada in the past 15 years) in northeastern British Columbia to Northwestern Alberta, where it can then link up with TransCanada Pipeline's transcontinental network to move gas to southern Canada and the United States. The new pipeline is scheduled for completion in March 2002. It will have an initial capacity of 680 million cubic feet per day but could eventually be expanded to 1.35 billion cubic feet per day [7].

Another project aimed at increasing Canada's ability to export natural gas to U.S. markets is being implemented in eastern Canada. Maritimes and Northeast Pipeline plans to increase pipeline capacity to 1 billion cubic feet per day to bring in new reserves from offshore Atlantic Canada. According to Maritimes and Northeast president Phillip Knoll, the existing system can be economically expanded through compression and looping to allow producers competitive rates for getting their supplies to New England markets for new gas-fired generators [8].

U.S. imports of LNG are expected to quadruple over the next two decades, increasing the LNG share of gas imports to 14.7 percent in 2020. The development of an LNG market in the United States has been constrained by limitations on the amount it can receive and regasify. There are currently four LNG receiving facilities in the United States. Two have been operating for several

Figure 39. Net U.S. Imports of Natural Gas, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001).

years, one in Everett, Massachusetts, and one in Lake Charles, Louisiana. In September 2001, a facility reopened at Elba Island, Georgia, after several years of inactivity. The fourth facility is scheduled to reopen at Cove Point, Maryland, by mid-2002.

Algeria was the only source of LNG supply for the United States until May 1999, when supplies began arriving from Trinidad and Tobago. Trinidad and Tobago has now replaced Algeria as the primary source of U.S. LNG supply. Trinidad and Tobago and Algeria currently have the only long-term contract sales for LNG, but spot cargos have been imported from Qatar, Nigeria, Australia, Oman, Indonesia, and the United Arab Emirates, and spot market sales in the U.S. market continue to grow [9]. In the third quarter of 2001, short-term LNG imports totaled 51.3 billion cubic feet, compared with 44.7 billion cubic feet in the third quarter 2000.

As a result of the renewed interest in LNG, numerous additional facilities are being considered, including sites in the Gulf of Mexico, North Carolina, and Florida; however, siting an LNG receiving terminal in the United States can be a formidable task. Aside from the geographical requirements, the NIMBY (Not In My Back Yard) factor can be close to insurmountable and is likely to be the most important factor in whether a facility is built at a particular location. To avoid this problem, there have been proposals to site the facilities outside US borders, notably, in Baja California (Mexico) and in the Bahamas. Local opposition makes the prospect of new facilities to serve U.S. markets uncertain for the near future.

The opposition to new LNG receiving facilities does not preclude expansion at existing facilities, however. El Paso subsidiary Southern LNG has plans to expand its Elba Island facility by 80 percent, adding 360 million cubic feet per day of sendout capacity to its current 440 million cubic feet per day. The added capacity is expected to be in place by June 1, 2005 [10]. Talk of new facilities continues in spite of a significant drop in natural gas prices over the past year, with many developers stating that even with the current U.S. prices of under \$3.00 per thousand cubic feet, they expect LNG to be economical in the future and are proceeding with their plans. The *AEO2002* forecast projects expansion of existing facilities and increases in gross LNG imports averaging 7.1 percent per year, from 220 billion cubic feet in 2000 to 890 billion cubic feet in 2020.

Mexico

In Mexico, natural gas consumption has been growing, but production has been falling. Mexico's consumption of natural gas is projected to increase by 3.4 percent per year between 1999 and 2020, with much of the increase

in the industrial sector and for new electricity generation. As a result of the widening gap between production and consumption, Mexico has had to increase imports, and its import capacity is also being expanded with an eye to the future. In October 2000, the bidirectional Coral Energy pipeline between Mexico and the border near McAllen, Texas, became operational (300 million cubic feet per day). Exports from the United States to Mexico increased by 72 percent between 1999 and 2000 and by 24 percent between the first 9 months of 2000 and the first 9 months of 2001 (98 billion cubic feet vs. 79 billion cubic feet) [11]. In addition, Tidelands Oil and Gas, based in Texas, has filed for approval to build three 6-mile pipelines from Eagle Pass in Texas to Piedras Negras in Mexico, which would supplement the current capacity at nine existing border crossings [12].

El Paso Natural Gas has filed to increase its capacity at the Mexican border from 208 million cubic feet per day to 308 million cubic feet per day [13]. According to El Paso, the increase is to meet Mexico's need for 60 million cubic feet per day of natural gas initially to fuel the new Chihuahua II power plant in El Encino and an additional 40 million cubic feet per day for a new turbine generator to be installed in February 2002. El Paso plans to add the capacity by increasing compression along the existing Samalayuca Lateral. Another major incentive for increased capacity between the United States and Mexico, according to El Paso, is the rapid development of northern Mexico's pipeline infrastructure [14].

In addition to pipeline imports, LNG is expected to meet some of Mexico's growing demand, and several LNG receiving facilities have been proposed to serve markets in northwestern Mexico and southern California. Sempra Energy and CMS Energy have proposed a joint venture for a terminal north of Ensenada in Mexico's Baja California with a sendout capacity of 1 billion cubic feet per day; Phillips Petroleum and El Paso Corporation have proposed a 630 million cubic feet per day facility; El Paso is also considering a terminal to be located offshore California; and Chevron is evaluating both offshore California and Baja California for a 750 million cubic feet per day facility [15]. Shell Oil, in partnership with El Paso, is planning a 0.5 to 1.0 billion cubic feet per day receiving facility in Mexico's east coast Tamaulipas state at Altamira that would receive gas from Africa, the Caribbean, and South America. Turning towards South America, Mexico has had preliminary talks outlining an economic agreement with Bolivia that would allow the Pacific LNG consortium (Respol-YPF, British Gas, and British Petroleum), to use Mexico's pipelines and plants to process LNG from Bolivia to be exported to the United States for use in southern California [16]. The arrangement would also provide Mexico with Bolivian gas for its own use.

Mexico is also struggling to restructure its natural gas industry in order to develop its vast natural gas resources. Two factors that hinder more rapid expansion of the gas market in Mexico are the complete control of the exploration and production sector of the market by Petroleos Mexicanos (Pemex), the state oil and gas company, and the lack of infrastructure to move gas from the main producing areas in the south to the major consuming regions in the north. While the distribution segment of the industry has been open to private investment since 1995 and has seen significant growth in recent years, exploration and production continue to be controlled by Pemex.

The Mexican government feels it is imperative that progress be made in opening the natural gas production sector, because the government does not have the financial resources to fully develop the country's reserves. To this end, Pemex is working to develop a multiple-service contract that can be used to get foreign investors to help develop Mexico's natural gas. According to Dominguez Vargas, first vice-president of technology and professional development for Pemex, the initial emphasis would be on getting contracts in place for development efforts in the Burgos basin in northeastern Mexico, where the largest production increase could be achieved [17].

The situation is a difficult one for Mexican President Vicente Fox, who took office on December 1, 2000. Most of Mexico's current natural gas production is associated with light crude oil production, and the declining ratio of light crude to total crude production yields a corresponding decline in associated gas production [18]. According to Energy Minister Ernesto Martens, Mexico will need to increase its gas production from the current 5 billion cubic feet per day to 12 billion cubic feet per day by 2006 [19]. The Fox administration favors restructuring Mexico's energy markets, but it will be difficult to implement any sweeping reform, because the party lacks a majority in both of the Mexican government's legislative bodies. At a minimum, Fox has indicated that he intends to open up exploration and development of nonassociated gas to private investment.

Western Europe

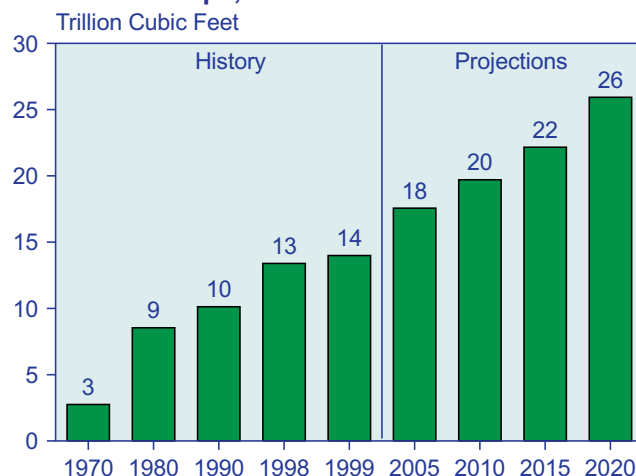
Natural gas is the fastest growing fuel source in Western Europe, despite the region's limited natural gas resources. The region accounts for less than 5 percent of the world's natural gas reserves but in 1999 consumed 17 percent of the world total. Over the next two decades, natural gas consumption in Western Europe is projected to grow at an average annual rate of 3.0 percent in the *IEO2002* reference case forecast, compared with a rate of 1.0 percent for total primary energy consumption (Figure 40). In addition to a preference for natural gas over coal for environmental reasons, Europe's natural

gas use is growing due to readily available supplies to supplement domestic production coming by pipeline from the FSU and Algeria, and by tanker in the form of LNG from a number of sources. Recent demand increases reflect rising gas use for power generation and for the industrial sector. Consumption of natural gas for electricity generation is projected to more than double over the projection period.

The European Union (EU) has played an important role in the development of Western Europe's natural gas markets, passing key legislation over the past several years to liberalize both the electricity and natural gas markets of its member countries. The EU Directive on Electricity was passed in January 1997, opening up electricity markets in member nations to competition within 2 years, and its Natural Gas Directive was passed in June 1998 requiring the opening of gas markets.

The objective of the Natural Gas Directive is to ensure the free movement of natural gas and improve security of supply and industrial competitiveness. It established common rules for the EU's internal natural gas market regarding the storage, transmission, supply, and distribution of natural gas. The rules addressed market access, criteria and procedures for systems operations, and the granting of licences for natural gas supply, transmission, storage, and distribution. The Directive set a deadline of August 10, 2000, for members (with the exception of emerging markets in Portugal and Greece) to have arrangements in place for third-party access to gas infrastructure. By that date all gas-fired power generators and customers using more than 883 million cubic feet of natural gas per year were to be eligible to choose a

Figure 40. Natural Gas Consumption in Western Europe, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

gas supplier. Customers using at least 530 million cubic feet per year are to be eligible by 2003, and those using at least 177 million cubic feet per year are to be eligible by 2008.

In May 1999 a report by the European Commission (a branch of the EU) was released, calling for the acceleration of the gas market liberalization from 2008 to January 2005 at the latest [20, 21]. Subsequently, on March 13, 2001, the Commission outlined the current state of progress, recommending the following measures to achieve the accelerated gas market objective:

- Adoption of appropriate rules with respect to the pricing of cross-border trade
- Adoption of rules for allocation and management of interconnection capacity
- Where economically justified, increasing existing physical interconnection capacity.

The largest consumers in Western Europe by far are the United Kingdom, Germany, Italy, the Netherlands, and France, and consumption in these countries is expected to grow steadily over the forecast period (Figure 41). More than one-half of the region's resources are concentrated in the United Kingdom, the Netherlands, and Norway, which are the region's primary producers. Almost all Western European gas production is consumed internally, with the exception of small quantities exported by France, Germany, and Norway to Eastern European markets.

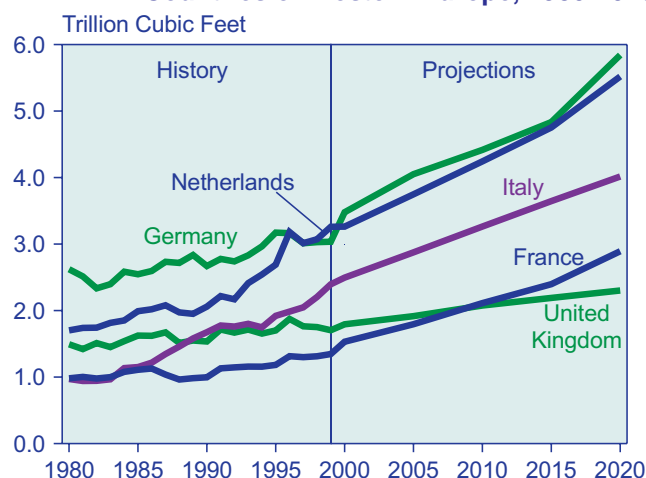
Although the projected incremental increases in consumption are far less than those in the largest consuming

countries, some of the most rapid growth rates in natural gas consumption in Western Europe are occurring in countries where natural gas markets are just beginning to flourish—including Portugal, Greece, Ireland, and Spain (Figure 42). Portugal and Greece are two of the smallest economies represented in the EU and are considered by the EU to be emerging gas markets, a status that gives them flexibility in meeting the deadlines of the Natural Gas Directive for opening their gas markets. Both countries consumed less than 10 billion cubic feet per year before 1998, when consumption in Portugal jumped to 28 billion cubic feet and in Greece to 30 billion cubic feet. Consumption in both countries rose dramatically again in 1999, to 80 and 53 billion cubic feet, and the growth is continuing. Natural gas markets in Ireland and Spain have been developing for a longer period, and recent consumption increases, while not as impressive, are nonetheless significant.

Portugal

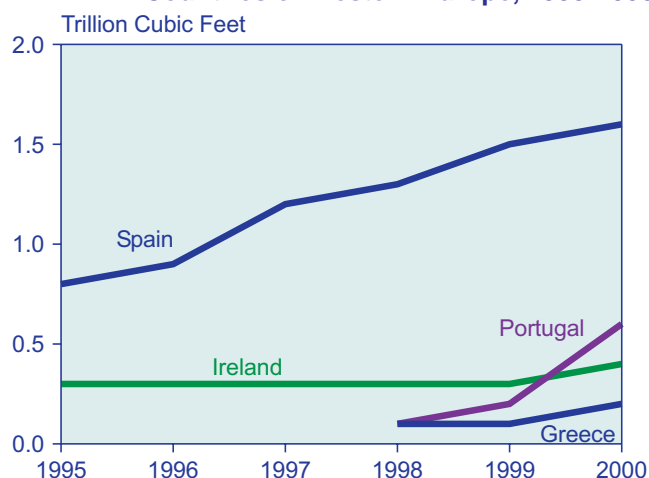
In Portugal, the natural gas market is less than 5 years old. There was no measurable consumption until 1997, when the Maghreb-Europe pipeline connected the Iberian peninsula to Algerian gas sources (via Morocco). Since then, gas use has risen steadily. Although virtually all of Portugal's natural gas still comes by pipeline from Algeria, it also began importing LNG in 1998 and in 1999 entered into a contract to purchase LNG from Nigeria for 20 years beginning in 2002. The LNG will be regasified initially in Spain and piped into Portugal until a terminal under construction at Sines, Portugal, scheduled to become operational in 2003, is completed. The Sines terminal will have a capacity of 580 billion cubic feet per year and will be operated by Transgas.

Figure 41. Natural Gas Consumption in Five Countries of Western Europe, 1980-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 42. Natural Gas Consumption in Four Countries of Western Europe, 1995-2000



Source: Energy Information Administration, Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001).

Almost all of the natural gas consumption in Portugal is to fuel electricity generation. A member of the EU, Portugal has received EU assistance in investment in its gas infrastructure. Approximately \$417 million (485 million euros) was spent on improving Portugal's infrastructure between 1994 and 1999, when the EU decided to cut back on spending. Nevertheless, there are still plans to expand the network from 3,761 miles in 1999 to 5,943 miles in 2010 [22]. Under the EU Gas Directive, as an emerging natural gas market Portugal is not required to open its domestic gas market to full competition until 2008. It was, however, required to open at least 33 percent of its market to competition by 2001—a target that still has not been met. As a result, the EU has begun infringement procedures.

Greece

In Greece, the government historically has maintained a prominent role in the energy industry, and the natural gas market remains under the control of the state-owned Greek Public Gas Company (DEPA). DEPA was established in 1988 to promote natural gas use in order to diversify Greece's energy sources, but the market actually declined until 1997 when the government loosened its control on the industry and allowed foreign participation. Since that time, rapid expansion has been occurring.

A member of the EU, Greece has taken full advantage of all the EU waivers its emerging market status allows in order to delay EU-mandated energy sector privatization, and it is only recently that privatization has made any inroads. Under agreements signed in July 2001, a new distribution company, EDA Attikis, 51 percent of which is owned by DEPA and the remainder by Cinergy of the United States and Royal Dutch/Shell, will supply Athens and its surrounding areas with natural gas, covering 30 percent of Greece's population. Although Athens was the first Greek city to have a gas distribution network, at present only about 8,000 customers are connected to the network in a city of more than 3.1 million [23]. EDA Attikis plans to expand the network to reach 55 percent of the region's population and expects demand to reach about 35 billion cubic feet by 2020. In 2000, the Italian utility company, Italgas (a subsidiary of ENI), won 30-year concessions to build and operate two city gas distribution networks, in Thessaloniki and Thessaly; and it will have a minority stake in the network ownership and management of each. DEPA has the exclusive contract to supply the three distribution networks for 15 years [24].

Greece intends to diversify its import sources, and in July 2000 it agreed to work with Turkey to develop connections between their natural gas networks. The two countries have agreed to work with the EU-sponsored Interstate Oil Gas Transport to Europe (INOGATE)

project, which provides technical assistance to modernize oil and gas transport in central Europe and Asia in order to work toward European pipeline linkages to Caucasus and Asian oil and gas.

In March 2001, Greece signed an agreement with Armenia and Iran to strengthen economic and energy cooperation. Discussions included the possibility of an EU-subsidized natural gas pipeline from Iran through either Armenia and Ukraine or Turkey and Greece to other European customers. LNG is also a source of imports for Greece. The country began importing LNG from Algeria in late 1999 into its LNG terminal at Revithoussa, near Athens. The terminal is small, with a receiving capacity of 23 billion cubic feet per year. It is possible that the terminal could be expanded, or that an additional terminal could be built; however, an under-sea natural gas pipeline from Italy to Greece is currently in the feasibility study phase [25], and if that project is approved it could reduce the impetus to expand LNG markets in Greece.

Ireland

In Ireland, switching to natural gas is seen as a way to reduce carbon dioxide emissions from electricity generation. According to the Ireland Department of Public Enterprise, close to half of Ireland's natural gas consumption is currently for electricity generation, and its share is expected to continue to increase [26]. There is also a strong move to continue the expansion of the residential and small commercial/industrial markets that have been growing as the distribution infrastructure expands. Phoenix Natural Gas, in particular, is currently focusing on this market.

At present, Ireland's only indigenous source of natural gas is the Kinsale Head Gas Field, which has been producing since 1978. The field is now in decline and is expected to be depleted by 2004. Dependence on imports is thus climbing as gas use accelerates. In 2000, one-half of Ireland's consumption of 134 billion cubic feet was imported from the United Kingdom. Kinsale production is likely to be supplemented in 2002 with supplies from the Corrib Gas Field, a recently discovered field off Ireland's northwest coast.

Natural gas imports to Ireland were first made possible by the completion of the 180-mile Interconnector from Scotland, with a capacity of 194 billion cubic feet per year [27]. Expansion of the country's pipeline transmission infrastructure is currently underway. The Celtic Energy consortium is planning to construct a pipeline linking North Dublin to Wales and England, scheduled for completion by the end of 2002, and the Premier Transco group is assessing the possibility of a pipeline linking Belfast and Dublin. Bord Gais Eireann has submitted an application to construct three natural gas

transmission pipelines: (1) to the west, from Dublin to Limerick to Galway Ringmain; (2) from Mayo to Galway; and (3) a second Scotland to Ireland Interconnector.

Spain

Strong growth in natural gas use is occurring in Spain as the country phases out its older nuclear and coal power plants in favor of gas. Estimates are that Spain could easily double its gas consumption by 2010 [28]. Spain is almost entirely dependent on imports to satisfy its gas demand, and that situation is not expected to change in the foreseeable future. The country's domestic resources are limited: its one major gas field ceased production in 1995, and there have been no new discoveries since then. In 2000, Spain imported half of the gas it consumed by pipeline from Norway and Algeria (primarily Algeria).

The remaining half of Spain's natural gas comes in the form of LNG. It is imported from a number of countries, including (in order of magnitude) Algeria, Nigeria, Libya, Trinidad and Tobago, Qatar, United Arab Emirates, Malaysia, and Oman. In fact, Spain is one of Europe's largest importers of LNG, second only to France. Spain currently has three LNG receiving terminals, all operated by Enagas, located in Barcelona, Huelva, and Cartagena. The three terminals, with a combined capacity of 500 billion cubic feet per year, became operational in 1969, 1988, and 1999. There is also considerable growth in LNG receiving capacity on the horizon, with two new terminals currently under construction and a third in the planning stage. The first of those under construction is scheduled to come online in 2003 in the port of Bilbao in the northern Basque region and be operated by Bahia de Bizkaia Gas. The second is expected to come online in 2005 in Valencia and be operated by Union Fenosa. The proposed terminal, to be located in Murgardos, will be operated by Union Fenosa, Endesa, and Sonatrach, in addition to local companies [29].

Eastern Europe and the Former Soviet Union

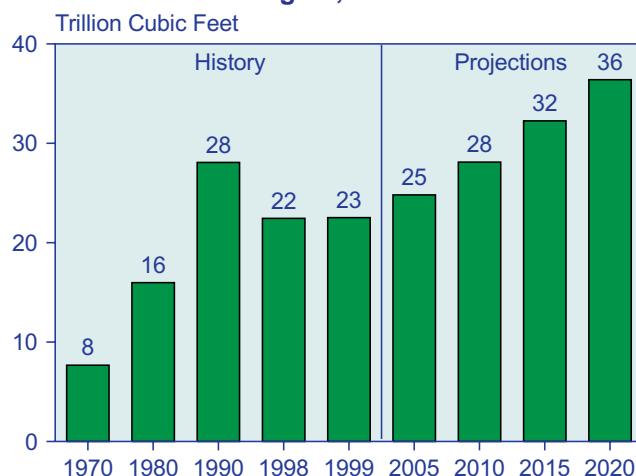
With 2,003 trillion cubic feet of proven natural gas reserves, the FSU accounts for 38 percent of the world total. Russia lays claim to 85 percent of those reserves, making it the largest potential source of natural gas in the world. Reserves in Iran, which is second to Russia, amount to less than one-half of Russia's total. Other gas producing countries in the FSU include Turkmenistan, Uzbekistan, Ukraine, and Kazakhstan. Of the four, Turkmenistan contains just over 100 trillion cubic feet of reserves, accounting for almost 2 percent of the world's total reserves, and the others each account for around 1 percent of the world's total.

Unstable political and economic conditions in the early to mid-1990s led to significant declines in EE/FSU natural gas markets. Between 1990 and 1998, consumption

declined by more than 20 percent. Although the declining trend has been reversed, the region still falls far short of both the production and consumption levels realized in 1990. Gas markets in the EE/FSU continue to face a number of complex issues, including curtailments, non-payment, declining Russian production, transit disputes, and economic and political conditions that have not been conducive to foreign investment. Restructuring of gas markets is occurring, however, and the prospects for natural gas market growth in the EE/FSU look promising. The *IEO2002* forecast is for increased growth, with consumption increasing at an average annual rate of 2.3 percent over the forecast period, from 23 trillion cubic feet in 1999 to 36 trillion cubic feet in 2020 (Figure 43). Growth in Eastern Europe is expected to far outpace growth in the FSU, with Eastern European consumption projected to grow at an average annual rate of 4.7 percent, compared with the FSU's 1.9 percent. This may be explained by the fact that most East European countries have enjoyed sustained economic recovery since the early 1990s, giving them a head start over the former Soviet Republics, which have only recently begun to see positive economic growth.

Natural gas production in Russia declined by 1.1 percent in 2000, and Russia fell behind the United States to become the world's second rather than top natural gas producer for the first time in a decade. Russia consumed 69 percent of its own production, exporting the balance. Russia is the world's largest exporter of natural gas (Figure 44), supplying Europe with about 30 percent of its gas supplies. Russia's biggest European export markets are Germany, Italy, and France, each relying on Russia for more than one-third of its natural gas. Most

Figure 43. Natural Gas Consumption in the EE/FSU Region, 1970-2020



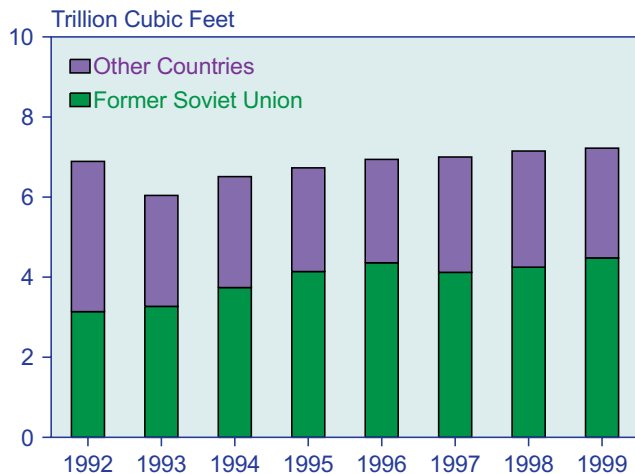
Source: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

EE/FSU countries continue to depend almost solely on Russia for their natural gas supplies. Russia has also begun to supply many of its customers, including Austria, Finland, Greece, Hungary, and Turkey, with well over half the natural gas they consume.

Russia has an extensive network of domestic pipelines as well as international pipelines linking it to export markets. Three pipelines, the Brotherhood (*Bratsvo*), Progress, and Union (*Soyuz*), deliver gas to Europe via

Ukraine. A fourth pipeline, the Yamal, transits Belarus to reach European markets. A fifth, the Northern Lights, transits both Belarus and Ukraine en route to Europe. Gas markets in Finland are served by the Volga/Urals-Vyborg pipeline. A new pipeline slated to serve markets in Turkey via the Black Sea, the Blue Stream Pipeline, is currently under construction. Work began in February 2000, and Gazprom has completed the aboveground section of the pipeline from Russian territory to the Black Sea coast at Tuapse. Turkey has completed its segment of the line, from Ankara to the Black Sea coast at Samsun. The final segment will run beneath the Black Sea, connecting the Russian and Turkish sections of the project. Laying of the underwater segment began in August 2001, with completion scheduled for 2002 [30].

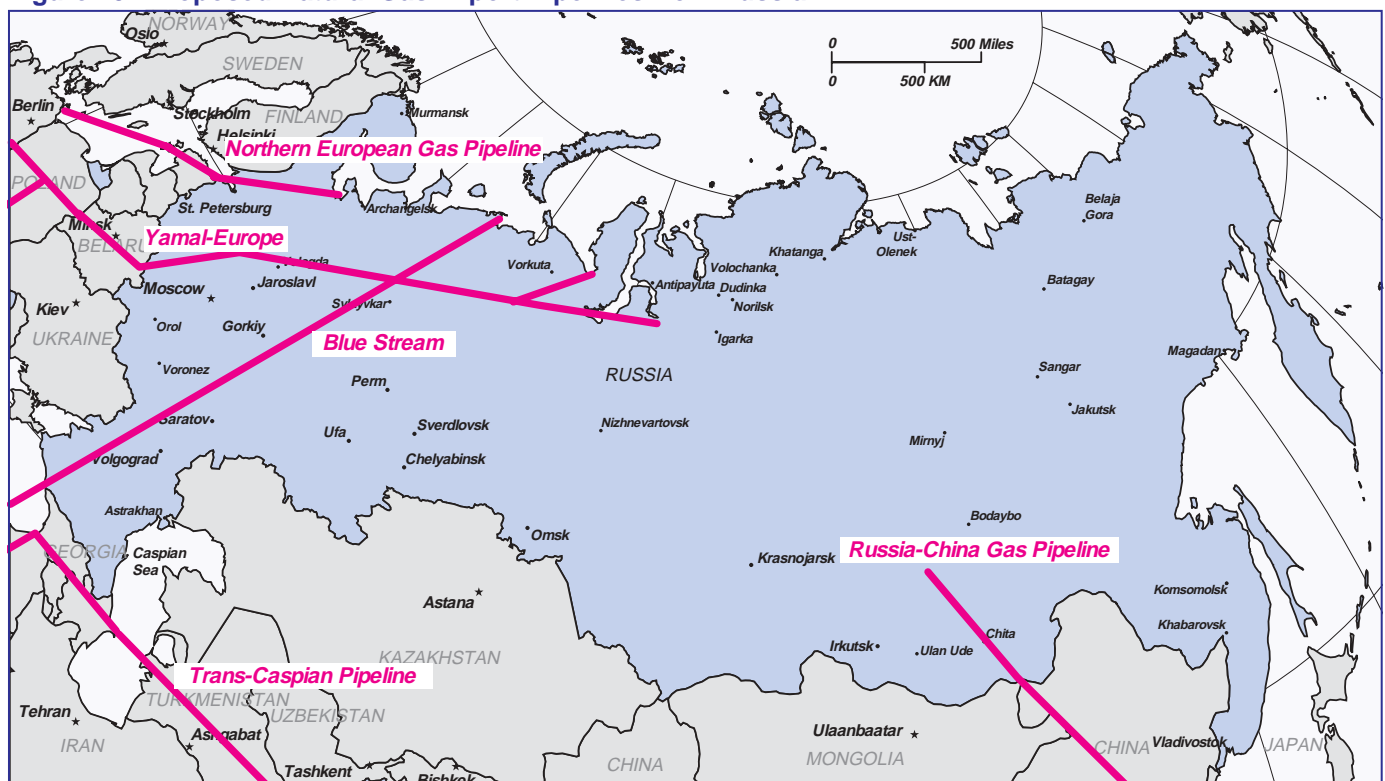
Figure 44. Russia's Net Natural Gas Exports, 1992-1999



Source: PlanEcon, *Energy Report*, Vol. 10, No. 1 (Washington, DC, May 2000), p. 38.

Russia hopes to both further expand its export capacity (Figure 45) and at the same time diversify its export markets so that it can ship less gas to debtor nations, such as Ukraine, and be less dependent on Ukraine as an export route. Ukraine currently serves as a transit route for more than 90 percent of Russia's exports to Europe. Problems between Russia and Ukraine continue, with Ukraine failing to keep current in its payments for gas imported from Russia, and Russia accusing Ukraine of siphoning gas it is not entitled to during transit, thus threatening Russia's European customers with natural gas shortages.

Figure 45. Proposed Natural Gas Export Pipelines from Russia



Source: P. Trafalgar, "Boom for Russia's Gas-Export Pipelines," *The Russia Journal* (November 23-29, 2001), p. 6

Russia plans to build the Yamal-Europe II pipeline, which would allow it to bypass Ukraine and, instead, transit Belarus, Poland, and Slovakia. A feasibility study is underway. One glitch is Poland's hesitancy to make a move that might damage the interests of Ukraine, because Ukraine is one of Poland's strategic allies. While Russia hopes to diversify its customer base, its customers have in turn attempted to reduce their dependence on Russia as a primary supplier, especially given the economic instability in Russia in the past. In order to diversify, Russia is exploring the possibility of exporting gas from eastern Siberia and/or Irkutsk to Asian markets, notably China, and several pipeline options are being considered. Gazprom has also undertaken a feasibility study on a pipeline, North TransGas, that would carry Russian gas across the Baltic Sea to serve Scandinavia and Germany. Firms developing the Sakhalin I field have proposed a pipeline to deliver Sakhalin gas to northern Japan and later Tokyo, and a feasibility study is being conducted [31].

Although Russian production declined in 2000, the FSU as a whole increased production by 2.7 percent, with production in Turkmenistan more than doubling and production in Kazakhstan growing by 15.6 percent. Much of the increased production in Turkmenistan was exported, primarily to other EE/FSU countries but also to Iran. At present, Turkmenistan is Iran's only source of imports. Turkmenistan is the only former Soviet Republic except Russia that is exporting substantial volumes of natural gas. The country produces about 70 percent more gas than it currently consumes. Approximately 85 percent of the excess production is exported to Iran for use in Iran's non-producing northern areas, with the remaining 15 percent going to other EE/FSU countries. This is almost the reverse of the situation in 1999, when 30 percent of Turkmenistan's exports went to Iran and 70 percent to other EE/FSU countries.

Central and South America

Natural gas markets in Central and South America are relatively small, but they are growing rapidly, with considerable upstream and downstream development. *IEO2002* projects that gas consumption in Central and South America will grow to 14.6 trillion cubic feet by 2020, at an average annual growth rate of 7.4 percent (Figure 46).

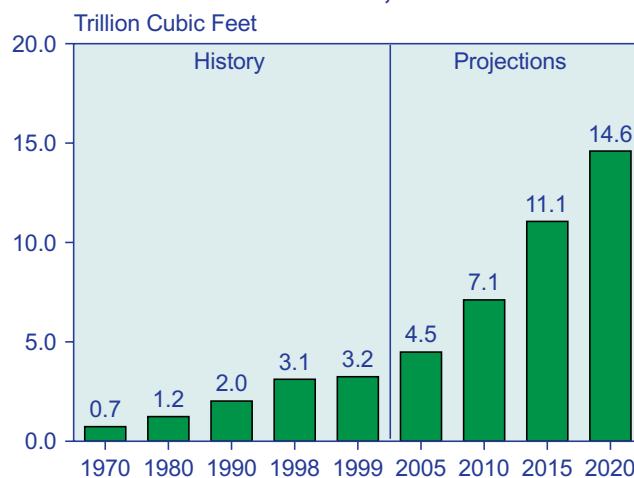
Because much of Central and South America has not yet been explored for gas, there is strong potential for new discoveries. Recent exploration activity has yielded promising discoveries, and the region's reserves have increased from 244 trillion cubic feet in 1999 to 253 trillion cubic feet in 2001. The highest concentrations of reserves are in Argentina and Bolivia in the Southern Cone Common Market, also referred to as Mercosur, and Venezuela and Trinidad and Tobago in the north.

Brazil

Consumption in Brazil has increased steadily over the past decade and is expected to grow at an average annual rate of 13.3 percent over the forecast period. Brazil is making an effort to diversify fuel use in its electricity generation sector, which is almost entirely dependent on hydropower. The country is currently experiencing an electricity shortage brought on by several years of below average rainfall that has left reservoirs less than 30 percent full and, in 2001, led the government to mandate that industrial and residential consumers reduce their electricity consumption by 20 percent. The energy crisis has added more urgency to plans for constructing substantial natural-gas-fired electricity generators. The Brazilian government is pressing to get 15 gas-fired power plants with a combined capacity of 6,423 megawatts operational by 2003 and has set a long-term goal of completing 55 new gas-fired generators before 2007 with a combined capacity of 23,000 megawatts [32] (see box on page 118). In an effort to promote natural gas use, plans are underway to privatize parts of the country's gas sector. Natural gas exploration and production historically have been controlled by the state company, Petrobrás, with distribution handled at the state level [33].

There are several pipeline projects available to serve the Brazilian markets, and several more are planned (Figure 47). One pipeline in operation connects Paraná, Argentina, to Uruguaiana, Brazil. It has been providing gas to a power plant in Uruguaiana since July 2000. An extension of the pipeline to Porto Alegre, Brazil, is currently under construction, with a targeted completion date of 2002.

Figure 46. Natural Gas Consumption in Central and South America, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Additional Argentina-Brazil pipelines are in various stages of the planning process, although recent natural gas discoveries in Bolivia and potential Brazilian discoveries could prevent development of these pipeline projects. The potential Argentina-Brazil pipelines include the Cruz del Sur, Trans-Iguacu, and Mercosur pipelines. The Cruz del Sur would extend to Brazil an Argentine-Uruguayan pipeline that currently is under construction (construction began in March 2001, with the first deliveries slated for early 2002). The Trans-Iguacu pipeline would cross from northern Argentina's Noroeste basin into southern Brazil. The Mercosur pipeline would tap northwestern Argentina's Neuquén basin to Curitiba, Brazil, and could extend to Sao Paulo [34].

Other Central and South America

With new natural gas fields being discovered and developed in Bolivia and the completion of the Bolivia-Brazil pipeline, Bolivia is poised to become a major participant in the South American natural gas market. Bolivia has plans for considerable expansion of its pipeline infrastructure that will allow the country to supply gas to new natural-gas-fired electricity generators in surrounding countries, and discussions with Mexico raise the possibility that Bolivia could become an exporter of LNG.

Argentina is both South America's largest producer and consumer of natural gas, but it has been in a recession for the past 4 years and now is in the throes of a full

Figure 47. Major Natural Gas Pipelines in South America



Source: "Gas and Power in Latin America," *Oil & Gas Journal*, Vol. 99, No. 42 (October 15, 2001), p. 74.

economic crisis. Argentina has enormous debt that it cannot repay, and on January 6, 2002, the government announced a 29-percent currency devaluation. Before the devaluation, the government placed a cap on bank withdrawals that angered the citizenry, leading to protests and encouraging many to flee the country. Because Argentina has already defaulted on part of its \$141 billion debt, it has in effect been cut off from international capital markets, and the International Monetary Fund (IMF) froze aid to Argentina in December 2001 [35]. Argentina's natural gas industry is entirely in the hands of the private sector and is operated within a competitive market structure. The economic crisis will certainly affect energy markets, most likely throughout South America, but the extent of the impact remains to be seen.

Chile is Argentina's largest export customer. Four pipelines currently connect the Argentine Neuquén basin with Chile, and there are plans to extend the GasAndes pipeline in central Chile, which has been in operation since 1997, to Rancagua, Chile, by the summer of 2002. In November 1999 the Gasoducto del Pacifico opened, transporting Argentine gas to industrial consumers in southern Chile's Bio Bio region. The other two Argentine-Chilean pipelines, the GasAtacama and the NorAndino, run parallel to each other and, along with Gasoducto del Pacifico, supply markets that do not yet fully utilize their capacities. The GasAtacama pipeline came online in July 1999 and primarily serves the Nopel power plant. The NorAndino pipeline came online in November 1999 and supplies two power plants.

Like Brazil, Chile's expected increase in natural gas consumption is fueled in part by a desire to become less dependent on hydropower, which is currently its largest source of electricity. Chile experienced rolling blackouts from late 1997 until well into 1999 as a result of drought [36]. Colombia saw less expansion of its natural gas sector in 2000 than did Brazil and Chile, but the government plans to foster future expansion in an attempt, like Brazil and Chile, to make its electricity sector less vulnerable to droughts. In early 2001, the Colombian congress was considering legislation to deregulate natural gas prices by 2003, to increase natural gas production for both domestic consumption and exports, and to support increased domestic consumption of natural gas, especially for electricity, was under consideration [37].

In the northern portion of South America, an active LNG market is developing. Atlantic LNG's Point Fortin facility, located in Trinidad and Tobago, became operational in 1999 with its first train of 3 million metric tons per year,⁶ exporting 51 billion cubic feet to the United States and 25 billion cubic feet to Spain by the year's end. Trains 2 and 3 are under construction and will add 3.3 million metric tons per year each by the fourth quarter of

2002 and third quarter of 2003, respectively. When completed, the expansion will triple Atlantic's LNG export capacity. Venezuela is planning to enter the LNG market with two single-train facilities of 2.1 and 4.0 million metric tons annual export capacity scheduled for completion in 2004 and 2005, respectively. Petroleos de Venezuela (PDVSA), the state oil and gas company, is a partner in both terminals. In addition to its major clients, Trinidad and Tobago is currently supplying gas to the EcoElectrica facility in Puerto Rico and has also signed an agreement to send LNG to a new import terminal in the Dominican Republic as early as late 2002. This highlights the potential for increased use of imported LNG in smaller markets.

Industrialized Asia

Natural gas consumption in industrialized Asia (Australia, New Zealand, and Japan) is projected to increase by 1.9 percent per year from 1999 to 2020, much slower than the 11.2-percent annual average increase from 1970 to 1999. Industrialized Asia contributed 7 percent of the increase in world gas consumption over the past 3 decades, but its contribution over the next 2 decades is expected to fall to 2 percent.

Australia

An expanding pipeline system and continuing deregulation are moving Australia toward a more competitive domestic natural gas market. Deregulation of the gas market is being done by the states rather than central authorities, resulting in a piecemeal approach that has been blamed for the slow pace and wide variations in the domestic gas market. Reform for free and fair trade in natural gas was agreed to by the Commonwealth and all states and territories in 1997 but has yet to be fully implemented [38]. Gas consumption in Australia and New Zealand is projected to increase by 2.3 percent per year from 1999 to 2020 (Figure 48).

New and planned pipelines are starting to turn the once separate supply systems into a national grid (Figure 49). The creation of competing sources of supply has the potential to change the structure of the gas markets. One such project, a 3,200-kilometer pipeline from Papua New Guinea down the east coast to Brisbane, could eventually supply gas to markets in New South Wales and Victoria [39]; however, the project continues to languish despite the new leadership of ExxonMobil [40].

Australia's natural gas supply capability is expected to expand at a faster pace than domestic consumption, providing opportunities for additional exports. A fourth train is planned for the Northwest Shelf LNG venture. Sales and purchase agreements were signed with two Japanese utilities for LNG deliveries starting in mid-2004 [41]. A methanol plant and a gas-to-liquids (GTL)

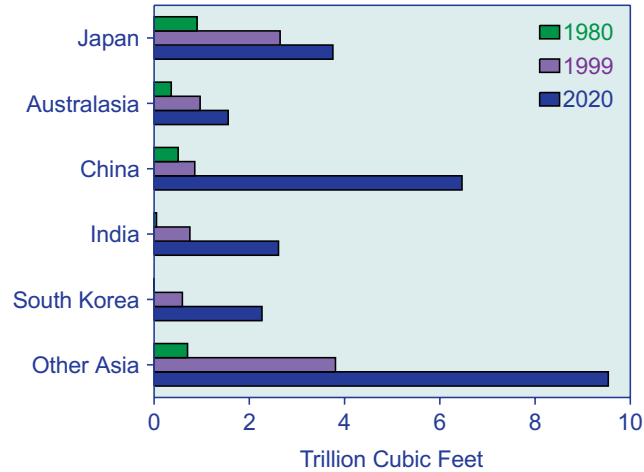
⁶A metric ton is equivalent to 48,700 cubic feet of natural gas.

facility are also being considered for the Northwest Shelf. Officials point out that the Northwest Shelf has ample gas to supply domestic as well as export projects [42].

Royal Dutch/Shell appears to have convinced its partners in the Greater Sunrise LNG project to develop a floating LNG facility rather than build a pipeline and a conventional onshore liquefaction plant near Darwin. Equity issues still have to be worked out, and agreements with buyers need to be secured. Greater Sunrise lies predominantly in the Australian part of the Timor Sea, but buyers remain wary because tax disputes with East Timor have halted progress on the adjacent Bayu-Undan project. Shell believes that the floating facility will be up to 40 percent cheaper than the onshore option [43].

The development of the 9.6 trillion cubic feet of untapped gas reserves in the Gorgon fields remains uncertain. The Gorgon partners have been trying for years to decide between an independent project and integrating their resources with the Northwest Shelf. The Northwest Shelf consortium currently believes that they can honor all contracts without the Gorgon reserves

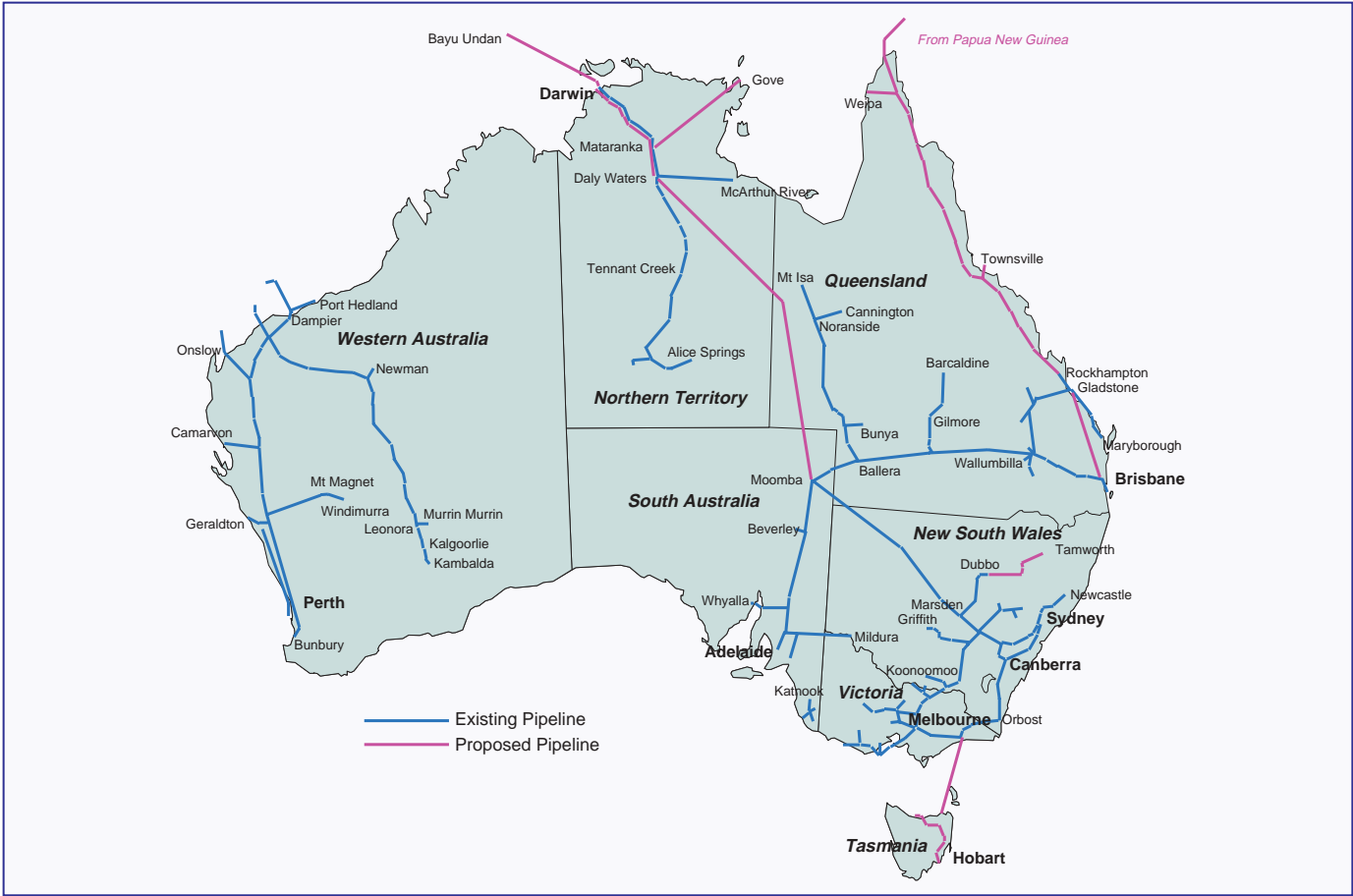
Figure 48. Natural Gas Consumption in Asia, 1980, 1999, and 2020



Note: Australasia includes Australia, New Zealand, and the U.S. Territories (Guam, Puerto Rico, and the U.S. Virgin Islands).

Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 49. Major Natural Gas Pipelines in Australia



Source: Australian Gas Association, web site www.gas.asn.au/SECTN1.htm (May 2001).

[44]. The China National Offshore Oil Corporation (CNOOC) signed a preliminary agreement with Chevron to study the feasibility of acquiring an equity stake in the Gorgon fields. The Gorgon gas is one of the possible sources of LNG supply for CNOOC's Guangdong LNG import project [45].

Japan

Natural gas demand in Japan is projected to increase by 1.7 percent per year from 1999 to 2020 (Figure 48), well below the average of 2.4 percent per year for the industrialized countries as a whole and the 3.2 percent annual average projected for world growth in natural gas use. Japan's economy continues to languish, and slow-paced deregulation of the electric power and natural gas markets is causing uncertainty about future gas demand in Japan. This uncertainty, combined with the shutdown of Indonesia's Arun facility for 7 months in 2001 (see below), may be changing the normally rigid, long-term orientation of LNG markets in Japan. For example, Chubu Electric Power has signed a framework agreement with Malaysia's LNG Tiga for emergency supplies of LNG. No minimum or maximum volumes are specified, and Chubu is required to give only 10 days notice before lifting. The price will be determined when the transaction takes place [46]. In addition, Japanese trading houses are starting to look outside Japan to help commercialize otherwise stranded gas reserves. The financial backing of the Japanese trading firms could speed up the development of such reserves [47].

Developing Asia

Developing Asia is expected to contribute 19 percent of the increase in world gas demand from 1999 to 2020. The growth of 14.9 trillion cubic feet over the forecast period is slightly higher than that projected for North America. The region includes countries that are major producers of natural gas and LNG as well as rapidly expanding gas-consuming countries.

China

Natural gas provided 23 percent of world energy demand in 1999 but in China only 3 percent of energy demand was met by gas. Natural gas consumption in China is projected to increase by 10.1 percent per year from 1999 to 2020, raising the natural gas share of China's energy consumption to 9 percent by 2020 (Figure 50).

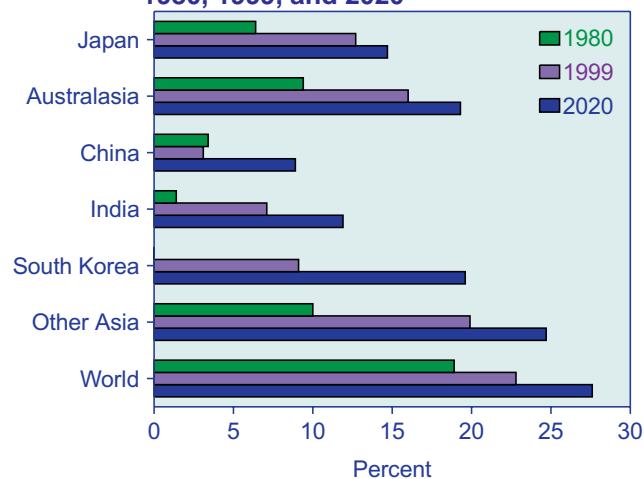
Environmental concerns in China are prompting movement toward gas and away from coal and oil, and energy security concerns are promoting the development of domestic gas supplies and the expansion of China's gas infrastructure. In early 2001, China's State Council approved a huge, \$12 billion project to develop gas reserves in the remote western part of the country and move the gas east by pipeline to Shanghai and other

Yangtze Delta cities [48] (see box on page 59). PetroChina completed the Sebei Lanzhou gas pipeline in September 2001, traversing a harsh natural environment. The pipeline has the capacity to move 141 billion cubic feet of gas annually from the Qaidam Basin to Lanzhou [49]. Supplying gas to Lanzhou has been a priority because it has the highest levels of sulfur dioxide and particulates in China and is considered one of the most polluted cities in the world [50].

In November 2001, PetroChina signed a contract to sell gas to the Wuhan municipal government. The gas is to be delivered through the proposed Zhong-Wu pipeline, using reserves from the Sichuan and Chongqing areas. The pipeline is expected to have an installed capacity of 3 billion cubic meters per year and provide gas to more than a dozen cities in the region. Wuhan agreed to a "take-or-pay" contract, with volumes increasing from 7 billion cubic feet in the first year to 42 billion cubic feet in the fifth year of operation. The central government is requiring PetroChina to enter take-or-pay contract deals with the cities along the pipeline route [51].

While China is promoting the expansion of domestic gas supplies, the development of an LNG import facility in Guangdong province is also proceeding. BP Amoco won the right to build the terminal but not necessarily the right to supply LNG to the facility. Both the Tangguh project in Irian Jaya, Indonesia, and the Greater Sunrise project in the Timor Gap are targeting the Guangdong

Figure 50. Natural Gas Share of Total Energy Consumption in Selected Asian Countries and the World, 1980, 1999, and 2020



Note: Australasia includes Australia, New Zealand, and the U.S. Territories (Guam, Puerto Rico, and the U.S. Virgin Islands).

Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

China's West-to-East Natural Gas Pipeline

Supplying natural gas to the industrial urban centers of eastern China, notably Shanghai, remains an important priority for the Chinese government. On March 25, 2000, China formally announced plans to build a massive cross-country pipeline that would transport natural gas from the Tarim basin in the west to Shanghai in the east. The pipeline would pass through seven provinces—Gansu, Ningxia, Shaanxi, Shanxi, Henan, Anhui, and Jiangsu—before reaching Shanghai. Construction of the 2,584-mile pipeline was originally slated to begin in September 2001 but has been postponed because contract negotiations between the government and the foreign companies that will be participating in the project have not been finalized.^a The Chinese government still expects that the line will be completed before the end of 2003, but the date will depend largely on whether construction begins soon.

The West-to-East pipeline would initially deliver 424 billion cubic feet of natural gas per year to the eastern markets. Shanghai is scheduled to receive the major share, some 350 billion cubic feet per year, with the balance supplied to other provinces along the pipeline route (see map). The natural gas supplied is eventually to be increased to 706 billion cubic feet per year.^b Thirty percent of total potential Chinese production capability of natural gas and 47 percent of the potential supply available to move between Chinese regions in 2010 is expected to originate in west China. These levels would justify the West-to-East gas pipeline, but China is also developing plans to import liquefied natural gas (LNG), as well as plans for other pipelines. The most prominent projects are the Guangzhou LNG project and the natural gas pipelines from Irkutsk in Siberia and Sakhalin in far eastern Russia.

(continued on page 60)



^aM. Hurle, "Energy Sector Analysis: China: Mega Pipeline Facing Delays," *World Markets OnLine*, web site www.worldmarketsonline.com (October 9, 2001).

^bFesharaki Associates Consulting & Technical Services (FACTS), Inc., *China's Natural Gas to 2015* (Honolulu-Singapore, October 2000), p. 4-22.

China's West-to-East Natural Gas Pipeline (Continued)

The share of natural gas in China energy consumption is currently very low, estimated at 3 percent in 1999, compared with 10 percent in the rest of developing Asia and 23 percent in the rest of the world. China has been adding significant amounts of natural gas reserves over the past decade, and current reserves are estimated at 38.8 trillion cubic feet.^c China considers an acceleration of natural gas production to be an attractive policy for switching to clean-burning fuels, both on environmental grounds and to tap domestic gas resources in substitution for domestic coal and imported oil. The *IEO2002* reference case forecast indicates that China's natural gas demand is expected to reach 2.8 trillion cubic feet by 2010 and 6.4 trillion cubic feet by 2020. A more optimistic, full-fledged fuel-switching policy could boost demand to 3.4 trillion cubic feet as early as 2010, with 53 percent going into power generation, 21 percent consumed in the chemical sector, and 25 percent used as city fuel.^d

Although China sees the importance of developing domestic sources of natural gas in order to enhance the security of energy supplies, the cross-country pipeline is not necessarily economically sound, nor are its potential supplies currently needed to meet the low level of demand in eastern China. Environmental quality has been a significant concern behind the government's determination to implement the West-to-East project. Major cities in China frequently have been ranked high in various top 10 lists of the most polluted cities in the world. Decades of expansionary coal use have resulted in environmental degradation, which needs urgent remediation. Estimates by some independent observers and by Chinese officials put the direct economic losses caused by pollution at approximately \$100 billion per year, and some analysts claim that China must now spend \$20 billion per year just to prevent pollution from rising above current levels.^e

For Shanghai, which is the target market for many large pipeline proposals, the high cost of supplying gas from western China largely reflects the cost of assembling gas from the various western supply basins (Tarim, Junggar, Turpan-Hami, and Qaidam) at a common point. From there, a large diameter pipeline

could be used to connect with the Ordos basin and on to Shanghai. The delivery costs to Shanghai from west China gas would be much higher than the cost of importing Irkutsk gas from eastern Siberia. As a result, if the Chinese government were basing its decisions about constructing the West-to-East pipeline solely on the cost of transporting the gas to market, Chinese policy makers would choose Irkutsk over western China as the source of remote gas supply.^f

While most of the natural gas industry in China continues to function under quotas and supply allocations, a parallel pricing regime has been created for all new foreign-invested projects. The new pricing structure attempts to create a mechanism to reflect the true economic cost of projects and an adequate gas transportation tariff to secure a profit margin for the developers. However, recent examples show that when the combination of the gas price and the pipeline tariff proposed by developers differs significantly from the maximum affordable citygate price, the Chinese gas regulators tend to adjust the total price by cutting the pipeline tariff. The Ordos-Beijing pipeline, owned by PetroChina and the Beijing city government, received approximately half its requested tariff (12.71 yuan, or \$1.41, per cubic foot, versus a proposed 26.12 yuan, or \$3.18); and the Zhongxian-Wuhan pipeline, partially financed by a foreign developer, was approved for a 9.53 yuan (\$1.06) per cubic foot tariff despite a proposed tariff of 12.71 yuan per cubic foot. In both cases, the developers decided to proceed despite concerns that the pipeline project was not economically viable.^g

Because of the project size and distance from market, the West-to-East gas pipeline project more nearly resembles import pipelines than those from domestic basins such as the Ordos and Sichuan, which serve the northeastern markets in and around Beijing. For example, the West-to-East China pipeline investment is larger than that required to supply a similar amount of gas from Sakhalin (far east Russia) and is nearly as large an investment as the Irkutsk (eastern Siberia) project and its giant Kovyktinsk field, which has double the supply capacity of west China fields.^h

(continued on page 61)

^cDRI-WEFA, "Energy Monitor: Asia," *World Energy Service Asia/Pacific Outlook* (Lexington, MA, October 2001).

^dLan Quan and Keun-Wook Paik, *China Natural Gas Report* (London, UK: Xinhua News Agency, Beijing and Royal Institute of International Affairs, 1998).

^eCambridge Energy Research Associates, *Onshore Gas Opportunities in China: A New Era?* (Cambridge, MA, February 2000), p. 3.

^fAsia Pacific Energy Research Center, *Natural Gas Infrastructure Development: Northeast Asia, Costs and Benefits* (Tokyo, Japan, March 2000), p. 113.

^gCambridge Energy Research Associates, *Betwixt and Between: China's Natural Gas Industry under Commercial Principles* (Cambridge, MA, February 2001), p. 6.

^hAsia Pacific Energy Research Center, *Natural Gas Infrastructure Development: Northeast Asia, Costs and Benefits* (Tokyo, Japan, March 2000), p. 111.

terminal. BP Amoco and the Indonesian state oil company, Pertamina, are promoting Tangguh; Royal Dutch/Shell is leading the Greater Sunrise project along with Woodside, Phillips, and Osaka Gas [52]. The Gorgon project in Australia is considered a long shot for supplying Guangdong, given technical problems related to its high carbon dioxide content [53].

In addition to the Guangdong facility, CNOOC signed an agreement with the Fujian provincial government to build a 2 million metric ton LNG receiving terminal. CNOOC would take responsibility for the terminal and an attached trunk pipeline, and the Fujian government would take care of the provincial distribution network. A detailed study must be done and submitted to the State Development Planning Commission for approval,

but CNOOC would like to begin operation by 2005 or 2006 [54]. Fujian province is located on the south China coast between the LNG facility planned for Guangdong and the West-East pipeline that is intended to extend to Shanghai.

India

India has also been the target of intense interest by LNG producers as a country with great growth potential. Many projects have been proposed, but the collapse of the Dabhol project, uncertainties concerning LNG policies, and problems associated with selling costly gas to financially troubled state power distributors have slowed the advance of LNG import projects. Natural gas demand growth is projected to remain strong, however, and some projects are making progress.

China's West-to-East Natural Gas Pipeline (Continued)

Another issue of concern to the West-to-East pipeline developers is that China currently does not have an adequate distribution network to send massive natural gas supplies to individual users in Chinese cities, although progress is being made in improving the situation. In fact, because of the lack of distribution networks, many of the pipelines already completed are running at rates that are lower than their design capacity. For instance, the 536-mile Shaan-Jing pipeline connecting Jingbian in Shaanxi Province with Beijing, completed in September 1997, still is operating below capacity. Although the Shaan-Jing pipeline was designed to transport 194 million cubic feet per day, the initial delivery was only 106 million cubic feet per day. Even at that level, Beijing's actual gas consumption was much lower.

The 480-mile Yacheng-Hong Kong Pipeline, the longest undersea pipeline in Asia and the second largest in the world, was completed in 1996. It connects the offshore Yacheng 13-1 gas field with Hong Kong power plant at Black Point. The total cost of the pipeline was \$1.1 billion. Because Hong Kong cannot consume all the gas delivered by contract, it must flare some of it under a "take-or-pay" clause. Other completed pipelines have encountered the same problem: extremely low utilization rates at the initial stage, because the target cities or industrial users were not ready.ⁱ

The future of natural gas in China's electricity generation sector—the largest targeted market for the West-to-East pipeline gas—is also uncertain. A number of factors could put the natural gas at a disadvantage

relative to other fuels. One is that the power sector, without proper environmental regulations such as taxing heavy polluters, would not expand the use of natural gas for electricity generation. Coal would remain the preferred fuel because of its ability to compete on cost. Secondly, the retail price of natural gas in Shanghai would have to compete with cheaper imports of LNG. The latter may occur if the Guangzhou LNG project is deemed a success and another terminal is built near Shanghai.^j Various governmental studies insist that the end-user prices of the pipeline gas will be competitive with LNG; however, the calculations are based largely on the assumption that pipeline utilization rates will be high. The cost will be much higher if the pipeline is underutilized.

To finance the West-to-East pipeline project, the Chinese government has announced that it would allow foreign investors to hold majority stakes in the pipeline, which will cost an estimated \$4.8 billion to build. China will also open potentially lucrative areas of gas development and marketing to foreign companies, which will require an additional \$13.2 billion in investment.^k PetroChina, the official sponsor of the West-to-East project, short-listed a foreign consortium, which is led by ExxonMobil, Royal Dutch/Shell, and BP. However, BP decided to withdraw from the project in early September 2001, in the face of a demanding deadline to submit its final investment proposal. BP's withdrawal has underscored doubts that the 2,584-mile natural gas pipeline's commercial potential matches its political importance.

ⁱFesharaki Associates Consulting & Technical Services (FACTS), Inc., *China's Natural Gas to 2015* (Honolulu-Singapore, October 2000), p. 4-16.

^j"Markets, Prizes, and Briefs," *Petroleum Intelligence Weekly*, Vol. 40, No. 24 (June 11, 2001), p. 11.

^k"China: BP Pulls Out of the 4,000 km West-East Pipeline Project," *CEDIGAS NEWS REPORT*, Vol. 40, No. 38 (September 29, 2001), p. 7.

Enron's Dabhol project had collapsed long before the company itself (see box on page 135). The Maharashtra State Electricity Board accused Enron of overcharging and refused to pay for the power from Dabhol. The Enron-controlled Dabhol Power Company then defaulted on interest payments to international lenders on the gas-fired, 1,440 megawatt second phase of the project, which was 90 percent complete [55]. A 2.5 million ton LNG receiving terminal was said to be roughly 85 percent complete. Indian financial institutions are laying claim to the Enron assets, but their success at taking over the assets remains unclear [56].

A few LNG projects are making progress. National Thermal Power Corporation, India's biggest power producer, invited bids to supply 4 million tons per year of LNG to its proposed gas-fired power plants. Qatar, Oman, and Iran are considered frontrunners. A potential stumbling block, however, is the shortage of pipelines to move the gas to the relatively distant locations of the generating facilities. Petronet LNG, which is planning to begin importing gas at its 5 million ton LNG facility at Dahej in Gujarat in December 2003, is also preparing to select a contractor to build a 2.5 million ton per year terminal at Kochi in Southern India [57].

LNG policy confusion and backpedaling on market liberalization could complicate LNG projects. Policy differences among ministries are delaying the adoption of an integrated policy on importing, consuming, and transporting LNG. The government is considering a proposal to free natural gas prices along with oil prices in April 2002, but because of opposition by the Ministry of Finance, natural gas prices may be only partially freed. Another measure under consideration would require 26 percent Indian ownership in any venture shipping LNG to India, gradually rising to 50 percent in 5 years. In order to ensure domestic control, the government is also likely to insist on free-on-board (f.o.b.) contracts that obligate the buyer to arrange for transporting the product [58].

South Korea

Natural gas demand in South Korea is expected to grow by 6.6 percent per year from 1999 to 2020. Despite an economic slowdown, gas consumption jumped by about 13 percent in the first half of 2001. The surge in demand occurred in the residential and industrial sectors as well as power generation, reflecting a rapidly expanding gas grid. City gas demand is expected to remain strong as progress is made on a nationwide transmission system. The increase in gas demand came despite LNG prices that topped \$5 per million Btu when oil prices were high. LNG prices are beginning to ease, but the responsiveness of gas demand to price was not evident in the first half of the year [59].

Other Developing Asia

Indonesia is the largest LNG producer in the world, but unrest in the province of Aceh resulted in the shutdown of the Arun LNG facility for 7 months in 2001. The shutdown left Korea Gas Corporation (Kogas) and Japan's Tohoku Electric searching for replacement supplies. Because South Korea's summer gas consumption is less than half of the winter level, Kogas was able to get by with an occasional cargo from Bontang to supplement its contracted supplies from the Middle East and Malaysia. Tohoku received several replacement cargoes from the Bontang facility and from Malaysia [60].

The Arun facility was commissioned in 1978 and was expected to reach the end of its producing life over the next decade or so due to declining gas reserves. Two trains were shut down in 2000 [61]. But the problems in Aceh may speed the scaling down of Arun. Two Japanese utilities indicated that they may cut imports from Arun from 3.5 million tons per year to 1 million tons per year when their 20-year contracts expire in 2005 [62].

Indonesia is planning to expand the LNG facility at Bontang and to build a new plant at Tangguh in Irian Jaya, but the instability could hurt the ability of these projects to secure buyers. Indonesian officials claimed that Japanese utilities and CPC Taiwan have committed to take over 3 million tons per year from Tangguh, but both CPC and the Japanese utilities denied any keen interest [63]. El Paso Natural Gas, a U.S. company, was seeking to secure LNG supplies from the Timor Gap, but with that project on hold El Paso is showing interest in Tangguh. An independent power project from the Philippines, GNPow, signed a letter of intent to buy 1.3 million tons per year from Tangguh even though the Malampaya fields just started to deliver gas onshore. Some sources expect the Malampaya gas to be more expensive than imported LNG [64].

Malaysia is expanding its Bintulu LNG facility without the long-term contracts in place that normally accompany an LNG project. The 6.8 million ton per year expansion will increase total capacity to 23 million metric tons per year, making Bintulu the largest LNG producing facility in the world. The project, which is being jointly developed by Petronas and Royal Dutch/Shell, had a letter of intent for 2.6 million tons per year from Enron's subsidiary in India, but that is highly unlikely at this point. That leaves a firm contract for only 0.9 million tons per year with Tohoku Electric. Malaysia is desperately seeking Japanese and South Korean customers to absorb the gas and could be a large contributor to the nascent LNG spot market [65].

While the Trans-ASEAN Gas Pipeline remains just a concept on paper, small pieces of what could eventually be a gas pipeline grid in Southeast Asia are being

developed. In January 2001, gas began to flow from Indonesia's West Natuna fields to Singapore, and in February a contract was signed to bring gas to Singapore from Indonesia's South Sumatran fields. The contract calls for gas to begin flowing in July 2002 and continue for 20 years. In March, Indonesia signed a contract with Malaysia to supply 1.5 trillion cubic feet of gas over a 20-year period from the West Natuna fields into the Malaysian peninsular network [66].

Delays continue for a planned gas pipeline from the Thailand-Malaysia joint development area (JDA) to southern Thailand and on to northwest Malaysia. Villagers at the proposed landing point for the pipeline protested that it would inflict environment damage and affect fishing in the area. Thai authorities rejected the project's environmental impact assessment. The pipeline was to have been completed by mid-2002 but now is not expected until the end of 2003 at the earliest [67]. A connection to Thailand's offshore gas fields and transmission system to the north of the JDA is also being considered, which would allow gas to be delivered to Bangkok [68].

Myanmar gas can now reach demand centers along Thailand's main gas transmission line following the completion of a 60-mile pipeline connection from Ratchaburi to Wang Noi. This should allow Thailand to take all of the gas specified in its contract with Myanmar. The reduction in electricity and gas demand after the 1997 financial crisis left Thailand with more gas than could be used at the Ratchaburi generating plant.

The Philippines inaugurated the Malampaya gas-to-power project in October 2001 and unveiled plans for expanded natural gas use. The privatization plan of the state-owned power company, the National Power Corporation, is supposed to include the conversion of certain plants to gas-fired power. A pipeline is planned to transport gas from Batangas to Manila (the so-called Batman project) to switch a power plant that is currently burning diesel to natural gas. The Malampaya infrastructure currently has enough capacity to fuel up to 4 gigawatts of power generation capacity, and 2.7 gigawatts are under contract [69].

The new government of Prime Minister Begum Khaleda Zia in Bangladesh is considering a gas export pipeline to India, although opposition remains fierce. Economic realities are compelling the deliberation, especially given foreign exchange difficulties that have halted payments totaling \$54 million each to Shell and Unocal for gas purchased over the past few months. Unocal indicated in its proposal for a 500 million cubic feet per day pipeline to Delhi that the Bangladeshi government could receive \$3.7 billion in revenue over the next 20 years [70]. Demonstrations and street protests followed

indications that the government was considering natural gas exports [71].

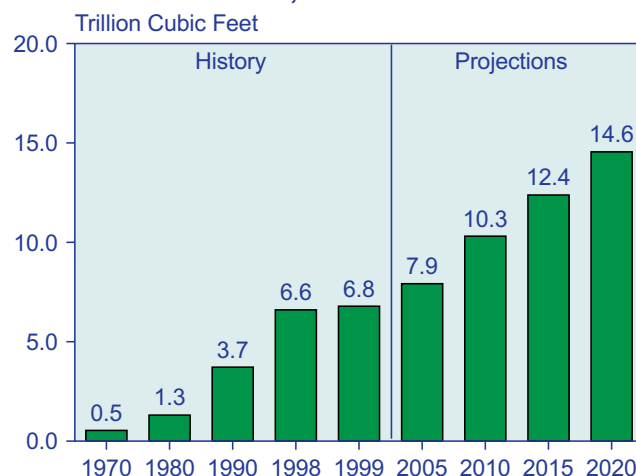
East Timor and Australia agreed to a 90/10 split of revenues from natural gas development in the Timor Gap. The original agreement, negotiated when East Timor was part of Indonesia, called for a 50/50 split of revenues [72]. The initial encouragement that the agreement gave to gas development in the region quickly dissipated when Phillips and its partners in the Bayu-Undan project indefinitely deferred development until certain legal, fiscal, and taxation issues arising from the new agreement are resolved [73].

Middle East

As of January 1, 2002, the Middle East's reserves of 1,975 trillion cubic feet were essentially equal to the FSU's 1,972 trillion cubic feet, but the region's production and consumption were less than one-third of those in the FSU. The Middle East more than doubled production between 1990 and 1999 and nearly doubled consumption. The region increasingly seeks to develop domestic gas markets, and rapid growth is expected in the *IEO2002* forecast (Figure 51). Consumption is projected to more than double, growing to 14.6 trillion cubic feet in 2020 from 6.8 trillion cubic feet in 1999, an average annual rate of 3.7 percent. The most significant reserves in the Middle East are held by (in order of size) Iran, Qatar, Saudi Arabia, and the United Arab Emirates (UAE), each holding in excess of 200 trillion cubic feet.

Because the bulk of Iranian natural gas reserves are located in nonassociated fields and have not been

Figure 51. Natural Gas Consumption in the Middle East, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

developed, Iran has tremendous potential for expansion of both its internal and export natural gas markets. Additionally, with much territory yet to be explored, Iran continues to make significant new discoveries. Most of Iran's reserves are in the southern part of the country, and Iran imports natural gas from Turkmenistan to satisfy demand in the northern part of the country. The country is also looking into the possibility of importing from Azerbaijan. Currently, Iran imports relatively small amounts of its gas, about 4 percent of its total natural gas consumption. Natural gas accounts for approximately 44 percent of Iran's total energy consumption, but the government plans to invest billions of dollars in the gas sector during its current Five-Year Development Plan, hoping to advance both its domestic and its export markets.

Over the past year or so, Iran has made a number of significant gas finds, though none that come close in magnitude to its South Pars field. South Pars is Iran's largest nonassociated natural gas field, projected to begin production in 2002. It is estimated to contain approximately 280 trillion cubic feet of gas, much of which is considered to be recoverable, and more than 17 billion barrels of liquids. South Pars is geologically an extension of Qatar's 241 trillion cubic feet North Field. Gas from South Pars is slated to be shipped north via the planned IGAT-3 pipeline, and possibly an additional IGAT-4 line, and then reinjected to boost oil output in mature fields that are currently in decline.

Iran's South Pars gas could also be exported, both by pipeline and possibly by tanker as LNG. In addition to the 280 trillion cubic feet in the South Pars field, a separate North Pars field contains an additional 48 trillion cubic feet. TotalFinaElf, Russia's Gazprom, and Malaysia's Petronas have jointly agreed to explore South Pars and to help develop the field during Phase 2 and 3 of its development. Phase 1, which is being handled by Petropars, has been delayed several times and now is scheduled for partial completion by the end of 2002. The development is expected to proceed through 12 phases, with phases 9 and 10 expected to supply the domestic market and phases 11 and 12 slated for LNG export [74].

Iran has reportedly discussed natural gas exports with Kuwait and the United Arab Emirates. To date, it has provided exports only to Turkey. In 1996, Iran agreed to supply Turkey with natural gas for a period of 22 years. Originally slated to commence in 1999 at a rate of 300 million cubic feet per day and increase to a level of 1 billion cubic feet per day in 2005, the flow of gas from the northwestern Iranian city of Tabriz to Ankara was postponed until September 2001 after Turkey requested a delay due to economic problems that prohibited it from completing its portion of the pipeline. A further delay came when Turkey maintained that a metering station

on the Iranian side was not ready for operation. Flows finally began on December 11, 2001.

Turkey's growth in natural gas consumption is proceeding at a much more rapid rate than its growth in production, and the country is expected to increase its imports from neighboring countries significantly. Currently Turkey is supplied by only Russia and Africa. Russian pipeline imports account for approximately 70 percent of Turkey's imports, with additional new pipeline supplies from Iran and LNG from Algeria and Nigeria accounting for the rest of its gas supply. Although it has had many recent gas finds, most of Turkey's gas is reinjected to enhance oil recovery, and domestic production is not expected to contribute significantly to internal consumption.

Across the border from Iran's South Pars is Qatar's North Field, the largest nonassociated gas field in the world. Internal consumption in Qatar declined by slightly over 9 percent in 2000, but its 2000 production exceeded 1999 production by 20 percent. The additional production was primarily to serve Qatar's rapidly growing export market. Almost half of Qatar's production was exported in 2000, all in the form of LNG. In 2000, Qatar was the fourth largest exporter of LNG in the world, behind Indonesia, Algeria, and Malaysia. Its major customers were Japan and South Korea, but the United States, Spain, Italy, and France also received cargoes from Qatar. Investment in LNG liquefaction facilities in Qatar has been significant. The first facility was completed in 1997, with three trains and a capacity of 7.7 million metric tons per year, and the second was completed in 1999, with two trains and a capacity of 6.6 million metric tons per year. There are plans to expand the second facility by 8.9 million metric tons per year by adding two additional trains.

Qatar is expected to play a major role in increasing natural gas use in the Middle East. According to current plans, gas will be exported by a new pipeline from Qatar's North Dome field to Abu Dhabi, Dubai, and Oman, with a possible future link to India. The planned pipeline, to be developed by Qatar's Dolphin Energy, Ltd. (DEL), will be the first cross-border pipeline in the Middle East. According to a Dolphin Energy press release on January 7, 2002, "the Dolphin project will complement the gas operations of Abu Dhabi National Oil Company (ADNOC) and meet demand for gas in the UAE, especially from the power generation sector, which is rising by between 10-12 percent a year" [75]. This will supplement Abu Dhabi's own production, which is not expected to increase as rapidly as its consumption, despite its plentiful natural gas resources. The pipeline will also provide opportunities to develop new industries in both Qatar and the UAE. Dolphin expects deliveries to its customers in the UAE to begin in

2005. If its projection of delivering 3 billion cubic feet per day is met, it would account for close to 10 percent of the world's pipeline trade.

The UAE contains extensive gas reserves, over 90 percent of which are in Abu Dhabi. LNG has been exported from Abu Dhabi's Das Island facility since 1977. The facility was expanded in 1994 and now consists of three trains with a total capacity of 3.3 million metric tons per year. Japan is the primary customer for Abu Dhabi's LNG exports. In May 2001 a pipeline from Abu Dhabi to Dubai (Abu Dhabi and Dubai are the two largest Emirates) began operating, supplementing Dubai's natural gas supply. Before May, Dubai was served entirely by Sharjah, another of the Emirates. UAE is intent on expanding its natural gas market and has invested heavily in moving to natural-gas-fired power plants and industry. It is also a partner in the Dolphin project to deliver gas from Qatar to the UAE, Oman, and potentially India.

Approximately two-thirds of Saudi Arabia's currently proven gas reserves consist of associated gas. Before 1984, when Saudi Arabia's Master Gas System (MGS) was completed to deliver gas to the industrial cities of Yanbu and Jubail, all of Saudi Arabia's natural gas was flared. While Saudi Arabia's gas sector has not shown significant growth in recent years, demand increases are anticipated, and Saudi Arabia has been promoting foreign investment in its gas sector. In May 2001, Saudi Arabia selected companies to participate in a \$25 billion "Saudi Gas Initiative," the first major reopening of Saudi Arabia's upstream hydrocarbons sector to foreign investment since nationalization in the 1970s. The purpose of the initiative, which consists of three "core ventures," is to integrate upstream gas development with downstream petrochemicals and power generation. Companies selected for the three core ventures under the Gas Initiative are (1) South Ghawar: ExxonMobil, Shell, BP, Phillips; (2) Red Sea: Exxon plus an Enron/Occidental partnership; and (3) Shaybah: Shell, Total, Conoco.

Core Venture 1 will include exploration, pipelines, two gas-fired power plants, two petrochemical plants, and two desalination units. Core Venture 2 will involve exploration and development in and along the coast of the Red Sea in northwestern Saudi Arabia and the construction of a petrochemical plant and a power station. Core Venture 3 will involve exploration near Shaybah in the Rub al-Khali ("Empty Quarter") of southeastern Saudi Arabia, development of the Kidan gas field, laying of pipelines from Shaybah to the Haradh and Hawiyah gas treatment plants east of Riyadh, and construction of a petrochemical plant in Jubail. Additional gas use is being encouraged for the country's growing petrochemical industry, for electricity generation, for desalination

plants and other industrial facilities, and as a replacement for oil burning. The use of gas instead of oil domestically is intended to help free up additional crude oil for export.

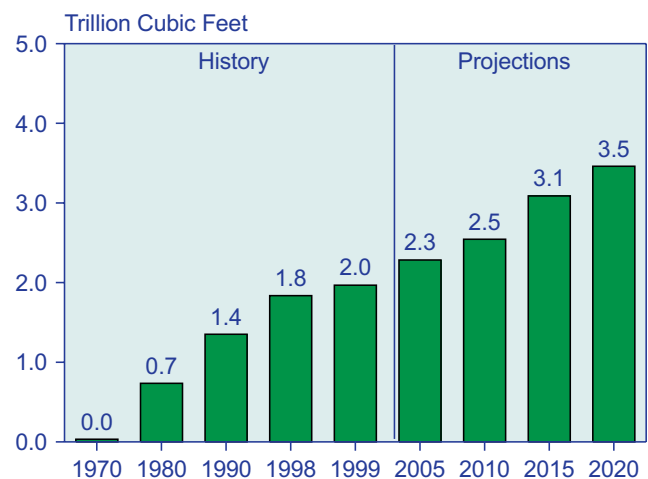
Africa

Africa's gas reserves, estimated at 394 trillion cubic feet, account for 7.4 percent of global reserves. Algeria and Nigeria account for 284 trillion cubic feet of reserves, or 72 percent of the total. Egypt and Libya account for another 21 percent, with the remainder of Africa containing only 7 percent of the continent's total reserves. Thus, gas exploration and production activities, along with export projects and plans to increase domestic use, are concentrated in north and west Africa.

Africa accounts for about 5 percent of the world's natural gas production but only 2 percent of the world's consumption. In 2000, Africa provided 17.4 percent of the world's natural gas exports, including 9.1 percent of pipeline exports and 41.0 percent of LNG exports [76]. Two-thirds of the total exports came from Algeria. Africa's natural gas consumption is increasing significantly, and the *IEO2002* reference case projects average increases of 7.4 percent per year, from 2.0 trillion cubic feet in 1999 to 3.5 trillion cubic feet in 2020 (Figure 52).

In Nigeria, increased associated gas production has developed as a result of increased crude oil production and intensified efforts to reduce gas flaring. Gas is liquefied at the Bonny Island facility, which has been in operation since 1999, and shipped to markets that include the United States, Spain, Italy, France, and Turkey. Two trains are currently operational with a combined

Figure 52. Natural Gas Consumption in Africa, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

capacity of 5.9 million metric tons per year. A third train, scheduled to come online in 2002, will provide another 2.95 million metric tons per year. A third expansion, proposed to come online in 2005/2006, will, if built, add two trains and an additional capacity of 8.0 million metric tons per year [77]. In 2000, Nigeria accounted for approximately 10 percent of Africa's LNG exports, and its exports are expected to grow as the Bonny Island facility expands.

Algeria is the continent's most developed export market, with 40 percent of its production being exported by pipeline to Italy, Spain, Portugal, Slovenia, and Tunisia and 37 percent exported as LNG to France, Belgium, Spain, Turkey, Italy, the United States, and Greece. The strong LNG market that has developed in Africa includes, in addition to Algeria and Nigeria, one operational facility in Libya, one facility under construction in Egypt and two proposed, and a proposed facility south of Nigeria in Angola [78]. Africa currently has 12 trains operational, with a combined capacity of 13.5 million metric tons per year. Three additional trains under construction will add another 11.8 million metric tons per year. Although Libya was the first to export LNG, beginning in 1970, Algeria was not far behind, opening its first facility in 1972. Nigeria entered the market in 1999 with the completion of its Bonny Island facility, and Egypt plans to enter in 2004 with its Damietta facility. Algeria has proposed locating another facility along the Mediterranean coast.

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Coal

Although coal use is expected to be displaced by natural gas in some parts of the world, only a slight drop in its share of total energy consumption is projected by 2020. Coal continues to dominate many national fuel markets in developing Asia.

World coal consumption has been in a period of generally slow growth since the late 1980s, a trend that is expected to continue. Although 1999 world consumption, at 4.7 billion short tons,⁷ was 15 percent higher than coal use in 1980, it was lower than in any year since 1984 (Figure 53). The *International Energy Outlook 2002* (IEO2002) reference case projects some growth in coal use between 1999 and 2020, at an average annual rate of 1.7 percent (on a tonnage basis), but with considerable variation among regions.

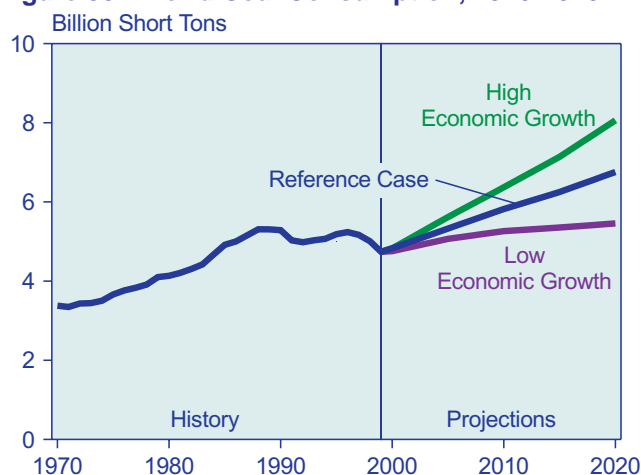
Coal use is expected to decline in Western Europe, Eastern Europe, and the former Soviet Union (FSU). Increases are expected in the United States, Japan, and developing Asia. In Western Europe, coal consumption declined by 35 percent between 1985 and 1999 (on a Btu basis), displaced in large part by the growing use of natural gas and, in France, nuclear power. Even sharper declines occurred in the countries of Eastern Europe and the former Soviet Union (EE/FSU), where coal use fell by 48 percent between 1985 and 1999 as a result of the economic collapse that followed the breakup of the Soviet Union, as well as some fuel switching. The projected slow growth in world coal use suggests that coal

will account for a shrinking share of global primary energy consumption. In 1999, coal provided 22 percent of world primary energy consumption, down from 27 percent in 1985. In the *IEO2002* reference case, the coal share of total energy consumption is projected to fall to 20 percent by 2020 (Figure 54).

The expected decline in coal's share of energy use would be even greater were it not for large increases in energy use projected for developing Asia, where coal continues to dominate many fuel markets, especially in China and India. As very large countries in terms of both population and land mass, China and India are projected to account for 29 percent of the world's total increase in energy consumption over the forecast period. The expected increases in coal use in China and India from 1999 to 2020 account for 83 percent of the total expected increase in coal use worldwide (on a Btu basis). Still, coal's share of energy use in developing Asia is projected to decline (Figure 55).

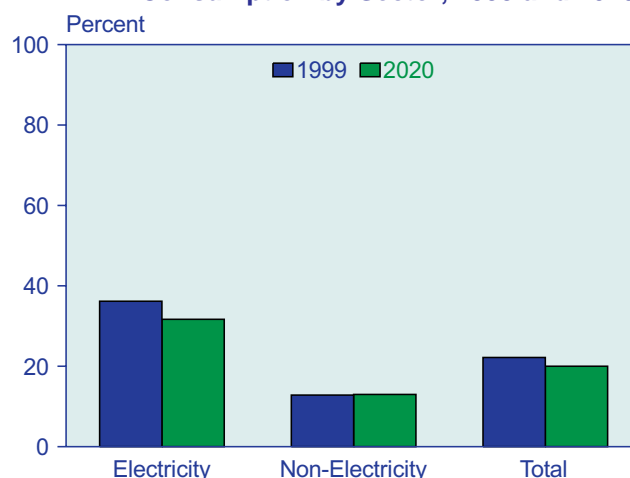
Coal consumption is heavily concentrated in the electricity generation sector, and significant amounts are also used for steel production. Almost 65 percent of the coal

Figure 53. World Coal Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 54. Coal Share of World Energy Consumption by Sector, 1999 and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

⁷Throughout this chapter, tons refers to short tons (2,000 pounds).

consumed worldwide is used for electricity generation. Power generation accounts for virtually all the projected growth in coal consumption worldwide. Where coal is used in the industrial, residential, and commercial sectors, other energy sources—primarily natural gas—are expected to gain market share. One exception is China, where coal continues to be the main fuel in a rapidly growing industrial sector, reflecting the country's abundant coal reserves and limited access to other sources of energy. Consumption of coking coal is projected to decline slightly in most regions of the world as a result of technological advances in steelmaking, increasing output from electric arc furnaces, and continuing replacement of steel by other materials in end-use applications.

The *IEO2002* projections are based on current laws and regulations and do not reflect the possible future ratification of proposed policies to address environmental concerns. In particular, the forecast does not assume compliance with the Kyoto Protocol, which currently is not a legally binding agreement. The implementation of plans and policies to reduce emissions of greenhouse gases could have a significant effect on coal consumption. For example, in an earlier study, the Energy Information Administration (EIA) projected that the United States could not meet its Kyoto emissions target without reducing annual coal consumption by somewhere between 18 percent and 77 percent (on a Btu basis) by 2010, depending on a number of other assumptions [1].

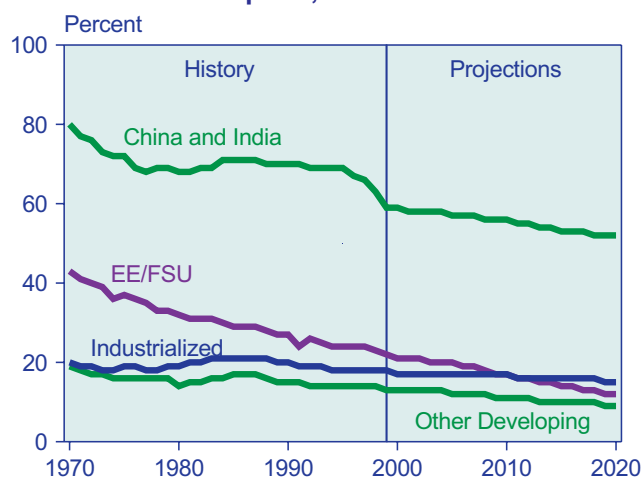
Developments in international coal markets are also important to the coal outlook. World coal trade grew by 55 million tons between 1999 and 2000, increasing to 604 million tons. In 2001, international coal markets were affected by a recovery in ocean shipping rates, higher

coal export prices than in 1999 and 2000, and a surge in Chinese coal exports to 95 million tons, representing an increase of nearly 35 million tons over its exports in 2000.

Highlights of the *IEO2002* projections for coal are as follows:

- World coal consumption is projected to increase by 2.0 billion tons, from 4.7 billion tons in 1999 to 6.8 billion tons in 2020. Alternative assumptions about economic growth rates lead to forecasts of world coal consumption in 2020 ranging from 5.5 to 8.1 billion tons (Figure 53).
- Coal use in developing Asia alone is projected to increase by 1.8 billion tons. China and India together are projected to account for 29 percent of the total increase in energy consumption worldwide between 1999 and 2020 and 83 percent of the world's total projected increase in coal use, on a Btu basis.
- China is projected to add an estimated 100 gigawatts of new coal-fired generating capacity (333 plants of 300 megawatts each) by 2020 and India approximately 65 gigawatts (217 plants of 300 megawatts each).
- The share of coal in world total primary energy consumption is expected to decline from 22 percent in 1999 to 20 percent in 2020. The coal share of energy consumed worldwide for electricity generation is also projected to decline, from 36 percent in 1999 to 32 percent in 2020.
- World coal trade is projected to increase from 604 million tons in 1999 to 776 million tons in 2020, accounting for between 11 and 12 percent of total world coal consumption over the period. Steam coal (including coal for pulverized coal injection at blast furnaces) accounts for most of the projected increase in world trade.

Figure 55. Coal Share of Regional Energy Consumption, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Environmental Issues

Like other fossil fuels, coal has played an important role in fueling the advancement of civilization, but its use also raises environmental issues. Coal mining has a direct impact on the environment, affecting land and causing subsidence, as well as producing mine waste that must be managed. Coal combustion produces several types of emissions that adversely affect the environment, particularly ground-level air quality. Concern for the environment has in the past and will in the future contribute to policies that affect the consumption of coal and other fossil fuels. The main emissions from coal combustion are sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulates, and carbon dioxide (CO₂). Recent studies on the health effects of mercury (Hg) have also brought to the forefront concerns about emissions of mercury from coal-fired power plants.

Sulfur dioxide emissions have been linked to acid rain, and many of the industrialized countries have instituted policies or regulations to limit sulfur dioxide emissions. Developing countries are also increasingly adopting and enforcing limits on sulfur dioxide emissions. Such policies typically require electricity producers to switch to lower sulfur fuels or invest in technologies—primarily flue gas desulfurization (FGD) equipment—that reduce the amounts of sulfur dioxide emitted with coal combustion.

Environmental regulation influences interfuel competition (i.e., how coal competes with other fuels, such as oil and gas), particularly in the power sector, where the competition is greatest. For example, compliance with increasingly stringent restrictions on emissions could be increasingly costly and could lead to reduced demand for coal. On the other hand, improved technologies may provide cost-effective ways to reduce emissions from coal-fired power plants. Integrated gasification combined-cycle (IGCC) technology, which may soon be commercially competitive, can increase generating efficiencies by 20 to 30 percent and also reduce emission levels (especially of carbon dioxide and sulfur oxides) more effectively than existing pollution control technologies [2].

At the end of 1999, more than 280 gigawatts of coal-fired capacity around the world—approximately 36 percent of it in the United States—were equipped with FGD or other SO₂ control technologies [3]. In the developing countries of Asia, only minor amounts of existing coal-fired capacity currently are equipped with desulfurization equipment. For example, in China, the world's largest emitter of sulfur dioxide, data for 1999 indicated that only about 2 percent of coal-fired generating capacity (at that time, less than 4 gigawatts out of a total of 207 gigawatts) had FGD equipment in place [4].

In addition to sulfur dioxide, increased restrictions on emissions of nitrogen oxides, particulates, and carbon dioxide are likely, especially in the industrialized countries. Although the potential magnitudes and costs of additional environmental restrictions for coal are uncertain, it seems likely that coal-fired generation worldwide will face steeper environmental cost penalties than will new natural-gas-fired generating plants. For nuclear and hydropower, which compete with coal for baseload power generation, the future is unclear. Proposals have been put forth in several of the developed countries to phase out nuclear capacity in full or in large measure. In other countries, it has become difficult to site new capacity because of unfavorable public reaction. The siting of new large hydroelectric dams is also becoming more difficult because of increased environmental scrutiny. In

addition, suitable sites for new large hydropower projects in the industrialized countries are limited [5].

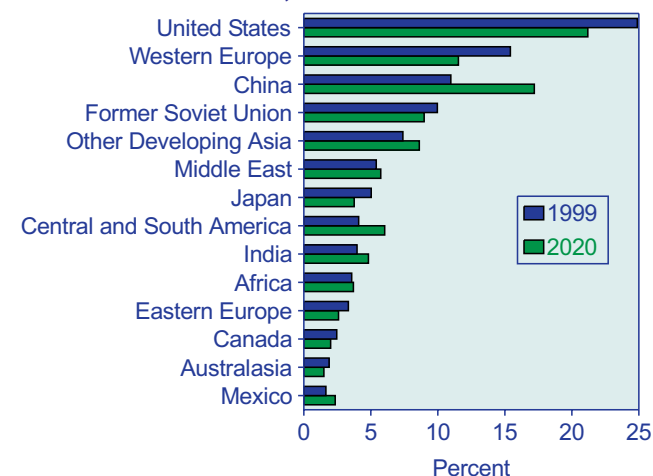
By far the most significant emerging issue for coal is the potential for a binding international agreement to reduce emissions of carbon dioxide and other greenhouse gases. On a Btu basis, the combustion of coal produces more carbon dioxide than the combustion of natural gas or of most petroleum products (combustion of petroleum coke produces slightly more carbon dioxide per unit of heat input than does combustion of coal). Carbon dioxide emissions per unit of energy obtained from coal are nearly 80 percent higher than those from natural gas and approximately 20 percent higher than those from residual fuel oil, which is the petroleum product most widely used for electricity generation [6].

In 1999, the United States and China were the world's dominant coal consumers and also the two top emitters of carbon dioxide, accounting for 25 percent and 11 percent, respectively, of the world's total emissions. Different economic growth rates and shifting fuel mixes explain in part why the U.S. share of world carbon emissions is projected in the *IEO2002* forecast to decline to 21 percent by 2020, while China's share is projected to increase to 17 percent (Figure 56). Worldwide, coal is projected to continue as the second largest source of carbon dioxide emissions (after petroleum), accounting for 31 percent of the world total in 2020.

Reserves

Total recoverable reserves of coal around the world are estimated at 1,089 billion tons⁸—enough to last

Figure 56. Regional Shares of World Carbon Emissions, 1999 and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, *World Energy Projection System* (2002).

⁸Recoverable reserves are those quantities of coal which geological and engineering information indicates with reasonable certainty can be extracted in the future under existing economic and operating conditions.

approximately 230 years at current consumption levels (Figure 57). Although coal deposits are widely distributed, 60 percent of the world's recoverable reserves are located in three regions: the United States (25 percent); FSU (23 percent); and China (12 percent). Another four countries—Australia, India, Germany, and South Africa—account for an additional 29 percent. In 1999, these seven regions accounted for 80 percent of total world coal production [7].

Quality and geological characteristics of coal deposits are other important parameters for coal reserves. Coal is a much more heterogeneous source of energy than is oil or natural gas, and its quality varies significantly from one region to the next and even within an individual coal seam. For example, Australia, the United States, and Canada are endowed with substantial reserves of premium coals that can be used to manufacture coke. Together, these three countries supplied 84 percent of the coking coal traded worldwide in 2000 (see Table 16 on page 82).

At the other end of the spectrum are reserves of low-Btu lignite or “brown coal.” Coal of this type is not traded to any significant extent in world markets, because of its relatively low heat content (which raises transportation costs on a Btu basis) and other problems related to transport and storage. In 1999, lignite accounted for 19 percent of total world coal production (on a tonnage basis) [8]. The top three producers were Germany (178 million tons), Russia (99 million tons), and the United States (84 million tons), which as a group accounted for 41 percent of the world's total lignite production in 1999. On a Btu basis, lignite deposits show considerable variation. Estimates by the International Energy Agency for coal produced in 1999 show that the average heat content of

lignite from major producers in countries of the Organization for Economic Cooperation and Development (OECD) varied from a low of 4.7 million Btu per ton in Greece to a high of 12.3 million Btu per ton in Canada [9].

Regional Consumption

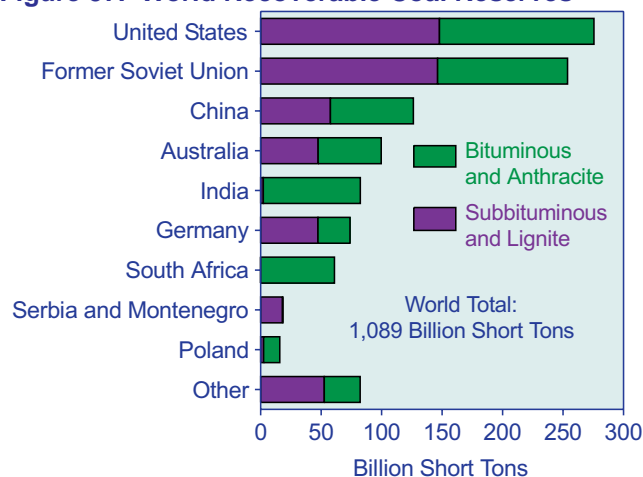
Developing Asia

The countries of developing Asia accounted for 36 percent of the world's coal consumption in 1999. Primarily as a result of substantial growth in coal consumption in China and India over the forecast period, developing Asia, taken as a whole, is projected to account for a 52-percent share of total world coal consumption by 2020.

The large increases in coal consumption projected for China and India are based on an outlook for strong economic growth (7.0 percent per year in China and 5.7 percent per year in India) and the expectation that much of the increased demand for energy will be met by coal, particularly in the industrial and electricity sectors (Figure 58). The *IEO2002* forecast assumes no significant changes in environmental policies in the two countries. It also assumes that necessary investments in the countries' mines, transportation, industrial facilities, and power plants will be made.

In China, 59 percent of the total increase in coal demand is projected to occur in the non-electricity sectors, for steam and direct heat for industrial applications (primarily in the chemical, cement, and pulp and paper industries) and for the manufacture of coal coke for input to the steelmaking process. In 1999, China was the world's leading producer of both steel and pig iron [10].

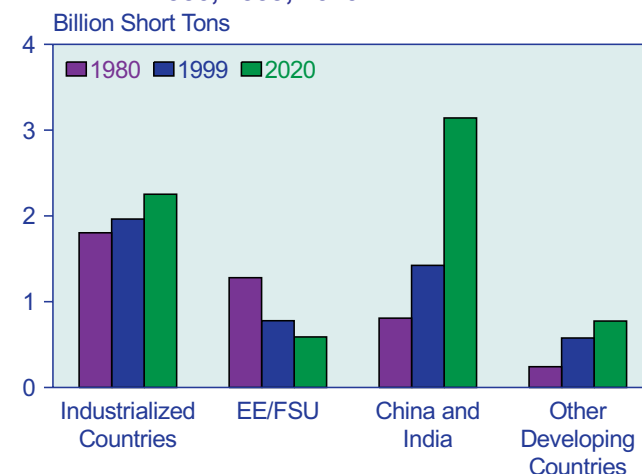
Figure 57. World Recoverable Coal Reserves



Note: Data represent recoverable coal reserves as of January 1, 1999.

Source: Energy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001), Table 8.2.

Figure 58. World Coal Consumption by Region, 1980, 1999, 2020



Sources: **1980 and 1999:** Energy Information Administration (EIA), Office of Energy Markets and End Use, *International Statistics Database* and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, *World Energy Projection System* (2002).

Coal remains the primary source of energy in China's industrial sector, primarily because China has limited reserves of oil and natural gas. In the non-electricity sectors, most of the projected increase in oil use comes from rising demand for energy for transportation. Growth in the consumption of natural gas is expected to come primarily from increased use for space heating in the residential and commercial sectors.

With a substantial portion of the increase in China's demand for both oil and natural gas projected to be met by imports, the government recently has expressed strong interest in developing a coal-to-liquids industry [11]. Initial plans call for the construction of several large coal-to-liquids projects over the next 10 years, with work on the first coal liquefaction plant to be initiated in the coal-rich Shanxi Province in late 2001 [12]. Compared with South Africa's most recently constructed coal liquefaction plant (built by SASOL at Secunda, South Africa, in 1982), which is capable of producing more than 25 million barrels of coal liquids annually, China's first plant will be relatively small, with an annual production capacity of less than 4 million barrels.

In the electricity sector in China, coal use is projected to grow by 2.2 percent a year, from 10.4 quadrillion Btu in 1999 to 16.4 quadrillion Btu in 2020. In comparison, coal consumption by electricity generators in the United States is projected to rise by 1.2 percent annually, from 19.3 quadrillion Btu in 1999 to 25.1 quadrillion Btu in 2020. One of the key implications of the substantial rise in coal use for electricity generation in China is that large financial investments in new coal-fired power plants and in the associated transmission and distribution systems will be needed. The projected growth in coal demand implies that China will need approximately 300 gigawatts of coal-fired capacity by 2020.⁹ At the beginning of 1999, China had 201 gigawatts of coal-fired generating capacity [13].

In India, projected growth in coal demand occurs primarily in the electricity sector, which currently accounts for more than two-thirds of India's total coal consumption (see box on page 74). Coal use for electricity generation in India is projected to rise by 2.9 percent per year, from 4.5 quadrillion Btu in 1999 to 8.1 quadrillion Btu in 2020, implying that India will need approximately 125 gigawatts of coal-fired capacity in 2020. At the beginning of 1999, India's total coal-fired generating capacity amounted to 59 gigawatts [14].¹⁰

⁹Based on the assumption that, on average, coal consumption at China's fleet of coal-fired power plants will rise to a level of 65 trillion Btu per gigawatt by 2020. Higher average utilization rates (or capacity factors) for coal plants, taken as a whole, would increase the amount of coal consumed per unit of generating capacity, while overall improvements in conversion efficiencies would have the opposite effect. In EIA's *Annual Energy Outlook 2002* reference case forecast, U.S. coal-fired power plants are projected to consume an average of 75 trillion Btu of coal per gigawatt of generating capacity in 2020, based on a projected average utilization rate of 84 percent and an average conversion efficiency 33.5 percent.

¹⁰Based on the assumption that, on average, coal consumption at India's coal-fired power plants will rise to a level of 65 trillion Btu per gigawatt by 2020. See previous footnote for discussion of the factors that affect the amount of coal consumed per unit of generating capacity.

In the remaining areas of developing Asia, a considerably smaller but significant rise in coal consumption is projected over the forecast period, based on expectations for strong growth in coal-fired electricity generation in South Korea, Taiwan, and the member countries of the Association of Southeast Asian Nations (primarily, Indonesia, Malaysia, the Philippines, Thailand, and Vietnam). In the electricity sector, coal use in the other developing countries of Asia (including South Korea) is projected to rise by 3.4 percent per year, from 2.4 quadrillion Btu in 1999 to 4.9 quadrillion Btu in 2020.

The key motivation for increasing use of coal in other developing Asia is diversity of fuel supply for electricity generation [15]. This objective is relatively strong even in countries that have abundant reserves of natural gas, such as Thailand, Malaysia, Indonesia, and the Philippines. In the *IEO2002* forecast, coal's share of fuel consumption for electricity generation in this region is projected to remain fairly constant, decreasing from 28 percent in 1999 to 27 percent by 2020.

Some of the planned additions of coal-fired generating capacity in other developing Asia for 2002 and later include: 6,100 megawatts of new coal-fired capacity for South Korea by 2015; 5,600 megawatts for Malaysia by 2007; and 3,400 megawatts for Thailand by 2007 [16]. In addition to planned capacity additions, a number of new coal-fired units have come online in the region between 1999 and 2001, adding a combined total of more than 10,000 megawatts of electric power supply in South Korea (3,700 megawatts), Taiwan (3,720 megawatts), Malaysia (1,000 megawatts), and the Philippines (2,040 megawatts) [17]. In Indonesia, several large coal-fired plants also have been completed recently or are near completion (Paiton I, Paiton II and Tanjung Jati-B); however, power purchase agreements with Perusahaan Listrik Negara (PLN), Indonesia's state-run utility, are still being negotiated, and power-line transmission capacity to serve the newest generating capacity has not yet been completed [18].

Because of environmental concerns and abundant gas reserves, there is considerable uncertainty about additions of planned coal-fired capacity in the region, particularly for countries such as Thailand and Malaysia. A number of individuals and environmental groups argue that a heavy reliance on local supplies of natural gas for electricity generation is a wiser and probably a more economical choice than constructing new coal-fired

A Profile of Coal in India

Energy consumption in India is dominated by coal. Coal accounts for more than one-half of the energy consumed in the country, and it is expected to remain an important part of the future fuel mix. More than two-thirds of the coal consumed in India is used in the power sector, and coal is also used for steel manufacturing and for such miscellaneous purposes as cooking in rural parts of the country (see figure below).

India has extensive coal reserves, with 80 billion short tons of recoverable anthracite and bituminous coal and 2 billion tons of recoverable lignite and subbituminous coal.^a Its 82 billion tons of coal reserves account for about 8 percent of the world's total recoverable reserves. Most of the country's coal is subbituminous (non-coking) coal; only 2 to 3 percent is coking coal.^b As a result, India's steel industry relies on imports of coking coal to meet between 20 and 25 percent of its annual requirements. Indian coal reserves are generally characterized as high in ash content, low in heat value, and relatively low in sulfur content.

With large coal reserves and heavy use, it is not surprising that India is the third largest producer of coal worldwide. Both surface and underground mining

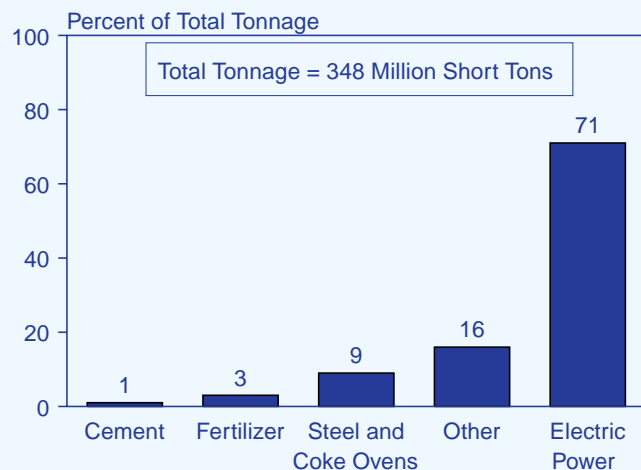
techniques are employed in India. From 1980 to 1997, surface mining increased by a factor of 20, and surface mines currently account for 75 percent of India's total coal output. Underground mining, however, has not developed as rapidly, growing by only 0.7 percent per year from 1980 to 1997, as compared with average growth of 7.6 percent per year for surface mining.^c

For the most part, coal reserves are located in eastern India in the states of West Bengal, Madhya Pradesh, and Orissa. Coal can also be found in Maharashtra, Uttar Pradesh, and Andhra Pradesh (see map below). The country's lignite reserves are found primarily in the Southern state of Tamil Nadu, as well as Western Gujarat, Rajasthan, and Jammu Kashmir.^d

Reserves tend to be located far from the major consuming centers of the central, western, and southern parts of the country. Therefore, transport is a major concern for the Indian coal industry. Some 37 percent of India's non-coking coal is shipped to electric power plants that are located more than 600 miles from the coal mines.^e Generally, India's coal is shipped by rail, and some is also shipped by road and water. Most commonly, coal

(continued on page 75)

Coal Consumption by End Use Sector, 2000



Source: Tata Energy Research Institute and Fesharaki Associates Consulting and Technical Services, Inc. (FACTS), *Emergence of a New Giant: India's Natural Gas Sector to 2015* (Honolulu, HI, August 2001), p. 2.11; and Energy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001).



^aEnergy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001), p. 115.

^bTata Energy Research Institute, *Tata Energy Data and Directory Yearbook 1999/2000* (New Delhi, India, 1999).

^cTata Energy Research Institute, *Tata Energy Data and Directory Yearbook 1999/2000* (New Delhi, India, 1999).

^dL. Clarke, S. Walker, and O. Montfort, *Coal Prospects in India*, IEAPER/37 (London, UK: International Energy Agency Coal Research, October 1997), pp. 30-31.

^eTata Energy Research Institute, *Tata Energy Data and Directory Yearbook 1999/2000* (New Delhi, India, 1999).

power plants that will rely on imported fuel and produce more pollution than gas-fired plants [19].

Industrialized Asia

Among the Asian industrialized countries—Australia, New Zealand, and Japan—Australia is the world's leading coal exporter and Japan is the leading coal importer in the world. In 1999, Australian coal producers shipped 189 million tons of coal to international consumers, and another 141 million tons of Australian coal (both hard coal and lignite) was consumed domestically, primarily for electricity generation. Coal-fired power plants accounted for 78 percent of Australia's total electricity generating needs in 1999 [20]. Over the forecast horizon, coal use in Australia is expected to increase slightly. At present, Australia's Queensland district has three new coal-fired power projects in various stages of completion: Callide C power plant (840 megawatts of capacity

to come online in 2001); Millmerran plant (840 megawatts of capacity to come online in 2002); and Tarong Power plant (450 megawatts scheduled for 2003) [21].

Japan, which is the third largest coal user in Asia and the eighth largest globally, imports most all the coal it consumes, much of it originating from Australia [22]. Japan's last two underground coal mines, Ikeshima with an annual production capacity of 1.1 million tons and Taiheiyo with a capacity of 2.2 million tons, were closed in late 2001 and early 2002 [23]. Currently, slightly more than one-half of the coal consumed in Japan is used by the country's steel industry (Japan is the world's second largest producer of both crude steel and pig iron) [24]. Coal is also used heavily in the Japanese power sector, and coal plants currently generate more than 20 percent of the country's electricity supply [25]. In 1999, Japanese power producers consumed 65 million tons of coal,

A Profile of Coal in India (Continued)

is shipped by rail to eastern ports, from which it is then shipped by water to southern destinations. There are 11 ports managed by the Port Trust of India, with Haldia, Vishakapatnam, and Paradip the most important eastern ports. Recently, private-sector participation was invited to develop and build additions to existing port facilities.

The coal industry in India is largely held in the public sector. The Ministry of Coal is the public entity that sets "policies and strategies for exploration and development," for the country's coal mines.^f Coal India, Ltd. (CIL) acts as the holding company and has eight fully-owned subsidiaries. CIL owns 90 percent of total coal production in India and 97 percent of the coalfields. Four major subsidiaries of CIL are Bharat Coking Coal Ltd. (BCCL), Western Coalfields Ltd. (WCL), South Eastern Coalfields Ltd. (SECL), and Northern Coalfields Ltd. (NCL).^g The coal industry was largely private until the 1970s, when it was nationalized to plan for growing industrial needs and equitable distribution of the country's coal resources. India's coal industry was nationalized in two stages: coking-coal mines in 1971 and other coal mines in 1973.^h Only coal mines captive to steel mines were not part of the nationalization process.

Eventually, dissatisfaction arose between the coal industry and electric power industry. Disputes

concerned the quality and quantity of coal delivered to electric utilities, as well as disputes about payment for the coal. Several other issues also plagued the coal industry, such as the lack of mechanization of certain processes, monopolistic construct of the coal industry, and the lack of State Electricity Board (SEB) funds.ⁱ To address some of these issues, an agreement was drawn up in 1977. Since then, there has been intermittent acceptance and adherence to that agreement. In 1998, the Indian Council of Power Utilities drafted a new agreement that was circulated to all the utilities as the model agreement. Some SEBs entered into this agreement with CIL, but others have not.

Environmental issues are also increasingly important in India, and they have begun to affect the coal industry. One of the defining characteristics of Indian coal is its high ash content, which increases the amount of pollutants released when it is burned. The ash content can be reduced before use through a beneficiation or washing process. Washing plants for coking coal exist, but many are old and low in unit capacity. In an attempt to lessen the pollutants emitted by burning coal, the Ministry of Environment and Forestry decreed that as of June 1, 2001, all coal supplied to power plants located further than 620 miles from the coal fields, or those located in critically polluted and sensitive urban areas, must have an ash content of no more than 34 percent.^j

^fIndia Ministry of Coal, "About Us," web site <http://coal.nic.in/vscoal/sub1.html> (not dated).

^gM. Kulshreshtha and J.K. Parikh, "A Study of Productivity in the Indian Coal Sector," *Energy Policy*, Vol. 29, No. 9 (July 2001) pp. 701-713.

^h"Making Arrangements To Supply Coal," web site www.terrin.org/energy/coal.htm (April 2001).

ⁱ"Making Arrangements To Supply Coal," web site www.terrin.org/energy/coal.htm (April 2001).

^jMining India, "Clamp on Use of Raw Coal in Thermal Power Plants," web site www.miningindia.com/writeups/798/24.htm (not dated).

representing 42 percent of the country's total coal consumption [26]. Japanese power companies plan to construct an additional 16 gigawatts of new coal-fired generating capacity between 2001 and 2010 [27].

Western Europe

In Western Europe, environmental concerns play an important role in the competition among coal, natural gas, and nuclear power. Recently, other fuels—particularly natural gas—have been gaining economic advantage over coal. Coal consumption in Western Europe has decreased by 39 percent over the past 9 years, from 894 million tons in 1990 to 546 million tons in 1999. The decline was smaller on a Btu basis, at 32 percent, reflecting the fact that much of it resulted from reduced consumption of low-Btu lignite in Germany.

Over the forecast period, Western European coal consumption is projected to decline by an additional 23 percent (on a Btu basis), reflecting a slower rate of decline than was experienced during the previous decade. Factors contributing to further cutbacks in coal consumption include further penetration of natural gas for electricity generation, environmental concerns, and continuing pressure on member countries of the European Union to reduce subsidies that support domestic production of hard coal.

The current set of guidelines for state aid to the European coal industry (Commission Decision No. 3632/93/ECSC of December 28, 1993) is set to expire on July 23, 2002, coinciding with the expiration date of the 50-year European Coal and Steel Community Treaty of 1951. In light of these pending expiration dates, the European Commission has proposed that a new state aid scheme for coal be established to allow for the continuation of subsidies for hard coal production in member states through December 31, 2010 [28]. In essence, the Commission wants to establish measures that will promote the development of renewable energy sources as well as maintain a minimum capacity of subsidized coal production in the European Union for the purpose of establishing an “indigenous primary energy base.” Under this new scheme, the guiding principle for coal will be that subsidized production will be limited to that which is strictly necessary for enhancing the security of energy supply (i.e., to maintain access to coal reserves, keep equipment in an operational state, preserve the professional qualifications of a nucleus of coal miners, and safeguard technological expertise).

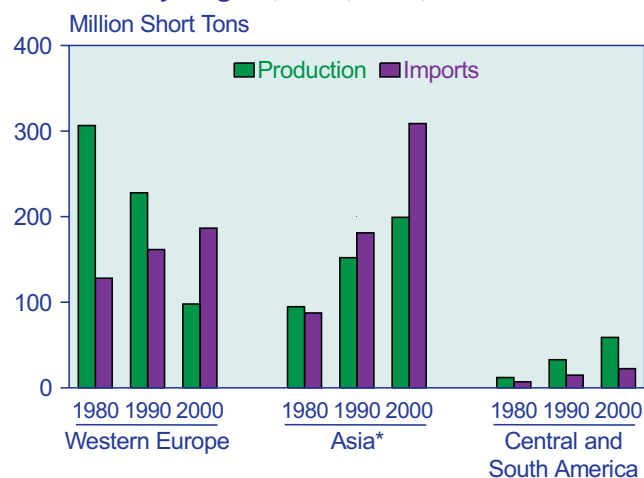
The recent trend in the consumption of hard coal¹¹ in Western Europe is closely correlated with the trend in the production of hard coal, primarily because coal

imports have increased by much less than production has declined (Figure 59). Following the closure of the last remaining coal mines in Belgium in 1992 and Portugal in 1994, only four member States of the European Union (the United Kingdom, Germany, Spain, and France) continue to produce hard coal [29], and all have seen their output of hard coal decline since 1990. In the near future, the proposed enlargement of the European Union would add two additional producers of hard coal, Poland and the Czech Republic [30].

Hard coal production in the United Kingdom decreased from 104 million tons in 1990 to 40 million tons in 1999, a decline of 64 million tons [31]. During the same period, coal consumption fell by 53 million tons. Most of the decline in coal consumption resulted from privatization in the electricity sector, which led to a rapid increase in natural-gas-fired generation at the expense of coal.

The massive switch to natural gas and its adverse impact on the country's coal industry prompted the British government, in mid-1998, to place a moratorium on the construction of new gas-fired plants and, at the same time, request that a study be completed to assess the state of the country's electric power industry [32]. The two key issues to be investigated were the design, operation, and structure of the country's wholesale electricity market and the diversity and security of fuel supplies for electricity generation. As a result of the study, revisions in the setup of the country's wholesale electricity market

Figure 59. Production and Imports of Hard Coal by Region, 1980, 1990, and 2000



*Data for Asia exclude China, India, and Australasia.

Note: Production and imports include data for anthracite, bituminous, and subbituminous coal.

Sources: Energy Information Administration, Office of Energy Markets and End Use, International Statistics Database.

¹¹Internationally, the term “hard coal” is used to describe anthracite and bituminous coal. In data published by the International Energy Agency, coal of subbituminous rank is classified as hard coal for some countries and as brown coal (with lignite) for others. In data series published by the Energy Information Administration, subbituminous coal production is included in the bituminous category.

were introduced, primarily aimed at getting generators to price their electricity more competitively. The revised electricity market, referred to as the New Electricity Trading Arrangements (NETA), went into effect on March 27, 2001, and the moratorium on the construction of new gas-fired generating plants was lifted in November 2000 [33]. Although the impact of the NETA measures on Britain's coal-fired generation is not yet known, they are generally seen as an improvement over the country's previous wholesale electricity market (the Electricity Pool). The lifting of the moratorium on the construction of new gas plants, however, opened the door for the planned construction of six new combined-cycle gas plants (representing 4.8 gigawatts of capacity), whose output will likely compete with generation from the country's existing coal-fired plants [34].

Currently, the United Kingdom's remaining coal mines are by far the most productive hard coal operations in Western Europe. Substantial improvements in the country's mining operations in recent years have led to an increase in average labor productivity from 1,190 tons per miner-year in 1990 to 3,200 tons per miner-year in 1999 [35]. Despite this achievement, the price of coal from domestic mines is essentially at parity with the price of coal imports, and it is likely that production from domestic mines will continue to be sensitive to changes in international coal prices [36]. In fact, following several years of sharp declines in international coal prices in 1998 and 1999, the UK government reinstated coal production subsidies for 2000 through 2002 in an effort to protect the country's remaining coal operations (Table 15) [37].

In Germany, Spain, and France, subsidies continue to support the domestic production of hard coal,¹² even though there is no hope that their production will ever be competitive with imports. For 2000, the European Commission authorized coal industry subsidies of \$4,245 million in Germany, \$1,035 million in Spain, and

\$933 million in France. In each of the three countries, the average subsidy per ton of coal produced exceeds the average value of imported coal (Table 15), and all three are currently taking steps to reduce subsidy payments, acknowledging that some losses in coal production are inevitable.

Germany's hard coal production declined from 86 million tons in 1990 to 48 million tons in 1999 [38]. In March 1997, the federal government, the mining industry, and the unions reached an agreement on the future structure of subsidies to the German hard coal industry. At that time, the agreement called for the closure of 8 to 9 of Germany's 19 operating hard coal mines, leading to an estimated decline in production to 33 million tons by 2005 [39]. The closure of three coal mines in 2000 (with a combined production capacity of approximately 8.3 million tons) left Germany with 12 operating hard coal mines at the end of the year [40].

Between 1990 and 1999, German lignite production declined by 242 million tons, primarily as a result of massive substitution of natural gas for both lignite and lignite-based "town gas"¹³ in the eastern states following reunification in 1990 [41]. The collapse of industrial output in the eastern states during this period also was a contributing factor. In the *IEO2002* reference case, Germany's coal consumption is projected to continue falling, although not as dramatically as in recent years. By 2020, coal use in Germany is projected to be 219 million tons, a drop of 39 million tons from the 1999 level of 258 million tons.

In Spain, hard coal production declined from 22 million tons in 1990 to 17 million tons in 1999 [42]. Spain has adopted a restructuring plan for 1998 through 2005 that provides for a gradual decline in production to 12 million tons [43]. In addition to hard coal, two lignite mines in Spain, which produced 10 million tons in 1999, are earmarked for closure within the next 3 to 4 years [44].

Table 15. Western European Coal Industry Subsidies, Production, and Import Prices, 2000

Country	Coal Industry Subsidies (Million 2000 U.S. Dollars)	Hard Coal Production (Million Tons)	Average Subsidy per Ton of Coal Produced (2000 U.S. Dollars)	Average Price per Ton of Coal Imported (2000 U.S. Dollars)
Germany	4,245	40.4	105	32
Spain	1,035	16.4	63	32
France	933	4.9	192	36
United Kingdom . .	132	35.3	4	38

Sources: **Coal Production Subsidies:** Commission of the European Communities, *Proposal for a Council Regulation on State Aid to the Coal Industry* (Brussels, Belgium, July 25, 2001), p. 28, web site www.europa.eu.int; and U.S. Federal Reserve Bank, "Foreign Exchange Rates (Annual)," web site www.bogfrb.fed.us (January 9, 2001). **Production:** Energy Information Administration, Office of Energy Markets and End Use, International Statistics Database. **Average Price of Coal Imports:** International Energy Agency, *Coal Information 2001* (Paris, France, September 2001).

¹²In Spain, subsidies support the production of both hard coal and subbituminous coal.

¹³"Town gas" (or "coal gas"), a substitute for natural gas, is produced synthetically by the chemical reduction of coal at a coal gasification facility.

Currently, the two generating plants that burn the lignite produced by the mines also rely partly on imports of subbituminous coal. Both plants are expected to increase their take of imported coal over the forecast, as lignite production from the two mines is ramped down.

In France, production of hard coal declined from 12 million tons in 1990 to 6 million tons in 1999 [45]. A modernization, rationalization, and restructuring plan submitted by the French government to the European Commission at the end of 1994 foresees the closure of all coal mines in France by 2005 [46]. The coal industry restructuring plan was based on a “Coal Agreement” between France’s state-run coal company, Charbonnages de France, and the coal trade unions.

Coal use in other major coal-consuming countries in Western Europe is projected either to decline or to remain close to current levels. In the Scandinavian countries (Denmark, Finland, Norway, and Sweden), environmental concerns and competition from natural gas are expected to reduce coal use over the forecast period. The government of Denmark has stated that its goal is to eliminate coal-fired generation by 2030 [47]. In 1999, 51 percent of Denmark’s electricity was supplied by coal-fired plants [48]. Coal consumption in Italy is projected to remain relatively flat in the *IEO2002* forecast.

Partly offsetting the expected declines in coal consumption elsewhere in Europe is a projected increase in consumption of indigenous lignite for power generation in Greece. Under an agreement reached by the countries of the European Union in June 1998, Greece committed to capping its emissions of greenhouse gases by 2010 at 25 percent above their 1990 level—a target that is much less severe than the emissions target for the European Union as a whole, which caps emissions at 8 percent below 1990 levels by 2010 [49].

Eastern Europe and the Former Soviet Union

In the EE/FSU countries, the process of economic reform continues as the transition to a market-oriented economy replaces centrally planned economic systems. The dislocations associated with institutional changes in the region have contributed substantially to declines in both coal production and consumption. Coal consumption in the EE/FSU region has fallen by 597 million tons since 1990, to 778 million tons in 1999. In the future, total energy consumption in the EE/FSU is expected to rise, primarily as the result of increasing production and consumption of natural gas. In the *IEO2002* reference case, coal’s share of total EE/FSU energy consumption is projected to decline from 22 percent in 1999 to 12 percent in 2020, and the natural gas share is projected to increase from 45 percent in 1999 to 50 percent in 2020.

The three main coal-producing countries of the FSU—Russia, Ukraine, and Kazakhstan—are facing similar

problems. The three countries have developed national programs for restructuring and privatizing their coal industries, but they have been struggling with related technical and social problems. Between 1990 and 1999, coal production declined by 151 million tons (37 percent) in Russia, by 91 million tons (51 percent) in Ukraine, and by 64 million tons (56 percent) in Kazakhstan [50]. While both Kazakhstan and Russia have shown considerable progress in terms of closing uneconomical mining operations and in selling government-run mining operations to the private sector, Ukraine has made considerably less progress in its restructuring efforts. In Kazakhstan, many of the high-cost underground coal mines have been closed, and its more competitive surface mines have been purchased and are now operated by international energy companies [51]. In Russia, the World Bank estimates that 77 percent of the country’s coal production in 2001 will originate from mines not owned by the government, and that percentage is expected to increase to 90 percent by the end of 2002 [52].

In Ukraine, a coal restructuring program initiated by the government in 1996, with advice and financial support provided by the World Bank, has been mostly unsuccessful at rejuvenating the industry. Key problems that continue to plague the Ukrainian coal industry are : (1) most of the country’s mines continue to be highly subsidized, government-run enterprises; (2) dangerous working conditions prevail (several catastrophic mine disasters have occurred in the past several years); (3) wage arrears continue to be a serious problem, with miners currently owed back wages of approximately \$3.5 billion; (4) productivity is very low due to antiquated mining equipment and the extreme depths at which coal is extracted (only three of Ukraine’s active coal mines are surface operations); and (5) nonpayment for coal by customers is rampant [53].

The World Bank has focused its efforts in Ukraine on trying to convince the government that it needs to close additional unprofitable mines [54]. In 2001, a spokesperson for the World Bank expressed his belief that an additional 50 to 60 of the country’s remaining coal mines need to be closed [55]. On the other hand, others indicate that problems with the Ukrainian coal industry will not be solved simply through the closure of the least economical mines. They point to delays in privatization of coal mining operations, the existence of widespread corruption and abuse in the coal sector, worsening geological conditions, and misdirection of government subsidies (e.g., not enough of the government subsidies have been directed toward equipment upgrades at existing mines).

Recent data showing a slight resurgence in coal production in the FSU since 1998, particularly in Russia and Kazakhstan, in combination with draft energy strategies for Russia and Ukraine, indicate an optimistic long-term

outlook for both coal production and consumption [56]. The *IEO2002* outlook for FSU coal consumption, however, indicates only slight positive growth between 1999 and 2005 with a declining trend thereafter. Natural gas and oil are expected to fuel most of the projected increase in energy consumption for the region.

In Eastern Europe, Poland is the largest producer and consumer of coal; in fact, it is the second largest coal producer and consumer in all of Europe, outranked only by Germany [57]. In 1999, coal consumption in Poland totaled 164 million tons, 45 percent of Eastern Europe's total coal consumption for the year [58]. Poland's hard coal industry produced 123 million tons in 1999, and lignite producers contributed an additional 67 million tons. Coal consumption in other Eastern European countries is dominated by the use of low-Btu subbituminous coal and lignite produced from local reserves. The region, taken as a whole, relies heavily on local production, with seaborne imports of coal to the region summing to less than 6 million tons in 1999 [59].

In 2001 Poland's hard coal industry operated at a slight loss, but it is expected to operate in the black in 2002 [60]. Over the past several years, a number of coal industry restructuring plans have been put forth for the purpose of transforming Poland's hard coal industry to a position of positive earnings, eliminating the need for government subsidies. The most recent plan was announced by Poland's Ministry of the Economy in March 1998. It called for the closure of 24 of the country's 50 unprofitable mines over the next 4 years, reducing the total number of mines in Poland from 65 in 1998 to 41 by 2002. In addition, the restructuring plan aims to reduce the number of miners by one-half, from 245,000 in 1998 to 128,000 by 2002 [61]. The Polish government projects that sales of hard coal from domestic mines will decline from 100 million tons in 1998 to 77 million tons by 2020. As of August 2001, the World Bank had approved a total of \$400 million in hard coal sector adjustment loans in support of the Polish government's restructuring program [62].

North America

Coal use in North America is dominated by U.S. consumption. In 1999, the United States consumed 1,045 million tons, accounting for 93 percent of the regional total. By 2020 U.S. consumption is projected to rise to 1,365 million tons. The United States has substantial supplies of coal reserves and has come to rely heavily on coal for electricity generation, a trend that continues in the forecast. Coal provided 51 percent of total U.S. electricity generation in 1999 and is projected to provide 46 percent in 2020 [63]. To a large extent, EIA's projections of declines in both minemouth coal prices and coal transportation rates are the basis for the expectation that coal will continue to compete as a fuel for U.S. power

generation. Increases in coal-fired generation are projected to result from both greater utilization of U.S. coal-fired generating capacity and the addition of 31 gigawatts of new coal-fired power plants by 2020. Over the forecast period, the average utilization rate of coal-fired generating capacity is projected to rise from 68 percent in 1999 to 84 percent by 2020.

In Canada, coal consumption accounted for approximately 12 percent of total energy consumption in 1999 and is projected to more or less maintain that share over the forecast period. In the near term, the restart of six of Canada's nuclear generating units (four at the Ontario Power's Pickering A plant and two at Bruce Power's Bruce A plant) over the next few years is expected to restrain the need for coal in eastern Canada, while increased demand for electricity in western Canada is expected to result in the need for some additional coal-fired generation there [64]. Fording, Inc., Canada's lead exporter of metallurgical grade coal, is currently exploring the possibility of building a new 1,000-megawatt coal-fired generation plant in the Province of Alberta, approximately 110 miles southeast of Calgary [65].

Mexico consumed 13 million tons of coal in 1999. Two coal-fired generating plants, Rio Escondido and Carbon II, operated by the state-owned utility Comision Federal de Electricidad (CFE), consume approximately 10 million tons of coal annually, most of which originates from domestic mines [66]. In addition, CFE is currently in the process of switching its six-unit, 2,100 megawatt Petacalco plant, located on the Pacific coast, from oil to coal. The utility estimates that the plant will require more than 5 million tons of imported coal annually. During 2001, CFE awarded a contract for 3.3 million tons of Chinese coal for delivery over a 6-month period ending April 2002 [67]. A coal import facility adjacent to the plant, with an annual throughput capacity of more than 9 million tons, serves both the power plant and a nearby integrated steel mill [68].

While natural gas is expected to fuel most new generating capacity to be built in Mexico over the *IEO2002* forecast period, some new coal-fired generation is also expected. Several manufacturing companies, such as Kimberly Clark and steelmakers Ispat and Altos Hornos de Mexico, are exploring the possibility of constructing some coal-fired plants near their production facilities [69]. The plants would be developed under Mexico's new self-supply provisions, which allow private power producers and large industrials the option of bypassing state-owned CFE as long as the industrial end users hold equity stakes in the projects [70]. In addition, based on authorization granted by the government's energy authority in 2001, the CFE is considering the possibility of constructing a new coal-fired plant on Mexico's Pacific coast [71].

Africa

Africa's coal production and consumption are concentrated heavily in South Africa. In 1999, South Africa produced 248 million tons of coal, 70 percent of which went to domestic markets and the remainder to exports [72]. Ranked third in the world in coal exports since the mid-1980s (behind Australia and the United States), South Africa moved up a notch in 1999 when its exports exceeded those from the United States. South Africa is also the world's largest producer of coal-based synthetic liquid fuels. In 1998, about 17 percent of the coal consumed in South Africa (on a Btu basis) was used to produce coal-based synthetic oil, which in turn accounted for more than one-fourth of all liquid fuels consumed in South Africa [73].

For Africa as a whole, coal consumption is projected to increase by 35 million tons between 1999 and 2020, primarily to meet increased demand for electricity, which is projected to increase at a rate of 3.6 percent per year. Some of the increase in coal consumption is expected outside South Africa, particularly as other countries in the region seek to develop and use domestic resources and more varied, less expensive sources of energy.

The Ministry of Energy in Kenya has begun prospecting for coal in promising basins in the hope of diversifying the fuels available to its power sector [74]. In Nigeria, several initiatives to increase the use of coal for electricity generation have been proposed, including the possible rehabilitation of the Oji River and Markurdi coal-fired power stations and tentative plans to construct a large new coal-fired power plant in southeastern Nigeria [75]. Also, Tanzania may move ahead on plans to construct a large coal-fired power plant. The new plant would help to improve the reliability of the country's power supply, which at present relies heavily on hydroelectric generation, and would promote increased use of the country's indigenous coal supply [76].

A recently completed coal project in Africa was the commissioning of a fourth coal-fired unit at Morocco's Jorf Lasfar plant in 2001. With a total generating capacity of 1,356 megawatts, this plant accounts for more than one-half of Morocco's total electricity supply and is the largest independent power project in Africa and the Middle East [77].

Central and South America

Historically, coal has not been a major source of energy in Central and South America. In 1999, coal accounted for about 5 percent of the region's total energy consumption, and in years past its share has never exceeded 6 percent. In the electricity sector, hydroelectric power has met much of the region's electricity demand, and new power plants are now being built to use natural gas produced in the region. Natural gas is expected to fuel much

of the projected increase in electricity generation over the forecast period.

Brazil, with the eighth largest steel industry worldwide in 1999, accounted for more than 66 percent of the region's coal demand (on a tonnage basis), with Colombia, Chile, Argentina, and to a lesser extent Peru accounting for much of the remainder [78]. The steel industry in Brazil accounts for more than 75 percent of the country's total coal consumption, relying on imports of coking coal to produce coke for use in blast furnaces [79].

In the forecast, Brazil accounts for most of the growth in coal consumption projected for the region, with increased use of coal expected for both steelmaking (both coking coal and coal for pulverized coal injection) and electricity production. With demand for electricity approaching the capacity of Brazil's hydroelectric plants, the government recently introduced a program aimed at increasing the share of fossil-fired electricity generation in the country, primarily promoting the construction of new natural-gas-fired capacity. The plan also includes several new coal-fired plants to be built near domestic coal deposits [80]. In addition, serious consideration is being given to the construction of a large coal-fired power plant at the port of Sepetiba, to be fueled by imported coal [81].

In Puerto Rico, the construction of a new coal-fired power plant is underway as part of a long-range plan to reduce the country's dependence on oil for electricity generation [82]. The 454-megawatt circulating fluidized bed (CFB) plant will require approximately 1.5 million tons of imported coal annually [83].

Middle East

Turkey accounts for almost 90 percent of the coal consumed in the Middle East. In 1999, Turkish coal consumption reached 84 million tons, most of it low-Btu, locally produced lignite (approximately 6.8 million Btu per ton) [84]. Over the forecast period, coal consumption (both lignite and hard coal) is projected to increase by 20 million tons, primarily to fuel additional coal-fired generating capacity. Two projects currently in the construction phase include a 1,210-megawatt hard-coal-fired plant being built on the southern coast of Turkey near Iskenderun, to be fueled by imported coal, and a 1,440-megawatt lignite-fired plant (Afsin-Elbistan B plant) being built in the lignite-rich Afsin-Elbistan region in southern Turkey [85]. When completed between 2003 and 2005, the two plants could add more than 10 million tons to Turkey's annual coal consumption.

Israel, which consumed 10 million tons of coal in 1999, accounts for most of the remaining coal use in the Middle East. In the near term, Israel's coal consumption is

projected to rise by approximately 3 million tons attributable to the completion of two new 575-megawatt coal-fired units at Israel Electric Corporation's Rutenberg plant in 2000 and 2001 [86]. Based on plans to complete an additional 1,200 megawatts of coal-fired generating capacity at the Rutenberg site in 2007 and 2008, additional growth in Israel's coal consumption is projected [87]. Some environmental groups and government officials in Israel are opposed to the recent go-ahead given to Israel Electric to construct additional coal plants, arguing that sufficient supplies of natural gas from both local and Egyptian sources will be available for electricity generation later in the decade.

Trade

Overview

The amount of coal traded in international markets is small in comparison with total world consumption. In 2000, world imports of coal amounted to 604 million tons (Figure 60 and Table 16), representing 13 percent of total consumption. By 2020, coal imports are projected to rise to 776 million tons, accounting for an 11-percent share of world coal consumption. Although coal trade has made up a relatively constant share of world coal consumption over time and should continue to do so in future years, the geographical composition of trade is shifting.

In recent years, international coal trade has been characterized by relatively stable demand for coal imports in Western Europe and expanding demand in Asia (Figure 59). Rising production costs in the indigenous coal industries in Western Europe, combined with continuing pressure to reduce industry subsidies, have led to substantial declines in production there, creating the potential for significant increases in coal imports; however, environmental concerns and increased electricity generation from natural gas, nuclear, and hydropower have curtailed the growth in coal imports. Conversely, growth in coal demand in Japan, South Korea, and Taiwan in recent years has contributed to a substantial rise in Asia's coal imports.

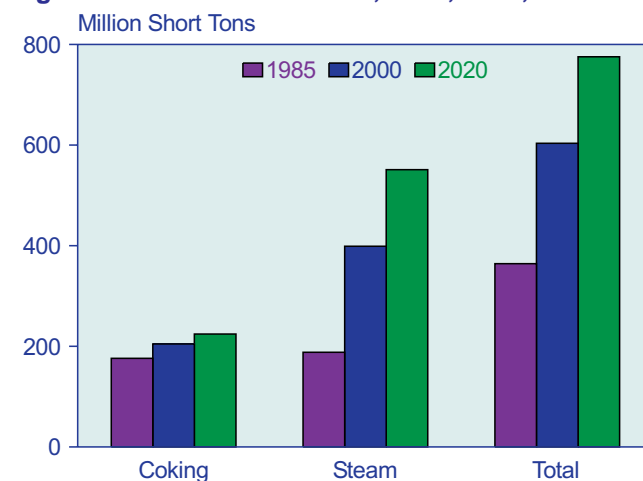
Most recently, in 2000 and 2001, international coal markets have undergone some significant changes on both the supply and demand side. In 2000, international coal markets were affected by several factors, including higher ocean freight rates, strong growth in coal import demand, a recovery in coal export prices (FOB port of exit) late in the year, and a substantial increase in coal exports from China. On the transport side, ocean freight rates rose substantially in 2000, with rates for much of the year typically double those seen in 1999. The

primary impacts of the higher rates were a shift in world coal trade patterns to shorter shipping routes for the year (for example, South Korea increased its take of coal from China in 2000, reducing its imports from more distant sources, such as Australia and South Africa [88]) and a higher delivered cost of coal imports. On the demand side, world coal trade rose substantially, increasing from 548 million tons in 1999 to 604 million tons in 2000.

The year 2001 was marked by continuing growth in coal import demand, further recovery in coal export prices from historical lows reached in 1999 and early 2000, a continuation of favorable exchange rates vis-a-vis the U.S. dollar for several key exporting countries [89],¹⁴ and a continuing surge in coal exports from China. One key difference between 2000 and 2001 was a return to much lower coal transportation rates in 2001, increasing the competitiveness of longer range shipments such as exports of Australian coal to Western Europe [90].

Between 1998 and 2000 coal exports from China expanded by 67 percent, from 36 million tons in 1998 to 41 million tons in 1999 and 60 million tons in 2000. Preliminary data indicate that China exported 95 million tons of coal during 2001 [91], making it the second leading coal export country in the world, ahead of South Africa and Indonesia. The United States, which was the

Figure 60. World Coal Trade, 1985, 2000, and 2020



Sources: **1985:** Energy Information Administration (EIA), *Annual Prospects for World Coal Trade 1987*, DOE/EIA-0363(87) (Washington, DC, May 1987). **2000:** International Energy Agency, *Coal Information 2001* (Paris, France, September 2001); Energy Information Administration, *Quarterly Coal Report, October-December 2000*, DOE/EIA-0121(2000/4Q) (Washington, DC, May 2001). **2020:** Energy Information Administration, National Energy Modeling System run IEO2002.D011402A (January 2002).

¹⁴The exchange rate for the Australian dollar was US\$0.51 in December 2001, 36 percent below its recent historical peak of US\$0.80 in May 1996. The exchange rate for the South African Rand was US\$0.09 in December 2001, 67 percent below its recent historical peak of US\$0.27 in January 1996. Between August 1998 and November 2001, the Russian ruble lost 77 percent of its value compared with the U.S. dollar.

Table 16. World Coal Flows by Importing and Exporting Regions, Reference Case, 2000, 2010, and 2020
(Million Short Tons)

Exporters	Importers											
	Steam ^a				Coking				Total			
	Europe ^b	Asia	America	Total ^c	Europe ^b	Asia ^d	America	Total ^c	Europe ^b	Asia	America	Total ^c
2000												
Australia	13.8	83.2	2.3	96.7	25.7	76.2	6.6	109.1	39.5	159.4	8.9	205.8
United States	5.8	4.3	15.4	25.6	21.6	2.3	8.9	32.8	27.4	6.6	24.3	58.4
South Africa	55.6	14.4	1.3	74.3	0.4	0.3	1.0	2.8	56.0	14.7	2.3	77.1
Former Soviet Union . .	18.4	6.0	0.1	23.3	3.1	3.7	0.0	8.0	21.5	9.7	0.1	31.3
Poland	15.7	0.0	0.0	14.6	3.3	0.0	0.1	3.0	19.0	0.0	0.1	17.6
Canada	0.3	3.3	0.7	5.1	8.2	19.3	3.6	32.8	8.5	22.6	4.3	37.9
China	3.2	53.8	0.2	53.0	0.3	7.1	0.0	7.4	3.5	60.9	0.2	60.4
South America ^e	30.4	0.0	15.0	46.4	0.4	0.1	0.1	0.7	30.8	0.1	15.1	47.1
Indonesia ^f	4.5	46.5	2.4	59.8	0.5	10.6	0.0	11.2	5.0	57.1	2.4	71.0
Total	147.7	211.5	37.5	398.8	63.5	119.6	20.4	204.7	211.2	331.1	57.9	603.5
2010												
Australia	10.0	108.2	0.7	118.8	35.6	85.5	8.0	129.1	45.6	193.7	8.7	247.9
United States	3.1	6.7	8.6	18.4	13.4	1.3	15.5	30.2	16.5	8.0	24.2	48.7
South Africa	70.5	8.2	4.4	83.0	1.1	0.5	0.0	1.7	71.6	8.7	4.4	84.7
Former Soviet Union . .	19.6	6.1	0.0	25.6	3.0	4.3	0.0	7.3	22.5	10.4	0.0	32.9
Poland	8.0	0.0	0.0	8.0	1.1	0.0	0.0	1.1	9.1	0.0	0.0	9.1
Canada	5.0	0.0	0.0	5.0	6.9	13.8	3.3	24.0	11.9	13.8	3.3	29.0
China	0.0	113.5	0.0	113.5	0.0	12.4	0.0	12.4	0.0	125.9	0.0	125.9
South America ^e	36.4	0.0	34.8	71.2	0.0	0.0	0.0	0.0	36.4	0.0	34.8	71.2
Indonesia ^f	7.6	65.9	0.0	73.5	0.5	9.1	0.0	9.6	8.1	75.0	0.0	83.1
Total	160.3	308.5	48.4	517.2	61.6	126.9	26.8	215.3	221.9	435.5	75.2	732.6
2020												
Australia	9.3	112.7	0.7	122.7	35.8	89.7	12.4	137.9	45.1	202.4	13.1	260.6
United States	1.9	7.5	7.2	16.6	12.1	1.4	18.1	31.7	14.1	8.9	25.3	48.3
South Africa	67.7	17.0	4.3	89.0	0.9	0.6	0.0	1.5	68.6	17.6	4.3	90.5
Former Soviet Union . .	16.1	7.2	0.0	23.3	3.0	4.7	0.0	7.7	19.1	11.9	0.0	31.0
Poland	5.5	0.0	0.0	5.5	1.1	0.0	0.0	1.1	6.6	0.0	0.0	6.6
Canada	2.9	0.0	0.0	2.9	6.8	14.0	1.7	22.5	9.7	14.0	1.7	25.4
China	0.0	121.3	0.0	121.3	0.0	12.4	0.0	12.4	0.0	133.6	0.0	133.6
South America ^e	50.0	0.0	36.1	86.1	0.0	0.0	0.0	0.0	50.0	0.0	36.1	86.1
Indonesia ^f	0.0	83.8	0.0	83.8	0.4	9.2	0.0	9.6	0.4	93.0	0.0	93.4
Total	153.4	349.4	48.3	551.1	60.2	132.1	32.2	224.4	213.6	481.4	80.5	775.5

^aReported data for 2000 are consistent with data published by the International Energy Agency (IEA). The standard IEA definition for "steam coal" includes coal used for pulverized coal injection (PCI) at steel mills; however, some PCI coal is reported by the IEA as "coking coal."

^bCoal flows to Europe include shipments to the Middle East and Africa.

^cIn 2000, total world coal flows include a balancing item used by the International Energy Agency to reconcile discrepancies between reported exports and imports. The 2000 balancing items by coal type were 2.1 million tons (steam coal), 1.2 million tons (coking coal), and 3.3 million tons (total).

^dIncludes 14.4 million tons of coal for pulverized coal injection at blast furnaces shipped to Japanese steelmakers in 2000.

^eCoal exports from South America are projected to originate from mines in Colombia and Venezuela.

^fIn 2000, coal exports from Indonesia include shipments from other countries not modeled for the forecast period. The 2000 non-Indonesian exports by coal type were 6.2 million tons (steam coal), 1.5 million tons (coking coal), and 7.7 million tons (total).

Notes: Data exclude non-seaborne shipments of coal to Europe and Asia. Totals may not equal sum of components due to independent rounding. The sum of the columns may not equal the total, because the total includes a balancing item between importers' and exporters' data.

Sources: **2000:** International Energy Agency, *Coal Information 2001* (Paris, France, September 2001); Energy Information Administration, *Quarterly Coal Report, October-December 2000*, DOE/EIA-0121(2000/4Q) (Washington, DC, May 2001). **Projections:** Energy Information Administration, National Energy Modeling System run IEO2002.D011402A (January 2002).

second largest coal exporter from 1984 through 1998, was surpassed by South Africa and Indonesia in 1999 and by China in 2000.

Recent actions by the Chinese government to encourage coal exports include an increase in coal export rebates and a reduction in the export handling fees charged by China's four official coal export agencies [92]. China's 10th Five-Year Plan envisions that coal exports will exceed 110 million tons by 2005 [93].

Asia

Despite setbacks that resulted from the region's financial crisis in 1998, Asia's demand for imported coal remains poised for additional increases over the forecast period, based on strong growth in electricity demand in the region. Continuing the recent historical trend, Japan, South Korea, and Taiwan are projected to account for much of the regional growth in coal imports over the forecast period.

Japan continues to be the world's leading importer of coal and is projected to account for 24 percent of total world imports in 2020, slightly less than its 2000 share of 27 percent [94]. In 2000, Japan produced just over 3 million tons of coal for domestic consumption and imported 160 million tons. The closure of Japan's Miike mine in March 1997 left the country with two remaining underground coal mines and several small surface mines [95]. The last two underground mines, Ikeshima and Taiheiyo, were closed in late 2001 and early 2002, respectfully, leaving virtually all of Japan's coal requirements to be met by imports [96].

As the leading importer of coal, Japan has been influential in the international coal market. Historically, contract negotiations between Japan's steel mills and coking coal suppliers in Australia and Canada established a benchmark price for coal that was used later in the year as the basis for setting contract prices for steam coal used at Japanese utilities [97]. Other Asian markets also tended to follow the Japanese price in settling contracts.

Japan's influence has declined somewhat over the past several years, however, and the benchmark pricing system that was so influential in setting contract prices for Japan's steel mills was revised substantially in 1996. The revisions reflected a move away from a system which, in effect, averaged coal prices (with minor adjustments for quality) to a regime with a broad spectrum of prices, where high-quality coking coals received a substantial premium relative to lower quality coals [98].

Similar changes have occurred in the annual negotiation process between Japanese electric utilities and Australian steam coal suppliers, with a tiered pricing structure replacing a single benchmark price. Through 2000, the new pricing system was characterized by a relatively

small portion of Australia's coal shipments to Japanese utilities being priced at or slightly below a negotiated "reference" price, with the remaining tonnage priced considerably lower [99]. The more recent environment of high spot prices for coal in 2001, however, has made the current reference pricing system for coal considerably less attractive to Japanese electricity producers, as they are essentially having to pay prices that are higher than the negotiated "reference price" for much of their purchased tonnage. As a result, Japan's Chubu Electric Power Company has been exploring alternative pricing schemes—reportedly trying to find the best way to minimize the average annual price they pay for coal [100].

In essence, liberalization of the Japanese electricity market is placing increased cost-cutting pressure on utilities, making them less concerned about long-term supply and much more focused on prices. What seems to be occurring in the Asian coal markets is a shift away from contract purchases to the spot market. The shift to more competitive coal markets in Asia implies that coal producers in Australia and other exporting countries will be under increased pressure to reduce mining costs in order to maintain current rates of return. It also means that less competitive suppliers, such as the United States, will find it difficult to increase or maintain coal export sales to the region.

China and India, which import relatively small quantities of coal at present, are expected to account for a significant portion of the remaining increase in Asian imports. Imports by China and India have the potential to be even higher than projected, but it is assumed in the forecast that domestic coal will be given first priority in meeting the large projected increase (1.6 billion tons) in coal demand. In addition, coal imports by Malaysia, the Philippines, and Thailand are also projected to rise substantially over the forecast period, primarily to satisfy demand at new coal-fired power plants. Diversification of fuel supply for electricity generation is the key factor underlying plans for additional coal-fired generating capacity in these countries.

During the 1980s, Australia became the leading coal exporter in the world, primarily by meeting increased demand for steam coal in Asia. Considerable growth in exports of coking coal also occurred, however, as countries such as Japan began using some of Australia's semi-soft or weak coking coals in their coke oven blends. As a result, imports of hard coking coals from other countries, including the United States, were displaced. Australia's share of total world coal trade, which increased from 17 percent in 1980 to 34 percent in 2000, is projected to remain near that level over the forecast period [101]. Australia should continue as the major exporter to Asia, but its share of the region's total coal import demand is projected to decline from 48 percent in 2000 to 42 percent by 2020.

Recently, coal from China has been displacing some Australian tonnage in several of Asia's major coal-importing countries, such as South Korea, Japan, and Taiwan [102]. Factors contributing to China's expanding coal export position in Asia include: (1) the recent completion of projects and further commitments by the Chinese government to improve rail links to ports and to construct new coal export facilities; (2) continuing support for China's coal export industry through state subsidies; (3) aggressive pricing of coal exports, emphasizing market share rather than profits; and (4) the relatively short transport distances from China's coal-exporting ports to Asia's major coal-importing countries, ensuring low shipping costs [103]. Over the forecast period, China is expected to capture an increasing share of the region's overall coal import market.

Europe, Middle East, and Africa

Coal imports to Europe, the Middle East, and Africa taken as a whole are projected to remain relatively constant over the forecast period (Figure 61). Projected declines in overall imports to the countries of Western Europe are offset by small increases projected for Turkey, Romania, Morocco, and Israel.

In Western Europe, strong environmental lobbies and competition from natural gas are expected gradually to reduce the reliance on steam coal for electricity generation, and further improvements in the steelmaking process will continue to reduce the amount of coal required for steel production. Strict environmental standards are expected to result in the closure of some of Western Europe's older coke batteries, increasing import requirements for coal coke but reducing imports of coking coal.

Projected reductions in indigenous coal production in the United Kingdom, Germany, Spain, and France are not expected to be replaced by equivalent volumes of coal imports. Rather, increased use of natural gas, renewable energy, and nuclear power (primarily in France) is expected to fill much of the gap in energy supply left by the continuing declines in the region's indigenous coal production.

In 2000, the leading suppliers of imported coal to Europe were South Africa (27 percent), Australia (19 percent), South America (15 percent), and the United States (13 percent). Over the forecast period, low-cost coal from South America (primarily from Colombia and Venezuela) is projected to meet an increasing share of European coal import demand, displacing some coal from such higher cost suppliers as the United States and Poland.

Despite expected gains in South America's foothold in Europe, South Africa is projected to maintain its position as the leading supplier of coal to Europe. Recently announced plans call for an 11-million-ton expansion in

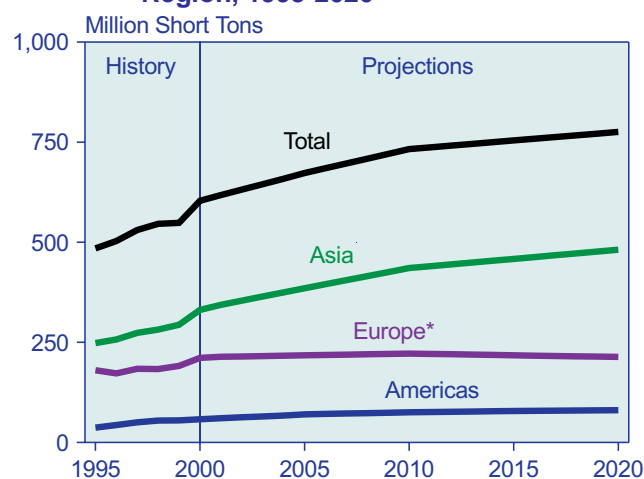
South Africa's Richards Bay Coal Terminal by the end of 2003, increasing the facility's annual coal export capacity to 90 million tons [104].

The Americas

Compared with European and Asian coal markets, imports of coal to North and South America are relatively small, amounting to only 58 million tons in 2000 (Table 16). Canada imported 33 percent of the 2000 total, followed by Brazil (26 percent) and the United States (22 percent) [105]. Most (81 percent) of the imports to Brazil were coking coal, and a majority of the remaining import tonnage was steam coal used for pulverized coal injection at steel mills [106].

Over the *IEO2002* forecast period, coal imports to the Americas are projected to increase by 23 million tons, with most of the additional tonnage going to the United States, Mexico, and Brazil. Coal imports to the United States are projected to increase from 13 million tons in 2000 to 20 million tons by 2020 [107]. Coal-fired power plants in the southeastern part of the country are expected to take most of the additional import tonnage projected over the forecast period, primarily as a substitute for higher priced coal from domestic producers. Brazil and Mexico are projected to import additional quantities of coal for both electricity generation and steelmaking.

Figure 61. Coal Imports by Major Importing Region, 1995-2020



*Coal imports to Europe include imports to the Middle East and Africa.

Note: Data exclude non-seaborne shipments of coal to Europe and Asia.

Sources: **1995-2000:** International Energy Agency, *Coal Information 2001* (Paris, France, September 2001); Energy Information Administration, *Quarterly Coal Report, October-December 2000*, DOE/EIA-0121(2000/4Q) (Washington, DC, May 2001), and previous issues. **Projections:** Energy Information Administration, National Energy Modeling System run IEO2002.D011402A (January 2002).

Partly offsetting the projected growth in coal imports elsewhere in the Americas, Canadian imports are expected to decline over the next few years as six nuclear generating units at the Pickering and Bruce plants gradually are returned to service, displacing generation from Ontario's coal-fired power plants. Coal plants in Nova Scotia, however, are expected to increase their take of imports after the closure of Canada's Phalen and Prince underground mines in 1999 and 2001 [108]. During 2000, Nova Scotia Power purchased 0.8 million tons of domestic coal (primarily from the Prince mine) and 2.3 million tons of imports [109].

Coking Coal

Historically, coking coal has dominated world coal trade, but its share has steadily declined, from 55 percent in 1980 to 34 percent in 1999 [110]. In the forecast, its share of world coal trade continues to shrink, to 29 percent by 2020. In absolute terms, despite a projected decline in imports by the industrialized countries, the total world trade in coking coal is projected to increase slightly over the forecast period as a result of increased demand for steel in the developing countries. Increased imports of coking coal are projected for South Korea, Taiwan, India, Brazil, and Mexico, where expansions in blast-furnace-based steel production are expected.

Factors that contribute to the decline in coking coal imports in the industrialized countries are continuing increases in steel production from electric arc furnaces (which do not use coal coke as an input) and technological improvements at blast furnaces, including greater use of pulverized coal injection equipment and higher average injection rates per ton of hot metal produced. Each ton of pulverized coal (categorized as steam coal) used in steel production displaces approximately one ton of coking coal [111].¹⁵ In 1999, the direct use of pulverized coal at blast furnaces accounted for 17 percent and 19 percent of the coal consumed for steelmaking in the European Union and Japan, respectively [112].

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¹⁵ Approximately 1.4 tons of coking coal are required to produce 1 ton of coal coke. However, according to information provided by the World Coal Institute, each ton of coal injected to the blast furnace through pulverized coal injection (PCI) equipment displaces only about 0.6 to 0.7 tons of coal coke. As a result, each ton of PCI coal displaces approximately 1 ton of coking coal. Steel companies are able to reduce their operating costs, however, because coal used for pulverized coal injection is typically less expensive than the higher quality coals required for the manufacture of coal coke.

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Nuclear Power

Nuclear power is projected to represent a growing share of the developing world's electricity consumption from 1999 through 2020. New plant construction and license extensions for existing plants are expected to produce a net increase in world nuclear capacity.

World nuclear power capacity is projected to increase slightly over the forecast period, from 350 gigawatts in 2000 to 359 gigawatts in 2020. Most of the growth is expected in developing Asia, particularly China, where 17 new power plants are expected to be operational over the forecast period. In the industrialized nations, with few additional nuclear plants being built and a significant number of plant retirements expected, nuclear power capacity is projected to fall considerably, despite

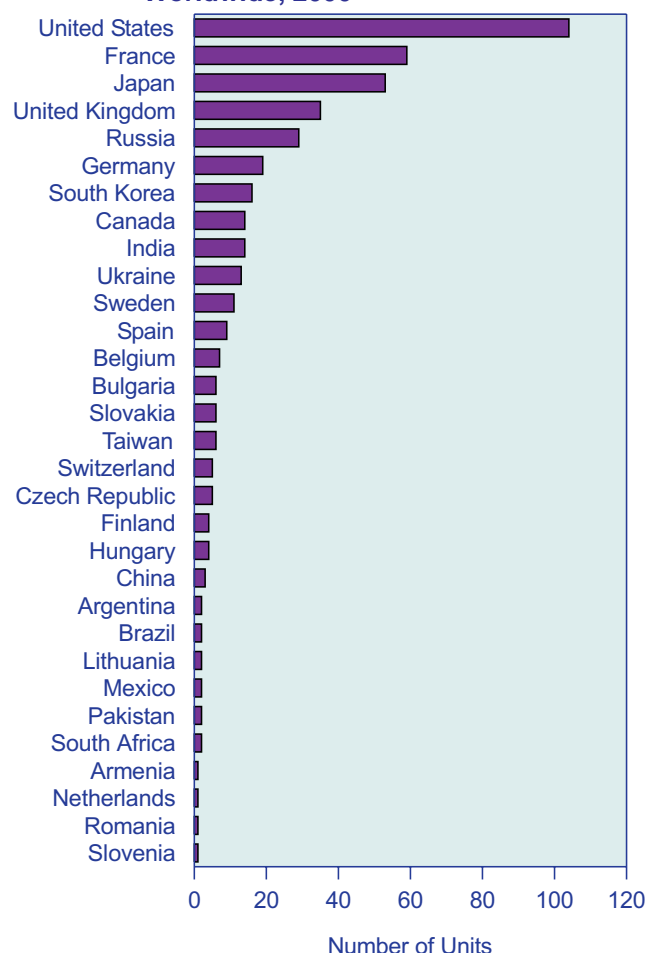
the fact that the projections include expected future life extensions for some of the nuclear power plants currently operating in the United States and other industrialized nations.

Nuclear power plants generated electricity in 30 countries in 2000. A total of 438 nuclear power plants were in operation around the world, including 104 in the United States, 59 in France, and 53 in Japan (Figure 62). Six new reactors came online in 2000, and two were shut down. The new reactors included Angra 2 (in Brazil), Temelin 1 (Czech Republic), Rajasthan 3 and 4 and Kaiga 1 (India), and Chasnupp 1 (Pakistan) for a total of 3,056 megawatts of capacity [1]. The country with the largest share of electricity generated by nuclear power was France, at 76 percent (Figure 63). Belgium, Bulgaria, France, Hungary, Lithuania, Slovakia, South Korea, and Ukraine depended on nuclear power for at least 40 percent of their electricity generation.

Nuclear power accounted for 16 percent of the world's total electricity supply in 1999. That share is projected to fall to 12 percent by 2020, primarily because the industrialized nations are expected to eschew the construction of new units while continuing to retire plants built in the 1970s and 1980s, during nuclear power's heyday. Nuclear power plant operating license extensions or the equivalent, which were first issued in the United States in 2000, are expected to be granted in other industrialized nations. In many countries, extending the operational life of a nuclear plant is a less formal procedure than in the United States, where the U.S. Nuclear Regulatory Commission (NRC) must approve license extensions. In some countries, extending a plant's operating life is a decision that is left primarily to the owner.

In developing Asia, 32 gigawatts of capacity is projected to be added by 2020 to the region's 23 gigawatts of nuclear capacity operating in 2000. China is expected to account for 14 gigawatts of net capacity additions (Table 17). There are currently 33 reactors under construction around the globe (Figure 64), half of which are being built in developing Asia. China accounts for 8 of the new units, South Korea 4, and India and Taiwan 2 each. There are no new plants currently under construction or on order in North America, South America, or Western Europe.

Figure 62. Operating Nuclear Power Plants Worldwide, 2000



Source: International Atomic Energy Agency, "Power Reactor Information System," web site www.iaea.org/programmes/a2/ (February 12, 2002).

The *International Energy Outlook 2002 (IEO2002)* reference case forecasts world net capacity at 359 gigawatts in 2020, or 9 gigawatts more than projected in the *International Energy Outlook 2001 (IEO2001)* reference case. Projected U.S. nuclear capacity in 2020 is 16 gigawatts higher in the *IEO2002* forecast as a result of an expectation that the owners of most of the nuclear power plants now operating in the United States will seek relicensing and will continue operating the plants. The *IEO2002* forecast projects 3 gigawatts fewer retirements in 2020 overseas but also projects fewer new builds overseas than did the *IEO2001* forecast.

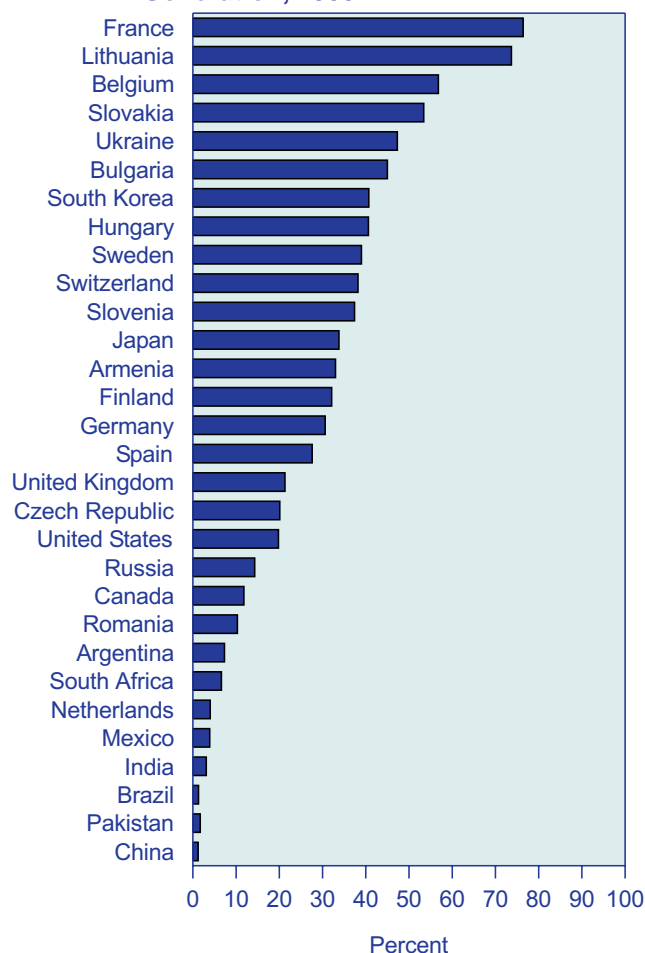
In many countries the decision to build a nuclear power plant is fraught with uncertainty. In many cases, nuclear power plants have been announced but their construction has been delayed or abandoned altogether. Some nuclear power plants have taken as little as 4 years to build; others have taken well over a decade. This chapter includes two examples illustrating the difficulties of forecasting nuclear capacity growth and how

contemporary events necessitate frequent revisions of earlier forecasts. The box on page 94 discusses the issues (largely political) that are likely to determine the future of nuclear power in the United Kingdom, and the box on page 95 describes financial issues that cast doubt on the future of Ukraine's nuclear option.

The September 11, 2001, terrorist attacks on New York City and Washington, DC, gave rise to new concerns over the safety of the nuclear power plants now operating in the United States. Uncertainties about whether nuclear power plants and nuclear fuel storage facilities were at risk from a similar terrorist attack resulted in heightened security measures at all nuclear facilities around the country. Although a containment tower had in the past survived a head-on test crash of a military jet without major damage [2], it remains uncertain whether the same could be said of a head-on crash with a large commercial aircraft loaded with jet fuel. Containment vessels typically have 4 feet of steel-reinforced concrete along with a steel liner. Fuel storage facilities may be more prone to damage in the event of a head-on crash, in that they are not nearly so well protected.

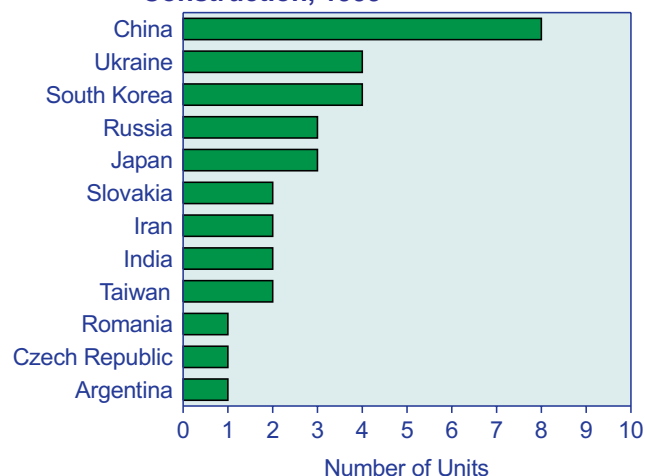
After the September 11 attacks, the Federal Aviation Administration banned commercial airplanes from flying within 10 nautical miles of any nuclear facility. In many States, National Guard troops were deployed to protect power plants from possible terrorist attacks. It is uncertain what lasting impact these recent developments will have on the prospects for nuclear power either in the United States or overseas; the *IEO2002* forecast has not been adjusted to take into account any policy changes resulting from the events of September 11, 2001. One argument that may favor nuclear power is that continued or increased use of nuclear power for electricity generation would lessen U.S. dependence on

Figure 63. Nuclear Shares of National Electricity Generation, 1999



Source: Energy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001).

Figure 64. Nuclear Power Reactors Under Construction, 1999



Source: International Atomic Energy Agency, *Nuclear Power Reactors in the World 1999* (Vienna, Austria, April 2000).

Table 17. Historical and Projected Operable Nuclear Capacities by Region, 2000-2020
(Net Gigawatts)

Region	2000 ^a	2005	2010	2015	2020
Reference Case					
Industrialized	278.1	280.3	277.3	268.4	260.4
United States	97.5	97.7	94.3	88.8	88.0
Other North America	11.4	15.0	15.0	15.0	15.0
Japan	43.5	44.3	47.8	50.8	53.4
France	63.2	62.9	62.9	62.9	64.4
United Kingdom	12.5	11.4	9.8	8.1	4.8
Other Western Europe	50.1	49.1	47.5	42.8	34.9
EE/FSU	44.5	46.2	42.6	41.5	36.7
Eastern Europe	10.7	11.7	10.1	10.1	10.7
Russia	19.8	21.7	21.3	20.3	14.8
Ukraine	11.2	11.2	11.2	11.2	11.2
Other FSU	2.7	1.6	0.0	0.0	0.0
Developing	27.4	35.9	43.3	50.6	62.3
China	2.2	6.6	9.6	11.6	16.6
South Korea	13.0	15.9	16.3	19.4	22.1
Other	12.2	13.5	17.5	19.6	23.6
Total World	349.9	362.5	363.2	360.6	359.4
Low Growth Case					
Industrialized	278.1	273.9	264.1	239.9	217.1
United States	97.5	97.7	94.3	86.4	85.6
Other North America	11.4	11.4	11.4	10.1	10.1
Japan	43.5	44.0	46.2	42.9	38.7
France	63.2	62.9	62.9	61.1	53.0
United Kingdom	12.5	11.0	8.1	4.2	1.2
Other Western Europe	50.1	46.9	41.2	35.3	28.5
EE/FSU	44.5	43.3	36.7	27.9	17.2
Eastern Europe	10.7	10.5	10.1	10.1	7.7
Russia	19.8	20.4	15.5	11.2	8.6
Ukraine	11.2	11.2	11.2	6.7	1.0
Other FSU	2.7	1.2	0.0	0.0	0.0
Developing	27.4	33.0	38.7	42.8	44.5
China	2.2	6.6	8.6	9.6	10.6
South Korea	13.0	14.9	16.3	18.5	20.2
Other	12.2	11.6	13.9	14.7	13.7
Total World	349.9	350.2	339.6	310.7	278.8
High Growth Case					
Industrialized	278.1	284.8	283.1	293.1	301.5
United States	97.5	97.7	95.4	89.9	89.1
Other North America	11.4	15.0	15.0	15.0	17.0
Japan	43.5	46.7	48.7	63.8	68.8
France	63.2	63.2	62.9	64.4	64.4
United Kingdom	12.5	12.3	11.0	10.6	12.4
Other Western Europe	50.1	50.1	50.1	49.5	49.9
EE/FSU	44.5	49.2	50.5	51.7	55.8
Eastern Europe	10.7	12.5	11.9	11.1	13.0
Russia	19.8	22.7	23.9	26.1	26.2
Ukraine	11.2	11.2	13.1	13.1	15.0
Other FSU	2.7	2.7	1.6	1.4	1.6
Developing	27.4	37.9	51.6	66.6	83.0
China	2.2	7.6	11.6	18.6	20.6
South Korea	13.0	16.8	19.7	21.4	26.2
Other	12.2	13.5	20.3	26.6	36.2
Total World	349.9	371.9	385.2	411.3	440.4

^aStatus as of December 31, 2000. Data are preliminary and may not match other EIA sources.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **United States:** Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001). **Foreign:** Based on detailed assessments of country-specific nuclear power programs.

United Kingdom Waxes and Wanes on Nuclear Power

In part because it is the most politicized of all electricity generation technologies, future nuclear power capacity is particularly difficult to forecast. The difficulty arises from a number of issues, such as safety, nuclear proliferation, waste disposal, plant decommissioning, and the cost of future plant construction. In recent years, some government officials and industry leaders have shown renewed interest in building additional nuclear power plants in countries where the movement away from nuclear power appeared inexorable. Nevertheless, the *IEO2002* reference case projects that a number of nuclear power plants currently planned in several nations over the forecast horizon will not be built, and that a fundamental reversal of the trend toward retirement of existing nuclear power plants—a trend that has been evident since the early 1990s—will not take place.

One country where new nuclear construction is now thought to be a possibility is the United Kingdom. In the *IEO2002* reference and low nuclear case forecasts, no new nuclear power plants are expected to come online in the United Kingdom by 2020; however, the high nuclear case projects that three new 1,000-megawatt units will be built and operating by the end of the forecast period. Currently, the UK government has no stated plans to build additional nuclear power plants, although there has been renewed public debate on the efficacy of nuclear power, and the current Labor party government appears to have softened its prior opposition. The *IEO2002* reference and low nuclear case forecasts assume that those factors in themselves are not enough to overcome all the obstacles currently arrayed against the further development of nuclear power in the United Kingdom.

One of the foremost difficulties in forecasting the future role of nuclear power is that different political parties often have opposing views on the subject. In many cases, future election results could alter the course of nuclear power, as they have done in the recent past. Germany's decision to abandon nuclear power, for instance, is clearly the result of the election of the Social Democrats and their anti-nuclear allies, the Green party. When the Conservative party government of Margaret Thatcher was in office in the United Kingdom, nuclear power was viewed as a viable future contributor to new electricity generation. When Labor assumed office, it was felt that Labor's stated opposition to nuclear power would become government policy. For some time, however, the government of

Prime Minister Tony Blair has left open the option that nuclear power would continue to play a role in the nation's electricity supply. Britain's support of the Kyoto Protocol was one factor forcing a reevaluation of the nuclear option: if the United Kingdom abandoned its nuclear option, compliance with the Kyoto Protocol would be more difficult. The initial Blair cabinet even included an energy minister, John Battle, who had come out in support of building new reactors.

In February 2002, a UK government review of energy was released. The review called for a national debate on nuclear power and for an examination of "low waste, modular designs of nuclear reactors" and urged the government to "continue to participate in research aimed in this direction."^a Moreover, the chief executive of the UK nuclear power company, BNFL, has urged the government to promote the building of nuclear power plants.^b

There are still several reasons why the UK is unlikely to renew its promotion of nuclear power as a source of electricity generation. Two reports completed in the fall of 2001 by the Labor government pointed out that nuclear power was much more costly than wind or biomass, and that increased energy efficiency and combined heat and power were preferable options. Concerns over nuclear proliferation and terrorism in the post-September 11 world may also have inspired a change of heart.

Since the late 1980s, the unexpected large construction cost overruns for Britain's nuclear power plants have led to a reevaluation of the future role of nuclear power in the nation's energy mix. As in the United States, most of the UK electric utility industry's stranded cost problem stemmed from past investments in nuclear energy, largely as a result of cost overruns in the construction of nuclear facilities and unforeseen spent-fuel reprocessing and disposal liabilities, as well as decommissioning costs.

Only one nuclear reactor (Sizewell B) has come online in the United Kingdom since 1988, and it has been controversial. During construction, the capital costs for Sizewell B escalated by 35 percent; and when the plant came online it generated electricity at a cost that was twice what the UK electricity pool was charging. Construction delays have also been a problem for the UK nuclear industry. The Dungeness B reactors, for instance, took 22 years to complete.

(continued on page 95)

^a"Minister Says UK Energy Review Keeps New Nuclear Option Open," *NucNet: The World's Nuclear News Agency*, Vol. 65, No. 2 (February 14, 2002).

^bP. Brown and D. Gow, "UK 'Needs Another 20 Nuclear Stations,'" *Guardian Unlimited* (September 7, 2001), web site www.guardian.co.uk/Archive/Article/0,4273,4252099,00.html.

United Kingdom Waxes and Wanes on Nuclear Power (Continued)

Since the reform of the UK electric power industry was started in 1989, its electricity market has developed into one of the most competitive around the globe. This too does not augur well for nuclear's future in the UK electricity supply industry. For example, a 1995 government white paper concluded that, in a competitive private market, no one would invest in new nuclear capacity and indicated that the government would not provide state subsidies to ensure new construction of nuclear plants.^c

In the *IEO2002* forecast, natural gas is expected to accommodate much of the growth in UK electricity demand to the year 2020, obviating the need for construction of additional nuclear units. Natural gas remains a viable future source of energy for electricity production in the United Kingdom. Despite increases in consumption over the past 20 years, the country's natural gas reserves have risen by 7 percent. Moreover, wholesale natural gas prices in the United Kingdom generally have tracked below U.S. natural gas prices.

^cG. MacKerron, "Nuclear Power Under Review," in *The British Electricity Experiment, Privatization: The Record, the Issues, the Lessons* (London, UK: Earthscan Publications Limited, 1996), pp. 159-160.

Can Ukraine Finance Nuclear Power?

In most of the industrialized nations, the decision to continue to develop nuclear power as a source of electricity hinges on such factors as the economic viability of a nuclear power plant relative to coal, natural gas, or other sources of electricity. Other considerations include power plant operating safety, decommissioning costs, waste disposal, and concerns about nuclear arms proliferation. In other countries, such as Ukraine, obtaining project funding has been the most critical issue in the development of a domestic nuclear power industry.

Although Ukraine's Khmelnytsky 2 and Rovno 4 (K2 and R4) today are 80 percent complete, it is not clear that either unit will ever be connected to the grid. Construction on both units was aborted in 1991 after the breakup of the former Soviet Union. In 1995, the European Bank for Reconstruction and Development (EBRD) and the Group of Seven (G7) signed a memorandum of understanding with Ukraine's government. An important goal of the EBRD and G7 was to encourage Ukraine to shut down its remaining Chernobyl vintage reactors.^a As a form of compensation, the EBRD agreed to fund the completion of K2 and R4. An understanding was reached that K2 and R4 would be operated at "western safety levels." Over the course of several years, three outside consulting firms provided analyses of the viability of K2 and R4. Two concluded that completion of the plants represented the least-cost

option, and one suggested that economics argued against their completion.^b Several Western European environmental groups and political parties have also opposed the construction of K2 and R4.

The \$1.48 billion in funding for the completion and safety upgrade of K2 and R4 was to have come from a number of sources: \$580 million from Euratom, \$348 million from export credit agencies, \$215 million from the EBRD, \$123 million from Russia, \$159 million from Energoatom, and \$50 million from the Ukrainian government.^c However, as coordinator of the loan package, EBRD's funding became critical to the future survival of the project. Energoatom, the Ukraine nuclear power utility, and the EBRD had a difficult time negotiating a loan agreement. Initially, the EBRD approved a \$215 million loan in December 2000 for the completion and safety upgrade of K2 and R4, pending certain conditions involving safety and funding availability. In December 2001, however, loan negotiations between the EBRD and the Ukrainian government foundered over an inability to agree on a future rate structure for sales of electricity from the two plants. Although it remains unclear whether K2 and R4 will be completed, the Ukraine's experience in trying to finance and build the plants is an example of the difficulties some nations face in their efforts to develop a nuclear power industry.

^aChernobyl 4 was shut down after the accident in 1986. Unit 2 was shut down after a turbine fire in 1991, and unit 1 was closed in 1997. Unit 3 was shut down in 2000.

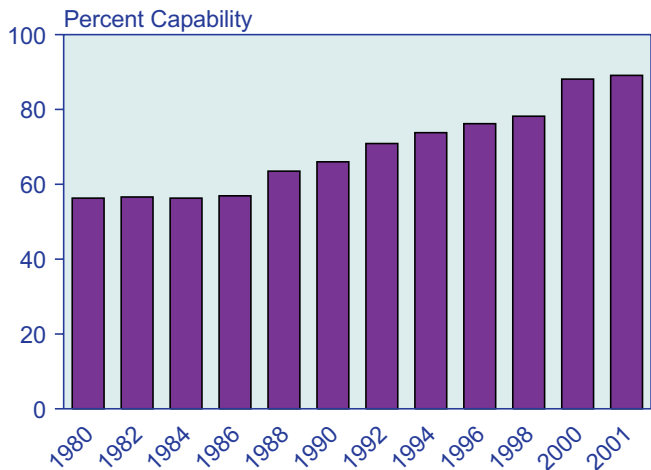
^bThe initial study was conducted by a German firm, Lahmeyer, which found completion to be the least-cost option. The second study, conducted by a group of energy experts (the Surrey Panel) argued against completion. The third study was conducted by Stone and Webster, a U.S.-based engineering and construction firm.

^cEuropean Bank for Reconstruction and Development, "EBRD Approves Ukrainian Nuclear Power Project Subject to Strict Conditions" (December 7, 2000), web site www.ebrd.com.

energy imports and thus provide greater national security. The “improved national security” argument can be taken only so far, however, given that the only imported fuel that competes significantly with nuclear power is natural gas, and almost all U.S. natural gas imports come from Canada. In other countries, nuclear power may well be considered a more secure form of electricity production, particularly by those nations heavily dependent on energy imports for electricity production. For instance, Japan relies on imported oil and natural gas for 38 percent of its electricity production, and 79 percent of its oil imports and 20 percent of its natural gas imports come from the Middle East [3].

Nuclear power first became a major source of electricity production in the 1970s. Nuclear power consumption worldwide grew from 188 billion kilowatthours in 1973 to 1,843 billion kilowatthours in 1989 [4]. By the 1990s, however, the growth of nuclear power consumption had begun to slow, and it is expected to level off by 2010. No lasting orders for new plants have occurred in Austria, Hungary, Italy, Mexico, the Netherlands, Switzerland, or the United States since 1973 [5]. Thus far, however, only Germany, Lithuania, Sweden, and Ukraine have committed to the early retirement of some if not all of their nuclear power plants. All other nations seeking to reduce their reliance on nuclear power intend to do so through attrition and by not building any new nuclear power plants. Still, many nations may find that viable alternatives to nuclear power are more difficult to develop than anticipated. Sweden, for instance, after committing to the closure of its Barsebäck nuclear power units by 2001, has delayed the closure of Barsebäck 2 until 2003.

Figure 65. U.S. Nuclear Unit Capacity Factors, 1980-2001



Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2000/02) (Washington, DC, February 2002), p. 113.

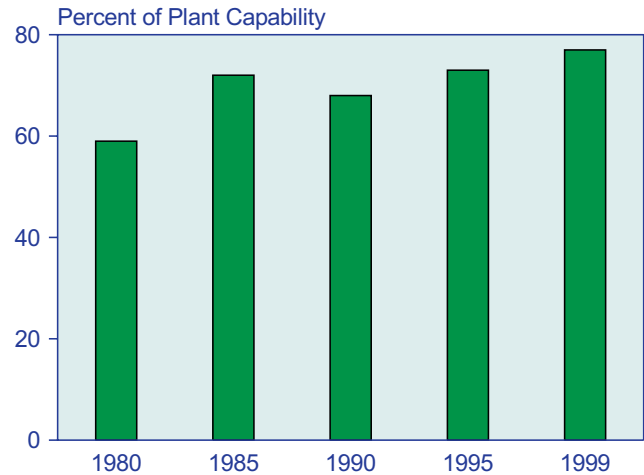
The Economics of Nuclear Power

There has been a significant improvement in the economics of nuclear power over the past several years. Capacity factors in the United States, for instance, which averaged 56.3 percent in 1980, grew to 89.1 percent in 2001 (Figure 65). Since the 1970s and 1980s, the average interval between refuelings for U.S. nuclear units has increased to 18 months from 12 months, resulting in less frequent outages [6], and since 1990 the average refueling cycle has fallen from 100 days to 80 days [7]. Overseas, capacity factors have also improved measurably. For those developed nations with nuclear power units in operation in both 1980 and 1999 (including the United States), the average capacity factor rose from 59 percent to 77 percent (Figure 66).

One of the ways to increase the capacity factor of a nuclear unit is to have fewer scheduled and unscheduled shutdowns; and improved operational safety has been an important factor in reducing shutdowns. Another means of increasing the output of nuclear power plants is to implement a power uprate, which can be viewed as increasing the absolute capacity of a plant rather than its utilization rate. Since the 1970s, the NRC has approved 62 uprates of U.S. nuclear plants, adding the equivalent of two large nuclear units [8]. Power uprates are typically achieved through plant upgrades, including investments in such items as pipes, heat exchangers, pumps, transformers, and generators.

Recently, the U.S. nuclear power industry has witnessed an unprecedented merger and acquisition spree, seeing roughly one-fourth of the industry change ownership and resulting in a much more concentrated industry.

Figure 66. Nuclear Unit Capacity Factors in Developed Nations, 1980-1999



Source: Energy Information Administration, Office of Energy Markets and End Use, International Statistics Database.

One possible motivation for consolidation is the belief on the part of the acquisition companies that a company with several power plants can operate them more efficiently than a company operating only one or a few plants. This also may lead to future efficiency improvements.

Although increased capacity utilization and uprates have improved the economics of nuclear power, for most nations and under most economic assumptions, nuclear power currently is a relatively expensive option for electricity generation when compared with natural gas or coal. A recent study by the International Energy Agency (IEA) on the relative competitiveness of natural gas, nuclear power, and coal among members of the Organization for Economic Cooperation and development (OECD) [9] examined various operating costs, capital costs, plant decommissioning costs, and the costs of waste disposal (see box on page 98). The study compared existing technologies and not future technologies. Expectations are that future nuclear power plants will see significant efficiency gains, although gains are also expected for natural gas, coal, and renewables.

In terms of operating costs, the IEA study concluded that nuclear power plants were competitive against coal and natural-gas-fired generation units. Natural-gas-fired units averaged 2.2 to 4.1 cents per kilowatt hour, coal plants between 1.9 and 3.3 cents per kilowatthour, and nuclear between 0.8 and 3.2 cents per kilowatthour (Table 18).¹⁶ The fuel costs (per kilowatthour of generation) for a nuclear power plant are significantly lower than those for coal or natural gas plants.

Capital costs, however, are another matter. The IEA study looked at different plants operating in various member countries (Table 19). In capital-intensive industries like electricity generation, interest rates play a key role in determining the relative economics of different generation fuel sources. The capital costs of a new

nuclear unit are substantially higher than those for new natural gas and coal units. Interest rates vary across countries, as do other factors that affect the relative costs of nuclear power, including labor costs, material and equipment costs, regulation, and infrastructure.

The IEA study assumed three discount rates, 0 percent (i.e., the overnight capital cost), 5 percent, and 10 percent. (As a point of comparison, the U.S. prime rate has averaged 9.30 percent since 1970 [10].) Due to their higher construction costs, the relative cost of nuclear power plants is much more sensitive to changes in interest rates than are the costs of coal or natural gas plants. For a French-built pressurized-water reactor, capital costs averaged \$1,636 per kilowatt at 0 percent, \$1,988 per kilowatt at 5-percent interest, and \$2,280 per kilowatt at 10-percent interest. It should be noted that the length of time to build a nuclear plant sometimes far exceeds the average. Although nuclear power plants can theoretically be built (and have been built) in 4 years [11], the IEA study notes that in the aftermath of the Three Mile Island accident in Pennsylvania, the average length of time to construct a U.S. power plant was 12 years.

Table 18. Projected Operating Costs of Nuclear, Coal, and Natural Gas Power Plants
(U.S. Cents per Kilowatthour)

Country	Nuclear	Coal	Natural Gas
Canada . . .	0.8	1.9	2.2
Finland	1.5	2.3	3.0
France	1.5	3.3	3.9
Japan	3.2	3.2	4.0
Korea	1.4	2.3	3.7
Spain	1.9	2.9	4.1

Source: International Energy Agency, *Energy Prices & Taxes, Quarterly Statistics, Second Quarter 2000* (Paris, France), p. xiii.

Table 19. Projected Operating Costs of Nuclear Power Plants
(U.S. Cents per Kilowatthour)

Country	Plant Type	Plant Net Capacity (Megawatts)	Total Capital Costs (Dollars per Kilowatthour)		
			Overnight Capital Cost	5% Discount Rate	10% Discount Rate
Canada . . .	Candu	1,330	1,697	2,139	2,384
Canada . . .	Candu	1,762	1,518	1,878	2,053
Finland	BWR	1,000	2,256	2,516	2,672
France	PWR	1,460	1,636	1,988	2,280
Japan	BWR	1,303	2,521	2,848	3,146
Korea	PWR	1,000	1,637	1,924	2,260
Spain	PWR	1,000	2,169	2,540	2,957

Candu = Canada Deuterium Uranium Reactor, which is a Canadian nuclear power plant design. BWR = Boiling Water Reactor. PWR = Pressurized Water Reactor.

Note: Technology to become commercially available by 2005-2010.

Source: International Energy Agency, *Energy Prices & Taxes, Quarterly Statistics, Second Quarter 2000* (Paris, France), p. xiii.

¹⁶Prices varied for different nations in the study, depending on domestic prices for coal and natural gas.

Nuclear Waste Disposal

Countries approach nuclear waste disposal in various ways (see table below). France, Japan, and the United Kingdom, for instance, rely on reprocessing that separates the spent reactor waste into both a recyclable fuel and a highly concentrated waste—a “closed fuel cycle” that produces both plutonium and uranium. The United States, Canada, and Sweden directly dispose of spent uranium from power reactors in an “open fuel cycle.” Several countries have yet to commit to any form of waste disposal, relying instead on interim storage for the foreseeable future. Although a long-term solution to storing nuclear waste is critical, short-term storage is an adequate solution for several years. In

Management of Spent Fuel by Country

Country	Deferred Decision	Direct Disposal	Reprocessing
Argentina	x		
Belgium	x		x
Brazil	x		
Bulgaria	x		x
Canada		x	
China			x
Czech Republic	x	x	x
Finland		x	
France			x
Germany		x	x
Hungary	x		x
India			x
Italy	x		x
Japan			x
South Korea	x		
Lithuania		x	
Mexico	x		
Netherlands			x
Pakistan	x		
Romania		x	
Russia			x
Slovakia		x	x
Slovenia	x		
South Africa		x	
Spain		x	
Sweden		x	
Switzerland	x		x
United Kingdom			x
Ukraine	x	x	x
United States		x	

Source: International Atomic Energy Agency, “Rising Needs Management of Spent Fuel at Nuclear Power Plants,” web site www.iaea.or.at/worldatom/inforesource/bulletin/bull401/article6.html.

^aP. Dyck and M.J. Crijns, “Rising Needs: Management of Spent Fuel at Nuclear Power Plants” (International Atomic Energy Agency, April 1998), web site www.iaea.or.at/worldatom/inforesource/bulletin/bull401/article6.html.

^bI. Hore-Lacy, *Nuclear Electricity*, Sixth Edition (Canberra, Australia: Uranium Information Centre and Minerals Council of Australia, August 2000), web site www.uic.com.au/ne.htm.

1997, reactor storage facilities stored 87,756 tons of nuclear fuel worldwide, well beneath their storage capacity of 147,868 tons of spent fuel.^a

In a closed fuel cycle, waste disposal involves the production of mixed oxide (MOX) fuel, a combination of plutonium and uranium. About 1 percent of the spent fuel coming out of a reactor is plutonium, which can be mixed with uranium to form MOX or used as a fuel for a breeder reactor.^b France, Belgium, and the United Kingdom account for most MOX recycling. Currently, a multinational consortium is building a MOX plant in Russia with the intention of recycling plutonium derived from destroyed nuclear weapons. An advantage of using MOX as a fuel is that its use should lead to a reduction in plutonium inventories, which could lessen the threat of nuclear weapons proliferation. The disadvantage is that it also results in the production of plutonium, which some fear could be used in the construction of atomic weapons.

France began to reprocess its spent commercial nuclear fuels in 1958, Germany in 1971, the United Kingdom in 1964, Belgium in 1966 (shut down in 1974), Japan in 1981, and the former Soviet Union in 1978. The United States built three commercial reprocessing facilities in the 1970s, but a moratorium was placed on nuclear reprocessing in 1977. Although the moratorium was lifted in 1981, by then the economics of reprocessing had become less viable because uranium prices had fallen.

There is a general consensus that stable, deep, geological formations are the best locations to store high-level nuclear waste. Most nations have identified potential underground storage sites and have conducted geological and geophysical tests as to the suitability of the proposed sites. Currently, however, no underground storage sites have progressed beyond the planning stage. Although in February 2002 President Bush authorized construction of the Yucca Mountain nuclear waste depository in the United States, the U.S. Congress may yet oppose the facility. The greatest concern over the storage of high-level nuclear wastes is that over the tens of thousands of years for which the waste will be stored in containers, it could eventually leak and leach its way into the water table. In addition to the radioactivity it releases, high-level nuclear waste also produces great amounts of heat, necessitating additional efforts at isolation. As a result, the wastes

(continued on page 99)

The IEA study concluded that, depending on the price of various operations and maintenance costs (which are heavily dependent on fuel costs, particularly for coal and natural gas) and the cost of capital (which affects nuclear disproportionately), the economics of natural gas, coal, and nuclear plants differ considerably. Assuming a 5-percent discount rate, nuclear power plants are estimated to be more efficient than coal or natural gas plants in 5 of 9 countries for which data on all three fuels were available. These countries are typically those with high natural gas prices. At a 10-percent discount rate, nuclear power is less efficient in every country. The IEA has also conducted case studies on countries such as China, India, South Korea, Pakistan, and Vietnam and has concluded that nuclear power in those countries was never the cheapest form of electricity production [12].

Although currently nuclear power plants are in general not competitive with other sources of electricity, future gains in their efficiency are expected. According to a publication sponsored by the U.S. Department of Energy, *A Roadmap To Deploy New Nuclear Power Plants in the United States by 2010*, which included data from the U.S. nuclear industry on nuclear power plant designs

that could be deployed by 2010, “new nuclear power plants can be deployed in the U.S. in this decade, provided that there is sufficient and timely private-sector financial investment.” The report also noted that “although conditions are currently more favorable for new nuclear plants than in many years, economic competitiveness in a deregulated electricity supply structure remains a key area of uncertainty with respect to near term deployment potential . . . [T]here are excellent new nuclear plant candidates that build on the experiences of existing reactors in the U.S. and around the world . . . [T]hose that are most advanced in terms of design completion and approval status appear to be economically competitive in some scenarios, but not all” [13].

Regional Developments

Western Europe

Western Europe relied on nuclear power for 35 percent of its electricity in 1999. Nuclear’s share of the Western European electricity market is expected to fall to 24 percent by 2020. Currently, among European countries, only France and Finland have shown any intent to expand their nuclear power industries. Most of the other nations of Western Europe have decided either to curtail

Nuclear Waste Disposal (Continued)

need to be stored for several years in steel-lined cooling pools or aboveground vaults before being transported to long-term waste depository sites.

The physical amount of waste produced thus far by all nations’ nuclear power plants is not considered large. For the United States, for instance, it has been estimated that all the wastes from power reactors that have accumulated since the advent of civilian nuclear power production could be stored in a football-field-sized area roughly five yards deep.^c Nevada’s Yucca Mountain, which is scheduled to begin accepting commercial radioactive waste in 2010, is one of the furthest along worldwide. President Bush is the first to officially approve a site.^d In the meantime, most, if not all, nuclear waste from U.S. power reactors is being stored on site at 70 nuclear power plants and two storage facilities. In addition, three low-level nuclear waste sites are in operation in South Carolina, Utah, and Washington.^e The U.S. commercial nuclear industry creates about 2,000 metric tons of spent fuel per year, and

about 40,000 metric tons of spent fuel are currently in temporary storage.^f

Other nations with nuclear generating stations face similar storage issues. Underground repository sites are being planned for Belgium (2030), Canada (2025), Finland (2020), France (2020), Germany (2010), Spain (2020), Sweden (2008), and Switzerland (2020). As in the United States, most high-level waste overseas is currently stored on site at nuclear reactors.

Russia appears to be entering the business of storing other nations’ high-level nuclear waste. On July 11, 2001, Russian President Vladimir Putin signed into law a measure exploring a plan to import and store other countries’ nuclear wastes. Putin authorized a study to determine the long-term environmental impact of such storage. It has been estimated that Russia could earn as much as \$20 billion over a decade by storing the nuclear wastes of countries whose own waste disposal efforts have made little progress.^g

^cNuclear Energy Institute, “Nuclear Waste Disposal: Resources: Used Nuclear Fuel Management,” web site www.nei.org (January 2002).

^dE. Pianin, “Nevada Nuclear Waste Site Affirmed,” *The Washington Post* (February 16, 2002), p. A1.

^eM. Holt, “IB92059: Civilian Nuclear Waste Disposal,” Congressional Research Service Report, web site cnie.org/NLE/CRSreports (U.S. Library of Congress, July 30, 2001).

^fM. Holt, “IB92059: Civilian Nuclear Waste Disposal,” Congressional Research Service Report, web site cnie.org/NLE/CRSreports (U.S. Library of Congress, July 30, 2001).

^gWashington Nuclear Corporation, Nuke-Energy.com, web site www.nuke-energy.com/data/other/russian_president.html.

further development of nuclear power or to abandon it entirely. Belgium, Germany, the Netherlands, Spain, Sweden, and Switzerland have made past commitments to gradual phaseouts of their nuclear power programs, although those commitments have been difficult to carry through, as described below.

Sweden and Germany have adopted the most aggressive plans to end their nuclear power programs. In 1980, Sweden committed to a scheduled 40-year phaseout of nuclear power, and in November 1997 the Swedish parliament approved a plan to shut down two of the nation's twelve nuclear reactors, Barsebäck 1 and Barsebäck 2, which accounted for 12 percent of Sweden's nuclear generation capacity. Barsebäck 1, a 615-megawatt reactor that began commercial operation in 1975, was shut down in November 1999, more than a year after the scheduled closing date of July 1998. Barsebäck 2, completed in 1977, was initially scheduled to be closed in July 2001, but in August 2000 the Swedish government announced that the Barsebäck 2 closure would also be delayed until 2003, and then only if secure sources of electricity could be obtained [14]. After closing Barsebäck 1, Sweden replaced the lost electricity generation with imported power from a coal-fired plant in Denmark, causing an increase in Western Europe's total carbon dioxide emissions.

In June 2000, Germany's electricity industry agreed to phase out its nuclear power plants ahead of schedule [15]. The plan calls for the shutdown of all of Germany's reactors after they have operated for 32 years. Accordingly, the final plant closure would occur in the mid-2020s. Germany's ruling government minority coalition partner, the environmentalist Green party, had favored a 10-year phaseout. The Social Democratic German Chancellor, Gerhard Schroeder, initially favored a 20-year phaseout but reached a compromise with the electric utility industry. The German government also decided eventually to stop the foreign reprocessing of its spent nuclear fuels, but that decision was rescinded in early 2001, ending a 3-year moratorium on spent fuel shipments to foreign reprocessing plants.

There has been some recent apparent backtracking on the move away from dependence on nuclear power as a source of electricity. In Italy, the interim head of the nation's Environmental Protection Agency (Anpa) stated that there was "wide support within the country's scientific community for review of a possible re-emergence of nuclear energy in Italy" [16]. Similarly, the European director general for energy, Francois Lamoureux, stated that the use of nuclear is "unavoidable in aiding security of supply and tackling climate change" [17]. Martin Villa, the chairman of the Spanish Electricity Company Endesa, called for a reopening of the debate on new plant construction [18]. The Tony

Blair government in the UK initially stated that it did not want an expansion of nuclear power; however, for some time the Blair government has left open the possibility that it would reverse that stance.

Japan

The Japanese government and electricity industry remain committed to building new commercial nuclear power reactors in the future, despite some public concern over operational safety. The *IEO2002* reference case projects that the nuclear share of Japan's total electricity generation will remain stable at about one-third through 2020.

Developing Asia

Alone among world regions, developing Asia is expected to see rapid growth in nuclear power. Nuclear power plants are currently in operation in China, India, Pakistan, South Korea, and Taiwan, and in the *IEO2002* reference case developing Asia is expected to more than double its nuclear capacity by 2020. Consumption of energy from nuclear power plants in developing Asia is projected to increase from 160 billion kilowatthours in 1999 to 425 billion kilowatthours in 2020. Increases in nuclear generating capacity are expected for all the developing Asian nations that currently have nuclear power plants in operation. By 2020, developing Asia is projected to account for 15 percent of the world's nuclear power capacity, up from 6 percent in 1999.

China and India are expected to show the most rapid growth in nuclear power capacity over the forecast period. China, which had 2,177 megawatts of capacity in 2000, is expected to increase its capacity to 16,607 megawatts by 2020. India is also expected to show a marked increase in nuclear power capacity. India, which currently has 2 nuclear power plants under construction, is expected to increase its capacity from 2,301 megawatts in 2000 to 6,451 megawatts by 2020.

IEO2002 expects substantial additional nuclear capacity to be added to the South Korean nuclear power sector over the forecast period. The additions projected are only slightly less than those forecast by the South Korean government or the state-owned national utility, KEPCO. In 1999, the South Korean nuclear power industry had 12,990 megawatts of capacity. By 2020, South Korea's nuclear power capacity is expected to rise to 22,125 megawatts.

North America

United States

The United States is expected to reduce its reliance on nuclear power significantly over the forecast period, from 20 percent of total electricity generation in 1999 to less than 15 percent in 2020. Only a few years ago it seemed likely that there would be numerous early

closures of nuclear power plants in the United States; however, several companies have recently applied to the NRC for extensions of reactor operating licenses, and as many as 90 percent of all operating plants could eventually be relicensed [19]. Reductions in operating costs over the past decade have made nuclear plants more competitive, even as electricity markets are increasingly being deregulated.

The Bush Administration's National Energy Policy favors expanding the role of nuclear power by, as stated in the report of the National Energy Policy Development Group, "encouraging the Nuclear Regulatory Commission to facilitate efforts by utilities to expand nuclear energy in the United States by uprating existing power plants safely . . ." and by encouraging "the NRC to relicense existing nuclear plants . . ." by directing the DOE and EPA to "assess the potential of nuclear to improve air quality . . . to increase resources as necessary for the nuclear safety enforcement in light of the potential increase in generation . . . to use the best science to provide a deep geologic repository for nuclear waste . . . to support legislation clarifying that qualified funds set aside by plant owners for eventual decommission will not be taxed as part of the transaction . . . to support legislation to extend the Price Anderson Act" [20], which limits a nuclear power plants liability in the case of an accident. In 2001, the Department of Energy's Office of Nuclear Energy, Science and Technology solicited proposals from the civilian nuclear electricity industry to conduct scoping studies "of potential sites for the deployment of new nuclear power plants" [21].

In the United States, some utilities have come out in favor of building new units and perhaps resurrecting units already shut down. In March 2001, the Tennessee Valley Authority (TVA) began reconsidering the restarting of Browns Ferry nuclear plant, which was shut down in 1985. In December 2001, the TVA announced that a "preferred option" is to extend the operation of all three Browns Ferry units [22]. Exelon Corp, the largest producer of nuclear power in the United States, has been discussing with the NRC the construction of new nuclear plants and announced that it is considering restarting one or both nuclear reactors at its Zion site (in Illinois), which was shut down in 1998. Recently, the NRC has approved three new versions of reactors that are deemed both safer and more economical.¹⁷ To date, however, no firm plans for either constructing a new unit or restarting a mothballed unit have been announced.

Canada

Nuclear power accounted for 14 percent of Canada's electricity generation in 1999, but its share is expected to

drop slightly, to 13 percent, by the end of the forecast period. In late 1997 and early 1998, Ontario Power Generation (formerly Ontario Hydro) shut down seven of its older nuclear power plants, or 17 percent (4,300 megawatts) of its operating capacity. Canada still has 14 nuclear power plants currently in operation. In July 2000, Ontario Power Generation announced its planned lease of the operation of eight of its Bruce reactors, four of which were shut down in 1998, to British Energy. In January 2001, Canada's nuclear safety commission scheduled two hearings for licenses to resume operation of three of the closed units. On October 2, 2001, the Canadian Nuclear Power Safety Commission approved an environmental review procedure that is expected to result in the reopening of Ontario's Bruce 3 and 4 nuclear power plants, with a total of 1,500 megawatts of capacity, by 2003 and 2004, respectively [23]. In November 2001, the Commission gave provisional approval for the restart of the Pickering A power plant [24].

Africa

Among African nations, South Africa is currently the only country with nuclear electricity generation capacity and the only nation expected to produce electricity from nuclear power over the forecast period. South Africa has two 921-megawatt reactors, Koeberg 1 and 2, now in operation, and nuclear power accounted for 7 percent of its electricity generation in 1999. South Africa's state-owned utility, Eskom, has been experimenting with pebble bed modular reactor technology since 1993 and had proposed the construction of a 110-megawatt demonstration reactor beginning in mid-2001, although the most recent phase calls for units in the 120 to 130 megawatt range. In November 2001, the proposed construction start time for the pebble bed modular reactor was delayed for up to 12 months upon completion of a feasibility study [25]. The *IEO2002* forecast does not expect the reactor to come online until late in the forecast period.

Eastern European and the Former Soviet Union

Nuclear power capacity in Eastern Europe and the former Soviet Union (EE/FSU) is expected to decline over the forecast period, primarily as a result of the retirement of plants in the FSU that have been the subject of safety concerns. By 2020, the region is expected to have 37,000 megawatts of capacity, compared with 44,000 megawatts in 1999.

The EE/FSU region has 59 reactors operating at 18 nuclear energy sites. Twenty-five are considered to be operating at standards below those acceptable in the West. A major goal of Western efforts has been to shut down the least safe nuclear reactors operating in the EE/FSU countries.

¹⁷These include the Westinghouse AP600 design, General Electric's Advanced Boiling-Water Reactor, and the Combustion Engineering Systems 80+ model.

In 1992, the International Atomic Energy Agency began a review of safety practices at Soviet-designed RBMK-type reactors. RBMKs are graphite-moderated channel reactors. Six of the 15 RBMK plants currently in operation are “first generation,” because they were built in the early to mid-1970s. They are considered less safe than those built later. In total, the Soviets built 17 RBMK units (including the 4 units at Chernobyl), of which 13 are still active. Eleven RBMK reactors are operating in Russia and two in Lithuania, and one is currently under construction.

Lithuania was promised 200 million euros (about \$180 million) from the European Commission and twelve other nations in grants to help ease the financial burden of shutting down its RBMK Ignalina 2 nuclear power plant before 2005. Similar efforts are being undertaken to close down Bulgaria’s Kozloduy plants and Slovakia’s Bohunice plants. Bulgaria intends to close Kozloduy units 1 and 2 in 2002 or 2003. Bulgaria has agreed to close Kozloduy units 1-4 “at the earliest possible date.” The European Union (EU) committed 200 million euros to help Bulgaria close Kozloduy units 1 and 2, and in February 2001 Westinghouse announced that it will modernize Kozloduy units 5 and 6. Both Lithuania’s and Slovakia’s future entry into the EU has been jeopardized by the concerns associated with their nuclear power industries. In December 1995, the Group of Seven and Ukraine reached an agreement to shut down all units at Chernobyl by 2000. The Chernobyl accident in 1986 destroyed unit 4, and unit 2 was shut down in 1991. Under the agreement, unit 1 was shut down in 1996, and Ukraine shut down the last of the four reactors, Chernobyl 3, in December 2000.

In October 2000, the first of the Czech Republic’s two Temelin nuclear power reactors was brought online after a long-running dispute with Austria and Germany. Construction on Temelin, which began in 1987, was delayed for financial and technical reasons [26]. Unlike the RBMKs discussed above, Temelin is a pressurized-water reactor. Westinghouse was brought in to upgrade the Temelin plant to Western standards.¹⁸ British Energy has indicated a willingness to purchase both the Temelin plant and the Czech Republic’s Dukovany reactors, adding to a portfolio of nuclear assets that includes plants in the United States and Canada.

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¹⁸Westinghouse is a unit of British Energy.

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Hydroelectricity and Other Renewable Resources

The renewable energy share of total world energy consumption is expected to decline slightly, from 9 percent in 1999 to 8 percent in 2020, despite a projected 53-percent increase in consumption of hydroelectricity and other renewable resources.

The use of hydropower and other renewable energy resources is projected to increase in the *International Energy Outlook 2002 (IEO2002)* mid-term forecast. From 1999 to 2020, worldwide consumption of renewable energy is projected to increase by 53 percent, as compared with expected increases of 92 percent for natural gas and 58 percent for oil consumption (Figure 67). Growth in demand for renewable energy resources is expected to continue to be constrained by relatively moderate fossil fuel prices.

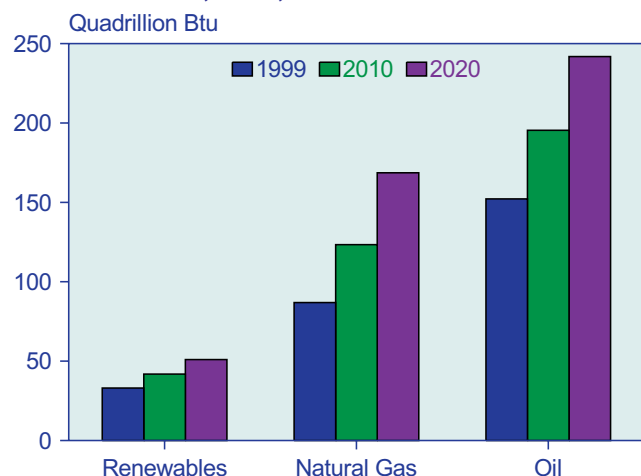
New, large-scale hydroelectric installations are expected to provide much of the growth in renewable energy use in the developing world. China, India, Malaysia, and other developing Asian countries continue to construct or plan large-scale hydropower projects. Construction on the largest project, China's 18,200-megawatt Three Gorges Dam, continued in 2001 despite reports of corruption and problems in the relocation of populations from the reservoir site. Malaysia continues to work on its 2,400-megawatt Bakun hydroelectric project, although to date only the mile-long underground river diversion tunnel has been completed [1].

The heavy reliance on hydroelectric power in many countries of Central and South America has become a

burden for some, because drought has endangered the reliable supply of electricity. In Brazil, persistent drought in 2001 led to a substantial decline in reservoir levels and, therefore, the ability of hydroelectric power plants to provide electricity. Brazil's government enforced a 20-percent cut in power use as part of a rationing program, and considered other measures such as reducing the work week, in an effort to avoid black-outs [2]. In the fall of 2001, reservoir levels were 28 percent below capacity in key regions of the country. Brazil is responding by increasing the pace of natural-gas-fired power plant construction, a trend that many governments in the region see as necessary in order to diversify electricity supply sources and avoid shortages in the future.

In the industrialized world, Canada is among the only countries with plans to expand large-scale hydroelectric resources, such as the 2,000-megawatt Lower Churchill Project at Gull Island in Newfoundland Province. Many developed countries have already substantially exploited their hydroelectric resources, and increments to their renewable energy consumption are expected to come from wind, solar, and other nonhydroelectric renewable energy sources.

Figure 67. Worldwide Consumption of Renewables, Natural Gas and Oil, 1999, 2010, and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, *World Energy Projection System* (2002).

Worldwide, some 3,800 megawatts of new wind energy capacity were installed during 2000, and the American Wind Energy Association estimated that another 5,000 megawatts would be added in 2001 [3]. Wind remains the fastest-growing source of renewable energy in the industrialized world. Germany added 1,650 megawatts of wind capacity in 2000, making it the country with the largest annual increment in wind capacity worldwide, as it has been for the past several years. Germany's increase was followed by Spain's 795 megawatts of installed new wind capacity and Denmark's 588 megawatts [4]. The European Union (EU) finalized the agreement for a Renewable Directive in September 2001 [5]. The directive sets goals of doubling the renewable energy share of total energy consumption in the inland EU to 12 percent by 2010, and increasing the renewable energy share of electricity generation from 14 percent in 2001 to 22 percent by 2010.

New wind capacity additions in the United States decreased sharply in 2000, after a record increment of 565 megawatts in 1999, when the wind energy

production tax credit expired. The credit has since been extended to December 31, 2003, and a similar surge in U.S. wind power additions was expected in 2001. The Energy Information Administration's *Annual Energy Outlook 2002* (AEO2002) estimates that 1,872 megawatts of wind capacity was added in the United States in 2001.

The *IEO2002* projections for hydroelectricity and other renewable energy sources include only on-grid renewables. Although noncommercial fuels from plant and animal sources are an important source of energy, particularly in the developing world, comprehensive data on the use of noncommercial fuels are not available and, as a result, cannot be included in the projections. Moreover, dispersed renewables (renewable energy consumed on the site of its production, such as solar panels used to heat water) are not included in the projections, because there are also few comprehensive sources of international data on their use.

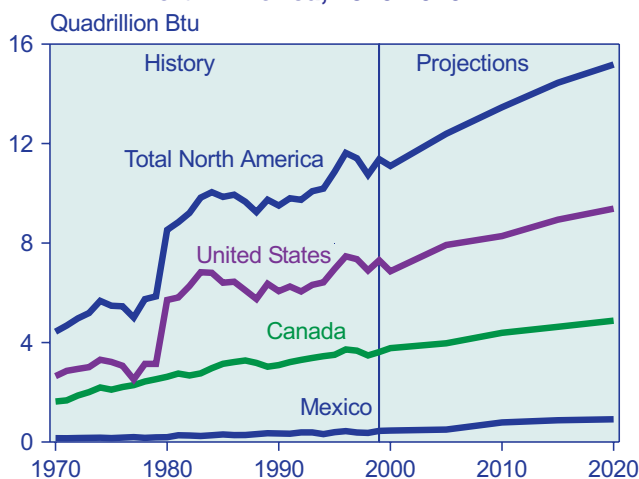
Regional Activity

North America

Hydroelectricity remains the predominant form of renewable energy use in North America, particularly in Canada. In 1999, hydroelectric power provided nearly 60 percent of the Canada's 551 billion kilowatthours of electricity generation [6], compared with 8 percent in the United States and 14 percent in Mexico.

In the *IEO2002* reference case forecast, renewable energy use in North America as a whole is projected to increase by 1.4 percent per year between 1999 and 2020 (Figure 68). Although Canada has announced some plans to expand its hydroelectric capacity over the next decade,

Figure 68. Renewable Energy Consumption in North America, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

hydropower consumption is expected to remain flat or decline slightly over the projection period for the region. Increases are expected for geothermal, wind, solar, biomass, and municipal solid waste (MSW) energy use.

United States

Potential sites for hydroelectric dams have already been largely established in the United States, and environmental concerns are expected to prevent the development of any new sites in the future. EIA's *AEO2002* projects that U.S. conventional hydroelectric generation will decline from 316 billion kilowatthours in 1999 to 304 billion kilowatthours in 2020 as increasing environmental and other competing needs reduce the productivity of generation from existing hydroelectric capacity [7].

Nonhydroelectric renewables are expected to account for 3.9 percent of all projected additions to U.S. generating capacity between 2000 and 2020. Generation from geothermal, biomass, landfill gas, solar, and wind energy is projected to increase from 77 billion kilowatthours in 1999 to 160 billion kilowatthours in 2020. Biomass (which includes cogeneration and co-firing in coal-fired power plants) is expected to grow from 38 billion kilowatthours in 2000 to 64 billion kilowatthours in 2020. Most of the increase is attributed to cogenerators, with a smaller amount from co-firing. Few new dedicated biomass plants are expected to be constructed over the forecast period.

The reference case projects substantial increments in U.S. geothermal and wind power. High-output geothermal capacity could increase by 87 percent over the next two decades, to 5,300 megawatts, and could provide almost 35 billion kilowatthours of electricity generation by 2020. This will depend, however, on the success of several new, untested sites. Wind capacity in the United States is projected to grow by nearly 300 percent over the forecast period, from 2,400 megawatts in 2000 to 4,300 megawatts in 2001 and 9,100 megawatts by 2020. Wind capacity was installed or under construction in 28 States by the end of 2001 (Figure 69), and State mandates for increasing the development of renewable energy sources are expected to provide the impetus for the large increment in wind power over the forecast. State mandates are expected to have the greatest impacts on renewable capacity additions in Texas (2,279 megawatts), California (1,930 megawatts), Nevada (1,148 megawatts), and New Jersey (904 megawatts), and smaller increases are expected in Massachusetts, Minnesota, Iowa, Wisconsin, and Arizona.

Canada

At present, 60 percent of Canada's total installed electricity generation capacity consists of hydroelectric dams [8]. Canada is exploring ways to increase its hydroelectric capacity still further with several proposals that are currently under consideration. In the

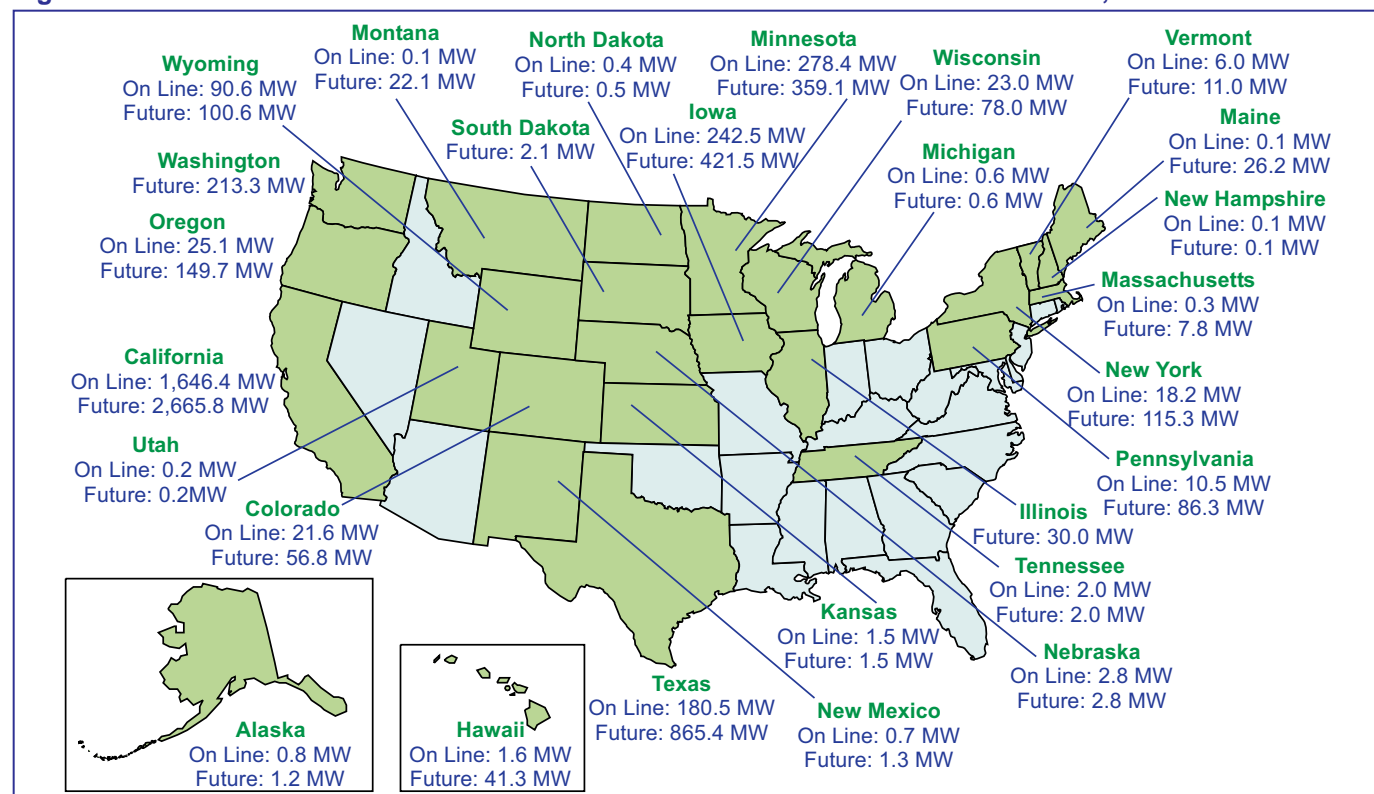
Northwest Territories there are proposals to develop hydroelectric projects that would total between 12,000 and 15,000 megawatts [9]. The projects would cost an estimated \$17.5 billion and would be constructed in a sparsely populated part of the country on six separate rivers: the Mackenzie, Bear, Lockhart, Talston, Snare, and Lac la Marte. The government has identified 10,000 megawatts of potential development that could be exploited by developing sites on the Mackenzie River. The largest site on the Mackenzie, Ramparts, has a potential for 4,500 megawatts. Estimates are that the projects would take between 5 and 20 years to complete.

The successful development of these projects, as well as many others in Canada will depend on agreements with the local populations that will be displaced or otherwise affected by the projects. In the past, local concerns were not always taken into consideration, and Canadian aboriginal groups began to fight further developments through legal means, often successfully suing developers for reparations or to scale down proposed projects. The current trend is for governments and companies to work with the aboriginal tribes to reach consensus before construction begins, including offers of joint ownership and extensive environmental impact studies. The government of the Northwest Territories is meeting with the indigenous groups that would be affected by hydroelectric development and must reach an agreement with them before any construction begins.

One successful outcome of the new government strategy to gain approval for development from the indigenous people who will be affected by the construction of new hydroelectric infrastructure is the 1,200-megawatt Eastmain Rupert project [10]. In 2000, the provincial utility Hydro-Quebec paid the Grand Council of the Crees some \$300,000 to conduct a 3-month study of the economic, commercial, and environmental aspects of the utility's proposal to construct the hydroelectric project. The project will cost an estimated \$2.5 billion to construct and will involve the diversion of the Rupert River in the James Bay region of Quebec. Although an agreement has been reached between Quebec and the Crees, feasibility studies and environmental authorizations remain to be completed and are expected to take nearly 4 years. If all approvals are obtained, construction could be completed in 2011.

There are still other plans to construct large-scale hydroelectric projects in Canada. The governments of Newfoundland and Quebec provinces have proposed construction of a 2,000 megawatt Lower Churchill Project at Newfoundland's Gull Island. The project has been scaled back from 2,800 megawatts, because Newfoundland determined that it would be too expensive to construct a phase of the project that involved building an 800-megawatt powerhouse at Muskrat Falls. The government of Newfoundland is working with U.S. company Alcoa on a study of the Lower Churchill River on

Figure 69. Grid-Connected Wind Power Plants in the United States as of December 31, 2000



Source: National Renewable Energy Laboratory, *IEA Wind Energy Annual Report 2000* (Golden, CO, May 2001), p. 186.

Labrador that will determine the feasibility of constructing hydroelectric facilities at Gull Island and Muskrat Falls to support proposed aluminum smelters in Newfoundland and Labrador [11].

Quebec's government has also approved a plan by Hydro-Quebec for construction of a dam and 526-megawatt powerhouse on the Toulmoustou River, on the north shore of the St. Lawrence River about 60 miles north of Baie-Comeau [12]. The project's powerhouse is part of a larger project supported by the Betsiamites Innu-Montagnais aborigines that would include several river diversions. Authorization has not yet been obtained for some parts of the larger project. Construction of the 526-megawatt powerhouse that has been approved will take an estimated \$400 million and will involve enlarging Lake Sainte-Anne reservoir, building a dam and a powerhouse, and connecting the powerhouse to the Micoua substation. Construction will not begin until the project has been approved by the Canadian federal government.

Hydro-Quebec has a number of plans for additional mid-size hydro power projects over the next decade. Quebec's government has authorized Hydro-Quebec to begin a draft design study for a dam and 220-megawatt powerhouse on the Romaine River near Havre-Saint-Pierre. If approved, construction of the \$335 million La Romaine Project could begin in 2004. The station could be commissioned in 2007, generating 1,000 gigawatt-hours annually. Another technical and environmental study has been launched for the development of a 450-megawatt hydroelectric plant on the Peribonka River nearly 200 miles north of Quebec City [13]. The project would generate an average 2,200 gigawatt-hours of electricity annually. If all goes according to plan, the studies will be completed by mid-2003, with construction beginning in 2004 and commissioning set for 2009.

Along with mid- to large-scale hydro projects, Canada is showing increasing interest in smaller scale hydroelectricity and alternative renewable energy sources, such as wind, that have not previously been exploited in the country. The Canadian Renewable Energy Corporation announced in September 2001 that it would evaluate nearly a dozen potential sites for small, run-of-river hydroelectric development in Ontario [14]. The company plans to install 38 megawatts of new renewable capacity within the next 3 years, beginning with the 3-megawatt Misema power project on the Misema River in eastern Ontario. Construction on Misema began in 2001 and is scheduled for completion in November 2002 [15].

Another example of the development of smaller scale hydroelectric facilities is the construction of the Granite Canal hydroelectric project on Newfoundland Island. Construction on the 40-megawatt site began in May

2001. The project is being built by Newfoundland & Labrador Hydro company and should be operating by 2003 [16].

At the end of 2000, there was an estimated 137 megawatts of total installed wind capacity in Canada [17]. At present, the provinces of Quebec and Alberta have the largest shares of Canada's wind capacity. There are, however, new government incentives to increase wind power projects throughout the country and as a result several projects are expected to become operational over the next year. In December 2001, Canada implemented a wind power production incentive. Wind projects installed between April 1, 2002, and March 31, 2007, will be eligible for a government incentive payment of about 0.8 cents per kilowatt-hour of generation [18]. The payment will gradually decline to 0.5 cents per kilowatt-hour.

In Saskatchewan's Gull Lake, the first phase of the \$12.8 million SunBridge Wind Power Project has begun generating electricity [19]. Three of the 17 wind turbines began generating in August 2001, and the remaining turbines should be operational by June 2002, when total installed capacity should reach 11.2 megawatts. The Canadian government has agreed to purchase electricity from emerging renewable sources in Saskatchewan and Prince Edward Island, and for the Gull Lake wind project this will mean an investment of around \$7.9 million over a 10-year period [20]. Power from the project will be fed into the provincial power grid and used to supply electricity to federal government buildings in Saskatchewan, among other customers.

In June 2001, the Canadian government, the Prince Edward Island provincial government, and Maritime Electric Company, Ltd. announced that an agreement had been signed for the development of a wind farm at North Cape to be constructed by the Prince Edward Island Energy Corporation [21]. The project, which is expected to cost \$5.9 million, will generate an estimated 16.6 million kilowatt-hours of electricity annually.

In August 2001, Ontario Power Generation commissioned North America's largest wind turbine at the Pickering Nuclear Generating Station [22]. The 1.8-megawatt turbine is supposed to generate enough energy to supply 600 average Canadian homes. The company is also planning a 10-megawatt wind farm near Lake Huron, which is scheduled for completion by summer 2002. Ontario Power Generation has committed to increasing its total renewable generating capacity to 500 megawatts by 2005, from a present 138 megawatts.

Mexico

In Mexico there are limited plans to expand the renewable energy resource base at the present time. Mexico has made some moves toward increasing the

development of geothermal resources, including studies by the state-owned Comisión Federal de Electricidad (CFE) [23] and a government pledge to invest some \$31 million in geothermal energy. There has been little activity in wind power development in Mexico, although by some estimates Mexico has wind resources that could support the installation of up to 5,000 megawatts of wind power capacity [24]. The country has about 3 megawatts of installed wind capacity but has not added any new capacity since 1998. Construction of a 54-megawatt wind power project proposed by CFE in 1996 has continued to be postponed. In addition, five other wind projects proposed by private companies are still being negotiated. Construction permits have been issued to four of the five projects, but no construction work has been started.

Western Europe

Expansion of renewable energy sources in Western Europe is expected to be mostly in the form of nonhydroelectric renewables. Most potential hydroelectric resources have already been developed in the region, and there are few plans to extend hydropower capacity over the next two decades. Among the other forms of renewable energy, wind has made the greatest gains over recent years and will probably contribute to much of the future growth in renewable energy use.

The EU has moved to increase the penetration of renewables in the European energy mix. In 2001, the European Parliament approved a Renewables Directive that would require the EU to double the renewable share of total energy consumption by 2010 [25]. According to the new law, the share of total inland energy consumption met by renewable energy resources will have to increase to 12 percent in 2010, from an estimated current level of about 6 percent. Furthermore, the share of electricity demand met by renewables will have to increase to 22 percent, from about 14 percent now.

Individual European countries have been implementing various strategies to increase their use of renewables. The United Kingdom has introduced a “renewables obligation,” which will require electricity suppliers to derive 3 percent of their electricity from renewable resources beginning in 2002, rising to 10 percent in 2011. Germany’s Gesetz für den Vorrang Erneuerbarer Energien law was enacted on April 1, 2000; it requires that electricity grid operators give “priority access to all renewable energy” and sets fixed rates for each renewable (the cost is passed to the consumer) [26]. France has also set rates for renewable energy in the wholesale market to ensure that a planned installation of 10,000 megawatts of wind power occurs by 2010 [27].

In contrast to the German and French strategies of ratesetting, the government of the Netherlands uses

“green certificates” to create a market for renewables. Generators are given green certificates for their renewable power production that provide tax credits and can be traded. The resulting tax savings or the earnings made from the sale of the certificates are supposed to allow renewable generators to sell more of their power in the market. In the past, Denmark has required utilities to allow private renewable energy producers access to the grid and has required utilities to pay the producers a percentage of their production and distribution costs. Now the Danish government is also introducing renewable energy certificates, similar to the Dutch scheme.

Of all the renewable energy sources, wind is the most promising in Europe. Germany, Spain, and Denmark have been among the world’s top wind capacity installers in recent years, and in 2000 Italy and the United Kingdom also saw sharp increases in wind power capacity installations.

In 2000, Germany expanded its total installed capacity by 1,668 megawatts, bringing its combined operating wind capacity to 6,113 megawatts. In August 2001, Europe’s largest onshore wind farm, the 105-megawatt Sintfeld wind farm, began production near Paderborn, Germany [28]. The project is expected to provide enough electricity for 70,000 homes.

Denmark added 588 megawatts of wind capacity in 2000, twice as much new capacity as it has installed in recent years [29]. The country has one of the most mature wind power markets in the world and currently meets an estimated 12 percent of its total electricity demand with wind energy. Under the government’s Energy 21 strategy, the national target is to have 1,500 megawatts of wind power installed by 2005 and 5,500 megawatts by 2030. The 2005 target has already been exceeded; however, most of the potential on-land sites available for wind facilities have already been exploited, and 4,000 of the 5,500 megawatts that must be in place by 2030 are supposed to be offshore (see box on page 110). Thus far, Denmark has only 50 megawatts of offshore installed wind capacity.

Like Germany and Denmark, Spain has seen substantial growth in wind power capacity over the past several years. In 2000, it added 795 megawatts of wind capacity, bringing the country’s total installed wind generation capacity to 2,334 megawatts, nearly the level of the mature wind market in Denmark. The government encourages the development of renewable generation by offering producers a choice of incentives. Either the producer can opt to be paid a fixed price for the electricity it produces (the price varies by renewable energy source), or it can accept a variable price based on the average price of the market pool, plus a bonus based on the amount produced.

Development of Offshore Wind Power in Denmark

Over the past decade, wind power has moved from being a novel, unconventional technology to achieving significant, and in some cases substantial, market penetration. In many industrialized countries, governments and environmental planners view wind energy as a low-cost pathway to achieving substantial reductions in greenhouse gas emissions and addressing other environmental problems associated with conventional generation technologies. To achieve these goals, many countries have started to look beyond conventional land-based wind turbine technology, with its economic and physical limitations, and have set their sights on the windy expanses of coastal oceans and seas surrounding northwestern Europe.

The Danish government has set substantial targets for growth in wind-powered electricity generation and expects it to account for 50 percent of domestic generation by 2030. In the country's Energy 21 plan, a target for installed wind capacity of 5,500 megawatts has been set, of which 4,000 megawatts is to be offshore.^a This means that, with wind energy currently at about 12 percent of electricity demand, much of the remaining land-based wind resource in Denmark is believed to be unsuited for development. Limitations include:

- Poor remaining resources: Denmark has never been rich in high-quality wind resources, and most of the suitable land resource is already utilized.^b
- Competing land uses: Denmark is a densely populated country, with correspondingly high land costs.
- Landscape impacts: Although the Danish people seem largely to have shared in their government's commitment to wind power, there is some evidence of growing resistance to further visual intrusion by the increasingly tall wind turbines in rural areas.^c

Denmark already has several pilot-scale offshore wind facilities and in 2000 commissioned what is, for now, the largest commercial offshore operation, a 20-turbine, 40-megawatt facility on the Middelgrunden shoal off of Copenhagen. Other recent European installations include a 10-megawatt facility near Blyth, England, and another 10-megawatt facility on the Utgrunden shoal in Swedish waters.

There are substantial additional costs associated with the offshore development of wind resources, and it might be asked, "Why build offshore at all?" For much of northwestern Europe, the answer is simple: that's where the wind is. Denmark has been an early adopter of wind energy, and its industry remains the global leader in the field. Not surprisingly, much of the early offshore development has occurred in Danish waters as suitable unused land sites in the country have become increasingly scarce. Although Germany has significant inland resources, many other countries, such as the United Kingdom, the Netherlands, and Belgium, find themselves with few easily developed land sites but ample coastlines.

Although concepts for offshore wind power have existed longer than there has been a commercial wind industry, realization of those visions had to wait for both the technology and the economic necessity to catch up. Enabling technologies have come, naturally, from the wind industry itself and have also benefited from the engineering expertise of the offshore oil industry. Even with technological advances, however, offshore wind power remains substantially more expensive than land-based wind power in good resource areas. As economically viable wind power opportunities on land are exhausted, offshore wind becomes an increasingly attractive proposition.

A key enabling technology for offshore wind is the turbine foundation.^d Foundation design and engineering concepts are based on offshore oil rig foundations. Unlike land-based foundations, offshore wind turbines face additional loading from wave action, sea-bed scouring, and (in northern climates) pack ice. Oil rig designs, made for largely static above-water loads, must be modified to face the additional dynamic loading imposed by the turbine itself. Additionally, while oil rig technology has progressed to ever-deeper waters, wind turbines will likely be limited, at least in the near term, to waters near shore with smaller critical wave heights, shorter distances to lay power transmission cables, and closer maintenance facilities.^e Of course, placement of turbines too close to shore will start to limit the offshore benefits, including

(continued on page 111)

^aInternational Energy Agency and National Renewable Energy Laboratory, *IEA Wind Energy Annual 2000* (Golden, CO, May 2001), p. 69.

^bThe *IEA Wind Energy Annual 2000*, p. 69, indicates that in 2000 approximately 2,300 megawatts of onshore capacity was installed, with a "realistic" maximum capacity of about 2,600 megawatts.

^cJ. Samuelsberg, "Analysis—Offshore Wind Power Swirls Through Europe," web site www.climateark.org/articles/2000/2nd/offswind.htm (April 13, 2000). See also web site <http://rotor.fb12.tu-berlin.de/windfarm/offshore.vindeby.html>.

^dSee various topics in *OWEN Workshop on Structure and Foundation Design of Offshore Wind Installations* (Offshore Wind Energy Network, March 2000), web site www.owen.eru.rl.ac.uk/workshop_3/ws3_final.pdf.

^eB. Standing, "Wave and Current Characterization Modeling," *OWEN Workshop on Structure and Foundation Design of Offshore Wind Installations* (Offshore Wind Energy Network, March 2000), web site www.owen.eru.rl.ac.uk/workshop_3/ws3_final.pdf.

Development of Offshore Wind Power in Denmark (Continued)

low-turbulence winds found over the relatively smooth ocean surfaces and less visibility from populated areas.

Because a major additional expense of offshore turbines compared to land-based turbines is in the foundation construction, the key development in turbine technology has been larger turbines. With larger turbines (2- to 5-megawatt turbines are currently under development for the offshore market, compared with 1 to 2 megawatts for onshore installations), fewer foundations have to be constructed to achieve comparable output, which reduces overall construction costs. Although the offshore foundations will be exposed to much rougher conditions from ocean waves than are land-based foundations, which are essentially static, the turbines themselves should encounter less turbulent winds (because the surface of the sea is not as rough as the trees, hills, and mountains on land) and may benefit from higher blade-tip speeds (because there is less concern over noise pollution from offshore turbines than there is for land-based turbines).

Some believe that reduced wind turbulence will increase the life of offshore turbines relative to land-based turbines; however, additional operations and maintenance expenses will also be incurred, resulting from the additional costs of transporting personnel to the facility and protecting against corrosion in the salt-water environments.^f The industry, still not mature, is effectively still building “first-of-a-kind” commercial units; but early indications show a 50- to 100-percent capital cost penalty compared to land-based units (\$1,500 to \$2,000 per kilowatt of capacity for offshore, around \$1,000 for land-based),^g as well as a significant maintenance penalty (also in the range of 50 to 100 percent, although the numbers are less reliable).

Over the past 15 years, the Danish government has encouraged the growth of a vibrant domestic wind

power industry through “grassroots” development. Individual farmers, or small farmer cooperatives, have been given incentives to develop small wind clusters on their lands, and the utilities in turn have been required to accommodate this new power source on the distribution grid. In the early years of the developing Danish wind industry, regulations required local ownership and consumption of wind power.^h Tax breaks and direct subsidies have also played an important role in spurring new installations.ⁱ Finally, Danish utilities are required not only to connect wind turbines to the distribution grid but also to upgrade distribution facilities where required to accommodate the resources.^j

To achieve their ambitious 2030 wind generation target, the Danes have, in some cases, turned to the American model of large “wind farms” of hundreds of megawatts of capacity built, owned, and operated by a utility or corporate third party.^k The Danes have recognized that development on the scale envisioned will inevitably require them to look to the ocean as an alternative to increasingly low-quality, high-cost, and unattractive resources onshore. Such development will not likely result from the grassroots efforts of independent farmers, but will require the capital and technological resources of established wind turbine manufacturers, developers, and utilities.

In much of the rest of Western Europe, offshore wind is also seen as an attractive generation technology, for much the same reasons: a political commitment to greenhouse gas reduction, limited land-based wind resources, high population density, and negative public reaction to the tall wind towers. In addition, Western Europe has a relatively shallow continental shelf, allowing placement of wind turbines farther offshore without encountering water that is too deep. As a result, the mid-term outlook for offshore wind seems largely focused on ocean shallows surrounding Western Europe.

^fG. Siefert, “5 Years of Ascension Island Wind Farm Operations,” *WindPower 2001 Conference Proceedings* (June 2001).

^gSee, for example, web sites <http://rotor.fb12.tu-berlin.de/windfarm/offshore.vindeby.html> and www.windpower.dk/tour/econ/offshore.htm.

^hF. Tranaes, “Danish Wind Energy Cooperatives” (Danish Wind Industry Association, 1997), web site www.windpower.dk/articles/coop2.htm.

ⁱInternational Energy Agency and National Renewable Energy Laboratory, *IEA Wind Energy Annual 2000* (Golden, CO, May 2001), p. 70.

^jF. Tranaes, “Danish Wind Energy Cooperatives” (Danish Wind Industry Association, 1997), web site www.windpower.dk/articles/coop2.htm.

^kInternational Energy Agency and National Renewable Energy Laboratory, *IEA Wind Energy Annual 2000* (Golden, CO, May 2001), p. 72.

Even some European countries that have been slow in developing wind programs heretofore are beginning to make plans for expanding this renewable energy source. Offshore wind is allowing European countries that do not have the land area to devote to wind turbines a chance to begin exploiting wind energy. TotalFinaElf plans to build a large wind farm off the coast of Belgium [30]. The company is currently seeking a license from the Belgian Electricity and Gas Regulatory Commission to construct and operate the wind farm. The project would consist of 40 wind turbines installed at a distance of 5 to 10 miles from shore. Upon completion, the facility would have a combined capacity of 100 megawatts, which TotalFinaElf estimates would provide enough power to supply some 150,000 households.

The United Kingdom experienced a jump in wind installations in 2000, after many years of lackluster activity. Ten projects with a combined capacity of 63 megawatts were completed in 2000. The greatest obstacle to new growth in the country's wind capacity remains the difficulty developers have in obtaining planning approvals. In 2001, ScottishPower announced plans to construct what will be the United Kingdom's largest wind farm at Eaglesham Moor south of Glasgow [31]. The \$213.8 million project will consist of 140 turbines and will have a combined capacity of 240 megawatts. The project could be completed by 2003; however, ScottishPower has yet to obtain the necessary regulatory approval.

There are also some plans to expand solar power in Western Europe. In anticipation of future growth in solar energy, BP Solar committed to constructing Europe's largest solar equipment manufacturing plant in Spain in 2001 [32]. The plant will be able to produce 60 megawatts per year of high-efficiency solar cells (with an aim to expand that amount to 100 megawatts). BP plans to invest \$101.7 million to expand existing facilities in the plant to be located north of Madrid. The project should be complete by 2002 [33].

Industrialized Asia

The countries of industrialized Asia (Australia, Japan, and New Zealand) have markedly different electricity energy mixes. Japan is the only one of the three countries with a nuclear generation program, supplying one-third of its electricity from nuclear power plants. Hydroelectricity and other renewable energy sources supply about 12 percent of Japan's electricity. Renewables also account for about 10 percent of Australia's electricity supply, and thermal generation (predominantly coal) accounts for nearly 90 percent. In contrast, renewable energy sources provide 73 percent of New Zealand's electricity supply.

Between 1999 and 2020, the use of hydroelectricity and other renewables is projected to increase by 1.4 percent per year in the region of Australasia (which includes

Australia and New Zealand, along with the U.S. Territories). Much of this modest increase is expected to be in the form of nonhydroelectric renewables, most notably wind.

Australia

On December 21, 2000, the Australian government passed the Renewable Energy (Electricity) Act 2000 in an effort to encourage renewable energy development [34]. The legislation, enacted on April 1, 2001, sets mandatory targets for renewable energy. It requires wholesale purchasers of electricity to contribute to the generation of an additional 9,500 gigawatthours of renewable energy each year by 2010. Interim targets are to be enforced, and penalties are to be assessed against electricity purchasers who do not attain their individual targets.

The Renewable Energy (Electricity) Act 2000 already appears to be having an impact on renewable energy markets in Australia. The country added 20 megawatts of its total installed wind capacity of 33 megawatts in 2000 alone. Several wind farms are either in the planning stage or currently under construction. The government has estimated that another 300 megawatts of wind capacity is expected to be operational by the end of 2002 [35]. In July 2001, the first wind power project in Victoria (and the largest to date in Australia) came online near Warmambool [36]. The 18.3-megawatt Codrington project cost an estimated \$15 million to construct. Pacific Hydro, which built and operates the project, is completing environmental impact statements for another four wind farms to be located in the Portland region. The company plans to complete construction of the combined 150 megawatts of new wind capacity before the end of 2002.

The 21-megawatt Toora wind farm is currently under construction in Victoria's South Gippsland region. Upon completion, its electricity generation is to be sold to CitiPower, an electricity retailer. Queensland's state-owned Stanwell Corporation plans to install 450 megawatts of wind capacity before 2006 [37]. Stanwell is looking to expand at a number of sites in South Australia, Western Australia, New South Wales, and Queensland.

Japan

Japan's wind energy development also increased sharply in 2000, when 50 megawatts of wind capacity was installed, bringing total installed capacity to 121 megawatts [38]. Tomen Corporation, a wind energy developer, is investing some \$64 million in a 32-megawatt wind plant. Two sites are also planned for the northern part of the country, with installed capacities of 25 megawatts and 15 megawatts.

Some effort has also been made to expand Japan's micro-hydroelectric capacity. In September 2001, Japan's Ministry of Economy, Trade, and Industry

(METI) approved plans to build three new small hydroelectric projects, with a combined generation of capacity of 14.2 megawatts [39]. The projects are Chugoku Electric Power Company's 11-megawatt plant in western Japan, Kyushu Electric Power Company's 0.5-megawatt plant on the western island of Kyushu, and the Electric Power Development Company's 2.7-megawatt project in northern Japan. All three plants are scheduled to come online before 2004.

In 2001, the Electric Power Development Company canceled plans to build a large-scale pumped storage hydroelectric station in northern Japan because of the lack of growth in electric power demand. The electricity wholesaler had planned to construct four 450-megawatt generators, with a total capacity of 1,800 megawatts, at Ynotani, Niigata Prefecture, for a total cost of around \$3 billion. The projects were supposed to come online in 2011 and 2012, but Tokyo Electric Power Company and Tohoku Electric Power Company requested the delay because electricity demand for 2011 is now expected to lag far behind the forecast made 4 years ago.

Developing Asia

Support for the construction of large-scale hydroelectric dams remains strong in many countries of developing Asia, and large-scale hydropower projects in China, India, Malaysia, and Vietnam, among others in the region, are expected to provide most of the 4.3-percent annual growth in renewable energy consumption worldwide in the *IEO2002* reference case forecast (Figure 70). There are more modest efforts to increase nonhydroelectric renewable energy use, primarily wind and solar, in China, India, and other developing Asian

countries, as well as generation from biomass in Bangladesh (see box on page 114). The projects are often aimed at reaching small, rural communities that would otherwise not have access to electricity through the national grid.

China

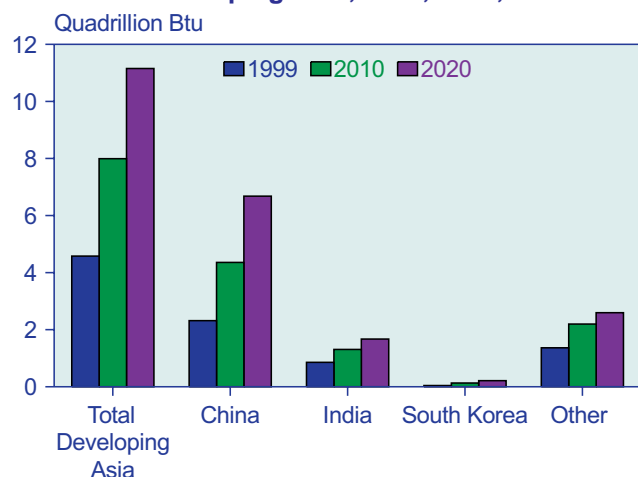
In China, work progresses more or less on schedule on the 18,200-megawatt Three Gorges Dam project, the largest hydroelectric project in the world. The dam is being built on China's Yangtze River. It is scheduled to begin producing electricity in 2003 and to be fully operational by 2009. The Three Gorges Dam project has encountered problems with accusations of corruption, and there have been difficulties in relocating the estimated 1.13 million residents who will have to move before the dam's reservoir can be flooded. Since 1993, more than 350,000 residents have been relocated [40].

The Chinese government has also announced that work will begin on another large-scale dam on the Hongshui River in Guangxi Province [41]. The Longtan hydroelectric project has a proposed capacity of 5,400 megawatts and is scheduled to begin generating electricity in 2007, with completion by 2009. The project will cost an estimated \$3.2 billion. Upon completion, Longtan will be the second largest hydroelectric project in Asia, exceeded in size only by Three Gorges Dam.

Beyond the expansion of large-scale hydropower, several other projects are underway to develop China's other renewable resources, notably, wind and solar. The Global Environment Facility (GEF) and the World Bank have begun a 10-year project to increase China's non-conventional renewable energy use by 14,300 megawatts by 2010 [42]. The goal of the China Renewable Energy Scale-Up Program (CRESP) is to begin to reduce China's dependence on coal-fired electricity, as well as to bring electrification to the remote, rural parts of China that do not have access to the national grid. The project is expected to cost billions of dollars. Thus far, the World Bank has committed \$100 million in a series of loans that give the country flexibility on meeting deadlines and targets. Another \$80 million in the first phase is to come from other donors and the Chinese government, along with \$190 million throughout the program's duration. The public investments are expected to encourage up to \$212 million in private investments in the first phase and as much as \$10 billion in indirect investments over the 10-year period.

One example of the donors that are being attracted to China because of the CRESP is the Asia Development Bank donation of \$58 million in 2000 for wind power development, in support of the World Bank project [43]. The loan is being used to construct three 26-megawatt wind farms in China. Shell Renewables has also

Figure 70. Renewable Energy Consumption in Developing Asia, 1999, 2010, and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, *World Energy Projection System* (2002).

Biomass Resource Utilization in Bangladesh

On many levels, Bangladesh is a country that is ideally suited for the development of small-scale biomass energy systems. Because the economy is largely dependent on agriculture, the residues needed for such projects are available. Approximately 75 percent of the 130 million people in the country live in rural areas, and for all practical purposes they are not able to benefit from the national electricity transmission grid. The country is relatively poor, with a per capita annual income of \$266 (1997 U.S. dollars), as compared with \$493 per person in neighboring India. As a result, it is difficult to attract the investment needed to expand the national energy infrastructure.

The lack of infrastructure in Bangladesh's rural areas has resulted in an increase in the migration of rural populations to the country's urban areas, putting enormous pressure on urban infrastructures that are ill-equipped to deal with the influx. As a result, the Bangladeshi government is interested in finding economical ways to bring electricity to the rural areas, both to improve economic development and to stem the migratory trend. Small-scale renewable energy systems fueled by biomass may offer Bangladesh a way to accomplish these goals.

The technologies that have been most popular in terms of development are biogas digesters running on animal or human wastes; turning agricultural wastes into solid fuel briquettes (similar to charcoal); and direct combustion of agricultural waste for household cooking. The main need for energy in rural Bangladesh is for cooking, although biomass is also used as housing material and animal feed. A limited amount of biomass is used as feedstock for recycled paper and in pulp mills. Sources of biomass include rice husks, jute stalks, sugarcane stalks, and peanut shells.

The patterns of biomass usage in developing countries such as Bangladesh could not be more different from those in industrialized countries such as the United States. In industrialized countries there is an abundance of waste biomass material that has only been used once and is contained in landfills, forests, or agricultural lands. A waste stream that may be attractive in the United States, such as municipal solid waste, is fraught with problems in developing countries. In the United States, wastes are carefully entombed in landfills and generally left undisturbed. In developing countries, entire communities of rag pickers, perhaps

for several generations, live on and alongside the dumps and earn their living by scavenging materials and selling them to small industries that turn them into a myriad of products ranging from combs to shoes to paper. Consequently, attempts to divert streams of municipal solid waste in developing countries can affect entire classes of people and the small industries that depend on them. Although large quantities of "waste" are generated in a country like Bangladesh due to the agricultural nature of the economy, relatively little of that biomass may be available for use in energy generation. As long as competing uses of biomass material fetch a higher price, or are easier to accomplish, the material will find use in non-energy applications. Two examples illustrate the opportunities and pitfalls for biomass commercialization in a developing country like Bangladesh.

A thriving business in Bangladesh is biomass briquetting or "densification." Briquetting processes require heat and pressure to produce fuel pellets from rice husks and wood chips. There are approximately 900 briquetting machines in operation in Bangladesh, the overwhelming majority of which are locally manufactured. Their capital cost is about \$1,080 to \$1,180, equipment costs are \$500 to \$670, land costs are about \$360, and installation costs are about \$150.^a Production costs range from \$0.78 to \$0.93 per pound, and the briquettes can be sold for about \$1.04 per pound. The machines produce briquettes at the rate of about 180 pounds per hour and have payback periods of 7.5 months to 18 months.

Briquettes have become popular as a fuel for heating urban hotels and tea shops. In addition, briquettes are in demand as a fuel for melting bitumen, which is used in road paving operations. Brick manufacturing industries can also use the briquettes as a fuel in their ovens. Overall, the prospects for growth of this industry in Bangladesh appear to be bright.

Another example of biomass use in Bangladesh is biodigesters. Unlike briquetting, biodigesters have a mixed record of success. In Faridpur District, a school with about 350 students and 50 staff members uses a biodigester to generate a methane-based cooking fuel.^b Sludge from the digester is used for fertilizer. The replacement cost for a plant of this type is estimated to range from \$515 to \$825. The Government of

(continued on page 115)

^aInstitute of Appropriate Technology, *Proceedings of Workshop on Reverse Engineering* (Bangladesh University of Engineering and Technology, Dhaka, Bangladesh, May 2001). Assuming an exchange rate of 70 Taka for 1 U.S. dollar.

^bA. Jimenez and T. Lawand, *Renewable Energy for Rural Schools* (Golden, CO: National Renewable Energy Laboratory, November 2000).

committed to supply solar power systems to 78,000 homes before 2006 [44]. Shell signed an agreement with Sun Oasis Company in Beijing to supply the systems (to be installed and maintained by Sun Oasis) in the western China Autonomous Region of Xinjiang.

India

The Indian government continues to pursue large-scale hydroelectric power, although the projects frequently face difficulties in obtaining financing, as well as protests from environmental and human rights activists. The Narmada Valley Development Project has been planned to include up to 30 large dams, in addition to numerous medium and small ones [45]. The 1,450-megawatt Sardar Sarovar hydroelectric project is only one of the large-scale dams to be constructed as part of the Narmada Valley plan.

In October 2000, India's Supreme Court dismissed a petition filed by the Narmada Bachao Andolan (NBA) movement to stop completion of Sardar Sarovar. Work on the project was halted in 1995 when the NBA filed the suit. NBA argued that the dam developers had not made adequate plans for relocating hundreds of thousands of people who would be displaced by the project. The court did rule that the dam may only be constructed to a height of 295 feet, although developers had planned for a height of 453 feet. For every 16-foot height addition beyond the 295 feet, the developers are required to obtain additional planning permission, including the approval of the environmental subgroup of the environment and forestry ministry. In August 2001, the developers gained permission to raise the height of Sardar Sarovar to 328 feet [46]. Upon completion, Sardar Sarovar will provide power to Madhya Pradesh and will offer irrigation and food production benefits to Gujarat, Rajasthan, and other arid areas along the north and south banks of the Narmada River, some 600 miles south of New Delhi. In August 2001, project managers announced that Rajasthan should begin receiving its share of water from Sardar Sarovar by June 2004.

India continues to encourage the development of renewable energy sources beyond hydroelectricity. In 2002, Indian Prime Minister Atal Bihari Vajpayee stated he

would like renewable energy to account for at least 10,000 megawatts of the 100,000 megawatts of new electricity capacity to be added between 2001 and 2012 [47]. The renewable resources that would be counted in this plan are small hydroelectricity, wind, solar, and biomass. The government expects that up to 2,000 megawatts of new wind capacity could be added to the current 1,340 megawatts before 2007, with biomass contributing 1,000 megawatts, small hydropower 800 megawatts, solar thermal 140 megawatts, waste-to-energy 100 megawatts, and grid-connected solar photovoltaic 15 megawatts. In recent years, bagasse (crushed sugar cane) cogeneration potential in cooperative and public-sector sugar mills has looked promising. Currently India has about 213 megawatts of installed bagasse cogeneration capacity, and another 263 megawatts is under construction at 29 plants.

Malaysia

Malaysia is another developing Asian country pursuing the development of large-scale hydropower. The country's Bakun hydroelectric project has been plagued by controversy and financial difficulties since it was first approved in 1994 [48]. The 2,400-megawatt project was scaled back in 1998, because the Asian economic crisis made the project too expensive to pursue, particularly given the sharp drop in electricity demand associated with the recession; however, the government recently announced that it would return to the original capacity of 2,400 megawatts. Bakun is expected to cost around \$2.4 billion, and it is scheduled for completion in 2005. Environmentalists argue against the dam, which will require that more than 172,000 acres of farm land—an area larger than Singapore—be flooded to serve as a reservoir for the 670-foot dam. The reservoir will submerge 15 villages of the indigenous Iban people in central Sarawak state, as well as destroying the habitat of some 100 endangered species [49].

On the other hand, the Malaysian government argues that electricity from the Bakun dam will be necessary to support expanded industrial activity in the region, as well as to diversify the Malaysian electricity fuel mix, which is dominated by natural gas. The government announced that three resource-based industries (oil

Biomass Resource Utilization in Bangladesh (Continued)

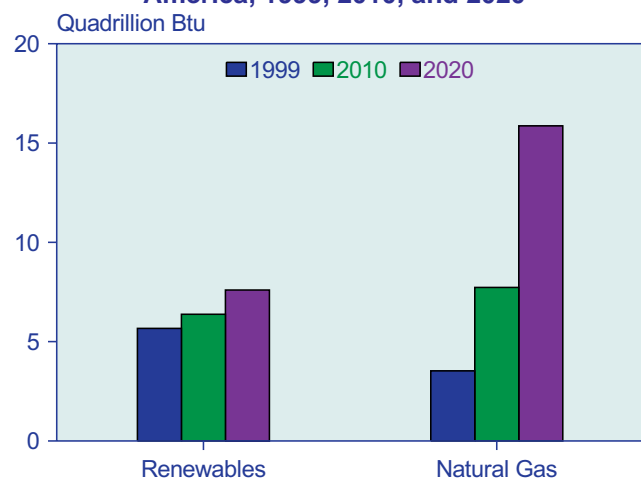
Bangladesh's Local Government Engineering Department provided the initial funding and paid for the entire system. The school pays for the operating and maintenance costs, which have been negligible. Although there have been successful installations of other biodigesters in the community, the school has not expanded its own biodigester program. The principal barriers to further commercialization of the technology are high capital costs and lack of financing options.

Despite the potential for problems associated with high capital costs, competing uses of biomass, availability of adequate quantity and quality of feedstocks, and lack of financing mechanisms, it is expected that biomass will continue to play a key role in supplying the energy needs of Bangladesh. The major question is how quickly more efficient biomass-using technologies can be introduced to allow the people of Bangladesh to obtain maximum benefit from the resource.

palm, cocoa, and wood) and four non-resource-based industries (electronics and engineering, manufacturing, petrochemicals, and steel) in Sabah and Sarawak will be the primary consumers of the electricity generated by Bakun [50]. The Sabah government has said it will open three industrial parks—Kudat Industrial Estate, the Integrated Timber Complex, and Palm Oil Industrial Cluster—that will consume an estimated 600 megawatts of electricity to be supplied by Bakun. Sarawak is expected to take about 500 megawatts of Bakun's electricity and neighboring country Brunei up to 500 megawatts; Kalimantan province in Indonesia is expected to take 100 megawatts. Upon completion, Bakun's capacity will be 1,700 megawatts, 700 megawatts below the full design capacity of 2,400 megawatts, because water levels are not expected to be sufficient initially to operate the generator at maximum capacity.

In addition to the large-scale hydroelectric expansion of Bakun, the Malaysian government has indicated an interest in developing the country's less controversial renewable resources. In 2001, the Malaysian government announced that it would like renewable energy to account for 5 percent of total power generation by 2005 [51]. The government hopes to support the development of renewables with its new Small Renewable Energy Power (SREP) program. Under the program, small power producers using renewable energy will be given a license for a 21-year period (from the date by which a plant is commissioned) to sell their power through the national power grid. The renewable energy sources permissible under the SREP program include biomass, biogas, municipal waste, solar, mini-hydro, and wind.

Figure 71. Renewable Energy and Natural Gas Consumption in Central and South America, 1999, 2010, and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, *World Energy Projection System* (2002).

While the plant size can be greater than 10 megawatts, the maximum capacity for power exports to the national distribution grid cannot exceed 10 megawatts.

Vietnam

Vietnam also proposes expanding its large-scale hydroelectric power over the next several years. In 2001, Vietnam's National Assembly approved construction of the 3,600-megawatt Son La hydropower project to be constructed on the Da River, about 200 miles west of Hanoi [52]. The project is the subject of some dispute, even among members of the National Assembly, because it has been sited for an area known to have frequent seismic disturbances, and it opposed by human rights activists because it would require the relocation of up to 700,000 people, mostly of ethnic minorities. Estimates for the cost of constructing Son La (which is scheduled for completion in 2016) have run as high as \$5.1 billion. Proponents of the project have argued that it is needed to help improve Vietnam's electricity fuel mix, reduce flood damage, and improve irrigation in the Red River Delta.

Pakistan

In Pakistan, several smaller hydroelectric and non-hydroelectric renewable projects were initiated in 2001. Work began on the Malakand III hydroelectric power project in September. Malakand is located at Dargai, Northwest Frontier Province, about 50 miles north of the Peshawar, which is considered the gateway to the Khyber Pass [53]. The project, which is being built by the Canadian Southern Electric Power Company, is scheduled for completion in 2005. In addition to the electricity to be generated by the dam, it should provide irrigation for some 20,000 acres of barren land.

Central and South America

Hydroelectricity is an important source of electricity generation in Central and South America. (In Brazil, the region's largest economy, hydropower typically supplies more than 90 percent of the country's electricity generation.) As a result, drought can have a devastating impact on electricity supply, and many countries of Central and South America are initiating projects to diversify the mix of electricity supply. Much of the diversification will consist of adding natural-gas-fired electricity capacity to reduce dependence on hydropower. As a result, although there is some projected growth in the use of hydroelectric and other renewable resources in the forecast, it is expected to be much less than the growth in natural gas consumption. In the *IEO2002* reference case forecast, demand for hydroelectricity and other renewables in Central and South America increases by only 0.8 percent per year between 1999 and 2020, whereas natural gas use in the region grows by 8.2 percent per year (Figure 71).

Rural electrification has also become an important issue for many Latin American countries. An estimated 75 million people in Latin America live without electricity [54]. In remote, rural locations where national electricity grids do not reach, renewable resources other than hydroelectricity are increasingly being used by government to bring electricity and telecommunications to the residents. Brazil, Chile, and Argentina, for instance, all have federal programs in place to improve access to electricity through off-grid renewable resources.

Brazil

In 2001, Brazil faced its worst drought in decades, which had a major impact on electricity supply (see also box on page 118). The country's reservoirs were, on average, 28 percent below normal capacity and in June the government was forced to initiate energy conservation and rationing measures in an effort to reduce electricity consumption by 20 percent [55]. The effort was largely successful in the first 2 months, with many regions meeting or exceeding their 20-percent demand reduction goal, but in August consumption was reduced by only 15 to 18 percent [56]. In an effort to improve the conservation effort, the government expanded an existing bonus scheme to benefit 75 percent of families living in energy rationing areas, as opposed to the previous 60 percent. Those who achieve a 20-percent savings and consume less than 225 kilowatthours per month will receive 1 real credit (about \$0.37) for every 1 real of energy saved. Previously, only those consuming up to 100 kilowatts were eligible for a bonus.

Although the country missed its targets in August, the Brazilian government announced that there was no risk of blackouts for the remainder of the year because water levels were about 3 percent higher than had been projected. In addition, according to the government, even in a worst case scenario—where rainfall was only 61 to 63 percent of normal levels—rationing would be extended into 2002, but at the lower rate of 5 percent of consumption.

In addition to the rationing and conservation strategies, Brazil is rushing to add additional capacity. By the end of 2002, Brazil plans to add 9,034 megawatts of natural-gas-fired electricity generation capacity, 6,381 megawatts of hydroelectric capacity, and 400 megawatts of mini-hydro capacity [57]. One of the hydroelectric projects included in the plans is the 112-megawatt Porto Estrela project on the Santo Antonio River, which began operating in October 2001 [58]. The project was constructed by a consortium led by Brazil's Cemig power company at a cost of \$50 million. It was built in record speed, with only a 26-month construction period.

In June 2001, Brazil's electricity regulator, Aneel, sold eight licenses to build and operate hydroelectric facilities in six southern Brazilian states. The licenses netted

the government about \$1.1 billion [59]. The six plants will add a total of 2,282 megawatts of power to the national energy grid. The largest project, which will be constructed by a consortium led by mining company Companhia Vale do Rio Doce (CVRD), is an 840-megawatt plant in the southern state of Rio Grande do Sul. Other plants will be located in the states of Santa Catarina, Parana, Rio Grande do Sul, Minas Gerais, Goias, and Tocantins. Brazil's southern region is not suffering from the drought that has hit other parts of the country, and the plants are expected to be completed between 2006 and 2008. Licenses were awarded in November for 11 additional hydroelectric power plants in Brazil, which are expected to add 2,700 megawatts of generating capacity by 2007 [60].

The government of Brazil is also working to develop nonhydroelectric renewables, especially in remote areas of the country that do not have access to the electricity grid. In 1998, the country started the National Program for Energy Development of States (PRODEEM) in an effort to install 20,000 megawatts of renewable energy capacity, with an investment of about \$25 billion in photovoltaic and other renewable energy technologies [61]. The project's aim was to expand electricity capacity through hundreds of community projects—each expected to reach about 200 people living in rural communities that would not be connected to an expanding electricity grid before 2003. In addition to photovoltaics, the PRODEEM program included aero-generators and wind turbines, small central hydroelectric plants, biomass-derived fuels (alcohol, vegetable oils, forest and farm wastes), and biodigesters.

Brazil is now launching a successor program to PRODEEM called ALVARADO, which will focus on increasing access to electricity in the northeastern part of the country. Starting in 2002, ALVARADO is expected to begin establishing small renewable energy systems. Like PRODEEM, ALVARADO will involve both local and international private-sector developers in its effort to install off-grid renewable energy projects.

Another Brazilian scheme to promote the development of renewable energy resources involves electricity produced from sugar cane. The second-largest distributor of electricity in São Paulo state, CPFL, has set a target to increase its marginal power purchases from sugar cane industries to 7 percent of its total demand by 2003. Further, the Pernambuco state power company (owned by Spain's Iberdrola) has agreed to purchase all the electricity that is produced by the Cruangi sugar refinery through 2006.

Chile

In Chile, the controversial and much-delayed 570-megawatt Ralco hydroelectric project was delayed for another 6 months. The \$540 million project being developed by

Energy Crisis in Brazil: Implications for Hydropower

Brazil is currently in the midst of an energy crisis that has exposed the risk that accompanies its high level of dependence on hydroelectric power. After the worst drought in 70 years, water levels in many of Brazil's hydroelectric reservoirs fell to critical lows by the summer of 2001. To avert impending blackouts and power interruptions, the Brazilian government introduced a series of emergency measures intended to cut electricity consumption and diversify supply sources.

As of June 1, 2001, industries and commercial businesses were required to reduce their power consumption by 15 to 25 percent.^{a,b} They were also barred from undertaking any major new expansion works requiring new electricity connections from the main system.^c Households that consume more than 100 kilowatt-hours of electricity per month were required to cut their consumption by 20 percent or face a 3- to 6-day cut in their electricity supply.^d The electricity rationing plans were initially implemented in areas of the South East, North East, and Center West regions of the

country, then extended to three more states (Pará and Tocantins in the North, and Maranhão in the North East) as of July 1 (see map below).

Electricity consumption dropped during the first few months of the rationing program, but reduction levels did not reach the 20-percent target in most regions.^e The program was initially expected to conclude in November, but the government announced in October that it would extend the rationing and initiate further demand-side measures. The government ordered a 4-day work week in several states and created three new "holidays" (October 22 and November 16 and 26) in North Eastern states, intended to help spur electricity consumption reductions in the manufacturing and buildings sectors.^f The new measures also required that power be cut off to residential customers using more than 500 kilowatt-hours of energy per month. Daylight savings measures were also introduced in most regions of the country.

(continued on page 119)



^a"Brazil: Power Rationing Begins," *World Markets Online*, web site www.worldmarketonline.com (June 4, 2001).

^b"Brazil: Government Loosens Electricity Penalties," *World Markets Online*, web site www.worldmarketonline.com (June 6, 2001).

^cWith the exception of residential and rural projects.

^dInitially, the noncompliance penalty for residential customers included surcharges. Under mounting public pressure, the government eliminated the surcharge penalties and relaxed the conditions for supply cuts. Power will now be cut off only for households that fail to meet their target for two consecutive months (3 days for the first offense, 6 days for the second offense).

^e"Electricity Rationing Extended to April," *Latin America Monitor*, Vol. 18, No. 8 (August 2001).

^f"Extra Holidays To Help North East Meet Power Saving Target," *World Markets Online*, web site www.worldmarketonline.com (October 11, 2001).

Energy Crisis in Brazil: Implications for Hydropower (Continued)

In December 2001, regional energy rationing targets (with the exception of heavy industry in each region) were lowered.^g In January 2002 the Brazilian government eased the power rationing targets for heavy industry to 10 percent of mid-2001 consumption,^h and all energy rationing was discontinued on March 1, 2002. According to the Brazilian national grid operator, ONS, water reservoir levels had increased sufficiently to guarantee power supply through 2002 and 2003, given the long-term forecasts for rainfall.ⁱ

Although more than 90 percent of Brazil's generating capacity and production currently comes from hydroelectric plants, the drought was not the sole factor behind the country's energy crisis. The demand for electricity in Brazil has been growing by almost 5 percent per year, on average, since 1990. Demand growth has been driven particularly by industrial use in the South East and Center West regions, where most of the country's population live. However, investments in new electricity generation and transmission capacity have not kept pace with demand. The Brazilian government now plans to build 49 new thermoelectric generators by 2003, fueled primarily by Bolivian natural gas; only a handful have come online so far. The absence of power line connections to regions of the South and the North of Brazil, as well as from Argentina, has prevented electricity from reaching the areas facing electricity shortages.

Factors such as private investors' increased perception of risk since the devaluation of the Brazilian real in 1999, the contractual terms of supply offered for natural gas by Petrobras (the federal oil and gas monopoly), and the electricity tariff controls set by Aneel (Brazil's power regulator) are believed to have impeded the capital investments needed to finance new generation and transmission projects in the country.^j The slowdown in efforts to privatize the electricity sector in recent years has also contributed to the current energy crisis, because some planned capacity additions were to occur after privatization.

Changes that have occurred since the onset of the rationing program have helped to remove some of the

financial and regulatory barriers to electricity sector investment in Brazil.^k Specifically, the National Development Bank of Brazil made several billion dollars worth of public funds available to companies wishing to enter partnerships in natural-gas-fired or hydroelectric power stations. The bank will provide up to 60 percent of the financing needed by private investors. A formula has also been established to protect investors against exchange rate risk. Furthermore, Petrobras has agreed to a set of supply terms that are considered more favorable by thermoelectric power plant investors, with natural gas to be provided at fixed prices for periods of 12 full months. On the transmission side, the Inter-American Development Bank has approved \$243.9 million in financing to build an additional 1,000-megawatt line connecting the electricity grids of Argentina and Brazil.

Substantial governmental effort on the supply side has focused on natural-gas-fired generating plants, which can be brought online faster and at less expense than most other comparable options. Despite the difficulties associated with depleted reservoirs, a significant expansion of Brazil's hydropower infrastructure is also considered a key element of the government's overall plan to shore up the country's electricity supply. Aneel awarded licenses for the construction and operation of 8 new hydroelectric power plants in June 2001, and licenses for another 11 were awarded in November.^l These new builds alone would add some 5,000 megawatts to Brazil's total generating capacity. The government has also expressed its intention to increase capacity from the country's third largest power generator, CESP Parana, in advance of its privatization. The reservoir quota for Itaipu—the world's largest hydroelectric plant—may also be increased in order to boost generation.^m Both CESP Parana and Itaipu serve the energy-starved South East region of Brazil.

Although expansion of the hydroelectric infrastructure may serve to alleviate electricity shortages in Brazil, it is not without controversy. The development of Brazil's existing hydroelectric facilities has given rise to

(continued on page 120)

^g"Power Rationing Reduced," *World Markets Online*, web site www.worldmarketsonline.com (November 23, 2001).

^h"Power-Saving Targets for Industry Reduced," *World Markets Online*, web site www.worldmarketsonline.com (January 25, 2002).

ⁱ"Power Rationing To End on 1 March," *World Markets Online*, web site www.worldmarketsonline.com (February 20, 2002).

^jA. de Oliveira, "The Changing Brazilian Electricity Market," Roundtable/Conference Reports, Institute of the Americas (March 27, 2000); "Brazil Stares Electricity Rationing in the Face," *Financial Times: Power in Latin America*, No. 70 (April 2001); "Biting the Hand That Electrifies," *Financial Times: Power in Latin America*, No. 71 (May 2001).

^k"Investing in Brazil Is Anything But Boring," *Financial Times: Power in Latin America*, No. 74 (August 2001).

^l"Government Sells Licenses for New Hydroelectric Power Plants," *World Markets Online*, web site www.worldmarketsonline.com (June 29, 2001); "Brazil: Aneel Sells Licenses to Build 11 New Hydroelectric Plants," *World Markets Online*, web site www.worldmarketsonline.com (December 3, 2001).

^m"Brazil Stares Electricity Rationing in the Face," *Financial Times: Power in Latin America*, No. 70 (April 2001).

Endesa España has been the subject of much criticism from environmentalists and human rights activists for its treatment of the indigenous Pehuenche people. Construction of Ralco will include flooding of some sacred Pehuenche land and will dislocate 91 families that currently live there [62]. In 2001, the problems were compounded by heavy rains in the late spring that caused the Bio Bio River to rise to five times its normal level. The dike constructed to reroute the river above the construction site collapsed, and the river reestablished its original course. As a result, construction was halted and did not resume until December, when river levels were low enough to allow reconstruction of the diversion dike. The project has been under construction for some 7 years, and the original completion date has been delayed for at least a year; it is now expected to be completed by January 2004 at the earliest.

Chile's National Energy Commission is planning to implement several projects that will involve nonhydroelectric renewable energy resources [63]. The government has passed legislation promoting the development of 120 new geothermal projects by independent power producers. The National Electricity Commission has initiated an aggressive rural electrification program aimed at providing electricity to communities that lack access to the national electricity grid. Since 1992, Chile has invested \$112 million in the program, which is expected to run until 2004, with the goal of supplying electricity to 100 percent of the population.

Other Central and South America

Other Central and South American countries are also attempting to address the problem of getting electricity to remote, rural areas. Costa Rica has one of the most ambitious programs for renewable energy in Latin America. The country instituted a policy mandating that by 2025 all forms of energy consumed in the country be derived from renewable sources. In Honduras the Inter-American Development Bank has estimated that almost 40 percent of the population does not have access

to electricity. The Bank has approved a \$5 million loan for a study to determine whether combining education and health assistance with telecommunications and energy technology for low-density populations is feasible [64]. The study will begin with two villages, providing solar thermal and photovoltaic home systems. If it is deemed a success, the Bank has indicated that it would allow as many as 100 villages to take part in the project.

In Argentina, the government and the World Bank are implementing a project that is to provide electricity to roughly 70,000 rural households and 1,100 provincial public service institutions, principally through the use of renewable energy systems [65]. Total cost of the project has been estimated at \$120.5 million. Energy sources will be principally photovoltaic and wind, with biomass used to make up any shortfalls. Argentina has expressed a particular interest in developing its wind resources. The country has passed legislation that requires all utilities to purchase wind power if it is available. This should help cover the costs of building the necessary transmission infrastructure from the wind turbines to the power distributors. Further, with approval of the Argentine government, Spanish companies Endesa and Elecnor are developing 3,000 megawatts of wind energy capacity, to be completed by 2010.

In a region like Latin America, where the grid is often underdeveloped and a large number of people live in rural areas without access to electricity, photovoltaics are promising because they can be installed and operated at the point of energy consumption. Roughly 75 million people in Latin America live without electricity because of inadequate transmission infrastructure. It can cost between \$1,000 and \$2,000 per mile to extend low-voltage distribution lines to the transmission grid. As a result, in areas where the population is so dispersed that load density can be as small as one customer per mile of line, the cost of extending remote sites to the transmission grid can be prohibitive. On the other hand, off-grid, individual photovoltaic systems average \$647

Energy Crisis in Brazil: Implications for Hydropower (Continued)

some economic, social, and environmental problems. The construction of large hydroelectric projects in particular, often beset by long delays and significant cost overruns, has contributed to the country's debt burden since the 1970s. Reservoir and dam development for large facilities has also disrupted the culture and sources of livelihood for many communities. Studies have indicated that the majority of people uprooted from their existing settlements as a result of dam development are poor and/or members of indigenous

populations or vulnerable ethnic minorities.ⁿ The displaced populations have also had to bear a disproportionate share of the social and environmental costs of large hydroelectric projects without gaining a commensurate share of the economic benefits. Reservoir and dam development for hydroelectric facilities has also led to loss of forests, wildlife habitats, species populations, aquatic biodiversity, upstream and downstream fisheries, and services provided by downstream flood plains and wetlands.

ⁿWorld Commission on Dams, *Dams and Development: A New Framework for Decision-Making* (London, UK: Earthscan Publications, 2000).

per installed household unit, assuming a system of 50 watts per household. As a result, the more remote the site, the more financially attractive photovoltaic systems can be.

Eastern Europe/Former Soviet Union

There are only a few plans to expand the use of renewable resources in the countries of Eastern Europe and the former Soviet Union (EE/FSU). Much of the increment in hydroelectricity from 1999 to 2020 is expected to be in the form of repairing and expanding existing facilities that suffered from a lack of maintenance during the Soviet era. In general, renewables are not competitive in the FSU, where fossil fuel resources are abundant and demand for clean forms of electricity can be met with cheaper natural-gas-fired capacity. FSU renewable energy demand is projected to increase by 1.6 percent per year. In Eastern Europe, the growth rates projected for hydroelectricity and other renewables are twice those for the FSU at 3.5 percent per year, reflecting the relatively small amount of renewable capacity currently installed in the region. By 2020, the reference case projects that use of hydropower and other renewables in Eastern Europe will be 55 percent of the current level in the FSU (Figure 72).

Former Soviet Union

Azerbaijan is one of the few former Soviet republics that has added new, large-scale hydroelectric power capacity. In May 2000, the 4,000-megawatt Yenikand hydroelectric facility was completed [66]. The project, originally begun in 1985, was later suspended and could only be started again in 1996 with the help of a \$53

million loan from the World Bank. The country's 360-megawatt Mingeaur hydroelectric power station is currently undergoing rehabilitation and should begin operation in the near future.

Georgia also plans to add hydroelectric capacity and repair some of the country's existing hydropower facilities. There are plans to construct two hydroelectric plants on the Rioni River, the 250-megawatt Namakhvani and the 100-megawatt Zhoneti [67], and a 40-megawatt Minadze hydroelectric plant on the Kura River. In November 2002, Georgia announced a tender for work to be done on the country's largest hydropower project, the Inguri. The estimated \$62 million project is designed to increase the facility's capacity to 1,300 megawatts from the current level of around 400 megawatts. The project will be funded in part by a long-term credit from the European Bank for Reconstruction and Development, along with funds from the European Union and Japan and the Georgian government.

In 2001 there were some modest attempts to increase the use of nonhydroelectric renewables in a few countries of the FSU. In July, Ukraine's parliament passed the Ukrainian Wind Power Development Project in an attempt to encourage the development of wind power and make wind power a "significant source" of electric power by 2020 [68]. Ukraine has extensive wind resources, although the development of a wind power industry would require technological and financial support.

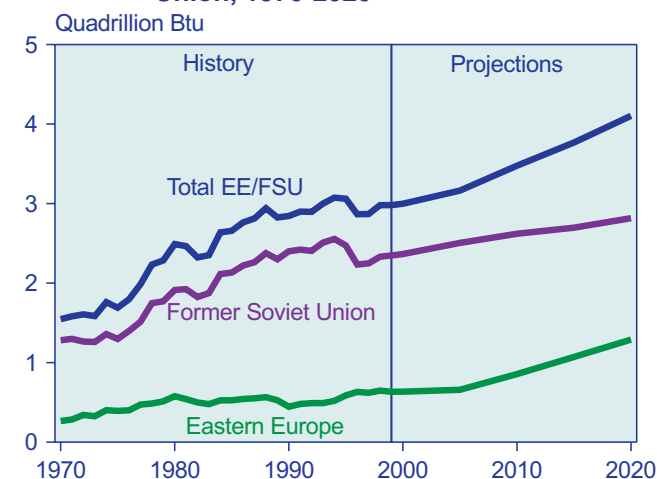
A Malaysian company, Ideal Fortune Holdings Sdn. Bhd., has been awarded a 25-year concession to build, own, operate, and transfer wind and hydroelectric power projects in Kazakhstan [69]. A combined capacity of 500 megawatts is to be added in Kazakhstan. The wind facilities are to be located in the Chilik Corridor, a valley 90 miles north of the city of Almaty. They will cost an estimated \$500 million and should be completed by 2006.

Eastern Europe

Much of Eastern Europe has been experiencing drought conditions over the past year, which has constrained electricity generation from the region's hydroelectric facilities. To counteract the decline in reservoir levels, there are some plans to expand the capacity of existing hydroelectric facilities throughout the region, as well as some plans to construct new facilities.

Albania has been particularly hard hit by the drought, and other countries have attempted to alleviate the resulting electricity shortages with exports or by increasing water flow at Albania's hydropower projects. In 2000, Macedonia allowed waters from Lake Ohrid to drain into the Black Drin River to increase the flow at Albanian hydroelectric projects downriver [70]. Croatia announced plans to construct a new hydroelectric

Figure 72. Renewable Energy Consumption in Eastern Europe and the Former Soviet Union, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

project on the Drava River that would be able to provide power to Albania. Likewise, Italy's Enelpower announced plans to construct a 100-megawatt hydroelectric project on the Vjosa River in Albania that would be able to supply power to Albania, Greece, or Italy (by submarine cable) as needed. China has agreed to build a hydropower plant on the Drini River that is expected to produce 350 million kilowatthours of electricity each year.

At the end of July 2001, Albania's state-owned electric utility, Korporata Elektroenergjetika Shqiptare (KESH) imposed daily power cuts of up to 10 percent on electricity consumption to conserve water reserves until the rainy season arrived. The International Monetary Fund urged the government to act quickly to avoid the blackouts that occurred in the previous year when summer droughts led to 12-hour-a-day blackouts during the winter.

KESH also signed an agreement with Croatia's largest electrical equipment manufacturer, Koncar Inzinjering, to repair and upgrade two hydroelectric facilities on the Mat River in central Albania [71]. The agreement will include the upgrade of generators, transformers, and switchgear at the 25-megawatt Ulza and 25-megawatt Shkopeti power plants. The \$2.9 million project is being financed by the European Bank for Reconstruction and Development and should be completed by the end of 2003. Koncar will also work with Bosnian Croat power utility Elektropivreda HZ Herceg Bosne (EP HZ HB) to complete Bosnia's Pec-Mlin and Mostarsko Blato hydropower plants, at an estimated cost of around \$87.9 million [72].

Romania's Hidroelectrica is in the process of completing, upgrading, and restoring 14 of its hydroelectric facilities [73]. The plants, in various stages of construction, would add a combined 780 megawatts of installed capacity. One project, the Siriu-Surdut-Nehoiasu hydroelectric project on the Buzau River in eastern Romania, is being handled by United Power Company, a joint venture between Hidroelectrica and U.S. Harza. The project was to be completed in the first quarter of 2002. The expansion of the Iron Gates I (located on the Danube River) refurbishment project began in 1999. The \$154 million contract includes restoration of six turbines and should boost capacity of the facility to 1,290 megawatts from the present 1,070 megawatts. The project is scheduled for completion by 2005.

There are a few plans to develop nonhydroelectric renewable energy resources in Eastern Europe. In 2001, a German renewable energy company, P&T Technology, announced plans to construct a series of wind power plants in Poland [74]. P&T has already reached agreements to construct 150 megawatts of wind power capacity and has obtained the approval of the local

Polish communities. The projects are located in the northwestern coastal area of the country. The first, a 4-megawatt wind farm, is being constructed near Kolobrzeg, Poland.

Hungary has also begun looking toward developing wind power. A 600-kilowatt wind turbine in the Hungarian village of Kulcs (about 40 miles south of Budapest) began operating at the end of August 2001 and will supply electricity to the public electricity grid [75]. The project is expected to provide around 1.2 million kilowatthours of electricity annually, enough to supply 750 households. The \$700,000 project is owned by Emszet (First Hungary Windpower), majority owned by Eon Hungaria, and was subsidized by government grants that covered 40 percent of the installation costs. The Hungarian government has established a target of having renewables supply 6 percent of the country's total energy production by 2010, from an estimated 2 to 3 percent currently. The Emszet wind generator is the second working unit in Hungary. The first was a 250-kilowatt unit built by Bakony Power in Inota, western Hungary. The Inota project cost \$428,000 and began operating in December 2000. Electricity from the project is fed into the local power station before being sold onto the national grid.

Africa/Middle East

In Africa and the Middle East, hydroelectricity and other renewable energy sources have not been widely established, except in a few countries. In the Middle East, only Turkey and Iran have extensively developed their hydroelectric resources. In Africa, Egypt and Congo (Kinshasa) have the largest volumes of hydroelectric capacity. Other countries, including Ivory Coast, Kenya, and Zimbabwe, are almost entirely dependent on hydropower for their electricity, not because they have extensively developed hydropower resources but rather because of a lack of development of electricity infrastructure. Renewable energy use in Africa and the Middle East is projected to rise from 1.2 quadrillion Btu in 1999 to 2.6 quadrillion Btu in 2020 in the *IEO2002* reference case (Figure 73).

In Africa, a number of hydroelectric projects moved forward in 2001. The Japanese government approved implementation of the delayed Sondu Miriu hydroelectric project in Kenya [76]. Funding for the 60-megawatt project in Nyakach had been partially withheld because of environmental concerns from local residents and nongovernment organizations. The Japanese Ministry of Foreign Affairs and representatives from the Japanese Bank for International Cooperation reviewed the project and met with those opposing it to reach consensus as to whether the project should continue. An agreement was reached in June 2001, and the \$52 million Sondu Miriu is expected to be completed by the end of 2003.

Uganda is also expected to see some hydroelectric projects begin operation over the next several years. A consortium of companies led by U.S. AES is constructing the 200-megawatt Bujagali hydroelectric project, to be located about 2.5 miles south of the source of the White Nile River at Lake Victoria [77]. The project is expected to cost an estimated \$500 million to build and is scheduled for completion before the end of 2005. Bujagali will increase Uganda's electricity capacity by more than 40 percent, and a portion will be exported to neighboring Kenya and Tanzania.

There is also a move to increase the use of small-scale hydroelectric power in Uganda. In 2001, the country issued tenders for the development of a 5-megawatt hydropower station at Nyagak Falls in the Nebbi District and a 1.5-megawatt plant at Olewas Falls (the latter to be financed by the World Bank). The two projects will cost an estimated \$18 million. No construction schedule has been released.

The River Senegal Basin Development Organization (OMVS) announced that all three member nations, Senegal, Mali, and Mauritania, should begin receiving electricity from the long-awaited Manantali hydroelectric project in Senegal by April 2002 [78]. The dam portion of the project was actually completed in 1987, but funding problems and military tensions between Mauritania and Senegal stopped the completion of the power station and transmission lines [79]. The 200-megawatt project cost a total of \$267 million to construct.

Other African hydropower projects that moved forward in 2001 include the Zambian 120-megawatt Itzhi-Tezhi,

to be located in the southern part of the country [80]. Tenders were issued in July 2001 for construction of this \$105 million project, which should be completed by July 2003.

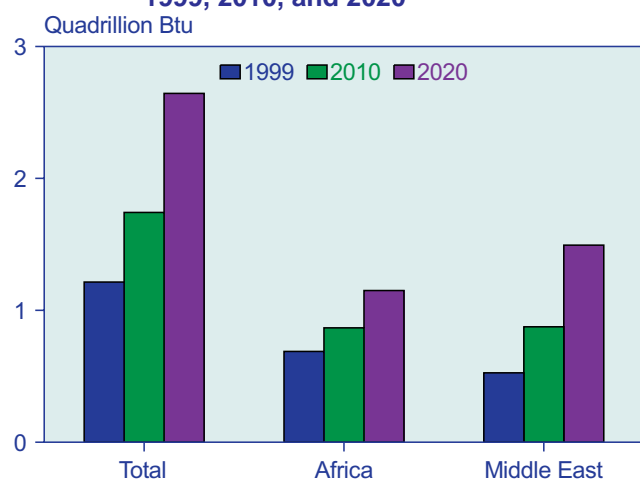
Mozambique's proposed Mepanda Uncua project—to be located downstream from the existing Cahora Bassa dam on the Zambezi River—also moved forward in 2001 [81]. The 1,200-megawatt Mepanda Uncua project will cost an estimated \$1.25 billion. In April 2001, the Mozambican government released results from its environmental impact study. The study indicated that potential environmental damage from the new project would be minimal, and that the project should proceed.

Finally, the Saudi Fund for Economic Development, the Abu Dhabi Fund for Development, the Arab Fund for Economic and Social Development, and the Kuwaiti Fund for Economic Development have jointly decided to fund the construction of a 1,250 megawatt hydroelectric project in Sudan [82]. The Merowe dam project is to be constructed at a cost of about \$780 million and will be located about 220 miles north of Khartoum on the Nile River. Tenders are scheduled to be issued for construction of the project in 2002.

There were also several advances in the development of nonhydroelectric renewable energy projects in Africa. Morocco continued its pursuit of installing wind power. The state-owned utility Office Nationale d'Electricite (ONE) is planning to construct 200 megawatts of wind power at Tangiers and Tarfaya. The country's first wind power plant, the 50-megawatt Koudia al-Baida, began operating in May 2000 and is generating an estimated 200 million kilowatthours of electricity annually. Egypt also has made some advances in wind power, installing 30 megawatts of wind capacity on the Red Sea coastline south of Cairo in 2000, with plans to add another 60-megawatt build-own-operate-transfer (BOOT) wind project at Zafrana [83]. The Egyptian New and Renewable Energy Authority (affiliated with the state-owned Egyptian Electricity Holding Company) hopes that wind will supply some 600 megawatts of electricity capacity to the national grid by 2007.

In the Middle East, much of the new development in renewable energy, particularly hydroelectricity, is centered in Turkey. The country has ambitious plans to construct a system of 21 dams and 19 hydroelectric plants, called the Southeast Anatolia Project (GAP) [84]. It is a joint hydroelectric power and irrigation project. Upon completion, the \$32 billion project will have a combined installed capacity of 7,500 megawatts. As of 2000, six of the hydropower plants had been completed (Karakaya, Ataturk, Kralkizi, Dickle, Batman, and Karkamis); three were under construction (Birecik, Kayacik, and Sanliurfa); and six others were in the planning phase (Erkenek, Garzan, Silvan, Adiyaman, Ilisu, and Cizre).

Figure 73. Renewable Energy Consumption in Africa and the Middle East, 1999, 2010, and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, *World Energy Projection System* (2002).

In recent years, Ilisu has been the most controversial project in the GAP scheme. The proposed 1,200-megawatt project would be the largest hydropower project on the Tigris River in the southern part of Turkey. The UK government was asked to provide export credit guarantees for construction of the \$1.8 billion project by Balfour Beatty, a British civil engineering company, which has a contract worth nearly \$290 million for construction work on Ilisu [85]. Environmentalists oppose the dam on the grounds that it will mean that more than 90 villages will be submerged by the reservoir that is to support the dam, and that it will force the relocation of up to 78,000 people, mostly of the minority ethnic Kurds [86]. The British government initially granted Balfour Beatty's guarantees, but amidst substantial protests it indicated that it might withdraw its support for the dam because of environmental concerns, leading Balfour Beatty to pull out of the project in November 2001 [87].

In a similar development, the UK government is considering whether to guarantee Turkey's \$844 million Yusefeli hydropower project [88]. The British construction firm Amec, which is part of a consortium seeking to build the Yusefeli hydroelectric dam, has applied to the British Export Credit Guarantee Department for a loan of \$96 million. Detractors of the project argue that up to 15,000 people—largely minority Georgians—would have to be relocated to construct Yusefeli.

Other hydroelectric projects are progressing in Turkey. In October 2001, a consortium of companies led by the Washington Group International announced that it had been awarded a planning contract to provide geotechnical exploration, engineering, and design for the first phase of the Hakkari dam, to be constructed on the Zap River in Southern Anatolia [89]. The \$600 million project will consist of a 558-foot dam, a 7-mile tunnel, and a 208-megawatt hydroelectric power station. Construction of the first phase is scheduled for completion by mid-2002.

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Electricity

Electricity consumption nearly doubles in the IEO2002 projections. Developing nations in Asia and in Central and South America are expected to lead the increase in world electricity use.

In the *International Energy Outlook 2002 (IEO2002)* reference case, worldwide electricity consumption is projected to increase at an average annual rate of 2.7 percent from 1999 to 2020 (Table 20 and Figure 74). The most rapid growth in electricity use is projected for the developing world, particularly developing Asia, where electricity consumption is expected to increase by 4.5 percent per year over the forecast horizon. Robust economic growth in developing Asia is expected to lead to increased demand for electricity to run newly purchased home appliances, such as air conditioners, refrigerators, stoves, space heaters, and water heaters. By 2020, developing Asia is expected to consume more than twice as much electricity as it did in 1999. China's electricity consumption alone is projected to triple, growing by an average of 5.5 percent per year over the forecast period.

Similarly, in Central and South America, high rates of economic growth are expected to improve standards of living and increase the demand for electricity for homes, businesses, and industry. The expected growth rate for electricity use in Central and South America is 3.9 percent per year between 1999 and 2020. For Brazil, the region's largest economy and largest consumer of electricity, electricity use is projected to increase by 3.6 percent per year, with increasing efforts to bring

electrification to rural populations that have previously not had access to the national grid.

Electricity consumption in the industrialized world is expected to grow at a more modest pace than in the developing world, at 1.9 percent per year—a considerably lower rate than has been seen in the past. In addition to expected slower growth in population and economic activity in the industrialized nations, market saturation and efficiency gains for some electronic appliances are expected to slow the growth of electricity consumption.

There have been two important developments in the electricity sector in recent years that may affect the way the industry works in the future. The first is the increasing role of foreign direct investment in the developing regions of the world. Greater access to foreign investment in the electricity sector has allowed developing nations to construct the infrastructure needed for substantial increases in access to electricity, a particular problem for many developing nations.

A second important component of the electric industry's evolution over the past several years is electricity reform. Many developing countries have implemented reforms to the rules governing electricity generation and

Table 20. World Net Electricity Consumption by Region, 1990-2020
(Billion Kilowatthours)

Region	History		Projections				Average Annual Percent Change, 1999-2020
	1990	1999	2005	2010	2015	2020	
Industrialized Countries	6,385	7,517	8,620	9,446	10,281	11,151	1.9
United States	2,817	3,236	3,793	4,170	4,556	4,916	2.0
EE/FSU	1,906	1,452	1,651	1,807	2,006	2,173	1.9
Developing Countries	2,258	3,863	4,912	6,127	7,548	9,082	4.2
Developing Asia	1,259	2,319	3,090	3,900	4,819	5,858	4.5
China	551	1,084	1,523	2,031	2,631	3,349	5.5
India	257	424	537	649	784	923	3.8
South Korea	93	233	309	348	392	429	3.0
Other Developing Asia	357	578	724	872	1,012	1,157	3.4
Central and South America	449	684	788	988	1,249	1,517	3.9
Total World	10,549	12,833	15,182	17,380	19,835	22,407	2.7

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

distribution in an effort to secure the foreign direct investment they need to modernize and improve the electricity infrastructure. In industrialized countries, many nations have undertaken electricity reforms to introduce greater competition in domestic markets in an effort to reduce the costs of electricity to consumers. These two factors are driving changes within the electricity sector and are expected to have a profound role on the development of the industry over the next two decades.

Primary Fuel Use for Electricity Generation

The mix of primary fuels used to generate electricity has changed a great deal over the past three decades on a worldwide basis. Coal has remained the dominant fuel, although electricity generation from nuclear power increased rapidly from the 1970s through the mid-1980s, and natural-gas-fired generation has grown rapidly in the 1980s and 1990s (Figure 75). In contrast, in conjunction with the high world oil prices brought on by the oil price shocks resulting from the OPEC oil embargo of 1973-1974 and the Iranian Revolution of 1979, the use of oil for electricity generation has been slowing since the mid-1970s.

In the *IEO2002* reference case, continued increases in the use of natural gas for electricity generation are expected worldwide. Coal is projected to continue to retain the largest market share of electricity generation, but its importance is expected to be diminished somewhat by the rise in natural gas use. The role of nuclear power in the world's electricity markets is projected to lessen as

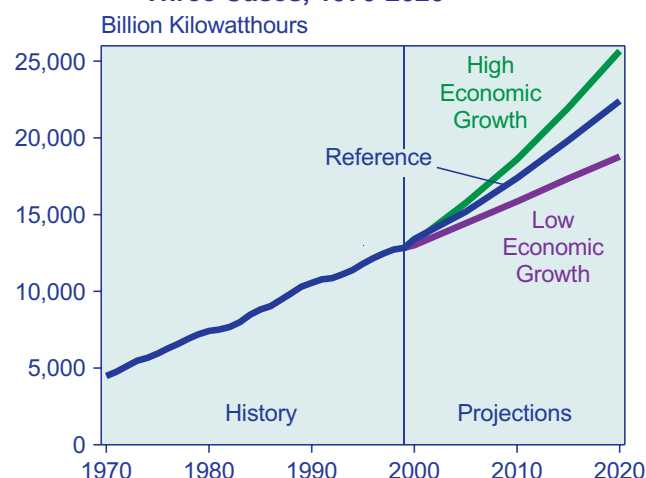
reactors in industrialized nations reach the end of their lifespans and few new reactors are expected to replace them. Generation from hydropower and other renewable energy sources is projected to grow by more than 50 percent over the next 20 years, but their share of total electricity generation is projected to remain near the current level of 20 percent.

Natural Gas

Electricity markets of the future are expected to rely increasingly on natural-gas-fired generation. This trend is evident throughout the world, as industrialized nations are intent on using combined-cycle gas turbines, which generally are cheaper to construct and more efficient to operate than other fossil-fuel-fired generation technologies. Natural gas is also seen as a cleaner fuel than other fossil fuels. Worldwide, natural gas use for electricity generation is projected to double over the forecast period (Table 21), as technologies for gas-fired generation continue to improve and ample gas reserves are exploited. In the developing world, natural gas is expected to be used to diversify electricity fuel sources, particularly in regions like Central and South America, where heavy reliance on hydroelectric power has led to shortages and blackouts when reservoirs are low.

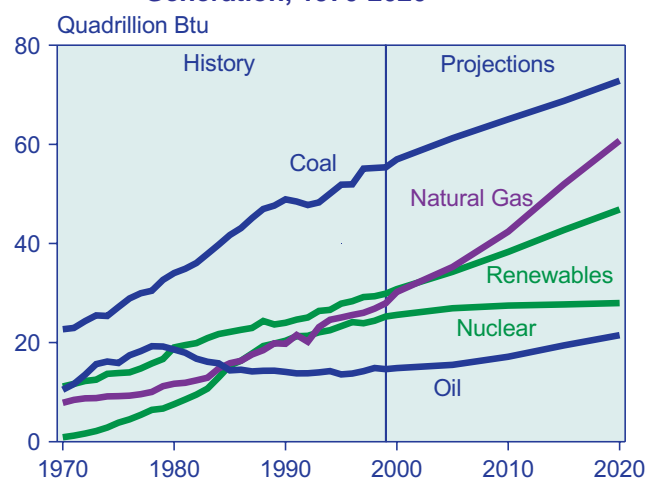
The former Soviet Union (FSU) accounted for more than one-third of natural gas use for electricity generation worldwide in 1999, and natural gas provided 51 percent of the energy used for electricity generation in the FSU. By 2020, natural gas is projected to account for 58 percent of the electricity generation market in the FSU. Relying increasingly on imports from Russia, the nations of Eastern Europe are also expected to increase

Figure 74. World Net Electricity Consumption in Three Cases, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 75. World Energy Use for Electricity Generation, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

their reliance on natural gas for electricity generation, from 10 percent in 1999 to 21 percent in 2020.

Natural gas use in the electricity generation sector is also expected to grow rapidly in North America and Western Europe. In the United States the natural gas share of the electricity fuel market is expected to double from 15 percent in 1999 to 32 percent in 2020, and in Canada the gas share is expected to grow from 3 percent in 1999 to 11 percent in 2020. The movement toward natural gas is expected to be accelerated by reduced reliance on nuclear power. In addition, Canadian exports are expected to provide a growing supply of natural gas to U.S. generators.

Western Europe is expected to see its use of natural gas double over the forecast period. In 1999 natural gas held a 14-percent share of the electricity fuel market in Western Europe. That share is projected to grow to 28 percent in 2020 as Western European nations reduce their reliance on nuclear power and coal. After the oil crisis of 1973, European nations (as in the United States) actively

discouraged the use of natural gas for electricity generation and instead favored domestic coal and nuclear power over dependence on natural gas imports. In 1975 a European Union (EU) directive restricted the use of natural gas in new power plants. The natural gas share of the electricity market in Western Europe fell from 9 percent in 1977 to 5 percent in 1981, where it remained for most of the 1980s. In the early 1990s, the growing availability of reserves from the North Sea and increased imports from Russia and North Africa lessened concerns about gas supply in the region, and the EU directive was repealed. As a result, the natural gas share of electricity generation increased rapidly.

In Central and South America natural gas accounted for 11 percent of the electricity fuel market in 1999. Its share is projected to grow to 32 percent in 2020. Hydropower is the major source of electricity supply in South America at present, but environmental concerns, cost overruns on large hydropower projects in the past, and electricity shortfalls during periods of drought have prompted South American governments to view natural

Table 21. World Energy Consumption for Electricity Generation by Region and Fuel, 1995-2020
(Quadrillion Btu)

Region and Fuel	History		Projections			
	1995	1999	2005	2010	2015	2020
Industrialized	77.1	83.8	91.4	97.5	104.4	110.5
Oil	5.7	6.5	5.6	5.6	6.0	6.5
Natural Gas	9.7	11.6	15.6	18.1	22.8	26.6
Coal	27.7	29.6	32.3	34.1	35.0	35.9
Nuclear	19.4	20.6	21.1	21.1	20.8	20.3
Renewables	14.7	15.4	16.9	18.5	19.8	21.1
EE/FSU	26.4	23.8	26.2	27.5	29.3	31.1
Oil	2.8	2.4	3.2	3.7	4.4	4.9
Natural Gas	10.6	10.3	11.2	12.5	14.2	15.9
Coal	7.4	5.4	5.5	4.8	4.0	3.6
Nuclear	2.5	2.7	3.2	3.0	3.0	2.8
Renewables	3.1	3.0	3.2	3.4	3.7	4.1
Developing	38.1	45.4	55.5	65.2	76.6	88.1
Oil	5.1	5.7	6.8	7.9	9.0	10.2
Natural Gas	4.8	6.1	8.5	11.8	15.1	18.3
Coal	16.8	20.3	23.5	26.1	29.7	33.3
Nuclear	1.4	1.9	2.6	3.3	3.9	4.9
Renewables	10.1	11.5	14.1	16.1	18.9	21.4
Total World	141.7	153.1	173.1	190.2	210.4	229.7
Oil	13.6	14.6	15.5	17.1	19.4	21.5
Natural Gas	25.1	28.0	35.3	42.4	52.0	60.8
Coal	51.9	55.4	61.2	65.0	68.7	72.8
Nuclear	23.3	25.3	26.9	27.5	27.7	28.0
Renewables	27.9	29.9	34.1	38.1	42.5	46.6

Note: EE/FSU = Eastern Europe and the former Soviet Union.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

gas as a means of diversifying their electricity supplies. A continent-wide natural gas pipeline system is emerging in South America, which will transport Argentine and Bolivian gas to Chile and Brazil.

Per capita consumption of natural gas in Asia and Africa is relatively small when compared with Europe and North America. Japan alone accounts for 26 percent of natural gas consumption in Asia, and almost all the natural gas consumed in Japan is liquefied natural gas (LNG). Japan is expected to increase its dependence on natural gas from 21 percent of the electricity fuels market in 1999 to 23 percent in 2020.

Coal

In 2020, coal is expected to account for 32 percent of the world's electricity fuel market, slightly lower than its 36-percent share in 1999. The United States accounted for 35 percent of all coal use for electricity generation in 1999 and developing Asia 31 percent. In the *IEO2002* forecast, the coal share of U.S. electricity generation is expected to decline to 46 percent in 2020 from 51 percent in 1999; and in developing Asia the coal share is projected to decline to 51 percent in 2020 from 62 percent in 1999. Although coal remains a relatively inexpensive fuel for electricity production, natural gas is generally regarded as being environmentally superior, and the improving economics of natural gas generation technology also suggest that natural gas will gain market share.

Reliance on coal for electricity generation is also expected to be reduced in other regions. In Western Europe, for example, coal accounted for 23 percent of the electricity fuel market in 1999 but is projected to have only a 15-percent share in 2020. Similarly, in Eastern Europe and the FSU (EE/FSU), coal's 23-percent share of the electricity fuel market in 1999 is projected to fall to 11 percent by 2020. For years, massive state subsidies were all that kept many Western and Eastern European coal mines in operation. In many cases, the subsidies were underwritten by electricity consumers. Europe's dependence on coal as a source of electric power generation has waned with the gradual diminution of state subsidies.

Nuclear Power

The nuclear share of energy use for electricity production is also expected to decline in many regions of the world as a result of operational safety concerns, waste disposal issues, concerns about nuclear arms proliferation, and the economics of nuclear power. In 2020, nuclear power is projected to capture 12 percent of the electricity fuels market worldwide, down from 16 percent in 1999. In many nations, the projected move away from nuclear power has slowed in the past several years. In the United States, for example, several nuclear utilities have been granted license extensions for their

nuclear power reactors. Moreover, in the United States and the United Kingdom, several nuclear utilities have announced their intentions to build new units in the future.

In the United States, the nuclear share is projected to drop from 20 percent of the electricity fuel market in 1999 (second behind coal) to 13 percent in 2020. In Canada, where the nuclear share of the market has been declining since 1984, its 14-percent share in 1999 is projected to remain stable. In Western Europe, the nuclear share of the electricity fuel market is projected to fall from 35 percent in 1999 to 24 percent in 2020—more than any other energy source. (Finland and France are alone among Western Europe's nuclear power producers in remaining committed to expansion of their nuclear power programs.)

In Japan, nuclear power accounted for 33 percent of the energy used for electricity generation in 1999. That share is expected to rise to 37 percent by 2020 in the *IEO2002* forecast. In the EE/FSU region, the nuclear share is projected to decline from 12 percent in 1999 to 9 percent in 2020.

Nuclear power contributes very little to electricity generation in the developing nations of Central and South America, Africa, and the Middle East, and it is expected to contribute little in 2020. Among South American nations, only Argentina and Brazil were nuclear power producers in 1999. In Africa, only South Africa generated electricity from nuclear power in 1999. There are no nuclear power plants in operation in the Middle East, although one is under construction in Iran.

In contrast to the rest of the world's regions, in developing Asia nuclear power is expected to play a growing role in electricity generation. China, India, Pakistan, South Korea, and Taiwan currently have nuclear power programs, and the nuclear share of the region's electricity fuel market is expected to remain stable at 6 to 8 percent from 1999 through 2020. China is expected to account for most of the region's nuclear power capacity additions.

Hydroelectricity and Other Renewables

Renewable energy, particularly hydropower, accounted for 20 percent of the world's energy use for electricity generation in 1999, where it is expected to remain in 2020. Of the world's consumption of renewable energy for electricity production in 1999, the United States and Canada together accounted for almost 26 percent of the total, Western Europe 19 percent, and Central and South America 19 percent (despite consuming just 5 percent of the world's electricity).

In 1999, renewables accounted for 11 percent of electricity production in the United States and 62 percent in Canada, both nations where hydroelectric power has

been extensively developed. The renewable shares of electricity generation are expected to decline in both countries over the forecast period, the U.S. share to 9 percent and the Canadian share to 54 percent. In North America and throughout the world, generation technologies using nonhydroelectric renewables are expected to improve over the forecast period, but they still are expected to be relatively expensive in the low price environment for energy fuels assumed in the *IEO2002* reference case.

Hydroelectricity is most widely used for electricity generation in Central and South America, and renewables accounted for 75 percent of the region's electricity fuel market in 1999. However, recent experiences with drought, cost overruns, and the negative environmental impacts of several large-scale hydroelectric projects have reduced the appeal of hydropower in South America. The renewable share of electricity generation in Central and South America is expected to decline to 55 percent by 2020 as the region works to diversify its electricity fuel mix.

Most of Western Europe's renewable energy consumption consists of hydroelectricity. Renewables in total accounted for 22 percent of the region's electricity market, and their share is expected to increase to 26 percent in 2020. Some European nations, particularly Denmark and Germany, are actively developing their nonhydroelectric renewable energy resources, most notably wind.

Some near-term growth in renewable energy use is expected in developing Asia, particularly in China, where the 18,200-megawatt Three Gorges Dam and a number of other major hydropower projects are expected to become operational during the forecast period. Developing Asia relied on renewables for 16 percent of its electricity production in 1999, and that share is expected to grow to 19 percent by 2020.

Oil

The role of oil in the world's electricity generation market has been on the decline since the second oil price shock that started in 1979. Oil accounted for 23 percent of electricity fuel use in 1977, but in 1999 its share was under 10 percent. Energy security concerns, as well as environmental considerations, have led most nations to reduce their use of oil for electricity generation. However, in regions where oil continues to hold a significant share of the generation fuel market, such as the FSU and the Middle East, it is expected to continue to play a relatively prominent role. As a result, the oil share of world energy use for electricity production is projected to slip only slightly, to 9 percent in 2020.

Developing Asia accounted for 17 percent of the world's consumption of oil for electricity generation in 1999, when 9 percent of its electricity fuel use consisted of oil

(down from 29 percent in 1977). The oil share of electricity fuel consumption in developing Asia is expected to remain stable through 2020. In the petroleum-rich Middle East, oil supplied 35 percent of the energy used for electricity generation in 1999, and its share is projected to fall to 24 percent in 2020, as these countries continue to build their reliance on natural-gas-fired generation.

Project Finance in the Developing World

Developing countries are expected to see their electricity consumption grow at a 4.2-percent annual rate through 2020 (Table 20). In order to achieve such growth, billions of dollars in capital investment will need to be raised.

There are numerous methods available for the financing of power projects in developing countries (for example, see box on page 132). These methods allow for various levels of participation and control by private (and sometimes foreign) investors. They range from management and operations contracts to greenfield projects to full divestitures:

- Management and operation contracts involve an outside private entity managing but not owning a public entity—often for a specified period of time. They involve the state ceding the least amount of control to private enterprise.
- Greenfield projects involve the construction of new power plants by private investors or by public-private ventures. They may be build-own-operate (BOO), build-operate-transfer (BOT), or build-lease-own (BLO) agreements [1].
- Divestitures fall on the other end of the spectrum from management contracts, allowing for a much deeper level of involvement as the private firm takes a substantial equity stake in what was a domestic (and sometimes publicly owned) enterprise.

The most common forms of financing are debt and equity. In the case of power projects, debt usually consists of commercial bank loans or bond issuances. Equity, on the other hand, usually consists of taking stock or ownership in the project or company. One instrument that blends the qualities of debt and equity is a subordinated loan, which is given "repayment priority over equity capital, but not over commercial loans or other senior debt" [2].

Another concern for investors in developing countries involves the claim that various loans and bonds have on the assets and cash flows of the project developer in the event of a default. Financing has ranged from traditional corporate finance to the now popular project finance. Traditional corporate lending usually involves the power project being backed by the sponsor's balance

Micro-Credit for Micro-Electricity in Bangladesh

A major impediment to providing much of the developing world with access to electricity has been the inability to obtain financing for the necessary infrastructure. The Grameen Bank (Village Bank) is a nongovernmental organization that has been providing micro-credit loans^a to rural inhabitants of Bangladeshi villages since 1976. The loans are used to finance small business activities, such as raising chickens, producing handicrafts, and operating cellular phone centers. They have been extremely successful in improving the lives of the rural poor in Bangladesh, and the concept has been replicated in many other countries of the world, including the United States. In 1996, the Grameen Bank established a subsidiary called Grameen Shakti (Village Power), with the intent of providing renewables-based electrification opportunities for rural populations.

The concept of the Village Power program is simple: to extend micro-credit opportunities that would allow rural households and commercial establishments the opportunity to finance renewable energy systems. For electricity consumers in developing countries, a typical 50-watt photovoltaic system costs about \$450,^b including photovoltaic panels, switches, outlets, wiring, a charge controller, end-use devices, and a battery. (On rainy days or in overcast weather the battery can provide backup power for a few days). In Bangladesh, 50-watt systems provide enough power to operate four 6-watt compact fluorescent lights, a black-and-white television, or a few small fans.^c This amounts to a significant amount of power for most rural households in Bangladesh, which currently have few existing means of connecting to power providers. Bangladeshi villagers either do without electricity (which is the prevalent option for most) or, if they are wealthy enough to afford it, purchase 2 or 3 car batteries, which must then be transported several miles by hand to the nearest market for periodic recharging.

Traditionally, rural lenders in countries such as Bangladesh have charged poor local villagers and farmers a steep premium over the interest rates charged by more established financial institutions operating in urban areas. Rates charged to villagers in Bangladesh have exceeded 150 percent.^d Part of the premium could be justified on the basis of the *real* creditworthiness of the two borrowers; part could also be ascribed to the relatively large transaction costs that accompany small-scale lending. However, part can also be attributed to “knowledge asymmetry,” which prevents market penetration by outsiders into the business of lending to rural villagers and provides justification for local monopoly. Other potential lenders include indigenous commercial banks and even foreign financial intermediaries, but they lack the intimate knowledge that local moneylenders have about the local business climate, such as which individuals have the industriousness and thrift habits that would make them desirable clients. These habits could easily be well known to local lenders living in the community but a mystery to outsiders.^e

The Grameen Bank managed to surmount this hurdle in several interesting ways. In order to qualify for a Grameen Bank loan, potential borrowers must form a group. Peer pressure is thus exerted to make borrowers comply with the agreed-upon repayment arrangement, as any noncompliance is made public to the group. Family members are excluded from joining the same group. Interestingly, 90 percent of loan recipients are female.^f

Small-scale photovoltaic systems have been installed in many places around the world. Grameen Shakti's innovation (at least in Bangladesh) was in arranging a marriage between micro-credit and renewable micro-energy. The \$450 cost of a photovoltaic system is an expensive proposition in a country where annual

(continued on page 133)

^aMicro-credit loans are small loans (average amounts are about \$100) that are provided to the poorest of poor in rural areas. The loans are provided in lieu of a business plan that the recipient has to present to show how the loan would be utilized. More than 90 percent of Grameen's borrowers are women. Loans are made to individual women, who help each other with repayment issues.

^bPersonal communication with Mr. Dipal Barua, Managing Director, Grameen Shakti, October 23, 2001.

^cDipal Barua, “Energy's Role in Rural Income Generation: The Grameen Strategy,” Presentation at Village Power Workshop 1998 (Washington, DC, October 1998).

^dH.R. Varian, “Economic Scene: In a Market for Lending in Developing Nations, a Bangladesh Bank Relies on Peer Pressure for Collateral,” *The New York Times* (November 22, 2001), p. C2.

^eOne seminal study, which among other things, analyzed the causes for the wide interest gap charged to Indian villagers relative to rates charged by large banks in central cities, attributed this gap in part to the asymmetry in knowledge possessed by traditional rural moneylenders over outsider financial intermediaries, thereby preventing outsiders from penetrating into their territory. See G.A. Akerlof, “The Market for Lemons: Quality Uncertainty and the Market Mechanism,” *Quarterly Journal of Economics*, Vol. 94, No. 3 (August, 1970), pp. 488-500.

^fH.R. Varian, “Economic Scene: In a Market for Lending in Developing Nations, a Bangladesh Bank Relies on Peer Pressure for Collateral,” *The New York Times* (November 22, 2001), p. C2.

sheet. In contrast, project finance separates the project's balance sheets from those of the sponsor company [3]. In this form of financing, only the revenues from the project are slated to pay the equity holders and creditors; in other words, the project investors can only lay claim to the project's cash flows and assets and not the cash flows and assets of the sponsor's other operations. This is known as nonrecourse financing. Most projects in developing countries combine both forms of backing in what are called limited recourse projects. Limited recourse projects might involve some additional backing, such as a pre-completion during the project's construction period, or a government or sponsor guarantee [4]. Whereas traditional corporate debt is beneficial in that it allows borrowers to pay lower rates of interest, non-recourse and limited recourse financing expose investors to less risk.

The selected project financing technique depends heavily on the creditworthiness of the country where the investment is taking place. Legal systems, economic and financial environments, and political stability are some of the factors that determine a nation's creditworthiness. The most obvious method for repayment of the costs of a power plant would be through the cash flow from the operations of the plant. However, many developing countries are plagued by theft of electricity or tariff rates that cannot support the cost of the plant. For riskier

projects, state Export Credit Agencies (ECAs) often play a role in providing loans, making guarantees to financiers of the project, or acting as an insurance facility. Developing countries are also recipients of major funding packages from multilateral and bilateral agencies or credit facilities, which have a function similar to that of ECAs.

Among world regions both Asia and Latin America stand out as major targets of private investment in electricity during the 1990s. During the 1990s, Latin America's power sector attracted \$78 billion in private investment (Figure 76). Seventy-one percent of that investment consisted of equity (Figure 77). Latin American countries have been pioneers in privatization, not only in the power sector but also in pension systems, telecommunications, etc. Among Latin American nations, Chile has been a leader in privatization and was the first to privatize and unbundle electricity generation, transmission, and distribution within the electricity industry. Chile was also a trailblazer in allowing foreign investment in its domestic electricity sector. Currently, Chilean electricity companies are investing in the power sectors of other Latin American countries. Argentina followed Chile's reform with a wholesale privatization and restructuring of the nation's electricity sector. In some Latin American nations, all segments of the electricity industry have been opened to private investment from

Micro-Credit for Micro-Electricity in Bangladesh (Continued)

per capita income is about half that. To provide villagers access to the necessary capital, the micro-finance aspect of Village Power involves a loan package under which households have the option of making a 15-percent down payment and paying the remainder over a 2-year period at an annual interest rate of about 12 percent. Grameen Shakti provides all the necessary equipment and meets service needs for one year—in effect, acting as a mini-utility.

There are a number of energy applications to which micro-credit financing mechanisms have been applied:

- Operation of a soldering iron to repair radios and televisions
- Residential and commercial lighting, which allows children to study at night and laborers to work past sunset
- Cellular phone charging and “renting out” phone services to allow surrounding villagers to communicate with the outside world
- Biodigesters to produce methane gas for cooking and fertilizer.

To date, the Grameen Shakti photovoltaic program in Bangladesh has been successful. An interesting aspect of the program has been the creativity that has been shown by borrowers. As loan recipients have had the opportunity to experience the benefits of renewable energy systems, they have developed innovative applications for the energy, which have helped sustain the micro-energy program in Bangladesh. For example, one loan recipient installed a solar-based mini-grid to supply electricity to shops in the village market.

As of September 2001, Grameen Shakti had installed 5,800 photovoltaic systems representing 290 kilowatts of capacity.⁸ In addition to continuing the sale of photovoltaic systems for residential lighting applications, the organization plans to expand the use of renewable energy systems to commercial activities that will generate income for villagers. It has installed and is successfully operating five solar-powered computer education centers at remote areas. Most importantly, however, the micro-credit loan programs have been able to improve the standard of living for many impoverished Bangladeshi without access to traditional electricity services or financial intermediaries.

⁸Personal communication with Mr. Dipal Barua, Managing Director, Grameen Shakti, October 23, 2001; and Grameen Shakti, “Programs: Photovoltaics (PV) Program,” web site www.grameen-info.org/grameen/gshakti (September 10, 2001).

generation to transmission to distribution. Municipally owned, state-owned, and nationally owned utilities have been wholly privatized and, in some instances, sold to foreign investors.

On the other end of the spectrum, developing Asian countries have generally not engaged in deep power sector reform and typically have chosen to rely more on independent power providers (IPPs) that outsource to the public grids. In contrast to Latin America, Asia's electricity sector, which attracted a greater \$93 billion in private investment between 1990 and 1999 (Figure 76), saw 72 percent of that investment directed to greenfield projects (Figure 77). Private-sector involvement generally has been limited to generation; transmission and distribution have traditionally been in the hands of the government. Private-sector participation in Asian electricity industries has focused on greenfield projects of IPPs, which bring in large amounts of new generation and foreign investment. This has sometimes led to serious problems, however, as the highly politicized issue of determining fair tariff rates discourages the ability to raise enough revenue to support the cost of generation without the aid of government subsidies. Recent controversial private electricity investments such as the Dabhol/Enron arrangement (see box on page 135) has led to some debate about the most suitable forms of privatization and financing for various regions.

World Electricity Deregulation

Recent efforts at electricity reform could be included as one of the most significant global energy developments of the past century. Since the mid-1990s, more than 30

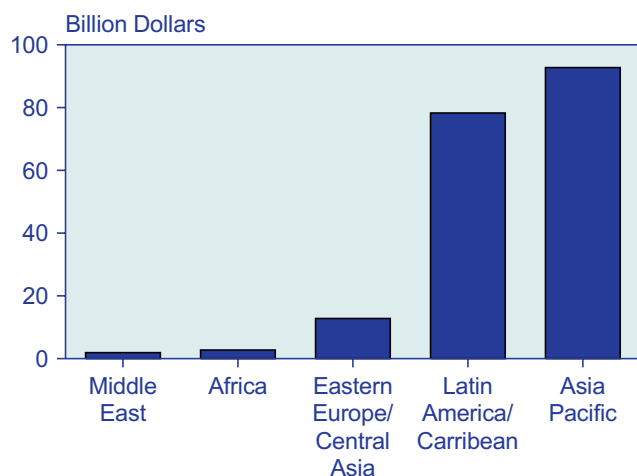
countries or regions within countries have attempted significant electricity reform measures [5].

In those developed nations where electricity assets have been publicly owned, privatization (and its weaker cousin, corporatization¹⁹) has been a major element of reform. Many industrialized nations have also for the first time opened their doors to foreign investment. For the most part, however, electricity reform in the industrialized world has involved a restructuring of the industry along the lines of its different functions, as well as a rewriting of the rules under which participants in electricity markets operate. The restructurings and rule changes vary among countries, but several similarities stand out.

Recent efforts at electricity reform can be traced to developments that occurred more than two decades ago. The United States embarked on an opening up of its electricity market to new entrants with the passage of the Public Utilities Regulatory Policies Act of 1978. Countries such as Chile (which started its reform in 1982), New Zealand (1987), Norway (1991), and Argentina (1992) were also early reformers. However, the United Kingdom, which embarked on sweeping privatization and restructuring of its electricity sector beginning in 1989, was the pioneer for reforms elsewhere.

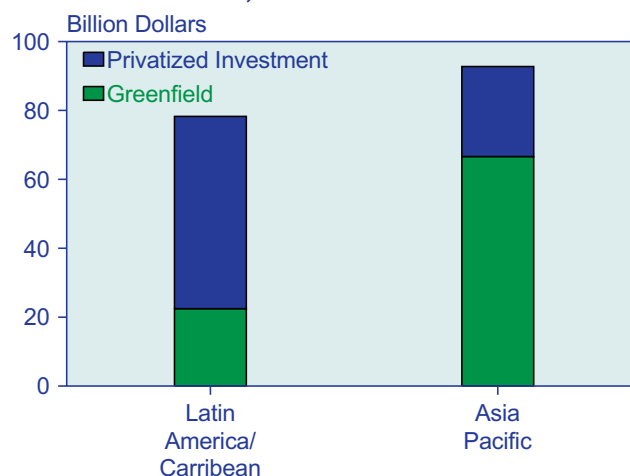
In countries with federalist forms of government, state or provincial governments have often led the way in electricity sector reform. In Australia, for instance, reforms in the state of Victoria predated national reforms. Similarly, in Canada, the province of Alberta (1996) was the first province to adopt electricity reform

Figure 76. Cumulative Private-Sector Investment in Electricity Among Developing Regions, 1990-2000



Source: Public Policy for the Private Sector, World Bank Data Base.

Figure 77. Cumulative Total Investment in Electricity Projects in Asia and Latin America, 1990-1999



Source: Public Policy for the Private Sector, World Bank Data Base.

¹⁹Corporatization maintains public ownership but allows management autonomy. The separation between the state and management of the entity is imposed in order to force the entity to behave more like a competitive business.

India's Dabhol Power Project

Domestic capital shortages in recent years have led some developing nations to open up their domestic electricity markets to foreign investors. In the early 1990s, a consortium led by U.S.-based Enron Corporation^a began negotiations with the state government of Maharashtra in India for Enron to build an electricity generation plant near Dabhol, 180 miles south of Mumbai (formerly Bombay). The Maharashtra State Electricity Board (MSEB)^b finalized an agreement that led to the creation of the Dabhol Power Corporation in June 1992. Since then, the project has progressed precariously, and serious contractual issues have arisen between Enron and the host state. Currently, the project is at a standstill.

Electricity reform in India began shortly before the Dabhol project was initiated. In 1991, a balance of payments crisis that followed a decade of economic isolationism prompted the Indian government to liberalize the nation's foreign investment policies. To attract foreign investment, India encouraged private-sector involvement in public-sector enterprises, including electricity generation. India's central government relaxed previously stringent measures in order to jump-start major power projects, known as the "fast track projects."^c

Dabhol, the first of India's fast track projects, got off the ground with a memorandum of understanding between Enron and the MSEB in June 1992. The understanding called for the construction of a 2,015-megawatt power plant. The original power purchase agreement (PPA) between Enron and Dabhol was signed for the first of two phases in December 1993. In Phase I, imported distillate was to be used to fuel the new power plant while construction of a receiving terminal and regasification facility for liquefied natural gas (LNG) was being completed. In Phase II, the power plant would be fueled with natural gas from the LNG import terminal. The agreement required the MSEB to buy 90 percent of the plant's baseload generation at 7.5 cents per kilowatthour for 20 years after commissioning.^d Both fuel price fluctuation risk and foreign exchange risk were assumed by the MSEB.

Concerns about the project were raised in 1995 when a new government represented by the Shiv Sena and the Bharatiya Janata Party (BJP) coalition party^e came into office in Maharashtra after conducting a campaign marked by economic nationalism. A review committee, headed by Gopinath Munde, former deputy chief minister of Maharashtra, was formed to examine the PPA contract along with other parameters of the project. The committee's report raised concerns about the project's potential environmental damage, the fact that the initial contract negotiation lacked competitive bidding and public scrutiny, and the reasonableness of the project's capital costs. It also noted that the World Bank had recommended using the plant for peak load and had suggested that another fuel source, such as coal or naphtha, would be more suitable than natural gas.^f

In June 1999, the Maharashtra government initiated the cancellation of the Dabhol project.^g In response, Enron agreed to a renegotiated contract that called for, among other things, a new PPA that attempted to resolve a number of the review committee's concerns. The total capacity of both project phases was increased (from 695 megawatts to 826 megawatts in Phase I and from 1,320 megawatts to 1,624 megawatts in Phase II), with the additional generating capacity to be provided by Enron at no additional cost. The power purchase charge—although still subject to fuel price and exchange rate fluctuations—was lowered from 7.5 cents to 6.0 cents kilowatthour. The capital cost charge was lowered by excluding the cost of the regasification facility, which was to be included instead in the cost of the fuel. There was a reduction in the foreign exchange component of payments to Enron by 400 billion rupee (about \$8.4 billion), and the MSEB was given an equity stake of 30 percent in the project. The project's fuel was switched to cheaper domestic naphtha for Phase I until commissioning of Phase II. More environmental provisions were agreed to, and employment was to be provided for one member of each family displaced by the project's construction site.^h

(continued on page 136)

^aEnron's partners included Bechtel Enterprises Holdings, Inc., and GE Capital Structured Finance Group, which were equity holders; various domestic and international financial institutions also supported the project through loans.

^bSEBs are state electricity boards which are in charge of providing generation, transmission, and distribution by coordinating with both public and private players involved both at the state and central level.

^cFast track projects were power projects of at least 1000-megawatt capacity and were given clearance much faster than normal power projects as a means of attracting foreign investment.

^dK.S. Parikh, "Thinking Through the Enron Issue," *Economic and Political Weekly* (April 28, 2001). This charge included the capital charge, operating and fuel charges.

^eThe Congress Party was in office when the original proceedings occurred, and it was pro-liberalization. Coalition parties often are formed among India's many diverse political parties.

^f"India: Dabhol Power Project," web site http://altindia.net/enron/Home_files/WBnote.htm (April 30, 1993).

^g"Munde Sub-Committee Report," web site www.hrw.org/reports/1999/enron/enron-b.htm.

measures. In the United States, the State of California (1998) had been at the forefront of State-initiated electricity reforms; however, the State has now begun to “re-regulate.”

Much of the electricity reform undertaken in various countries has been motivated by similar issues, including the following:

- Technological developments, particularly those related to the growing efficiency of natural gas turbines
- Investment shortages, particularly among developing countries
- High electricity prices
- A rethinking of the notion of electricity supply as a natural monopoly.

Technological Developments

For most of the last century, reductions in the cost of electricity generation were achieved through the building of larger and larger generators, which in essence supported the view that electricity generation was a natural monopoly.²⁰ In recent years, however, developments in natural gas technology have reversed that trend, allowing maximum efficiencies to be realized at lower and lower generation capacity levels. Almost all new generation capacity added in the United States currently is gas-fired. Gas-fired capacity offers several technological advantages over its alternatives, and—at all but the lowest interest rates—is more competitive than coal. Today, a state-of-the-art combined-cycle natural gas unit is more efficient than coal or nuclear units. Gas-fired plants also have shorter startup times. The time needed to build a natural-gas-fired generation unit averages 2 to 3 years, compared with 3 to 5 years for coal

India's Dabhol Power Project (Continued)

The new PPA became legally binding in August 1996, and Phase I began operation in 1999. The new contract soon ran into trouble, however. In July 2000, the average price of power from the Dabhol project rose sharply, following a depreciation of the rupee against the U.S. dollar and an increase in natural gas prices from 1999 to 2000. Early in 2001, the MSEB defaulted on its November electricity bill. The bill was eventually paid by the MSEB with assistance from the state government, but Phase I of the project was shut down, and construction on Phase II was halted.

A new energy review committee, chaired by Madhav Godbole, former chairman of the MSEB, was established by the Maharashtra state government. The committee's mandate was to review the electricity situation and particular electricity projects, including Dabhol. The review committee submitted Part I of the report on April 10, 2001.ⁱ It concluded that the Dabhol Power Corporation was overcharging the MSEB in terms of the regasification facility, shipping and harbor costs, operating and maintenance costs, and fuel consumption. Several guidelines were recommended to reduce the tariff and liability of the project.

The project hit another obstacle when the parent corporation, Enron, after tumbling into a financial abyss,

filed for bankruptcy in December 2001. Enron's share prices declined from \$85 one year earlier to 26 cents by late 2001.^j As a consequence, in December 2001, the Dabhol Power Corporation laid off 200 of its remaining employees. Many different approaches to the Dabhol project's financial difficulties are currently being entertained. Various entities that have been involved have stepped forward to offer possible solutions, including the World Bank and various other financial institutions, as well as external parties new to the scene, including domestic rivals Bombay Suburban Electric Supply and Tata Power Company, as well as other global energy giants that may seek to fill the role left vacant by Enron's apparent demise.

Whatever its eventual outcome, the drama of the Dabhol project has exposed some of the ills of India's electricity system. According to R.K. Pauchari, director of the Tata Energy Research Institute, electricity reform could add 1 to 2 percent to India's Gross Domestic Product “almost instantly,” and although reform has occurred at different levels in a handful of states (Orissa, for example) widespread reform is still in the early stages.^k The project has also exposed some of the difficulties foreign companies face in investing in countries currently making a transition toward freer market economies.

ⁱJ.W. Salacuse, “Renegotiating International Project Agreements,” *Centre for Energy, Petroleum and Mineral Law and Policy Internet Journal*, web site www.dundee.ac.uk/cepmlp (August 2001).

^jThe report can be found at web site www.maharashtra.gov.in/english/energy/lerc.htm. Part II was published September 2001 and focuses mostly on the general sector reform.

^kK.M. Kristof, “Bankruptcy of Energy Trader May Hurt Many,” *Los Angeles Times* (December 3, 2001).

^l“Red Tape and Blue Sparks: A Survey of India's Economy,” *The Economist*, Vol. 359, No. 8224 (June 2, 2001), pp. 9-14.

²⁰A natural monopoly is desirable in a situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms.

plants. In many countries nuclear power plants, if still an option, would take even more time to construct than a coal-fired plant.

Natural gas plants are also more flexible. The maximum efficiency of a gas-fired power plant is achieved at a much smaller level of capacity than a coal-fired unit. This feature increases the attractiveness of natural-gas-fired units, because the size of a new natural gas plant being introduced can be adapted readily to various changes in demand, and it can be built closer to the location where those changes are taking place. For all these reasons, future new capacity additions no longer need to be the domain of large utilities, and indeed no longer need to be in the domain of utilities at all. In both the United States and the United Kingdom, the move to natural gas has done much to foster an independent power generation industry—an industry less subject to government regulation than are traditional utilities.

Investment Shortages in Developing Countries

In the developing world, a lack of access to capital has in many instances hindered investment in electricity infrastructure. As a result, many countries have opened their electricity sectors to more direct forms of investment from overseas. This has been particularly true in the case of countries that suffered most during the widespread debt crisis of the 1980s. In Latin America, where economic growth and investment languished throughout most of the period, the 1980s were known as the “lost decade.” Moreover, during the 1980s, financial institutions, in particular commercial banks, incurred severe losses from loan defaults among developing nations, which may have had a limiting impact on the developing world’s access to some world capital markets and may have driven developing countries to allow greater direct investment from abroad. Another reform measure, which was commonly employed by developing countries in Asia, was to open up domestic electricity sectors to greenfield investments by foreign sources.

High Electricity Prices

Electricity prices vary considerably across regions and countries. Some of the variation can be accounted for by the degree of access to relatively cheap forms of electricity. For instance, in Norway, which relies on relatively cheap hydropower for almost all its electricity, electricity prices typically have been relatively low by industrial world standards [6]. The same is true of the Pacific Northwest of the United States, where colossal dams, many of which were built during the 1930s, provide relatively cheap sources of electricity.

Regional and national electricity prices also vary considerably with the ownership structure of the industry and the degree of regulation. The resulting price differentials can have a significant effect on a region or area’s degree

of competitiveness. They can also affect real standards of living. Many high-cost electricity countries, provinces, and U.S. States were among the earliest reformers. For instance, in 1995 electricity prices in California were 43 percent higher than the U.S. average [7], and industrial electricity prices in Germany were 15 percent higher than in the Organization of Economic Cooperation and Development (OECD) as a whole (Table 22).

Monopoly Industry and Competitive Industry

Another aspect of electricity reform is a rethinking of the notion that electricity supply is a natural monopoly. The rethinking has focused mostly on the generation

Table 22. OECD Industrial Electricity Prices, 1990-2000
(1999 Dollars per Kilowatthour)

OECD Country	1990	1995	1999	2000
Australia	0.042	0.048		
Austria	0.053	0.060	0.056	
Belgium	0.054	0.055		
Canada	0.032			
Czech Republic . . .	0.101	0.149	0.121	0.125
Denmark	0.041	0.046	0.053	0.054
Finland	0.038	0.045	0.042	0.041
France	0.046	0.046	0.040	0.039
Germany	0.071	0.071	0.052	
Greece	0.073	0.071	0.061	
Hungary	0.180	0.093	0.124	0.129
Ireland	0.059	0.064	0.059	0.056
Italy	0.082	0.097	0.093	0.117
Japan	0.091	0.103	0.101	
Korea	0.092	0.093	0.101	0.112
Mexico	0.074	0.059	0.069	0.079
Netherlands	0.044	0.059	0.061	0.068
New Zealand	0.036	0.040	0.038	0.035
Norway	0.023			
Poland	0.080	0.084	0.075	0.081
Portugal	0.135	0.148	0.116	0.113
Spain	0.091	0.083	0.067	
Sweden	0.033	0.029		
Switzerland	0.056	0.074	0.073	0.075
Turkey	0.144	0.156	0.170	0.187
United Kingdom . . .	0.066	0.066	0.059	0.056
United States	0.047	0.047	0.044	0.045
OECD Europe	0.067	0.070	0.060	0.047
OECD Total	0.062	0.062	0.057	0.040

Notes: Prices were calculated using purchasing power parities. Some data points are missing, because not all countries provide price information of each year.

Source: International Energy Agency, *Energy Prices & Taxes, Quarterly Statistics* (Paris, France, Fourth Quarter 2001); and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC, various issues).

side of the business and the relatively new business of electricity marketing. As mentioned earlier, with the economics of the industry changing in favor of smaller and smaller generation units, the opportunities for competition among different companies have grown. As a consequence, in many instances, countries have fully or partially liberated the generation side of the business from regulatory constraints while retaining regulation for the “wires” (transmission and distribution) side of the business. Competition in generation has also led to the creation of electricity pools, along with various hedging markets.

Global Electricity Reform

Various states, provinces, countries, and regions have undertaken efforts to reform their electricity sectors over the past two decades or so. Some of the reform efforts bear similarities; some have been unique. In general, however, the different paths to reform have involved one or more of the following actions:

- Unbundling of electricity assets through divestiture, or a vertical separation of ownership, and/or control, of certain electricity assets in order to promote competition, particularly in generation
- Creation of electricity trading arrangements (pools)
- Creation of independent system operators (ISOs) and, in the United States, regional trading organizations (RTOs)
- Privatization of electricity assets through sale or public auction, or the corporatization of the governance of the assets
- Deregulation of electricity prices and the implementation of a more restrained (light-handed) form of regulation where regulation was retained
- Open access to the grid
- Opening up of domestic electricity assets to foreign investment
- Retail competition.

Unbundling

Unbundling of electricity operations generally involves one of two approaches: (1) a separation of ownership of the various forms of electricity supply, i.e., generation, transmission, distribution, and marketing; or (2) a separation of control of the various forms of electricity supply. There are several motivations behind unbundling. One is to separate the potentially competitive elements of the business from those still bearing monopoly characteristics. Another is to offer various services with various price schedules, thus pricing various aspects of electricity supply at their costs of production, which adds greater transparency to electricity prices and enables consumers to make price comparisons.

In one form or another, most electricity reform around the globe has involved an unbundling of energy services. Several nations have attempted to achieve this goal through a vertical separation of ownership of various segments of the electricity industry. In Australia, Argentina, the United Kingdom, and the United States, unbundling involved the breaking up of vertically integrated utilities along their separate lines of business, creating distinct and separate corporate entities. In New Zealand, most of Western Europe, and the Nordic countries (Denmark, Finland, Norway, and Sweden), unbundling has generally involved the separate pricing of various electricity services and sometimes instituting an accounting separation between the different segments of electricity supply.

The United Kingdom was the first country to divest generation from distribution and transmission, which it accomplished in 1990. In the United Kingdom, the former government-owned power company (which included generation, transmission, and distribution assets) was separated during privatization into two generation companies, along with a transmission company and 12 distribution companies. A similar separation was instituted in Australia. As part of its reform efforts, California required its three major vertically integrated utilities to shed half their generation assets, which were largely sold off to independent power producers.

Another means of instilling more competition in generation involved not the separation of ownership but the separation of control. For instance, New Zealand separated transmission from distribution (although both remained government owned) and created two state-owned electricity generation companies so that they could compete against each other. Similar accounting separations occurred in Finland, Germany, Ireland, Portugal, and Spain [8].

Electricity Pools

Another important element of electricity reform involves the development of wholesale electricity trading arrangements, or electricity pools. In the past, most electricity was sold in bilateral forward markets. Several efforts at reform have initiated the introduction of pools to electricity exchanges. In several instances, electricity pools have been quite volatile. This volatility can serve a purpose in some market structures (e.g., by reducing demand or signaling a need for greater investment), but in others it has led to unwanted swings in earnings and prices to consumers. In order to deal with these and other complexities, various market designs have been employed by various countries and various regions in creating their electricity pools. These have sometimes included a variety of different trading arrangements: real-time pricing, day-ahead pricing, forward markets, and various hedging tools, such as futures markets and contracts for differences markets.

Although no two pool arrangements are identical, several share some similarities. In some cases, participation in electricity pools has been made mandatory, as initially was the case in Australia and the United Kingdom, or non-mandatory, as is the case in New Zealand, Nord Pool, Spain, and the Pennsylvania-New Jersey-Maryland pool (PJM) [9]. In several instances, unregulated bilateral markets have operated side by side with the pools, as in the United Kingdom, New Zealand, and the Nordic countries, or have been discouraged, as was the case in California. In some cases, prices have been set beforehand (as in the United Kingdom and Nord Pool), or by estimated supply and demand. In other cases, prices have been set after the market has cleared (as in Australia and New Zealand) or by actual supply and demand [10].

An important issue in the development of electricity pools involves ownership and/or corporate governance and the relationship of the pool to the entities that generate, transmit, and distribute electricity. Although electricity pools have existed in the United States since the late 1960s, the United Kingdom was the first to create a nationwide electricity pool, which has been in operation since 1990. In many ways the structure of this pool was copied elsewhere. Initially, the UK electricity pool was operated by the privately held National Grid Company, which was also responsible for electricity transmission. In turn, the National Grid Company was initially owned by 12 regional distribution companies (which were forced to divest their shares in 1995, when the National Grid became a separate, privately held concern). Similar organizational structures emerged in Sweden and Norway, where both system operation and pool operations fell under one umbrella organization [11]. In other countries and regions, ownership and/or control of the transmission system was separated from ownership and/or control of the electricity pool. This was true in Victoria (Australia) and California, where separate power exchanges were created in order to separate operation of the transmission system from operation of the pool.

Various countries have taken other approaches to pool ownership. In Alberta, Canada, the pool is operated on a cooperative basis governed by a council of pool participants [12]. In Finland, the power exchange was initially owned by a Securities and Derivatives Exchange. In New Zealand, the wholesale market is owned by the government-owned generation utility, the Electricity Marketing Company (EMCO). The PJM power pool is owned by 10 primary members, which are vertically integrated utilities.

Another important element of electricity pools is the rules under which they operate. The UK Pool (as it was initially set up), in some ways set the framework for many pools to follow. In order to balance electricity

supply and demand, the UK government instituted a power pool to act as a clearinghouse between suppliers of electricity (generators) and wholesale consumers of electricity (primarily the regional electricity distribution companies).

In the UK Power Pool, every day was broken up into 48 half-hour segments. The system manager forecast demand for each half-hour segment. Twenty-four hours in advance, generators submitted bids for the various levels of power they were willing to supply at various prices and for various periods, for each half-hour period of the following day. The system manager then ranked the bids from least to most expensive. The system manager also calculated the minimum amount of generating capacity needed to meet demand projections. A merit order dispatch schedule was created, with the cheapest generation units selected first and supply capped when enough generation units were selected into the system to provide sufficient generation capacity to supply one unit of energy over and above the demand forecast [13].

The Pool purchase price for all suppliers was set by the highest bid from the last generation facility needed to accommodate the last unit of demand. This balancing activity was an attempt to arrive at the electricity generation industry's marginal cost, or the system marginal price (SMP). The price actually paid to generators also included a financial incentive (capacity payment) for maintaining some additional (peak load) generation capacity in the event that demand exceeded the consumption forecasts. This merit order system of estimating a supply/demand equilibrium has been duplicated elsewhere. Argentina and California have adopted similar mechanisms to set market clearing prices.

In the United Kingdom, as a means of controlling price volatility, a hedging market developed. This market, called the contract for differences market (CfD), allowed for bilateral contracts to be negotiated between generators and consumers. In the CfD market, generators and electricity purchasers could hedge Pool prices by committing to a contract with an agreed-upon price (the strike price). The strike price, for instance, might be set at an average of expected daily Pool prices. If the strike price turned out to be higher than the daily average Pool price, then the generator paid the purchaser the difference. Conversely, if the strike price turned out to be lower than the daily average Pool price, the electricity purchaser reimbursed the generator for the difference. In reality, the CfD market used a variety of different hedging contracts. Contracts for differences were purely financial contracts. A contracts for differences market also emerged in Australia.

In early 2001, the United Kingdom shut down the Pool and embarked on a new form of electricity trading,

called the New Electricity Trading Arrangement (NETA). This was done because it was felt that the old pool arrangements failed to foster adequate competition. Even after the UK generation market was broken up during the mid-1990s, the Pool was still highly concentrated (Table 23). Devising trading arrangements suitable to a commodity with such unusual features as electricity has been a problem that has dogged deregulators in several countries, states, and provinces. In several ways, NETA comes closer to resembling Nord Pool than the old Pool of England and Wales. It allows for self-dispatch instead of giving the National Grid Company the role of scheduler and orderer. It also allows for firms to be paid the price they bid rather than the system marginal price. Further, NETA opens up the wholesale market to nongenerators, thus allowing commodity traders to participate in the market [14]. Unlike the old Pool, NETA does not include a capacity mechanism, which is currently the case for the Nord Pool, the California Pool, the Australian National Pool, and the New Zealand Pool [15].

The Nord Pool, which has been in operation since 1996, was the world's first international electricity commodity exchange. The Nord Pool evolved from an informal arrangement whereby Scandinavian nations had traded electricity for decades [16]. Currently, Denmark, Finland, Norway, and Sweden buy and sell electricity in the Nord Pool. The Nord Pool employs two markets, a day-ahead spot market, Elspot, and a financial market, Eltermin, for weekly contracts. The Eltermin market does not actually trade power. Rather, like the contracts for differences markets which emerged in the United Kingdom and Australia, Eltermin allows for a financial settlement between electricity buyers and sellers. Unlike the pools set up in California and the United Kingdom, the Nord Pool is a voluntary market that is accompanied by a great deal of bilateral trade. In 1998, Elspot and Eltermin accounted for only 20 percent of the total power sold in the Nordic market [17].

In 1995, Alberta passed its Electric Utilities Act (EUA), which led to the establishment of an electricity pool in

1996, the Alberta Power Pool, which was a non-profit corporation. Unlike in the United Kingdom, in Alberta electricity buyers and sellers could negotiate direct sales. However, the Alberta Power Pool initially restricted entry into the buy side of the market to entitled buyers, which were the incumbent utilities when the pool was formed [18]. In Alberta's pool, prices were not entirely competitive, in that generators were under rate-of-return regulation for their fixed costs. The EUA also established an ISO to manage Alberta's transmission network. In 1998, Alberta adopted amendments to the EUA that were intended to encourage further price competition by allowing independent power production and requiring incumbent utilities to undertake power purchasing arrangements with independent marketers [19].

In setting about electricity reform, California borrowed several elements from the UK model. For example, California's electricity reform required all sales to be conducted through a daily pool [20]. In the California Power Exchange, the pool price was set as follows: the California Power Exchange created an electricity supply and demand curve by combining all generator supply bids with all consumer demand bids. The clearing price—the price paid to the generators by the suppliers—was determined by the intersection of the supply and demand curves. This is similar to the pricing scheme initially employed in the United Kingdom, except that in the UK Pool demand was estimated by the National Grid Company. What distinguishes the California exchange from the UK Pool is the separation of the California Independent System Operator (CAISO) from the Power Exchange (PX). Moreover, California reforms did not provide pool participants with the hedging opportunities that the contracts for differences market provided in the United Kingdom and Australia, or the Eltermin market provided Nordic country participants.

Independent System Operators and Regional Transmission Organizations

ISOs have been developed in several states, countries, and provinces. In most cases, the ISO's function is to manage the grid and provide support to regional system operators. There are a number of forms an ISO can take, and there is an ongoing debate as to which is superior. One is a Transco, which is an independent system operator that both owns and operates the grid. Although Transcos may be profit or nonprofit enterprises, they are independent of system sellers and buyers. The National Grid Company in England and Wales is an example of a for-profit Transco [21].

In some cases, as mentioned in the above discussion of the UK Pool, the ISO and the pool have been one in the same, as in the case of the National Grid Company, which manages both the grid and the wholesale electricity market. Another form of ISO is the one operating in

Table 23. Levels of Horizontal Concentration in Selected Generation Markets, 1996 and 1998

Market	Market Share of Two Largest Generators	
	1996	1998
UK (England and Wales)	55	41
Nord Pool	40	35
Australia (National Electricity Market) . .	40	36
New Zealand	90	53

Source: International Energy Agency, *Competition in Electricity Markets* (Paris, France, February 2001), p. 35.

California. CAISO is a nonprofit ISO that manages the grid but also allows for a separate power exchange, the California (CAL PX). Ownership of the transmission lines remained with the three major utilities.

Australia, New Zealand, Spain, the United Kingdom, and the Nordic countries have opted for the full separation of the grid from the generation of electricity. In the United Kingdom, Finland, Sweden, and Norway, the grid companies are under separate ownership from generation companies. In California, Spain, and the Netherlands, generators own the grid, but it operates independently from them [22]. Argentina created an ISO that was owned by the generation, transmission, and distribution companies [23].

Congestion management is a major concern of the newly created ISOs. Congestion management in California was based on a system of zonal pricing, similar to that used in Australia, which differs from the “postage stamp” rates²¹ that are insensitive to congestion (and distance) operating in Alberta, Finland, Norway, the United Kingdom, and Sweden [24]. In contrast, Argentina, Chile, New Zealand, the PJM, and the New York ISO have opted for zonal pricing systems, which are most sensitive to congestion and distance traveled.

In the United States, current efforts at electricity reform have focused on improving the efficiency of the nation’s transmission network. The transmission system in the United States is not a nationwide operation but rather a mixture of balkanized regional arrangements that result in lost trading opportunities and in some cases rates that are artificially higher than they should be. Rates reflect transmission charges that are often “pancaked” when electricity crosses several transmission networks, amassing layer upon layer of tariffs.²² The overall goal of the new system is the creation of a national grid.

The Federal Energy Regulatory Commission (FERC) recently attempted to promote greater unification of the nation’s electricity grid by consolidating the operations of several regional ISOs. The FERC’s most recent effort at introducing more competition in the electricity industry was laid out in Order 2000, which was issued December 1999. Order 2000 advocates the formation of RTOs to operate the transmission network. Order 2000 requires that “each public utility that owns, operates, or controls facilities for the transmission of electric energy in

interstate commerce” [25] be required to submit proposals on how they would participate in RTOs. Order 2000 stated no preference for RTOs to be publicly owned ISOs or privately held Transcos.²³ Order 2000 also took a stance in favor of “zonal pricing”²⁴ and extensively discussed performance-based ratemaking [26].

As a followup to its Order 2000 Rulemaking, on July 12, 2001, the FERC directed the formation of four RTOs in the Northeast, the Southeast, the West, and the Midwest. (Texas would be handled separately.) In the Northeast, it was expected that the PJM pool would merge with ISOs in New England and New York [27]. The FERC ordered the groups to use elements of the PJM as a platform for building the new organization. The FERC expects that RTOs representing the Northeast and Southeast will be the first in operation.

The intent behind the creation of RTOs is to improve the coordination of regional transmission activities, which should allow for greater flexibility and efficiency, fewer bottlenecks, and more electricity trade. One benefit of RTOs is that they may lessen the impact of pancaking. It is also hoped that RTOs will reduce discriminatory treatment directed at producers that do not own transmission lines.

Privatization

Naturally, privatization has been a feature of electricity reform only in those nations where electric utilities were publicly owned. Until recently, the United States, Belgium, Germany, and Japan were in general unique among countries in the degree to which privately held companies supplied electric power. For most other countries, electricity asset ownership was public.

Ideological and political factors have in part motivated the different paths undertaken to privatization. In some cases, where privatization was a major component of electricity reform, such as England and Wales, privatization of electricity preceded deregulation. In Australia, efforts to privatize and deregulate have proceeded piecemeal, and in New Zealand, Norway, and Sweden deregulation has occurred largely without privatization [28].

A less dramatic step than privatization involves the corporatization of electricity assets. New Zealand, for instance, during its initial electricity reform program

²¹Postage stamp rates refer to the situation where fixed transmission costs are recovered through a single access fee over an entire region.

²²When multiple regions exist and a generator has to pay separate transmission access fees for moving power through each region, the rates are said to be “pancaked,” because they are added on top of one another.

²³Federal Energy Regulatory Commission, *Regional Transmission Organizations: Final Rule*, Docket No. RM99-2-000, Order 2000, 18 CFR Part 35 (December 20, 1999), p. 6, states: “. . . we do not propose to require or prohibit any one form of organization for RTOs or require or prohibit RTO ownership of transmission facilities. The characteristics and functions could be satisfied by different organization forms, such as ISOs, transcos, combinations of the two, or even new organizational forms not yet discussed in the industry or proposed to the Commission.”

²⁴Zonal pricing refers to the case where a region is broken into multiple subregions (zones) that have different wholesale electricity prices when transmission congestion occurs between the subregions.

transferred the nation's electricity assets from the Ministry of Energy to a newly created state-owned enterprise, the Electricity Corporation of NZ Ltd. Although the assets were to remain under government ownership, political control was diminished somewhat with the new accounting separation. Similarly, in New South Wales, Norway, Sweden, and Finland, where there has been a strong tradition of public ownership, privatization was not seen as an essential ingredient to achieving more competition in electricity supply. Rather, in general, the industries were reorganized to remove the monopoly franchise and to instill more commercial practices. Norwegian reform, for instance, separated the national grid from the power company.

Regulatory Reform

Several countries have attempted to deregulate the prices of various forms of energy service. Most of the deregulatory effort has focused on generation. For the wires business (transmission and distribution) the adoption of price-cap regulation and movement away from rate-of-return regulation has been a unique feature of recent regulatory reform efforts. The United Kingdom initiated what has become a much imitated model, allowing generation companies to sell their goods into a competitive market at competitive prices but applying a novel form of incentive regulation for the transmission and distribution sides of the business. Price-cap regulation attempts to restrain costs by applying price ceilings. Price-cap regulation was used as a means of instilling efficiency gains in the UK wire business. The price cap, known in the United Kingdom as RPI-X, allows for inflation-adjusted prices less expected efficiency gains. This form of "performance-based" regulation has been duplicated in other nations, including Argentina, Australia, New Zealand, and, in the United States, California and Texas.

Texas imposed a similar form of incentive regulation in its "price to beat." The "price to beat" is a price established to stimulate competition for sales to residential and small commercial customers. It is scheduled to go into effect in Texas in January 2002. For existing electric utilities the "price to beat" was set at 6 percent below the regulated retail rates in effect on January 1, 1999.

Open Access

Nondiscriminatory open access to the electricity grid has been a major goal of electricity reform in Australasia, North America, Western Europe, and South America. New Zealand's transmission system has been open to all levels of demand since reform efforts got started in 1994. Norway introduced open access when it began its reforms in 1991. Western Europe is currently the scene of attempts to create a continent-wide electricity market. A

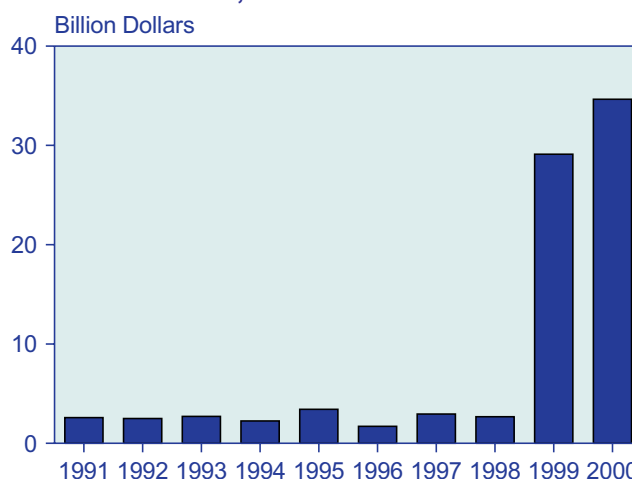
1996 European Community directive required all signatories to open up their electricity markets to new suppliers starting in February 1999.

Since opening their markets to non-incumbent suppliers, some countries have seen more or less switching among large customers. In some cases, switching has been deterred when incumbent suppliers have reduced prices in order to forestall market entry by new suppliers.

Foreign Investment

Although the desire to attract foreign investment has been an important motivation for electricity reform in the developing world, it has been the developed nations that have seen the greatest flows of foreign investment into their electricity sectors. For example, between the middle of 1995 and early 1997, U.S. utilities acquired 8 of the 12 privatized regional electricity companies in the United Kingdom, in transactions valued at more than \$25 billion in total. Similarly, in Australia, many electricity assets were purchased by U.S.- and UK-based companies after Australia deregulated its electricity sector and opened it up to foreign investors. In turn, several companies from the United Kingdom have recently acquired U.S. electricity assets, a development heretofore rare in the U.S. electricity industry. The largest was Scottish Power's purchase of PacifiCorp of Oregon in 1999, valued at an estimated \$12.9 billion. Indeed, the value of foreign investment in U.S. utilities rose from \$2.8 billion in 1998 to \$34.6 billion in 2000 (Figure 78),

Figure 78. Foreign Direct Investment in U.S. Utilities, 1991-2000



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments during 1999 is largely the result of investments in U.S. electric utilities by foreign companies.

Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (various issues).

exceeding the value of U.S. investment in overseas utilities (Figure 79).

Developing nations have also attracted some foreign investment. In some instances, particularly in Asian nations, foreign capital has been restricted to greenfield electricity generation projects. In contrast, in South America, foreign investors have been allowed to acquire domestic utilities in their entirety.

Retail Competition

One of the most far-reaching of all electricity reform efforts has been to allow consumers to choose their electricity suppliers, which could in some ways be seen as the other side of open access. In general, retail choice has been offered first at the wholesale level to large, primarily industrial and commercial users of electricity. Offering the ability to choose one's supplier to households has not been as widespread, and in at least one instance (California) has been less successful than efforts to open up wholesale markets. One of the difficulties faced by new suppliers trying to encourage households to switch from their incumbent suppliers is that any savings that a new supplier might provide as a result of better management of its generation or wires business is likely to be only a small percentage of the average household electricity bill, which is heavily weighted toward such costs as service fees, hookup charges, and billing fees.

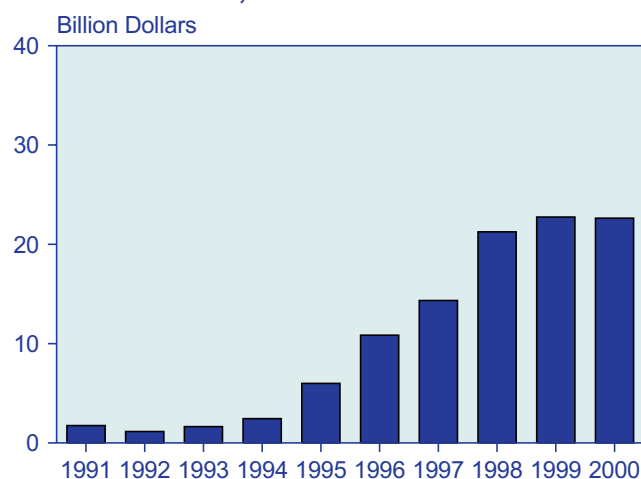
Some countries and states have, by and large, had good experiences with retail competition. Norway, New Zealand, Finland, Germany, Australia, the United

Kingdom, and Pennsylvania have generally been successful in introducing competition at the household level. It has been suggested that by 2007 an estimated 500 million OECD consumers will be able to choose their electricity suppliers [29]. In the United States, roughly half of the States have adopted plans for retail competition, and retail competition is currently available in Massachusetts and Rhode Island. In Texas retail choice began in 2002 [30]. In Australia, the state of Victoria has offered retail choice since January 2001, and New South Wales is expected to offer retail choice by January 2002 and South Australia by January 2003.

Retail choice has in some instances led to greater competition in electricity markets. Between October 1999 and February 2000, 7 percent of Scandinavian households switched electricity providers, and another 18 percent renegotiated electricity prices with incumbent suppliers [31]. By February 2000, 14 percent of consumers in England and Wales had switched suppliers [32]. In Germany, by the year 2005, "71 percent of industrial users, 45 percent of commercial users and 32 percent of residential users are expected to switch providers" [33].

California's experience with retail choice was less successful. In California, Assembly Bill 1890 provided customer choice by allowing more than 70 percent of California's electricity customers to change providers. By the time the retail market was opened to competition, 250 power marketing companies had signed up to sell electricity directly to California consumers. California consumers have, however, been reluctant to switch from their incumbent suppliers. They may have been discouraged by retail rate caps and by the fees charged for making a switch.

Figure 79. U.S. Direct Investment in Overseas Utilities, 1991-2000



Note: The utility investments shown include, in addition to electricity, natural gas distribution and sanitary services; however, the sharp rise in investments from 1995 through 1999 is almost entirely the result of investments in overseas electric utilities by U.S. companies.

Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (various issues).

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Transportation Energy Use

Oil is expected to remain the primary fuel source for transportation throughout the world, and transportation fuels are projected to account for almost 57 percent of total world oil consumption by 2020.

Trends and Projections

Energy demand for transportation is projected to grow by 2.5 percent per year from 1999 to 2020, a higher pace than that forecast for energy demand as a whole (Table 24 and Figure 80). As a result, the transportation sector's share of total world energy consumption is projected to rise slightly, to just over 21 percent by 2020. Economic expansion and higher incomes are expected to increase the use of energy for transportation, as businesses and individuals demand greater mobility for themselves and their products. At the regional level, "transportation energy intensity"—defined here as the amount of energy used in the transportation sector per unit of gross domestic product (GDP)—is expected to decline in all regions over the forecast period (Figure 81), holding down some of the potential growth in transportation energy use. For the world as a whole, transportation energy demand per unit of GDP is expected to fall by 0.7 percent per year from 1999 to 2020.

The high oil prices and tight markets that characterized the world energy industry in 2000 were reversed in 2001. Even before the terrorist attacks of September 11, 2001, slowing economic growth and switching back to natural gas were moderating growth in oil demand [1]. The 2001

growth in energy demand for the transportation sector is likely to be the lowest in several years. From 1995 to 1999, energy consumption for transportation increased at an annual average rate of about 1 million barrels per day. In 2001, however, jet fuel and gasoline, the mainstays of the transport sector, both showed demand weakness that was exacerbated after September 11. World oil demand projections for 2001 were lowered to an increase of 0.4 million barrels per day in EIA's November *Short-Term Energy Outlook*, from 1.0 million barrels per day in the forecast before the attacks [2].

Jet fuel is expected to remain the fastest growing fuel for transportation, although the near-term outlook was severely weakened by the September 11 attacks. The demand for air travel fell significantly as a general reluctance to fly caused many travelers to postpone or cancel their travel plans. In the aftermath of the attacks, EIA estimated that jet fuel demand probably fell by about 10 percent outside the United States and as much as twice that within the United States. Jet fuel demand in the United States is estimated to have fallen by 11 percent in the second half of 2001 from year-earlier levels. A 1-percent increase is projected for the United States in 2002, and global jet fuel demand is expected to be down by roughly 5 percent [3].

Table 24. Transportation Energy Use by Region, 1990-2020

Region	Transportation Energy Consumption (Million Barrels Oil Equivalent per Day)				Average Annual Percent Change	
	1990	1999	2010	2020	1990-1999	1999-2020
Industrialized	21	25	31	36	1.9	1.7
North America	13	15	20	24	1.8	2.1
Western Europe	6	8	9	9	1.8	1.1
Industrialized Asia	2	3	3	3	3.0	1.1
EE/FSU	4	2	3	4	-5.4	2.9
Developing	8	11	17	25	4.4	3.8
Asia	3	6	10	16	6.4	4.9
Middle East	1	2	2	2	2.6	0.6
Africa	1	1	2	2	1.9	2.9
Central and South America . . .	2	2	3	5	3.2	3.1
Total World	33	39	52	65	2.0	2.5

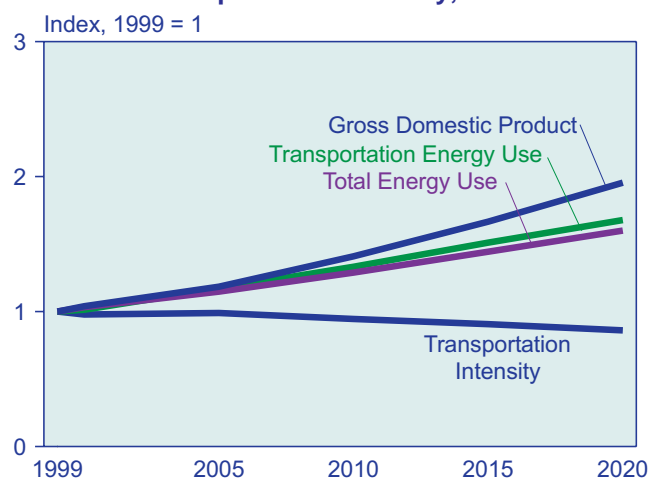
Note: Data include nonpetroleum sources of energy used in the transportation sector.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

The airline industry, which was showing signs of weakness before the attacks, has also been severely affected. In response to the drop in air travel, airlines in the United States have cut flights and announced job losses exceeding 100,000 [4]. The U.S. Congress allocated \$15 billion to sustain the airlines as executives warned of imminent bankruptcies in the industry [5]. Airline troubles extended beyond the U.S. border due to the steep decline in international air travel and soaring insurance rates. Financial support was announced for several airlines, with some declared bankrupt and closed down or sold. French airplane manufacturer Airbus announced that it was freezing its production expansion plans at current levels, although it will still proceed with the development of its A380 super jumbo aircraft [6]. Airbus expects the number of the very large aircraft in service to reach 1,235 by 2019, more than half of which are expected to operate from only 10 airports [7].

Airport development continued in 2001, and growth in air travel is expected to remain robust in the long term; but finding space for new airports remains a problem. The new Incheon International Airport near Seoul, South Korea, is built on a man-made land bridge between two islands, following the example set by Japan's Osaka International Airport, which is built on a man-made island [8]. Japan is considering a new 1.6-mile runway for Tokyo's Haneda Airport, elevated 66 feet above sea level in Tokyo Bay in order not to interfere with maritime traffic [9]. Two locations are being considered for a new airport for Mexico City, one 22 miles from the city and the other 53 miles to the north [10].

Figure 80. Changes in World Gross Domestic Product, Energy Demand, Transportation Energy Use, and Transportation Intensity, 1999-2020



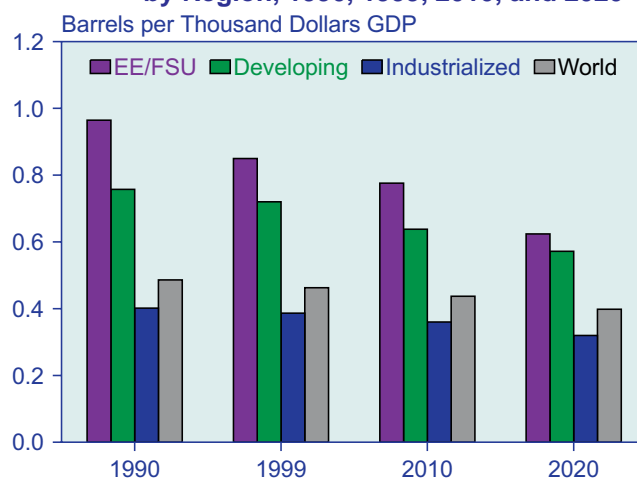
Sources: **1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2000-2020:** EIA, World Energy Projection System (2002).

After jet fuel, diesel fuel is projected to show the strongest growth, further increasing demand for the middle of the barrel at the expense of gasoline and heavy fuel oil. Europe and South Korea currently have tax regimes that favor diesel over gasoline. Strong growth in diesel fuel is also projected for China and India. Some believe that the United States will have to move toward diesel if fuel efficiency standards are raised.

World vehicle ownership is projected to increase from 122 vehicles per thousand people in 1999 to 144 vehicles per thousand in 2020. Growth in per capita vehicle ownership is expected to slow in industrialized countries as saturation levels begin to be reached. In most of the developing nations, growth in vehicle ownership is expected to continue at a rapid pace. More rapid demand growth in the developing countries is a trend that is expected to occur throughout the transportation sector (Figure 82), and more than one-half of the increase in the world's transportation energy use is projected to take place in developing countries. With their higher economic growth rates and higher energy intensities, the developing countries' share of transportation energy demand is expected to rise from 29 percent in 1999 to 38 percent in 2020.

Future transportation demand trends will also be influenced by government policies directed at reducing emissions and congestion while promoting alternative fuels, new vehicle technologies, and mass transit. Such policies are aimed at vehicle efficiencies, the cost and quality of fuels consumed, the composition of fuels used for transportation, infrastructure development, and the research and development of new technologies.

Figure 81. World Transportation Energy Intensity by Region, 1990, 1999, 2010, and 2020



Sources: **1990 and 1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, World Energy Projection System (2002).

Tensions among the goals of achieving economic growth, environmental improvement, and energy security are especially evident in the transportation sector. The ability to develop sustainable mobility and meet those three goals has been the focus of numerous studies and policy development activities. Over the past year, several governmental bodies around the world have produced or are in the process of developing transportation sector policies that could have considerable impact on the shape of future transportation trends, as discussed in the regional activity section below.

Sustainable mobility has become a catch phrase, defined as “the ability to meet the needs of society to move freely, gain access, communicate, trade, and establish relationships without sacrificing other essential human or ecological values today or in the future” [11]. It is being driven by the desire to improve urban air quality, reduce greenhouse gas emissions, and lower dependence on oil imports. Some have argued that it is through efficiency gains that sustainability is possible [12]. The focus is often on technological advances that will result in vehicles with few if any harmful emissions and significantly lower fossil fuel consumption. In the long term, sustainability is seen by many as a movement completely away from fossil fuels to a hydrogen-based energy system [13].

Alternatives to oil are being promoted to move toward sustainability goals in the near term. Compressed natural gas (CNG) and liquefied petroleum gases (LPG)²⁵ continue to be promoted in many countries. Thailand and Malaysia are experimenting with the development

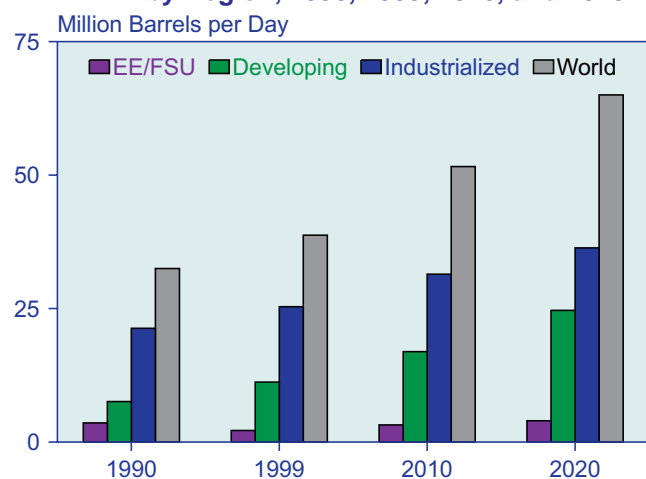
of fuel using palm and coconut oils, and Brazil, Mexico and Thailand are promoting ethanol from sugar cane. Although many countries are promoting alternatives to petroleum, their market share is expected to remain relatively small throughout the forecast, because market penetration is slow and the development of the infrastructure needed to support new energy sources remains daunting.

The share of transportation energy use made up by oil consumption is not expected to drop significantly in the *IEO2002* forecast, but oil’s dominance may begin to be challenged by advancing technologies. Several technologies designed to improve the efficiency of internal combustion engines are already entering the market, including continuously variable transmission, which provides an infinite set of gear ratios, and displacement-on-demand, which turns cylinders on or off according to driving conditions. Gas-to-liquids (GTL) technology may be able to provide liquid fuels from a non-oil source without requiring major changes in fuel distribution infrastructure. Hybrid and fuel cell vehicles, however, are getting most of the attention as technologies that could significantly alter future transportation oil demand.

Most of the world’s major automobile companies have plans to introduce some form of hybrid and/or fuel cell vehicle in the next decade. Honda and Toyota already have hybrid cars on the market. General Motors is developing a diesel hybrid bus, to be followed by hybrid pickups and sport utility vehicles, and expects to have gasoline-powered fuel cell vehicles developed by the end of the decade that will cut emissions to trace amounts and increase the fuel efficiency of today’s vehicles by 50 percent [14]. DaimlerChrysler, Honda, and Toyota have also stated that they plan to have fuel cell vehicles developed by 2004 [15]. Honda Motor Company began road tests in July 2001 on a new fuel cell vehicle that runs on compressed hydrogen. The vehicle achieved driving performance closer to that of traditional vehicles, showing improvement over previous versions with regard to speed, acceleration, and cruising distance [16].

Significant technological, economic, and fueling infrastructure barriers remain for both hybrid and fuel cell vehicles. For example, the U.S. National Research Council has indicated that successful commercial application of fuel cells for passenger vehicles is at least 10 to 15 years away [17]. General Motors has also indicated that although fuel cell vehicles will begin to appear on streets in the next few years, they will be demonstration projects at least through the middle of the decade. Even if the projected cost reductions for fuel cell vehicles are

Figure 82. World Transportation Energy Use by Region, 1990, 1999, 2010, and 2020



Sources: **1990 and 1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** EIA, *World Energy Projection System* (2002).

²⁵ Although LPG is an oil product, a large proportion is derived from wet natural gas streams. Because reserves of natural gas are widely dispersed, LPG use does not evoke the same security concerns as other petroleum products.

achieved, the economics still may favor traditional gasoline engines in countries where gasoline prices are relatively low [18].

One of the biggest obstacles to the penetration of fuel cell vehicles is the infrastructure needed to make the fuel widely available. For gasoline fuel cells the infrastructure is already in place, but infrastructure would have to be developed for methanol or hydrogen. In the United States a task force has been formed to draft a plan for the development of infrastructure for hydrogen-based vehicles and power plants. So far, it appears that the infrastructure needed to produce, transport, store, and distribute hydrogen will be very expensive to develop [19]. It may also be possible, however, to develop a dual-fuel engine that would run on gasoline as well, which would allow the infrastructure to be introduced gradually. BMW has unveiled a prototype car with a hydrogen-powered engine [20].

Although the existing distribution system favors gasoline fuel cell vehicles, hybrid vehicles may be able to achieve levels of fuel efficiency and emissions reductions comparable to those of gasoline fuel cell vehicles at a much lower cost. If so, it is possible that gasoline fuel cell cars could lose out to hybrids [21].

The movement toward advanced technologies will continue to put pressure on refiners to produce the cleaner fuels needed for fuel efficiency gains and emission reductions. Essentially sulfur-free gasoline and diesel, containing 10 parts per million (ppm) sulfur or less, will be needed for the most promising advanced engine and emission control systems. Even lower sulfur levels will be needed for fuel cell vehicles. In addition, gasoline with more tightly controlled distillation properties may be needed, as well as lower aromatics in both gasoline and diesel fuel [22]. Although refiners have resisted improving some fuel characteristics to the extent that automakers say they need, the movement toward cleaner fuels is a worldwide trend that is likely to continue.

Regional Activity

North America

North America accounted for 39 percent of the world's fuel use for transportation and 49 percent of the world's gasoline consumption in 1999. The largest regional increase in gasoline demand in the forecast period is projected for North America (Figure 83), where gasoline currently captures 62 percent of the transportation fuels market.

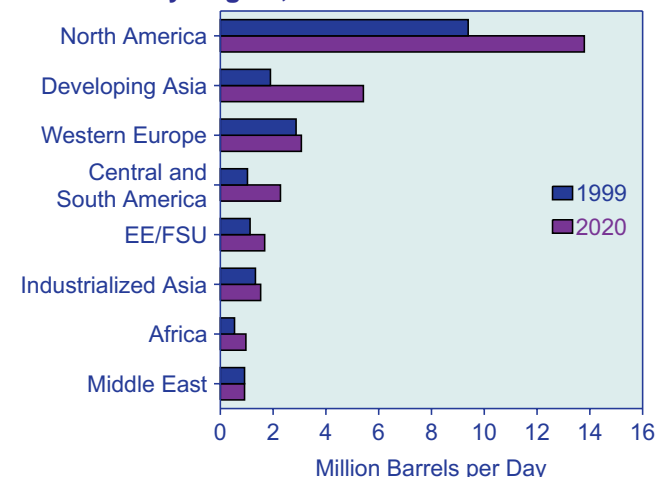
United States

High prices and tight markets for energy fuels over the past several years have moved energy security and energy policy issues back into prominence in the United

States. In May 2001, the Office of Transportation Technology (OTT) in the U.S. Department of Energy released a study on future highway energy use [23]. The study focused on advanced vehicle and fuel technologies as a means to lower oil consumption and reduce emissions without curtailing transportation service. Its purpose was to demonstrate that plausible alternatives exist, but that achieving them will require both continued technological advances and effective public policies. The study estimated that hybrid vehicles currently are 10 to 20 percent more expensive than conventional vehicles and that fuel cell vehicles are at least 20 percent more expensive.

The average fuel economy of new vehicles in the United States reached a 21-year low in model year 2001 at 20.4 miles per gallon, as a result of increased sales of sport utility vehicles, vans, and pickup trucks [24]. Higher vehicle fuel economy standards have been proposed as a means of reducing oil demand and imports [25], and a National Research Council study has suggested that automakers could significantly raise the fuel efficiency of passenger cars and light-duty trucks by 16 to 47 percent over the next 10 to 15 years [26]. Increasing corporate average fuel economy (CAFE) standards for light duty trucks, however, could result in a shift toward diesel fuel that would have implications for the refining industry. U.S. refiners normally target about a 2-to-1 ratio of gasoline to diesel production, and a significant decline could necessitate refinery modifications. In contrast to the United States, Europe typically exports gasoline and imports diesel fuel. If the United States shifts toward diesel fuel, the result may be excess gasoline production capacity and tight diesel markets [27]. In the absence of increased CAFE standards, EIA projects an increase of 0.3 percent per year in the fuel efficiency of the U.S. light-duty vehicle fleet [28].

Figure 83. World Motor Gasoline Demand by Region, 1999 and 2020



Sources: **1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

The transportation sector is expected to contribute 89 percent of the projected increase in oil demand in the United States. One-fourth of the increase in world transportation energy use is expected to occur in the United States. Gasoline is expected to continue to dominate the sector, although its share is projected to decline slightly from 61 percent in 2000 to 58 percent in 2020.

Alternative fuels are not expected to penetrate the U.S. market to a large extent in the forecast period, despite some movement to alternative fuels. In California, 24 of the State's 43 largest transit agencies have opted for natural gas buses over diesel-powered engines with emissions reduction devices for ultra-low-sulfur diesel fuel. The natural gas buses are up to 15 percent more expensive but are far cleaner with respect to nitrogen oxide, air toxics, and soot [29]. CNG consumption in the United States is projected to grow by nearly 10 percent per year from 2000 to 2020.

Canada

Transportation energy use in Canada is projected to rise by 1.4 percent per year from 1999 to 2020. Canada has a transportation fuels market similar to that in the United States. Gasoline makes up 61 percent of Canada's transportation fuel demand, and its per capita consumption of transportation fuels is second only to that of the United States (12.4 and 17.8 barrels per person per year, respectively). Canada announced plans in February 2001 to harmonize certain fuel qualities with those of the United States in order to maintain product fungibility between the two countries. Sulfur levels in highway diesel fuel will be limited to 15 parts per million starting June 1, 2006, matching the U.S. requirement enacted in December 2000. Environment Canada is also developing future standards for off-road diesel and fuel oils and additional restrictions on gasoline [30].

Oil's share of transportation energy use in Canada is projected to remain at about 90 percent. The Government of Canada, however, is working with the alternative transportation fuels industry and major vehicle manufacturers to expand the use of fuel cells and fuels such as natural gas, ethanol, and electricity and is working to achieve new vehicle efficiency targets by 2010 [31]. In the 1990s, the average fuel efficiency of Canada's vehicle fleet improved despite the trend toward heavier and more powerful vehicles; however, with sales of minivans and sport utility vehicles expected to grow, efficiency gains are likely to be more challenging in the future [32].

The Canadian government launched a 12-month initiative in April 2001 to develop a federal strategy to respond to the major challenges that will face Canada's transportation sector over the next decade and beyond. The initiative will build on the work of the Canada

Transportation Review Act Panel and the Transportation Climate Change Table. The Transportation Review Act Panel made a number of wide-ranging recommendations related to enhancing competition, evaluating mergers, financing infrastructure, developing policies, and other areas. The Transportation Climate Change Table provided options for reducing greenhouse gas emissions from transportation, the largest source of greenhouse gas emissions in Canada [33].

The Canadian Pacific Railway is calling for transportation policy that promotes competition and allows natural market forces to prevail, pointing out that Canada is the only country in the world that enjoys the benefit of two competing national railway systems that are not supported by taxpayers [34].

Mexico

Transportation energy demand in Mexico is projected to grow at the fastest rate among the industrialized countries. By 2020, per capita consumption of transportation fuels is expected to approach the level in Japan. Road use is expected to dominate, accounting for 82 percent of transportation consumption in 2020. The number of vehicles per thousand people in Mexico currently stands at 25 percent of the level in the United States but is expected to jump to 48 percent of the U.S. level by 2020, with gasoline comprising about 58 percent of the increase in transportation fuel use.

Mexico is studying the possibility of replacing the gasoline blending component methyl tertiary butyl ether (MTBE) with ethanol made from sugar cane. The Mexican sugar industry, unable to meet the challenge of fructose imports, is facing a severe crisis of overproduction. Producing ethanol would help to eliminate the surplus, in addition to doing away with the controversial ether [35]. MTBE has been detected in groundwater samples in the United States, causing several States to restrict its use.

Considerable progress has been made in reducing air pollution in Mexico City. Over the past 10 years, ambient lead concentrations have been reduced by 98 percent, sulfur dioxide concentrations have fallen to acceptable levels, and few violations of the carbon monoxide standard remain. Serious problems still persist, however, with high concentrations of ozone and particulates. The transportation sector is the main source of air pollution in the Mexico City metropolitan area. Several measures were enacted in the 1990s to improve air quality, including tax policies to reduce the price differential between leaded and unleaded gasoline, the installation of vapor recovery systems at service stations, the introduction of reformulated gasoline and low-sulfur diesel fuel, upgraded emission standards for new vehicles, and inspection and maintenance

programs. The creation of an Environmental Trust Fund through a surcharge on gasoline in Mexico City is considered to be an important step in sustaining the progress that has been made [36].

Western Europe

Sustainable mobility was the impetus behind a White Paper developed by the European Commission that proposed some 60 measures aimed at bringing about substantial improvements in the quality and efficiency of transport in Europe. It also presented a strategy designed to gradually break the link between constant transport growth and economic growth, in order to reduce the pressure on the environment and prevent congestion while maintaining competitiveness. The proposals included a harmonization of fuel taxes across the countries, infrastructure development concentrating on filling in the missing links in trans-European networks, and improving safety and quality. Other measures were aimed at developing fair infrastructure charging, taking into account external costs and encouraging the use of the least polluting modes of transport. Another proposed objective was to shift the balance between modes of transport by 2010 by revitalizing the railways, promoting maritime and inland waterway transport, and linking up the different modes of transport [37]. Since 1980, the length of the European Union (EU) motorway network has increased by more than 70 percent, but railway lines and inland waterways have decreased by about 9 percent. Sixty percent of the international funding for the trans-European transport network has been targeted for rail, but actual investments are still biased toward highways [38].

Gasoline consumption in Western Europe in 1999 was at the same level as in 1990. Despite growth in car traffic, the static gasoline market resulted from the use of smaller, more efficient cars and the shift to diesel fuel. Consumers have been encouraged to purchase diesel-fueled cars through beneficial taxation policies, the development of efficient engines, and the perception that the fuel is more environmentally friendly [39]. These trends are projected to continue, with diesel fuel consumption estimated to rise by 0.7 million barrels per day from 1999 to 2020 (Figure 84) and gasoline by 0.2 million barrels per day.

The European Commission has also indicated that it plans to introduce a harmonized excise duty on diesel fuel across the EU that would be higher than the current average tax on diesel. The medium-range goal would be to tax gasoline and diesel similarly for all users. Exemptions for hydrogen and biofuels are expected to be included, not only for environmental benefits but also as a way to boost energy security [40].

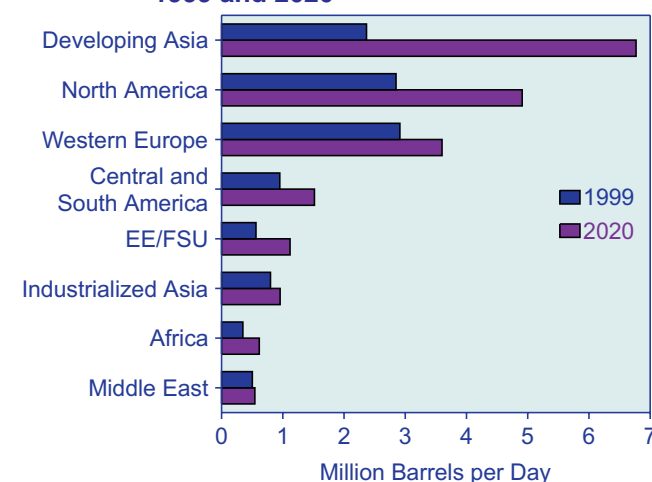
The September 11 attacks in the United States severely affected airline companies in Europe. British Airways

cut 7,000 jobs and reduced operations by 10 percent [41]. Swissair, which had been having financial difficulties for months, suspended operations on October 2 and resumed flights only after the Swiss government stepped in with a bailout package [42]. The European Commission approved compensation for losses that stemmed from the cancellation of flights to and from the United States for four days after September 11 but made it clear that no public subsidy would be permitted for any other reason [43]. Restructuring in the European airline industry is expected to result in only four or five international carriers plus an ensemble of regional carriers [44]. In the long term, however, strong growth in jet fuel consumption is expected. The increase in jet fuel consumption from 1999 to 2020 is projected to equal that of gasoline and diesel fuel for transport combined. By 2020, demand for air travel is expected to reach 19 percent of the region's transportation energy demand.

The United Kingdom is projected to contribute 22 percent of the increase in transportation energy use in Western Europe from 1999 to 2020. Consumption for air travel makes up a larger proportion of transportation demand in the United Kingdom than in continental European countries, and that share is projected to reach 27 percent by 2020. Despite the growth in air travel, London and the Southeast United Kingdom have added little runway capacity in the past 50 years. The Confederation of Business Industry has called for expansion of airport capacity, stating that it is essential for business and economic growth [45].

Despite the lower proportion of fuel consumption for road use in the United Kingdom as a whole, the people of London listed traffic congestion as the number one

Figure 84. Diesel Fuel Demand by Region, 1999 and 2020



Sources: **1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

transportation issue that they wanted tackled. In addition to proposals to expand the capacity of the rail and subway lines, the Mayor of London has proposed congestion charging as a means to reduce traffic in the city [46].

Higher prices and a weak euro resulted in a small decrease in oil consumption in France in 2000. Diesel consumption, however, continues to increase due to a favorable tax regime. In 2000, 34.7 percent of privately owned cars in France had diesel motors, and a record 49 percent of new registrations were for diesel cars [47]. While the share of gasoline declines, diesel fuel is projected to continue to make up more than one-half of total transportation energy use in France.

Germany is the largest transportation market in Western Europe. Ultra-low-sulfur gasoline and diesel fuels (50 ppm) were introduced on November 1, 2001, without the price spikes and market disruptions sometimes associated with changes in product specifications. The fuels were brought into the market using tax incentives rather than mandates. Domestic refiners are producing most of the low-sulfur gasoline, but a significant portion is being imported [48]. Gasoline made up 50 percent of Germany's transportation fuel market in 1990, but its share is expected to fall to 43 percent by 2020. Strong growth is projected for jet fuel and diesel fuel consumption.

In an effort to improve air quality, Germany slashed the excise duty on CNG to a quarter of that on gasoline and diesel until 2009. That brings CNG down to 60 percent of the cost of traditional fuel on an energy equivalent basis. Excluding taxes, CNG is still 8 percent more expensive than natural gas delivered to households, which provides incentives to suppliers. Natural gas pumps are expected at 1,000 filling stations within 5 years. The program is aimed chiefly at commuters. CNG vehicles have a range of 109 to 124 miles, and the tank takes up about half a normal car's trunk space. The goal is to have 1 million vehicles running on natural gas by 2006, up from about 10,000 currently [49].

Italy ranks second to Argentina in numbers of natural gas vehicles with about 370,000 or about 1 percent of all vehicles. Italian motorists have been encouraged to switch from gasoline to CNG since the 1930s, when the wartime government was anxious to lessen reliance on imported oil [50]. At 612 vehicles per thousand people, Italy's per capita vehicle ownership is higher than that of Germany, France, or the United Kingdom. Road use fuel consumption currently amounts to 84 percent of Italy's transportation energy demand, ranking among the highest in Europe, and it is expected to remain relatively high at 80 percent in 2020.

Austria's OMV oil and gas group plans to install 20 new natural gas filling stations over the next 3 years, given a pending reduction of excise duty on CNG. An Austrian

network would enable motorists using CNG to drive from the northern part of Germany to southern Italy. The company estimates that 1 to 2 percent of Austria's vehicles could be running on CNG within 10 years [51].

Industrialized Asia

Transportation energy demand in industrialized Asia is projected to increase by 1.1 percent per year from 1999 to 2020, down from its 3.0-percent average annual growth rate from 1990 to 1999. Slower economic growth is expected for the region, and per capita vehicle ownership levels are already high, contributing to the expectation of slower growth in transportation fuel use.

Australia

The need to overcome large distances contributed to development of the transportation sector in Australia. About 567,302 miles of highways, 21,014 miles of rail, and more than 400 airports provide transportation infrastructure for the movement of goods and people [52]. Jet fuel's share of total transportation energy use is one of the highest among the countries in the forecast, and Australia has the second highest national per capita vehicle ownership rate after the United States.

Australia is expanding the number of CNG refueling sites, with the total expected to exceed 30 stations in the next 18 months. It is hoped that the increase in refueling sites will encourage motorists to consider the economic and environmental benefits of converting to CNG. With CNG sourced entirely within the country, prices are not affected by fluctuations in world crude oil prices or exchange rates [53].

Ansett Airlines became one of the victims of the post-September 11 slowdown in air travel. It ceased operations in September until the Australian government decided to underwrite tickets to get five airplanes back in operation. Qantas Airways picked up much of Ansett's 39-percent share of the Australian domestic air travel market, which helped to shield Qantas from the slowdown in international demand [54].

Japan

Despite the economic malaise of the past decade, per capita vehicle ownership in Japan grew at a higher rate than any other industrialized country in the forecast except Mexico. It was the used car market, however, that had the biggest boom. In contrast to 1990, when new car registrations were about 20 percent higher than used cars, used car registrations now exceed those for new cars by about 37 percent. Toyota and Honda are accelerating efforts to expand their used-car businesses in hopes of promoting sales of their new cars [55].

The market for mini-vehicles with lower costs and higher efficiencies is also growing in Japan. (Mini-vehicles are defined as vehicles with 0.66-liter engines or

smaller.) New mini-vehicle sales rose by 21.2 percent to a record 1.88 million units in 1999, the first gain in 4 years [56]. The use of smaller, more efficient vehicles and greater reliance on mass transit has helped to give Japan the lowest level of transportation energy consumption per unit of GDP among the countries in the forecast. In 1999, Japan's transportation energy intensity was 57 percent of the level in Western Europe and 31 percent of the level in the United States.

Public works projects have become a source of contention as the Japanese government steers between getting its runaway budget deficit under control and providing fiscal stimulus to keep the economy from sliding further into recession [57]. This was evident when three research councils associated with the ruling Liberal Democratic Party jointly adopted a resolution calling for full implementation of an expressway construction program, resisting Prime Minister Koizumi's plans to scale back Japan's expressway projects [58].

The Japanese Ministry of Land, Infrastructure and Transport is proposing to expand Tokyo's Haneda Airport rather than build a third airport in the greater Tokyo area [59]. Haneda's international flights had been limited to only those of Taiwan's China Airlines until February 2001, when Japan's three major airlines and two South Korean airlines were allowed to begin some international charter flights [60]. Tokyo's Narita Airport wanted to add a 1.6-mile runway to accommodate larger passenger airlines but was forced to scale back plans to only 1.4 miles as a result of disputes with farmers living next to the airport [61]. Until May 2001, Narita had only one runway, 2.5 miles in length [62].

Developing Asia

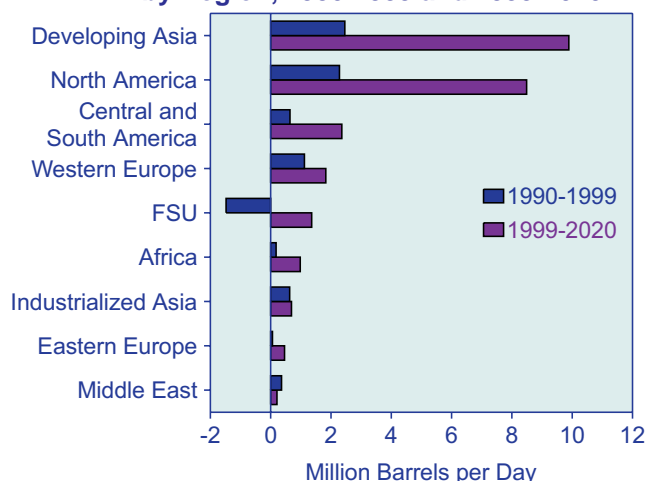
Developing Asia is expected to have the highest growth rate among the regions in the forecast, and transportation energy demand in the region is projected to exceed that in Western Europe by 2010, making it second in transportation fuel consumption after North America. Developing Asia is projected to account for 38 percent of the increase in world transportation energy demand from 1999 to 2020 (Figure 85), with an annual average growth rate of 4.9 percent. Jet fuel demand is expected to increase more than fourfold (Figure 86), and gasoline and diesel fuel consumption are projected to nearly triple.

China

The transportation sector was left out of China's economic plans for many years, and the resulting lack of infrastructure is a major bottleneck for the country's energy sector and overall economy. China has recently begun working on the development of roads, railways, and inland waterways. In 1999, the total length of operational freeways reached 7,208 miles, ranking third in the world behind the United States and Canada. China also plans to develop a high-speed railway network around the country.

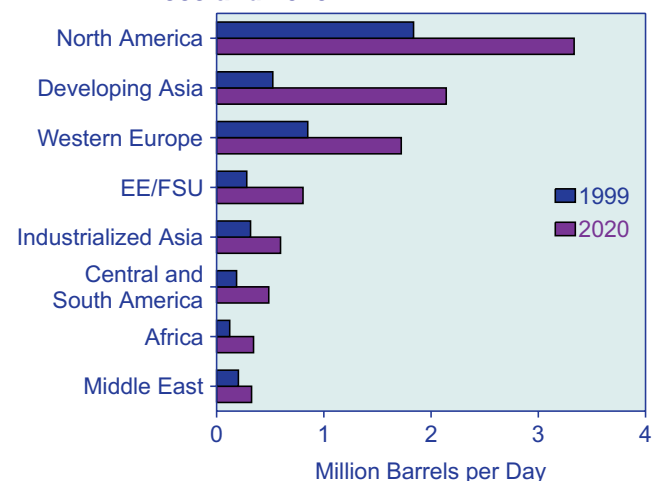
China's vehicle stock is dominated by heavy commercial vehicles, but passenger cars are expected to be the fastest growing component of in the forecast. Mass transit is expected to continue to dominate, however, and car density is expected to remain low in comparison with industrialized countries [63]. The number of vehicles per thousand people in China is projected to reach 52 in 2020

Figure 85. Changes in Transportation Energy Use by Region, 1980-1999 and 1999-2020



Sources: **1980-1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **1990-2020:** EIA, World Energy Projection System (2002).

Figure 86. Jet Fuel Demand by Region, 1999 and 2020



Sources: **1999:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

from 12 in 1999. The projected strong growth in automobile sales reflect China's economic growth, the development of car financing, efforts to make car ownership easier, the launch of new models, and greater price competition [64].

Transportation energy demand in China is projected to grow by 6.4 percent per year from 1999 to 2020, increasing its share of world energy use for transportation from 4.1 percent in 1999 to 9.1 percent in 2020. China is expected to pass Japan by 2005 and become the world's second largest consumer of transportation fuels. The strongest growth is projected for gasoline, and gasoline consumption in China is expected to exceed that in Western Europe by 2020.

In 2000, China began to tie domestic petroleum product prices to international prices in Singapore. The prices were linked to the previous month's averages on Singapore's spot market, enabling wholesalers to estimate the price trends in advance and determine product volumes accordingly. This resulted in large demand swings for refiners and left them with unsold product. As a result, starting in October 2001, domestic gasoline and distillate prices were linked to Rotterdam and New York prices as well as Singapore. Linking the prices to Rotterdam and New York in addition to Singapore is expected to even out price volatility and limit the scope for manipulation [65].

The Air Transport Action Group predicts that China will overtake Japan as the dominant market for air travel in the Asia-Pacific region, projecting a rise from 70 million passengers annually in 1999 to 200 million by 2014 [66]. Pudong International Airport in Shanghai is planning to build a second runway and undergo further expansion that will make it the busiest airport in China and one of the busiest airports in the world by 2010 [67].

India

India's consumption of energy for transportation is projected to rise by 6.8 percent per year from 1999 to 2020, making it the third largest after the United States and China. On a per capita basis, however, India still would rank among the lowest in the world.

India has been advancing the use of CNG in an effort to reduce air pollution. Gujarat Gas Company, Ltd., is developing a compressed natural gas business in Gujarat. It has a pipeline network that feeds gas to users in the Surat, Ankleswar, and Bharuch areas and is already supplying CNG to about 800 vehicles in Surat city [68].

Delhi's compulsory transition of the city's entire public transport fleet to CNG revealed some of the difficulties that alternative fuels face. In July 1998, India's Supreme Court set a deadline of March 31, 2001, for the public

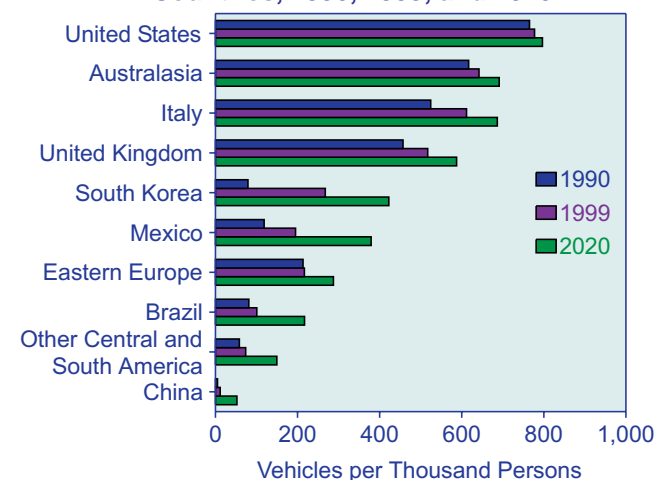
transport fleet in Delhi to be converted to CNG. A month before the deadline, however, only a fraction of the fleet had been converted, and the city had only three CNG bus filling stations [69]. The court extended the deadline to September 30, 2001, but restricted the number of diesel buses to the number of orders placed for new CNG buses or for conversions [70]. By October, only about one-third of the bus fleet was using CNG, and the court agreed to allow extra time. A new deadline is expected after the court reviews detailed plans and timetables from authorities and receives input from bus manufacturers, conversion agencies, and the gas supplier, Indraprastha Gas, Ltd. [71].

The Tata Energy Research Institute (TERI) called for the consideration of ultra-low-sulfur diesel as an alternative to CNG buses in Delhi, arguing that similar air pollution benefits could be obtained for a much cheaper price. TERI also pointed out some of the problems in the decisionmaking process, that the economics of the changeover and the practical feasibility of putting the infrastructure in place were not carefully considered, and that the decision was made without any trials being carried out under operating conditions [72]. The transition is being made, but the process has proven painful for those involved.

South Korea

Per capita vehicle ownership in South Korea increased by 14.5 percent per year from 1990 to 1999. The pace is expected to slow in the forecast period, but by 2020 the number of vehicles per thousand people in South Korea is projected to equal 53 percent of the level in the United States, as compared with 10 percent in 1990 (Figure 87). South Korea's automobile manufacturers have been

Figure 87. Motorization Levels in Selected Countries, 1990, 1999, and 2020



Sources: 1990 and 1999: Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). 2020: EIA, World Energy Projection System (2002).

struggling since the financial crisis of 1998. General Motors Corporation acquired Daewoo Motor Company in September 2001. Daewoo had been in court receivership since filing for bankruptcy in November 2000 after negotiations with Ford Motor Company broke down [73]. Hyundai/Kia is now the lone Korean-owned manufacturer [74].

Gasoline consumption makes up just 26 percent of the transportation fuel market in South Korea, primarily because its gasoline prices are among the highest in the world. Diesel fuel is less than half as expensive, and its consumption for transportation is 34 percent higher than that of gasoline [75]. Consumption of LPG for transportation use increased by nearly 25 percent per year in 1999 and 2000 and by another 13 percent in the first 3 months of 2001 [76]. That rapid growth is likely to slow, however, after a fourfold increase in the excise tax on LPG that started July 1, 2001. Additional tax increases are planned every 6 months for the next 5 years to bring the LPG price from 22 percent of the cost of gasoline to 65 percent. The government also plans to raise the excise tax on diesel fuel to bring its price to 80 percent of the gasoline price [77].

Jet fuel demand in South Korea is projected to more than triple over the forecast period. A new airport has been built in the greater Seoul area, Incheon International Airport, which can handle as many as 27 million passengers and 1.7 million tons of freight each year. South Korea is hoping that the new facility will help it compete with rival facilities in northeast Asia [78].

Other Developing Asia

The Thai cabinet approved a scheme that included builder tax incentives for four new ethanol plants using sugar cane and other crops. The government plans eventually to use ethanol in a 10-percent blend in all gasoline in an effort to reduce imports of oil and MTBE [79]. In July 2001, the government exempted non-petroleum portions of fuel from taxes, providing additional incentives for blending with ethanol and other alternative fuels. Higher oil prices and lower coconut and palm oil prices have led to renewed interest in biodiesel production. King Bhumibol Adulyadej holds a patent on palm-oil biodiesel, and a coconut-oil biodiesel process was patented in March 2001. The Petroleum Authority of Thailand (PTT) has been selling 3,000 to 4,000 liters (793 to 1,057 gallons) daily of 5 percent refined palm-oil biodiesel since July when the tax exemption began [80].

In spite of a growing vehicle population, Bangkok's air has become quantifiably cleaner over the past few years. Leaded gasoline has been banned since 1996, and all cars exported to and produced in Thailand are required to meet European emission standards. In 2001, 90 percent of new motorcycles sold in Bangkok were cleaner, more

fuel-efficient four-stroke models. In addition, open green space in Bangkok has more than doubled since 1993. While more progress is needed, Bangkok is slowly making improvements in air quality [81].

Jakarta, Indonesia, ranks as one of the most polluted cities in the world due in large part to automobile emissions. In 2000, atmospheric lead pollution was measured at 1.3 micrograms per cubic meter, above the World Health Organization limit of 0.5 to 1.0 micrograms per cubic meter. Controlling air pollution has been difficult because the economic slowdown has not hindered the growth in the number of vehicles, which has continued at 15 percent per year, but has made it more difficult for Pertamina, the national oil company, to secure loans to build catalytic reformers to provide the high-octane blending components needed to produce unleaded gasoline [82]. Indonesia is still planning to phase out leaded gasoline by 2003. Pertamina is continuing to upgrade its refineries to meet the fuel standards but expects that imports of unleaded gasoline may be needed to meet demand [83].

Air quality has deteriorated significantly in Hong Kong in recent years. Vehicles are the primary cause of street-level pollution, producing smoke, particulates, and chemicals in quantities that regularly exceed health standards. In May 2001, participants in a Cleaner Vehicles and Fuels Workshop gathered ideas and developed action plans for reducing vehicle emissions. The group recommended that Hong Kong establish an Energy Commission to develop a clear, coordinated energy policy. The Commission would develop long-term policies to remove barriers to the introduction of cleaner vehicles and fuels, adopt performance-based incentives to promote the cleanest vehicles and fuels infrastructure, develop an integrated education and training strategy, and promote research and development. The ultimate goal is to achieve zero emissions from transportation, probably by means of hydrogen-powered fuel cell vehicles [84].

Central and South America

Central and South America is one of the most urbanized regions of the developing world, with approximately 80 percent of its population residing in metropolitan areas and more than 55 metropolitan areas of 1 million inhabitants or more. The process of urbanization has occurred fairly rapidly and has accelerated dramatically in the past 30 years. The urban transportation sector is commonly regarded as one of the main culprits behind the high levels of urban air pollution in the region [85].

Congestion is also a major problem. Per capita vehicle ownership in Central and South America is much higher than in other developing regions, although it remains considerably lower than in the industrialized countries.

The number of vehicles per thousand people in Central and South America is projected to increase to 215 by 2020. Some cities have begun a strategy of deemphasizing cars and providing public transport instead. Curitiba, Brazil, built a system of dedicated busways and zoned for higher density development along those thoroughfares. The city now enjoys better air quality and more parks for its 2.5 million people. Car-free days are also being used to promote public transportation and reduce dependence on cars [86].

Most of the countries in Central and South America have phased lead out of gasoline in the past several years. When Venezuela completes its lead phasedown program, nearly all gasoline in the region will be lead free. Venezuela has targeted 2015 for lead phaseout, but discussions are under way to move up the date. Venezuela will likely accomplish the phaseout by converting its large leaded premium pool into unleaded regular gasoline with minimal octane loss [87].

Brazil

Brazil has nearly 1.2 million miles of roads—more than twice as many as Australia, Canada, or Russia—but less than 10 percent are paved [88] and road conditions in the rural sections are often poor [89]. The road portion of transportation energy use in Brazil is projected to decline slightly to 84 percent by 2020, and per capita vehicle ownership is expected to more than double to 217 vehicles per thousand people.

Congestion and air pollution are big problems in Brazil's cities. In 1999, 90 percent of Sao Paulo's smog resulted from motor vehicle emissions. Sao Paulo's pollution levels are fueled by poor infrastructure design, gasoline prices that are among the lowest in the world, and inefficient automobiles. The local government instituted a pollution control program in 1999 requiring that motorists leave their cars home one day a week. An orbital motorway, additional metro lines, and improvements to the rail system are also planned to improve environmental conditions [90].

Gasoline in Brazil consists of about 20 percent ethanol made from sugar cane. The Brazilian National Alcohol Program started in the 1970s as an alternative to oil and to promote self-sufficiency. The ethanol market is regulated to keep the price competitive with gasoline [91]. Gasoline prices are controlled at the refinery but not at the pump. Refinery prices are adjusted every 3 months, taking into account international oil prices and the value of the Brazilian real in relation to the U.S. dollar [92]. The Petrobras monopoly on refining and distribution of petroleum products came to an end in 1998, and since then other companies have sought to expand into Brazil's market. Petroleos de Venezuela (PDV) has plans

to open a number of gasoline stations in Northeastern Brazil starting in the fourth quarter of 2001 [93].

Argentina

Argentina's recession continued, with the economic situation deteriorating sharply in the summer of 2001. The International Monetary Fund (IMF) provided additional monetary assistance in September 2001, but most analysts do not think it will be sufficient to prevent further financial difficulties [94].

Argentina has an extensive transportation network, much of which has been privatized over the past decade. Maintaining and upgrading the highway system is a challenge in a country that stretches 2,485 miles from north to south. Argentina has 133,592 miles of highways, of which 29 percent are paved [95]. An estimated 87 percent of passenger and 85 percent of domestic freight traffic is carried by road. The most highly traveled sections of more than 30 national highways have become privately operated toll roads. Traffic managers have stressed that improved road conditions on those highways reduce vehicle maintenance costs and travel time, more than making up for the fees that drivers have to pay. Moreover, the government has been able to apply road taxes to repair secondary roads, pave dirt roads, and construct new roads [96].

Some 8 million cars and a large fleet of buses operate in the city of Buenos Aires each day, creating serious health problems [97]. A workshop sponsored by the World Bank Clean Air Initiative identified improved inspection and maintenance systems and the planning and development of a cycle lane system as two important projects to help reduce emissions and congestion [98]. In addition, Argentina is planning to reduce sulfur levels in gasoline and diesel fuel to 50 ppm by 2006 [99]. Tax incentives for biodiesel have been announced in an effort to help farmers as well as reduce emissions. The incentives, which extend to excise, income, and property taxes, could allow production of biodiesel at sales prices well below that of regular diesel fuel [100]. Argentina also has 687,000 natural gas vehicles, more than any other country in the world [101].

In the early 1970s, Argentina could boast that all its cities with a population of 10,000 or more (with the exception of Ushuaia in Tierra del Fuego) were served by rail; however, government ownership led to management decisions that were often based on politics, government priorities, and expediency. Investment and research and development were deemphasized, and by the late 1980s huge operating subsidies were required to keep the system running at even a marginal level. Since 1992, all but one of Argentina's railways have been privatized. Since privatization, the passenger and freight traffic have

risen and service has improved. The railroad industry is also trying to improve its relationship with ports to persuade traders that rails can serve them as well as trucks [102].

Waterways are an important part of Argentina's transportation sector. Nearly 90 percent of the country's foreign trade passes by water through its sea and river ports. Argentina has 2,175 miles of navigable waterways. Since privatization, investment has gone into increasing port capacity and improving operations. The work force has been reduced by 75 percent, management has been restructured, and operations have been streamlined. Argentina's move to revamp its marine terminals and waterways should bolster the country's increasingly important waterborne trade [103].

Aerolineas Argentinas was grounded for 5 months in 2001 after declaring bankruptcy protection when two of the seven unions representing its employees refused to go along with a restructuring plan that would have slashed wages and benefits in return for guaranteed job continuity. Flights resumed in November under new ownership [104].

Middle East

Gasoline makes up a larger share of the transportation fuel market in the Middle East than in other developing regions. As a result of slower growth in motorization rates, transportation demand in the region is projected to increase by 0.6 percent per year from 1999 to 2020. Jet fuel is expected to show the strongest growth as air travel expands in the region.

The large increase in traffic that has ensued from Saudi Arabia's economic development made it necessary to upgrade several of the nation's inter-city roads to multi-lane expressways. Traffic congestion in the cities has also resulted in the development of ring roads around city centers, as well as overpasses and underpasses to keep traffic flowing [105]. Air pollution in Saudi cities is the lowest in the Middle East and should continue to improve with the introduction of unleaded gasoline in January 2001. The switch to unleaded gasoline will result in the need for an estimated 3 million catalytic converters in order to reduce pollution from vehicle exhaust [106].

In 1945, U.S. President Roosevelt presented Saudi King Abdul Aziz with a DC-3 Dakota airplane. The King quickly realized the contribution that air travel could make to the development of the Kingdom and promptly ordered two more planes. Saudi Arabia now has three international airports and 22 regional and local airports, linking together all parts of the country [107].

Dubai International Airport in the United Arab Emirates is the fastest growing airport in the region. It handled 6.8

million passengers in the first half of 2001, up by 14 percent from the same period in the previous year. Freight traffic increased by 8 percent [108]. A \$2.5 billion expansion program was announced to add another terminal and two concourses. Completion is planned for 2006 [109].

Africa

Maintaining the road infrastructure has been a big challenge for much of Africa. At the end of the 1980s, Sub-Saharan Africa had nearly 1.2 million miles of roads worth about \$170 billion, but nearly one-third of that investment has been lost through lack of maintenance. A Road Maintenance Initiative (RMI) was launched, bringing the roads into the marketplace, setting fees for use, and managing them like any business enterprise. Although the pace and impact of reform have been slower than expected, several countries have shown substantial increases in the proportion of main roads designated as "good." Conditions on rural and feeder roads have not improved, however, and the Sub-Saharan Africa Transport Policy Program is accessing obstacles to continued improvements and ways to overcome them [110].

Former Soviet Union

Transportation energy demand declined by 7.3 percent per year from 1990 to 1999 in the former Soviet Union (FSU) as a result of the turmoil that accompanied the end of the Soviet era. Trucks used to dominate the traffic on Russian city streets, but private car ownership grew rapidly in the 1990s [111]. Road use energy demand in the FSU is projected to increase by 3.3 percent per year from 1999 to 2020 and jet fuel demand by 4.8 percent per year. By 2020, transportation energy demand in the FSU is expected to be at nearly the same level as in 1990.

Infrastructure development remains a serious concern in Russia. In the 1990s, roads, bridges, and other infrastructure fell into an advanced state of decay, and investment was inadequate for the needed repairs [112]. As fast as the Russian economy declined, investment declined even faster. A combination of low domestic savings, limited foreign investment, and government deficits resulted in an investment crisis that hindered infrastructure development [113]. Over the past several years, however, Russia has shown strong economic growth. Higher oil prices, exchange rate depreciation, and moderating inflation have contributed to a renewal of economic growth and an improved investment climate [114].

Eastern Europe

Transportation energy demand in Eastern Europe fell as a result of the economic turmoil that occurred after the collapse of the Soviet Union, but from 1990 to 1999 it grew at an average annual rate of 1.1 percent. The

transportation infrastructure in Eastern Europe shows the effects of 40 years of central planning and lack of investment. The density of the national public road networks and their quality are generally lagging far behind road network standards of EU countries. Many roads are in poor repair because they were not made to handle the current high volumes of traffic and the weight of modern trucks [115]. Travelers and goods used to move mainly by train but the importance of railways is decreasing and the future of many rural lines is uncertain. The frequency of service has declined and fares have increased [116]. Fuel quality also lags behind that in Western Europe, but countries in Eastern Europe are working hard to improve fuel quality to harmonize with EU fuel standards. Gasoline's share of the market is much higher in Eastern Europe than in Western Europe.

Poland

Poland is using tax incentives to encourage consumption of unleaded gasoline and low-sulfur diesel fuel. More than 80 percent of the diesel fuel currently used is estimated to contain less than 500 ppm sulfur, and 25 percent contains less than 50 ppm sulfur. The excise tax on 500 ppm sulfur fuel is 5 percent less than the tax on diesel fuel with 2,000 ppm, and diesel fuel with a sulfur content of 50 ppm has an excise tax that is 1.5 percent less than that on 500 ppm fuel. The excise tax on unleaded gasoline is 10 percent less than on leaded fuel, but the market penetration of unleaded gasoline has been slower because cars in the country average 10 years old, and only 27 percent are equipped with catalytic converters. In 2000, unleaded gasoline made up 20 percent of total gasoline sales [117].

The Polish government is also proposing to commercialize, restructure, and partially privatize the Polish State Railways (PKP) over the period 2001-2003. The reform initiative aims to encourage the development of rail transport services that meet the needs of a market economy, reduce the burden on the state imposed by PKP's heavy losses, and help to prepare the transport system for Poland's entry into the EU. The World Bank approved a loan for the project, which includes severance payments and redeployment services for displaced workers [118].

Romania

Romania's transportation infrastructure reflects many years of poor investment. Most roads are in poor condition, and only 25 percent of the road network is modernized. Road density with regard to both population and land area is the lowest among all central and east European countries [119]. Car ownership is increasing rapidly, but most of the cars on the road in Romania are old and poorly maintained, running on gasoline that has the highest lead content in Eastern Europe [120]. Vehicle ownership in the country increased by 79 percent from

1990 to 1996, and more than 80 percent of the vehicle fleet is gasoline powered. All new vehicles, imported and domestically produced, are now required to have catalytic converters. Romania is planning a complete phaseout of leaded gasoline by 2003 [121].

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Environmental Issues and World Energy Use

In the coming decades, global environmental issues could significantly affect patterns of energy use around the world. Any future efforts to limit carbon emissions are likely to alter the composition of total energy-related carbon emissions by energy source.

Global climate change is a wide-reaching environmental issue that has received increased attention in recent years. Carbon dioxide, one of the most prevalent greenhouse gases in the atmosphere, has two major anthropogenic (human-caused) sources: the combustion of fossil fuels and changes in land use. Net releases of carbon dioxide from these two sources are believed to be contributing to the rapid rise in atmospheric concentrations since pre-industrial times. Because estimates indicate that approximately 80 percent all anthropogenic carbon dioxide emissions currently come from fossil fuel combustion, world energy use has emerged at the center of the climate change debate [1].

Global Outlook for Carbon Dioxide Emissions

The *International Energy Outlook 2002 (IEO2002)* projects emissions of energy-related carbon dioxide, which, as noted above, account for the majority of global anthropogenic carbon dioxide emissions. Based on expectations of regional economic growth and dependence on fossil energy in the *IEO2002* reference case, global carbon dioxide emissions are expected to grow more rapidly over the projection period than they did

during the 1990s. An increase in fossil fuel consumption, particularly in developing countries, is largely responsible for the expectation of fast-paced growth in carbon dioxide emissions. Factors such as population growth, rising personal incomes, rising standards of living, and further industrialization are expected to have a much greater influence on levels of energy consumption in developing countries than in industrialized nations. Energy-related emissions are projected to grow most rapidly in China, the country expected to have the highest rate of growth in per capita income and fossil fuel use over the forecast period.

Carbon intensity—the amount of carbon dioxide emitted per dollar of gross domestic product (GDP)—is projected to improve (decrease) throughout the world over the next two decades (Table 25). The steepest rates of improvement are, for the most part, expected to occur among the transitional economies of Eastern Europe and the former Soviet Union (EE/FSU). In the FSU, economic recovery from the upheaval of the 1990s is expected to continue throughout the forecast. The FSU nations are also expected to replace old and inefficient capital stock and increasingly use less carbon-intensive natural gas for electricity generation and other end uses

Table 25. Carbon Intensities for Selected Countries and Regions, 1999-2020
(Metric Tons Carbon Equivalent per Thousand 1997 Dollars of GDP)

Country or Region	1999	2005	2010	2020	Annual Percent Change, 1999-2020
United States	168	159	146	124	-1.4
Canada	214	194	178	155	-1.5
Mexico	230	234	218	185	-1.0
United Kingdom	109	104	96	81	-1.4
France	72	68	62	56	-1.2
Germany	105	98	90	78	-1.4
Australasia	223	203	187	159	-1.6
Former Soviet Union . .	1,068	900	785	589	-2.8
Eastern Europe	558	482	411	305	-2.8
China	645	555	493	392	-2.3
India	511	457	403	315	-2.3
South Korea	218	201	177	142	-2.0
Brazil	108	100	100	94	-0.6
Turkey	268	253	229	191	-1.6

Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2005-2020:** EIA, World Energy Projection System (2002).

in place of more carbon-intensive oil and coal. Eastern European nations have been in economic recovery longer than has the FSU, and natural gas is expected to continue to displace coal use in the region, resulting in an average 2.8-percent annual improvement (decrease) in carbon intensity for Eastern Europe as a whole.

The developing Asian countries of China and India are also expected to enjoy a fairly rapid improvement in carbon intensity over the projection period, primarily as a result of rapid economic growth rather than a switch to less carbon-intensive fuels. Both China and India are projected to remain heavily dependent on fossil fuels, particularly coal, in the *IEO2002* reference case, but their annual GDP growth is projected to average 6.6 percent, compared with an expected 4.4-percent annual rate of increase in fossil fuel use from 1999 to 2020.

In 1999, carbon dioxide emissions from industrialized countries accounted for 51 percent of the global total, followed by developing countries at 35 percent and the EE/FSU at 13 percent. By 2020, developing countries are projected to account for the largest share of world carbon dioxide emissions, at 46 percent, followed by the industrialized world at 42 percent and the EE/FSU at 12 percent. The *IEO2002* projections indicate that carbon dioxide emissions from developing countries could surpass those from industrialized countries around 2015 (Figure 88).

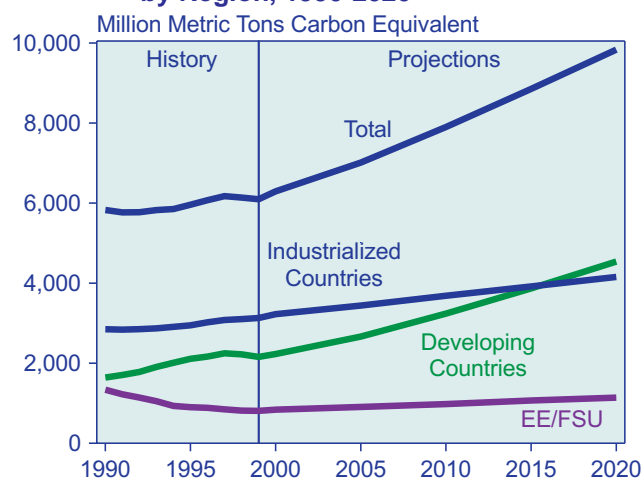
In the industrialized world, almost one-half of all energy-related carbon dioxide emissions in 1999 came from oil use, followed by coal at 30 percent (Figure 89). Over the forecast period, oil is projected to remain

the primary source of carbon dioxide emissions in industrialized countries because of its continued importance in the transportation sector, where there are currently few economical alternatives. Natural gas use and associated emissions are projected to increase substantially, particularly for electricity generation. By 2020, the share of natural-gas-related emissions is expected to be approximately equal to that of coal at 26 percent.

The United States is currently the largest energy consumer in the industrialized world, accounting for the majority of its energy-related carbon dioxide emissions. Natural gas and coal use for electricity generation in the United States are projected to increase over the forecast period, whereas generation from nuclear energy is expected to decline after 2010. No new nuclear plants are expected to be constructed in the United States by 2020, given the more favorable economics of competing technologies. As a result, U.S. electricity generation is projected to become more carbon intensive over the forecast period.

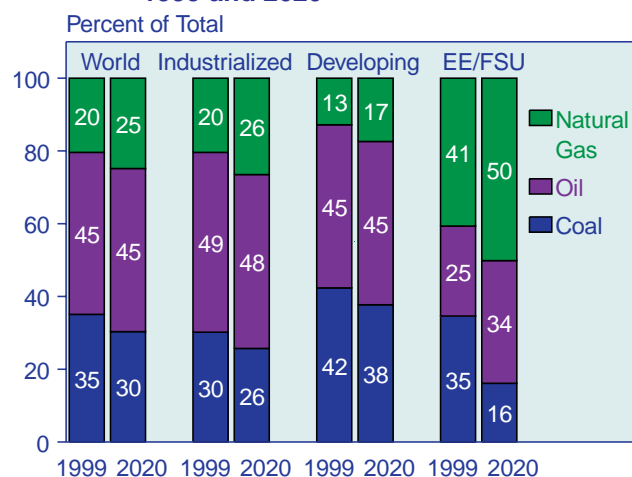
With the exception of Australia, most other industrialized countries rely much less heavily on coal to meet domestic energy needs than does the United States. In Western Europe, coal consumption is projected to continue to decline over the forecast period as natural gas consumption, particularly for electricity generation, increases. The projected decline in Western Europe's carbon intensity, brought on by the continued shift in the overall energy supply toward more natural gas, is lessened somewhat by the projected decline in nuclear power generation after 2010. Germany and Sweden have committed to shutting down their nuclear power

Figure 88. World Carbon Dioxide Emissions by Region, 1990-2020



Sources: **History:** Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database and *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Figure 89. Shares of World Carbon Dioxide Emissions by Region and Fuel Type, 1999 and 2020



Sources: **1999:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2020:** EIA, World Energy Projection System (2002).

industries, and other European countries are considering similar proposals. Electricity generation from other non-emitting energy sources, such as hydroelectricity and wind power, is not expected to fully offset the drop in nuclear energy production in these regions.

In the transitional economies of the EE/FSU region, the majority of energy-related carbon dioxide emissions currently come from natural gas combustion. Coal production and consumption in the EE/FSU declined as a result of economic reforms and industry restructuring during the 1990s, bringing about an increase in the natural gas share of the energy and emissions mix during the period. With further development of the vast natural gas reserves in Russia and the Caspian Sea region, natural gas is expected to continue to displace coal. Oil consumption is also projected to increase in the FSU, particularly for transportation and power generation, as Soviet-era nuclear reactors are retired in the coming years. As a result, both natural gas and oil are projected to account for increasing shares of the region's total carbon dioxide emissions, reaching 47 percent and 34 percent, respectively, by 2020.

With further restructuring of the coal mining industries in Poland and the Czech Republic, declines in coal production and consumption are expected to continue. On the other hand, natural gas consumption in Eastern Europe is expected to increase significantly, driven in part by the need for many countries to meet the strict environmental standards required for membership in the European Union (EU). As a result of the projected changes in the energy mix, Eastern Europe's carbon intensity is expected to decline more than in any other world region over the forecast period. However, the decline in Eastern Europe's carbon intensity is not expected to keep pace with the expected growth in its total energy consumption. Consequently, annual carbon dioxide emissions in the region are expected to increase by nearly 26 percent between 1999 and 2020.

Compared with most of the industrialized countries, a much larger share of energy consumption in developing countries (particularly in Africa and Asia) comes from biomass, which includes wood, charcoal, animal waste, and agricultural residues. Because data on biomass use in developing nations are often sparse or inadequate, *IEO2002* does not include the combustion of biomass fuels in its coverage of current or projected energy consumption and associated carbon dioxide emissions, except for the United States.

Of the fossil fuels, oil and coal currently account for the majority of total energy-related carbon dioxide emissions in the developing world, and they are projected to remain the dominant sources of emissions throughout the forecast period. China and India are expected to continue to rely heavily on domestic coal supplies for

electricity generation and industrial activities. Most other developing regions are expected to continue to depend on oil to meet the majority of their energy needs, especially in light of the projected increase in transportation energy demand.

The largest increases in energy consumption and carbon emissions are projected for China, given the expectations for continued economic expansion and population growth. Coal reserves are abundant in China, and access to other energy fuels is limited in many parts of the country. Second only to developing Asia in terms of projected growth in energy consumption and carbon dioxide emissions, is Central and South America. Many countries in the region, most notably Brazil, have relied heavily on hydropower to provide the majority of their electricity. Natural gas is expected to take on an increasing share of the energy mix in Central and South America over the forecast period, however, as the countries continue their efforts to lessen dependence on hydropower by tapping into the region's large natural gas reserves. As a result of the expected change in the region's fuel mix, coupled with an increase in overall energy demand, carbon dioxide emissions from Central and South America are expected to more than double between 1999 and 2020.

Future levels of energy-related carbon dioxide emissions in all regions are likely to differ significantly from *IEO2002* projections if measures to mitigate emissions are enacted, such as those outlined under the Kyoto Protocol of the United Nations Framework Convention on Climate Change (UNFCCC). The Kyoto Protocol, which calls for limitations on greenhouse gas emissions (including carbon dioxide) for developed countries and some countries with economies in transition, could have profound effects on future fuel use worldwide. Because the Kyoto Protocol has not yet come into force, the *IEO2002* projections do not reflect the potential effects of the treaty or of any other proposed climate change policy measures.

Issues in Energy-Related Emissions Policy

International Climate Negotiations

The world community's effort to address global climate change has taken place largely under the auspices of the UNFCCC, which was adopted in May 1992 and entered into force in March 1994. The ultimate objective of the UNFCCC is the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" [2]. The most ambitious proposal coming out of subsequent conferences has been the Kyoto Protocol, which was developed in December 1997 at the third Conference of the Parties (COP-3). The terms of the

Kyoto Protocol call for Annex I countries to reduce their overall greenhouse gas emissions by at least 5 percent below 1990 levels over the 2008 to 2012 time period. Quantified emissions targets are differentiated by country.²⁶

In addition to any domestic emission reduction measures that Annex I parties may choose to implement in order to meet their emission targets, the Kyoto Protocol allows the use of four “flexibility mechanisms” (sometimes called “Kyoto mechanisms”):

- *International emissions trading* allows Annex I countries to transfer some of their allowable emissions to other Annex I countries, beginning in 2008, for the cost of an emission credit. For example, an Annex I country that reduces its 2010 greenhouse gas emissions level by 10 million metric tons carbon equivalent more than needed to meet its target level can sell the “surplus” emission reductions to other Annex I countries. This trade would lower the seller’s allowable emissions level by 10 million metric tons of carbon equivalent and raise the buyers’ allowances by the same amount in total.
- *Joint fulfillment* allows Annex I countries that are members of an established regional grouping to achieve their reduction targets jointly, provided that their aggregate emissions do not exceed the sum of their combined Kyoto commitments. For example, EU countries have adopted a burden-sharing agreement that reallocates the aggregate Kyoto emission reduction commitment for the EU among the member countries [3].
- *The clean development mechanism (CDM)* allows Annex I countries, either through the government or a legal entity, to invest in emission reduction or sink enhancement projects in non-Annex I countries, gain credit for those “foreign” emissions reductions, and then apply the credits toward their own national emissions reduction commitments. The CDM, in principle, redistributes emission reductions from developing country parties to Annex I parties.
- *Joint implementation (JI)* is similar to the clean development mechanism except that the investment in emission reduction projects must occur within the Annex I countries.

The Kyoto targets refer to overall greenhouse gas emission levels, which encompass emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons,

perfluorocarbons, and sulfur hexafluoride. Hence, a country may opt for relatively greater reductions of other greenhouse gases emissions and smaller reductions of carbon dioxide, or vice versa, in order to meet its entire Kyoto obligation. Currently, carbon dioxide emissions account for the majority of greenhouse gas emissions in most Annex I countries, followed by methane and nitrous oxide [4].

Changes in emission levels resulting from human-induced actions that release or remove carbon dioxide and other greenhouse gases from the atmosphere via terrestrial “sinks” (trees, plants, and soils) are also allowed as “reductions” under the Protocol. The extent to which each Annex I party makes use of sinks and the mechanisms for counting the offsets will influence the amount of domestic emission reductions needed to comply with the Protocol.

Details of the operation of the Kyoto Protocol have been the subject of several UNFCCC meetings since COP-3. Some of the more contentious topics in the negotiation process have been the regime for enforcement of emission reduction commitments, the treatment of sinks, and rules for meeting national emissions targets via the Kyoto mechanisms. These issues were scheduled to be resolved at the November 2000 COP-6 meeting in The Hague, the Netherlands, but the meeting ended without agreement, and delegates reconvened in Bonn, Germany, in July 2001 to continue the COP-6 proceedings.

The main agreements reached at Bonn stipulate that forests, cropland, and grazing land management can be used to increase the amount of carbon sequestered in biologic sinks during the first commitment period (2008-2012), subject to some upper bounds; afforestation and reforestation projects can be eligible for the CDM; and no quantitative limits can be placed on emissions credit trading as a means of meeting the Kyoto commitments. The Bonn agreement also calls for 2 percent of the certified emissions reductions issued for any CDM project to go toward a fund for climate change adaptation projects in developing countries. The procedures and institutions needed to make the Kyoto Protocol fully operational were finalized by delegates at COP-7, held in Marrakech, Morocco, from October 29 through November 9, 2001.

Although the United States was present at COP-6 and COP-7, it did not take an active role in the negotiations. In March 2001, the United States announced that it would not support the Kyoto Protocol. As it currently stands, the only Annex I countries that have ratified the

²⁶Turkey and Belarus, which are represented under Annex I of the UNFCCC, do not face quantified emission targets under the Kyoto Protocol. The Kyoto Protocol includes emission targets for 4 countries not listed under Annex I—namely, Croatia, Liechtenstein, Monaco, and Slovenia. Collectively, the 39 parties facing specific emissions targets under the Kyoto Protocol are commonly referred to as “Annex B parties,” because their targets were specified in Annex B of the Protocol.

Kyoto Protocol are the Czech Republic and Romania.²⁷ The Protocol enters into force 90 days after it has been ratified by at least 55 Parties to the UNFCCC, including a representation of Annex I countries accounting for at least 55 percent of the total 1990 carbon dioxide emissions from the Annex I group. The United States had the largest share of Annex I emissions in 1990, at 34.6 percent. Even without participation from the United States, however, the Protocol still could enter into force for the other signatories.

The *IEO2002* reference case projections indicate that energy-related carbon dioxide emissions from the entire Annex I group of countries will exceed the group's 1990 emissions level by 12 percent in 2010 (Figure 90). Taking the prescribed Kyoto emission reduction targets on the basis of energy-related carbon dioxide emissions alone, the industrialized Annex I countries would face an emission limit of 2,579 million metric tons of carbon equivalent in 2010, or 27 percent less than their projected baseline emissions.²⁸ On the other hand, energy-related carbon dioxide emissions from the group of transitional Annex I countries have been decreasing throughout the 1990s as a result of economic and political crises in the EE/FSU. Baseline emissions from the transitional Annex I countries are projected to be 38 percent below their combined Kyoto Protocol reduction target by 2010.

Greenhouse Gas Emissions Trading

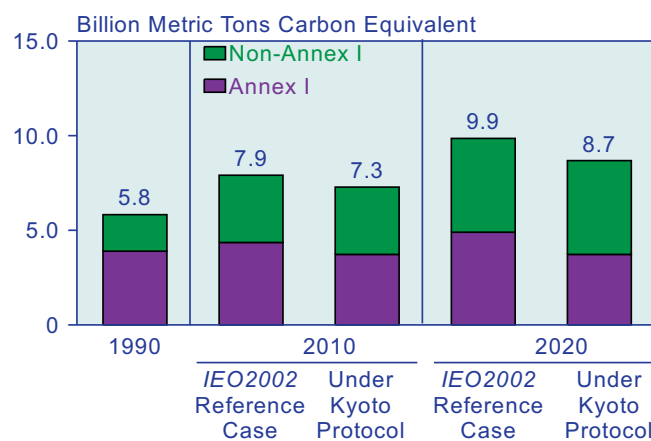
At COP-7 in Marrakech, it was established that international emissions trading under the Kyoto Protocol could start as of 2008. In advance of any international emissions trading under the Protocol, however, some Annex I parties have established or are in the process of establishing their own internal greenhouse gas emissions trading programs. The economic rationale behind emissions trading is to reduce the costs associated with achieving a set reduction in greenhouse gases.

One framework for emissions trading is "cap and trade," whereby a regulatory authority establishes a permanent cap on aggregate emissions for a group of emitters. The cap may, for example, be set at a fraction of the historic emissions from the group of participants. The cap is divided into a set number of allowances, each of which gives the holder the right to emit a specified quantity of the regulated pollutant in a given compliance period. In the case of greenhouse gas emissions, each allowance could grant the holder the right to emit one

metric ton of carbon dioxide equivalent. Once distributed among the participants, the allowances may be bought, sold, or (possibly) banked for future use. At the end of each compliance period, each participant must hold allowances equal to its actual emissions or else face a penalty. Although it has not been used to achieve a mandatory large-scale reduction of greenhouse gas emissions, the cap and trade system is not new, having been used in the United States during the 1990s to achieve reductions in stationary-source sulfur dioxide emissions.

Emissions trading can also be based on concepts other than cap and trade. An offsets or credit-based emissions trading system can incorporate capped and non-capped industries and entities that trade voluntarily created, permanent emissions reductions that are legally recognized by a regulator. This system essentially allows entities with emissions increases to obtain offsetting reductions from other entities. Other trading variants include baseline emissions trading systems, which allow entities to reduce emissions below a level that would otherwise occur under business as usual, and then trade the emissions reductions. Rate-based emissions trading focuses on the emission per unit of output rather than absolute emissions; entities that improve their efficiency

Figure 90. Carbon Dioxide Emissions in Annex I and Non-Annex I Nations Under the Kyoto Protocol, 2010 and 2020



Sources: **1990:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **2010 and 2020:** World Energy Projection System (2002).

²⁷The following 49 Parties to the Convention have ratified, accepted, acceded, or approved the Protocol as of March 6, 2002: Antigua and Barbuda, Argentina, Azerbaijan, Bahamas, Bangladesh, Barbados, Benin, Bolivia, Burundi, Colombia, Cook Islands, Cyprus, Czech Republic, Dominican Republic, Ecuador, El Salvador, Equatorial Guinea, Fiji, Gambia, Georgia, Guatemala, Guinea, Honduras, Jamaica, Kiribati, Lesotho, Malawi, Maldives, Malta, Mauritius, Mexico, Micronesia, Mongolia, Morocco, Nauru, Nicaragua, Niue, Palau, Panama, Paraguay, Romania, Samoa, Senegal, Trinidad and Tobago, Turkmenistan, Tuvalu, Uruguay, Uzbekistan, and Vanuatu.

²⁸The Kyoto Protocol emission targets are based on the average of emissions between 2008 and 2012—the first commitment period. Because 2010 is the midpoint of the first commitment period, it is commonly used as the reference year for calculating emissions reductions under the Kyoto agreement.

beyond the target levels can trade the excess improvement with other companies.

In October 2001, the EU released a final proposal for establishing its own internal greenhouse gas emissions trading system [5]. The first phase of the scheme would run from 2005 through 2007, regulating carbon dioxide emissions from all heat and electricity generators over 20 megawatts of rated thermal input capacity and from all refineries, coke ovens, iron and steel production processes, pulp and paper plants, and mineral industry installations. The proposal requires operators of such installations to hold permits as a condition for emitting greenhouse gases. The second phase of the scheme would be concurrent with the first compliance period under the Kyoto Protocol (2008-2012), should it come into force, and each subsequent phase would last for 5 years. The trading scheme may be extended to include all greenhouse gases after the first phase.

The EU member states would determine the quantity of allowances to be issued in each phase. During the first phase, with no legally binding limits on greenhouse gas emissions, allowances would be distributed free of charge. Noncompliance sanctions would be applied to any installation that did not have enough allowances to cover actual emissions each year. The allowances, which would be tradable across the entire EU could be banked from year to year within each phase but not across phases.

The EU proposal was designed to be compatible with the international emissions trading under the Kyoto framework and with some market-based instruments for emission reductions being developed in individual countries, such as tradable renewable energy certificates. Currently, Denmark is the only country that has instituted a mandatory cap and trade system to reduce carbon dioxide emissions from electricity producers. A cap of 22 million tons of carbon dioxide was set for 2001; the cap will decline by 1 million metric tons per year. The trading system became operational in April 2001 and will run through 2003. Free allowances were allocated to eight firms, based on their emissions during the 1994-1998 period. Should the program be extended, its allowances are likely to be compatible with the proposed EU trading scheme.

The compatibility of the EU proposal with the voluntary emissions trading program in the United Kingdom that is set to begin in April 2002 is more questionable. The programs differ in several aspects, including rules for participation, generation of allowances, and sectoral coverage. Under the British program, any company can opt to enter the trading scheme by negotiating energy efficiency targets or absolute emission reduction targets in return for incentive payments offered by the government, or by carrying out a project that results in a

verified emissions reduction. Companies earn tradable allowances for carbon dioxide computed either from their targets or from the project-based reduction. At this point, it is unclear to what extent allowances earned under the UK scheme could be traded under the proposed EU scheme.

Abating Other Energy-Related Emissions

Many countries currently have policies or regulations in place that limit energy-related emissions other than carbon dioxide. Criteria pollutants such as sulfur oxides and nitrogen oxides are also emitted as a result of fossil fuel combustion, contributing to a variety of health and environmental problems that include acid rain, deterioration of soil and water quality, and human respiratory illnesses. Nitrogen oxide emissions additionally contribute to the formation of ground-level ozone (smog). Furthermore, criteria pollutants indirectly affect the global climate by reacting with other chemical compounds in the atmosphere to form greenhouse gases or, in the case of sulfur dioxide, by affecting the absorptive characteristics of the atmosphere.

To date, the measures taken to mitigate criteria pollutant emissions have been focused primarily on the main sources. Fossil fuel combustion for electricity generation, particularly coal-fired power, represents the largest source of sulfur dioxide emissions in many countries. Other significant energy-related sources include fuel combustion for manufacturing industries, vehicles, and petroleum refining. Nitrogen oxides are emitted as a result of fossil-fuel-based electricity generation, although oil use for road transportation is generally the single largest source.

With the tightening of emissions limitations on combustion plants, sulfur dioxide emissions fell in many industrialized countries during the 1990s. In Europe, the shift from coal to natural gas for electricity production (most notably in the United Kingdom and Germany) also contributed to the reduction in the region's sulfur dioxide emissions. Many industrialized countries have scheduled further restrictions on sulfur dioxide emissions from stationary sources to take effect over the next 10 years.

Despite the imposition of emissions regulations, nitrogen oxide emissions rose during the 1990s in most industrialized countries as a result of continued increases in consumption of transportation fuels. In Europe, however, the decrease in coal-fired electricity generation and the introduction of catalytic converters on vehicles actually led to a gradual drop in nitrogen oxide emissions [6]. To continue combating ground-level ozone formation, several countries plan to tighten their emissions standards for new vehicles over the

coming years (Table 26). Limits on the sulfur content of gasoline and diesel are also being required in order to ensure the effectiveness of the emissions control technologies used to meet the new vehicle standards (Table 27).

In the United States, the main initiatives to reduce emissions of criteria pollutants stem from the 1970 Clean Air Act—the comprehensive Federal law that regulates air emissions from stationary and mobile sources. Subsequent amendments to the Clean Air Act imposed emissions standards and requirements that the best available control technologies be used for new sources. Largely intended to address specific environmental problems, the Clean Air Act Amendments of 1990 (CAAA90) set emissions reduction goals for particular air pollutants

and designated stricter emissions standards across a wider range of sources.

To control acid deposition, Title IV of CAAA90 sets a goal of reducing annual sulfur dioxide emissions by 10 million tons below 1980 levels and annual nitrogen oxide emissions by 2 million tons below 1980 levels. The sulfur dioxide program specifies a two-phase reduction in emissions from fossil-fired electric power plants greater than 25 megawatts in output capacity and from all new power plants. Phase II of the program, which began in January 2000, lowered the total allowable level of sulfur dioxide emissions from all electricity generators, capping annual emissions at 8.95 million metric tons by 2010.²⁹ Individual plant operators may reduce

Table 26. Current and Future Nitrogen Oxide Emission Standards for New Vehicles in Selected Countries

Vehicle Type	Vehicle Class	United States		European Union		Australia	
		Limit	Date	Limit	Date	Limit	Date
Gasoline . .	Light Duty	0.60-1.53 g/mile	Current standard	0.15-0.21 g/km	Current standard	0.63-1.40 g/km	Current standard
		0.07 g/mile	Phase-in 2004-2007	0.08 g/km ^b	Starting 2005	0.22 g/km	Starting 2003
				0.1-0.11 g/km ^c	Starting 2006	0.15-0.21 g/km	Starting 2005
	Heavy Duty	4.0 g/bhp-hr	Current standard				
		1.0 g/bhp-hr ^a	Starting 2004				
		0.2 g/bhp-hr	Phase-in 2008-2009				
Diesel	Light Duty	0.97-1.53 g/mile	Current standard	0.50-0.78 g/km	Current standard	0.78-1.20 g/km	Current standard
		0.07 g/mile	Starting 2004	0.25-0.39 g/km	Starting 2005	0.50-0.78 g/km	Starting 2003
	Heavy Duty	4.0 g/bhp-hr	Current standard	5.0 g/kWh	Current standard	8.0 g/kWh	Current standard
		1.0 g/bhp-hr ^a	Starting 2004	3.5 g/kWh	Starting 2005	5.0 g/kWh	Starting 2002
		0.2 g/bhp-hr	Phase-in 2007-2010	2.0 g/kWh	Starting 2008	3.5 g/kWh	Starting 2006

^aCombined nitrogen oxide and hydrocarbon emissions limit.

^bFor passenger cars and class I light commercial vehicles.

^cFor other light commercial vehicles.

Note: The mix of vehicle types varies by region.

Sources: **United States:** U.S. Environmental Protection Agency, Office of Mobile Sources, *Emission Facts*, EPA-420-F-99-017 (Washington, DC, May 1999). **European Union:** European Parliament, Directive 98/69/EC, Official Journal L 350 (December 28, 1998), and Directive 99/96/EC, Official Journal L 44 (February 16, 2000). **Australia:** Department of Transport and Regional Services, "Vehicle Emission Australian Design Rules (ADRs)" (August 7, 2001).

Table 27. Future Sulfur Content Limits on Motor Fuels in Select Countries

Fuel	United States		European Union		Australia	
	Limit	Date	Limit	Date	Limit	Date
Gasoline . .	30 ppm	Phase-in 2004-2006	50 ppm	As of 1/1/2005	500 ppm ^a	As of 1/1/2002
					150 ppm ^b	As of 1/1/2002
					150 ppm ^c	As of 1/1/2005
Diesel	15 ppm	As of 6/1/2006	50 ppm	As of 1/1/2005	500 ppm	As of 12/31/2002
					50 ppm	As of 1/1/2006

^aFor unleaded petrol and lead replacement petrol.

^bFor premium unleaded petrol.

^cFor all grades.

Sources: **United States:** U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emission Standards and Gasoline Control Requirements," *Federal Register* (February 10, 2000). **European Union:** European Parliament, Directive 98/70/EC, Official Journal L 350 (December 28, 1998). **Australia:** Attorney General's Department, Office of Legislative Drafting, "Fuel Standards Quality Act of 2000: Fuel Standards (Diesel and Petrol)" (October 8, 2001).

²⁹Because some power companies accumulated (banked) emissions allowances during Phase I of the program (1995 to 1999), the Phase II cap of 8.95 million tons per year will not be reached until the banked allowances have been exhausted.

their emissions through any combination of strategies, including installation of scrubbers, switching to low sulfur fuels, and emissions allowance trading and banking. Emissions reductions under the nitrogen oxide program, which targets certain coal-fired utility boilers, are also scheduled according to two phases. As with the sulfur dioxide program, the Phase II nitrogen oxide limits became effective in January 2000; however, the nitrogen oxide program neither sets an emissions cap nor incorporates emissions allowance trading as a compliance option. The program requires utility boilers to meet a specified nitrogen oxide emissions rate, depending on boiler capacity.

To reduce ozone formation, the U.S. Environmental Protection Agency has promulgated a multi-State summer season cap on power plant nitrogen oxide emissions that will take effect in 2004. The rules, commonly referred to as the "NO_x SIP Call," require abatement efforts greater than those required to comply with the nitrogen oxide limits under Title IV of CAAA90. Additional requirements for electric power plant operators to reduce sulfur dioxide and nitrogen oxide emissions beyond the levels called for in current regulations are being considered at both the Federal and State levels. Power plant operators may also face requirements to reduce mercury and carbon dioxide emissions. At present, neither the future reductions nor the timing for compliance is known for any of these airborne emissions (see box on page 171).

CAAA90 also designates more stringent emissions standards for motor vehicles. The "Tier 1" standards cover emissions of several pollutants from light-duty vehicles, beginning with model year 1994. Tighter "Tier 2" standards will be phased in starting in 2004, marking the first time that both cars and light-duty trucks will be subject to the same national pollution control system in the United States. The current emissions standards for heavy-duty vehicles, which have been in place since 1998, will be further tightened in two stages: a new combined nitrogen oxide and hydrocarbon emission standard will take effect in 2004, and further emission reductions will be phased in starting in 2007 [7, 8].

Concurrent with the introduction of Tier 2 emissions standards, the U.S. Government is requiring a reduction in the sulfur content of gasoline and diesel used for transportation [9, 10]. The new gasoline sulfur standard will be phased in between 2004 and 2007, in order to ease the transition for domestic refineries. By June 1, 2006, refiners and importers must produce highway diesel according to the new standard, although the law incorporates a phase-in period and hardship provisions for small refiners through May 2010.

In Canada, efforts to abate sulfur dioxide emissions have focused on the seven easternmost provinces, where acid rain has already begun to damage sensitive ecosystems.³⁰ The Eastern Canada Acid Rain Program placed a region-wide cap on sulfur dioxide emissions at 2.3 million metric tons per year for 1994, mostly restricting emissions from large industrial facilities. Some provinces extended the emissions cap through 2000 and beyond. Recently, further sulfur dioxide emission reduction targets were announced by Ontario, Quebec, New Brunswick, and Nova Scotia for the 2002-2015 time frame.

Addressing the problems of acid rain and ground-level ozone in Canada has required cooperation from the United States, given the transboundary flows of air pollutants between the two countries. Actions taken under the various sulfur dioxide and nitrogen oxide programs of the U.S. CAAA90 have supplemented Canada's domestic efforts. Recently, new measures at federal and provincial levels in Canada were enacted to reduce their nitrogen oxide emissions. Starting in 2007, fossil fuel power plants in central and southern Ontario will face an annual cap of 39,000 tons, and emissions from plants in southern Quebec will be capped at 5,000 tons.

Until recently, Canada's emission regulations for light-duty vehicles were aligned with those of the United States for the 1998 model year. The Canadian government has now reached an agreement with vehicle manufacturers to equip new light-duty vehicles and trucks sold with the same emissions control and monitoring equipment needed to meet the U.S. Federal emissions standards for the 2001-2003 model years. Canada will also require a diesel fuel sulfur cap of 15 parts per million by June 2006, mirroring the U.S. highway diesel regulation.

In Europe, efforts to limit aggregate emissions of sulfur dioxide and nitrogen oxides were first coordinated under the 1979 United Nations/European Economic Commission Convention on Long-Range Transboundary Air Pollution (CLRTAP), which was drafted after scientists demonstrated the link between sulfur dioxide emissions in continental Europe and the acidification of Scandinavian lakes. Since its entry into force, the Convention has been extended by eight protocols that set emissions limits for a variety of pollutants. The 1999 Gothenburg Protocol calls for national emissions ceilings for sulfur dioxide and nitrogen oxides. As with previous CLRTAP protocols, the Gothenburg Protocol specifies tight limit values for specific emissions sources based on the critical loads concept, and requires best available technologies to be used to achieve the

³⁰The seven Canadian provinces covered under the Eastern Canada Acid Rain Program are Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Newfoundland, and Prince Edward Island.

Multiple Emissions Controls in U.S. Electricity Markets

Electric power plant operators in the United States may face new requirements to reduce emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) beyond the levels called for in current regulations. They could also face requirements to reduce carbon dioxide (CO₂) and mercury (Hg) emissions. At present neither the future reductions nor the timing for compliance is known for any of these airborne emissions. Given these uncertainties, compliance planning is difficult for plant owners.

Until recently, each of these environmental issues was addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, the Clean Air Act Amendments of 1990 (CAAA90) required operators of electric power plants to reduce emissions of SO₂ and NO_x. Phase II of the SO₂ reduction program—lowering allowable SO₂ emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000.^a More stringent NO_x emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. For example, in 1997 the U.S. Environmental Protection Agency (EPA) issued new standards for particulate matter and ozone. The ozone standard was tightened from 0.12 parts per million measured over 1 hour to 0.08 parts per million measured over 8 hours. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of SO₂ and NO_x contribute to the formation of regional haze, States could require that these emissions be reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in NO_x and SO₂ emissions.

To reduce ozone formation, the EPA has promulgated a multi-State summer season cap on power plant NO_x emissions that will take effect in 2004. Emissions that lead to fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are associated with power plant emissions of NO_x and SO₂, and further reductions in NO_x and SO₂ emissions could be required by as early as 2007 in order

to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations will be developed over the next 3 years, possibly as part of a multi-emissions reduction strategy. Further, if the United States decided that emissions of greenhouse gases need to be mitigated, energy-related CO₂ emissions would also have to be reduced.^b

Because the timing and levels of emission reduction requirements under the new standards are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions.

The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO₂ and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO₂ and NO_x today may not be the optimal choice in the future if Hg and CO₂ emissions must also be reduced.

Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that reduces SO₂ and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence. Aware of these difficulties, both the previous and current Congresses have proposed legislation that would require simultaneous reductions of multiple emissions.

There have been three Congressional requests to the Energy Information Administration (EIA) for analyses of proposed legislation for reductions of multiple emissions. The Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of

(continued on page 172)

^aA description of the legislation is available at web site www.epa.gov/oar/caa/contents.html.

^bOn February 14, 2002, President Bush proposed that U.S. businesses voluntarily track and reduce their output of greenhouse gases. He proposed that goals for reductions be tied to the growth rate of the economy. It is believed that this approach will minimize the loss in economic efficiency. The President's proposal for multiple emissions controls would cut annual sulfur dioxide emissions by 73 percent, from current emissions of 11 million tons to caps of 4.5 million tons in 2010 and 3 million tons in 2018. It would cut emissions of nitrogen oxides by 67 percent, from current emissions of 5 million tons to caps of 2.1 million tons in 2008 and 1.7 million tons in 2018. Mercury emissions would be reduced by 69 percent, from current emissions of 48 tons to caps of 26 tons in 2010 and 15 tons in 2018. The President's proposal for control of multiple emissions is available at web site www.whitehouse.gov/news/releases/2002/02/clearskies.html.

Multiple Emissions Controls in U.S. Electricity Markets (Continued)

the U.S. House of Representatives Committee on Government Reform^c asked EIA to “analyze the potential costs of various multi-emissions strategies to reduce the air emissions from electric power plants.”^d The Subcommittee requested that EIA examine cases with alternative NO_x, SO₂, CO₂, and Hg emission reductions, with and without a renewable portfolio standard (RPS) requiring a specified portion of all electricity sales to come from generators that use nonhydro-electric renewable fuels.

In the cases specified by the Subcommittee, emissions of NO_x and SO₂ were to be reduced to 75 percent below 1997 levels beginning in 2002, and compliance was to be achieved by 2008. CO₂ emissions were required to be reduced to 1990 levels by 2008 and 7 percent below 1990 levels by 2012. Hg emissions were to be reduced by 90 percent from 1997 levels by 2008. The RPS was targeted to reach 20 percent by 2020. The analysis examined the impacts of these requirements both for individual emissions and for all emissions taken together.

In a second study, requested by Senators Smith, Voinovich, and Brownback, EIA was asked to examine the costs of different multi-emissions reduction strategies for NO_x, SO₂, and Hg. The Senators also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increases in CO₂ emissions beyond the levels currently expected for 2008. The request called for 50- to 75-percent reductions in NO_x below 1997 levels, 50- to 75-percent reductions in SO₂ emissions below full implementation of CAAA90 Title IV, and 50- to 75-percent reductions in Hg emissions below 1999 levels, with half the reductions to be achieved by 2007 and the full reductions to occur by 2012. The emissions reduction programs, covering all electricity generators other than cogenerators producing both electricity and useful thermal output, were patterned after the SO₂ allowance program created in the CAAA90. One-half of the reductions in Hg emissions were to come from site-specific reductions.^e

A third analysis, requested by Senators Jeffords and Lieberman, was to examine the potential impacts of limits on SO₂, NO_x, CO₂, and Hg emissions from electricity generators.^f Using 2002 as a start date for emissions reductions, the request specified that, by 2007, NO_x emissions from electricity generators were to be reduced to 75 percent below 1997 levels, SO₂ emissions to 75 percent below the full implementation of the Phase II requirements under CAAA90 Title IV, Hg emissions to 90 percent below 1999 levels, and CO₂ emissions to 1990 levels. It was assumed that the emissions limits would be applied to all electricity generators, excluding cogenerators. This analysis examined the impacts of the specified limits or “caps” on electricity-sector emissions of SO₂, NO_x, Hg, and CO₂ under four scenarios with different assumptions about technology cost and performance, energy policies, and consumer behavior.

Emission caps imposed were assumed to be implemented under a “cap and trade” system patterned after the SO₂ CAAA90 allowance program.^g All electricity generators, excluding cogenerators, were assumed to be covered by the emissions caps. Electricity generators were assumed to behave competitively, incorporating the costs of emissions allowances in their electricity bid prices. The cases included all energy laws and regulations in effect as of July 1, 2000, including the NO_x and SO₂ regulations established in the CAAA90, plus the new appliance efficiency standards announced in January 2001, as modified by the Bush Administration.

There are common findings across the three Congressional analyses of multiple emissions strategies. Generally, the costs of implementing multiple emissions strategies vary with the stringency of the reductions required and, to a lesser extent, the time frame for compliance. The costs of multiple emissions strategies also vary widely depending on whether CO₂ controls are included or excluded. The impacts of multiple emissions controls for SO₂, NO_x, and Hg that exclude CO₂

(continued on page 173)

^cIn the 107th Congress, this subcommittee was renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

^dEnergy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/index.html.

^eEnergy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, SR/OIAF/2001-04 (Washington, DC, September 2001), web site [www.eia.doe.gov/oiaf/servicerpt/mepp/pdf/sroiaf\(2001\)04.pdf](http://www.eia.doe.gov/oiaf/servicerpt/mepp/pdf/sroiaf(2001)04.pdf).

^fEnergy Information Administration, *Analysis of Strategies for Reducing Emissions from Electric Power Plants with Advanced Technology Scenarios*, SR/OIAF/2001-05 (Washington, DC, October 2001), web site [www.eia.doe.gov/oiaf/servicerpt/eppats/pdf/sroiaf\(2001\)05.pdf](http://www.eia.doe.gov/oiaf/servicerpt/eppats/pdf/sroiaf(2001)05.pdf).

^gNumerous policy instruments are available, including taxes, maximum achievable control technology, no-cost allowance allocation with cap and trade, allowance auction with cap and trade, and generation performance standard allowance allocation with cap and trade. Each of these options would have different price and cost impacts.

emissions reductions. To date, Luxembourg is the only country that has ratified the Gothenburg Protocol. Parallel to CLRTAP developments, the EU has been considering other proposals for national emissions ceilings for sulfur dioxide, nitrogen oxides, volatile organic compounds, and ammonia at levels that are stricter than those set under the Gothenburg Protocol [11].

Specific measures for abating sulfur dioxide and nitrogen oxide emissions are already defined in a number of existing EU directives. The Large Combustion Plant Directive of 1988 and subsequent amendments impose emissions limits for sulfur dioxide and nitrogen oxides on existing and new plants with a rated thermal input capacity greater than 50 megawatts. For plants licensed before July 1, 1987, the Directive places a gradually declining ceiling (cap) on total annual emissions of each pollutant. The ceiling values are differentiated by country. The Directive does not stipulate how the emissions reductions are to be achieved, although the general approach used by several European countries has been to require the use of specific emissions control technologies and combustion fuels. All plants licensed after July 1, 1987, face uniform emissions limit values, which are set according to plant capacity size and fuel type. The EU is considering a proposal to tighten the air pollution limits from new combustion plants in line with the substantial technical progress that has been made in this sector. The proposed emission limits for new plants are twice as strict as the current limits [12].

Nitrogen oxide emissions from motor vehicles have been regulated in Europe since the 1970 Motor Vehicle

Directive. The most stringent vehicle emission limits were passed in 1998 and 1999 by Directives 98/69/EC and 99/96/EC. As the law currently stands, all new vehicles must meet the so-called "Euro 3" emissions standards by 2000 and 2001, depending on weight class. Between 2005 and 2008, the tighter Euro 4 and Euro 5 standards for new vehicles will take effect. Directive 98/70/EC designates current and future sulfur content limits for motor fuels. Germany, the Netherlands, Belgium, and the United Kingdom have encouraged the switch to low-sulfur gasoline and diesel by offering tax incentives. Sweden already requires all of its "city diesel" to meet the same sulfur standard (50 parts per million) required by the EU in 2005. Currently, the EU is considering a proposal that includes the mandatory introduction of sulfur-free motor fuels³¹ by January 1, 2005, and a complete ban on all non-sulfur-free fuels by January 1, 2009 [13, 14]. The implementation of the measure would coincide with the introduction of Euro 4 vehicles in the European market.

In Australia, measures to reduce sulfur dioxide and nitrogen oxide emissions have been focused primarily on the transportation sector. Although Australia relies heavily on domestic coal for electricity generation, it has a lower sulfur content than the coal produced in most other countries. The ambient air quality concentrations of sulfur dioxide in most Australian towns and cities usually have remained well within a level that the government deems to be safe. Because of the health risks associated with high concentrations of nitrogen dioxide, particular in urban centers, the Australian government has begun to implement measures to reduce current and

Multiple Emissions Controls in U.S. Electricity Markets (Continued)

are significantly less than the results discussed here where CO₂ controls are included.

The higher the requirement to reduce CO₂ emissions and the shorter the time frame for the reductions, the higher the costs are expected to be. For example, when the emission reduction requirements are increased from 75 percent in the analysis that excludes CO₂ limits to 90 percent in the Jeffords-Lieberman reference case, which includes CO₂ limits, the projected cumulative resource costs (including fuel, operations and maintenance, and investment costs) to achieve them increase from \$89 billion to \$177 billion.

Higher resource costs and higher electricity prices to consumers are projected in all the multiple emissions cases analyzed. Electricity prices increase as a result of investments in emission control technologies, purchases of allowances, construction of new generating

equipment to replace existing equipment, and higher fuel costs.

In all the analyses, higher electricity prices result in part from increases in natural gas consumption and the attendant high prices for natural gas in the emissions limits cases over the prices that would be expected without emissions limits. Natural gas consumption increases because it has lower emissions than other fossil fuels, particularly coal. Nuclear power and renewable energy sources also have lower emissions than either coal or natural gas. When emissions limits are assumed, the use of coal as a fuel for electricity generation is less desirable, and as a result consumption declines. In most of the cases that include caps on CO₂ emissions, coal-fired generation in 2020 declines to about one-half the level expected without CO₂ emissions limits.

³¹ Gasoline and diesel fuel with sulfur content below 10 parts per million.

future emissions. Approximately 80 percent of the nitrogen dioxide emissions in Australian cities come from motor vehicle exhaust [15].

Vehicle emissions in Australia are regulated under the Motor Vehicle Standards Act of 1989. The most stringent emissions standards for new vehicles were set in December 1999, based on the schedule of vehicle standards used in the EU. According to the new Australian Design Rule 79/00, Euro 2 standards for all new light-duty vehicles will be phased in according to weight class and fuel type, starting in 2002. Rule 79/01 applies the Euro 3 standard for all new light-duty gasoline-powered vehicles starting in 2005 and the Euro 4 standard for all new light-duty diesel-powered vehicles starting in 2006. Rules 80/00 and 80/01 similarly phase in Euro 3 and Euro 4 emissions standards for new medium- and heavy-duty vehicles.

The high sulfur content of gasoline and diesel in Australia was identified as a particular problem for the effective operation of engine catalysts needed to meet tighter emission standards. In May 2001, the Australian government announced the first fuel quality standards to be adopted under the Fuel Quality Standards Act of 2000. Standards for gasoline and diesel will apply starting in 2002, in order to ensure compatibility between the fuels and the vehicle emissions control technologies that will start to come into use at that time. The government plans to develop standards for other fuels over time.

In Japan, the regulation of sulfur oxides and other particulate emissions from fuel combustion began after the passage of the Air Pollution Control Law of 1968. Emissions standards were established by order of the Prime Minister's Office and were last amended in 1998. Limit values for sulfur oxide emissions from stationary sources vary according to the geographic location of the facility and height of the exhaust stack, and nitrogen oxide emission limit values vary according to boiler or furnace type. Sulfur content limits for fuels were included under the Air Pollution Control Law by amendments in 1995 and have been in force since 1996. Vehicle emissions standards were also established by the Air Pollution Control Law and by the Automobile NO_x Law of 1992.

Some developing countries have also enacted targeted air pollution abatement measures designed to limit energy-related emissions including sulfur dioxide and nitrogen oxide. Compliance with emissions regulations is often low in developing countries, however, particularly in the transportation sector, due to inadequate means for measuring emissions levels accurately and enforcing emissions standards [16]. Thus, in the face of strong population growth and economic development, emissions of criteria pollutants in urban centers of the developing world have increased steadily.

Urban air quality in India ranks among the world's poorest [17]. Efforts to improve urban air quality have focused significantly on vehicles, which account for the majority of the country's criteria pollutant emissions. Emissions limits for gasoline and diesel-powered vehicles came into force in 1991 and 1992, respectively. Emissions standards for passenger cars and commercial vehicles were tightened in 2000 at levels equivalent to the Euro 1 standards. For the metro areas of Delhi, Mumbai, Chennai, and Kolkata, tighter Euro 2 standards have been required since 2001, and the sulfur content of motor fuels sold in the four metro areas has also been restricted to 500 parts per million since 2001, in order to be compatible with the tighter vehicle emissions standards. Since January 2000, motor fuel sulfur content in all other regions of the country has been limited to 2,500 parts per million.

The measures taken to reduce vehicle emissions in New Delhi have been more controversial. In 1998, India's Supreme Court ordered all of the city's buses to be run on compressed natural gas by March 31, 2001. Compliance was to be achieved either by converting existing diesel engines or by replacing the buses themselves. Only 200 compressed natural gas buses were available by the initial deadline (out of a total fleet of 12,000), and protests ensued as all other buses were banned from use [18]. To ease the transition for both bus owners and commuters, the Delhi government is now allowing for a gradual phaseout of the existing diesel bus fleet [19].

Although India is a large coal consumer, the country's Central Pollution Control Board has not set any sulfur dioxide emissions limits for coal-fired power plants, because most of the coal mined in India is low in sulfur content. Coal-fired power plants do not face any nitrogen oxide emissions limits either, although natural gas and naphtha-based thermal plants face emissions standards between 50 parts per million and 100 parts per million, depending on their capacity. Enforcement of the standards has been recognized as a major problem in India [20].

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Appendix A

Reference Case Projections:

World Energy Consumption
Gross Domestic Product
Carbon Dioxide Emissions
Nuclear Power Capacity
World Population

Table A1. World Total Energy Consumption by Region, Reference Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	100.1	112.7	115.7	129.3	140.5	151.3	161.3	1.6
United States ^a	84.2	94.6	97.0	107.6	115.6	123.6	130.9	1.4
Canada	10.9	12.1	12.5	13.7	14.8	15.8	16.7	1.4
Mexico	5.0	6.1	6.1	7.9	10.0	11.9	13.7	3.9
Western Europe	59.8	65.8	66.0	71.5	74.7	77.7	81.5	1.0
United Kingdom	9.3	9.9	9.9	10.7	11.2	11.7	12.2	1.0
France	8.8	10.2	10.3	11.2	11.7	12.3	13.0	1.1
Germany	14.8	14.2	14.0	15.3	15.9	16.4	17.0	0.9
Italy	7.0	8.0	8.0	8.9	9.4	9.9	10.4	1.2
Netherlands	3.4	3.8	3.8	4.1	4.3	4.4	4.6	0.9
Other Western Europe	16.6	19.8	20.0	21.3	22.2	23.0	24.3	0.9
Industrialized Asia	22.8	27.6	27.9	29.7	31.5	33.2	34.9	1.1
Japan	17.9	21.5	21.7	22.9	24.2	25.4	26.6	1.0
Australasia	4.8	6.1	6.2	6.8	7.3	7.8	8.3	1.4
Total Industrialized	182.7	206.1	209.7	230.6	246.6	262.2	277.8	1.3
EE/FSU								
Former Soviet Union	60.7	38.7	39.2	44.1	48.0	53.1	57.1	1.8
Eastern Europe	15.6	11.9	11.2	12.7	13.8	15.2	16.3	1.8
Total EE/FSU	76.3	50.6	50.4	56.8	61.8	68.2	73.4	1.8
Developing Countries								
Developing Asia	51.0	72.9	70.9	92.5	113.9	137.1	162.2	4.0
China	27.0	35.3	31.9	42.9	55.1	68.8	84.4	4.7
India	7.8	11.6	12.2	15.2	18.2	21.8	25.4	3.6
South Korea	3.7	6.9	7.3	9.6	10.7	12.0	13.0	2.7
Other Asia	12.6	19.1	19.5	24.8	29.8	34.6	39.5	3.4
Middle East	13.1	19.1	19.3	22.0	26.3	30.5	34.8	2.8
Turkey	2.0	3.0	3.0	3.4	3.9	4.5	5.1	2.6
Other Middle East	11.1	16.1	16.4	18.7	22.4	26.0	29.7	2.9
Africa	9.3	11.6	11.8	14.0	15.7	18.1	20.3	2.6
Central and South America . . .	13.7	19.4	19.8	22.7	28.3	35.6	43.1	3.8
Brazil	5.7	8.2	8.5	9.4	11.5	14.0	16.8	3.3
Other Central/South America . .	8.1	11.2	11.2	13.3	16.8	21.6	26.3	4.1
Total Developing	87.2	123.0	121.8	151.2	184.1	221.3	260.3	3.7
Total World	346.2	379.7	381.9	438.6	492.6	551.7	611.5	2.3
Annex I								
Industrialized	177.7	200.1	203.5	222.6	236.6	250.3	264.0	1.2
EE/FSU	64.6	43.4	43.3	48.5	52.5	57.8	61.9	1.7
Total Annex I	242.3	243.5	246.9	271.2	289.1	308.1	326.0	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A1; and World Energy Projection System (2002).

Table A2. World Total Energy Consumption by Region and Fuel, Reference Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America								
Oil	40.4	44.6	45.8	50.6	56.0	61.2	66.2	1.8
Natural Gas	22.7	26.2	26.8	31.4	34.8	38.7	41.7	2.1
Coal	20.5	23.5	23.5	25.9	27.5	28.5	29.8	1.2
Nuclear.	7.0	8.0	8.6	9.2	9.0	8.7	8.7	0.1
Other	9.5	10.7	11.4	12.1	13.1	14.1	14.8	1.3
Total	100.1	112.7	115.7	129.3	140.5	151.3	161.3	1.6
Western Europe								
Oil	25.8	29.1	28.7	30.7	31.4	32.0	32.5	0.6
Natural Gas	9.7	13.6	14.3	18.0	20.2	22.8	26.7	3.0
Coal	12.4	8.8	8.4	7.7	7.4	7.1	6.5	-1.2
Nuclear.	7.4	8.8	8.9	8.6	8.6	8.2	7.5	-0.8
Other	4.5	5.4	5.6	6.5	7.1	7.6	8.2	1.9
Total	59.8	65.8	66.0	71.5	74.7	77.7	81.5	1.0
Industrialized Asia								
Oil	12.5	13.7	13.9	14.8	15.7	16.3	16.8	0.9
Natural Gas	2.5	3.6	3.8	4.1	4.3	4.8	5.5	1.9
Coal	4.2	5.3	5.4	5.8	6.0	6.2	6.3	0.7
Nuclear.	2.0	3.2	3.2	3.3	3.6	3.8	4.1	1.2
Other	1.6	1.7	1.7	1.8	1.9	2.1	2.2	1.3
Total	22.8	27.6	27.9	29.7	31.5	33.2	34.9	1.1
Total Industrialized								
Oil	78.7	87.4	88.4	96.1	103.1	109.5	115.6	1.3
Natural Gas	35.0	43.5	44.8	53.5	59.4	66.3	74.0	2.4
Coal	37.1	37.5	37.3	39.4	41.0	41.8	42.7	0.6
Nuclear.	16.3	20.0	20.6	21.1	21.1	20.8	20.3	-0.1
Other	15.6	17.9	18.6	20.4	22.1	23.8	25.3	1.5
Total	182.7	206.1	209.7	230.6	246.6	262.2	277.8	1.3
EE/FSU								
Oil	21.0	10.9	10.8	14.1	16.3	19.1	21.1	3.2
Natural Gas	28.8	22.7	22.9	25.2	28.6	32.8	37.0	2.3
Coal	20.8	11.4	11.1	11.2	10.5	9.6	8.6	-1.3
Nuclear.	2.9	2.7	2.7	3.2	3.0	3.0	2.8	0.0
Other	2.8	3.0	3.0	3.2	3.4	3.7	4.1	1.5
Total	76.3	50.6	50.4	56.8	61.8	68.2	73.4	1.8
Developing Countries								
Developing Asia								
Oil	16.0	26.7	27.7	34.0	41.8	50.9	59.9	3.7
Natural Gas	3.2	6.0	6.4	10.8	14.1	18.3	22.8	6.2
Coal	27.7	34.5	30.7	39.0	47.0	54.7	64.0	3.6
Nuclear.	0.9	1.5	1.6	2.3	2.9	3.5	4.4	4.8
Other	3.2	4.3	4.6	6.5	8.0	9.7	11.2	4.3
Total	51.0	72.9	70.9	92.5	113.9	137.1	162.2	4.0

See notes at end of table.

Table A2. World Total Energy Consumption by Region and Fuel, Reference Case, 1990-2020 (Continued)
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Developing Countries (Continued)								
Middle East								
Oil	8.1	10.4	10.5	11.8	13.2	14.7	16.4	2.1
Natural Gas	3.9	6.9	7.1	8.3	10.8	13.0	15.3	3.7
Coal	0.8	1.2	1.1	1.2	1.4	1.5	1.5	1.3
Nuclear.	0.0	0.0	0.0	0.0	0.1	0.1	0.1	—
Other	0.4	0.6	0.5	0.8	0.9	1.2	1.5	5.2
Total	13.1	19.1	19.3	22.0	26.3	30.5	34.8	2.8
Africa								
Oil	4.2	5.1	5.2	6.7	8.0	9.4	10.9	3.6
Natural Gas	1.5	2.0	2.1	2.5	2.8	3.3	3.8	2.7
Coal	3.0	3.7	3.6	3.8	3.9	4.2	4.3	0.9
Nuclear.	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.9
Other	0.6	0.7	0.7	0.8	0.9	1.0	1.2	2.5
Total	9.3	11.6	11.8	14.0	15.7	18.1	20.3	2.6
Central and South America								
Oil	7.0	9.4	9.5	10.6	13.0	15.3	18.1	3.1
Natural Gas	2.2	3.4	3.5	4.9	7.7	12.0	15.9	7.4
Coal	0.6	0.9	0.9	1.0	1.0	1.1	1.3	1.7
Nuclear.	0.1	0.1	0.1	0.2	0.2	0.2	0.2	3.7
Other	3.9	5.6	5.7	6.0	6.4	7.0	7.6	1.4
Total	13.7	19.4	19.8	22.7	28.3	35.6	43.1	3.8
Total Developing Countries								
Oil	35.2	51.5	52.9	63.1	76.0	90.3	105.2	3.3
Natural Gas	10.8	18.3	19.2	26.4	35.4	46.7	57.7	5.4
Coal	32.1	40.3	36.3	44.9	53.3	61.5	71.1	3.3
Nuclear.	1.1	1.7	1.9	2.6	3.3	3.9	4.9	4.7
Other	8.0	11.1	11.5	14.1	16.1	18.9	21.4	3.0
Total	87.2	123.0	121.8	151.2	184.1	221.3	260.3	3.7
Total World								
Oil	134.9	149.8	152.2	173.4	195.4	219.0	241.8	2.2
Natural Gas	74.5	84.5	86.9	105.2	123.4	145.8	168.6	3.2
Coal	90.0	89.3	84.8	95.6	104.7	112.8	122.3	1.8
Nuclear.	20.4	24.4	25.3	26.9	27.5	27.7	28.0	0.5
Other	26.5	32.0	33.1	37.6	41.6	46.4	50.7	2.1
Total	346.2	379.7	381.9	438.6	492.6	551.7	611.5	2.3

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A1; and World Energy Projection System (2002).

Table A3. World Gross Domestic Product (GDP) by Region, Reference Case, 1990-2020
(Billion 1997 Dollars)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	7,723	9,760	10,165	12,014	14,280	16,770	19,349	3.1
United States ^a	6,836	8,675	9,029	10,620	12,559	14,676	16,837	3.0
Canada	555	665	699	829	967	1,110	1,262	2.9
Mexico	332	421	437	565	754	985	1,249	5.1
Western Europe	7,597	8,731	8,944	10,381	11,723	13,181	14,786	2.4
United Kingdom	1,146	1,353	1,384	1,613	1,839	2,085	2,357	2.6
France	1,299	1,455	1,499	1,744	1,965	2,200	2,443	2.4
Germany	1,879	2,156	2,187	2,506	2,801	3,123	3,481	2.2
Italy	1,079	1,188	1,207	1,380	1,565	1,767	2,006	2.4
Netherlands	317	392	407	475	535	601	673	2.4
Other Western Europe	1,877	2,187	2,260	2,665	3,017	3,405	3,826	2.5
Industrialized Asia	4,054	4,765	4,821	5,140	5,860	6,629	7,474	2.1
Japan	3,673	4,271	4,304	4,530	5,155	5,818	6,545	2.0
Australasia	381	494	516	611	705	812	929	2.8
Total Industrialized	19,374	23,256	23,930	27,536	31,863	36,580	41,609	2.7
EE/FSU								
Former Soviet Union	1,009	545	569	761	948	1,236	1,501	4.7
Eastern Europe	348	358	363	459	568	693	837	4.1
Total EE/FSU	1,357	903	932	1,221	1,516	1,929	2,337	4.5
Developing Countries								
Developing Asia	1,739	2,975	3,165	4,355	5,823	7,538	9,690	5.5
China	427	968	1,037	1,588	2,287	3,146	4,315	7.0
India	268	445	473	653	865	1,145	1,507	5.7
South Korea	297	445	493	674	861	1,044	1,232	4.5
Other Asia	748	1,118	1,162	1,440	1,810	2,202	2,636	4.0
Middle East	379	580	577	722	900	1,115	1,363	4.2
Turkey	140	196	186	224	278	342	416	3.9
Other Middle East	239	384	391	498	622	773	947	4.3
Africa	405	485	499	628	768	929	1,110	3.9
Central and South America . . .	1,136	1,467	1,452	1,715	2,191	2,815	3,623	4.5
Brazil	674	810	816	1,002	1,302	1,711	2,258	5.0
Other Central/South America . .	462	657	636	713	890	1,104	1,365	3.7
Total Developing	3,660	5,507	5,693	7,420	9,683	12,397	15,786	5.0
Total World	24,392	29,665	30,555	36,176	43,063	50,906	59,733	3.2
Annex I								
Industrialized	19,043	22,835	23,493	26,970	31,109	35,596	40,360	2.6
EE/FSU	1,212	813	842	1,096	1,353	1,720	2,076	4.4
Total Annex I	20,255	23,648	24,335	28,067	32,462	37,316	42,436	2.7

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: DRI-WEFA, *World Economic Outlook*, Vol. 1 (Lexington, MA, 3rd Quarter 2001); and Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A20.

Table A4. World Oil Consumption by Region, Reference Case, 1990-2020
(Million Barrels per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	20.4	22.7	23.4	25.9	28.6	31.2	33.7	1.8
United States ^a	17.0	18.9	19.5	21.3	23.2	25.1	26.7	1.5
Canada	1.7	1.9	1.9	2.1	2.2	2.3	2.4	1.1
Mexico	1.7	1.9	2.0	2.5	3.1	3.8	4.6	4.1
Western Europe	12.5	14.1	13.9	14.9	15.2	15.5	15.8	0.6
United Kingdom	1.8	1.8	1.7	2.0	2.1	2.2	2.2	1.2
France	1.8	2.0	2.0	2.1	2.2	2.3	2.3	0.6
Germany	2.7	2.9	2.8	3.1	3.1	3.2	3.2	0.6
Italy	1.9	2.1	2.0	2.1	2.1	2.2	2.2	0.5
Netherlands	0.7	0.8	0.8	0.9	0.9	0.9	1.0	0.7
Other Western Europe	3.6	4.5	4.5	4.7	4.8	4.8	4.9	0.4
Industrialized Asia	6.2	6.8	6.9	7.3	7.8	8.0	8.3	0.9
Japan	5.1	5.5	5.6	5.9	6.2	6.3	6.4	0.7
Australasia	1.0	1.3	1.3	1.5	1.6	1.7	1.9	1.8
Total Industrialized	39.0	43.6	44.2	48.1	51.5	54.8	57.8	1.3
EE/FSU								
Former Soviet Union	8.4	3.8	3.7	5.0	5.9	7.1	8.0	3.7
Eastern Europe	1.6	1.4	1.5	1.7	1.9	2.0	2.1	1.8
Total EE/FSU	10.0	5.2	5.2	6.7	7.8	9.2	10.1	3.2
Developing Countries								
Developing Asia	7.6	12.8	13.3	16.3	20.1	24.5	28.8	3.7
China	2.3	4.1	4.3	5.3	6.8	8.6	10.5	4.3
India	1.2	1.8	1.9	2.5	3.2	4.1	4.9	4.6
South Korea	1.0	2.0	2.0	2.5	2.8	2.9	3.0	1.9
Other Asia	3.1	4.9	5.0	6.1	7.4	8.8	10.3	3.5
Middle East	3.9	5.0	5.0	5.7	6.3	7.0	7.8	2.1
Turkey	0.5	0.6	0.6	0.8	0.9	1.0	1.2	3.0
Other Middle East	3.4	4.3	4.4	4.9	5.4	6.0	6.7	2.0
Africa	2.1	2.5	2.5	3.3	3.9	4.5	5.3	3.6
Central and South America . . .	3.4	4.6	4.7	5.2	6.3	7.5	8.8	3.1
Brazil	1.3	1.9	2.0	2.1	2.5	3.1	3.9	3.3
Other Central/South America . .	2.1	2.7	2.7	3.1	3.8	4.3	4.9	2.9
Total Developing	17.0	24.8	25.5	30.4	36.6	43.5	50.7	3.3
Total World	66.0	73.6	74.9	85.2	96.0	107.5	118.6	2.2
Annex I								
Industrialized	37.3	41.7	42.2	45.5	48.4	50.9	53.1	1.1
EE/FSU	8.1	4.3	4.2	5.5	6.4	7.4	8.2	3.2
Total Annex I	45.4	45.9	46.5	51.0	54.8	58.4	61.3	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A21; and World Energy Projection System (2002).

Table A5. World Natural Gas Consumption by Region, Reference Case, 1990-2020
(Trillion Cubic Feet)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	22.0	25.4	26.1	30.6	33.9	37.7	40.7	2.1
United States ^a	18.7	21.3	21.7	25.5	28.1	31.3	33.8	2.1
Canada	2.4	2.9	3.1	3.3	3.6	3.9	4.3	1.6
Mexico	0.9	1.3	1.3	1.8	2.2	2.5	2.6	3.4
Western Europe	10.1	13.4	14.0	17.6	19.7	22.2	25.9	3.0
United Kingdom	2.1	3.1	3.3	3.7	4.2	4.8	5.5	2.5
France	1.0	1.3	1.3	1.8	2.1	2.4	2.9	3.7
Germany	2.7	3.0	3.0	4.0	4.4	4.8	5.8	3.2
Italy	1.7	2.2	2.4	2.9	3.3	3.6	4.0	2.5
Netherlands	1.5	1.8	1.7	1.9	2.1	2.2	2.3	1.4
Other Western Europe	1.2	2.0	2.3	3.2	3.6	4.4	5.4	4.2
Industrialized Asia	2.6	3.5	3.6	4.0	4.2	4.6	5.3	1.9
Japan	1.9	2.5	2.6	2.8	2.9	3.2	3.8	1.7
Australasia	0.8	0.9	1.0	1.1	1.3	1.4	1.6	2.3
Total Industrialized	34.8	42.3	43.7	52.1	57.8	64.5	71.9	2.4
EE/FSU								
Former Soviet Union	25.0	19.9	20.1	21.7	24.0	27.0	30.1	1.9
Eastern Europe	3.1	2.5	2.4	3.1	4.1	5.3	6.3	4.7
Total EE/FSU	28.1	22.4	22.5	24.8	28.1	32.3	36.4	2.3
Developing Countries								
Developing Asia	3.0	5.6	6.0	10.1	13.1	16.9	20.9	6.1
China	0.5	0.8	0.9	1.8	2.8	4.5	6.4	10.1
India	0.4	0.8	0.8	1.2	1.6	2.2	2.6	6.1
South Korea	0.1	0.5	0.6	1.2	1.4	1.8	2.3	6.6
Other Asia	1.9	3.6	3.8	5.9	7.3	8.3	9.6	4.5
Middle East	3.7	6.6	6.8	7.9	10.3	12.4	14.6	3.7
Turkey	0.1	0.4	0.4	0.5	0.6	0.8	1.1	4.2
Other Middle East	3.6	6.2	6.3	7.4	9.7	11.6	13.5	3.7
Africa	1.4	1.8	2.0	2.3	2.5	3.1	3.5	7.4
Central and South America . . .	2.0	3.1	3.2	4.5	7.1	11.1	14.6	7.4
Brazil	0.1	0.2	0.2	0.6	1.3	2.4	3.2	13.3
Other Central/South America . .	1.9	2.9	3.0	3.9	5.8	8.7	11.4	6.5
Total Developing	10.1	17.2	18.0	24.7	33.1	43.4	53.5	5.3
Total World	72.9	81.9	84.2	101.7	119.0	140.2	161.8	3.2
Annex I								
Industrialized	33.9	41.0	42.4	50.4	55.6	62.1	69.3	2.4
EE/FSU	24.2	19.3	19.3	20.9	23.5	27.1	30.5	2.2
Total Annex I	58.1	60.2	61.7	71.3	79.1	89.2	99.9	2.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A13; and World Energy Projection System (2002).

Table A6. World Coal Consumption by Region, Reference Case, 1990-2020
(Million Short Tons)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	959	1,121	1,122	1,263	1,349	1,401	1,480	1.3
United States ^a	895	1,040	1,045	1,176	1,251	1,294	1,365	1.3
Canada	55	66	63	66	73	78	83	1.3
Mexico	9	15	13	21	25	29	32	4.3
Western Europe	894	566	546	498	485	469	436	-1.1
United Kingdom	119	70	65	60	58	53	43	-1.9
France	35	29	26	23	16	17	14	-3.1
Germany	528	269	258	237	237	233	219	-0.8
Italy	23	19	19	17	17	15	15	-1.2
Netherlands	15	16	14	12	8	8	7	-3.3
Other Western Europe	173	164	165	149	148	143	138	-0.8
Industrialized Asia	231	287	295	311	323	332	337	0.6
Japan	125	144	149	164	173	181	185	1.0
Australasia	106	142	145	148	149	151	152	0.2
Total Industrialized	2,084	1,974	1,963	2,072	2,157	2,201	2,252	0.7
EE/FSU								
Former Soviet Union	848	396	414	421	397	364	326	-1.1
Eastern Europe	527	414	363	361	330	298	263	-1.5
Total EE/FSU	1,375	810	778	782	727	662	589	-1.3
Developing Countries								
Developing Asia	1,583	1,903	1,686	2,141	2,577	3,004	3,515	3.6
China	1,124	1,300	1,075	1,421	1,797	2,170	2,592	4.3
India	242	333	348	414	450	482	546	2.2
South Korea	42	60	65	81	89	94	96	1.8
Other Asia	175	210	197	226	241	258	282	1.7
Middle East	66	99	96	101	119	125	127	1.3
Turkey	60	86	84	88	98	102	104	1.0
Other Middle East	6	12	12	12	21	23	23	3.1
Africa	152	181	177	186	191	203	212	0.9
Central and South America . . .	26	42	41	43	47	52	58	1.7
Brazil	17	28	27	30	35	40	47	2.6
Other Central/South America . .	9	15	14	14	12	12	11	-0.9
Total Developing	1,827	2,226	2,000	2,472	2,935	3,384	3,912	3.2
Total World	5,287	5,009	4,740	5,326	5,819	6,247	6,753	1.7
Annex I								
Industrialized	2,075	1,959	1,950	2,051	2,132	2,172	2,220	0.6
EE/FSU	1,166	702	686	692	650	594	535	-1.2
Total Annex I	3,242	2,660	2,635	2,743	2,781	2,766	2,755	0.2

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. To convert short tons to metric tons, divide each number in the table by 1.102.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A16; and World Energy Projection System (2002).

Table A7. World Nuclear Energy Consumption by Region, Reference Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	649	750	808	860	841	814	811	0.0
United States ^a	577	674	728	759	737	707	702	-0.2
Canada	69	68	70	92	95	97	100	1.7
Mexico	3	9	10	9	9	9	9	-0.2
Western Europe	703	836	846	830	821	790	728	-0.7
United Kingdom	59	95	91	67	60	52	31	-5.0
France	298	369	375	393	400	406	423	0.6
Germany	145	154	161	154	147	138	104	-2.1
Italy	0	0	0	0	0	0	0	—
Netherlands	3	4	4	4	0	0	0	-100.0
Other Western Europe	198	215	215	212	215	193	170	-1.1
Industrialized Asia	192	316	309	318	347	374	398	1.2
Japan	192	316	309	318	347	374	398	1.2
Australasia	0	0	0	0	0	0	0	—
Total Industrialized	1,544	1,902	1,962	2,008	2,010	1,977	1,937	-0.1
EE/FSU								
Former Soviet Union	201	183	190	207	203	202	171	-0.5
Eastern Europe	54	61	60	82	73	74	81	1.4
Total EE/FSU	256	244	250	288	276	276	252	0.0
Developing Countries								
Developing Asia	88	145	160	231	289	342	425	11.2
China	0	13	14	51	75	91	131	11.2
India	6	11	11	15	25	30	45	6.8
South Korea	50	85	98	126	130	157	180	2.9
Other Asia	32	36	37	38	58	64	69	3.0
Middle East	0	0	0	0	6	12	13	—
Turkey	0	0	0	0	0	0	0	—
Other Middle East	0	0	0	0	6	12	13	—
Africa	8	14	13	12	13	14	15	0.9
Central and South America . . .	9	10	11	17	17	16	24	4.1
Brazil	2	3	4	10	11	12	20	8.3
Other Central/South America . .	7	7	7	6	6	4	4	-2.2
Total Developing	105	169	184	260	325	384	478	4.7
Total World	1,905	2,315	2,396	2,555	2,610	2,637	2,667	0.5
Annex I								
Industrialized	1,541	1,893	1,952	1,999	2,000	1,968	1,928	-0.1
EE/FSU	255	243	248	286	276	276	252	0.1
Total Annex I	1,797	2,136	2,200	2,285	2,277	2,244	2,179	0.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A8; and World Energy Projection System (2002).

Table A8. World Consumption of Hydroelectricity and Other Renewable Energy by Region, Reference Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	9.5	10.7	11.4	12.1	13.1	14.1	14.8	1.3
United States ^a	6.1	6.9	7.3	7.9	8.3	8.9	9.4	1.2
Canada	3.1	3.5	3.6	3.6	4.0	4.3	4.5	1.1
Mexico	0.3	0.4	0.4	0.5	0.8	0.9	0.9	3.5
Western Europe	4.5	5.4	5.6	6.5	7.1	7.6	8.2	1.9
United Kingdom	0.1	0.1	0.1	0.3	0.3	0.4	0.4	5.6
France	0.6	0.7	0.8	0.2	0.3	0.3	0.4	-3.5
Germany	0.3	0.3	0.4	0.6	0.7	0.8	1.0	4.8
Italy	0.4	0.5	0.6	1.1	1.2	1.3	1.4	4.3
Netherlands	0.0	0.0	0.0	0.3	0.3	0.3	0.4	10.4
Other Western Europe	3.2	3.7	3.7	4.0	4.1	4.3	4.7	1.1
Industrialized Asia	1.6	1.7	1.7	1.8	1.9	2.1	2.2	1.3
Japan	1.1	1.2	1.2	1.2	1.3	1.4	1.5	1.3
Australasia	0.4	0.5	0.5	0.6	0.6	0.6	0.7	1.4
Total Industrialized	15.6	17.9	18.6	20.4	22.1	23.8	25.3	1.5
EE/FSU								
Former Soviet Union	2.4	2.3	2.3	2.5	2.6	2.7	2.8	0.8
Eastern Europe	0.4	0.6	0.6	0.7	0.9	1.1	1.3	3.4
Total EE/FSU	2.8	3.0	3.0	3.2	3.4	3.7	4.1	1.5
Developing Countries								
Developing Asia	3.2	4.3	4.6	6.5	8.0	9.7	11.2	4.3
China	1.3	2.1	2.3	3.4	4.3	5.4	6.6	5.1
India	0.7	0.8	0.9	1.1	1.3	1.5	1.7	3.3
South Korea	0.0	0.0	0.0	0.1	0.1	0.2	0.2	7.9
Other Asia	1.1	1.3	1.4	1.9	2.3	2.6	2.7	3.2
Middle East	0.4	0.6	0.5	0.8	0.9	1.2	1.5	5.2
Turkey	0.2	0.4	0.4	0.4	0.5	0.5	0.5	2.0
Other Middle East	0.1	0.2	0.2	0.4	0.4	0.7	1.0	8.8
Africa	0.6	0.7	0.7	0.8	0.9	1.0	1.2	2.5
Central and South America . . .	3.9	5.6	5.7	6.0	6.4	7.0	7.6	1.4
Brazil	2.2	3.1	3.3	3.8	4.1	4.2	4.4	1.4
Other Central/South America . .	1.7	2.5	2.4	2.2	2.3	2.8	3.2	1.4
Total Developing	8.0	11.1	11.5	14.1	16.1	18.9	21.4	3.0
Total World	26.5	32.0	33.1	37.6	41.6	46.4	50.7	2.1
Annex I								
Industrialized	15.3	17.5	18.2	19.8	21.3	22.9	24.3	1.4
EE/FSU	2.2	2.3	2.3	2.4	2.6	2.8	3.1	1.5
Total Annex I	17.4	19.8	20.5	22.2	23.8	25.7	27.4	1.4

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. U.S. totals include net electricity imports, methanol, and liquid hydrogen.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A1; and World Energy Projection System (2002).

Table A9. World Net Electricity Consumption by Region, Reference Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	3,362	4,046	3,904	4,585	5,093	5,605	6,100	2.1
United States ^a	2,817	3,400	3,236	3,793	4,170	4,556	4,916	2.0
Canada	438	485	498	558	612	661	711	1.7
Mexico	107	162	171	235	311	388	473	5.0
Western Europe	2,077	2,399	2,435	2,743	2,959	3,183	3,455	1.7
United Kingdom	287	330	333	365	389	413	438	1.3
France	326	394	399	450	486	523	572	1.7
Germany	489	492	495	567	609	649	699	1.7
Italy	222	266	272	320	356	395	438	2.3
Netherlands	72	95	98	110	118	128	138	1.7
Other Western Europe	681	822	838	931	999	1,074	1,170	1.6
Industrialized Asia	945	1,158	1,178	1,292	1,395	1,493	1,596	1.5
Japan	765	932	947	1,036	1,117	1,194	1,275	1.4
Australasia	181	226	231	255	278	299	322	1.6
Total Industrialized	6,385	7,604	7,517	8,620	9,446	10,281	11,151	1.9
EE/FSU								
Former Soviet Union	1,488	1,068	1,075	1,218	1,331	1,479	1,600	1.9
Eastern Europe	418	390	377	433	475	527	573	2.0
Total EE/FSU	1,906	1,459	1,452	1,651	1,807	2,006	2,173	1.9
Developing Countries								
Developing Asia	1,259	2,175	2,319	3,092	3,900	4,819	5,858	4.5
China	551	1,013	1,084	1,523	2,031	2,631	3,349	5.5
India	257	396	424	537	649	784	923	3.8
South Korea	93	207	233	309	348	392	429	3.0
Other Asia	357	560	578	724	872	1,012	1,157	3.4
Middle East	263	470	494	572	690	808	932	3.1
Turkey	51	102	106	122	144	166	190	2.8
Other Middle East	213	368	388	449	546	642	742	3.1
Africa	287	361	367	460	550	671	776	3.6
Central and South America . . .	449	656	684	788	988	1,249	1,517	3.9
Brazil	229	334	354	398	494	613	748	3.6
Other Central/South America . .	220	322	330	390	494	635	769	4.1
Total Developing	2,258	3,663	3,863	4,912	6,127	7,548	9,082	4.2
Total World	10,549	12,725	12,833	15,182	17,380	19,835	22,407	2.7
Annex I								
Industrialized	6,278	7,442	7,346	8,385	9,135	9,893	10,678	1.8
EE/FSU	1,576	1,227	1,268	1,388	1,519	1,687	1,828	1.8
Total Annex I	7,854	8,669	8,615	9,773	10,654	11,580	12,506	1.8

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Electricity consumption equals generation plus imports minus exports minus distribution losses.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table A10. World Carbon Dioxide Emissions by Region, Reference Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1,562	1,742	1,767	1,986	2,171	2,346	2,515	1.7
United States ^a	1,352	1,495	1,517	1,694	1,835	1,965	2,088	1.5
Canada	126	146	150	160	173	185	196	1.3
Mexico	84	101	101	132	164	197	231	4.0
Western Europe	930	947	940	1,008	1,045	1,086	1,136	0.9
United Kingdom	164	154	151	167	176	183	191	1.1
France	102	110	109	118	122	128	136	1.1
Germany	271	237	230	246	253	259	270	0.8
Italy	112	122	121	132	139	144	150	1.0
Netherlands	58	66	64	67	67	70	71	0.5
Other Western Europe	223	260	264	278	288	301	318	0.9
Industrialized Asia	357	412	422	451	475	496	518	1.0
Japan	269	300	307	327	343	356	370	0.9
Australasia	88	112	115	124	132	140	148	1.2
Total Industrialized	2,849	3,101	3,129	3,445	3,692	3,928	4,169	1.4
EE/FSU								
Former Soviet Union	1,036	599	607	685	745	822	884	1.8
Eastern Europe	301	217	203	222	233	246	255	1.1
Total EE/FSU	1,337	816	810	907	978	1,068	1,139	1.6
Developing Countries								
Developing Asia	1,053	1,435	1,361	1,748	2,139	2,558	3,017	3.9
China	617	765	669	881	1,127	1,393	1,692	4.5
India	153	231	242	298	349	410	475	3.3
South Korea	61	101	107	136	152	164	175	2.3
Other Asia	223	338	343	433	511	591	675	3.3
Middle East	231	325	330	372	439	501	566	2.6
Turkey	35	50	50	57	64	71	80	2.2
Other Middle East	196	275	280	315	375	430	486	2.7
Africa	179	216	218	256	287	327	365	2.5
Central and South America . . .	178	246	249	290	377	484	595	4.2
Brazil	62	87	88	100	130	169	213	4.3
Other Central/South America . .	116	159	162	190	247	315	382	4.2
Total Developing	1,641	2,222	2,158	2,667	3,241	3,870	4,542	3.6
Total World	5,827	6,139	6,097	7,018	7,910	8,866	9,850	2.3
Annex I								
Industrialized	2,765	3,001	3,028	3,313	3,527	3,731	3,938	1.3
EE/FSU	1,132	704	700	776	832	905	962	1.5
Total Annex I	3,897	3,704	3,729	4,088	4,359	4,636	4,900	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. The U.S. numbers include carbon dioxide emissions attributable to renewable energy sources.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A19; and World Energy Projection System (2002).

Table A11. World Carbon Dioxide Emissions from Oil Use by Region, Reference Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	716	775	793	874	969	1,064	1,154	1.8
United States ^a	590	635	650	705	771	835	891	1.5
Canada	61	66	68	73	78	82	85	1.1
Mexico	65	74	76	96	120	146	177	4.1
Western Europe	474	525	517	552	566	576	586	0.6
United Kingdom	66	65	63	74	76	79	81	1.2
France	67	72	72	76	79	81	82	0.6
Germany	103	107	104	113	115	116	117	0.6
Italy	74	78	74	80	81	81	82	0.5
Netherlands	27	30	31	32	34	35	36	0.7
Other Western Europe	138	172	173	178	182	185	187	0.4
Industrialized Asia	217	230	233	248	263	273	282	0.9
Japan	179	183	185	195	205	209	213	0.7
Australasia	38	46	48	53	58	63	69	1.8
Total Industrialized	1,407	1,529	1,543	1,675	1,798	1,912	2,021	1.3
EE/FSU								
Former Soviet Union	334	148	146	197	233	280	312	3.7
Eastern Europe	66	55	55	64	70	76	80	1.8
Total EE/FSU	400	202	201	261	303	355	392	3.2
Developing Countries								
Developing Asia	304	479	496	609	750	914	1,074	3.7
China	94	152	160	196	251	317	390	4.3
India	45	70	73	94	121	158	187	4.6
South Korea	38	60	62	76	85	90	93	1.9
Other Asia	127	197	201	243	294	349	404	3.4
Middle East	155	195	198	222	248	277	308	2.1
Turkey	17	22	22	27	31	36	40	3.0
Other Middle East	138	173	177	195	216	241	267	2.0
Africa	83	95	97	126	150	175	203	3.6
Central and South America . . .	132	173	176	197	239	283	335	3.1
Brazil	51	70	71	77	93	114	141	3.3
Other Central/South America . .	81	104	105	120	147	169	193	2.9
Total Developing	674	942	968	1,154	1,387	1,648	1,919	3.3
Total World	2,482	2,673	2,712	3,090	3,488	3,916	4,332	2.3
Annex I								
Industrialized	1,342	1,455	1,468	1,578	1,679	1,766	1,844	1.1
EE/FSU	324	164	162	211	244	286	314	3.2
Total Annex I	1,666	1,620	1,630	1,790	1,923	2,052	2,158	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A19; and World Energy Projection System (2002).

Table A12. World Carbon Dioxide Emissions from Natural Gas Use by Region, Reference Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	326	377	381	450	499	555	598	2.2
United States ^a	277	315	317	374	413	460	496	2.2
Canada	35	42	46	49	53	58	63	1.6
Mexico	15	20	19	26	33	37	39	3.4
Western Europe	140	196	206	259	291	328	385	3.0
United Kingdom	30	47	50	57	65	73	84	2.5
France	16	21	21	29	34	38	46	3.2
Germany	32	42	43	57	62	68	82	3.2
Italy	25	32	35	42	48	54	59	2.5
Netherlands	20	23	22	25	27	28	30	1.4
Other Western Europe	18	31	35	50	56	68	84	4.2
Industrialized Asia	36	52	54	59	62	69	80	1.9
Japan	24	38	40	43	43	48	56	1.7
Australasia	12	14	14	17	19	21	23	2.3
Total Industrialized	503	626	641	768	852	953	1,062	2.4
EE/FSU								
Former Soviet Union	369	291	294	317	351	394	440	1.9
Eastern Europe	46	36	35	46	60	78	93	4.7
Total EE/FSU	414	327	329	363	411	472	532	2.3
Developing Countries								
Developing Asia	45	86	92	155	204	263	328	6.2
China	8	13	14	31	47	76	108	10.1
India	7	13	12	19	26	36	43	6.1
South Korea	2	8	10	15	19	23	30	5.5
Other Asia	29	53	56	90	111	129	147	4.7
Middle East	56	100	102	120	156	187	220	3.7
Turkey	2	6	7	7	7	10	13	3.0
Other Middle East	54	94	96	113	148	177	207	3.7
Africa	22	29	31	36	40	48	54	2.7
Central and South America . . .	32	49	51	70	111	173	228	7.4
Brazil	2	3	4	8	20	35	48	13.3
Other Central/South America . .	30	46	47	62	92	138	180	6.6
Total Developing	155	263	276	380	510	672	831	5.4
Total World	1,072	1,216	1,247	1,512	1,774	2,096	2,425	3.2
Annex I								
Industrialized	488	606	622	742	819	916	1,023	2.4
EE/FSU	344	296	277	281	284	305	343	1.0
Total Annex I	832	902	900	1,023	1,103	1,220	1,367	2.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A19; and World Energy Projection System (2002).

Table A13. World Carbon Dioxide Emissions from Coal Use by Region, Reference Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	520	595	592	662	704	728	763	1.2
United States ^a	485	550	549	614	650	670	701	1.2
Canada	31	38	36	38	42	45	47	1.3
Mexico	4	7	6	10	12	13	15	4.4
Western Europe	315	225	216	196	188	181	166	-1.3
United Kingdom	68	42	39	36	35	32	26	-1.9
France	20	17	15	13	9	10	8	-3.0
Germany	137	87	83	76	76	75	71	-0.8
Italy	14	11	12	10	10	9	9	-1.4
Netherlands	11	13	11	10	7	7	5	-3.4
Other Western Europe	66	56	56	51	51	49	47	-0.8
Industrialized Asia	104	130	135	143	149	154	156	0.7
Japan	66	78	81	89	94	99	100	1.0
Australasia	38	52	53	54	55	55	56	0.2
Total Industrialized	939	951	943	1,002	1,041	1,063	1,086	0.7
EE/FSU								
Former Soviet Union	333	160	168	170	161	148	133	-1.1
Eastern Europe	189	127	113	112	103	92	82	-1.5
Total EE/FSU	522	287	280	282	264	241	215	-1.3
Developing Countries								
Developing Asia	704	870	773	984	1,185	1,381	1,615	3.6
China	514	600	495	655	828	1,000	1,195	4.3
India	101	148	156	185	202	216	245	2.2
South Korea	21	33	36	44	49	52	53	1.8
Other Asia	67	88	87	99	106	113	124	1.7
Middle East	20	30	29	30	36	37	38	1.3
Turkey	16	23	21	23	25	26	26	1.0
Other Middle East	4	7	7	8	11	12	12	2.2
Africa	74	93	90	95	97	103	108	0.9
Central and South America . . .	15	23	22	24	26	28	32	1.7
Brazil	9	14	13	15	18	20	24	2.7
Other Central/South America . .	5	9	9	9	8	8	8	-0.3
Total Developing	812	1,017	914	1,132	1,343	1,550	1,793	3.3
Total World	2,274	2,254	2,137	2,417	2,648	2,854	3,094	1.8
Annex I								
Industrialized	935	944	937	992	1,029	1,049	1,071	0.6
EE/FSU	452	259	257	260	244	224	202	-1.1
Total Annex I	1,387	1,203	1,194	1,252	1,274	1,273	1,273	0.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A19; and World Energy Projection System (2002).

Table A14. World Nuclear Generating Capacity by Region and Country, Reference Case, 1999-2020
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Industrialized Countries						
North America	108,776	108,867	112,656	109,298	103,791	102,981
United States	97,470	97,509	97,700	94,342	88,835	88,025
Canada	9,998	9,998	13,596	13,596	13,596	13,596
Mexico	1,308	1,360	1,360	1,360	1,360	1,360
Industrialized Asia	43,691	43,491	44,289	47,793	50,837	53,406
Japan	43,691	43,491	44,289	47,793	50,837	53,406
Western Europe	125,991	125,726	123,397	120,191	113,778	103,989
Belgium	5,712	5,712	5,712	5,712	5,712	3,966
Finland	2,656	2,656	2,656	2,656	2,656	2,656
France	63,103	63,153	62,920	62,920	62,920	64,370
Germany	21,122	21,122	20,142	18,975	17,735	13,134
Netherlands	449	449	449	0	0	0
Spain	7,470	7,512	7,512	7,512	6,913	6,913
Sweden	9,432	9,432	9,432	9,432	6,907	6,077
Switzerland	3,079	3,192	3,192	3,192	2,827	2,115
United Kingdom	12,968	12,498	11,382	9,792	8,108	4,758
Total Industrialized	278,458	278,084	280,342	277,282	268,406	260,376
EE/FSU						
Eastern Europe	10,605	10,675	11,692	10,060	10,060	10,710
Bulgaria	3,538	3,538	2,722	1,906	1,906	1,906
Czech Republic	1,648	1,648	3,481	3,481	3,481	3,481
Hungary	1,729	1,755	1,755	1,755	1,755	1,755
Romania	650	650	650	650	650	1,300
Slovakia	2,408	2,408	2,408	1,592	1,592	1,592
Slovenia	632	676	676	676	676	676
Former Soviet Union	34,704	33,796	34,511	32,543	31,471	26,004
Armenia	376	376	376	0	0	0
Lithuania	2,370	2,370	1,185	0	0	0
Russia	19,843	19,843	21,743	21,336	20,264	14,797
Ukraine	12,115	11,207	11,207	11,207	11,207	11,207
Total EE/FSU	45,309	44,471	46,203	42,603	41,531	36,714

See notes at end of table.

Table A14. World Nuclear Generating Capacity by Region and Country, Reference Case, 1999-2020
(Continued)
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Developing Countries						
Developing Asia	22,063	22,777	30,259	37,663	44,099	54,447
China	2,167	2,177	6,597	9,597	11,587	16,607
India	1,897	2,301	2,503	3,973	4,423	6,451
Korea, North	0	0	0	0	950	950
Korea, South	12,990	12,990	15,850	16,254	19,425	22,125
Pakistan	125	425	425	425	300	900
Taiwan	4,884	4,884	4,884	7,414	7,414	7,414
Central and South America	1,561	2,790	2,790	2,790	2,455	3,684
Argentina	935	935	935	935	600	600
Brazil	626	1,855	1,855	1,855	1,855	3,084
Middle East	0	0	1,073	1,073	2,146	2,146
Iran	0	0	1,073	1,073	2,146	2,146
Africa	1,842	1,800	1,800	1,800	1,930	2,060
South Africa	1,842	1,800	1,800	1,800	1,930	2,060
Total Developing	25,466	27,367	35,922	43,326	50,630	62,337
Total World	349,233	349,922	362,467	363,211	360,567	359,427

Sources: **History:** International Atomic Energy Agency, *Nuclear Power Reactors in the World 2000* (Vienna, Austria, April 2001). **Projections:** Energy Information Administration (EIA), *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A9; and EIA, Office of Coal, Nuclear, Electric and Alternate Fuels, based on detailed assessments of country-specific nuclear power plants.

Table A15. World Total Energy Consumption in Oil-Equivalent Units by Region, Reference Case, 1990-2020
(Million Tons Oil Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	2,522	2,841	2,916	3,258	3,540	3,813	4,066	1.6
United States ^a	2,121	2,383	2,446	2,712	2,913	3,116	3,297	1.4
Canada	275	305	316	346	374	398	422	1.4
Mexico	126	153	155	200	252	299	346	3.9
Western Europe	1,508	1,659	1,664	1,802	1,881	1,958	2,054	1.0
United Kingdom	234	251	250	269	282	295	308	1.0
France	222	256	258	282	296	309	328	1.1
Germany	373	357	352	387	400	412	428	0.9
Italy	176	201	203	223	237	249	262	1.2
Netherlands	85	96	97	104	108	112	116	0.9
Other Western Europe	419	498	504	538	559	581	612	0.9
Industrialized Asia	574	695	704	750	793	836	879	1.1
Japan	452	541	547	578	609	640	671	1.0
Australasia	122	153	157	171	184	196	209	1.4
Total Industrialized	4,604	5,194	5,284	5,810	6,215	6,607	7,000	1.3
EE/FSU								
Former Soviet Union	1,529	975	988	1,112	1,210	1,337	1,439	1.8
Eastern Europe	393	299	283	321	348	382	411	1.8
Total EE/FSU	1,923	1,274	1,271	1,433	1,558	1,720	1,851	1.8
Developing Countries								
Developing Asia	1,286	1,837	1,788	2,332	2,869	3,455	4,087	4.0
China	681	890	803	1,080	1,388	1,734	2,127	4.7
India	196	293	307	384	459	549	639	3.6
South Korea	92	173	185	243	270	302	327	2.7
Other Asia	317	481	492	626	752	871	994	3.4
Middle East	330	481	487	556	663	768	876	2.8
Turkey	50	76	74	85	99	113	127	2.6
Other Middle East	280	405	413	471	564	655	749	2.9
Africa	235	292	297	352	395	455	510	2.6
Central and South America . . .	346	489	498	571	713	898	1,086	3.8
Brazil	142	208	215	237	289	353	424	3.3
Other Central/South America . .	204	282	283	334	424	544	662	4.1
Total Developing	2,197	3,100	3,069	3,810	4,640	5,576	6,559	3.7
Total World	8,724	9,568	9,623	11,053	12,413	13,902	15,410	2.3
Annex I								
Industrialized	4,479	5,042	5,129	5,610	5,962	6,308	6,653	1.2
EE/FSU	1,628	1,094	1,092	1,223	1,322	1,456	1,561	1.7
Total Annex I	6,106	6,136	6,221	6,833	7,284	7,764	8,214	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A1; and World Energy Projection System (2002).

Table A16. World Population by Region, Reference Case, 1990-2020
(Millions)

Region/Country	History			Projections				Annual Average Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	366	397	401	426	446	466	486	0.9
United States ^a	255	271	273	288	300	313	325	0.8
Canada	28	30	30	32	33	34	36	0.7
Mexico	83	96	97	106	113	119	125	1.2
Western Europe	377	388	389	391	391	389	387	0.0
United Kingdom	58	59	59	60	60	61	61	0.1
France	57	59	59	60	61	62	62	0.3
Germany	79	82	82	82	81	81	80	-0.1
Italy	57	58	58	57	56	55	54	-0.3
Netherlands	15	16	16	16	16	16	17	0.2
Other Western Europe	112	115	115	116	115	115	114	-0.1
Industrialized Asia	148	153	154	156	158	158	158	0.1
Japan	124	127	127	128	128	128	126	0.0
Australasia	24	27	27	28	30	31	32	0.8
Total Industrialized	890	938	943	974	995	1,014	1,031	0.4
EE/FSU								
Former Soviet Union	290	294	292	286	283	280	278	-0.2
Eastern Europe	122	119	121	120	119	118	116	-0.2
Total EE/FSU	412	413	413	406	402	398	394	-0.2
Developing Countries								
Developing Asia	2,788	3,151	3,194	3,447	3,651	3,846	4,025	1.1
China	1,155	1,254	1,265	1,321	1,366	1,410	1,446	0.6
India	845	976	993	1,089	1,164	1,230	1,291	1.3
South Korea	43	46	46	48	50	51	51	0.5
Other Asia	745	875	891	989	1,072	1,154	1,237	1.6
Middle East	191	231	236	268	295	325	355	2.0
Turkey	56	65	66	71	75	79	83	1.1
Other Middle East	135	166	171	196	220	246	272	2.3
Africa	619	757	775	892	997	1,110	1,231	2.2
Central and South America . . .	354	404	410	447	477	507	534	1.3
Brazil	148	166	168	181	191	201	211	1.1
Other Central/South America . .	206	238	242	266	286	305	324	1.4
Total Developing	3,953	4,542	4,616	5,053	5,421	5,787	6,146	1.4
Total World	5,255	5,893	5,972	6,433	6,817	7,199	7,570	1.1
Annex I								
Industrialized	807	842	846	868	882	895	906	0.3
EE/FSU	311	307	305	296	288	281	274	-0.5
Total Annex I	1,118	1,149	1,151	1,163	1,170	1,176	1,180	0.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **United States:** Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A20. **Other Countries:** United Nations, *World Populations: The 2000 Revision, Volume 1, Comprehensive Tables* (New York, NY, 2001).

Appendix B

High Economic Growth Case Projections:

World Energy Consumption

Gross Domestic Product

Carbon Dioxide Emissions

Nuclear Power Capacity

Table B1. World Total Energy Consumption by Region, High Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	100.1	112.7	115.7	131.9	145.4	158.2	171.2	1.9
United States ^a	84.2	94.6	97.0	109.1	119.1	128.7	138.2	1.7
Canada	10.9	12.1	12.5	14.3	15.7	16.8	17.8	1.7
Mexico	5.0	6.1	6.1	8.5	10.6	12.7	15.2	4.4
Western Europe	59.8	65.8	66.0	73.8	78.2	82.5	88.0	1.4
United Kingdom	9.3	9.9	9.9	11.1	11.8	12.6	13.4	1.4
France	8.8	10.2	10.3	11.6	12.4	13.2	14.2	1.6
Germany	14.8	14.2	14.0	15.9	16.7	17.4	18.3	1.3
Italy	7.0	8.0	8.0	9.2	9.9	10.6	11.2	1.6
Netherlands	3.4	3.8	3.8	4.2	4.4	4.7	4.9	1.2
Other Western Europe	16.6	19.8	20.0	21.8	22.9	24.1	26.0	1.3
Industrialized Asia	22.8	27.6	27.9	31.0	32.9	35.0	37.1	1.4
Japan	17.9	21.5	21.7	24.0	25.3	26.7	28.2	1.2
Australasia	4.8	6.1	6.2	7.0	7.6	8.2	8.9	1.7
Total Industrialized	182.7	206.1	209.7	236.8	256.5	275.7	296.3	1.7
EE/FSU								
Former Soviet Union	60.7	38.7	39.2	46.2	52.5	61.3	69.7	2.8
Eastern Europe	15.6	11.9	11.2	12.9	14.8	17.6	20.1	2.8
Total EE/FSU	76.3	50.6	50.4	59.1	67.3	78.9	89.8	2.8
Developing Countries								
Developing Asia	51.0	72.9	70.9	103.9	135.0	172.7	215.4	5.4
China	27.0	35.3	31.9	45.7	61.5	80.6	102.8	5.7
India	7.8	11.6	12.2	16.4	20.5	25.4	30.6	4.5
South Korea	3.7	6.9	7.3	9.8	11.3	13.5	15.7	3.7
Other Asia	12.6	19.1	19.5	32.0	41.8	53.2	66.3	6.0
Middle East	13.1	19.1	19.3	23.8	30.2	37.3	45.9	4.2
Turkey	2.0	3.0	3.0	3.7	4.6	5.5	6.7	4.0
Other Middle East	11.1	16.1	16.4	20.1	25.6	31.8	39.2	4.2
Africa	9.3	11.6	11.8	15.3	18.0	21.8	25.6	3.8
Central and South America . . .	13.7	19.4	19.8	26.5	34.5	44.7	55.0	5.0
Brazil	5.7	8.2	8.5	10.3	12.9	15.8	19.0	3.9
Other Central/South America . .	8.1	11.2	11.2	16.2	21.6	28.9	36.0	5.7
Total Developing	87.2	123.0	121.8	169.4	217.6	276.4	341.9	5.0
Total World	346.2	379.7	381.9	465.2	541.4	631.0	728.0	3.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table B2. World Total Energy Consumption by Region and Fuel, High Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America								
Oil	40.4	44.6	45.8	51.8	58.4	64.7	71.2	2.1
Natural Gas	22.7	26.2	26.8	32.2	36.2	40.5	43.5	2.3
Coal	20.5	23.5	23.5	26.2	28.1	29.5	32.1	1.5
Nuclear.	7.0	8.0	8.6	9.3	9.1	8.8	8.8	0.1
Other.	9.5	10.7	11.4	12.4	13.7	14.8	15.7	1.5
Total	100.1	112.7	115.7	131.9	145.4	158.2	171.2	1.9
Western Europe								
Oil	25.8	29.1	28.7	31.6	32.9	34.0	35.1	1.0
Natural Gas	9.7	13.6	14.3	18.6	21.2	24.3	28.9	3.4
Coal	12.4	8.8	8.4	7.9	7.8	7.6	7.0	-0.9
Nuclear.	7.4	8.8	8.9	8.9	9.0	8.7	8.2	-0.4
Other.	4.5	5.4	5.6	6.7	7.3	8.0	8.8	2.2
Total	59.8	65.8	66.0	73.8	78.2	82.5	88.0	1.4
Industrialized Asia								
Oil	12.5	13.7	13.9	15.5	16.4	17.1	17.8	1.2
Natural Gas	2.5	3.6	3.8	4.3	4.5	5.1	5.9	2.1
Coal	4.2	5.3	5.4	6.0	6.3	6.5	6.7	1.0
Nuclear.	2.0	3.2	3.2	3.4	3.7	4.0	4.3	1.5
Other.	1.6	1.7	1.7	1.8	1.9	2.2	2.4	1.6
Total	22.8	27.6	27.9	31.0	32.9	35.0	37.1	1.4
Total Industrialized								
Oil	78.7	87.4	88.4	98.9	107.7	115.8	124.1	1.6
Natural Gas	35.0	43.5	44.8	55.1	61.9	69.8	78.3	2.7
Coal	37.1	37.5	37.3	40.1	42.1	43.6	45.8	1.0
Nuclear.	16.3	20.0	20.6	21.6	21.8	21.6	21.3	0.1
Other.	15.6	17.9	18.6	21.0	23.0	24.9	26.9	1.8
Total	182.7	206.1	209.7	236.8	256.5	275.7	296.3	1.7
EE/FSU								
Oil	21.0	10.9	10.8	14.6	17.8	22.1	25.8	4.2
Natural Gas	28.8	22.7	22.9	26.3	31.1	37.9	45.2	3.3
Coal	20.8	11.4	11.1	11.6	11.4	11.1	10.5	-0.3
Nuclear.	2.9	2.7	2.7	3.3	3.3	3.5	3.4	1.0
Other.	2.8	3.0	3.0	3.3	3.7	4.3	5.0	2.5
Total	76.3	50.6	50.4	59.1	67.3	78.9	89.8	2.8
Developing Countries								
Developing Asia								
Oil	16.0	26.7	27.7	38.8	50.8	66.2	82.7	5.4
Natural Gas	3.2	6.0	6.4	12.8	17.8	24.4	32.2	8.0
Coal	27.7	34.5	30.7	42.4	53.5	65.6	80.1	4.7
Nuclear.	0.9	1.5	1.6	2.5	3.4	4.2	5.6	6.1
Other.	3.2	4.3	4.6	7.3	9.6	12.3	14.8	5.7
Total	51.0	72.9	70.9	103.9	135.0	172.7	215.4	5.4

See notes at end of table.

Table B2. World Total Energy Consumption by Region and Fuel, High Economic Growth Case, 1990-2020
(Continued)
 (Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Developing Countries (Continued)								
Middle East								
Oil	8.1	10.4	10.5	12.7	15.1	18.0	21.6	3.5
Natural Gas	3.9	6.9	7.1	8.9	12.4	15.9	20.1	5.1
Coal	0.8	1.2	1.1	1.3	1.6	1.8	2.0	2.7
Nuclear.	0.0	0.0	0.0	0.0	0.1	0.1	0.2	—
Other	0.4	0.6	0.5	0.8	1.0	1.5	2.0	6.6
Total	13.1	19.1	19.3	23.8	30.2	37.3	45.9	4.2
Africa								
Oil	4.2	5.1	5.2	7.4	9.2	11.3	13.7	4.7
Natural Gas	1.5	2.0	2.1	2.7	3.2	4.0	4.7	3.9
Coal	3.0	3.7	3.6	4.2	4.5	5.0	5.5	2.0
Nuclear.	0.1	0.1	0.1	0.1	0.1	0.2	0.2	2.0
Other	0.6	0.7	0.7	0.9	1.0	1.3	1.5	3.6
Total	9.3	11.6	11.8	15.3	18.0	21.8	25.6	3.8
Central and South America								
Oil	7.0	9.4	9.5	12.4	15.8	19.2	23.1	4.3
Natural Gas	2.2	3.4	3.5	5.7	9.4	15.1	20.3	8.7
Coal	0.6	0.9	0.9	1.1	1.3	1.4	1.6	2.8
Nuclear.	0.1	0.1	0.1	0.2	0.2	0.2	0.3	4.9
Other	3.9	5.6	5.7	7.0	7.8	8.8	9.7	2.6
Total	13.7	19.4	19.8	26.5	34.5	44.7	55.0	5.0
Total Developing Countries								
Oil	35.2	51.5	52.9	71.4	90.9	114.7	141.2	4.8
Natural Gas	10.8	18.3	19.2	30.1	42.8	59.5	77.4	6.9
Coal	32.1	40.3	36.3	49.0	60.8	73.8	89.1	4.4
Nuclear.	1.1	1.7	1.9	2.8	3.8	4.8	6.3	5.9
Other	8.0	11.1	11.5	16.1	19.4	23.8	28.0	4.3
Total	87.2	123.0	121.8	169.4	217.6	276.4	341.9	5.0
Total World								
Oil	134.9	149.8	152.2	184.9	216.3	252.6	291.0	3.1
Natural Gas	74.5	84.5	86.9	111.5	135.9	167.2	200.8	4.1
Coal	90.0	89.3	84.8	100.7	114.3	128.4	145.4	2.6
Nuclear.	20.4	24.4	25.3	27.8	28.9	29.9	30.9	1.0
Other	26.5	32.0	33.1	40.3	46.1	53.0	59.8	2.9
Total	346.2	379.7	381.9	465.2	541.4	631.0	728.0	3.1

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table B3. World Gross Domestic Product (GDP) by Region, High Economic Growth Case, 1990-2020
(Billion 1997 Dollars)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	7,723	9,760	10,165	13,417	16,433	19,770	23,595	4.1
United States ^a	6,836	8,675	9,029	11,909	14,552	17,454	20,754	4.0
Canada	555	665	699	900	1,077	1,246	1,411	3.4
Mexico	332	421	437	608	804	1,070	1,430	5.8
Western Europe	7,597	8,731	8,944	11,076	13,036	15,260	17,794	3.3
United Kingdom	1,146	1,353	1,384	1,750	2,077	2,493	2,944	3.7
France	1,299	1,455	1,499	1,870	2,217	2,560	2,938	3.3
Germany	1,879	2,156	2,187	2,674	3,118	3,623	4,203	3.2
Italy	1,079	1,188	1,207	1,469	1,719	2,001	2,317	3.2
Netherlands	317	392	407	505	596	700	819	3.4
Other Western Europe	1,877	2,187	2,260	2,809	3,310	3,882	4,573	3.4
Industrialized Asia	4,054	4,765	4,821	5,530	6,313	7,285	8,336	2.6
Japan	3,673	4,271	4,304	4,887	5,551	6,380	7,256	2.5
Australasia	381	494	516	643	762	905	1,080	3.6
Total Industrialized	19,374	23,256	23,930	30,023	35,783	42,315	49,726	3.5
EE/FSU								
Former Soviet Union	1,009	545	569	838	1,162	1,751	2,447	7.2
Eastern Europe	348	358	363	574	826	1,181	1,656	7.5
Total EE/FSU	1,357	903	932	1,411	1,988	2,932	4,104	7.3
Developing Countries								
Developing Asia	1,739	2,975	3,165	4,925	7,119	10,077	14,093	7.4
China	427	968	1,037	1,730	2,654	3,911	5,693	8.4
India	268	445	473	727	1,027	1,444	2,018	7.2
South Korea	297	445	493	711	983	1,346	1,827	6.4
Other Asia	748	1,118	1,162	1,757	2,454	3,376	4,554	6.7
Middle East	379	580	577	806	1,084	1,476	2,023	6.2
Turkey	140	196	186	262	352	477	645	6.1
Other Middle East	239	384	391	544	731	999	1,377	6.2
Africa	405	485	499	708	935	1,211	1,554	5.6
Central and South America . . .	1,136	1,467	1,452	2,067	2,770	3,668	4,832	5.9
Brazil	674	810	816	1,166	1,575	2,089	2,761	6.0
Other Central/South America . .	462	657	636	900	1,195	1,578	2,071	5.8
Total Developing	3,660	5,507	5,693	8,505	11,907	16,431	22,501	6.8
Total World	24,392	29,665	30,555	39,940	49,678	61,679	76,330	4.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: DRI-WEFA, *World Economic Outlook*, Vol. 1 (Lexington, MA, 3rd Quarter 2001); Energy Information Administration (EIA), *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B20; and EIA, World Energy Projection System (2002).

Table B4. World Oil Consumption by Region, High Economic Growth Case, 1990-2020
(Million Barrels per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	20.4	22.7	23.4	26.5	29.8	33.0	36.3	2.1
United States ^a	17.0	18.9	19.5	21.6	24.1	26.4	28.5	1.8
Canada	1.7	1.9	1.9	2.2	2.4	2.5	2.6	1.4
Mexico	1.7	1.9	2.0	2.7	3.3	4.1	5.1	4.7
Western Europe	12.5	14.1	13.9	15.3	15.9	16.5	17.0	1.0
United Kingdom	1.8	1.8	1.7	2.1	2.2	2.3	2.4	1.7
France	1.8	2.0	2.0	2.2	2.4	2.4	2.5	1.1
Germany	2.7	2.9	2.8	3.2	3.3	3.4	3.4	0.9
Italy	1.9	2.1	2.0	2.2	2.3	2.3	2.4	0.8
Netherlands	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.0
Other Western Europe	3.6	4.5	4.5	4.7	4.9	5.1	5.2	0.7
Industrialized Asia	6.2	6.8	6.9	7.6	8.1	8.5	8.8	1.2
Japan	5.1	5.5	5.6	6.1	6.5	6.6	6.8	0.9
Australasia	1.0	1.3	1.3	1.5	1.7	1.8	2.0	2.1
Total Industrialized	39.0	43.6	44.2	49.5	53.8	57.9	62.1	1.6
EE/FSU								
Former Soviet Union	8.4	3.8	3.7	5.3	6.5	8.3	9.7	4.7
Eastern Europe	1.6	1.4	1.5	1.7	2.0	2.3	2.6	2.8
Total EE/FSU	10.0	5.2	5.2	7.0	8.5	10.6	12.3	4.2
Developing Countries								
Developing Asia	7.6	12.8	13.3	18.6	24.4	31.8	39.7	5.4
China	2.3	4.1	4.3	5.7	7.6	10.0	12.8	5.3
India	1.2	1.8	1.9	2.7	3.6	4.8	5.9	5.5
South Korea	1.0	2.0	2.0	2.5	2.9	3.3	3.7	2.8
Other Asia	3.1	4.9	5.0	7.8	10.3	13.6	17.3	6.1
Middle East	3.9	5.0	5.0	6.1	7.2	8.6	10.3	3.5
Turkey	0.5	0.6	0.6	0.9	1.0	1.3	1.5	4.4
Other Middle East	3.4	4.3	4.4	5.2	6.2	7.4	8.8	3.3
Africa	2.1	2.5	2.5	3.6	4.5	5.5	6.7	4.7
Central and South America . . .	3.4	4.6	4.7	6.1	7.7	9.4	11.3	4.3
Brazil	1.3	1.9	2.0	2.3	2.9	3.5	4.4	4.0
Other Central/South America . .	2.1	2.7	2.7	3.8	4.9	5.8	6.9	4.5
Total Developing	17.0	24.8	25.5	34.4	43.8	55.2	68.0	4.8
Total World	66.0	73.6	74.9	90.8	106.1	123.8	142.4	3.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B21; and World Energy Projection System (2002).

Table B5. World Natural Gas Consumption by Region, High Economic Growth Case, 1990-2020
(Trillion Cubic Feet)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	22.0	25.4	26.1	31.3	35.3	39.4	42.4	2.3
United States ^a	18.7	21.3	21.7	26.0	29.1	32.6	35.0	2.3
Canada	2.4	2.9	3.1	3.5	3.8	4.2	4.6	1.9
Mexico	0.9	1.3	1.3	1.9	2.3	2.6	2.8	3.9
Western Europe	10.1	13.4	14.0	18.2	20.7	23.6	28.0	3.4
United Kingdom	2.1	3.1	3.3	3.9	4.5	5.1	6.0	3.0
France	1.0	1.3	1.3	1.9	2.2	2.6	3.2	4.2
Germany	2.7	3.0	3.0	4.2	4.6	5.1	6.3	3.5
Italy	1.7	2.2	2.4	3.0	3.4	3.9	4.3	2.8
Netherlands	1.5	1.8	1.7	2.0	2.2	2.3	2.5	1.8
Other Western Europe	1.2	2.0	2.3	3.3	3.7	4.6	5.8	4.6
Industrialized Asia	2.6	3.5	3.6	4.1	4.3	4.9	5.6	2.2
Japan	1.9	2.5	2.6	3.0	3.0	3.4	4.0	2.0
Australasia	0.8	0.9	1.0	1.2	1.3	1.5	1.7	2.7
Total Industrialized	34.8	42.3	43.7	53.6	60.3	67.9	76.1	2.7
EE/FSU								
Former Soviet Union	25.0	19.9	20.1	22.7	26.2	31.2	36.7	2.9
Eastern Europe	3.1	2.5	2.4	3.1	4.4	6.1	7.8	5.7
Total EE/FSU	28.1	22.4	22.5	25.9	30.6	37.3	44.5	3.3
Developing Countries								
Developing Asia	3.0	5.6	6.0	12.0	16.7	22.7	29.9	7.9
China	0.5	0.8	0.9	2.0	3.2	5.3	7.9	11.1
India	0.4	0.8	0.8	1.2	1.8	2.6	3.2	7.1
South Korea	0.1	0.5	0.6	1.2	1.5	2.1	2.7	7.5
Other Asia	1.9	3.6	3.8	7.6	10.2	12.8	16.1	7.1
Middle East	3.7	6.6	6.8	8.5	11.8	15.2	19.2	5.1
Turkey	0.1	0.4	0.4	0.5	0.7	1.0	1.4	5.6
Other Middle East	3.6	6.2	6.3	8.0	11.1	14.1	17.8	5.0
Africa	1.4	1.8	2.0	2.5	2.9	3.7	4.4	8.7
Central and South America . . .	2.0	3.1	3.2	5.2	8.7	13.9	18.6	8.7
Brazil	0.1	0.2	0.2	0.6	1.5	2.7	3.6	13.9
Other Central/South America . .	1.9	2.9	3.0	4.6	7.2	11.2	15.0	7.9
Total Developing	10.1	17.2	18.0	28.3	40.1	55.5	72.1	6.8
Total World	72.9	81.9	84.2	107.8	131.0	160.7	192.7	4.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B13; and World Energy Projection System (2002).

Table B6. World Coal Consumption by Region, High Economic Growth Case, 1990-2020
(Million Short Tons)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	959	1,121	1,122	1,273	1,375	1,449	1,585	1.7
United States ^a	895	1,040	1,045	1,181	1,271	1,335	1,462	1.6
Canada	55	66	63	69	77	83	88	1.5
Mexico	9	15	13	22	27	31	36	4.9
Western Europe	894	566	546	514	508	497	469	-0.7
United Kingdom	119	70	65	63	61	57	47	-1.5
France	35	29	26	23	17	18	15	-2.6
Germany	528	269	258	245	249	247	236	-0.4
Italy	23	19	19	18	18	16	16	-0.9
Netherlands	15	16	14	13	9	9	7	-3.0
Other Western Europe	173	164	165	152	153	149	147	-0.5
Industrialized Asia	231	287	295	323	337	350	359	0.9
Japan	125	144	149	171	181	191	195	1.3
Australasia	106	142	145	152	156	159	164	0.6
Total Industrialized	2,084	1,974	1,963	2,110	2,220	2,295	2,413	1.0
EE/FSU								
Former Soviet Union	848	396	414	442	435	425	403	-0.1
Eastern Europe	527	414	363	365	356	344	324	-0.5
Total EE/FSU	1,375	810	778	807	791	769	727	-0.3
Developing Countries								
Developing Asia	1,583	1,903	1,686	2,335	2,942	3,606	4,405	4.7
China	1,124	1,300	1,075	1,516	2,005	2,541	3,156	5.3
India	242	333	348	446	505	563	659	3.1
South Korea	42	60	65	82	93	106	116	2.8
Other Asia	175	210	197	291	339	397	474	4.3
Middle East	66	99	96	109	137	153	167	2.7
Turkey	60	86	84	97	114	125	136	2.4
Other Middle East	6	12	12	12	23	27	31	4.5
Africa	152	181	177	204	218	245	268	2.0
Central and South America	26	42	41	51	58	65	74	2.8
Brazil	17	28	27	32	40	45	53	3.2
Other Central/South America	9	15	14	19	18	20	21	2.1
Total Developing	1,827	2,226	2,000	2,699	3,355	4,069	4,914	4.4
Total World	5,287	5,009	4,740	5,615	6,366	7,134	8,054	2.6

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. To convert short tons to metric tons, divide each number in the table by 1.102.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B16; and World Energy Projection System (2002).

Table B7. World Nuclear Energy Consumption by Region, High Economic Growth Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	649	750	808	865	847	820	818	0.1
United States ^a	577	674	728	759	737	707	702	-0.2
Canada	69	68	70	96	100	103	106	2.0
Mexico	3	9	10	10	10	10	10	0.3
Western Europe	703	836	846	858	864	841	791	-0.3
United Kingdom	59	95	91	70	63	56	34	-4.6
France	298	369	375	408	424	437	463	1.0
Germany	145	154	161	160	154	147	112	-1.7
Italy	0	0	0	0	0	0	0	—
Netherlands	3	4	4	4	0	0	0	-100.0
Other Western Europe	198	215	215	216	222	202	182	-0.8
Industrialized Asia	192	316	309	333	363	394	421	1.5
Japan	192	316	309	333	363	394	421	1.5
Australasia	0	0	0	0	0	0	0	—
Total Industrialized	1,544	1,902	1,962	2,055	2,074	2,056	2,030	0.2
EE/FSU								
Former Soviet Union	201	183	190	217	222	233	208	0.4
Eastern Europe	54	61	60	82	78	86	99	2.4
Total EE/FSU	256	244	250	299	300	319	308	1.0
Developing Countries								
Developing Asia	88	145	160	248	331	417	548	12.2
China	0	13	14	55	83	106	159	12.2
India	6	11	11	16	29	35	55	7.7
South Korea	50	85	98	128	137	177	218	3.9
Other Asia	32	36	37	49	82	99	116	5.6
Middle East	0	0	0	0	6	15	17	—
Turkey	0	0	0	0	0	0	0	—
Other Middle East	0	0	0	0	6	15	17	—
Africa	8	14	13	13	14	17	19	2.0
Central and South America . . .	9	10	11	18	19	18	29	4.9
Brazil	2	3	4	11	12	13	23	9.0
Other Central/South America . .	7	7	7	6	7	5	6	-0.8
Total Developing	105	169	184	279	371	467	613	5.9
Total World	1,905	2,315	2,396	2,634	2,745	2,841	2,950	1.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B8; and World Energy Projection System (2002).

Table B8. World Consumption of Hydroelectricity and Other Renewable Energy by Region, High Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	9.5	10.7	11.4	12.4	13.7	14.8	15.7	1.5
United States ^a	6.1	6.9	7.3	8.1	8.5	9.3	9.9	1.4
Canada	3.1	3.5	3.6	3.8	4.3	4.6	4.8	1.4
Mexico	0.3	0.4	0.4	0.5	0.8	1.0	1.0	4.0
Western Europe	4.5	5.4	5.6	6.7	7.3	8.0	8.8	2.2
United Kingdom	0.1	0.1	0.1	0.3	0.4	0.4	0.5	6.0
France	0.6	0.7	0.8	0.2	0.3	0.4	0.4	-3.1
Germany	0.3	0.3	0.4	0.6	0.8	0.9	1.0	5.2
Italy	0.4	0.5	0.6	1.2	1.2	1.4	1.5	4.6
Netherlands	0.0	0.0	0.0	0.3	0.4	0.4	0.4	10.7
Other Western Europe	3.2	3.7	3.7	4.1	4.3	4.5	5.0	1.5
Industrialized Asia	1.6	1.7	1.7	1.8	1.9	2.2	2.4	1.6
Japan	1.1	1.2	1.2	1.3	1.3	1.5	1.6	1.6
Australasia	0.4	0.5	0.5	0.6	0.6	0.7	0.7	1.8
Total Industrialized	15.6	17.9	18.6	21.0	23.0	24.9	26.9	1.8
EE/FSU								
Former Soviet Union	2.4	2.3	2.3	2.6	2.8	3.1	3.4	1.8
Eastern Europe	0.4	0.6	0.6	0.7	0.9	1.2	1.6	4.5
Total EE/FSU	2.8	3.0	3.0	3.3	3.7	4.3	5.0	2.5
Developing Countries								
Developing Asia	3.2	4.3	4.6	7.3	9.6	12.3	14.8	5.7
China	1.3	2.1	2.3	3.6	4.8	6.3	8.0	6.1
India	0.7	0.8	0.9	1.2	1.5	1.8	2.0	4.2
South Korea	0.0	0.0	0.0	0.1	0.1	0.2	0.3	8.9
Other Asia	1.1	1.3	1.4	2.4	3.2	4.0	4.5	5.8
Middle East	0.4	0.6	0.5	0.8	1.0	1.5	2.0	6.6
Turkey	0.2	0.4	0.4	0.4	0.5	0.6	0.7	3.3
Other Middle East	0.1	0.2	0.2	0.4	0.5	0.9	1.3	10.2
Africa	0.6	0.7	0.7	0.9	1.0	1.3	1.5	3.6
Central and South America . . .	3.9	5.6	5.7	7.0	7.8	8.8	9.7	2.6
Brazil	2.2	3.1	3.3	4.1	4.6	4.8	4.9	2.0
Other Central/South America . .	1.7	2.5	2.4	2.9	3.2	4.0	4.8	3.3
Total Developing	8.0	11.1	11.5	16.1	19.4	23.8	28.0	4.3
Total World	26.5	32.0	33.1	40.3	46.1	53.0	59.8	2.9

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. U.S. totals include net electricity imports, methanol, and liquid hydrogen.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table B9. World Net Electricity Consumption by Region, High Economic Growth Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	3,362	4,046	3,904	4,668	5,264	5,857	6,456	2.4
United States ^a	2,817	3,400	3,236	3,833	4,284	4,735	5,173	2.3
Canada	438	485	498	581	646	700	752	2.0
Mexico	107	162	171	254	334	422	531	5.5
Western Europe	2,077	2,399	2,435	2,842	3,111	3,393	3,744	2.1
United Kingdom	287	330	333	390	423	459	493	1.9
France	326	394	399	444	490	534	594	1.9
Germany	489	492	495	590	642	692	756	2.0
Italy	222	266	272	349	395	444	496	2.9
Netherlands	72	95	98	114	125	137	150	2.0
Other Western Europe	681	822	838	954	1,036	1,128	1,255	1.9
Industrialized Asia	945	1,158	1,178	1,362	1,474	1,592	1,715	1.8
Japan	765	932	947	1,084	1,168	1,258	1,349	1.7
Australasia	181	226	231	278	306	334	366	2.2
Total Industrialized	6,385	7,604	7,517	8,872	9,849	10,842	11,915	2.2
EE/FSU								
Former Soviet Union	1,488	1,068	1,075	1,243	1,418	1,666	1,904	2.8
Eastern Europe	418	390	377	442	516	617	712	3.1
Total EE/FSU	1,906	1,459	1,452	1,685	1,934	2,283	2,616	2.8
Developing Countries								
Developing Asia	1,259	2,175	2,319	3,217	4,267	5,573	7,103	5.5
China	551	1,013	1,084	1,436	2,001	2,722	3,602	5.9
India	257	396	424	555	699	878	1,069	4.5
South Korea	93	207	233	294	344	415	487	3.6
Other Asia	357	560	578	932	1,223	1,558	1,944	5.9
Middle East	263	470	494	578	742	928	1,155	4.1
Turkey	51	102	106	134	167	205	250	4.2
Other Middle East	213	368	388	444	575	724	904	4.1
Africa	287	361	367	504	629	810	980	4.8
Central and South America . . .	449	656	684	899	1,176	1,529	1,891	5.0
Brazil	229	334	354	461	588	736	898	4.5
Other Central/South America . .	220	322	330	438	588	794	993	5.4
Total Developing	2,258	3,663	3,863	5,198	6,815	8,840	11,128	5.2
Total World	10,549	12,725	12,833	15,756	18,598	21,965	25,659	3.4

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Electricity consumption equals generation plus imports minus exports minus distribution losses.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B2; and World Energy Projection System (2002).

Table B10. World Carbon Dioxide Emissions by Region, High Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1,562	1,742	1,767	2,023	2,244	2,453	2,678	2.0
United States ^a	1,352	1,495	1,517	1,714	1,887	2,046	2,215	1.8
Canada	126	146	150	168	183	196	208	1.6
Mexico	84	101	101	141	174	211	256	4.5
Western Europe	930	947	940	1,041	1,095	1,153	1,227	1.3
United Kingdom	164	154	151	174	186	197	209	1.6
France	102	110	109	123	129	138	149	1.5
Germany	271	237	230	255	266	275	291	1.1
Italy	112	122	121	137	147	154	162	1.4
Netherlands	58	66	64	69	70	74	76	0.8
Other Western Europe	223	260	264	284	298	315	340	1.2
Industrialized Asia	357	412	422	469	496	523	550	1.3
Japan	269	300	307	342	359	375	392	1.2
Australasia	88	112	115	127	137	147	159	1.5
Total Industrialized	2,849	3,101	3,129	3,534	3,836	4,129	4,456	0.0
EE/FSU								
Former Soviet Union	1,036	599	607	718	814	950	1,080	2.8
Eastern Europe	301	217	203	224	250	285	313	2.1
Total EE/FSU	1,337	816	810	942	1,064	1,235	1,393	2.6
Developing Countries								
Developing Asia	1,053	1,435	1,361	1,950	2,516	3,192	3,966	5.2
China	617	765	669	940	1,255	1,629	2,058	5.5
India	153	231	242	321	392	478	574	4.2
South Korea	61	101	107	142	164	193	220	3.5
Other Asia	223	338	343	547	704	891	1,114	5.8
Middle East	231	325	330	401	503	613	747	4.0
Turkey	35	50	50	63	77	92	110	3.8
Other Middle East	196	275	280	338	426	521	637	4.0
Africa	179	216	218	281	328	394	460	3.6
Central and South America . . .	178	246	249	339	459	607	759	5.4
Brazil	62	87	88	109	146	191	240	4.9
Other Central/South America . .	116	159	162	230	314	416	519	5.7
Total Developing	1,641	2,222	2,158	2,971	3,806	4,806	5,932	4.9
Total World	5,827	6,139	6,097	7,446	8,706	10,170	11,781	3.2

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. The U.S. numbers include carbon dioxide emissions attributable to renewable energy sources.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table B11. World Carbon Dioxide Emissions from Oil Use by Region, High Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	716	775	793	894	1,008	1,120	1,235	2.1
United States ^a	590	635	650	714	799	876	948	1.8
Canada	61	66	68	77	83	87	90	1.4
Mexico	65	74	76	103	127	157	197	4.7
Western Europe	474	525	517	570	592	611	632	1.0
United Kingdom	66	65	63	77	81	85	89	1.7
France	67	72	72	79	84	87	90	1.1
Germany	103	107	104	117	120	123	126	0.9
Italy	74	78	74	83	85	87	89	0.8
Netherlands	27	30	31	33	35	37	38	1.0
Other Western Europe	138	172	173	181	188	193	200	0.7
Industrialized Asia	217	230	233	259	275	288	299	1.2
Japan	179	183	185	204	215	221	225	0.9
Australasia	38	46	48	55	61	67	74	2.1
Total Industrialized	1,407	1,529	1,543	1,722	1,875	2,019	2,166	1.6
EE/FSU								
Former Soviet Union	334	148	146	207	254	323	380	4.7
Eastern Europe	66	55	55	64	75	88	98	2.8
Total EE/FSU	400	202	201	271	330	411	479	4.2
Developing Countries								
Developing Asia	304	479	496	696	911	1,187	1,484	5.4
China	94	152	160	209	280	371	474	5.3
India	45	70	73	101	136	184	226	5.5
South Korea	38	60	62	77	89	101	112	2.8
Other Asia	127	197	201	309	406	530	671	5.9
Middle East	155	195	198	239	284	339	406	3.5
Turkey	17	22	22	30	36	44	53	4.4
Other Middle East	138	173	177	210	247	295	353	3.4
Africa	83	95	97	138	172	211	256	4.7
Central and South America . . .	132	173	176	230	292	355	427	4.3
Brazil	51	70	71	84	104	128	160	4.0
Other Central/South America . .	81	104	105	146	188	226	267	4.5
Total Developing	674	942	968	1,303	1,658	2,091	2,573	4.8
Total World	2,482	2,673	2,712	3,297	3,863	4,520	5,218	3.2

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table B12. World Carbon Dioxide Emissions from Natural Gas Use by Region, High Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	326	377	381	461	518	580	623	2.4
United States ^a	277	315	317	381	427	479	513	2.3
Canada	35	42	46	51	56	62	67	1.9
Mexico	15	20	19	28	35	40	43	3.9
Western Europe	140	196	206	268	306	349	416	3.4
United Kingdom	30	47	50	60	68	78	92	3.0
France	16	21	21	30	36	41	50	3.5
Germany	32	42	43	59	65	72	89	3.5
Italy	25	32	35	44	51	57	64	2.8
Netherlands	20	23	22	25	28	30	32	1.8
Other Western Europe	18	31	35	51	58	71	89	4.6
Industrialized Asia	36	52	54	62	65	73	85	2.1
Japan	24	38	40	45	45	51	60	2.0
Australasia	12	14	14	17	20	22	25	2.7
Total Industrialized	503	626	641	790	889	1,002	1,123	2.7
EE/FSU								
Former Soviet Union	369	291	294	332	383	455	537	2.9
Eastern Europe	46	36	35	46	65	90	114	5.7
Total EE/FSU	414	327	329	378	448	545	651	3.3
Developing Countries								
Developing Asia	45	86	92	184	256	352	464	8.0
China	8	13	14	33	53	89	131	11.1
India	7	13	12	21	30	42	52	7.1
South Korea	2	8	10	19	24	33	44	7.5
Other Asia	29	53	56	111	150	188	236	7.1
Middle East	56	100	102	129	178	229	290	5.1
Turkey	2	6	7	8	11	16	21	5.6
Other Middle East	54	94	96	121	167	213	269	5.0
Africa	22	29	31	39	45	58	68	3.9
Central and South America . . .	32	49	51	82	136	217	292	8.7
Brazil	2	3	4	9	22	40	54	13.9
Other Central/South America . .	30	46	47	73	114	177	237	8.0
Total Developing	155	263	276	434	616	856	1,114	6.9
Total World	1,072	1,216	1,247	1,602	1,953	2,404	2,888	4.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table B13. World Carbon Dioxide Emissions from Coal Use by Region, High Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	520	595	592	669	718	754	820	1.6
United States ^a	485	550	549	619	661	692	754	1.5
Canada	31	38	36	40	44	47	50	1.5
Mexico	4	7	6	10	12	14	16	4.9
Western Europe	315	225	216	203	198	192	179	-0.9
United Kingdom	68	42	39	38	37	34	28	-1.5
France	20	17	15	14	10	10	9	-2.6
Germany	137	87	83	79	81	80	76	-0.4
Italy	14	11	12	11	11	10	10	-0.9
Netherlands	11	13	11	10	7	7	6	-3.0
Other Western Europe	66	56	56	52	52	51	50	-0.5
Industrialized Asia	104	130	135	149	156	162	166	1.0
Japan	66	78	81	93	99	104	106	1.3
Australasia	38	52	53	56	57	58	60	0.6
Total Industrialized	939	951	943	1,021	1,071	1,109	1,166	1.0
EE/FSU								
Former Soviet Union	333	160	168	179	176	172	163	-0.1
Eastern Europe	189	127	113	113	110	107	100	-0.5
Total EE/FSU	522	287	280	292	287	279	263	-0.3
Developing Countries								
Developing Asia	704	870	773	1,070	1,349	1,653	2,018	4.7
China	514	600	495	698	923	1,169	1,452	5.3
India	101	148	156	200	227	252	295	3.1
South Korea	21	33	36	45	51	58	63	2.8
Other Asia	67	88	87	127	148	173	207	4.2
Middle East	20	30	29	33	41	46	50	2.7
Turkey	16	23	21	25	29	32	35	2.4
Other Middle East	4	7	7	8	12	14	15	3.5
Africa	74	93	90	104	111	125	136	2.0
Central and South America . . .	15	23	22	27	31	35	40	2.8
Brazil	9	14	13	16	20	22	26	3.2
Other Central/South America . .	5	9	9	12	12	13	14	2.3
Total Developing	812	1,017	914	1,234	1,532	1,859	2,245	4.4
Total World	2,274	2,254	2,137	2,547	2,889	3,246	3,674	2.6

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table B14. World Nuclear Generating Capacity by Region and Country, High Economic Growth Case, 1999-2020
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Industrialized Countries						
North America	108,776	108,867	112,656	110,404	104,897	106,087
United States	97,470	97,509	97,700	95,448	89,941	89,131
Canada	9,998	9,998	13,596	13,596	13,596	14,596
Mexico	1,308	1,360	1,360	1,360	1,360	2,360
Industrialized Asia	43,691	43,491	46,681	48,705	63,768	68,818
Japan	43,691	43,491	46,681	48,705	63,768	68,818
Western Europe	125,991	125,726	125,480	123,997	124,424	126,643
Belgium	5,712	5,712	5,712	5,712	5,712	5,712
Finland	2,656	2,656	2,656	3,656	3,656	4,656
France	63,103	63,153	63,153	62,920	64,370	64,370
Germany	21,122	21,122	21,122	20,142	18,975	18,735
Italy	0	0	0	0	0	1,000
Netherlands	449	449	449	449	0	0
Spain	7,470	7,512	7,512	7,512	8,512	7,913
Sweden	9,432	9,432	9,432	9,432	9,432	7,507
Switzerland	3,079	3,192	3,192	3,192	3,192	4,392
United Kingdom	12,968	12,498	12,252	10,982	10,575	12,358
Total Industrialized	278,458	278,084	284,817	283,106	293,089	301,548
EE/FSU						
Eastern Europe	10,605	10,675	12,508	11,934	11,098	13,039
Bulgaria	3,538	3,538	3,538	2,722	1,906	2,859
Czech Republic	1,648	1,648	3,481	3,481	3,481	3,481
Hungary	1,729	1,755	1,755	1,755	1,755	2,355
Romania	650	650	650	1,300	1,300	1,300
Slovakia	2,408	2,408	2,408	2,000	1,980	2,368
Slovenia	632	676	676	676	676	676
Former Soviet Union	34,704	33,796	36,652	38,597	40,560	42,762
Armenia	376	376	376	376	376	0
Kazakhstan	0	0	0	0	0	600
Lithuania	2,370	2,370	2,370	1,185	1,000	1,000
Russia	19,843	19,843	22,699	23,929	26,077	26,155
Ukraine	12,115	11,207	11,207	13,107	13,107	15,007
Total EE/FSU	45,309	44,471	49,160	50,531	51,658	55,801

See notes at end of table.

Table B14. World Nuclear Generating Capacity by Region and Country, High Economic Growth Case, 1999-2020 (Continued)
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Developing Countries						
Developing Asia	22,063	22,777	32,219	43,369	57,663	69,849
China	2,167	2,177	7,597	11,597	18,617	20,607
India	1,897	2,301	2,503	4,273	8,253	9,253
Korea, North	0	0	0	0	950	1,900
Korea, South	12,990	12,990	16,810	19,660	21,404	26,175
Pakistan	125	425	425	425	1,025	900
Taiwan	4,884	4,884	4,884	7,414	7,414	9,414
Thailand	0	0	0	0	0	600
Vietnam	0	0	0	0	0	1,000
Central and South America	1,561	2,790	2,790	4,019	4,019	5,109
Argentina	935	935	935	935	935	1,025
Brazil	626	1,855	1,855	3,084	3,084	4,084
Middle East	0	0	1,073	2,146	2,586	4,626
Israel	0	0	0	0	0	600
Iran	0	0	1,073	2,146	2,586	3,026
Turkey	0	0	0	0	0	1,000
Africa	1,842	1,800	1,800	2,060	2,320	3,440
Egypt	0	0	0	0	0	600
South Africa	1,842	1,800	1,800	2,060	2,320	2,840
Total Developing	25,466	27,367	37,882	51,594	66,588	83,024
Total World	349,233	349,922	371,859	385,231	411,335	440,373

Sources: **History:** International Atomic Energy Agency, *Nuclear Power Reactors in the World 2000* (Vienna, Austria, April 2001). **Projections:** Energy Information Administration (EIA), *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A9; and EIA, Office of Coal, Nuclear, Electric and Alternate Fuels, based on detailed assessments of country-specific nuclear power plants.

Table B15. World Total Energy Consumption in Oil-Equivalent Units by Region, High Economic Growth Case, 1990-2020
(Million Tons Oil Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	2,522	2,841	2,916	3,324	3,664	3,987	4,315	1.9
United States ^a	2,121	2,383	2,446	2,749	3,001	3,243	3,484	1.7
Canada	275	305	316	362	396	423	448	1.7
Mexico	126	153	155	214	268	321	384	4.4
Western Europe	1,508	1,659	1,664	1,861	1,971	2,080	2,218	1.4
United Kingdom	234	251	250	279	298	318	337	1.4
France	222	256	258	293	314	332	359	1.6
Germany	373	357	352	401	421	438	462	1.3
Italy	176	201	203	232	249	266	282	1.6
Netherlands	85	96	97	107	112	118	124	1.2
Other Western Europe	419	498	504	549	577	608	655	1.3
Industrialized Asia	574	695	704	781	829	881	934	1.4
Japan	452	541	547	605	637	674	710	1.2
Australasia	122	153	157	176	192	207	225	1.7
Total Industrialized	4,604	5,194	5,284	5,966	6,464	6,948	7,467	1.7
EE/FSU								
Former Soviet Union	1,529	975	988	1,165	1,322	1,545	1,757	2.8
Eastern Europe	393	299	283	324	374	443	505	2.8
Total EE/FSU	1,923	1,274	1,271	1,489	1,696	1,988	2,263	2.8
Developing Countries								
Developing Asia	1,286	1,837	1,788	2,618	3,402	4,352	5,428	5.4
China	681	890	803	1,153	1,549	2,030	2,590	5.7
India	196	293	307	414	515	641	772	4.5
South Korea	92	173	185	246	284	340	395	3.7
Other Asia	317	481	492	805	1,054	1,341	1,671	6.0
Middle East	330	481	487	599	760	940	1,156	4.2
Turkey	50	76	74	93	115	139	168	4.0
Other Middle East	280	405	413	506	645	801	988	4.2
Africa	235	292	297	385	453	549	645	3.8
Central and South America . . .	346	489	498	667	869	1,126	1,387	5.0
Brazil	142	208	215	258	324	399	479	3.9
Other Central/South America . .	204	282	283	409	545	727	908	5.7
Total Developing	2,197	3,100	3,069	4,269	5,484	6,966	8,615	5.0
Total World	8,724	9,568	9,623	11,724	13,644	15,902	18,345	3.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Low Economic Growth Case Projections:

World Energy Consumption

Gross Domestic Product

Carbon Dioxide Emissions

Nuclear Power Capacity

Table C1. World Total Energy Consumption by Region, Low Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	100.1	112.7	115.7	127.7	135.9	143.5	149.8	1.2
United States ^a	84.2	94.6	97.0	106.6	113.0	119.2	124.1	1.2
Canada	10.9	12.1	12.5	13.5	14.0	14.3	14.5	0.7
Mexico	5.0	6.1	6.1	7.6	8.8	9.9	11.2	2.9
Western Europe	59.8	65.8	66.0	69.5	71.1	72.6	74.3	0.6
United Kingdom	9.3	9.9	9.9	10.5	10.8	11.1	11.4	0.7
France	8.8	10.2	10.3	10.9	11.2	11.4	11.7	0.6
Germany	14.8	14.2	14.0	14.8	15.1	15.3	15.5	0.5
Italy	7.0	8.0	8.0	8.5	8.7	8.9	9.1	0.6
Netherlands	3.4	3.8	3.8	4.0	4.1	4.2	4.3	0.5
Other Western Europe	16.6	19.8	20.0	20.8	21.2	21.6	22.3	0.5
Industrialized Asia	22.8	27.6	27.9	28.3	28.8	29.4	30.0	0.3
Japan	17.9	21.5	21.7	21.8	22.0	22.4	22.7	0.2
Australasia	4.8	6.1	6.2	6.6	6.8	7.0	7.3	0.8
Total Industrialized	182.7	206.1	209.7	225.5	235.8	245.5	254.1	0.9
EE/FSU								
Former Soviet Union	60.7	38.7	39.2	41.4	43.2	46.5	48.7	1.0
Eastern Europe	15.6	11.9	11.2	11.9	12.7	13.5	14.2	1.1
Total EE/FSU	76.3	50.6	50.4	53.3	55.8	60.1	62.9	1.1
Developing Countries								
Developing Asia	51.0	72.9	70.9	87.6	100.8	114.0	126.7	2.8
China	27.0	35.3	31.9	38.3	44.4	50.2	55.7	2.7
India	7.8	11.6	12.2	14.6	16.6	18.8	20.9	2.6
South Korea	3.7	6.9	7.3	8.6	9.3	10.3	11.1	2.0
Other Asia	12.6	19.1	19.5	26.1	30.5	34.8	39.0	3.4
Middle East	13.1	19.1	19.3	21.3	24.1	27.0	30.2	2.1
Turkey	2.0	3.0	3.0	3.3	3.7	4.1	4.5	2.0
Other Middle East	11.1	16.1	16.4	18.0	20.4	22.9	25.7	2.2
Africa	9.3	11.6	11.8	13.4	14.5	15.8	16.9	1.7
Central and South America . . .	13.7	19.4	19.8	23.0	26.3	29.8	32.9	2.5
Brazil	5.7	8.2	8.5	9.4	10.6	11.7	12.8	2.0
Other Central/South America . .	8.1	11.2	11.2	13.6	15.7	18.1	20.1	2.8
Total Developing	87.2	123.0	121.8	145.2	165.6	186.6	206.7	2.6
Total World	346.2	379.7	381.9	424.1	457.3	492.1	523.6	1.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table C2. World Total Energy Consumption by Region and Fuel, Low Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America								
Oil	40.4	44.6	45.8	49.9	53.8	57.6	60.7	1.4
Natural Gas	22.7	26.2	26.8	30.9	33.6	36.6	38.8	1.8
Coal	20.5	23.5	23.5	25.8	27.0	27.5	28.2	0.9
Nuclear.	7.0	8.0	8.6	9.2	9.0	8.5	8.4	-0.1
Other	9.5	10.7	11.4	11.9	12.6	13.3	13.7	0.9
Total	100.1	112.7	115.7	127.7	135.9	143.5	149.8	1.2
Western Europe								
Oil	25.8	29.1	28.7	29.8	29.9	29.9	29.6	0.1
Natural Gas	9.7	13.6	14.3	17.5	19.3	21.3	24.4	2.6
Coal	12.4	8.8	8.4	7.5	7.1	6.7	6.0	-1.6
Nuclear.	7.4	8.8	8.9	8.4	8.2	7.7	6.8	-1.2
Other	4.5	5.4	5.6	6.3	6.7	7.1	7.5	1.4
Total	59.8	65.8	66.0	69.5	71.1	72.6	74.3	0.6
Industrialized Asia								
Oil	12.5	13.7	13.9	14.1	14.4	14.4	14.4	0.2
Natural Gas	2.5	3.6	3.8	3.9	4.0	4.3	4.8	1.1
Coal	4.2	5.3	5.4	5.5	5.5	5.5	5.4	0.0
Nuclear.	2.0	3.2	3.2	3.1	3.2	3.4	3.5	0.4
Other	1.6	1.7	1.7	1.7	1.7	1.8	1.9	0.6
Total	22.8	27.6	27.9	28.3	28.8	29.4	30.0	0.3
Total Industrialized								
Oil	78.7	87.4	88.4	93.8	98.1	101.9	104.7	0.8
Natural Gas	35.0	43.5	44.8	52.4	56.8	62.2	68.0	2.0
Coal	37.1	37.5	37.3	38.7	39.5	39.7	39.6	0.3
Nuclear.	16.3	20.0	20.6	20.7	20.4	19.6	18.7	-0.5
Other	15.6	17.9	18.6	19.9	21.1	22.2	23.1	1.0
Total	182.7	206.1	209.7	225.5	235.8	245.5	254.1	0.9
EE/FSU								
Oil	21.0	10.9	10.8	13.2	14.7	16.8	18.1	2.5
Natural Gas	28.8	22.7	22.9	23.6	25.7	28.8	31.6	1.6
Coal	20.8	11.4	11.1	10.5	9.5	8.4	7.3	-2.0
Nuclear.	2.9	2.7	2.7	3.0	2.7	2.7	2.4	-0.7
Other	2.8	3.0	3.0	3.0	3.1	3.3	3.5	0.7
Total	76.3	50.6	50.4	53.3	55.8	60.1	62.9	1.1
Developing Countries								
Developing Asia								
Oil	16.0	26.7	27.7	32.7	38.1	44.2	49.5	2.8
Natural Gas	3.2	6.0	6.4	10.7	13.3	16.3	19.2	5.4
Coal	27.7	34.5	30.7	35.9	39.7	42.6	45.8	1.9
Nuclear.	0.9	1.5	1.6	2.2	2.6	3.0	3.5	3.8
Other	3.2	4.3	4.6	6.2	7.1	8.0	8.6	3.0
Total	51.0	72.9	70.9	87.6	100.8	114.0	126.7	2.8

See notes at end of table.

Table C2. World Total Energy Consumption by Region and Fuel, Low Economic Growth Case, 1990-2020
(Continued)
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Developing Countries (Continued)								
Middle East								
Oil	8.1	10.4	10.5	11.4	12.0	13.0	14.2	1.4
Natural Gas	3.9	6.9	7.1	8.0	9.9	11.5	13.3	3.0
Coal	0.8	1.2	1.1	1.1	1.3	1.3	1.3	0.7
Nuclear.	0.0	0.0	0.0	0.0	0.1	0.1	0.1	—
Other	0.4	0.6	0.5	0.7	0.8	1.1	1.3	4.5
Total	13.1	19.1	19.3	21.3	24.1	27.0	30.2	2.2
Africa								
Oil	4.2	5.1	5.2	6.5	7.4	8.2	9.1	2.7
Natural Gas	1.5	2.0	2.1	2.4	2.5	2.9	3.1	1.8
Coal	3.0	3.7	3.6	3.7	3.6	3.6	3.6	0.0
Nuclear.	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other	0.6	0.7	0.7	0.8	0.8	0.9	1.0	1.6
Total	9.3	11.6	11.8	13.4	14.5	15.8	16.9	1.7
Central and South America								
Oil	7.0	9.4	9.5	10.8	12.0	12.8	13.8	1.8
Natural Gas	2.2	3.4	3.5	4.9	7.2	10.1	12.1	6.0
Coal	0.6	0.9	0.9	1.0	1.0	0.9	1.0	0.4
Nuclear.	0.1	0.1	0.1	0.2	0.2	0.1	0.2	2.3
Other	3.9	5.6	5.7	6.1	5.9	5.9	5.8	0.1
Total	13.7	19.4	19.8	23.0	26.3	29.8	32.9	2.5
Total Developing Countries								
Oil	35.2	51.5	52.9	61.3	69.6	78.2	86.6	2.4
Natural Gas	10.8	18.3	19.2	26.0	32.9	40.8	47.7	4.4
Coal	32.1	40.3	36.3	41.7	45.6	48.4	51.7	1.7
Nuclear.	1.1	1.7	1.9	2.5	2.9	3.3	4.0	3.7
Other	8.0	11.1	11.5	13.8	14.6	15.8	16.6	1.8
Total	87.2	123.0	121.8	145.2	165.6	186.6	206.7	2.6
Total World								
Oil	134.9	149.8	152.2	168.4	182.4	196.9	209.4	1.5
Natural Gas	74.5	84.5	86.9	102.0	115.4	131.7	147.3	2.5
Coal	90.0	89.3	84.8	90.9	94.6	96.5	98.7	0.7
Nuclear.	20.4	24.4	25.3	26.1	26.1	25.6	25.1	0.0
Other	26.5	32.0	33.1	36.6	38.8	41.3	43.2	1.3
Total	346.2	379.7	381.9	424.1	457.3	492.1	523.6	1.5

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table C3. World Gross Domestic Product (GDP) by Region, Low Economic Growth Case, 1990-2020
(Billion 1997 Dollars)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	7,723	9,760	10,165	11,973	13,310	14,527	15,729	2.1
United States ^a	6,836	8,675	9,029	10,630	11,788	12,827	13,835	2.1
Canada	555	665	699	801	870	912	936	1.4
Mexico	332	421	437	542	652	788	958	3.8
Western Europe	7,597	8,731	8,944	9,854	10,518	11,164	11,804	1.3
United Kingdom	1,146	1,353	1,384	1,558	1,677	1,826	1,955	1.7
France	1,299	1,455	1,499	1,664	1,789	1,873	1,949	1.3
Germany	1,879	2,156	2,187	2,378	2,514	2,649	2,786	1.2
Italy	1,079	1,188	1,207	1,307	1,386	1,463	1,536	1.2
Netherlands	317	392	407	449	481	513	544	1.4
Other Western Europe	1,877	2,187	2,260	2,499	2,670	2,841	3,035	1.4
Industrialized Asia	4,054	4,765	4,821	4,912	5,083	5,317	5,514	0.6
Japan	3,673	4,271	4,304	4,340	4,468	4,655	4,797	0.5
Australasia	381	494	516	572	615	663	717	1.6
Total Industrialized	19,374	23,256	23,930	26,739	28,910	31,009	33,048	1.5
EE/FSU								
Former Soviet Union	1,009	545	569	647	723	882	994	2.7
Eastern Europe	348	358	363	444	517	597	675	3.0
Total EE/FSU	1,357	903	932	1,091	1,240	1,479	1,669	2.8
Developing Countries								
Developing Asia	1,739	2,975	3,165	4,037	4,934	5,898	6,954	3.8
China	427	968	1,037	1,343	1,669	1,988	2,338	3.9
India	268	445	473	613	752	917	1,112	4.2
South Korea	297	445	493	599	718	852	1,002	3.4
Other Asia	748	1,118	1,162	1,482	1,795	2,141	2,502	3.7
Middle East	379	580	577	678	790	933	1,108	3.2
Turkey	140	196	186	220	257	301	353	3.1
Other Middle East	239	384	391	458	533	631	754	3.2
Africa	405	485	499	596	681	764	848	2.6
Central and South America . . .	1,136	1,467	1,452	1,740	2,020	2,316	2,643	2.9
Brazil	674	810	816	982	1,149	1,320	1,510	3.0
Other Central/South America . .	462	657	636	758	871	996	1,132	2.8
Total Developing	3,660	5,507	5,693	7,051	8,425	9,910	11,553	3.4
Total World	24,392	29,665	30,555	34,881	38,576	42,398	46,269	2.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: DRI-WEFA, *World Economic Outlook*, Vol. 1 (Lexington, MA, 3rd Quarter 2001); Energy Information Administration (EIA), *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B20; and EIA, World Energy Projection System (2002).

Table C4. World Oil Consumption by Region, Low Economic Growth Case, 1990-2020
(Million Barrels per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	20.4	22.7	23.4	25.5	27.5	29.4	30.9	1.3
United States ^a	17.0	18.9	19.5	21.1	22.6	24.0	25.0	1.2
Canada	1.7	1.9	1.9	2.1	2.1	2.1	2.1	0.4
Mexico	1.7	1.9	2.0	2.4	2.7	3.2	3.8	3.1
Western Europe	12.5	14.1	13.9	14.4	14.5	14.5	14.4	0.1
United Kingdom	1.8	1.8	1.7	2.0	2.0	2.0	2.1	0.9
France	1.8	2.0	2.0	2.1	2.1	2.1	2.1	0.1
Germany	2.7	2.9	2.8	3.0	3.0	2.9	2.9	0.1
Italy	1.9	2.1	2.0	2.0	2.0	1.9	1.9	-0.2
Netherlands	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.3
Other Western Europe	3.6	4.5	4.5	4.5	4.5	4.5	4.5	0.0
Industrialized Asia	6.2	6.8	6.9	7.0	7.1	7.1	7.1	0.2
Japan	5.1	5.5	5.6	5.6	5.6	5.6	5.5	-0.1
Australasia	1.0	1.3	1.3	1.4	1.5	1.6	1.7	1.2
Total Industrialized	39.0	43.6	44.2	46.9	49.1	51.0	52.4	0.8
EE/FSU								
Former Soviet Union	8.4	3.8	3.7	4.7	5.3	6.3	6.8	2.9
Eastern Europe	1.6	1.4	1.5	1.6	1.7	1.8	1.8	1.2
Total EE/FSU	10.0	5.2	5.2	6.3	7.1	8.1	8.6	2.5
Developing Countries								
Developing Asia	7.6	12.8	13.3	15.7	18.3	21.2	23.8	2.8
China	2.3	4.1	4.3	4.7	5.5	6.3	7.0	2.3
India	1.2	1.8	1.9	2.4	2.9	3.6	4.1	3.6
South Korea	1.0	2.0	2.0	2.2	2.4	2.5	2.6	1.2
Other Asia	3.1	4.9	5.0	6.4	7.5	8.9	10.1	3.4
Middle East	3.9	5.0	5.0	5.5	5.8	6.2	6.8	1.4
Turkey	0.5	0.6	0.6	0.8	0.8	0.9	1.0	2.4
Other Middle East	3.4	4.3	4.4	4.7	4.9	5.3	5.8	1.3
Africa	2.1	2.5	2.5	3.1	3.6	4.0	4.4	2.7
Central and South America . . .	3.4	4.6	4.7	5.3	5.9	6.2	6.7	1.8
Brazil	1.3	1.9	2.0	2.1	2.4	2.6	3.0	2.0
Other Central/South America . .	2.1	2.7	2.7	3.1	3.5	3.6	3.8	1.6
Total Developing	17.0	24.8	25.5	29.6	33.5	37.7	41.7	2.4
Total World	66.0	73.6	74.9	82.8	89.6	96.7	102.7	1.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B21; and World Energy Projection System (2002).

Table C5. World Natural Gas Consumption by Region, Low Economic Growth Case, 1990-2020
(Trillion Cubic Feet)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	22.0	25.4	26.1	30.1	32.7	35.6	37.8	1.8
United States ^a	18.7	21.3	21.7	25.2	27.4	30.0	32.0	1.9
Canada	2.4	2.9	3.1	3.3	3.4	3.6	3.7	0.9
Mexico	0.9	1.3	1.3	1.7	1.9	2.1	2.1	2.4
Western Europe	10.1	13.4	14.0	17.1	18.8	20.7	23.7	2.5
United Kingdom	2.1	3.1	3.3	3.7	4.1	4.5	5.1	2.2
France	1.0	1.3	1.3	1.8	2.0	2.2	2.6	3.2
Germany	2.7	3.0	3.0	3.9	4.2	4.5	5.3	2.7
Italy	1.7	2.2	2.4	2.8	3.0	3.3	3.5	1.8
Netherlands	1.5	1.8	1.7	1.9	2.0	2.1	2.1	1.1
Other Western Europe	1.2	2.0	2.3	3.1	3.5	4.1	4.9	3.8
Industrialized Asia	2.6	3.5	3.6	3.8	3.8	4.1	4.6	1.1
Japan	1.9	2.5	2.6	2.7	2.6	2.8	3.2	0.9
Australasia	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.7
Total Industrialized	34.8	42.3	43.7	51.0	55.3	60.5	66.1	2.0
EE/FSU								
Former Soviet Union	25.0	19.9	20.1	20.4	21.6	23.6	25.6	1.2
Eastern Europe	3.1	2.5	2.4	2.9	3.8	4.7	5.5	4.0
Total EE/FSU	28.1	22.4	22.5	23.3	25.4	28.4	31.1	1.6
Developing Countries								
Developing Asia	3.0	5.6	6.0	10.0	12.4	15.1	17.8	5.3
China	0.5	0.8	0.9	1.6	2.3	3.3	4.3	7.9
India	0.4	0.8	0.8	1.1	1.4	1.9	2.2	5.1
South Korea	0.1	0.5	0.6	1.1	1.2	1.6	1.9	5.8
Other Asia	1.9	3.6	3.8	6.2	7.5	8.4	9.5	4.4
Middle East	3.7	6.6	6.8	7.6	9.4	11.0	12.6	3.0
Turkey	0.1	0.4	0.4	0.5	0.6	0.8	0.9	3.6
Other Middle East	3.6	6.2	6.3	7.2	8.8	10.2	11.7	1.8
Africa	1.4	1.8	2.0	2.2	2.4	2.7	2.9	1.8
Central and South America . . .	2.0	3.1	3.2	4.5	6.6	9.2	11.1	6.0
Brazil	0.1	0.2	0.2	0.6	1.2	2.0	2.4	11.8
Other Central/South America . .	1.9	2.9	3.0	4.0	5.4	7.3	8.7	5.2
Total Developing	10.1	17.2	18.0	24.4	30.8	38.0	44.5	4.4
Total World	72.9	81.9	84.2	98.6	111.4	126.9	141.7	2.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Energy totals include net imports of coal coke and electricity generated from biomass in the United States. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B13; and World Energy Projection System (2002).

Table C6. World Coal Consumption by Region, Low Economic Growth Case, 1990-2020
(Million Short Tons)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	959	1,121	1,122	1,254	1,326	1,357	1,400	1.1
United States ^a	895	1,040	1,045	1,169	1,235	1,262	1,303	1.1
Canada	55	66	63	65	69	71	72	0.6
Mexico	9	15	13	20	22	24	26	3.3
Western Europe	894	566	546	483	462	439	399	-1.5
United Kingdom	119	70	65	59	56	50	40	-2.2
France	35	29	26	22	15	15	12	-3.5
Germany	528	269	258	228	225	217	201	-1.2
Italy	23	19	19	16	16	14	13	-1.8
Netherlands	15	16	14	12	8	8	6	-3.7
Other Western Europe	173	164	165	145	142	134	126	-1.2
Industrialized Asia	231	287	295	298	297	296	291	-0.1
Japan	125	144	149	155	158	160	157	0.2
Australasia	106	142	145	143	139	136	134	-0.4
Total Industrialized	2,084	1,974	1,963	2,035	2,085	2,091	2,091	0.3
EE/FSU								
Former Soviet Union	848	396	414	395	358	322	281	-1.8
Eastern Europe	527	414	363	339	303	265	229	-2.2
Total EE/FSU	1,375	810	778	734	662	588	510	-2.0
Developing Countries								
Developing Asia	1,583	1,903	1,686	1,975	2,183	2,338	2,521	1.9
China	1,124	1,300	1,075	1,269	1,449	1,582	1,710	2.2
India	242	333	348	396	410	416	450	1.2
South Korea	42	60	65	72	77	81	82	1.1
Other Asia	175	210	197	238	247	259	279	1.7
Middle East	66	99	96	97	109	110	110	0.7
Turkey	60	86	84	86	92	92	92	0.4
Other Middle East	6	12	12	11	17	18	18	1.9
Africa	152	181	177	179	176	178	177	0.0
Central and South America . . .	26	42	41	44	44	43	44	0.4
Brazil	17	28	27	30	33	33	35	1.3
Other Central/South America . .	9	15	14	15	11	10	9	-2.1
Total Developing	1,827	2,226	2,000	2,295	2,512	2,670	2,852	1.7
Total World	5,287	5,009	4,740	5,065	5,259	5,349	5,453	0.7

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. To convert short tons to metric tons, divide each number in the table by 1.102.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B16; and World Energy Projection System (2002).

Table C7. World Nuclear Energy Consumption by Region, Low Economic Growth Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	649	750	808	858	834	793	785	-0.1
United States ^a	577	674	728	759	737	697	691	-0.2
Canada	69	68	70	90	90	88	87	1.0
Mexico	3	9	10	9	8	8	7	-1.1
Western Europe	703	836	846	808	785	739	660	-1.2
United Kingdom	59	95	91	66	58	49	29	-5.3
France	298	369	375	383	383	379	380	0.1
Germany	145	154	161	149	139	129	95	-2.5
Italy	0	0	0	0	0	0	0	—
Netherlands	3	4	4	4	0	0	0	-100.0
Other Western Europe	198	215	215	206	206	181	156	-1.5
Industrialized Asia	192	316	309	302	316	330	338	0.4
Japan	192	316	309	302	316	330	338	0.4
Australasia	0	0	0	0	0	0	0	0.0
Total Industrialized	1,544	1,902	1,962	1,967	1,936	1,861	1,784	-0.5
EE/FSU								
Former Soviet Union	201	183	190	194	183	177	145	-1.3
Eastern Europe	54	61	60	77	66	66	70	0.8
Total EE/FSU	256	244	250	270	249	243	216	-0.7
Developing Countries								
Developing Asia	88	145	160	213	256	291	346	3.7
China	0	13	14	46	60	66	86	9.0
India	6	11	11	15	23	26	37	5.8
South Korea	50	85	98	113	113	135	154	2.2
Other Asia	32	36	37	40	60	65	68	3.0
Middle East	0	0	0	0	5	11	11	—
Turkey	0	0	0	0	0	0	0	—
Other Middle East	0	0	0	0	5	11	11	—
Africa	8	14	13	12	12	12	13	0.0
Central and South America . . .	9	10	11	15	15	12	17	2.3
Brazil	2	3	4	10	10	10	15	6.9
Other Central/South America . .	7	7	7	5	5	2	2	-6.4
Total Developing	105	169	184	240	288	326	388	3.6
Total World	1,905	2,315	2,396	2,478	2,473	2,430	2,388	0.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B8; and World Energy Projection System (2002).

Table C8. World Consumption of Hydroelectricity and Other Renewable Energy by Region, Low Economic Growth Case, 1990-2020
(Quadrillion Btu)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	9.5	10.7	11.4	11.9	12.6	13.3	13.7	0.9
United States ^a	6.1	6.9	7.3	7.8	8.1	8.7	9.0	1.0
Canada	3.1	3.5	3.6	3.6	3.8	3.9	3.9	0.4
Mexico	0.3	0.4	0.4	0.5	0.7	0.7	0.8	2.5
Western Europe	4.5	5.4	5.6	6.3	6.7	7.1	7.5	1.4
United Kingdom	0.1	0.1	0.1	0.3	0.3	0.4	0.4	5.2
France	0.6	0.7	0.8	0.2	0.3	0.3	0.3	-4.0
Germany	0.3	0.3	0.4	0.6	0.7	0.8	0.9	4.4
Italy	0.4	0.5	0.6	1.1	1.1	1.2	1.2	3.6
Netherlands	0.0	0.0	0.0	0.3	0.3	0.3	0.4	10.0
Other Western Europe	3.2	3.7	3.7	3.9	4.0	4.1	4.3	0.7
Industrialized Asia	1.6	1.7	1.7	1.7	1.7	1.8	1.9	0.6
Japan	1.1	1.2	1.2	1.2	1.1	1.3	1.3	0.5
Australasia	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.8
Total Industrialized	15.6	17.9	18.6	19.9	21.1	22.2	23.1	1.0
EE/FSU								
Former Soviet Union	2.4	2.3	2.3	2.3	2.3	2.3	2.4	0.0
Eastern Europe	0.4	0.6	0.6	0.6	0.8	1.0	1.1	2.8
Total EE/FSU	2.8	3.0	3.0	3.0	3.1	3.3	3.5	0.7
Developing Countries								
Developing Asia	3.2	4.3	4.6	6.2	7.1	8.0	8.6	3.0
China	1.3	2.1	2.3	3.0	3.4	3.9	4.3	3.0
India	0.7	0.8	0.9	1.1	1.2	1.3	1.4	2.3
South Korea	0.0	0.0	0.0	0.1	0.1	0.1	0.2	7.1
Other Asia	1.1	1.3	1.4	2.0	2.3	2.6	2.6	3.2
Middle East	0.4	0.6	0.5	0.7	0.8	1.1	1.3	4.5
Turkey	0.2	0.4	0.4	0.4	0.4	0.4	0.5	1.4
Other Middle East	0.1	0.2	0.2	0.3	0.4	0.6	0.8	8.0
Africa	0.6	0.7	0.7	0.8	0.8	0.9	1.0	1.6
Central and South America . . .	3.9	5.6	5.7	6.1	5.9	5.9	5.8	0.1
Brazil	2.2	3.1	3.3	3.8	3.8	3.5	3.3	0.1
Other Central/South America . .	1.7	2.5	2.4	2.3	2.2	2.3	2.5	0.2
Total Developing	8.0	11.1	11.5	13.8	14.6	15.8	16.6	1.8
Total World	26.5	32.0	33.1	36.6	38.8	41.3	43.2	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding. The electricity portion of the national fuel consumption values consists of generation for domestic use plus an adjustment for electricity trade based on a fuel's share of total generation in the exporting country. U.S. totals include net electricity imports, methanol, and liquid hydrogen.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Table C9. World Net Electricity Consumption by Region, Low Economic Growth Case, 1990-2020
(Billion Kilowatthours)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	3,362	4,046	3,904	4,533	4,939	5,331	5,696	1.8
United States ^a	2,817	3,400	3,236	3,760	4,084	4,404	4,691	1.8
Canada	438	485	498	546	577	599	615	1.0
Mexico	107	162	171	227	277	329	390	4.0
Western Europe	2,077	2,399	2,435	2,676	2,830	2,985	3,160	1.2
United Kingdom	287	330	333	369	386	404	420	1.1
France	326	394	399	417	442	464	488	1.0
Germany	489	492	495	549	579	608	642	1.2
Italy	222	266	272	322	348	375	403	1.9
Netherlands	72	95	98	108	115	122	129	1.3
Other Western Europe	681	822	838	911	960	1,012	1,078	1.2
Industrialized Asia	945	1,158	1,178	1,244	1,291	1,339	1,385	0.8
Japan	765	932	947	983	1,017	1,053	1,085	0.6
Australasia	181	226	231	261	274	286	300	1.3
Total Industrialized	6,385	7,604	7,517	8,453	9,060	9,656	10,240	1.5
EE/FSU								
Former Soviet Union	1,488	1,068	1,075	1,113	1,167	1,264	1,329	1.0
Eastern Europe	418	390	377	411	440	475	504	1.4
Total EE/FSU	1,906	1,459	1,452	1,523	1,607	1,739	1,833	1.1
Developing Countries								
Developing Asia	1,259	2,175	2,319	2,715	3,188	3,679	4,171	2.8
China	551	1,013	1,084	1,202	1,447	1,695	1,952	2.8
India	257	396	424	493	566	649	730	2.6
South Korea	93	207	233	259	284	316	346	1.9
Other Asia	357	560	578	762	891	1,018	1,143	3.3
Middle East	263	470	494	518	593	671	760	2.1
Turkey	51	102	106	120	135	151	168	2.2
Other Middle East	213	368	388	399	458	521	591	2.0
Africa	287	361	367	442	508	587	646	2.7
Central and South America . . .	449	656	684	779	895	1,019	1,130	2.4
Brazil	229	334	354	422	483	544	603	2.6
Other Central/South America . .	220	322	330	357	412	476	527	2.3
Total Developing	2,258	3,663	3,863	4,455	5,184	5,956	6,707	2.7
Total World	10,549	12,725	12,833	14,431	15,851	17,351	18,780	1.8

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Electricity consumption equals generation plus imports minus exports minus distribution losses.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B2; and World Energy Projection System (2002).

Table C10. World Carbon Dioxide Emissions by Region, Low Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1,562	1,742	1,767	1,963	2,102	2,229	2,338	1.3
United States ^a	1,352	1,495	1,517	1,680	1,795	1,897	1,980	1.3
Canada	126	146	150	157	163	168	170	0.6
Mexico	84	101	101	126	144	164	188	3.0
Western Europe	930	947	940	980	996	1,014	1,036	0.5
United Kingdom	164	154	151	164	169	174	178	0.8
France	102	110	109	115	117	120	122	0.6
Germany	271	237	230	237	240	242	247	0.3
Italy	112	122	121	127	129	130	132	0.4
Netherlands	58	66	64	65	65	66	66	0.1
Other Western Europe	223	260	264	271	276	283	292	0.5
Industrialized Asia	357	412	422	430	435	440	445	0.3
Japan	269	300	307	310	312	314	315	0.1
Australasia	88	112	115	120	123	126	130	1.0
Total Industrialized	2,849	3,101	3,129	3,373	3,533	3,683	3,820	1.0
EE/FSU								
Former Soviet Union	1,036	599	607	643	670	721	754	1.0
Eastern Europe	301	217	203	208	213	219	221	0.4
Total EE/FSU	1,337	816	810	850	883	940	975	0.9
Developing Countries								
Developing Asia	1,053	1,435	1,361	1,645	1,876	2,100	2,321	2.6
China	617	765	669	786	907	1,014	1,115	2.5
India	153	231	242	285	318	354	392	2.3
South Korea	61	101	107	125	136	147	156	1.8
Other Asia	223	338	343	449	515	585	658	3.1
Middle East	231	325	330	359	402	444	491	1.9
Turkey	35	50	50	56	62	68	74	1.9
Other Middle East	196	275	280	304	340	376	418	1.9
Africa	179	216	218	246	265	285	304	1.6
Central and South America . . .	178	246	249	294	349	405	454	2.9
Brazil	62	87	88	100	120	141	161	2.9
Other Central/South America . .	116	159	162	194	230	264	292	2.9
Total Developing	1,641	2,222	2,158	2,545	2,892	3,234	3,570	2.4
Total World	5,827	6,139	6,097	6,767	7,309	7,857	8,365	1.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. The U.S. numbers include carbon dioxide emissions attributable to renewable energy sources.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table C11. World Carbon Dioxide Emissions from Oil Use by Region, Low Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	716	775	793	863	933	1,002	1,060	1.4
United States ^a	590	635	650	699	754	805	841	1.2
Canada	61	66	68	72	74	74	74	0.4
Mexico	65	74	76	92	105	122	145	3.1
Western Europe	474	525	517	536	539	538	533	0.1
United Kingdom	66	65	63	72	73	75	75	0.9
France	67	72	72	74	76	75	74	0.1
Germany	103	107	104	109	109	108	107	0.1
Italy	74	78	74	76	75	73	72	-0.2
Netherlands	27	30	31	32	32	33	33	0.3
Other Western Europe	138	172	173	173	174	173	172	0.0
Industrialized Asia	217	230	233	236	241	242	242	0.2
Japan	179	183	185	185	187	185	181	-0.1
Australasia	38	46	48	51	54	57	61	1.2
Total Industrialized	1,407	1,529	1,543	1,636	1,713	1,781	1,835	0.8
EE/FSU								
Former Soviet Union	334	148	146	185	209	245	266	2.9
Eastern Europe	66	55	55	60	64	68	70	1.2
Total EE/FSU	400	202	201	245	274	313	335	2.5
Developing Countries								
Developing Asia	304	479	496	586	683	793	888	2.8
China	94	152	160	175	202	231	257	2.3
India	45	70	73	90	110	136	154	3.6
South Korea	38	60	62	68	74	77	79	1.2
Other Asia	127	197	201	254	298	349	397	3.3
Middle East	155	195	198	215	226	245	267	1.4
Turkey	17	22	22	27	29	32	36	2.4
Other Middle East	138	173	177	188	197	212	231	1.3
Africa	83	95	97	121	139	153	169	2.7
Central and South America . . .	132	173	176	199	222	236	255	1.8
Brazil	51	70	71	77	85	95	107	2.0
Other Central/South America . .	81	104	105	122	137	142	148	1.6
Total Developing	674	942	968	1,121	1,271	1,427	1,580	2.4
Total World	2,482	2,673	2,712	3,002	3,257	3,521	3,750	1.6

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table C12. World Carbon Dioxide Emissions from Natural Gas Use by Region, Low Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	326	377	381	443	481	524	557	1.8
United States ^a	277	315	317	369	402	441	470	1.9
Canada	35	42	46	48	50	53	55	0.9
Mexico	15	20	19	25	29	31	31	2.4
Western Europe	140	196	206	252	277	307	351	2.6
United Kingdom	30	47	50	56	62	69	78	3.2
France	16	21	21	28	32	36	41	3.2
Germany	32	42	43	55	59	63	75	2.7
Italy	25	32	35	41	45	48	52	1.8
Netherlands	20	23	22	24	26	27	27	1.1
Other Western Europe	18	31	35	48	54	64	77	3.8
Industrialized Asia	36	52	54	57	57	61	68	1.1
Japan	24	38	40	40	39	42	48	0.9
Australasia	12	14	14	16	18	19	20	1.7
Total Industrialized	503	626	641	751	815	892	976	2.0
EE/FSU								
Former Soviet Union	369	291	294	298	316	345	375	1.2
Eastern Europe	46	36	35	43	55	69	81	4.0
Total EE/FSU	414	327	329	340	371	415	455	1.6
Developing Countries								
Developing Asia	45	86	92	153	191	234	277	5.4
China	8	13	14	27	38	55	71	7.9
India	7	13	12	18	24	31	36	5.1
South Korea	2	8	10	17	20	25	31	5.8
Other Asia	29	53	56	91	109	123	139	4.4
Middle East	56	100	102	115	142	165	191	3.0
Turkey	2	6	7	7	9	12	14	3.6
Other Middle East	54	94	96	108	133	154	176	3.0
Africa	22	29	31	34	37	42	45	1.8
Central and South America . . .	32	49	51	71	103	145	174	6.0
Brazil	2	3	4	8	18	30	36	11.8
Other Central/South America . .	30	46	47	63	85	115	138	5.2
Total Developing	155	263	276	374	474	587	687	4.4
Total World	1,072	1,216	1,247	1,466	1,660	1,894	2,118	2.6

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table C13. World Carbon Dioxide Emissions from Coal Use by Region, Low Economic Growth Case, 1990-2020
(Million Metric Tons Carbon Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	520	595	592	657	689	703	722	1.0
United States ^a	485	550	549	611	639	651	669	0.9
Canada	31	38	36	37	39	41	41	0.6
Mexico	4	7	6	9	10	11	12	3.3
Western Europe	315	225	216	191	180	170	152	-1.7
United Kingdom	68	42	39	36	33	30	24	-2.2
France	20	17	15	13	9	9	7	-3.5
Germany	137	87	83	74	73	70	65	-1.2
Italy	14	11	12	10	10	8	8	-1.8
Netherlands	11	13	11	10	7	6	5	-3.7
Other Western Europe	66	56	56	49	48	46	43	-1.2
Industrialized Asia	104	130	135	137	137	137	135	0.0
Japan	66	78	81	85	86	87	86	0.2
Australasia	38	52	53	52	51	50	49	-0.4
Total Industrialized	939	951	943	985	1,006	1,009	1,009	0.3
EE/FSU								
Former Soviet Union	333	160	168	160	145	130	114	-1.8
Eastern Europe	189	127	113	105	94	82	71	-2.2
Total EE/FSU	522	287	280	265	239	213	185	-2.0
Developing Countries								
Developing Asia	704	870	773	905	1,001	1,073	1,156	1.9
China	514	600	495	584	667	728	787	2.2
India	101	148	156	177	184	187	202	1.2
South Korea	21	33	36	40	42	44	45	1.1
Other Asia	67	88	87	104	108	114	122	1.6
Middle East	20	30	29	29	33	33	33	0.7
Turkey	16	23	21	22	23	24	24	0.4
Other Middle East	4	7	7	7	9	10	10	1.2
Africa	74	93	90	91	90	90	90	0.0
Central and South America . . .	15	23	22	24	24	23	24	0.4
Brazil	9	14	13	15	16	16	17	1.3
Other Central/South America . .	5	9	9	9	8	7	6	-1.4
Total Developing	812	1,017	914	1,049	1,147	1,220	1,303	1.7
Total World	2,274	2,254	2,137	2,300	2,392	2,442	2,496	0.7

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B19; and World Energy Projection System (2002).

Table C14. World Nuclear Generating Capacity by Region and Country, Low Economic Growth Case, 1999-2020
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Industrialized Countries						
North America	108,776	108,867	109,058	105,700	96,458	95,648
United States	97,470	97,509	97,700	94,342	86,370	85,560
Canada	9,998	9,998	9,998	9,998	8,728	8,728
Mexico	1,308	1,360	1,360	1,360	1,360	1,360
Industrialized Asia	43,691	43,491	44,043	46,223	42,935	38,710
Japan	43,691	43,491	44,043	46,223	42,935	38,710
Western Europe	125,991	125,726	120,781	112,222	100,536	82,708
Belgium	5,712	5,712	5,712	5,712	4,358	3,966
Finland	2,656	2,656	2,656	2,656	2,656	1,328
France	63,103	63,153	62,920	62,920	61,080	53,030
Germany	21,122	21,122	18,975	16,179	13,134	11,859
Netherlands	449	449	0	0	0	0
Spain	7,470	7,512	7,512	6,913	6,913	6,913
Sweden	9,432	9,432	8,832	6,907	6,077	3,279
Switzerland	3,079	3,192	3,192	2,827	2,115	1,145
United Kingdom	12,968	12,498	10,982	8,108	4,203	1,188
Total Industrialized	278,458	278,084	273,882	264,145	239,929	217,066
EE/FSU						
Eastern Europe	10,605	10,675	10,468	10,060	10,060	7,690
Bulgaria	3,538	3,538	2,314	1,906	1,906	1,906
Czech Republic	1,648	1,648	3,481	3,481	3,481	3,481
Hungary	1,729	1,755	1,755	1,755	1,755	877
Romania	650	650	650	650	650	650
Slovakia	2,408	2,408	1,592	1,592	1,592	776
Slovenia	632	676	676	676	676	0
Former Soviet Union	34,704	33,796	32,803	26,689	17,872	9,500
Armenia	376	376	0	0	0	0
Lithuania	2,370	2,370	1,185	0	0	0
Russia	19,843	19,843	20,411	15,482	11,222	8,550
Ukraine	12,115	11,207	11,207	11,207	6,650	950
Total EE/FSU	45,309	44,471	43,271	36,749	27,932	17,190

See notes at end of table.

Table C14. World Nuclear Generating Capacity by Region and Country, Low Economic Growth Case, 1999-2020 (Continued)
(Megawatts)

Region/Country	History		Projections			
	1999	2000	2005	2010	2015	2020
Developing Countries						
Developing Asia	22,063	22,777	28,784	33,368	38,107	40,399
China	2,167	2,177	6,597	8,587	9,587	10,587
India	1,897	2,301	2,113	2,113	3,631	4,436
Korea, South.	12,990	12,990	14,890	16,254	18,475	20,170
Pakistan	125	425	300	300	300	300
Taiwan	4,884	4,884	4,884	6,114	6,114	4,906
Central and South America	1,561	2,790	2,455	2,455	1,829	1,229
Argentina	935	935	600	600	600	0
Brazil.	626	1,855	1,855	1,855	1,229	1,229
Middle East.	0	0	0	1,073	1,073	1,073
Iran.	0	0	0	1,073	1,073	1,073
Africa	1,842	1,800	1,800	1,800	1,800	1,800
South Africa	1,842	1,800	1,800	1,800	1,800	1,800
Total Developing	25,466	27,367	33,039	38,696	42,809	44,501
Total World	349,233	349,922	350,192	339,590	310,670	278,757

Sources: **History:** International Atomic Energy Agency, *Nuclear Power Reactors in the World 2000* (Vienna, Austria, April 2001). **Projections:** Energy Information Administration (EIA), *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A9; and EIA, Office of Coal, Nuclear, Electric and Alternate Fuels, based on detailed assessments of country-specific nuclear power plants.

Table C15. World Total Energy Consumption in Oil-Equivalent Units by Region, Low Economic Growth Case, 1990-2020
(Million Tons Oil Equivalent)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	2,522	2,841	2,916	3,218	3,424	3,615	3,776	1.2
United States ^a	2,121	2,383	2,446	2,687	2,849	3,003	3,128	1.2
Canada	275	305	316	340	354	362	366	0.7
Mexico	126	153	155	191	222	250	282	2.9
Western Europe	1,508	1,659	1,664	1,751	1,792	1,829	1,872	0.6
United Kingdom	234	251	250	264	272	280	287	0.7
France	222	256	258	275	283	288	295	0.6
Germany	373	357	352	373	379	385	392	0.5
Italy	176	201	203	214	220	225	229	0.6
Netherlands	85	96	97	101	103	106	108	0.5
Other Western Europe	419	498	504	524	535	545	562	0.5
Industrialized Asia	574	695	704	714	726	742	755	0.3
Japan	452	541	547	548	555	564	571	0.2
Australasia	122	153	157	166	172	178	184	0.8
Total Industrialized	4,604	5,194	5,284	5,683	5,943	6,185	6,403	0.9
EE/FSU								
Former Soviet Union	1,529	975	988	1,043	1,088	1,172	1,227	1.0
Eastern Europe	393	299	283	301	319	341	358	1.1
Total EE/FSU	1,923	1,274	1,271	1,343	1,407	1,513	1,584	1.1
Developing Countries								
Developing Asia	1,286	1,837	1,788	2,207	2,540	2,873	3,193	2.8
China	681	890	803	965	1,119	1,264	1,403	2.7
India	196	293	307	367	418	474	527	2.6
South Korea	92	173	185	217	235	259	280	2.0
Other Asia	317	481	492	658	768	876	983	3.4
Middle East	330	481	487	537	607	680	761	2.1
Turkey	50	76	74	83	93	102	113	2.0
Other Middle East	280	405	413	454	514	577	648	2.2
Africa	235	292	297	338	365	398	425	1.7
Central and South America . . .	346	489	498	578	662	751	829	2.5
Brazil	142	208	215	237	266	295	322	2.0
Other Central/South America . .	204	282	283	342	395	456	507	2.8
Total Developing	2,197	3,100	3,069	3,660	4,174	4,701	5,208	0.0
Total World	8,724	9,568	9,623	10,687	11,523	12,400	13,195	1.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union.

Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table B1; and World Energy Projection System (2002).

Appendix D

Projections of Oil Production Capacity and Oil Production in Three Cases:

Reference
High World Oil Price
Low World Oil Price

Table D1. World Oil Production Capacity by Region and Country, Reference Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf						
Iran	3.2	3.8	4.0	4.4	4.5	4.7
Iraq	2.2	2.6	3.1	3.9	4.5	5.5
Kuwait	1.7	2.5	2.8	3.5	4.1	4.8
Qatar	0.5	0.9	0.5	0.6	0.7	0.7
Saudi Arabia	8.6	9.4	12.5	14.6	18.2	22.1
United Arab Emirates	2.5	2.5	3.0	3.7	4.4	5.1
Total Persian Gulf	18.7	21.7	25.9	30.7	36.4	42.9
Other OPEC						
Algeria	1.3	1.4	1.9	2.2	2.3	2.5
Indonesia	1.5	1.6	1.5	1.5	1.5	1.5
Libya	1.5	1.5	2.1	2.5	2.8	3.2
Nigeria	1.8	2.1	2.8	3.3	4.0	4.7
Venezuela	2.4	3.1	4.2	4.6	5.0	5.4
Total Other OPEC	8.5	9.7	12.5	14.1	15.6	17.3
Total OPEC	27.2	31.4	38.4	44.8	52.0	60.2
Non-OPEC						
Industrialized						
United States	9.7	9.1	8.7	8.9	9.7	10.0
Canada	2.0	2.7	3.1	3.2	3.4	3.6
Mexico	3.0	3.5	3.9	4.2	4.4	4.4
Australia	0.7	0.9	0.8	0.8	0.8	0.8
North Sea	4.2	6.3	6.7	6.5	6.2	6.0
Other	0.5	0.8	0.8	0.8	0.8	0.8
Total Industrialized	20.1	23.3	24.0	24.4	25.3	25.6
Eurasia						
China	2.8	3.3	3.2	3.1	3.0	3.0
Former Soviet Union	11.4	8.1	10.1	12.1	13.8	14.9
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.4
Total Eurasia	14.5	11.6	13.5	15.5	17.1	18.3
Other Non-OPEC						
Central and South America	2.3	3.8	4.2	4.8	5.6	6.5
Middle East	1.4	2.0	2.2	2.4	2.5	2.4
Africa	2.2	2.9	3.1	3.9	4.7	5.8
Asia	1.7	2.4	2.6	2.6	2.6	2.5
Total Other Non-OPEC	7.6	11.1	12.1	13.7	15.4	17.2
Total Non-OPEC	42.2	46.0	49.6	53.6	57.8	61.1
Total World	69.4	77.4	88.0	98.4	109.8	121.3

Note: OPEC = Organization of Petroleum Exporting Countries.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Table D2. World Oil Production Capacity by Region and Country, High Oil Price Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf						
Iran	3.2	3.8	3.8	4.1	4.2	4.5
Iraq	2.2	2.6	2.9	3.2	3.5	4.1
Kuwait	1.7	2.5	2.6	3.1	3.5	4.0
Qatar	0.5	0.9	0.5	0.6	0.7	0.7
Saudi Arabia	8.6	9.4	10.9	11.3	13.5	16.1
United Arab Emirates	2.5	2.5	2.6	2.8	3.1	3.5
Total Persian Gulf	18.7	21.7	23.3	25.1	28.5	32.9
Other OPEC						
Algeria	1.3	1.4	1.6	1.8	2.1	2.4
Indonesia	1.5	1.6	1.5	1.5	1.5	1.5
Libya	1.5	1.5	1.6	1.9	2.1	2.5
Nigeria	1.8	2.1	2.3	2.5	3.0	3.7
Venezuela	2.4	3.1	3.5	3.7	4.3	5.0
Total Other OPEC	8.5	9.7	10.5	11.4	13.0	15.1
Total OPEC	27.2	31.4	33.8	36.5	41.5	48.0
Non-OPEC						
Industrialized						
United States	9.7	9.1	9.0	9.3	10.4	11.1
Canada	2.0	2.7	3.2	3.5	3.7	3.9
Mexico	3.0	3.5	4.0	4.5	4.8	4.9
Australia	0.7	0.9	0.8	0.9	0.9	0.9
North Sea	4.2	6.3	6.8	6.7	6.5	6.2
Other	0.5	0.8	0.9	0.9	0.8	0.8
Total Industrialized	20.1	23.3	24.7	25.8	27.1	27.8
Eurasia						
China	2.8	3.3	3.3	3.3	3.2	3.3
Former Soviet Union	11.4	8.1	10.7	13.6	15.8	17.0
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.4
Total Eurasia	14.5	11.6	14.2	17.2	19.3	20.7
Other Non-OPEC						
Central and South America	2.3	3.8	4.4	5.4	6.4	7.4
Middle East	1.4	2.0	2.3	2.5	2.7	2.7
Africa	2.2	2.9	3.4	4.4	5.5	6.9
Asia	1.7	2.4	2.7	2.8	2.7	2.7
Total Other Non-OPEC	7.6	11.1	12.8	15.1	17.3	19.7
Total Non-OPEC	42.2	46.0	51.7	58.1	63.7	68.2
Total World	69.4	77.4	85.5	94.6	105.2	116.2

Note: OPEC = Organization of Petroleum Exporting Countries.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Table D3. World Oil Production Capacity by Region and Country, Low Oil Price Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf						
Iran	3.2	3.8	4.2	4.5	4.8	5.1
Iraq	2.2	2.6	3.4	4.2	5.1	6.0
Kuwait	1.7	2.5	3.0	3.7	4.5	5.3
Qatar	0.5	0.9	0.5	0.6	0.7	0.8
Saudi Arabia	8.6	9.4	14.9	18.3	23.1	28.3
United Arab Emirates	2.5	2.5	3.2	4.0	4.8	5.6
Total Persian Gulf	18.7	21.7	29.2	35.3	43.0	51.1
Other OPEC						
Algeria	1.3	1.4	1.8	2.3	2.5	2.8
Indonesia	1.5	1.6	1.5	1.5	1.5	1.5
Libya	1.5	1.5	2.2	2.7	3.2	3.6
Nigeria	1.8	2.1	2.7	3.6	4.2	4.7
Venezuela	2.4	3.1	3.9	4.7	5.1	5.9
Total Other OPEC	8.5	9.7	12.1	14.8	16.5	18.5
Total OPEC	27.2	31.4	41.3	50.1	59.5	69.6
Non-OPEC						
Industrialized						
United States	9.7	9.1	8.5	8.3	8.8	9.0
Canada	2.0	2.7	3.1	3.2	3.3	3.5
Mexico	3.0	3.5	3.8	4.1	4.2	4.3
Australia	0.7	0.9	0.8	0.8	0.8	0.8
North Sea	4.2	6.3	6.6	6.4	6.1	5.9
Other	0.5	0.8	0.8	0.8	0.8	0.7
Total Industrialized	20.1	23.3	23.6	23.6	24.0	24.2
Eurasia						
China	2.8	3.3	3.2	3.0	3.0	2.9
Former Soviet Union	11.4	8.1	9.9	11.9	13.4	14.5
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.3
Total Eurasia	14.5	11.6	13.3	15.2	16.7	17.7
Other Non-OPEC						
Central and South America	2.3	3.8	4.1	4.7	5.4	6.3
Middle East	1.4	2.0	2.2	2.3	2.5	2.4
Africa	2.2	2.9	3.1	3.8	4.6	5.6
Asia	1.7	2.4	2.6	2.6	2.5	2.5
Total Other Non-OPEC	7.6	11.1	12.0	13.4	15.0	16.8
Total Non-OPEC	42.2	46.0	48.9	52.2	55.7	58.7
Total World	69.4	77.4	90.2	102.3	115.2	128.3

Note: OPEC = Organization of Petroleum Exporting Countries.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Table D4. World Oil Production by Region and Country, Reference Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf	16.2	21.2	23.8	28.8	34.2	39.6
Other OPEC	8.3	9.7	11.5	13.3	15.2	17.6
Total OPEC	24.5	30.9	35.3	42.1	49.4	57.2
Non-OPEC						
Industrialized						
United States	9.7	9.1	8.7	8.9	9.7	10.0
Canada	2.0	2.7	3.1	3.2	3.4	3.6
Mexico	3.0	3.5	3.9	4.2	4.4	4.4
Western Europe	4.6	7.1	7.4	7.2	6.9	6.5
Other	0.8	0.9	0.9	0.9	0.9	0.9
Total Industrialized	20.1	23.3	24.0	24.4	25.3	25.4
Eurasia						
China	2.8	3.2	3.2	3.1	3.1	3.0
Former Soviet Union	11.4	8.2	10.1	12.1	13.7	14.9
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.4
Total Eurasia	14.5	11.6	13.5	15.5	17.1	18.3
Other Non-OPEC						
Central and South America	2.4	3.8	4.2	4.8	5.6	6.5
Pacific Rim	1.7	2.4	2.6	2.6	2.6	2.5
Other	3.5	4.8	5.3	6.3	7.2	8.4
Total Other Non-OPEC	7.6	11.0	12.1	13.7	15.4	17.4
Total Non-OPEC	42.2	45.9	49.6	53.6	57.8	61.1
Total World	66.7	76.8	84.9	95.7	107.2	118.3
Persian Gulf Production as a Percentage of World Consumption	24.6	28.1	27.9	30.0	31.8	33.4

Note: OPEC = Organization of Petroleum Exporting Countries. Production includes crude oil (including lease condensates), natural gas liquids, other hydrogen hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Table D5. World Oil Production by Region and Country, High Oil Price Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf	16.2	21.2	21.0	23.3	26.2	31.2
Other OPEC	8.3	9.7	10.1	11.0	13.2	14.4
Total OPEC	24.5	30.9	31.1	34.3	39.4	45.6
Non-OPEC						
Industrialized						
United States	9.7	9.1	9.0	9.3	10.4	11.1
Canada	2.0	2.7	3.2	3.5	3.7	3.9
Mexico	3.0	3.5	4.0	4.5	4.8	4.9
Western Europe	4.6	7.1	7.6	7.6	7.3	7.0
Other	0.8	0.9	0.9	0.9	0.9	0.9
Total Industrialized	20.1	23.3	24.7	25.8	27.1	27.8
Eurasia						
China	2.8	3.2	3.3	3.3	3.2	3.3
Former Soviet Union	11.4	8.2	10.7	13.6	15.8	17.0
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.4
Total Eurasia	14.5	11.6	14.2	17.2	19.3	20.7
Other Non-OPEC						
Central and South America	2.4	3.8	4.4	5.4	6.4	7.4
Pacific Rim	1.7	2.4	2.7	2.8	2.7	2.7
Other	3.5	4.8	5.7	6.9	8.2	9.6
Total Other Non-OPEC	7.6	11.0	12.8	15.1	17.3	19.7
Total Non-OPEC	42.2	45.9	51.7	58.1	63.7	68.2
Total World	66.7	76.8	82.8	92.4	103.1	113.8
Persian Gulf Production as a Percentage of World Consumption	24.6	28.1	25.3	25.1	25.3	27.3

Note: OPEC = Organization of Petroleum Exporting Countries. Production includes crude oil (including lease condensates), natural gas liquids, other hydrogen hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Table D6. World Oil Production by Region and Country, Low Oil Price Case, 1990-2020
(Million Barrels per Day)

Region/Country	History (Estimates)		Projections			
	1990	2000	2005	2010	2015	2020
OPEC						
Persian Gulf	16.2	21.2	26.2	32.7	40.5	48.3
Other OPEC	8.3	9.7	11.8	14.4	16.0	17.9
Total OPEC	24.5	30.9	38.0	47.1	56.5	66.2
Non-OPEC						
Industrialized						
United States	9.7	9.1	8.5	8.3	8.8	9.0
Canada	2.0	2.7	3.1	3.2	3.3	3.5
Mexico	3.0	3.5	3.8	4.1	4.2	4.3
Western Europe	4.6	7.1	7.4	7.2	6.9	6.6
Other	0.8	0.9	0.8	0.8	0.8	0.8
Total Industrialized	20.1	23.3	23.6	23.6	24.0	24.2
Eurasia						
China	2.8	3.2	3.2	3.0	3.0	2.9
Former Soviet Union	11.4	8.2	9.9	11.9	13.4	14.5
Eastern Europe	0.3	0.2	0.2	0.3	0.3	0.3
Total Eurasia	14.5	11.6	13.3	15.2	16.7	17.7
Other Non-OPEC						
Central and South America	2.4	3.8	4.1	4.7	5.4	6.3
Pacific Rim	1.7	2.4	2.6	2.6	2.5	2.5
Other	3.5	4.8	5.3	6.0	7.1	8.0
Total Other Non-OPEC	7.6	11.0	12.0	13.3	15.0	16.8
Total Non-OPEC	42.2	45.9	48.9	52.1	55.7	58.7
Total World	66.7	76.8	86.9	99.2	112.2	124.9
Persian Gulf Production as a Percentage of World Consumption						
	24.6	28.1	30.0	32.9	36.0	38.6

Note: OPEC = Organization of Petroleum Exporting Countries. Production includes crude oil (including lease condensates), natural gas liquids, other hydrogen hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Energy Information Administration (EIA), Energy Markets and Contingency Information Division. **Projections:** EIA, Office of Integrated Analysis and Forecasting, World Energy Projection System; and U.S. Department of the Interior, U.S. Geological Survey, *World Petroleum Assessment 2000* (Reston, VA, July 2000).

Appendix E

Projections of Transportation Energy Use in the Reference Case

Table E1. World Total Energy Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	12.9	14.6	15.1	17.6	19.7	21.8	23.6	2.1
United States ^a	11.4	12.9	13.3	15.3	17.0	18.6	19.9	1.9
Canada	0.9	1.0	1.0	1.1	1.2	1.3	1.4	1.4
Mexico	0.6	0.7	0.8	1.2	1.6	1.9	2.3	5.5
Western Europe	6.3	7.6	7.4	8.1	8.5	8.9	9.3	1.1
United Kingdom	1.0	1.1	1.1	1.2	1.3	1.4	1.5	1.5
France	1.0	1.0	1.0	1.1	1.2	1.3	1.3	1.2
Germany	1.3	1.6	1.5	1.6	1.7	1.8	1.8	0.9
Italy	0.8	1.0	0.9	1.0	1.0	1.0	1.1	0.7
Netherlands	0.4	0.5	0.5	0.6	0.6	0.6	0.6	1.0
Other Western Europe	1.8	2.4	2.4	2.6	2.7	2.8	2.9	1.0
Industrialized Asia	2.1	2.7	2.8	3.0	3.2	3.3	3.4	1.1
Japan	1.6	2.0	2.1	2.2	2.3	2.4	2.4	0.8
Australasia	0.6	0.7	0.7	0.8	0.9	0.9	1.0	1.8
Total Industrialized	21.3	24.9	25.3	28.7	31.4	34.0	36.4	1.7
EE/FSU								
Former Soviet Union	3.0	1.5	1.5	2.0	2.3	2.6	2.9	3.1
Eastern Europe	0.6	0.6	0.6	0.8	0.9	1.0	1.1	2.6
Total EE/FSU	3.6	2.2	2.2	2.8	3.2	3.7	4.0	2.9
Developing Countries								
Developing Asia	3.3	5.5	5.7	7.7	10.0	13.0	15.6	4.9
China	0.9	1.5	1.6	2.3	3.2	4.5	5.9	6.4
India	0.6	0.8	0.9	1.4	2.0	3.0	3.5	6.8
South Korea	0.3	0.6	0.7	0.9	1.0	1.1	1.1	2.7
Other Asia	1.5	2.5	2.6	3.2	3.8	4.4	5.0	3.2
Middle East	1.4	1.7	1.7	1.8	1.8	1.9	1.9	0.6
Turkey	0.2	0.2	0.2	0.3	0.3	0.4	0.4	2.2
Other Middle East	1.2	1.4	1.5	1.5	1.5	1.5	1.5	0.2
Africa	1.0	1.2	1.2	1.5	1.7	1.9	2.2	2.9
Central and South America . . .	1.9	2.5	2.6	2.8	3.4	4.0	4.9	3.1
Brazil	0.8	1.0	1.1	1.2	1.3	1.5	1.7	2.3
Other Central/South America . .	1.1	1.5	1.5	1.7	2.1	2.6	3.2	3.7
Total Developing	7.6	10.9	11.2	13.9	16.9	20.9	24.7	3.8
Total World	32.5	38.0	38.7	45.4	51.6	58.5	65.0	2.5

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E2. World Total Gasoline Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	8.1	9.2	9.4	10.8	11.9	12.9	13.8	1.8
United States ^a	7.1	8.1	8.3	9.3	10.2	11.0	11.6	1.6
Canada	0.6	0.6	0.6	0.7	0.7	0.8	0.8	1.0
Mexico	0.4	0.5	0.5	0.8	1.0	1.2	1.4	5.1
Western Europe	2.9	2.9	2.9	3.0	3.1	3.1	3.1	0.3
United Kingdom	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.5
France	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Germany	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.2
Italy	0.3	0.5	0.4	0.4	0.5	0.5	0.5	0.2
Netherlands	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.6
Other Western Europe	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.3
Industrialized Asia	1.1	1.3	1.3	1.4	1.5	1.5	1.5	0.7
Japan	0.8	1.0	1.0	1.0	1.1	1.1	1.1	0.5
Australasia	0.3	0.4	0.4	0.4	0.4	0.4	0.5	1.1
Total Industrialized	12.0	13.5	13.6	15.2	16.5	17.5	18.4	1.5
EE/FSU								
Former Soviet Union	1.1	0.8	0.8	1.0	1.1	1.2	1.2	1.9
Eastern Europe	0.3	0.3	0.3	0.4	0.5	0.5	0.5	2.0
Total EE/FSU	1.4	1.1	1.1	1.4	1.5	1.6	1.7	1.9
Developing Countries								
Developing Asia	1.0	1.8	1.9	2.6	3.4	4.5	5.4	5.1
China	0.4	0.7	0.8	1.2	1.8	2.6	3.4	7.3
India	0.1	0.1	0.1	0.2	0.3	0.4	0.4	5.5
South Korea	0.1	0.2	0.2	0.2	0.2	0.3	0.3	2.1
Other Asia	0.5	0.8	0.8	1.0	1.1	1.3	1.3	2.3
Middle East	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.0
Turkey	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.3
Other Middle East	0.5	0.8	0.8	0.8	0.8	0.8	0.8	-0.2
Africa	0.5	0.5	0.5	0.7	0.8	0.9	1.0	2.8
Central and South America . . .	0.9	1.0	1.0	1.1	1.4	1.8	2.3	3.9
Brazil	0.3	0.3	0.3	0.4	0.4	0.5	0.6	3.2
Other Central/South America . .	0.6	0.7	0.7	0.8	1.0	1.3	1.7	4.1
Total Developing	3.0	4.3	4.4	5.4	6.6	8.1	9.6	3.8
Total World	16.4	18.9	19.1	22.0	24.6	27.3	29.7	2.1

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E3. World Total Diesel Fuel Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	2.1	2.7	2.8	3.5	4.1	4.5	4.9	2.6
United States ^a	1.8	2.3	2.4	3.0	3.4	3.8	4.1	2.5
Canada	0.2	0.2	0.2	0.3	0.3	0.3	0.3	1.5
Mexico	0.2	0.2	0.2	0.3	0.4	0.4	0.5	4.8
Western Europe	2.1	3.0	2.9	3.2	3.4	3.5	3.6	1.0
United Kingdom	0.3	0.4	0.4	0.4	0.4	0.5	0.5	1.4
France	0.4	0.5	0.5	0.6	0.6	0.7	0.7	1.2
Germany	0.4	0.6	0.6	0.6	0.7	0.7	0.7	1.2
Italy	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.7
Netherlands	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.7
Other Western Europe	0.7	1.0	1.0	1.0	1.1	1.1	1.1	0.8
Industrialized Asia	0.6	0.8	0.8	0.9	0.9	0.9	1.0	0.9
Japan	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.6
Australasia	0.1	0.2	0.2	0.2	0.2	0.2	0.2	1.7
Total Industrialized	4.9	6.5	6.6	7.6	8.3	9.0	9.5	1.8
EE/FSU								
Former Soviet Union	0.9	0.3	0.3	0.5	0.6	0.7	0.7	3.7
Eastern Europe	0.2	0.2	0.2	0.3	0.3	0.4	0.4	2.7
Total EE/FSU	1.1	0.6	0.6	0.8	0.9	1.0	1.1	3.3
Developing Countries								
Developing Asia	1.2	2.3	2.4	3.3	4.3	5.7	6.8	5.1
China	0.1	0.4	0.4	0.6	0.9	1.3	1.8	6.9
India	0.4	0.6	0.7	1.1	1.6	2.4	2.8	7.0
South Korea	0.2	0.2	0.2	0.3	0.4	0.4	0.4	3.2
Other Asia	0.5	1.0	1.0	1.3	1.5	1.7	1.8	2.7
Middle East	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Turkey	0.1	0.1	0.1	0.1	0.1	0.1	0.1	2.5
Other Middle East	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-0.2
Africa	0.3	0.3	0.3	0.4	0.5	0.6	0.6	2.8
Central and South America . . .	0.6	0.9	1.0	1.0	1.2	1.3	1.5	2.2
Brazil	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.6
Other Central/South America . .	0.3	0.5	0.5	0.6	0.7	0.8	1.0	3.4
Total Developing	2.6	4.1	4.2	5.3	6.5	8.1	9.4	4.0
Total World	8.6	11.1	11.3	13.7	15.8	18.1	20.0	2.8

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E4. World Total Jet Fuel Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1.6	1.8	1.8	2.1	2.4	2.8	3.3	2.9
United States ^a	1.5	1.6	1.7	1.9	2.2	2.5	2.8	2.5
Canada	0.1	0.1	0.1	0.1	0.1	0.1	0.2	1.5
Mexico	0.0	0.1	0.1	0.1	0.1	0.2	0.4	9.7
Western Europe	0.6	0.9	0.8	1.1	1.3	1.5	1.7	3.4
United Kingdom	0.1	0.2	0.2	0.2	0.3	0.3	0.4	3.5
France	0.1	0.1	0.1	0.1	0.2	0.2	0.2	3.1
Germany	0.1	0.1	0.1	0.2	0.2	0.2	0.2	3.0
Italy	0.0	0.1	0.1	0.1	0.1	0.1	0.1	3.5
Netherlands	0.0	0.1	0.1	0.1	0.1	0.1	0.1	3.2
Other Western Europe	0.2	0.3	0.3	0.4	0.4	0.5	0.6	3.7
Industrialized Asia	0.1	0.3	0.3	0.4	0.4	0.5	0.6	3.1
Japan	0.1	0.2	0.2	0.2	0.3	0.3	0.3	2.4
Australasia	0.1	0.1	0.1	0.1	0.2	0.2	0.2	4.3
Total Industrialized	2.4	3.0	3.0	3.5	4.1	4.8	5.7	3.1
EE/FSU								
Former Soviet Union	0.5	0.3	0.3	0.3	0.4	0.6	0.7	4.8
Eastern Europe	0.0	0.0	0.0	0.0	0.1	0.1	0.1	7.6
Total EE/FSU	0.6	0.3	0.3	0.4	0.5	0.7	0.8	5.2
Developing Countries								
Developing Asia	0.4	0.5	0.5	0.8	1.1	1.6	2.1	6.9
China	0.1	0.1	0.1	0.1	0.2	0.3	0.3	6.2
India	0.0	0.0	0.0	0.1	0.1	0.2	0.3	9.1
South Korea	0.0	0.0	0.0	0.1	0.1	0.1	0.2	5.9
Other Asia	0.2	0.3	0.3	0.5	0.7	1.0	1.3	6.9
Middle East	0.2	0.2	0.2	0.2	0.3	0.3	0.3	2.3
Turkey	0.0	0.0	0.0	0.0	0.1	0.1	0.1	4.8
Other Middle East	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6
Africa	0.1	0.1	0.1	0.2	0.2	0.3	0.3	5.1
Central and South America . . .	0.1	0.2	0.2	0.2	0.3	0.4	0.5	4.7
Brazil	0.0	0.0	0.0	0.1	0.1	0.1	0.1	5.4
Other Central/South America . .	0.1	0.1	0.1	0.2	0.2	0.3	0.3	4.4
Total Developing	0.8	1.0	1.0	1.4	1.9	2.5	3.3	5.7
Total World	3.8	4.2	4.3	5.3	6.5	8.0	9.8	4.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E5. World Total Residual Fuel Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	0.5	0.3	0.4	0.5	0.5	0.5	0.5	0.8
United States ^a	0.4	0.3	0.4	0.5	0.5	0.5	0.5	0.8
Canada	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Western Europe	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.3
United Kingdom	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
France	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Germany	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Italy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Other Western Europe	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Industrialized Asia	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.6
Japan	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.5
Australasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Total Industrialized	1.1	1.1	1.2	1.3	1.3	1.4	1.4	0.5
EE/FSU								
Former Soviet Union	0.2	0.0	0.0	0.0	0.0	0.0	0.1	5.2
Eastern Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6
Total EE/FSU	0.2	0.0	0.0	0.1	0.1	0.1	0.1	3.3
Developing Countries								
Developing Asia	0.3	0.7	0.7	0.7	0.8	0.9	0.9	1.5
China	0.0	0.1	0.1	0.1	0.1	0.1	0.2	1.4
India	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7
South Korea	0.0	0.1	0.1	0.2	0.2	0.2	0.2	1.4
Other Asia	0.2	0.4	0.4	0.4	0.5	0.5	0.6	1.5
Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.9
Turkey	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Other Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	2.0
Africa	0.1	0.1	0.1	0.2	0.2	0.2	0.2	1.2
Central and South America . . .	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.7
Brazil	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.9
Other Central/South America . .	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.6
Total Developing	0.7	1.0	1.1	1.2	1.3	1.3	1.4	1.4
Total World	2.0	2.2	2.4	2.5	2.7	2.8	2.9	1.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E6. World Total Other Fuel Consumption for Transportation by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	0.6	0.6	0.6	0.7	0.8	0.9	1.1	2.6
United States ^a	0.5	0.5	0.6	0.7	0.7	0.8	1.0	2.4
Canada	0.0	0.0	0.0	0.0	0.0	0.1	0.1	6.4
Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
Western Europe	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.6
United Kingdom	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
France	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Germany	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Italy	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3
Netherlands	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Other Western Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Industrialized Asia	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.9
Japan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Australasia	0.0	0.0	0.0	0.1	0.1	0.1	0.1	1.3
Total Industrialized	0.8	0.9	1.0	1.1	1.2	1.3	1.5	2.0
EE/FSU								
Former Soviet Union	0.3	0.1	0.1	0.1	0.2	0.2	0.2	3.8
Eastern Europe	0.0	0.0	0.0	0.0	0.1	0.1	0.1	1.0
Total EE/FSU	0.3	0.1	0.1	0.2	0.2	0.3	0.3	3.1
Developing Countries								
Developing Asia	0.3	0.2	0.3	0.3	0.3	0.3	0.4	1.5
China	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.1
India	0.1	0.0	0.0	0.0	0.0	0.0	0.0	1.5
South Korea	0.0	0.1	0.1	0.1	0.1	0.1	0.1	1.8
Other Asia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Turkey	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Other Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.0
Central and South America . . .	0.1	0.2	0.2	0.3	0.3	0.4	0.5	3.1
Brazil	0.1	0.2	0.2	0.2	0.3	0.3	0.4	3.3
Other Central/South America . .	0.0	0.1	0.1	0.1	0.1	0.1	0.1	2.4
Total Developing	0.5	0.5	0.6	0.6	0.7	0.8	0.9	2.3
Total World	1.6	1.6	1.7	1.9	2.1	2.4	2.7	2.2

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A2; and World Energy Projection System (2002).

Table E7. World Total Road Use Energy Consumption by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	9.9	11.7	12.1	14.3	16.0	17.6	18.9	2.1
United States ^a	8.7	10.3	10.6	12.3	13.7	14.9	15.9	1.9
Canada	0.7	0.8	0.8	0.9	1.0	1.0	1.1	1.4
Mexico	0.6	0.7	0.7	1.1	1.4	1.6	1.9	5.0
Western Europe	4.7	5.5	5.4	5.8	6.0	6.1	6.2	0.7
United Kingdom	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0
France	0.8	0.8	0.8	0.9	0.9	1.0	1.0	0.9
Germany	1.1	1.3	1.3	1.3	1.4	1.4	1.4	0.7
Italy	0.6	0.8	0.8	0.8	0.8	0.9	0.9	0.4
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.8
Other Western Europe	1.2	1.6	1.6	1.7	1.7	1.7	1.8	0.6
Industrialized Asia	1.6	2.1	2.1	2.2	2.3	2.4	2.5	0.7
Japan	1.2	1.6	1.6	1.7	1.7	1.8	1.8	0.5
Australasia	0.4	0.5	0.5	0.6	0.6	0.6	0.7	1.3
Total Industrialized	16.2	19.3	19.6	22.3	24.4	26.1	27.6	1.6
EE/FSU								
Former Soviet Union	1.6	1.1	1.0	1.4	1.7	1.9	2.1	3.3
Eastern Europe	0.5	0.5	0.5	0.7	0.8	0.8	0.9	2.3
Total EE/FSU	2.1	1.6	1.6	2.1	2.5	2.8	2.9	3.0
Developing Countries								
Developing Asia	2.0	3.7	3.8	5.4	7.1	9.4	11.2	5.2
China	0.5	0.9	1.0	1.5	2.2	3.3	4.5	7.6
India	0.4	0.7	0.8	1.3	1.9	2.8	3.2	7.0
South Korea	0.2	0.4	0.4	0.5	0.6	0.6	0.7	2.7
Other Asia	0.9	1.7	1.7	2.1	2.4	2.7	2.8	2.4
Middle East	1.1	1.4	1.4	1.5	1.5	1.5	1.5	0.2
Turkey	0.2	0.2	0.2	0.2	0.3	0.3	0.3	1.8
Other Middle East	0.9	1.2	1.2	1.2	1.2	1.2	1.2	-0.1
Africa	0.8	0.8	0.9	1.1	1.3	1.4	1.6	2.9
Central and South America . . .	1.6	2.1	2.1	2.3	2.8	3.3	4.1	3.2
Brazil	0.7	0.9	0.9	1.0	1.1	1.2	1.4	2.2
Other Central/South America . .	0.9	1.2	1.2	1.4	1.7	2.1	2.7	3.8
Total Developing	5.4	8.0	8.2	10.3	12.6	15.6	18.3	3.9
Total World	23.7	28.9	29.4	34.8	39.5	44.5	48.9	2.4

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Table E8. World Total Air Use Energy Consumption by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1.6	1.8	1.8	2.1	2.4	2.8	3.3	2.9
United States ^a	1.5	1.6	1.7	1.9	2.2	2.5	2.8	2.5
Canada	0.1	0.1	0.1	0.1	0.1	0.1	0.2	1.5
Mexico	0.0	0.1	0.1	0.1	0.1	0.2	0.4	9.7
Western Europe	0.6	0.9	0.8	1.1	1.3	1.5	1.7	3.4
United Kingdom	0.1	0.2	0.2	0.2	0.3	0.3	0.4	3.5
France	0.1	0.1	0.1	0.1	0.2	0.2	0.2	3.1
Germany	0.1	0.1	0.1	0.2	0.2	0.2	0.2	3.0
Italy	0.0	0.1	0.1	0.1	0.1	0.1	0.1	3.5
Netherlands	0.0	0.1	0.1	0.1	0.1	0.1	0.1	3.2
Other Western Europe	0.2	0.3	0.3	0.4	0.4	0.5	0.6	3.7
Industrialized Asia	0.1	0.3	0.3	0.4	0.4	0.5	0.6	3.1
Japan	0.1	0.2	0.2	0.2	0.3	0.3	0.3	2.4
Australasia	0.1	0.1	0.1	0.1	0.2	0.2	0.2	4.3
Total Industrialized	2.4	3.0	3.0	3.5	4.1	4.8	5.7	3.1
EE/FSU								
Former Soviet Union	0.5	0.3	0.3	0.3	0.4	0.6	0.7	4.8
Eastern Europe	0.0	0.0	0.0	0.0	0.1	0.1	0.1	7.6
Total EE/FSU	0.6	0.3	0.3	0.4	0.5	0.7	0.8	5.2
Developing Countries								
Developing Asia	0.4	0.5	0.5	0.8	1.1	1.6	2.1	6.9
China	0.1	0.1	0.1	0.1	0.2	0.3	0.3	6.2
India	0.0	0.0	0.0	0.1	0.1	0.2	0.3	9.1
South Korea	0.0	0.0	0.0	0.1	0.1	0.1	0.2	5.9
Other Asia	0.2	0.3	0.3	0.5	0.7	1.0	1.3	6.9
Middle East	0.2	0.2	0.2	0.2	0.3	0.3	0.3	2.3
Turkey	0.0	0.0	0.0	0.0	0.1	0.1	0.1	4.8
Other Middle East	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6
Africa	0.1	0.1	0.1	0.2	0.2	0.3	0.3	5.1
Central and South America . . .	0.1	0.2	0.2	0.2	0.3	0.4	0.5	4.7
Brazil	0.0	0.0	0.0	0.1	0.1	0.1	0.1	5.4
Other Central/South America . .	0.1	0.1	0.1	0.2	0.2	0.3	0.3	4.4
Total Developing	0.8	1.0	1.0	1.4	1.9	2.5	3.3	5.7
Total World	3.8	4.2	4.3	5.3	6.5	8.0	9.8	4.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Table E9. World Total Other Transportation Use Energy Consumption by Region, Reference Case, 1990-2020
(Million Barrels of Oil per Day)

Region/Country	History			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	1.3	1.1	1.2	1.3	1.3	1.3	1.4	0.8
United States ^a	1.2	1.0	1.0	1.1	1.1	1.2	1.2	0.7
Canada	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.0
Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.2
Western Europe	1.1	1.2	1.2	1.3	1.3	1.3	1.3	0.4
United Kingdom	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5
France	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5
Germany	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3
Italy	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4
Netherlands	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Other Western Europe	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.5
Industrialized Asia	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.7
Japan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6
Australasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.2
Total Industrialized	2.7	2.7	2.7	2.9	2.9	3.0	3.1	0.6
EE/FSU								
Former Soviet Union	0.9	0.2	0.2	0.2	0.2	0.1	0.1	-2.5
Eastern Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.5
Total EE/FSU	1.0	0.3	0.3	0.3	0.3	0.2	0.2	-1.0
Developing Countries								
Developing Asia	0.9	1.3	1.4	1.6	1.8	2.0	2.3	2.5
China	0.3	0.5	0.5	0.6	0.8	0.9	1.1	3.4
India	0.1	0.1	0.1	0.1	0.0	0.0	0.0	-3.1
South Korea	0.1	0.2	0.2	0.3	0.3	0.3	0.3	1.7
Other Asia	0.3	0.6	0.6	0.6	0.7	0.8	0.9	2.1
Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Turkey	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3
Other Middle East	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.8
Africa	0.1	0.2	0.2	0.2	0.2	0.3	0.3	1.2
Central and South America . . .	0.2	0.3	0.3	0.3	0.3	0.3	0.4	1.4
Brazil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.3
Other Central/South America . .	0.1	0.2	0.2	0.2	0.2	0.2	0.2	1.5
Total Developing	1.3	1.9	2.0	2.2	2.4	2.7	3.0	2.1
Total World	5.0	4.9	5.0	5.3	5.6	6.0	6.4	1.2

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, World Energy Projection System (2002).

Table E10. World Per Capita Vehicle Ownership (Motorization) by Region, Reference Case, 1990-2020
(Vehicles per Thousand Population)

Region/Country	History (Estimates)			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	601	612	614	630	645	664	689	0.5
United States ^a	765	775	777	787	792	795	797	0.1
Canada	596	598	607	646	665	678	686	0.6
Mexico	119	154	158	201	251	318	410	4.6
Western Europe	473	522	528	553	568	582	597	0.6
United Kingdom	457	509	517	552	569	580	587	0.6
France	502	552	560	598	617	629	636	0.6
Germany	485	551	559	592	609	619	626	0.5
Italy	525	603	612	649	667	679	687	0.6
Netherlands	385	428	435	462	476	485	490	0.6
Other Western Europe	384	445	450	471	481	488	492	0.4
Industrialized Asia	638	608	615	648	667	684	702	0.6
Japan	467	562	569	603	620	631	638	0.5
Australasia	617	637	642	666	678	686	691	0.4
Total Industrialized	638	608	615	648	667	684	702	0.6
EE/FSU								
Former Soviet Union	357	128	134	162	176	184	190	1.7
Eastern Europe	213	209	217	251	269	280	287	1.4
Total EE/FSU	314	152	158	188	203	212	218	1.5
Developing Countries								
Developing Asia	10	19	20	28	35	44	53	4.6
China	5	11	12	18	27	40	52	7.5
India	5	9	10	15	22	33	44	7.6
South Korea	79	250	268	344	382	407	422	2.2
Other Asia	18	30	32	40	43	46	47	1.9
Middle East	38	56	57	68	80	98	124	3.8
Turkey	42	80	83	100	108	114	117	1.6
Other Middle East	37	50	50	60	73	94	126	4.5
Africa	24	25	26	30	32	33	34	1.3
Central and South America . . .	78	99	100	126	155	191	236	4.2
Brazil	81	101	101	131	163	201	248	4.4
Other Central/South America . .	58	75	75	93	112	134	160	3.7
Total Developing	21	31	32	41	50	61	73	4.0
Total World	124	121	122	130	136	143	150	1.0

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from American Automobile Manufacturers Association, *World Motor Vehicle Data* (Detroit, MI, 1997).
Projections: Energy Information Administration, World Energy Projection System (2002).

Table E11. World Per Capita Transportation Energy Use by Region, Reference Case, 1990-2020
(Barrels Oil Equivalent per Person)

Region/Country	History (Estimates)			Projections				Average Annual Percent Change, 1999-2020
	1990	1998	1999	2005	2010	2015	2020	
Industrialized Countries								
North America	12.8	13.5	13.8	15.1	16.1	17.1	17.8	1.2
United States ^a	16.3	17.4	17.8	19.4	20.6	21.7	22.4	1.1
Canada	11.7	12.0	12.4	13.0	13.5	13.8	14.1	0.6
Mexico	2.7	2.8	2.9	4.2	5.1	5.9	6.8	4.2
Western Europe	6.1	6.8	7.0	7.6	8.0	8.4	8.7	1.1
United Kingdom	6.5	6.7	6.7	7.4	7.9	8.4	8.9	1.3
France	6.3	6.4	6.4	6.9	7.2	7.5	7.7	0.9
Germany	6.0	6.1	6.7	7.3	7.6	8.0	8.3	1.0
Italy	4.9	5.4	5.9	6.3	6.6	6.9	7.3	1.0
Netherlands	10.4	11.7	12.2	12.8	13.3	13.8	14.3	0.8
Other Western Europe	6.0	7.5	7.5	8.1	8.5	9.0	9.4	1.1
Industrialized Asia	5.2	6.1	6.5	6.9	7.3	7.6	8.0	0.9
Japan	4.6	5.6	5.9	6.2	6.5	6.7	7.0	0.8
Australasia	8.6	8.8	9.6	10.2	10.7	11.2	11.8	1.0
Total Industrialized	8.7	9.5	9.8	10.8	11.5	12.2	12.9	1.3
EE/FSU								
Former Soviet Union	3.8	1.7	1.9	2.5	2.9	3.4	3.8	3.3
Eastern Europe	1.7	1.9	2.0	2.5	2.9	3.2	3.5	2.8
Total EE/FSU	3.2	1.8	1.9	2.5	2.9	3.4	3.7	3.2
Developing Countries								
Developing Asia	0.4	0.6	0.7	0.8	1.0	1.2	1.4	3.7
China	0.3	0.4	0.5	0.6	0.8	1.2	1.5	5.7
India	0.2	0.3	0.3	0.5	0.6	0.9	1.0	5.5
South Korea	3.0	5.6	5.1	6.5	7.2	7.7	8.2	2.2
Other Asia	0.7	1.0	1.1	1.2	1.3	1.4	1.5	1.7
Middle East	2.6	2.6	2.7	2.5	2.3	2.1	2.0	-1.4
Turkey	1.3	1.6	1.4	1.5	1.6	1.7	1.7	1.1
Other Middle East	3.2	3.0	3.2	2.8	2.5	2.3	2.1	-2.0
Africa	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Central and South America . . .	2.0	1.9	2.3	2.3	2.6	2.9	3.4	1.9
Brazil	2.0	1.9	2.3	2.3	2.5	2.7	3.0	1.2
Other Central/South America . .	2.0	1.9	2.3	2.3	2.6	3.1	3.7	2.2
Total Developing	0.7	0.8	0.9	1.0	1.1	1.3	1.5	2.4
Total World	2.3	2.3	2.4	2.6	2.8	3.0	3.1	1.3

^aIncludes the 50 States and the District of Columbia. U.S. Territories are included in Australasia.

Notes: EE/FSU = Eastern Europe/Former Soviet Union. Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001), and United Nations, *World Population Prospects: The 2000 Revision* (New York, NY, 2001). **Projections:** EIA, World Energy Projection System (2002).

World Energy Projection System

The projections of world energy consumption published annually by the Energy Information Administration (EIA) in the *International Energy Outlook (IEO)* are derived from the World Energy Projection System (WEPS). WEPS is an integrated set of personal-computer-based spreadsheets containing data compilations, assumption specifications, descriptive analysis procedures, and projection models. The WEPS accounting framework incorporates projections from independently documented models and assumptions about the future energy intensity of economic activity (ratios of total energy consumption divided by gross domestic product [GDP]) and about the rate of incremental energy requirements met by natural gas, coal, and renewable energy sources (hydroelectricity, geothermal, solar, wind, biomass, and other renewable sources).

WEPS provides projections of total world primary energy consumption, as well as projections of energy consumption by primary energy type (oil, natural gas, coal, nuclear, and hydroelectric and other renewable resources), and projections of net electricity consumption and energy use in the transportation sector. Projections of energy consumed by fuel type are also provided for electricity generation and for transportation. Carbon dioxide emissions resulting from fossil fuel use are derived from the energy consumption projections. All projections are computed in 5-year intervals through the year 2020. For both historical series and projection series, WEPS provides analytical computations of energy intensity and energy elasticity (the percentage change in energy consumption per percentage change in GDP).

WEPS projections are provided for regions and selected countries. Projections are made for 14 individual countries, 9 of which—United States, Canada, Mexico, Japan, United Kingdom, France, Germany, Italy, and Netherlands—are part of the designation “industrialized countries.” Individual country projections are also made for China, India, South Korea, Turkey, and Brazil, all of which are considered “developing countries.” Beyond these individual countries, the rest of the world is divided into regions. Industrialized regions include North America (Canada, Mexico, and the United States), Western Europe (United Kingdom, France, Germany, Italy, Netherlands, and Other Europe), and Pacific (Japan and Australasia, which consists of Australia, New Zealand, and the U.S. Territories). Developing regions include developing Asia (China, India, South Korea, and Other Asia), Middle East (Turkey and Other

Middle East), Africa, and Central and South America (Brazil and Other Central and South America). The transitional economies, consisting of the countries in Eastern Europe (EE) and the former Soviet Union (FSU), are considered as a separate country grouping, neither industrialized nor developing. Within the EE/FSU, projections are made separately for nations designated as Annex I and non-Annex I in the Kyoto Climate Change Protocol.

The process of creating the projections begins with the calculation of a reference case total energy consumption projection for each country or region for each 5-year interval in the forecast period. The total energy consumption projection for each forecast year is the product of an assumed GDP growth rate, an assumed energy elasticity, and the total energy consumption for the prior forecast year. For the first year of the forecast, the prior year consumption is based on historical data. Subsequent calculations are based on the energy consumption projections for the preceding years.

Projections of world oil supply are provided to WEPS from EIA’s International Energy Module, which is a submodule of the National Energy Modeling System (NEMS). Projections of world nuclear energy consumption are derived from nuclear power electricity generation projections from EIA’s International Nuclear Model (INM), PC Version (PC-INM). All U.S. projections are taken from EIA’s *Annual Energy Outlook (AEO)*.

A full description of WEPS is provided in a model documentation report: Energy Information Administration, *World Energy Projection System Model Documentation*, DOE/EIA-M050(97) (Washington, DC, September 1997). The report presents a description of each of the spreadsheets associated with WEPS, along with descriptions of the methodologies and assumptions used to produce the projections. The entire publication can be found through the Internet in portable document format (PDF) at: <ftp://ftp.eia.doe.gov/pub/pdf/model.docs/m05097.pdf>.

The WEPS model will be made available for downloading through the Internet on EIA’s home page by May 2002. The package will allow users to replicate the projections that appear in *IEO2002*. It is coded in Excel, version 5.0, and can be executed on any IBM-compatible personal computer in a Windows environment. The package requires about 14 megabytes of hard disk space for complete installation and model execution.

Performance of Past *IEO* Forecasts for 1990 and 1995

In an effort to measure how well the *IEO* projections have estimated future energy consumption trends over the series' 17-year history, we present a comparison of *IEO* forecasts produced for the years 1990 and 1995. The forecasts are compared with actual data published in EIA's *International Energy Annual 1999*,³⁹ as part of EIA's commitment to provide users of the *IEO* with a set of performance measures to assess the forecasts produced by this agency.

The *IEO* has been published since 1985. In *IEO85*, mid-term projections were derived only for the world's market economies. That is, no projections were prepared for the centrally planned economies (CPE) of the Soviet Union, Eastern Europe, Cambodia, China, Cuba, Laos, Mongolia, North Korea, and Vietnam. The *IEO85* projections extended to 1995 and included forecasts of energy consumption for 1990 and 1995 and primary consumption of oil, natural gas, coal, and "other fuels." *IEO85* projections were also presented for several individual countries and subregions: the United States, Canada, Japan, the United Kingdom, France, West Germany, Italy, the Netherlands, other OECD Europe, other OECD (Australia, New Zealand, and the U.S. Territories), OPEC, and other developing countries. Beginning with *IEO86*, nuclear power projections were published separately from the "other fuel" category.

The regional aggregation has changed from report to report. In 1990, the report coverage was expanded for the first time from coverage of only the market economies to coverage of the entire world. Projections for China, the former Soviet Union, and other CPE countries were provided separately.

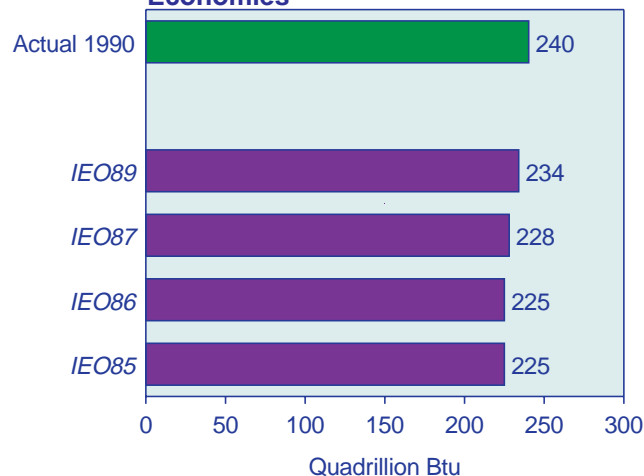
Historical data for total regional energy consumption in 1990 show that the *IEO* projections from those early years were consistently lower than the actual data for the market economies. For the four editions of the *IEO* printed between 1985 and 1989 (no *IEO* was published in 1988) in which 1990 projections were presented, total projected energy consumption in the market economies ran between 3 and 7 percent below the actual amounts published in the *International Energy Annual 1999* (Figure G1).

In addition, market economy projections for 1995 in the 1985 through 1993 *IEO* reports (EIA did not release

forecasts for 1995 after the 1993 report) were consistently lower than the historical 1995 data (Figure G2). Most of the difference is attributed to those market economy countries outside the Organization for Economic Cooperation and Development (OECD). Through the years, EIA's economic growth assumptions for OPEC and other market economy countries outside the OECD have been low. The 1993 forecast was, as one might expect, the most accurate of the forecasts for 1995, but its projection for OPEC and the other market economy countries was still more than 10 percent below the actual number.

IEO90 marked the first release of a worldwide energy consumption forecast. Since *IEO90*, the forecasts for worldwide energy demand have been between 2 and 5 percent higher than the actual amounts consumed (Figure G3). Much of the difference can be explained by the unanticipated collapse of the Soviet Union economies in the early 1990s. The *IEO* forecasters could not foresee the extent to which energy consumption would fall in this region. In *IEO90*, total energy consumption in the FSU was projected to reach 67 quadrillion Btu in 1995. The projection was reduced steadily in the next three *IEO* reports, but even in 1993 energy demand for

Figure G1. Comparison of *IEO* Forecasts with 1990 Energy Consumption in Market Economies



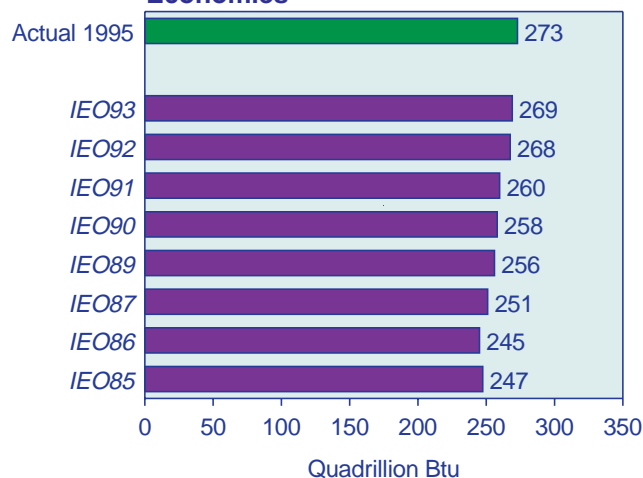
Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

³⁹Energy Information Administration, *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001).

1995 in the FSU region was still projected to be 53 quadrillion Btu, as compared with actual 1995 energy consumption of 43 quadrillion Btu, some 10 quadrillion Btu (or about 5 million barrels of oil per day) less than projected in *IEO93*.

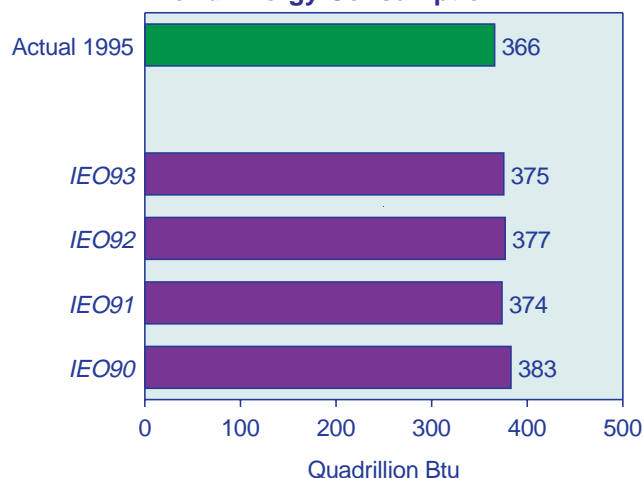
Considering the forecasts for the year 1995 strictly in terms of depicting future trends associated with the fuel mix, the *IEO* reports have performed well. Each *IEO*

Figure G2. Comparison of *IEO* Forecasts with 1995 Energy Consumption in Market Economies



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

Figure G3. Comparison of *IEO* Forecasts with 1995 World Energy Consumption



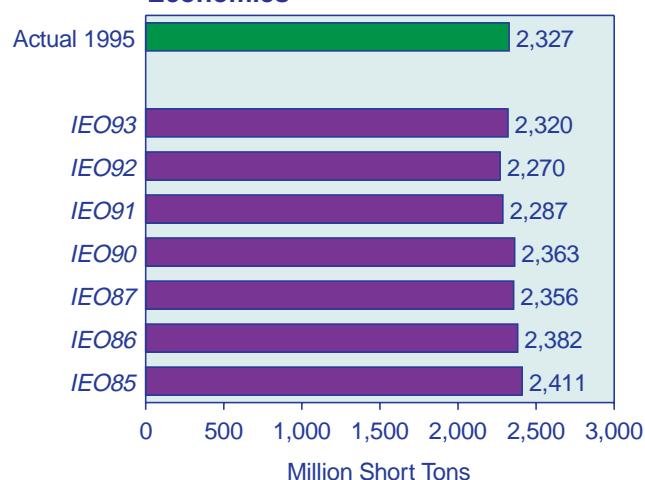
Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

⁴⁰Projections for West Germany and later unified Germany have been removed from the values considered here because of the lack of continuity in the coal data series after reunification.

since 1990 has projected the fuel mix within 3.5 percentage points of the actual 1995 mix. The earliest *IEOs* tended to be too optimistic about the growth of coal use in the market economies⁴⁰ (Figure G4), and not optimistic enough about the recovery of oil consumption after the declines in the early 1980s that followed the price shocks caused by oil embargoes in 1973 and 1974 and the 1979-1980 revolution in Iran (Figure G5). The *IEO85* and *IEO86* reports projected that oil would account for only about 40 percent of total energy consumption for the market economies in 1995, whereas oil actually accounted for 45 percent of the total in 1995.

The forecasts for world coal consumption that appeared in the *IEOs* printed between 1990 and 1993 were consistently high, between 4 and 16 percent higher than actual coal use (Figure G6), largely because of overestimates for the former Soviet Union and Eastern Europe—regions that experienced substantial declines in coal consumption during the years following the collapse of the Soviet Union. Most of the by-fuel projections for the FSU were greater than the actual consumption numbers, with the exception of hydroelectricity and other renewable resources (Figure G7). Natural gas use did not decline as much as oil and coal use because gas is a plentiful resource in the region and was used extensively to fuel the domestic infrastructure, but even the *IEO* estimates for 1995 natural gas use were 16 to 22 percent higher than the actual use.

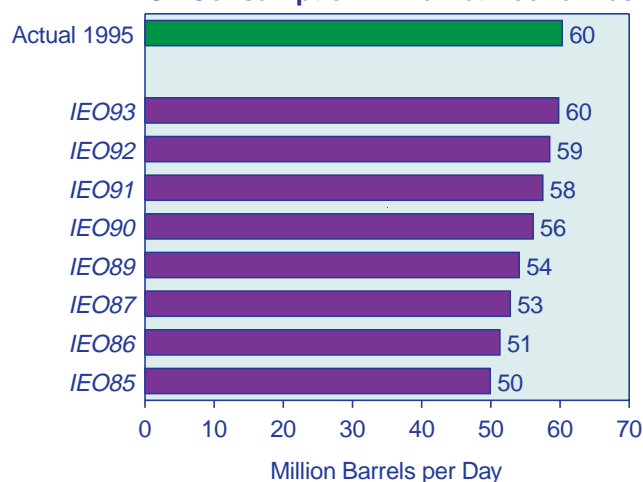
Figure G4. Comparison of *IEO* Forecasts with 1995 Coal Consumption in Market Economies



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

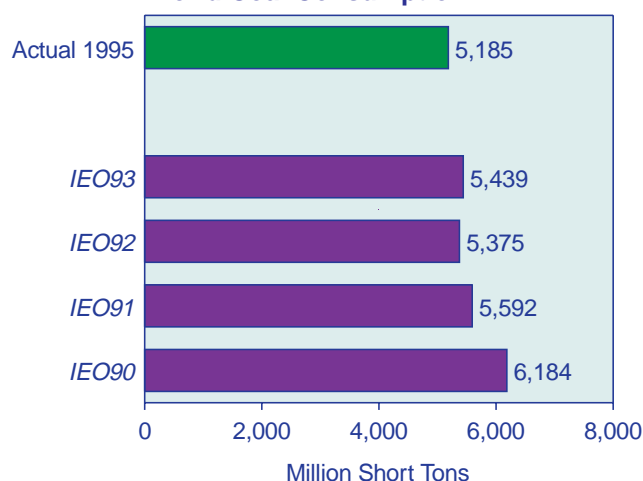
The EIA projections for total energy consumption in China were below the actual 1995 consumption level in *IEO90* (by 13 percent) and *IEO91* (by 8 percent) but higher in *IEO92* (by 6 percent) and about the same in *IEO93*. The underestimates in the earlier *IEOs* balanced, in part, the overestimates for the EE/FSU countries; however, even the 4- to 17-percent underestimate of projected 1995 coal use in China could not make up for the 30- to 54-percent overestimate of FSU coal use. In terms of other fuels, EIA consistently overestimated China's gas consumption and underestimated its oil

Figure G5. Comparison of *IEO* Forecasts with 1995 Oil Consumption in Market Economies



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

Figure G6. Comparison of *IEO* Forecasts with 1995 World Coal Consumption

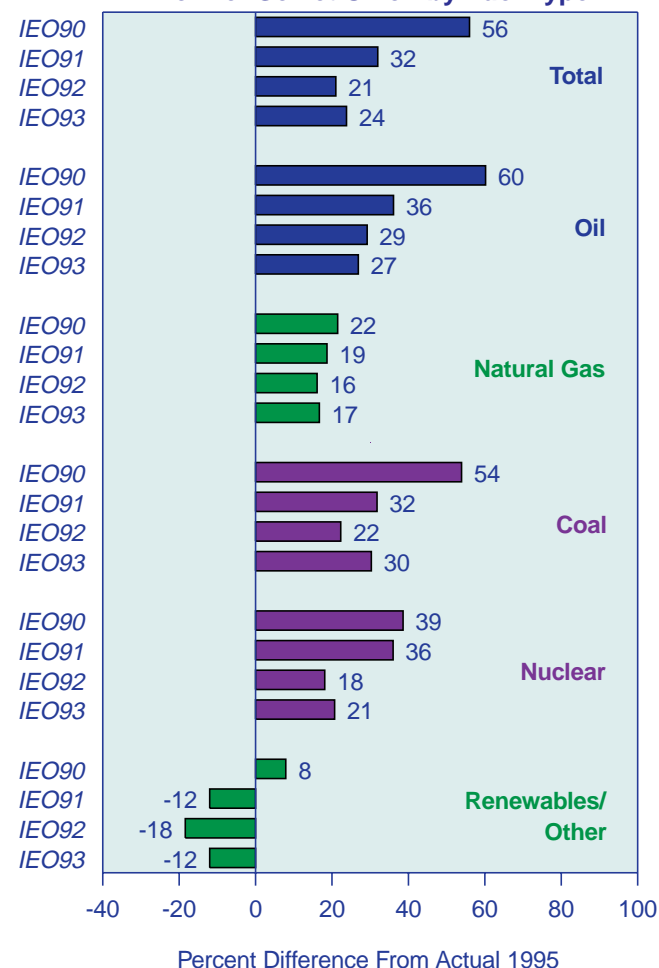


Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

consumption. Nuclear power forecasts were fairly close for China, within 5 percent of the actual consumption (Figure G8). It is noteworthy, however, that consumption of natural gas and nuclear power was quite small in 1995, so that any variation between actual historical consumption and the projections results in a large percentage difference. EIA consistently underestimated economic growth in China. As late as 1993, EIA expected GDP in China to grow by about 7.3 percent per year during the decade of the 1990s, whereas it actually grew by 10.7 percent per year between 1990 and 1995.

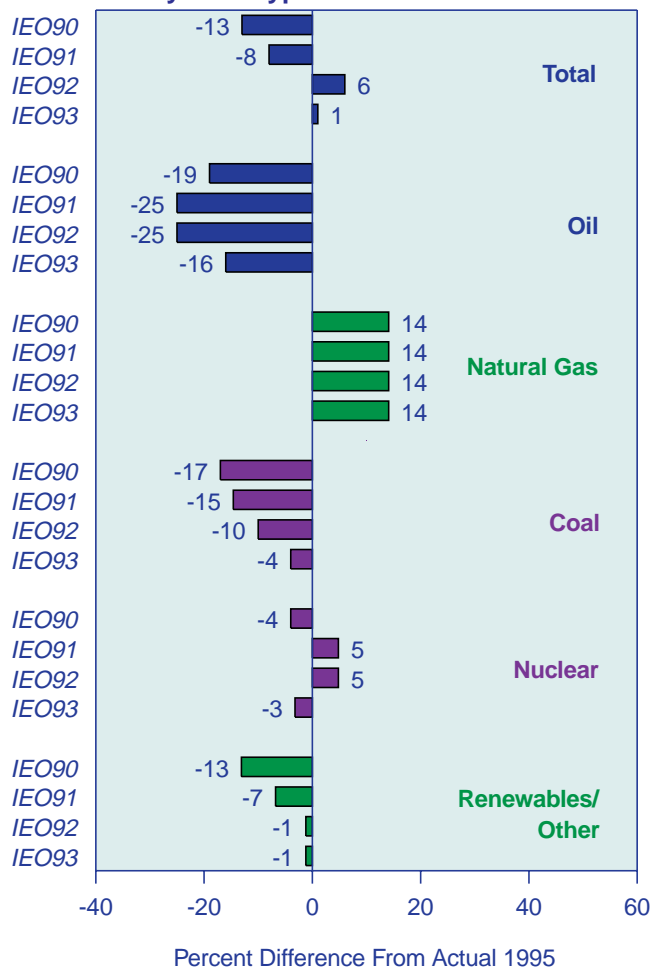
The comparison of *IEO* projections and historical data in the context of political and social events underscores the importance of these events in shaping the world's energy markets. Such comparisons also point out how important a model's assumptions are to the derivation of accurate forecasts. The political and social upheaval in

Figure G7. Comparison of *IEO* Forecasts with 1995 Energy Consumption in the Former Soviet Union by Fuel Type



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

Figure G8. Comparison of IEO Forecasts with 1995 Energy Consumption in China by Fuel Type

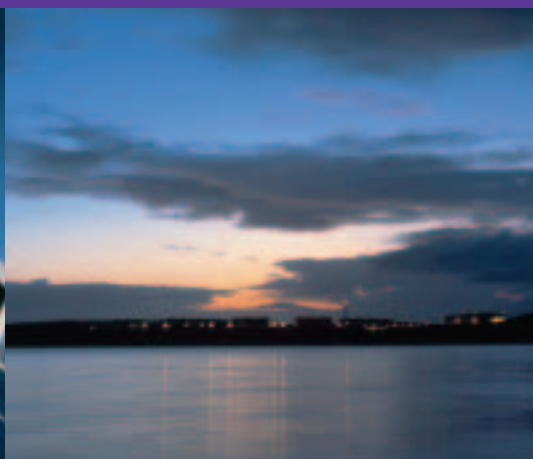


Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 1999*, DOE/EIA-0219(99) (Washington, DC, February 2001). **Projections:** EIA, *International Energy Outlook*, DOE/EIA-0484 (Washington, DC, various years).

Eastern Europe and the former Soviet Union was not predictable, and it dramatically affected the accuracy of the projections for the region. If higher economic growth rates had been assumed for China, more accurate forecasts for that region might have been achieved. It is important for users of the *IEO* or any other projection series to realize the limitations of the forecasts. Failing an ability to predict future volatility in social, political, or economic events, the projections should be used as a plausible path or trend for the future and not as a precise prediction of future events.



BP is one of the world's largest petroleum and petrochemicals companies. Our main activities are exploration for and production of crude oil and natural gas; oil refining, marketing, supply and transportation; and manufacturing and marketing of petrochemicals. We have a growing activity in gas, power and renewables and in solar power generation. BP has well-established operations in Europe, North and South America, Asia, Australasia and Africa.



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The BP Statistical Review of World Energy on bp.com

Our website contains all data found in the printed edition, plus a number of additions, including the historical series from 1965 for many sections. This year we have extra tables for coal, hydroelectricity and nuclear energy. The website provides additional tools and energy topics, including renewable energy, to assist researchers. All data can be downloaded.

foreword

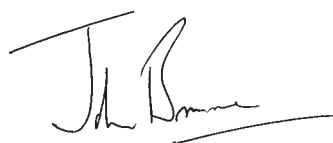
The volatility of energy markets in recent years and the current geopolitical situation have led to a renewed focus on energy policy and the central issue of energy security. An informed debate on this important subject requires a sound understanding of current energy markets and how those markets have evolved over time. This in turn requires ready access to a consistent and objective set of historical energy data.

It is therefore my pleasure to introduce the 51st edition of the BP Statistical Review of World Energy. Throughout its life, the Review has aimed to provide a comprehensive source of high-quality data for analysts, policy makers and all those with an interest in energy matters. Over time, the Review has tracked major changes in the structure of the energy business, the response of the markets to shocks such as the oil crises of the 1970s and the changing pattern of energy trade. I hope that it will continue to inform the ongoing energy debate.

As the data shows, 2001 was a volatile year in the world's energy markets, as a result both of the economic downturn and the horrific events of 11 September. Despite all the volatility, however, markets continued to operate effectively, demonstrating once again the value that flows from the maintenance of diverse sources of supply, particularly for oil and natural gas.

Production of a printed document such as this inevitably places limitations on the volume of data that can be shown. Electronic media impose fewer constraints. We have therefore made a more comprehensive data set available at www.bp.com/centres/energy/, with many of the series going back as far as 1965.

I would like to thank all those who have helped produce this Review and I hope that readers find it both useful and interesting.

A handwritten signature in black ink, appearing to read 'J. Browne', with a horizontal line extending from the end.

The Lord Browne of Madingley
Group Chief Executive
June 2002

bp statistical review of world energy

2001 in review



World consumption of primary energy increased only marginally in 2001, growing by 0.3%. 2001 was the third year since 1998 in which primary energy consumption increased by less than 0.5% year-on-year. The main cause of demand weakness in 2001 was the downturn in the world economy: world economic growth dropped to 1.5%, well below the 10-year (1991-2001) annual trend of 2.7%.

Energy developments

Analysed by fuel, coal and nuclear energy showed some relative strength in 2001, growing by 1.7% and 2.8% respectively, while hydroelectric power fell by a steep 3.7%. Oil and natural gas consumption was broadly flat, possibly reflecting the impact of continued high prices.

Analysed by region, energy demand was especially weak in the Americas and in most of Asia. This reflected economic developments during the year as the sharp deceleration in the US economy also affected that country's main trading partners. North American consumption fell year-on-year for the first time in a decade, declining by a sizeable 2.4%. Consumption in South and Central America decreased by 0.3%, compared with a 10-year annual trend growth of 3.2%. Asia (excluding China) recorded some growth in energy use, at 1.3%, but this was well below the 10-year annual trend rate of 3.4%.

China and the Former Soviet Union bucked the trend of relative demand weakness. Chinese energy use grew by a robust 4.3% as the recent trend of declining coal demand came to an abrupt end. Former Soviet Union consumption rose for a third consecutive year as economic recovery continued.

Oil

Brent oil prices averaged \$24.77 per barrel in 2001. This was lower than the \$28.98 recorded in 2000 but still well above the post-1986 average of around \$19 per barrel. Through a series of quota reductions, OPEC was successful in keeping prices (for the OPEC crude basket) within its \$22-28 target range through late September. However, the market could not sustain prices at these levels following the 11 September terrorist attacks on the

USA, which had a severe negative impact on oil demand. Brent prices hit a low point of \$16.54 per barrel in mid-November and averaged well under \$20 per barrel in the fourth quarter.

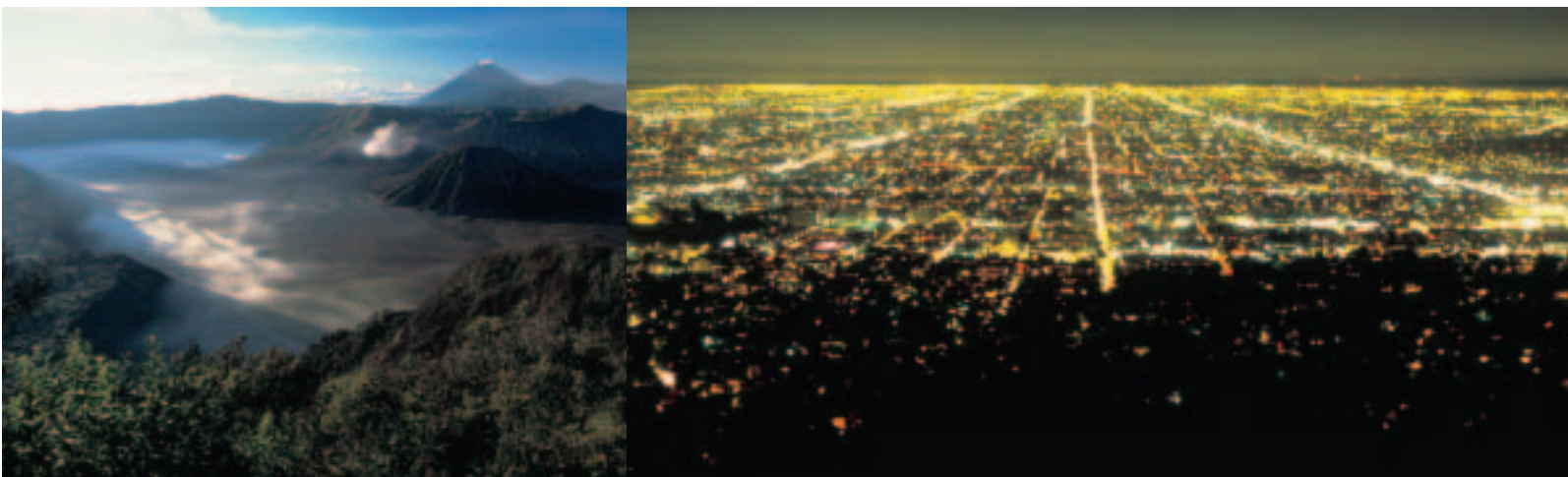
In total, OPEC oil production fell by 720,000 barrels per day (b/d) or 2.7% year-on-year. In percentage terms, the largest decrease was of 8.4% in Iraq, where UN-sanctioned exports were disrupted severely in January, June and December, following rollovers of the UN's 'Oil for Food' programme. In absolute terms, the largest fall was in Saudi Arabia, whose 350,000 b/d cut accounted for almost half the OPEC total.

The decline in OPEC oil production during 2001 was almost exactly offset by the increase in production outside OPEC. For the second consecutive year, Former Soviet Union production grew strongly, taking the two-year production increase to over one million b/d. Outside the Former Soviet Union, non-OPEC production grew by less than 100,000 b/d. Modest gains in Mexico, Brazil, Norway and Equatorial Guinea were largely offset by falls in Colombia, Australia and the UK.

World oil consumption in 2001 was down marginally on the year before: the first decline since 1993. Europe and Africa were the only regions to register consumption increases. Demand weakness was especially pronounced in Asia, where consumption fell 0.5% compared with a 10-year trend of 3.6% annual growth.

Natural gas

Consumption of natural gas grew by only 0.3% in 2001, a marked change from the 4.3% increase registered in 2000. The global picture was heavily influenced by developments in North America, where record high gas prices and the economic



downturn resulted in a sharp 5% consumption decrease. Consumption in all other regions increased, with Asia Pacific especially strong, up by 5%.

The decline in North American gas consumption was not matched on the production side. North American production rose 1.6%, stimulated by high prices. The rise in production allowed a rebuilding of US and Canadian gas inventories, which began the year at record lows but ended 2001 well above seasonal norms. The Middle East was the fastest-growing gas production region in 2001, driven by the expansion of Qatari and Omani liquefied natural gas exports.

Other fuels

World coal consumption increased by 1.7% in 2001, as Chinese demand grew strongly, following four years of decline, and strong increases were recorded in some other Asian countries. European coal use resumed its trend decline, falling 1.2%. US coal consumption fell 1.7%, reversing much of the strong growth seen during 2000.

Consumption of nuclear power rose in all regions except Africa, expanding by 2.8% globally, despite a very limited increase in nuclear generation capacity. Hydroelectric generation contracted by a sizeable 3.7%, reflecting sharp drops of 14.1% in North America and 11.7% in Brazil.

Methodological changes

Two major methodological changes have been made to this year's Review.

- The primary energy values of both nuclear and hydroelectric power generation have been derived by calculating the equivalent amount of fossil fuel required to generate the same volume of electricity in a thermal power station, assuming a conversion efficiency of 38% (the average for OECD thermal power generation). Previously, thermal equivalence was calculated for nuclear power only, using a lower conversion efficiency of 33%.
- Refinery gain and loss is no longer deducted from the US oil consumption figure, bringing the country into line with the rest of the world.

Acknowledgements

We express our gratitude to our numerous contacts worldwide who provide the basic data for this publication.

oil

proved reserves

	At end 1981 Thousand million barrels	At end 1991 Thousand million barrels	At end 2000 Thousand million barrels	Thousand million barrels	Thousand million tonnes	At end 2001 Share of total	R/P ratio
USA	36.5	33.7	30.1	30.4	3.7	2.9%	10.7
Canada	8.5	8.0	6.4	6.6	0.8	0.6%	8.8
Mexico	57.0	51.3	28.3	26.9	3.8	2.6%	21.7
Total North America	102.0	93.0	64.8	63.9	8.4	6.1%	13.5
Argentina	2.7	1.6	3.1	3.0	0.4	0.3%	10.1
Brazil	1.3	2.8	8.1	8.5	1.2	0.8%	17.5
Colombia	0.5	1.9	2.0	1.8	0.2	0.2%	7.7
Ecuador	0.9	1.6	2.1	2.1	0.3	0.2%	14.0
Peru	0.8	0.4	0.3	0.3	†	•	8.9
Trinidad & Tobago	0.6	0.5	0.7	0.7	0.1	0.1%	15.7
Venezuela	20.3	59.1	76.9	77.7	11.2	7.4%	63.5
Other S. & Cent. America	0.9	0.6	1.4	1.9	0.3	0.2%	38.6
Total S. & Cent. America	28.0	68.5	94.5	96.0	13.7	9.1%	38.8
Denmark	0.5	0.8	1.1	1.1	0.2	0.1%	8.9
Italy	0.6	0.7	0.6	0.6	0.1	0.1%	21.7
Norway	7.6	7.6	9.4	9.4	1.3	0.9%	7.8
Romania	n/a	1.2	1.4	1.0	0.1	0.1%	20.4
United Kingdom	14.8	4.0	5.0	4.9	0.7	0.5%	5.6
Other Europe	4.3	2.1	1.6	1.6	0.2	0.2%	13.7
Total Europe	27.9	16.3	19.2	18.7	2.5	1.8%	7.8
Azerbaijan	n/a	n/a	6.9	7.0	1.0	0.7%	64.3
Kazakhstan	n/a	n/a	8.0	8.0	1.1	0.8%	27.6
Russian Federation	n/a	n/a	48.6	48.6	6.7	4.6%	19.1
Turkmenistan	n/a	n/a	0.5	0.5	0.1	0.1%	9.3
Uzbekistan	n/a	n/a	0.6	0.6	0.1	0.1%	11.2
Other Former Soviet Union	n/a	n/a	0.7	0.7	0.1	0.1%	15.2
Total Former Soviet Union	63.0	57.0	65.3	65.4	9.0	6.2%	21.1
Iran	57.0	92.9	89.7	89.7	12.3	8.5%	67.4
Iraq	29.7	100.0	112.5	112.5	15.2	10.7%	*
Kuwait	67.7	96.5	96.5	96.5	13.3	9.2%	*
Oman	2.6	4.3	5.5	5.5	0.7	0.5%	15.8
Qatar	3.4	3.7	13.2	15.2	2.0	1.4%	55.5
Saudi Arabia	167.9	260.3	261.7	261.8	36.0	24.9%	85.0
Syria	1.9	1.7	2.5	2.5	0.3	0.2%	12.5
United Arab Emirates	32.2	98.1	97.8	97.8	13.0	9.3%	*
Yemen	–	4.0	4.0	4.0	0.5	0.4%	24.2
Other Middle East	0.2	0.1	0.2	0.1	†	•	7.8
Total Middle East	362.6	661.6	683.5	685.6	93.4	65.3%	86.8
Algeria	8.1	9.2	9.2	9.2	1.2	0.9%	17.6
Angola	1.5	1.8	5.4	5.4	0.7	0.5%	20.3
Cameroon	0.5	0.4	0.4	0.4	0.1	•	13.7
Republic of Congo (Brazzaville)	1.3	0.8	1.5	1.5	0.2	0.1%	15.2
Egypt	2.9	4.5	2.9	2.9	0.4	0.3%	11.1
Gabon	0.5	0.7	2.5	2.5	0.3	0.2%	22.8
Libya	22.6	22.8	29.5	29.5	3.8	2.8%	57.3
Nigeria	16.5	17.9	22.5	24.0	3.2	2.3%	30.8
Tunisia	1.7	1.7	0.3	0.3	†	•	11.6
Other Africa	0.7	0.6	0.6	0.9	0.1	0.1%	5.4
Total Africa	56.2	60.5	74.9	76.7	10.2	7.3%	27.4
Australia	1.7	1.5	2.9	3.5	0.4	0.3%	14.0
Brunei	1.6	1.4	1.4	1.4	0.2	0.1%	19.4
China	19.9	24.0	24.0	24.0	3.3	2.3%	19.9
India	2.7	6.1	4.7	4.8	0.6	0.5%	17.8
Indonesia	9.8	6.6	5.0	5.0	0.7	0.5%	10.1
Malaysia	2.8	3.0	3.9	3.0	0.4	0.3%	11.2
Papua New Guinea	–	0.2	0.4	0.2	†	•	11.5
Thailand	–	0.3	0.4	0.5	0.1	•	9.5
Vietnam	–	0.5	0.6	0.6	0.1	0.1%	4.7
Other Asia Pacific	0.5	0.5	0.8	0.7	0.1	0.1%	14.7
Total Asia Pacific	39.0	44.1	44.0	43.8	5.9	4.2%	15.6
TOTAL WORLD	678.7	1000.9	1046.2	1050.0	143.0	100.0%	40.3
of which: OECD#	128.9	109.5	85.3	85.0	11.2	8.1%	11.5
OPEC	435.2	767.1	814.4	818.8	111.8	78.0%	76.6
Non-OPEC‡	180.5	176.8	166.5	165.8	22.2	15.8%	13.3

*Over 100 years.

†Less than 0.05.

•Less than 0.05%.

‡Excludes Former Soviet Union.

#1981 excludes Central European members.

n/a not available.

Notes:

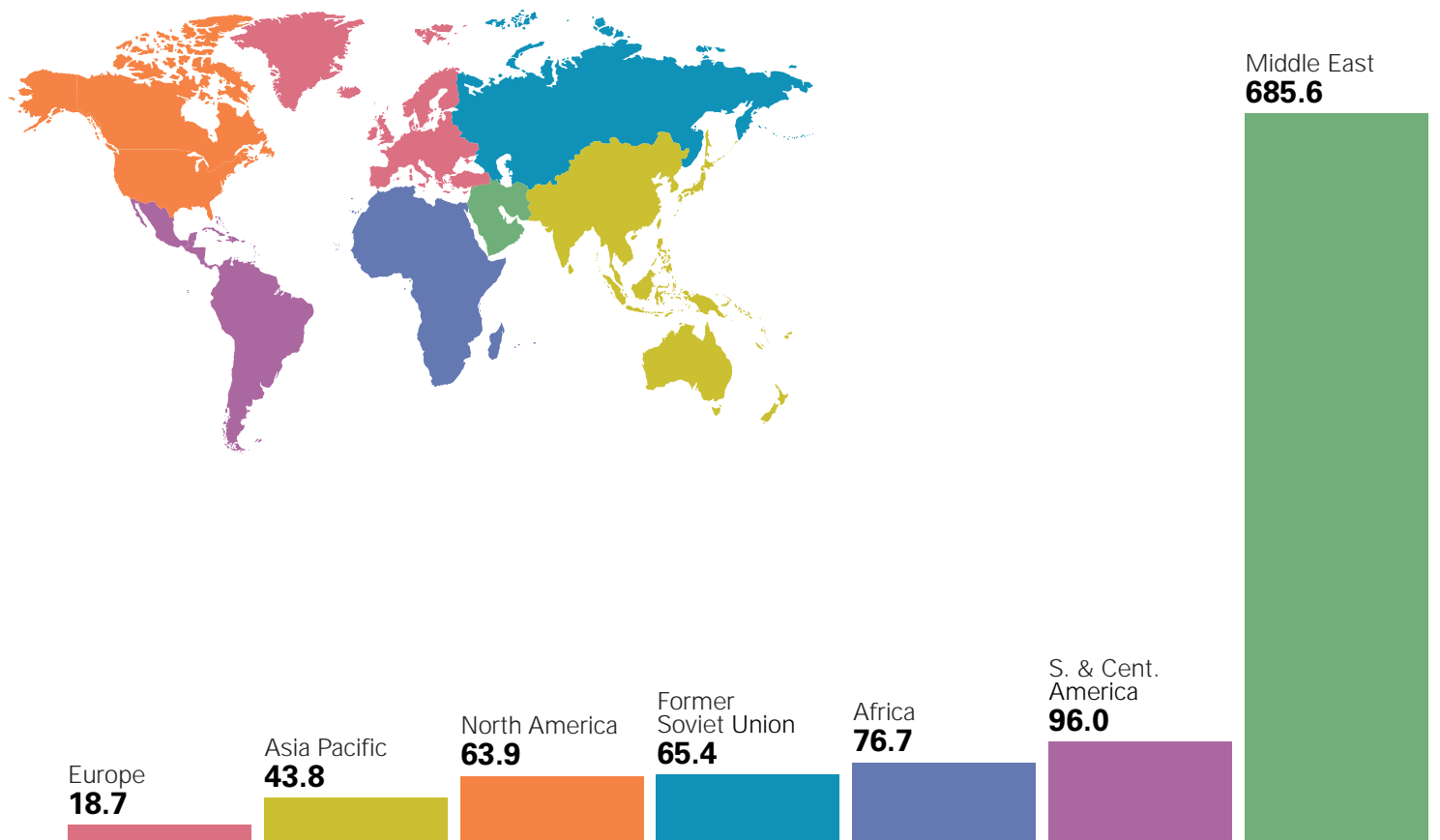
Proved reserves of oil – Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

Reserves/Production (R/P) ratio – If the reserves remaining at the end of any year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level.

Source of data – With the exception of Azerbaijan and Kazakhstan, the estimates contained in this table are those published by the Oil and Gas Journal, plus an estimate of natural gas liquids for USA and Canada. Reserves of shale oil and oil sands are not included.

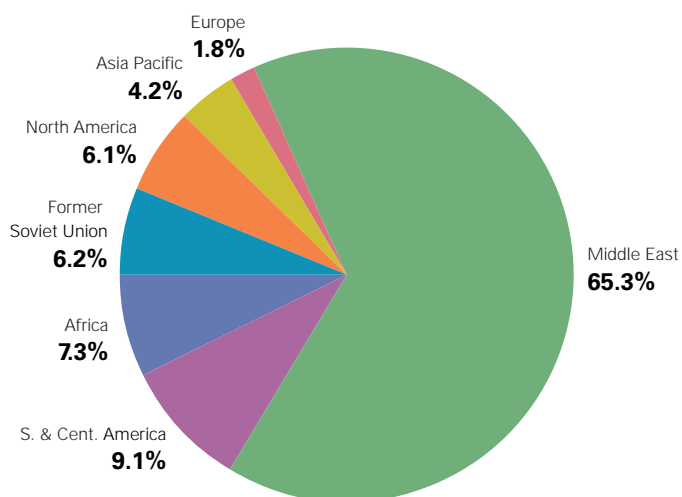
proved reserves at end 2001

Thousand million barrels



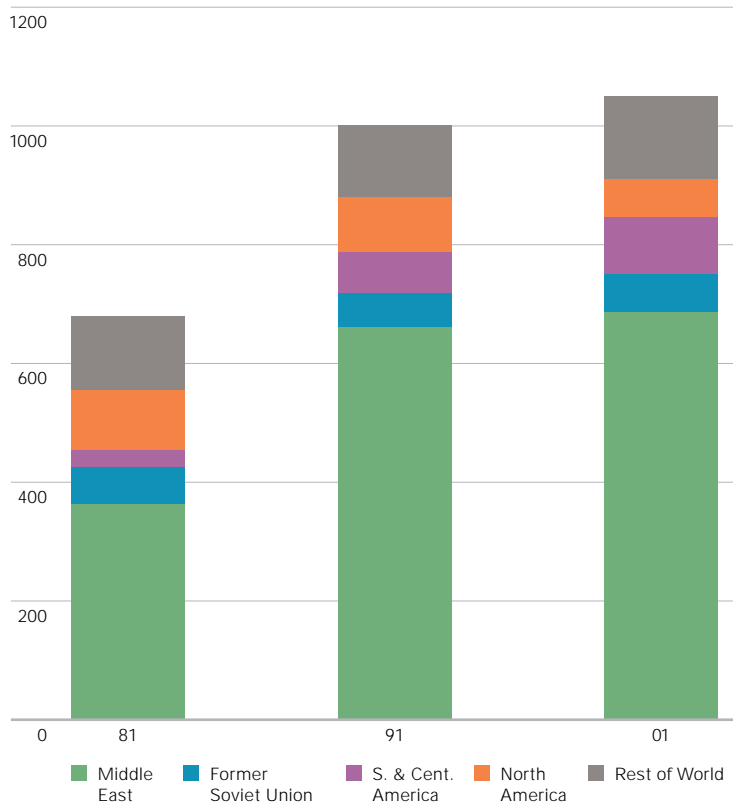
distribution of proved reserves 2001

Thousand million barrels %



proved reserves

Thousand million barrels





production*

Thousand barrels daily	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	9076	8868	8583	8389	8322	8295	8269	8011	7731	7733	7717	-0.3%	9.8%
Canada	1980	2062	2184	2276	2402	2480	2588	2672	2604	2721	2763	1.7%	3.6%
Mexico	3126	3120	3132	3142	3065	3277	3410	3499	3343	3450	3560	3.1%	4.9%
Total North America	14182	14050	13899	13807	13789	14052	14267	14182	13678	13904	14040	1.0%	18.3%
Argentina	526	587	630	695	758	823	877	889	843	811	822	1.1%	1.1%
Brazil	643	652	664	693	718	807	868	1003	1133	1268	1337	5.0%	1.9%
Colombia	430	442	458	460	591	635	667	775	838	711	627	-12.1%	0.9%
Ecuador	307	328	353	388	395	393	397	384	382	409	416	1.4%	0.6%
Peru	116	117	127	128	123	121	120	119	117	100	102	0.5%	0.1%
Trinidad & Tobago	149	144	134	141	142	141	135	134	141	139	135	-4.3%	0.2%
Venezuela	2501	2499	2592	2752	2959	3137	3321	3512	3249	3321	3418	2.7%	4.9%
Other S. & Cent. America	77	76	83	90	96	98	107	122	127	134	144	7.1%	0.2%
Total S. & Cent. America	4749	4845	5040	5347	5782	6155	6492	6938	6830	6894	7001	1.3%	9.9%
Denmark	141	156	167	184	185	204	229	231	296	359	342	-4.9%	0.5%
Italy	83	86	89	94	101	104	114	108	96	88	79	-10.7%	0.1%
Norway	1923	2198	2359	2692	2889	3234	3279	3136	3132	3347	3414	1.0%	4.5%
Romania	146	142	144	145	145	142	141	137	133	131	130	-0.7%	0.2%
United Kingdom	1919	1981	2119	2675	2749	2735	2713	2805	2903	2667	2503	-6.6%	3.3%
Other Europe	505	494	462	471	442	411	387	372	344	336	341	0.8%	0.5%
Total Europe	4718	5057	5341	6261	6511	6831	6863	6788	6905	6927	6808	-2.4%	9.0%
Azerbaijan	238	226	209	193	185	183	185	230	278	281	300	6.6%	0.4%
Kazakhstan	569	549	490	430	434	474	536	537	631	744	828	12.4%	1.1%
Russian Federation	9326	8038	7173	6419	6288	6114	6227	6169	6178	6536	7056	7.7%	9.7%
Turkmenistan	113	109	92	87	84	90	108	129	143	144	162	12.0%	0.2%
Uzbekistan	69	79	94	124	172	174	182	191	191	177	172	-3.2%	0.2%
Other Former Soviet Union	157	147	139	138	134	137	139	135	131	131	134	2.3%	0.2%
Total Former Soviet Union	10472	9149	8196	7391	7297	7171	7377	7391	7551	8013	8652	7.8%	11.8%
Iran	3500	3523	3683	3692	3695	3709	3726	3803	3552	3772	3688	-2.6%	5.1%
Iraq	279	526	465	522	575	625	1201	2162	2581	2624	2414	-8.4%	3.3%
Kuwait	185	1097	1966	2100	2135	2126	2139	2199	2038	2169	2142	-1.7%	2.9%
Oman	716	748	785	819	868	897	909	905	911	961	959	-0.5%	1.3%
Qatar	420	495	460	451	461	568	694	747	724	796	783	-2.3%	1.0%
Saudi Arabia	8820	9098	8962	8873	8890	9036	9213	9219	8549	9115	8768	-4.2%	11.8%
Syria	472	518	570	568	603	591	582	581	584	555	551	-1.1%	0.8%
United Arab Emirates	2639	2510	2443	2482	2410	2495	2490	2556	2299	2491	2422	-3.2%	3.2%
Yemen	197	184	209	346	351	357	375	382	396	438	458	4.2%	0.6%
Other Middle East	53	54	53	52	52	50	50	49	48	49	49	-0.3%	0.1%
Total Middle East	17280	18754	19597	19905	20040	20454	21378	22603	21681	22970	22233	-3.6%	30.0%
Algeria	1351	1323	1329	1324	1327	1386	1421	1461	1515	1579	1563	-1.6%	1.8%
Angola	498	550	504	557	633	716	741	731	745	736	731	-1.0%	1.0%
Cameroon	143	134	130	115	106	110	124	105	95	88	80	-9.3%	0.1%
Republic of Congo (Brazzaville)	156	167	185	185	180	200	225	264	293	275	271	-1.8%	0.4%
Egypt	896	906	941	921	924	894	873	857	827	781	758	-3.8%	1.0%
Equatorial Guinea	-	2	5	5	7	17	60	83	100	113	181	60.1%	0.3%
Gabon	295	289	305	337	356	365	364	337	340	327	301	-8.2%	0.4%
Libya	1439	1473	1402	1431	1439	1452	1489	1480	1425	1475	1425	-3.7%	1.9%
Nigeria	1890	1950	1985	1988	1998	2138	2303	2163	2028	2103	2148	1.9%	2.9%
Tunisia	110	110	99	93	90	89	81	85	86	80	73	-9.1%	0.1%
Other Africa	33	29	38	44	53	68	73	75	120	238	284	19.0%	0.4%
Total Africa	6810	6933	6922	7001	7112	7435	7753	7640	7574	7795	7814	-0.1%	10.3%
Australia	606	598	566	611	583	610	668	644	577	812	733	-10.1%	0.9%
Brunei	164	182	175	179	175	165	163	157	182	193	195	0.8%	0.3%
China	2828	2841	2888	2930	2989	3170	3211	3212	3213	3252	3308	1.4%	4.6%
India	703	643	620	707	794	782	800	800	788	778	782	♦	1.0%
Indonesia	1669	1579	1588	1589	1578	1580	1557	1520	1408	1456	1410	-4.1%	1.9%
Malaysia	660	670	662	674	724	736	764	815	791	791	788	-1.1%	1.0%
Papua New Guinea	-	53	126	121	100	106	76	81	88	69	57	-17.6%	0.1%
Thailand	75	83	87	87	87	97	116	121	132	164	178	6.7%	0.2%
Vietnam	80	111	128	144	155	179	205	245	296	328	350	5.4%	0.5%
Other Asia Pacific	148	159	156	143	136	145	158	143	137	136	143	5.2%	0.2%
Total Asia Pacific	6933	6918	6996	7185	7320	7570	7718	7739	7612	7980	7943	-0.9%	10.6%
TOTAL WORLD	65144	65705	65990	66897	67851	69668	71848	73280	71832	74482	74493	-0.3%	100.0%
of which: OECD	19354	19549	19650	20526	20726	21350	21675	21487	21039	21523	21462	-0.5%	28.1%
OPEC	24692	26074	26875	27204	27466	28252	29553	30821	29368	30901	30181	-2.7%	40.7%
Non-OPEC†	29980	30483	30919	32301	33088	34245	34918	35068	34913	35569	35660	♦	47.4%

*Includes crude oil, shale oil, oil sands and NGLs (natural gas liquids – the liquid content of natural gas where this is recovered separately).

Excludes liquid fuels from other sources such as coal derivatives.

♦Less than 0.05%.

†Excludes Former Soviet Union.

Note: Annual changes and shares of total are calculated using million tonnes per annum figures rather than thousand barrels daily. Because of rounding some totals may not agree exactly with the sum of their component parts.

production*

Million tonnes	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	422.9	413.0	397.0	387.5	383.6	382.1	380.0	368.1	352.6	352.6	351.7	-0.3%	9.8%
Canada	93.0	97.0	102.0	106.4	111.9	115.5	120.7	125.1	121.0	126.9	129.1	1.7%	3.6%
Mexico	153.7	153.7	153.8	154.4	150.5	162.6	169.7	173.5	165.2	171.2	176.6	3.1%	4.9%
Total North America	669.6	663.7	652.9	648.3	646.0	660.1	670.4	666.7	638.8	650.8	657.4	1.0%	18.3%
Argentina	25.9	29.0	31.1	34.5	37.5	40.8	43.4	44.0	41.7	40.2	40.6	1.1%	1.1%
Brazil	31.9	32.3	32.9	34.3	35.5	40.2	43.1	49.8	56.3	63.2	66.3	5.0%	1.9%
Colombia	21.5	22.2	22.9	23.0	29.5	31.8	33.2	38.5	41.6	35.3	31.0	-12.1%	0.9%
Ecuador	15.6	16.7	17.9	19.7	20.1	20.0	20.2	19.5	19.4	20.9	21.2	1.4%	0.6%
Peru	5.7	5.8	6.3	6.3	6.1	6.0	5.9	5.8	5.7	4.9	4.9	0.5%	0.1%
Trinidad & Tobago	7.6	7.3	6.8	7.1	7.0	7.0	6.7	6.7	7.0	6.8	6.5	-4.3%	0.2%
Venezuela	129.3	129.6	134.0	142.0	152.4	162.2	171.4	181.0	167.1	171.6	176.2	2.7%	4.9%
Other S. & Cent. America	3.6	3.6	3.9	4.3	4.6	4.8	5.3	6.0	6.4	6.8	7.3	7.1%	0.2%
Total S. & Cent. America	241.0	246.5	255.7	271.2	292.8	312.7	329.1	351.4	345.1	349.6	354.0	1.3%	9.9%
Denmark	7.0	7.8	8.3	9.1	9.2	10.1	11.4	11.4	14.7	17.8	16.9	-4.9%	0.5%
Italy	4.3	4.5	4.6	4.9	5.2	5.5	6.0	5.6	5.0	4.6	4.1	-10.7%	0.1%
Norway	93.3	106.9	114.1	129.4	138.5	155.5	156.9	150.0	149.4	160.5	162.1	1.0%	4.5%
Romania	7.0	6.8	6.9	7.0	7.0	6.9	6.8	6.6	6.4	6.3	6.2	-0.7%	0.2%
United Kingdom	91.3	94.3	100.2	126.5	129.9	129.7	128.2	132.5	137.1	126.2	117.9	-6.6%	3.3%
Other Europe	24.7	24.1	22.4	22.9	21.4	20.0	18.8	18.0	16.7	16.3	16.5	0.8%	0.5%
Total Europe	227.5	244.4	256.6	299.8	311.2	327.6	327.9	324.2	329.2	331.8	323.7	-2.4%	9.0%
Azerbaijan	11.7	11.1	10.3	9.6	9.2	9.1	9.2	11.4	13.8	14.0	14.9	6.6%	0.4%
Kazakhstan	26.6	25.8	23.0	20.3	20.6	23.0	25.8	25.9	30.1	35.3	39.7	12.4%	1.1%
Russian Federation	461.9	398.8	354.9	317.6	310.8	302.9	307.4	304.3	304.8	323.3	348.1	7.7%	9.7%
Turkmenistan	5.4	5.2	4.4	4.2	4.1	4.4	5.4	6.4	7.1	7.2	8.0	12.0%	0.2%
Uzbekistan	2.8	3.3	4.0	5.5	7.6	7.6	7.9	8.2	8.1	7.5	7.3	-3.2%	0.2%
Other Former Soviet Union	7.4	7.0	6.6	6.5	6.2	6.4	6.4	6.2	6.1	6.1	6.2	2.3%	0.2%
Total Former Soviet Union	515.8	451.2	403.2	363.7	358.4	353.3	362.0	362.5	369.9	393.3	424.2	7.8%	11.8%
Iran	174.4	175.7	183.2	183.6	183.7	184.8	185.1	188.9	176.2	187.7	182.9	-2.6%	5.1%
Iraq	13.7	26.0	22.7	25.3	27.4	30.0	58.3	105.6	126.1	128.6	117.9	-8.4%	3.3%
Kuwait	9.2	54.6	97.2	103.8	105.0	105.0	105.2	107.9	99.5	106.0	104.2	-1.7%	2.9%
Oman	35.3	37.0	38.8	40.5	42.8	44.4	44.9	44.7	45.0	47.6	47.4	-0.5%	1.3%
Qatar	19.7	22.8	21.1	20.6	21.1	26.2	32.2	34.6	33.4	36.8	36.0	-2.3%	1.0%
Saudi Arabia	428.4	442.4	432.8	427.7	428.3	436.3	443.8	444.5	411.9	441.4	422.9	-4.2%	11.8%
Syria	23.5	25.8	28.3	28.2	29.9	29.4	28.9	28.8	29.0	27.6	27.3	-1.1%	0.8%
United Arab Emirates	125.0	118.9	114.8	116.6	114.0	117.9	117.0	119.9	107.6	117.0	113.2	-3.2%	3.2%
Yemen	9.4	8.7	9.9	16.4	16.7	16.9	17.7	18.1	18.7	20.8	21.7	4.2%	0.6%
Other Middle East	2.5	2.5	2.5	2.4	2.4	2.3	2.3	2.3	2.2	2.3	2.3	-0.3%	0.1%
Total Middle East	841.0	914.4	951.2	965.1	971.2	993.2	1035.4	1095.2	1049.6	1115.8	1075.6	-3.6%	30.0%
Algeria	57.7	56.6	56.7	56.4	56.6	59.3	60.3	61.8	63.9	66.8	65.8	-1.6%	1.8%
Angola	24.5	27.2	24.8	27.4	31.2	35.4	36.5	36.0	36.7	36.4	36.0	-1.0%	1.0%
Cameroon	7.2	6.8	6.6	5.8	5.4	5.6	6.3	5.3	4.8	4.5	4.1	-9.3%	0.1%
Republic of Congo (Brazzaville)	8.1	8.6	9.5	9.6	9.3	10.4	11.6	13.6	15.1	14.2	14.0	-1.8%	0.4%
Egypt	45.4	46.0	47.5	46.5	46.6	45.1	43.8	43.0	41.4	38.8	37.3	-3.8%	1.0%
Equatorial Guinea	-	0.1	0.2	0.2	0.3	0.9	3.0	4.1	5.0	5.6	9.0	60.1%	0.3%
Gabon	14.7	14.5	15.2	16.8	17.8	18.3	18.2	16.9	17.0	16.4	15.0	-8.2%	0.4%
Libya	67.9	69.7	66.1	67.5	67.9	68.6	70.0	69.6	67.0	69.5	67.0	-3.7%	1.9%
Nigeria	93.1	96.3	97.1	97.0	97.5	104.7	112.7	105.9	99.2	103.3	105.2	1.9%	2.9%
Tunisia	5.2	5.2	4.7	4.4	4.3	4.2	3.8	4.0	4.1	3.8	3.4	-9.1%	0.1%
Other Africa	1.7	1.5	1.8	2.1	2.6	3.3	3.6	3.6	5.9	11.7	13.9	19.0%	0.4%
Total Africa	325.5	332.4	330.4	333.8	339.3	355.7	369.7	363.7	360.0	370.9	370.7	-0.1%	10.3%
Australia	26.9	26.5	24.9	26.9	25.4	26.6	28.8	27.4	24.5	35.4	31.8	-10.1%	0.9%
Brunei	7.9	8.9	8.5	8.7	8.5	8.0	7.9	7.6	8.9	9.4	9.5	0.8%	0.3%
China	141.0	142.0	144.0	146.1	149.0	158.5	160.1	160.2	160.2	162.6	164.9	1.4%	4.6%
India	33.1	30.2	29.0	33.2	37.3	36.5	37.3	37.0	36.5	36.1	36.1	♦	1.0%
Indonesia	81.0	76.7	76.9	76.9	76.5	76.7	75.7	74.2	68.6	71.5	68.6	-4.1%	1.9%
Malaysia	31.2	31.7	31.1	31.7	34.0	34.4	35.1	36.9	35.6	35.5	35.1	-1.1%	1.0%
Papua New Guinea	-	2.5	5.9	5.7	4.7	5.0	3.5	3.8	4.1	3.2	2.7	-17.6%	0.1%
Thailand	3.0	3.3	3.4	3.5	3.4	3.8	4.5	4.7	5.2	6.6	7.1	6.7%	0.2%
Vietnam	4.0	5.5	6.3	7.1	7.7	8.9	10.1	12.1	14.6	16.2	17.1	5.4%	0.5%
Other Asia Pacific	6.9	7.4	7.3	6.6	6.3	6.7	7.3	6.6	6.3	6.3	6.6	5.2%	0.2%
Total Asia Pacific	334.9	334.7	337.1	346.3	352.6	365.2	370.3	370.5	364.4	382.9	379.4	-0.9%	10.6%
TOTAL WORLD	3155.5	3187.3	3187.0	3228.0	3271.6	3367.8	3464.9	3534.1	3457.0	3595.0	3584.9	-0.3%	100.0%
of which: OECD	916.5	926.8	926.6	967.3	974.9	1007.3	1020.9	1011.9	986.5	1011.9	1006.9	-0.5%	28.1%
OPEC	1199.3	1269.3	1302.5	1317.5	1330.3	1371.7	1431.8	1493.8	1420.5	1500.2	1459.7	-2.7%	40.7%
Non-OPEC‡	1440.4	1466.8	1481.3	1546.9	1582.8	1642.8	1671.1	1677.8	1666.6	1701.5	1701.0	♦	47.4%

*Includes crude oil, shale oil, oil sands and NGLs (natural gas liquids – the liquid content of natural gas where this is recovered separately).

Excludes liquid fuels from other sources such as coal derivatives.

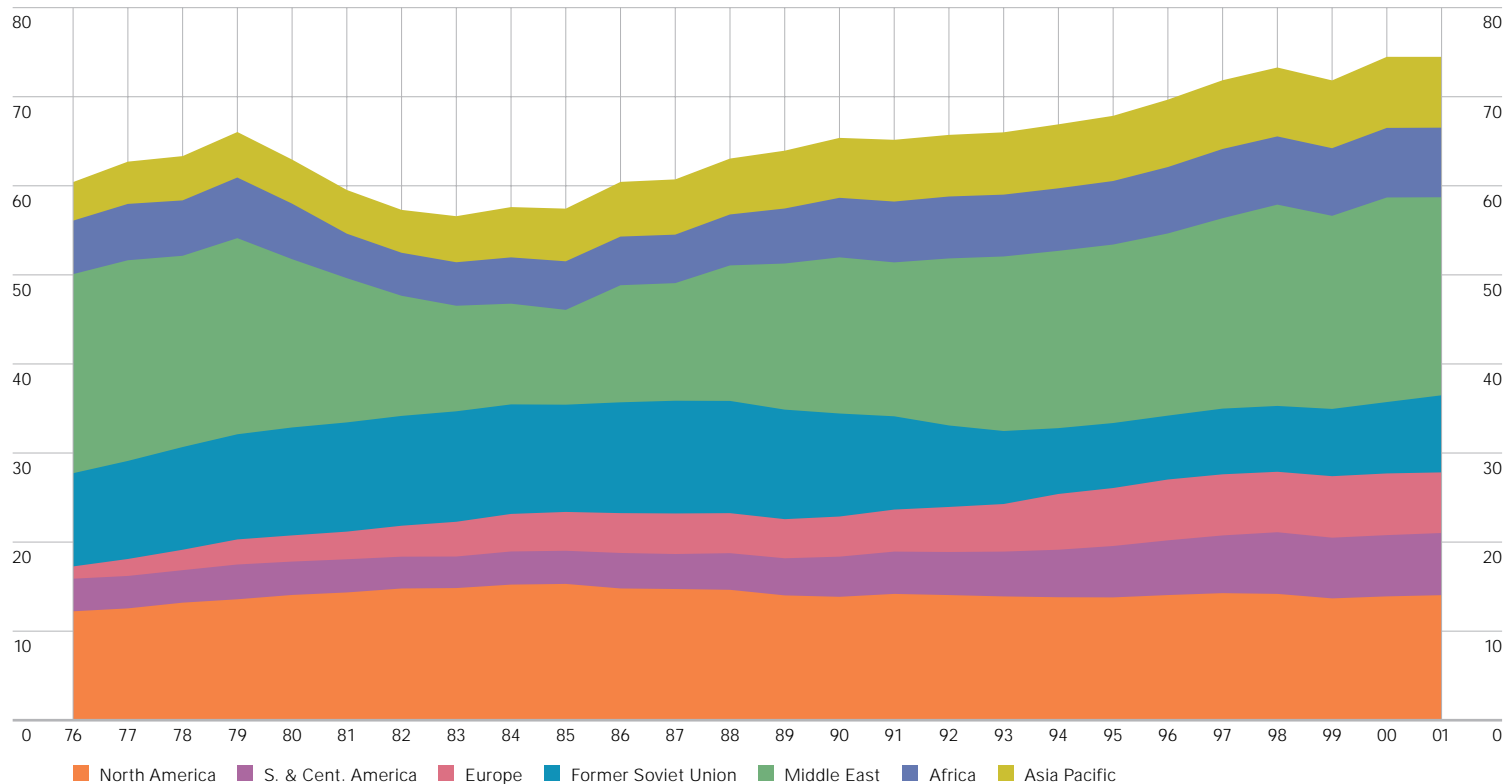
♦Less than 0.05%.

‡Excludes Former Soviet Union.

Note: Because of rounding some totals may not agree exactly with the sum of their component parts.

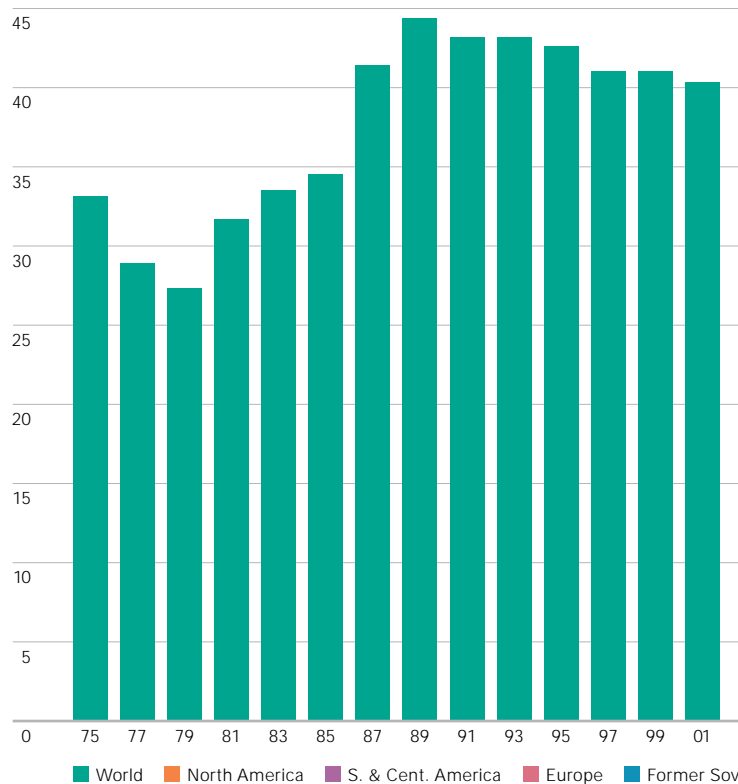
production by area

Million barrels daily

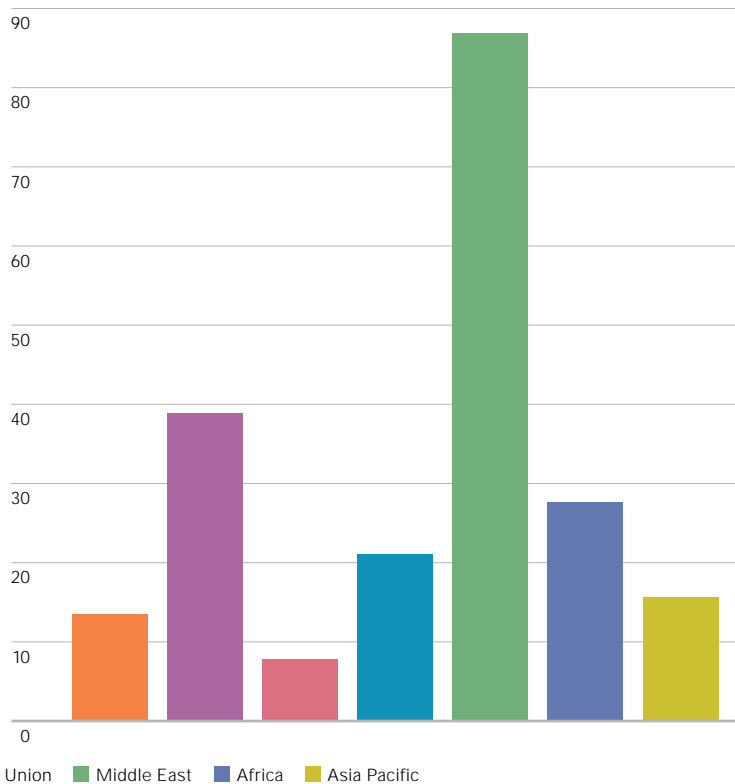


R/P ratios

World – Reserves to production ratio



2001 by area – Reserves to production ratio



The world's oil R/P ratio increased in 2001 as global oil production fell slightly and reserves increased modestly. However, at 40.3, the R/P ratio was still somewhat down on the 43.2 years of a decade ago.

consumption*

Thousand barrels daily	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	16713	17033	17236	17719	17725	18309	18621	18917	19519	19701	19633	-0.2%	25.5%
Canada	1673	1703	1712	1742	1776	1818	1888	1913	1926	1937	1941	-0.1%	2.5%
Mexico	1522	1543	1549	1685	1561	1608	1682	1763	1765	1835	1813	-1.7%	2.4%
Total North America	19908	20279	20498	21145	21061	21736	22191	22593	23210	23473	23386	-0.3%	30.4%
Argentina	411	417	418	416	415	432	451	467	445	431	404	-6.2%	0.5%
Brazil	1289	1328	1354	1418	1498	1601	1729	1800	1879	1867	1865	-0.4%	2.4%
Chile	148	159	174	190	209	228	245	247	253	256	262	2.0%	0.3%
Colombia	213	233	238	246	260	268	272	266	238	232	220	-5.6%	0.3%
Ecuador	104	101	106	115	112	125	142	145	131	129	132	2.3%	0.2%
Peru	111	116	120	130	148	152	152	154	157	153	145	-5.8%	0.2%
Venezuela	405	431	430	436	446	426	452	475	474	496	491	-1.3%	0.6%
Other S. & Cent. America	915	936	963	1022	1073	1095	1125	1154	1168	1168	1175	0.2%	1.6%
Total S. & Cent. America	3596	3722	3801	3973	4162	4327	4568	4709	4745	4732	4693	-1.1%	6.2%
Austria	241	235	237	235	234	242	246	255	250	244	257	5.3%	0.4%
Belgium & Luxembourg	544	558	546	556	546	606	629	656	670	702	672	-4.6%	0.9%
Bulgaria	118	121	127	118	115	114	92	100	93	95	96	1.5%	0.1%
Czech Republic	145	140	142	149	169	177	170	174	174	169	178	5.1%	0.2%
Denmark	187	186	196	209	217	235	229	223	222	215	211	-2.4%	0.3%
Finland	221	216	206	216	208	216	213	221	224	224	222	-1.5%	0.3%
France	2018	2011	1940	1878	1893	1930	1948	2016	2044	2007	2032	0.9%	2.7%
Germany	2833	2849	2904	2880	2882	2921	2913	2915	2824	2763	2804	1.4%	3.7%
Greece	323	329	342	346	361	372	379	374	383	406	396	-2.8%	0.6%
Hungary	169	170	162	169	159	148	150	157	151	145	144	-1.2%	0.2%
Iceland	13	14	15	15	16	16	18	18	18	19	19	2.4%	♦
Republic of Ireland	100	105	106	116	118	124	136	152	172	170	181	6.3%	0.2%
Italy	1918	1950	1924	1920	1987	1956	1969	1974	1980	1956	1946	-0.8%	2.6%
Netherlands	767	793	788	792	828	810	856	854	880	899	948	5.3%	1.3%
Norway	193	196	210	212	212	218	223	215	216	201	213	2.9%	0.3%
Poland	313	288	296	314	321	368	391	424	431	427	407	-4.8%	0.5%
Portugal	239	265	252	253	270	256	290	315	321	312	318	1.7%	0.4%
Romania	309	258	242	226	274	260	276	242	195	203	207	1.4%	0.3%
Slovakia	89	81	67	70	69	71	72	80	73	73	73	-0.9%	0.1%
Spain	1056	1113	1079	1120	1177	1221	1290	1381	1423	1452	1508	3.9%	2.1%
Sweden	326	343	335	354	338	362	336	338	337	318	326	2.5%	0.4%
Switzerland	277	281	264	272	253	261	276	279	271	263	280	6.9%	0.4%
Turkey	469	499	574	553	610	635	646	640	638	695	662	-3.9%	0.9%
United Kingdom	1758	1775	1791	1777	1757	1798	1752	1745	1727	1684	1649	-2.3%	2.2%
Other Europe	349	264	276	267	282	314	340	347	345	336	346	2.8%	0.5%
Total Europe	14976	15038	15022	15019	15295	15633	15839	16092	16063	15975	16093	0.6%	21.7%
Azerbaijan	165	162	165	163	171	140	120	151	149	124	92	-25.8%	0.1%
Belarus	482	425	281	257	247	186	193	167	139	122	118	-3.3%	0.2%
Kazakhstan	436	407	315	247	242	204	207	165	133	140	155	10.0%	0.2%
Lithuania	165	90	78	72	64	66	66	76	63	49	57	15.9%	0.1%
Russian Federation	4888	4494	3788	3267	2934	2606	2593	2484	2534	2474	2456	-1.0%	3.5%
Turkmenistan	100	98	64	74	78	60	60	56	50	46	48	4.3%	0.1%
Ukraine	1155	853	498	398	380	284	277	287	255	240	255	5.8%	0.4%
Uzbekistan	221	182	163	145	134	148	135	141	143	128	131	1.6%	0.2%
Other Former Soviet Union	369	257	185	121	108	84	100	100	91	88	94	7.2%	0.1%
Total Former Soviet Union	7980	6969	5536	4744	4357	3779	3751	3626	3556	3412	3407	-0.4%	4.8%
Iran	995	1017	1044	1099	1204	1248	1221	1160	1192	1158	1131	-3.4%	1.5%
Kuwait	72	110	102	124	130	126	139	180	202	202	206	1.6%	0.3%
Qatar	18	17	17	19	21	23	25	26	24	25	30	19.7%	♦
Saudi Arabia	1174	1095	1116	1160	1123	1163	1199	1267	1306	1333	1347	0.5%	1.8%
United Arab Emirates	318	326	335	353	349	344	317	235	257	280	282	0.6%	0.4%
Other Middle East	921	1005	1090	1135	1202	1207	1261	1293	1301	1309	1309	-0.3%	1.8%
Total Middle East	3497	3571	3704	3891	4028	4110	4161	4161	4283	4307	4306	-0.6%	5.9%
Algeria	209	211	210	204	198	187	187	194	187	192	200	3.5%	0.3%
Egypt	470	457	438	437	474	501	531	559	573	564	551	-3.5%	0.7%
South Africa	359	369	383	401	427	437	445	451	462	475	488	2.1%	0.7%
Other Africa	956	1006	1041	1088	1099	1115	1144	1180	1216	1224	1251	1.9%	1.7%
Total Africa	1994	2043	2073	2130	2198	2240	2307	2385	2439	2455	2490	0.8%	3.3%
Australia	676	679	720	753	781	794	823	825	843	837	845	1.0%	1.1%
Bangladesh	35	38	43	45	59	60	69	76	70	70	71	1.0%	0.1%
China	2411	2662	2913	3145	3390	3672	3935	4047	4416	4985	5041	0.8%	6.6%
China Hong Kong SAR	131	167	174	185	198	194	192	184	193	201	198	-2.1%	0.3%
India	1233	1296	1313	1413	1533	1663	1753	1835	2016	2067	2072	-0.4%	2.8%
Indonesia	669	729	782	774	820	888	963	914	980	1053	1095	3.7%	1.5%
Japan	5410	5521	5440	5745	5784	5812	5761	5525	5618	5576	5427	-3.2%	7.0%
Malaysia	292	296	330	372	381	405	431	407	439	441	407	-8.8%	0.5%
New Zealand	105	111	112	121	125	127	131	131	134	134	134	-0.4%	0.2%
Pakistan	230	249	272	291	315	329	339	350	363	373	377	0.7%	0.5%
Philippines	227	278	290	306	344	360	389	392	375	348	347	-0.5%	0.5%
Singapore	457	474	516	590	617	586	630	651	619	654	726	10.2%	1.1%
South Korea	1254	1518	1675	1840	2009	2144	2373	2030	2178	2229	2235	-0.1%	2.9%
Taiwan	566	583	620	665	713	717	741	766	820	816	776	-5.2%	1.1%
Thailand	446	489	556	617	717	776	785	736	734	725	714	-2.8%	1.0%
Other Asia Pacific	238	260	282	294	310	344	368	383	400	432	453	4.4%	0.6%
Total Asia Pacific	14379	15350	16038	17155	18094	18868	19680	19250	20200	20941	20916	-0.5%	27.7%
TOTAL WORLD	66331	66972	66671	68058	69195	70692	72496	72815	74495	75295	75291	-0.2%	100.0%
of which: European Union 15	12533	12726	12646	12654	12816	13049	13186	13417	13457	13350	13469	0.7%	18.2%
OECD	41555	42503	42822	44012	44383	45556	46409	46508	47412	47589	47471	-0.4%	62.4%
Former Soviet Union	7980	6969	5536	4744	4357	3779	3751	3626	3556	3412	3407	-0.4%	4.8%
Other EMEs	16796	17501	18313	19302	20455	21357	22336	22682	23527	24294	24413	♦	32.8%

*Inland demand plus international aviation and marine bunkers and refinery fuel and loss.

♦Less than 0.05%.

Note: Differences between these world consumption figures and world production statistics on page 6 are accounted for by stock changes, consumption of non-petroleum additives and substitute fuels, and unavoidable disparities in the definition, measurement or conversion of oil supply and demand data. Annual changes and shares of total are calculated using million tonnes per annum figures rather than thousand barrels daily. The US volumetric consumption levels include no adjustment for processing gain (see 'definitions' on the inside back cover).



consumption*

Million tonnes	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	765.6	782.2	789.3	809.8	807.7	836.5	848.0	863.8	888.9	897.6	895.6	-0.2%	25.5%
Canada	75.3	76.8	77.1	78.4	79.8	82.1	85.2	86.7	87.2	88.1	88.0	-0.1%	2.5%
Mexico	70.4	71.2	71.0	77.8	71.4	73.8	77.3	81.2	80.8	84.1	82.7	-1.7%	2.4%
Total North America	911.3	930.2	937.4	966.0	958.9	992.4	1010.5	1031.7	1056.9	1069.8	1066.3	-0.3%	30.4%
Argentina	19.4	19.6	19.6	19.4	19.5	20.4	21.2	22.1	21.0	20.3	19.0	-6.2%	0.5%
Brazil	59.0	62.1	62.9	65.7	69.2	74.1	79.9	83.2	85.7	85.4	85.1	-0.4%	2.4%
Chile	6.8	7.4	8.0	8.8	9.7	10.6	11.4	11.4	11.7	11.8	12.0	2.0%	0.3%
Colombia	9.6	10.6	10.8	11.1	11.8	12.2	12.3	12.0	10.6	10.5	9.9	-5.6%	0.3%
Ecuador	4.7	4.6	4.8	5.2	5.1	5.7	6.5	6.6	6.0	5.8	5.9	2.3%	0.2%
Peru	5.3	5.5	5.7	6.2	7.1	7.3	7.2	7.3	7.4	7.3	6.8	-5.8%	0.2%
Venezuela	18.6	19.7	19.4	19.6	20.0	19.0	20.4	21.6	21.3	22.5	22.2	-1.3%	0.6%
Other S. & Cent. America	44.9	46.1	47.3	50.2	52.7	53.9	55.3	56.7	57.3	57.4	57.5	0.2%	1.6%
Total S. & Cent. America	168.3	175.6	178.5	186.2	195.1	203.2	214.2	220.9	221.0	221.0	218.4	-1.1%	6.2%
Austria	11.6	11.3	11.4	11.3	11.3	11.6	11.9	12.3	12.1	11.8	12.4	5.3%	0.4%
Belgium & Luxembourg	26.5	27.1	26.5	27.0	26.4	29.4	30.3	31.6	32.4	33.9	32.3	-4.6%	0.9%
Bulgaria	5.9	6.0	6.2	5.8	5.6	5.5	4.4	4.8	4.5	4.5	4.6	1.5%	0.1%
Czech Republic	7.1	6.8	6.9	7.1	8.0	8.4	8.0	8.3	8.2	7.9	8.3	5.1%	0.2%
Denmark	9.1	9.0	9.5	10.1	10.5	11.4	11.1	10.7	10.6	10.4	10.1	-2.4%	0.3%
Finland	10.6	10.3	9.9	10.4	9.9	10.3	10.2	10.5	10.7	10.7	10.5	-1.5%	0.3%
France	94.6	94.4	91.1	88.2	89.0	91.0	91.7	95.0	96.4	94.9	95.8	0.9%	2.7%
Germany	133.1	134.3	136.3	135.1	135.1	137.4	136.5	136.6	132.4	129.8	131.6	1.4%	3.7%
Greece	15.8	16.1	16.7	16.9	17.6	18.2	18.4	18.2	18.7	19.9	19.4	-2.8%	0.6%
Hungary	8.0	8.1	7.7	8.1	7.7	7.1	7.1	7.4	7.1	6.8	6.8	-1.2%	0.2%
Iceland	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	2.4%	♦
Republic of Ireland	4.9	5.1	5.1	5.6	5.7	6.0	6.6	7.4	8.3	8.2	8.7	6.3%	0.2%
Italy	92.4	94.5	92.6	92.5	95.5	94.2	94.6	94.7	94.4	93.5	92.8	-0.8%	2.6%
Netherlands	35.8	36.5	36.4	36.4	38.0	37.4	39.5	39.4	40.6	41.7	43.9	5.3%	1.3%
Norway	8.7	9.0	9.5	9.6	9.6	10.1	10.3	10.0	10.1	9.4	9.7	2.9%	0.3%
Poland	14.9	13.6	14.0	14.8	14.9	17.2	18.2	19.9	19.9	20.0	19.0	-4.8%	0.5%
Portugal	11.5	12.8	12.0	12.0	12.9	12.1	13.7	15.1	15.4	14.9	15.2	1.7%	0.4%
Romania	15.6	12.7	12.1	11.2	13.5	13.0	13.7	12.0	9.5	10.0	10.1	1.4%	0.3%
Slovakia	4.4	3.9	3.2	3.3	3.2	3.4	3.4	3.8	3.4	3.4	3.4	-0.9%	0.1%
Spain	49.4	52.8	51.3	53.5	56.3	58.7	62.0	66.4	68.4	70.0	72.7	3.9%	2.1%
Sweden	15.5	16.4	16.1	17.0	16.1	17.4	16.1	16.2	16.1	15.2	15.6	2.5%	0.4%
Switzerland	13.0	13.1	12.3	12.7	11.8	12.2	12.8	13.0	12.6	12.2	13.1	6.9%	0.4%
Turkey	22.1	23.5	27.0	25.8	28.4	29.8	30.0	29.6	29.5	31.6	30.4	-3.9%	0.9%
United Kingdom	82.5	83.6	84.0	82.9	81.9	83.9	81.3	80.9	79.7	77.9	76.1	-2.3%	2.2%
Other Europe	16.9	13.0	13.4	13.0	13.7	15.3	16.4	16.7	16.7	16.3	16.8	2.8%	0.5%
Total Europe	710.5	714.6	711.9	711.0	723.4	741.8	749.1	761.4	758.6	755.8	760.2	0.6%	21.7%
Azerbaijan	8.2	8.1	8.2	8.1	8.5	7.0	6.0	7.5	7.4	6.2	4.6	-25.8%	0.1%
Belarus	24.0	21.2	14.0	12.8	12.3	9.3	9.6	8.3	6.9	6.1	5.9	-3.3%	0.2%
Kazakhstan	21.7	20.3	15.7	12.3	12.0	10.2	10.3	8.2	6.6	7.0	7.7	10.0%	0.2%
Lithuania	8.2	4.5	3.9	3.6	3.2	3.3	3.3	3.8	3.1	2.4	2.8	15.9%	0.1%
Russian Federation	243.4	224.4	188.6	162.7	146.1	130.1	129.1	123.7	126.2	123.5	122.3	-1.0%	3.5%
Turkmenistan	5.0	4.9	3.2	3.7	3.9	3.0	3.0	2.8	2.5	2.3	2.4	4.3%	0.1%
Ukraine	57.5	42.6	24.8	19.8	18.9	14.2	13.8	14.3	12.7	12.0	12.7	5.8%	0.4%
Uzbekistan	11.0	9.1	8.1	7.2	6.7	7.4	6.7	7.0	7.1	6.4	6.5	1.6%	0.2%
Other Former Soviet Union	18.4	12.9	9.2	6.1	5.4	4.2	5.0	5.0	4.5	4.4	4.7	7.2%	0.1%
Total Former Soviet Union	397.4	348.0	275.7	236.3	217.0	188.7	186.8	180.6	177.0	170.3	169.6	-0.4%	4.8%
Iran	49.0	50.0	50.9	53.4	58.4	60.6	59.0	55.9	57.3	56.1	54.2	-3.4%	1.5%
Kuwait	3.7	5.6	5.0	6.2	6.5	6.3	6.9	9.1	10.3	10.4	10.5	1.6%	0.3%
Qatar	0.8	0.8	0.8	0.9	1.0	1.1	1.1	1.2	1.1	1.2	1.4	19.7%	♦
Saudi Arabia	55.4	51.4	52.1	53.5	51.4	53.7	55.3	58.8	60.9	62.4	62.7	0.5%	1.8%
United Arab Emirates	16.5	16.9	17.2	18.2	18.0	17.8	16.3	11.9	13.0	14.2	14.3	0.6%	0.4%
Other Middle East	44.9	49.0	52.6	54.9	58.1	58.6	61.0	62.6	63.0	63.5	63.3	-0.3%	1.8%
Total Middle East	170.3	173.7	178.6	187.1	193.4	198.1	199.6	199.5	205.6	207.8	206.4	-0.6%	5.9%
Algeria	9.1	9.1	9.1	8.7	8.4	8.1	8.0	8.2	8.1	8.5	8.8	3.5%	0.3%
Egypt	23.4	22.7	21.6	21.5	23.3	24.6	26.0	27.3	27.8	27.2	26.2	-3.5%	0.7%
South Africa	16.7	17.3	18.0	18.8	20.1	20.7	21.0	21.3	21.8	22.5	23.0	2.1%	0.7%
Other Africa	45.4	47.8	49.3	51.5	51.9	52.7	53.9	55.7	57.4	57.9	59.0	1.9%	1.7%
Total Africa	94.6	96.9	98.0	100.5	103.7	106.1	108.9	112.5	115.1	116.1	117.0	0.8%	3.3%
Australia	30.8	30.9	32.7	34.0	35.3	35.9	37.0	37.0	38.0	37.7	38.1	1.0%	1.1%
Bangladesh	1.7	1.8	2.1	2.2	2.9	2.9	3.3	3.7	3.4	3.4	3.4	1.0%	0.1%
China	117.9	129.0	140.5	149.5	160.7	174.4	185.6	190.3	207.2	230.1	231.9	0.8%	6.6%
China Hong Kong SAR	6.3	8.1	8.3	8.9	9.5	9.3	9.2	8.8	9.3	9.7	9.5	-2.1%	0.3%
India	58.9	62.1	62.7	67.4	73.0	79.4	83.3	86.8	95.2	97.5	97.1	-0.4%	2.8%
Indonesia	32.2	35.1	37.6	37.0	39.1	42.4	45.9	43.5	46.8	50.4	52.3	3.7%	1.5%
Japan	252.1	257.5	251.9	267.4	267.6	268.8	265.0	253.6	257.3	255.4	247.2	-3.2%	7.0%
Malaysia	13.9	14.0	15.6	17.4	17.9	19.0	20.2	19.0	20.3	20.4	18.6	-8.8%	0.5%
New Zealand	4.9	5.2	5.2	5.6	5.8	5.9	6.1	6.1	6.3	6.3	6.2	-0.4%	0.2%
Pakistan	11.4	12.4	13.5	14.5	15.8	16.6	17.0	17.6	18.2	18.8	18.9	0.7%	0.5%
Philippines	11.1	13.7	14.1	14.9	16.8	17.5	18.8	19.1	18.0	16.6	16.5	-0.5%	0.5%
Singapore	23.7	24.7	26.7	30.6	32.0	30.3	32.4	33.3	31.6	33.5	36.9	10.2%	1.1%
South Korea	59.9	72.3	79.3	87.0	94.8	101.4	111.4	93.9	100.7	103.2	103.1	-0.1%	2.9%
Taiwan	27.6	28.4	30.2	32.3	34.7	34.8	36.0	37.2	39.9	39.8	37.7	-5.2%	1.1%
Thailand	21.4	23.6	26.8	29.8	34.7	37.5	37.8	35.4	35.4	34.8	33.8	-2.8%	1.0%
Other Asia Pacific	11.4	12.5	13.5	14.0	14.7	16.4	17.5	18.2	19.0	20.6	21.5	4.4%	0.6%
Total Asia Pacific	685.2	731.3	760.7	812.5	855.3	892.5	926.5	903.5	946.6	978.2	972.7	-0.5%	27.7%
TOTAL WORLD	3137.6	3170.3	3140.8	3199.6	3246.8	3322.8	3395.6	3410.1	3480.8	3519.0	3510.6	-0.2%	100.0%
of which: European Union 15	593.3	604.2	598.9	598.9	606.2	619.0	623.9	635.0	636.2	632.8	637.1	0.7%	18.2%
OECD	1931.1	1979.0	1986.7	2041.0	2053.0	2112.4	2144.6	2150.2	2187.1	2197.4	2189.6	-0.4%	62.4%
Former Soviet Union	397.4	348.0	275.7	236.3	217.0	188.7	186.8	180.6	177.0	170.3	169.6	-0.4%	4.8%
Other EMEs	809.1	843.3	878.4	922.3	976.8	1021.7	1064.2	1079.3	1116.7	1151.3	1151.4	♦	32.8%

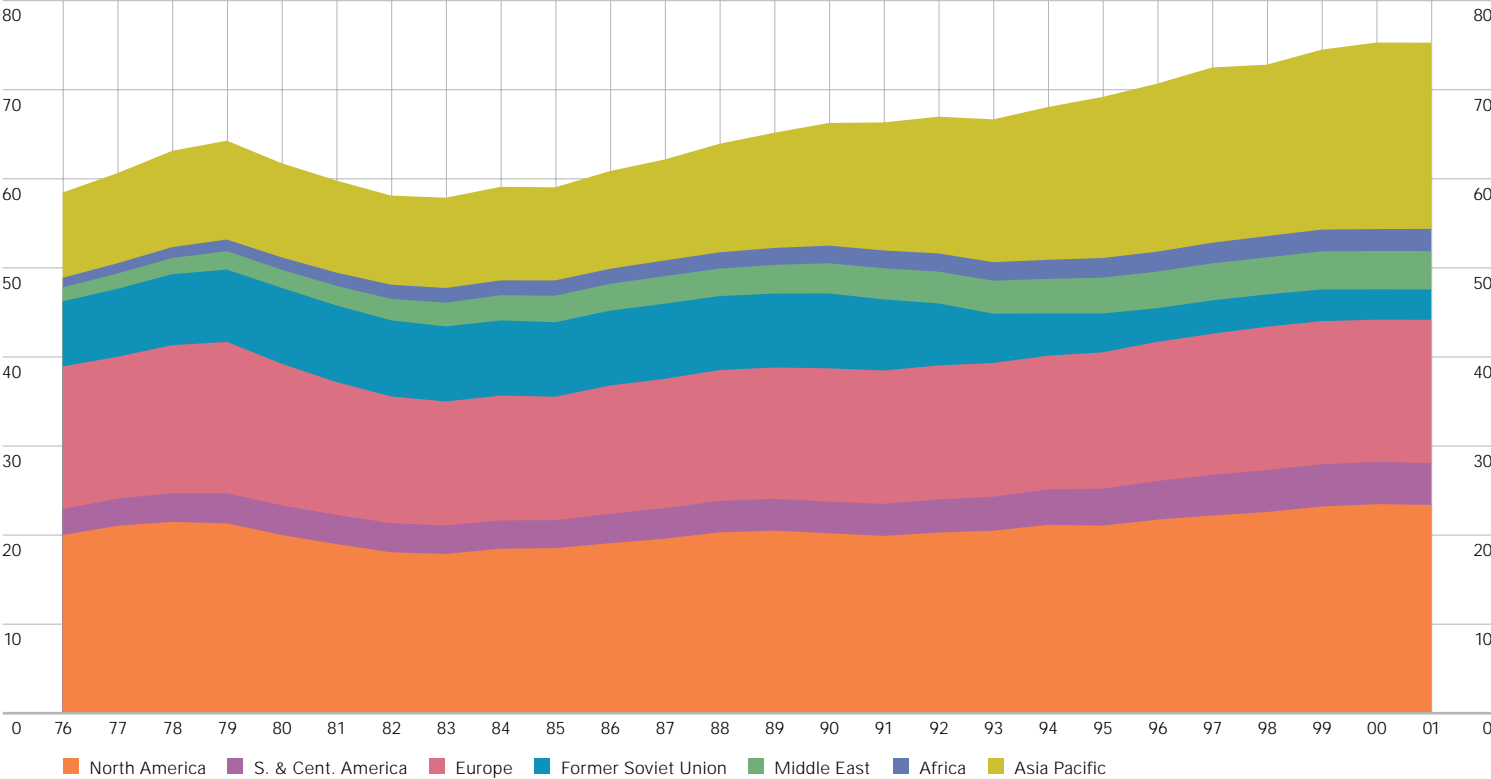
*Inland demand plus international aviation and marine bunkers and refinery fuel and loss.

♦Less than 0.05%.

Note: Differences between these world consumption figures and world production statistics on page 7 are accounted for by stock changes, consumption of non-petroleum additives and substitute fuels, and unavoidable disparities in the definition, measurement or conversion of oil supply and demand data. The US volumetric consumption levels include no adjustment for processing gain (see 'definitions' on the inside back cover).

consumption by area

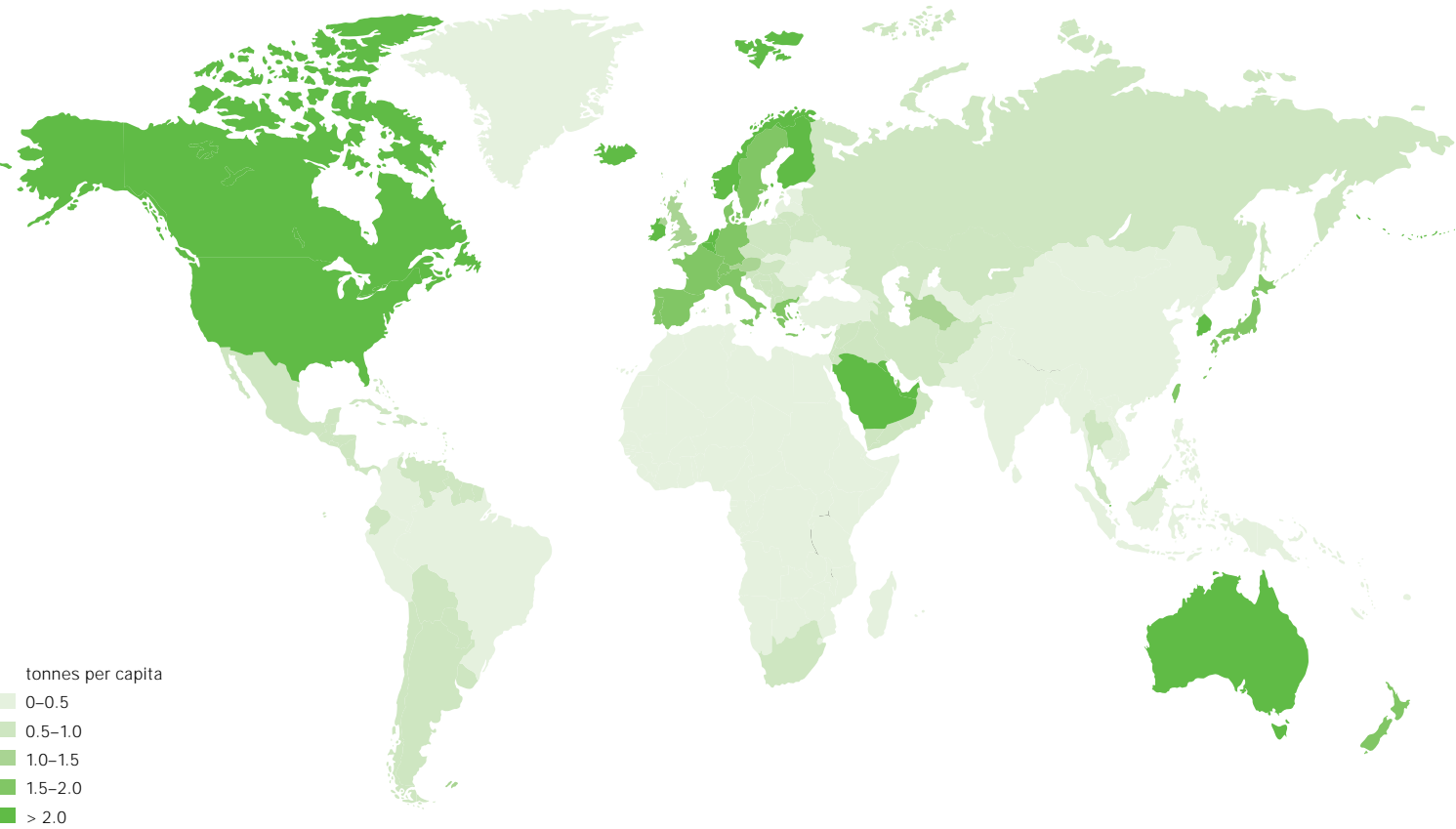
Million barrels daily



Global oil consumption failed to grow in 2001 for the first time since 1993. Having been the engine of consumption growth for much of the 1990s, Asian oil demand growth has slowed sharply since the economic crisis of 1997/98.

consumption per capita

Tonnes





regional consumption – by product group

Thousand barrels daily	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
North America													
Gasolines	8680	8833	8975	9100	9235	9389	9560	9849	9998	10106	10200	0.9%	43.6%
Middle distillates	5369	5449	5600	5895	5935	6194	6398	6450	6628	6811	6767	-0.6%	28.9%
Fuel oil	1701	1619	1571	1571	1336	1348	1351	1506	1415	1518	1451	-4.4%	6.2%
Others	4158	4378	4352	4579	4555	4805	4882	4788	5169	5037	4969	-1.4%	21.3%
Total North America	19908	20279	20498	21145	21061	21736	22191	22593	23210	23473	23386	-0.4%	100.0%
of which: USA													
Gasolines	7529	7670	7792	7880	8025	8167	8324	8579	8716	8813	8883	0.8%	45.2%
Middle distillates	4648	4711	4844	5084	5132	5342	5502	5545	5700	5852	5843	-0.2%	29.8%
Fuel oil	1147	1079	1062	1003	835	831	777	869	814	893	829	-7.2%	4.2%
Others	3389	3573	3539	3751	3733	3969	4017	3924	4290	4143	4078	-1.6%	20.8%
Total USA	16713	17033	17236	17719	17725	18309	18621	18917	19519	19701	19633	-0.3%	100.0%
S. & Cent. America													
Gasolines	981	983	1025	1105	1160	1197	1266	1283	1396	1374	1346	-2.0%	28.7%
Middle distillates	1223	1276	1312	1398	1476	1538	1625	1700	1680	1690	1705	0.9%	36.3%
Fuel oil	704	682	697	721	753	788	845	868	776	749	725	-3.2%	15.4%
Others	688	781	767	749	773	804	831	857	893	919	917	-0.3%	19.6%
Total S. & Cent. America	3596	3722	3801	3973	4162	4327	4568	4709	4745	4732	4693	-0.8%	100.0%
Europe													
Gasolines	4177	4213	4158	4129	4201	4227	4279	4318	4334	4217	4121	-2.3%	25.6%
Middle distillates	5774	5809	5871	5883	6045	6356	6421	6631	6694	6722	6939	3.2%	43.1%
Fuel oil	2447	2385	2353	2280	2283	2260	2206	2191	2088	1982	1981	-0.1%	12.3%
Others	2579	2631	2639	2727	2766	2790	2933	2952	2946	3053	3052	*	19.0%
Total Europe	14976	15038	15022	15019	15295	15633	15839	16092	16063	15975	16093	0.7%	100.0%
Middle East													
Gasolines	560	616	635	708	763	774	814	830	841	840	843	0.4%	19.6%
Middle distillates	1180	1169	1235	1336	1435	1468	1465	1459	1482	1483	1517	2.2%	35.2%
Fuel oil	1210	1167	1142	1170	1187	1206	1205	1173	1251	1281	1241	-3.1%	28.8%
Others	547	620	691	678	644	662	678	699	709	703	704	0.2%	16.4%
Total Middle East	3497	3571	3704	3891	4028	4110	4161	4161	4283	4307	4306	*	100.0%
Africa													
Gasolines	504	516	527	539	554	552	559	568	574	580	591	2.1%	23.8%
Middle distillates	780	795	818	840	866	893	919	949	985	1007	1032	2.4%	41.5%
Fuel oil	413	424	412	416	435	445	466	491	494	474	456	-3.6%	18.3%
Others	297	308	316	335	343	349	363	376	386	395	410	3.8%	16.4%
Total Africa	1994	2043	2073	2130	2198	2240	2307	2385	2439	2455	2490	1.4%	100.0%
Asia Pacific incl. China and Japan													
Gasolines	3266	3540	3731	4013	4317	4549	4973	5018	5311	5549	5525	-0.4%	26.4%
Middle distillates	5225	5619	6014	6262	6724	7160	7430	7186	7596	7798	7878	1.0%	37.7%
Fuel oil	3509	3637	3622	3892	3857	3795	3829	3563	3548	3505	3366	-4.0%	16.1%
Others	2379	2553	2671	2988	3196	3364	3447	3483	3745	4089	4147	1.4%	19.8%
Total Asia Pacific	14379	15350	16038	17155	18094	18868	19680	19250	20200	20941	20916	-0.1%	100.0%
China													
Gasolines	642	711	804	848	904	986	1111	1098	1164	1313	1245	-5.2%	24.7%
Middle distillates	683	790	898	878	997	1080	1202	1277	1455	1633	1698	4.0%	33.7%
Fuel oil	661	674	725	665	669	719	750	725	694	725	728	0.4%	14.4%
Others	425	488	486	755	819	888	871	946	1103	1314	1371	4.3%	27.2%
Total China	2411	2662	2913	3145	3390	3672	3935	4047	4416	4985	5041	1.1%	100.0%
Japan													
Gasolines	1269	1338	1355	1442	1548	1576	1646	1611	1702	1735	1711	-1.4%	31.5%
Middle distillates	1788	1824	1853	1905	1971	2027	1991	1949	1978	1958	1958	-	36.1%
Fuel oil	1277	1264	1112	1292	1135	1067	977	879	861	804	690	-14.2%	12.7%
Others	1076	1095	1120	1105	1129	1142	1147	1085	1077	1079	1067	-1.1%	19.7%
Total Japan	5410	5521	5440	5745	5784	5812	5761	5525	5618	5576	5427	-2.7%	100.0%
World excl. Former Soviet Union													
Gasolines	18169	18700	19051	19594	20230	20688	21451	21866	22454	22665	22626	-0.2%	31.5%
Middle distillates	19550	20117	20850	21614	22480	23609	24258	24375	25064	25512	25839	1.3%	35.9%
Fuel oil	9984	9915	9797	10051	9851	9842	9902	9794	9572	9510	9221	-3.0%	12.8%
Others	10648	11272	11436	12055	12277	12775	13133	13155	13848	14196	14199	*	19.8%
Total World excl. Former Soviet Union	58351	60004	61135	63314	64838	66913	68745	69190	70939	71883	71884	*	100.0%
European Union 15													
Gasolines	3574	3620	3562	3512	3550	3559	3590	3607	3622	3545	3458	-2.5%	25.7%
Middle distillates	4953	4978	5033	5051	5179	5440	5514	5679	5762	5813	6000	3.2%	44.5%
Fuel oil	1857	1887	1841	1797	1791	1755	1703	1733	1658	1552	1533	-1.2%	11.4%
Others	2150	2241	2211	2294	2296	2295	2379	2398	2415	2440	2477	1.5%	18.4%
Total European Union 15	12533	12726	12646	12654	12816	13049	13186	13417	13457	13350	13469	0.9%	100.0%
OECD													
Gasolines	14585	14961	15124	15378	15721	15968	16415	16728	17028	17070	17056	-0.1%	35.9%
Middle distillates	13420	13647	13973	14414	14777	15468	15738	15753	16111	16265	16437	1.1%	34.6%
Fuel oil	5578	5539	5324	5505	5115	5036	4904	4827	4666	4637	4441	-4.2%	9.4%
Others	7972	8357	8401	8714	8769	9084	9353	9199	9607	9617	9537	-0.8%	20.1%
Total OECD	41555	42503	42822	44012	44383	45556	46409	46508	47412	47589	47471	-0.2%	100.0%
Other EMEs													
Gasolines	3584	3739	3927	4215	4509	4719	5037	5138	5426	5595	5570	-0.4%	22.8%
Middle distillates	6130	6470	6877	7200	7703	8141	8520	8622	8953	9247	9402	1.7%	38.5%
Fuel oil	4406	4376	4472	4546	4735	4806	4999	4966	4906	4873	4779	-1.9%	19.6%
Others	2676	2915	3036	3341	3507	3691	3780	3956	4242	4579	4662	1.8%	19.1%
Total Other EMEs†	16796	17501	18313	19302	20455	21357	22336	22682	23527	24294	24413	0.5%	100.0%

*Less than 0.05%.

†Excludes Former Soviet Union.

Notes: For the purposes of this table, annual changes and shares of total are calculated using thousand barrels daily figures.

'Gasolines' consists of aviation and motor gasolines and light distillate feedstock.

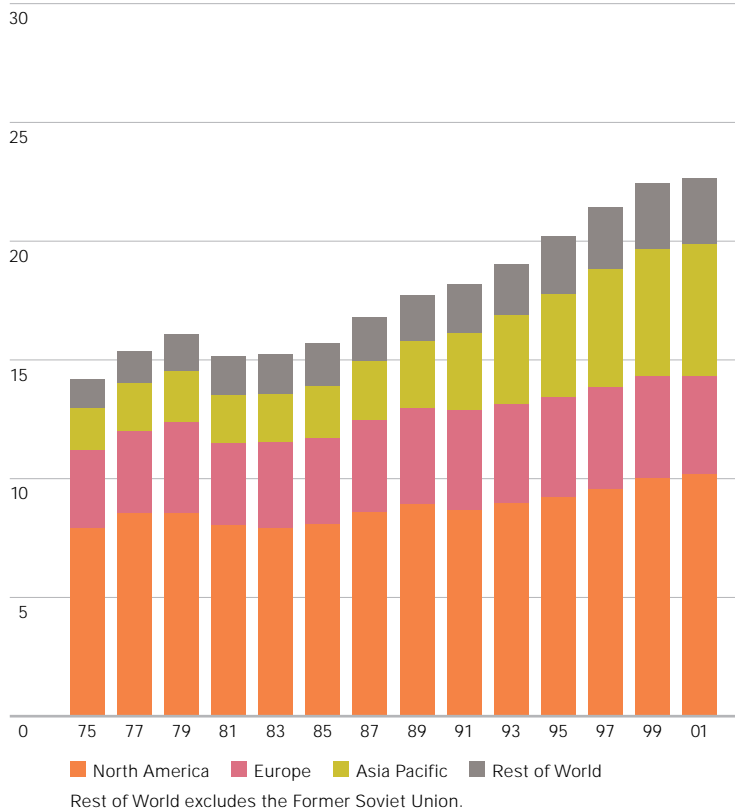
'Middle distillates' consists of jet and heating kerosenes, and gas and diesel oils (including marine bunkers).

'Fuel oil' includes marine bunkers and crude oil used directly as fuel.

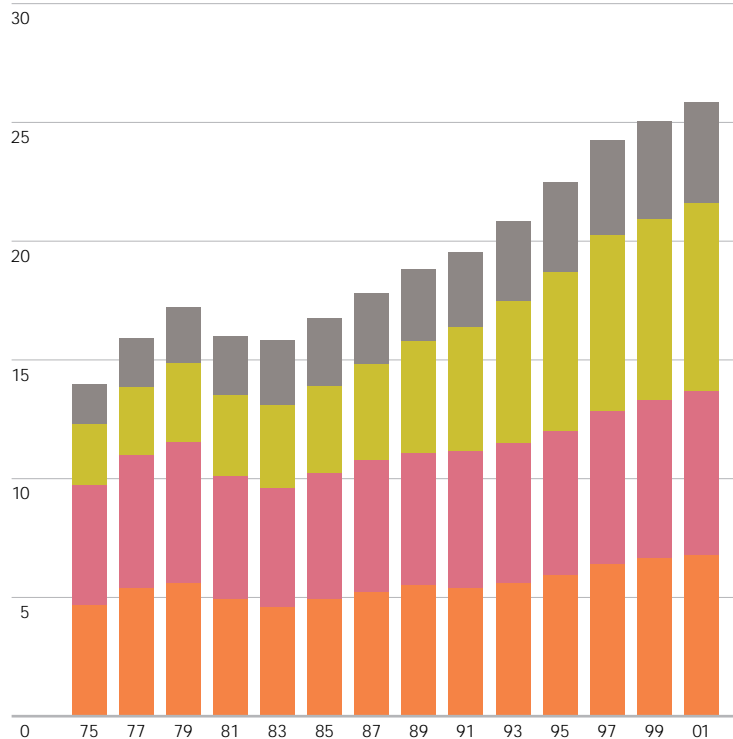
'Others' consists of refinery gas, LPGs, solvents, petroleum coke, lubricants, bitumen, wax and refinery fuel and loss.

product consumption – by region

Gasolines (million barrels daily)

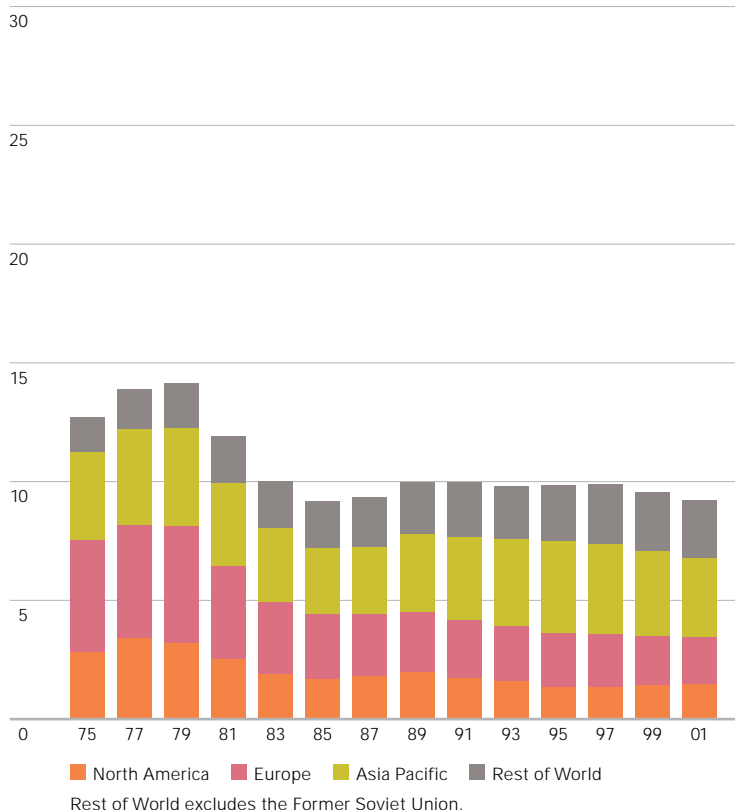


Middle distillates (million barrels daily)

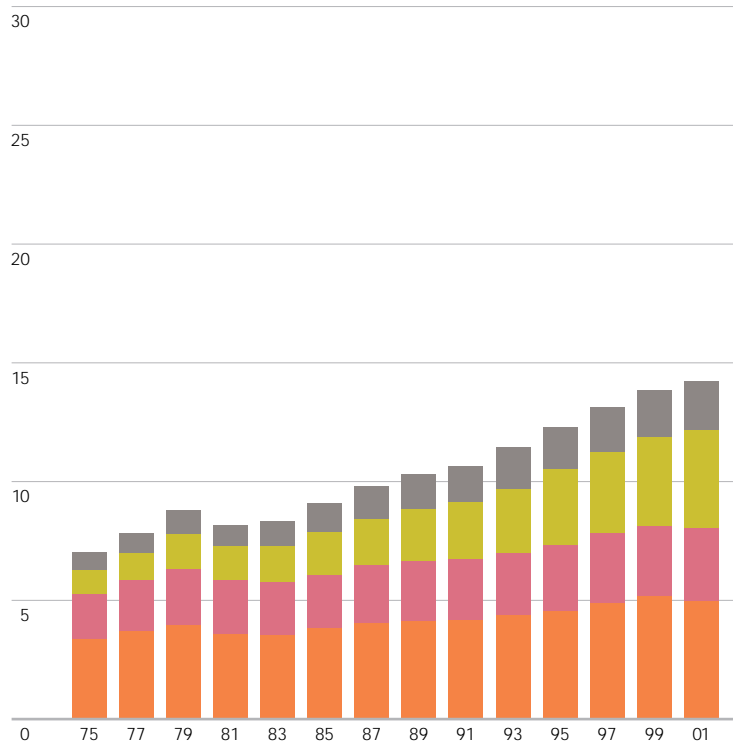


product consumption – by region

Fuel oil (million barrels daily)



Others (million barrels daily)



Middle distillates have registered the largest increment in consumption over the last 20 years, followed by gasolines and other oil. Fuel oil use has been flat since 1985, following sharp falls in the early 1980s. The fastest growth in product demand has been in Asia Pacific.

oil

spot crude prices

US dollars per barrel	Dubai \$/bbl*	Brent \$/bbl†	Nigerian Forcados \$/bbl	West Texas Intermediate \$/bbl‡
1972	1.90	–	–	–
1973	2.83	–	–	–
1974	10.41	–	–	–
1975	10.70	–	–	–
1976	11.63	12.80	12.87	12.23
1977	12.38	13.92	14.21	14.22
1978	13.03	14.02	13.65	14.55
1979	29.75	31.61	29.25	25.08
1980	35.69	36.83	36.98	37.96
1981	34.32	35.93	36.18	36.08
1982	31.80	32.97	33.29	33.65
1983	28.78	29.55	29.54	30.30
1984	28.06	28.66	28.14	29.39
1985	27.53	27.51	27.75	27.99
1986	13.01	14.38	14.45	15.04
1987	16.91	18.42	18.40	19.19
1988	13.20	14.96	14.99	15.97
1989	15.68	18.20	18.30	19.68
1990	20.50	23.81	23.85	24.50
1991	16.56	20.05	20.11	21.54
1992	17.21	19.37	19.61	20.57
1993	14.90	17.07	17.41	18.45
1994	14.76	15.98	16.25	17.21
1995	16.09	17.18	17.26	18.42
1996	18.56	20.80	21.16	22.16
1997	18.13	19.30	19.33	20.61
1998	12.16	13.11	12.62	14.39
1999	17.30	18.25	18.00	19.31
2000	26.24	28.98	28.42	30.37
2001	22.80	24.77	24.23	25.93

*1972-1985 Arabian Light, 1986-2001 Dubai.

†1976-1984 Forties, 1985-2001 Brent.

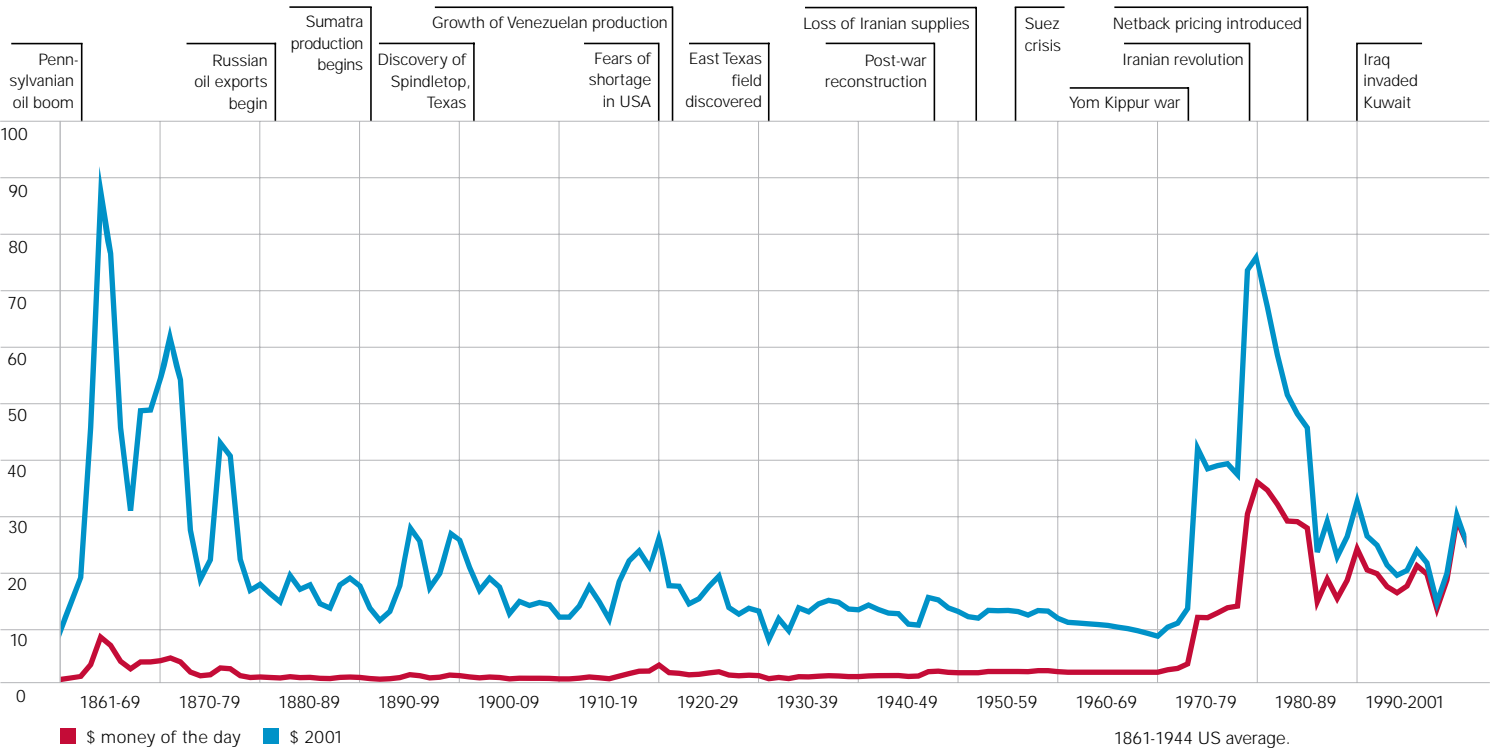
‡1976-1983 Posted WTI prices, 1984-2001 Spot WTI prices.

Source: Platts.

crude oil prices since 1861

US dollars per barrel

World events

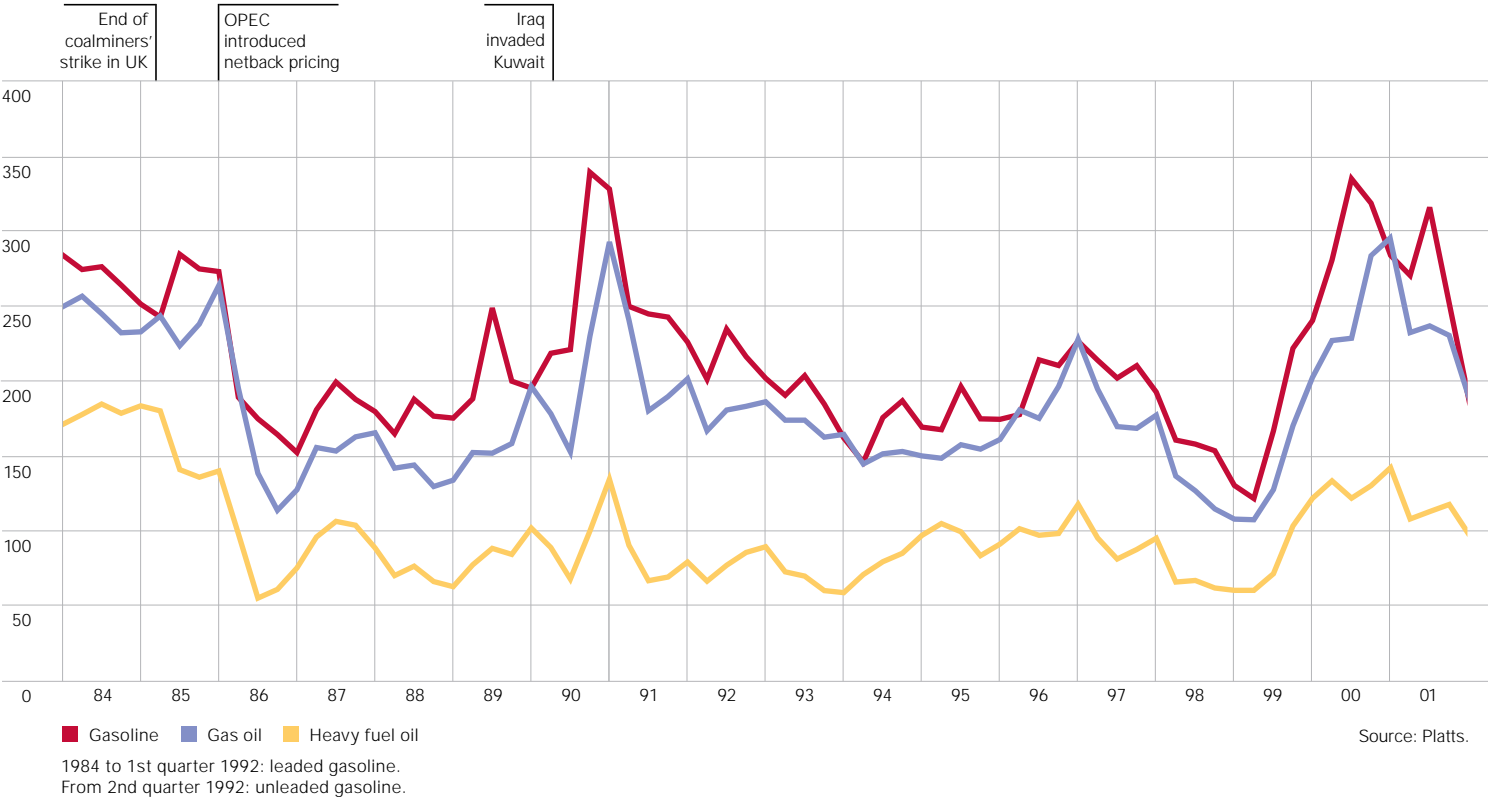


1861-1944 US average.
1945-1985 Arabian Light posted at Ras Tanura.
1986-2001 Brent spot.

Rotterdam product prices

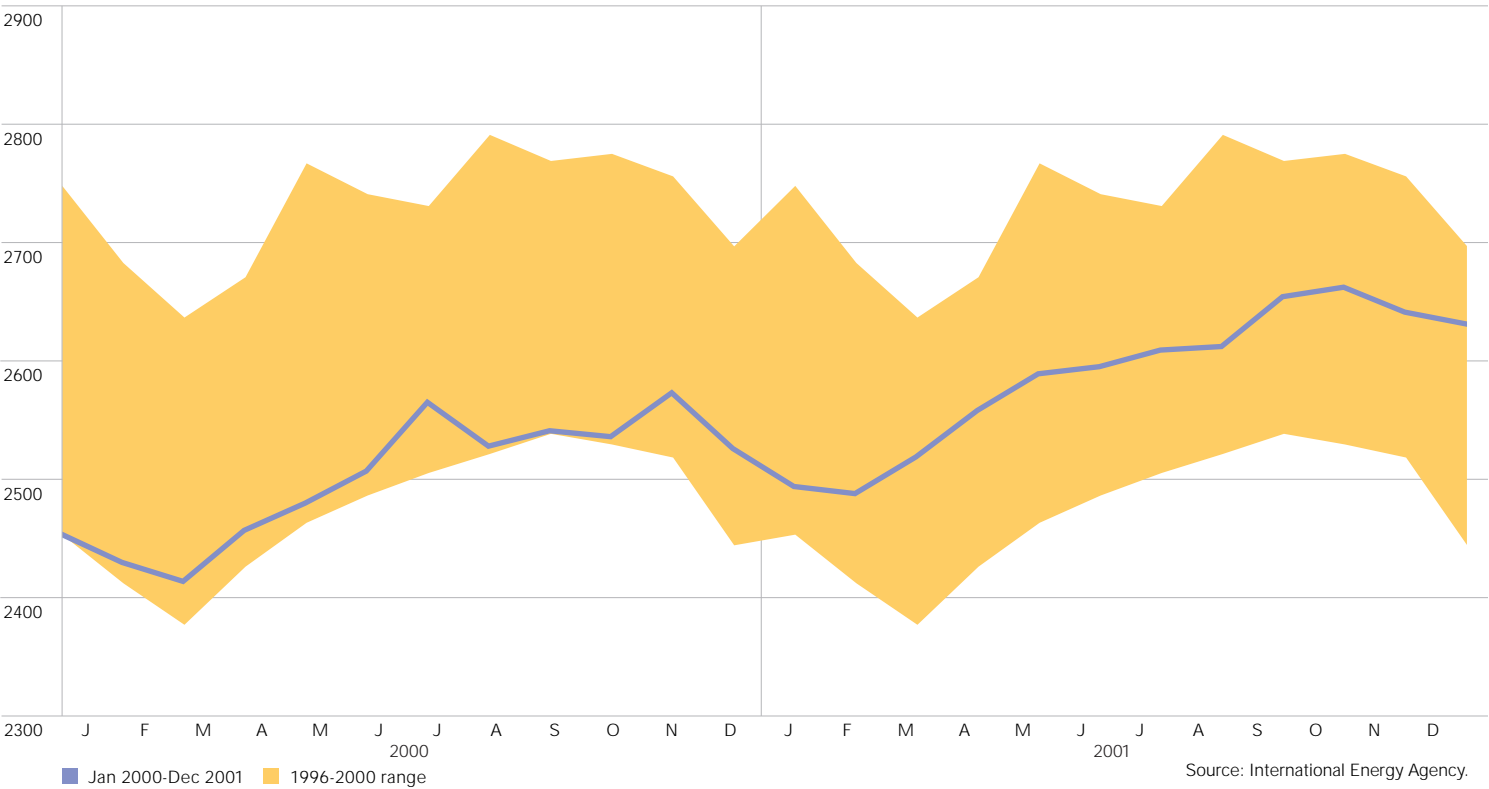
US dollars per tonne

World events



OECD total commercial oil stocks

Million barrels





refinery capacities

Thousand barrels daily*	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	15700	15120	15030	15434	15333	15452	15711	16261	16512	16595	16814	1.3%	20.5%
Canada	1903	1911	1824	1832	1792	1807	1811	1844	1861	1861	1862	0.1%	2.3%
Mexico	1448	1448	1444	1444	1444	1444	1449	1449	1449	1481	1458	-1.6%	1.8%
Total North America	19051	18479	18298	18710	18569	18703	18971	19554	19822	19937	20134	1.0%	24.5%
Argentina	694	694	688	663	648	651	653	650	650	657	657	-	0.8%
Brazil	1445	1444	1429	1473	1481	1481	1739	1742	1773	1773	1773	-	2.2%
Netherlands Antilles & Aruba	460	460	467	485	505	520	520	520	535	535	590	10.3%	0.7%
Trinidad & Tobago	240	240	240	240	240	160	160	160	160	160	160	-	0.2%
Venezuela	1224	1224	1181	1181	1181	1183	1183	1183	1183	1183	1183	-	1.4%
Other S. & Cent. America	2049	2010	2009	1984	2042	2104	2127	2031	2071	2076	2066	-0.5%	2.5%
Total S. & Cent. America	6112	6072	6014	6026	6097	6099	6382	6286	6372	6384	6429	0.7%	7.8%
Belgium	706	690	692	692	692	690	698	732	736	770	778	1.0%	0.9%
France	1699	1711	1687	1697	1728	1749	1872	1918	1933	1984	1961	-1.2%	2.4%
Germany	2209	2219	2248	2272	2104	2098	2170	2206	2240	2262	2274	0.5%	2.8%
Greece	403	367	295	385	403	403	403	403	403	413	418	1.2%	0.5%
Italy	2422	2433	2360	2272	2272	2256	2241	2269	2292	2292	2292	-	2.8%
Netherlands	1225	1254	1197	1197	1197	1169	1196	1196	1212	1212	1233	1.7%	1.5%
Norway	288	288	288	288	298	308	308	310	323	318	305	-4.1%	0.4%
Portugal	291	290	291	291	291	290	291	291	291	291	291	-	0.4%
Spain	1255	1232	1245	1205	1215	1232	1265	1247	1247	1247	1247	-	1.5%
Sweden	422	421	422	422	422	421	422	422	422	422	422	-	0.5%
Turkey	673	671	673	673	673	671	673	643	643	643	643	-	0.8%
United Kingdom	1827	1837	1844	1866	1844	1873	1823	1848	1777	1778	1769	-0.5%	2.2%
Other Europe	3366	3241	3218	3104	3098	3054	3024	3022	2759	2704	2741	1.4%	3.3%
Total Europe	16786	16654	16460	16364	16237	16214	16386	16507	16278	16336	16374	0.2%	19.9%
Total Former Soviet Union	12310	10090	10085	10215	10302	10341	10410	9988	8730	8712	8695	-0.2%	10.6%
Bahrain	250	250	250	250	250	250	250	250	250	250	250	-	0.3%
Iran	957	957	1092	1092	1235	1330	1378	1448	1450	1450	1474	1.7%	1.8%
Iraq	350	584	634	634	634	634	634	634	634	639	644	0.8%	0.8%
Kuwait	140	380	455	720	795	825	880	895	895	690	720	4.3%	0.9%
Saudi Arabia	1750	1550	1550	1670	1670	1670	1693	1780	1811	1811	1816	0.3%	2.2%
Other Middle East	1065	1088	1102	1121	1123	1172	1317	1259	1320	1469	1730	17.8%	2.1%
Total Middle East	4512	4809	5083	5487	5707	5881	6152	6266	6360	6309	6634	5.2%	8.1%
Total Africa	2715	2749	2871	2723	2785	2870	2807	2780	2842	2957	3080	4.2%	3.7%
Australasia	765	782	791	796	818	848	890	916	919	919	926	0.8%	1.1%
China	2892	3044	3334	3567	4014	4226	4559	4592	5401	5407	5402	-0.1%	6.6%
India	1122	1041	1069	1072	1133	1210	1236	1356	2190	2219	2261	1.9%	2.8%
Indonesia	867	867	867	932	992	992	992	1028	1060	1065	1065	-	1.3%
Japan	4505	4636	4802	4862	5006	5006	5056	5088	5109	5029	4811	-4.3%	5.9%
Singapore	1085	1115	1160	1158	1273	1245	1246	1246	1246	1255	1255	-	1.5%
South Korea	984	1370	1591	1615	1727	1917	2316	2316	2316	2316	2316	-	2.8%
Other Asia Pacific	1597	1787	1835	1964	2285	2546	2550	2704	2745	2763	2823	2.2%	3.4%
Total Asia Pacific	13817	14642	15449	15966	17248	17990	18845	19246	20986	20973	20859	-0.5%	25.4%
TOTAL WORLD	75303	73495	74260	75491	76945	78098	79953	80627	81390	81608	82205	0.7%	100.0%
of which: European Union 15	13110	13090	12924	12982	12887	12921	13069	13237	13265	13392	13406	0.1%	16.3%
OECD	40421	40360	40412	40977	40999	41359	42289	43104	43443	43606	43595	♦	53.0%
Former Soviet Union	12310	10090	10085	10215	10302	10341	10410	9988	8730	8712	8695	-0.2%	10.6%
Other EMEs	22572	23045	23763	24299	25644	26398	27254	27535	29217	29290	29915	2.1%	36.4%

*Atmospheric distillation capacity on a calendar-day basis.

♦Less than 0.05%.

Note: For the purposes of this table, annual changes and shares of total are calculated using thousand barrels daily figures.

refinery throughputs

Thousand barrels daily*	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	13301	13411	13613	13866	13973	14195	14662	14889	14804	15067	15130	0.4%	21.6%
Canada	1491	1458	1539	1580	1569	1644	1694	1709	1714	1765	1823	3.3%	2.6%
Mexico	1511	1497	1540	1459	1488	1491	1438	1451	1389	1364	1400	2.6%	2.0%
S. & Cent. America	4648	4625	4697	4849	4849	4994	5238	5443	5405	5401	5535	2.5%	7.9%
Europe	13810	14003	14272	14397	14448	14697	14859	15336	14838	14989	14849	-0.9%	21.2%
Former Soviet Union	8818	7156	5926	5075	4888	4624	4735	4482	4468	4558	4900	7.5%	7.0%
Middle East	3828	4277	4666	5244	5160	5408	5448	5595	5672	5635	5616	-0.3%	8.0%
Africa	2255	2255	2279	2244	2358	2381	2539	2408	2448	2393	2442	2.0%	3.5%
Australasia	745	747	756	787	788	844	872	865	881	881	885	0.5%	1.3%
China	2282	2426	2570	2548	2711	2850	3084	3060	3686	4218	4210	-0.2%	6.0%
Japan	3653	3882	3982	4167	4169	4168	4319	4212	4149	4145	4107	-0.9%	5.9%
Other Asia Pacific	5270	5717	6051	6314	6822	7544	8183	8010	8309	8914	9061	1.6%	13.0%
TOTAL WORLD	61612	61453	61892	62529	63223	64840	67072	67460	67763	69330	69958	0.9%	100.0%
of which: European Union 15	11739	12038	12169	12214	12158	12430	12569	13038	12631	12737	12646	-0.7%	18.1%
OECD	34985	35911	36638	37191	37521	38431	39673	40146	39677	40064	39996	-0.2%	57.2%
Former Soviet Union	8818	7156	5926	5075	4888	4624	4735	4482	4468	4558	4900	7.5%	7.0%
Other EMEs	17809	18386	19328	20263	20815	21785	22663	22831	23618	24707	25062	1.4%	35.8%

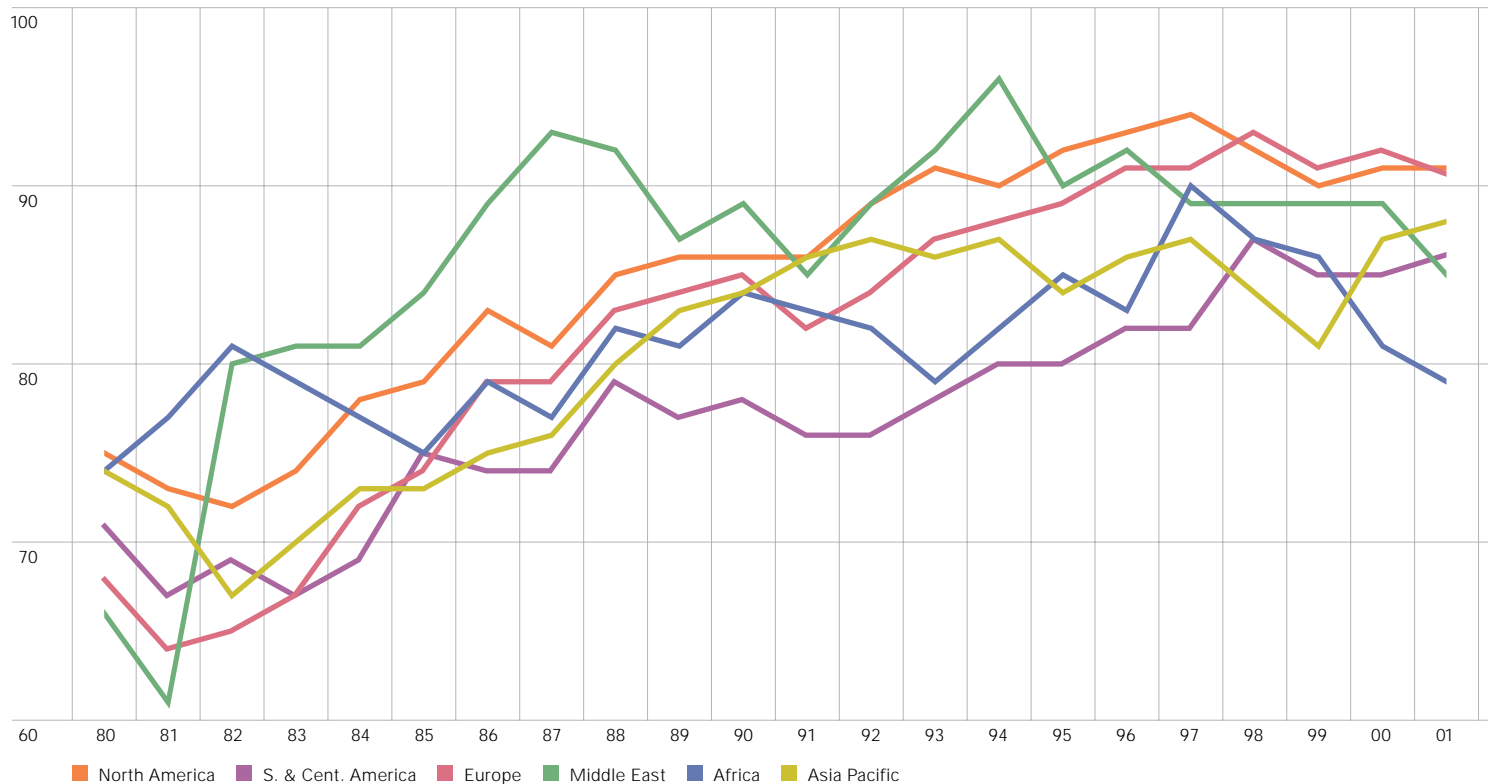
*Calendar day.

Source: Includes data from Parpinelli Tecnol.

Note: For the purposes of this table, annual changes and shares of total are calculated using thousand barrels daily figures.

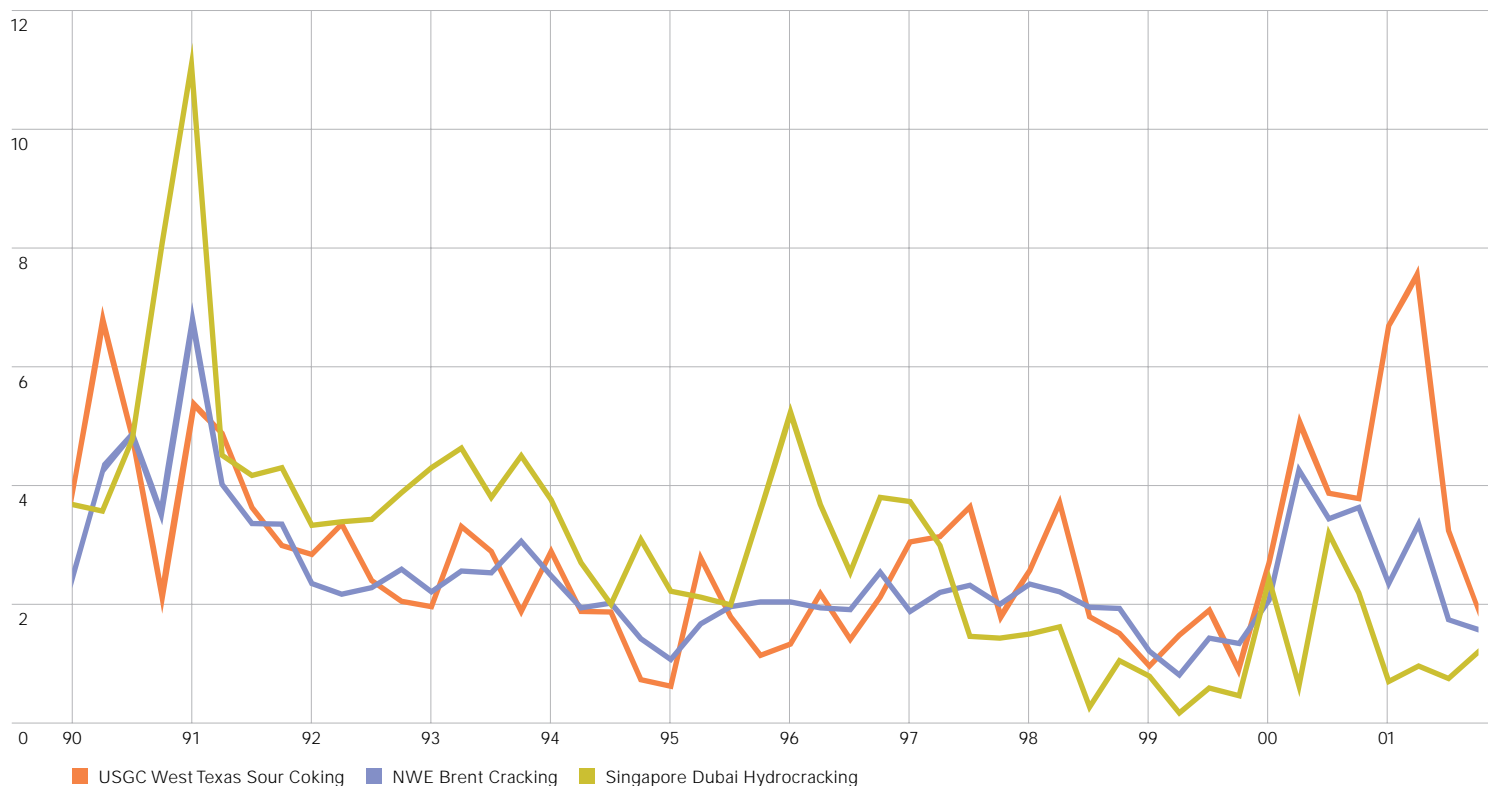
refinery utilization

Percentage



regional refining margins

US dollars per barrel



Note: The refining margins presented are benchmark margins for three major global refining centres, US Gulf Coast (USGC), North West Europe (NWE) (Rotterdam) and Singapore. In each case they are based on a single crude appropriate for that region and have optimized product yields based on a generic refinery configuration (cracking, hydrocracking or coking), again appropriate for that region. The margins are on a semi-variable basis, i.e. the margin after all variable costs and fixed energy costs.

oil

trade movements

Thousand barrels daily	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
Imports													
USA	7791	7888	8620	8929	8831	9400	9907	10382	10550	11092	11618	4.7%	26.5%
Europe†	10171	10319	11083	10740	10436	10472	10421	11017	10670	11070	11531	4.2%	26.4%
Japan	4925	5306	5307	5612	5581	5685	5735	5259	5346	5329	5202	-2.4%	11.9%
Rest of World*	9451	9884	9753	10464	11562	12764	13721	13432	14157	14911	15403	3.3%	35.2%
TOTAL WORLD	32338	33397	34763	35745	36410	38321	39784	40090	40723	42402	43754	3.2%	100.0%
Exports													
USA	1000	918	959	943	949	978	976	1011	956	890	910	2.2%	2.1%
Canada	1111	1101	1215	1323	1402	1484	1492	1603	1520	1703	1804	5.9%	4.1%
Mexico	1468	1469	1434	1421	1422	1656	1767	1770	1739	1814	1882	3.7%	4.3%
S. & Cent. America	1953	2374	2391	2695	2797	3011	3219	3240	3145	3079	3143	2.1%	7.2%
Europe	n/a	n/a	1358	1634	1472	1540	1463	1344	1851	1967	1947	-1.0%	4.5%
Former Soviet Union#	1860	2298	2436	2531	2731	3239	3413	3569	4019	4273	4679	9.5%	10.7%
Middle East	13829	15453	16456	16513	16651	17170	18184	18702	18341	18944	19098	0.8%	43.6%
North Africa	2781	2849	2685	2652	2696	2756	2743	2712	2726	2732	2724	-0.3%	6.2%
West Africa	2500	2679	2676	2675	2723	2916	3102	3094	2985	3293	3182	-3.4%	7.3%
Asia Pacific†	2257	2414	2420	2517	2576	2790	2735	2490	2650	2767	2879	4.0%	6.6%
Rest of World*	3579	1842	733	841	991	781	690	555	791	940	1506	60.2%	3.4%
TOTAL WORLD	32338	33397	34763	35745	36410	38321	39784	40090	40723	42402	43754	3.2%	100.0%

*Includes unidentified trade.

†Excludes Japan.

‡Prior to 1993, excludes Central Europe (Albania, Bulgaria, Czech Republic, Former Republic of Yugoslavia, Hungary, Poland, Romania, Slovakia).

n/a not available.

#Prior to 1993, includes Central Europe and excludes movements between Former Soviet Union and Central Europe.

Note: For the purposes of this table, annual changes and shares of total are calculated using thousand barrels daily figures.

inter-area movements 2001

From	To												Total
	USA	Canada	Mexico	S. & C. America	Europe	Africa	Austral- asia	China	Japan	Other Asia Pacific	Rest of World	Uniden- tified	
From													
USA	–	6.3	12.1	7.9	11.1	0.2	0.3	0.3	0.6	3.9	0.9	–	43.6
Canada	88.0	–	–	0.2	0.5	–	–	–	–	0.2	–	–	88.9
Mexico	70.8	1.3	–	9.2	9.8	0.2	–	–	1.1	1.0	0.2	–	93.6
S. & Cent. America	126.3	6.0	1.5	–	13.8	0.6	–	0.3	0.4	5.6	–	–	154.5
Europe	46.2	28.9	0.3	2.2	–	7.1	–	1.1	0.1	5.2	4.2	–	95.3
Former Soviet Union	4.3	–	–	7.1	181.2	0.5	–	5.3	0.7	8.7	2.3	20.0	230.1
Middle East	138.0	7.2	1.1	11.8	176.2	41.0	9.1	34.2	208.8	316.7	2.5	–	946.6
North Africa	13.7	3.6	0.8	4.3	96.9	3.9	–	0.3	0.5	7.0	3.2	–	134.2
West Africa	68.1	1.0	–	11.3	34.9	1.5	–	3.8	0.8	36.9	–	–	158.3
East & Southern Africa	–	–	–	–	–	–	–	5.0	1.4	0.9	–	–	7.3
Australasia	2.2	–	–	–	–	–	–	1.0	3.9	14.1	–	–	21.2
China	1.1	–	–	0.3	0.2	–	0.3	–	4.2	8.4	–	–	14.5
Japan	0.4	–	–	–	0.1	0.2	0.2	1.1	–	2.5	–	–	4.5
Other Asia Pacific	9.4	0.2	0.2	–	2.3	0.3	19.4	27.2	34.2	10.8	0.8	–	104.8
Unidentified*	5.2	2.3	–	–	42.9	–	1.2	8.7	0.5	1.1	–	–	61.9
TOTAL IMPORTS	573.7	56.8	16.0	54.3	569.9	55.5	30.5	88.3	257.2	423.0	14.1	20.0	2159.3

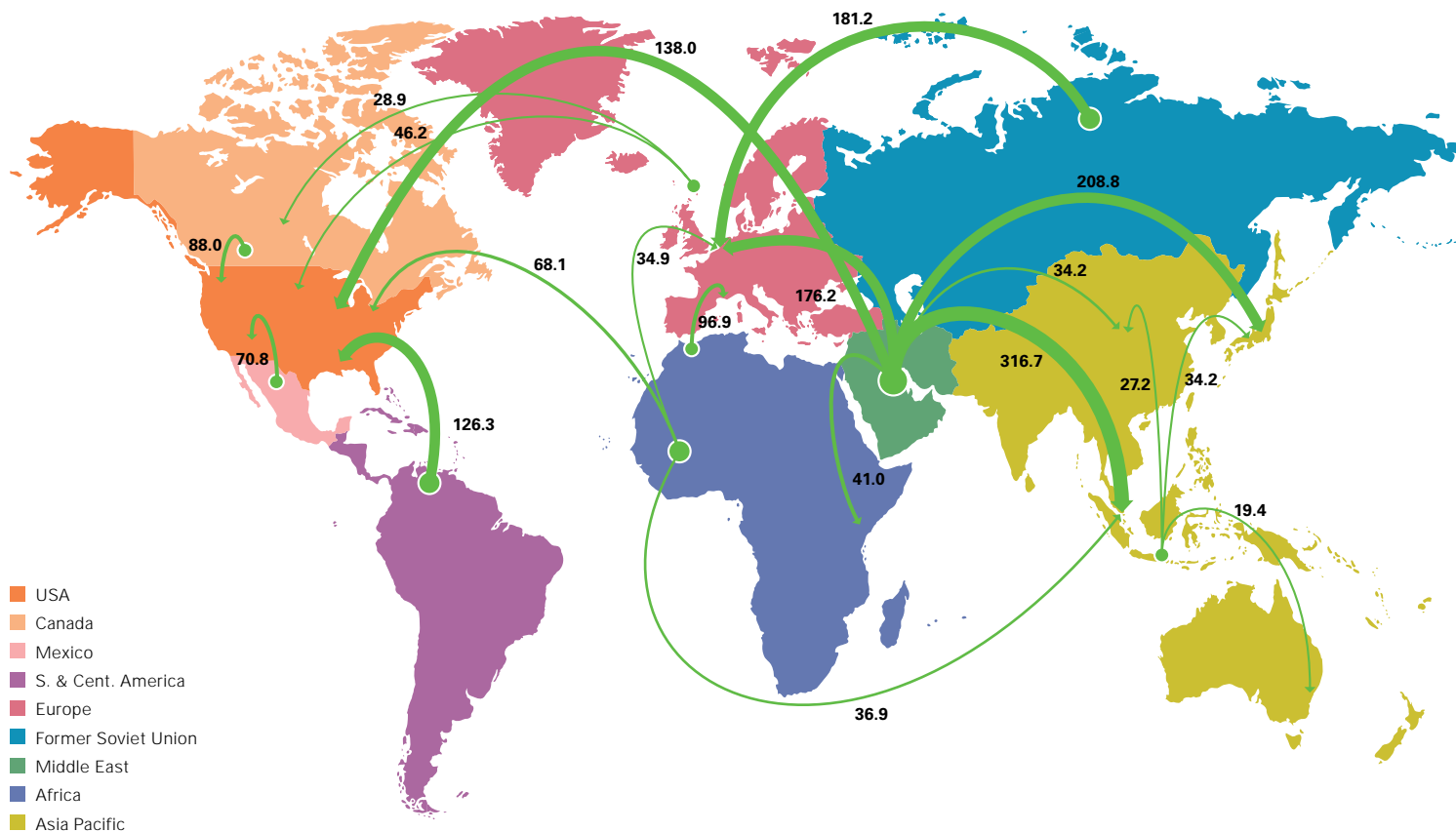
Thousand barrels daily

From													
USA	–	130	253	165	232	4	6	6	13	82	19	–	910
Canada	1786	–	–	4	10	–	–	–	–	4	–	–	1804
Mexico	1424	26	–	185	197	4	–	–	22	20	4	–	1882
S. & Cent. America	2567	122	31	–	281	12	–	6	8	114	–	–	3143
Europe	945	582	6	45	–	148	–	22	2	108	88	–	1947
Former Soviet Union	90	–	–	143	3668	10	–	109	14	179	47	418	4679
Middle East	2775	145	23	237	3548	831	183	689	4211	6405	52	–	19098
North Africa	286	72	17	86	1961	79	–	6	10	142	64	–	2724
West Africa	1370	20	–	227	701	30	–	76	16	741	–	–	3182
East & Southern Africa	–	–	–	–	–	–	–	100	28	18	–	–	147
Australasia	45	–	–	–	–	–	–	20	80	285	–	–	430
China	23	–	–	6	4	–	6	–	85	174	–	–	298
Japan	8	–	–	–	2	4	4	23	–	52	–	–	94
Other Asia Pacific	193	4	4	–	48	6	391	562	703	222	17	–	2151
Unidentified*	107	47	–	–	878	–	25	175	10	22	–	–	1265
TOTAL IMPORTS	11618	1149	334	1098	11531	1130	616	1796	5202	8569	291	418	43754

*Includes changes in the quantity of oil in transit, movements not otherwise shown, unidentified military use etc.

major trade movements

Trade flows worldwide (million tonnes)



imports and exports 2001

	Million tonnes				Thousand barrels daily			
	Crude imports	Product imports	Crude exports	Product exports	Crude imports	Product imports	Crude exports	Product exports
USA	455.4	118.3	1.9	41.7	9145	2473	38	872
Canada	47.0	9.8	65.9	23.0	944	205	1323	481
Mexico	–	16.0	90.8	2.8	–	334	1823	59
S. & Cent. America	44.6	9.7	105.2	49.3	896	203	2113	1031
Europe	464.6	105.3	54.8	40.5	9330	2201	1101	847
Former Soviet Union	–	5.5	159.5	70.6	–	115	3203	1476
Middle East	4.2	4.4	838.7	107.9	84	92	16843	2256
North Africa	8.1	5.1	98.7	35.5	163	107	1982	742
West Africa	2.6	8.1	154.7	3.6	52	169	3107	75
East & Southern Africa	26.5	5.1	7.1	0.2	532	107	143	4
Australasia	26.1	4.4	16.2	5.0	524	92	325	105
China	60.3	28.0	6.6	7.9	1211	585	133	165
Japan	212.0	45.2	–	4.5	4257	945	–	94
Other Asia Pacific	332.6	90.4	48.4	56.4	6679	1890	972	1179
Unidentified*	–	20.0	35.5	26.4	–	418	713	552
TOTAL WORLD	1684.0	475.3	1684.0	475.3	33818	9936	33818	9936

*Includes changes in the quantity of oil in transit, movements not otherwise shown, unidentified military use etc.

Note: Bunkers are not included as exports. Intra-area movements (for example, between countries in Europe) are excluded.

natural gas

proved reserves

	At end 1981 Trillion cubic metres	At end 1991 Trillion cubic metres	At end 2000 Trillion cubic metres	Trillion cubic metres	At end 2001 Trillion cubic feet	Share of total	R/P ratio
USA	5.61	4.79	4.74	5.02	177.4	3.2%	9.2
Canada	2.55	2.74	1.73	1.69	59.7	1.1%	9.8
Mexico	2.13	2.02	0.86	0.84	29.5	0.5%	24.0
Total North America	10.29	9.56	7.33	7.55	266.7	4.9%	10.0
Argentina	0.66	0.58	0.75	0.78	27.5	0.5%	20.3
Bolivia	0.15	0.13	0.52	0.68	24.0	0.4%	*
Brazil	0.05	0.11	0.23	0.22	7.8	0.1%	28.8
Colombia	0.12	0.11	0.20	0.12	4.3	0.1%	20.1
Ecuador	0.12	0.11	0.10	0.10	3.7	0.1%	*
Trinidad & Tobago	0.31	0.25	0.60	0.66	23.5	0.4%	51.4
Venezuela	1.33	3.11	4.16	4.18	147.6	2.7%	*
Other S. & Cent. America	0.11	0.32	0.37	0.42	14.7	0.3%	*
Total S. & Cent. America	2.86	4.73	6.93	7.16	253.0	4.6%	71.6
Denmark	0.06	0.11	0.10	0.08	2.7	♦	9.2
Germany	0.17	0.25	0.33	0.34	12.1	0.2%	20.1
Hungary	n/a	0.11	0.08	0.04	1.3	♦	13.3
Italy	0.10	0.32	0.23	0.23	8.1	0.1%	14.8
Netherlands	1.58	1.97	1.77	1.77	62.5	1.1%	25.1
Norway	1.40	1.72	1.25	1.25	44.0	0.8%	21.7
Romania	n/a	0.10	0.37	0.10	3.6	0.1%	8.0
United Kingdom	0.74	0.55	0.76	0.73	26.0	0.5%	6.9
Other Europe	0.53	0.39	0.33	0.32	11.4	0.2%	27.8
Total Europe	4.57	5.52	5.21	4.86	171.7	3.1%	16.1
Azerbaijan	n/a	n/a	0.85	0.85	30.0	0.5%	*
Kazakhstan	n/a	n/a	1.84	1.84	65.0	1.2%	*
Russian Federation	n/a	n/a	48.14	47.57	1680.0	30.7%	83.1
Turkmenistan	n/a	n/a	2.86	2.86	101.0	1.8%	56.6
Ukraine	n/a	n/a	1.12	1.12	39.6	0.7%	62.2
Uzbekistan	n/a	n/a	1.87	1.87	66.2	1.2%	33.2
Other Former Soviet Union	n/a	n/a	0.02	0.02	0.8	♦	55.8
Total Former Soviet Union	32.85	49.55	56.71	56.14	1982.6	36.2%	78.5
Bahrain	0.24	0.17	0.11	0.09	3.2	0.1%	10.3
Iran	13.71	17.00	23.00	23.00	812.3	14.8%	*
Iraq	0.77	2.69	3.11	3.11	109.8	2.0%	*
Kuwait	0.98	1.37	1.49	1.49	52.7	1.0%	*
Oman	0.08	0.28	0.83	0.83	29.3	0.5%	61.9
Qatar	1.70	4.59	11.15	14.40	508.5	9.3%	*
Saudi Arabia	3.35	5.23	6.05	6.22	219.5	4.0%	*
United Arab Emirates	0.66	5.64	6.01	6.01	212.1	3.9%	*
Yemen	–	0.20	0.48	0.48	16.9	0.3%	*
Other Middle East	0.09	0.18	0.29	0.29	10.2	0.2%	56.7
Total Middle East	21.58	37.35	52.52	55.91	1974.6	36.1%	*
Algeria	3.71	3.30	4.52	4.52	159.7	2.9%	57.8
Egypt	0.08	0.35	1.00	1.00	35.2	0.6%	47.5
Libya	0.66	1.22	1.31	1.31	46.4	0.8%	*
Nigeria	1.15	2.97	3.51	3.51	124.0	2.3%	*
Other Africa	0.40	0.95	0.82	0.84	29.5	0.5%	*
Total Africa	5.99	8.78	11.16	11.18	394.8	7.2%	90.2
Australia	0.53	0.43	1.26	2.55	90.0	1.6%	77.9
Bangladesh	0.20	0.72	0.30	0.30	10.6	0.2%	27.8
Brunei	0.20	0.32	0.39	0.39	13.8	0.3%	34.3
China	0.69	1.00	1.37	1.37	48.3	0.9%	45.1
India	0.35	0.73	0.65	0.65	22.9	0.4%	24.5
Indonesia	0.78	1.84	2.05	2.62	92.5	1.7%	41.6
Malaysia	0.54	1.67	2.31	2.12	75.0	1.4%	44.8
Pakistan	0.46	0.64	0.61	0.71	25.1	0.5%	35.6
Papua New Guinea	–	0.23	0.22	0.35	12.2	0.2%	*
Thailand	0.34	0.39	0.33	0.36	12.7	0.2%	19.9
Vietnam	–	†	0.19	0.19	6.8	0.1%	96.3
Other Asia Pacific	0.21	0.51	0.65	0.66	23.4	0.4%	36.9
Total Asia Pacific	4.30	8.47	10.34	12.27	433.3	7.9%	43.8
TOTAL WORLD	82.44	123.97	150.19	155.08	5476.7	100.0%	61.9
of which: European Union 15	2.87	3.32	3.24	3.21	113.4	2.1%	14.5
OECD#	15.29	15.42	13.45	14.87	525.0	9.6%	13.7

*Over 100 years.

†Less than 0.05.

•Less than 0.05%.

#1981 excludes Central European members.

n/a not available.

Notes:

Proved reserves of natural gas – Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

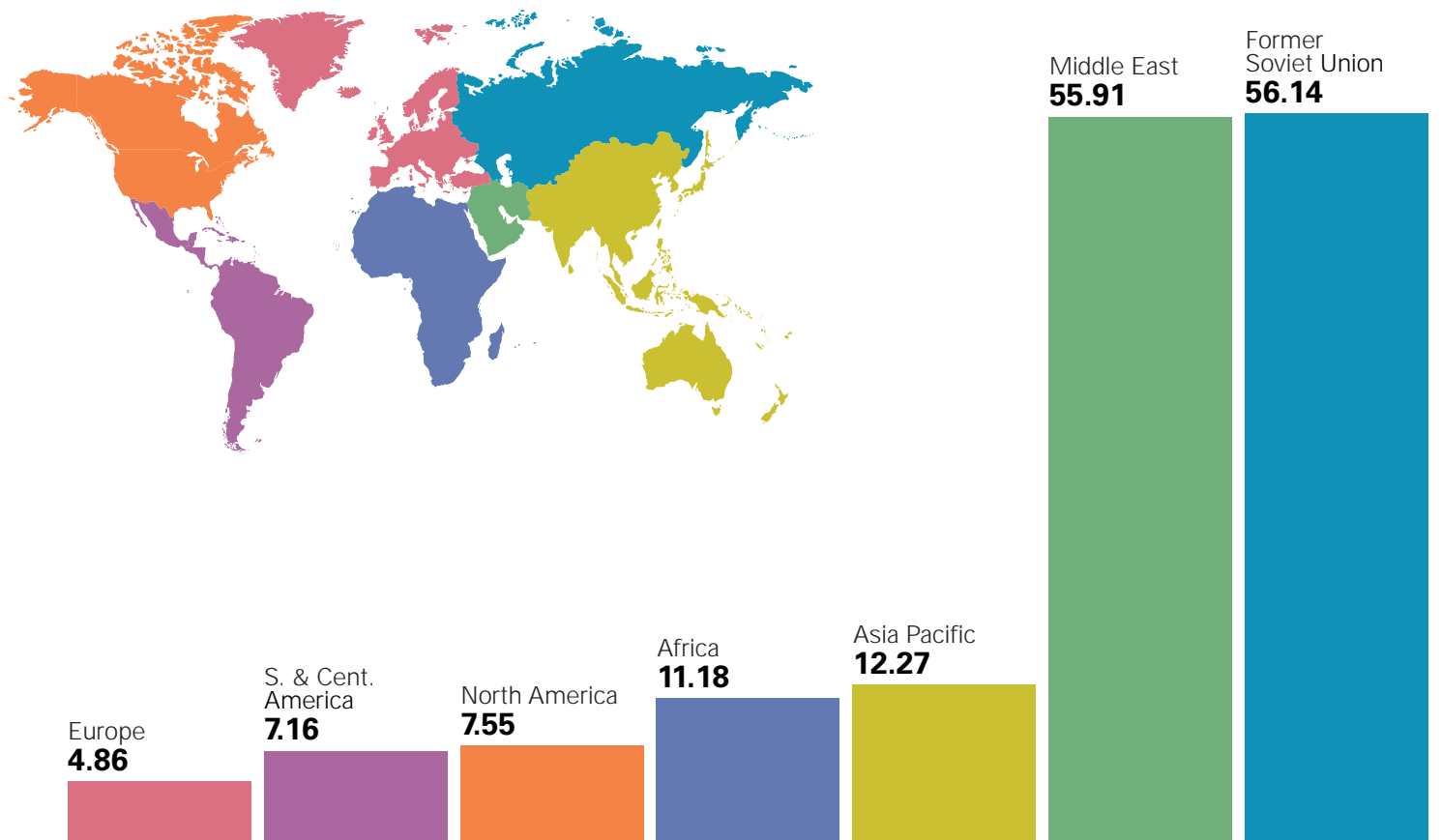
Reserves/Production (R/P) ratio – If the reserves remaining at the end of any year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level.

Source of data – With the exception of Azerbaijan, the estimates contained in this table are those published by the Oil and Gas Journal.

Trillion equals one million million (10¹²). 1 trillion cubic feet of natural gas = 26 million tonnes of oil (approximately).

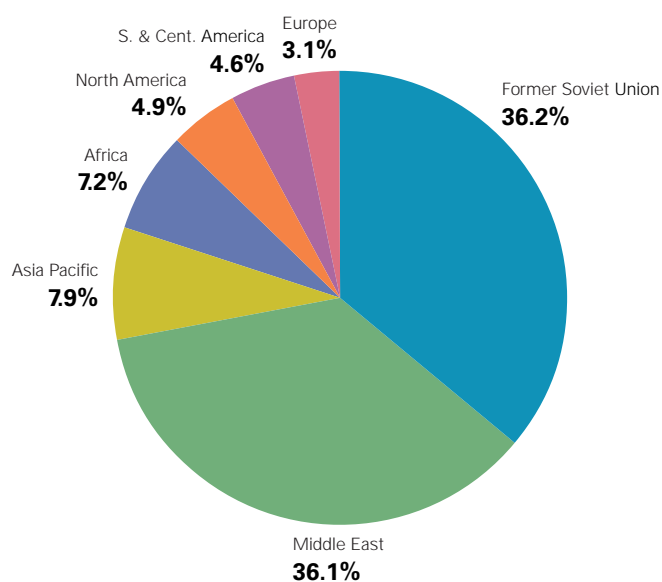
proved reserves at end 2001

Trillion cubic metres



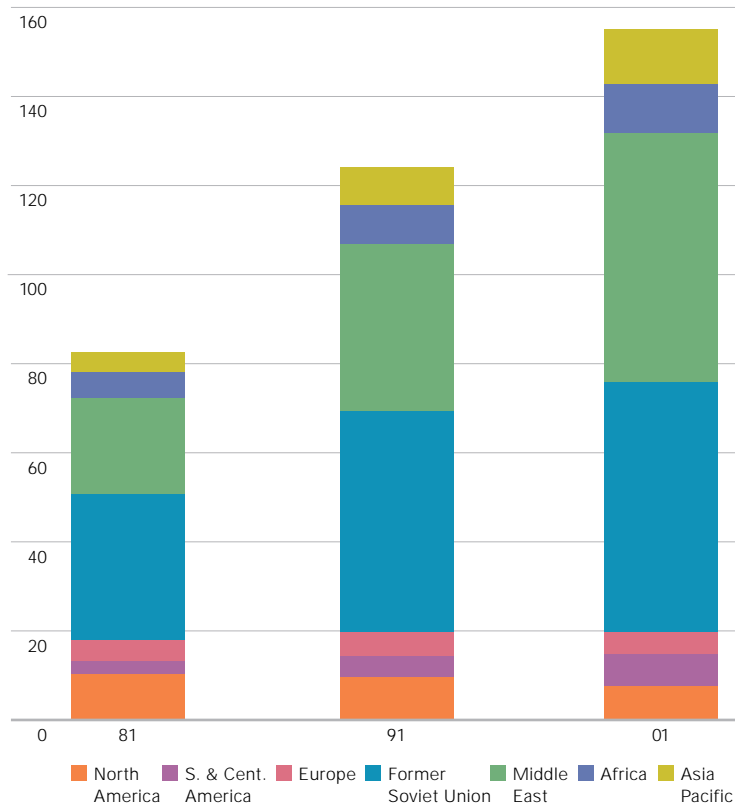
distribution of proved reserves 2001

Trillion cubic metres %



proved reserves

Trillion cubic metres



natural gas

production*

Billion cubic metres	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	510.4	514.5	520.4	541.8	534.9	542.2	543.1	549.2	541.6	544.9	555.4	1.9%	22.5%
Canada	105.4	116.1	125.5	135.9	148.2	153.6	156.2	160.5	162.2	167.8	172.0	2.5%	7.0%
Mexico	27.9	27.8	27.8	28.7	28.1	31.2	33.8	36.6	38.5	37.1	34.7	-6.3%	1.4%
Total North America	643.7	658.4	673.7	706.4	711.2	727.0	733.1	746.3	742.3	749.8	762.1	1.6%	30.9%
Argentina	19.9	20.1	21.5	22.3	25.0	26.6	27.4	29.6	34.6	37.4	38.4	2.6%	1.6%
Bolivia	3.0	3.0	3.0	3.3	3.2	3.2	3.3	3.1	2.5	3.4	4.1	20.5%	0.2%
Brazil	3.9	4.0	4.5	4.5	4.8	5.5	6.0	6.3	6.7	6.8	7.7	13.3%	0.3%
Colombia	4.1	4.0	4.2	4.2	4.4	4.7	5.9	6.3	5.2	5.9	6.1	3.0%	0.2%
Trinidad & Tobago	5.7	6.0	5.9	6.2	6.1	7.1	7.4	8.6	10.9	13.0	12.9	-0.5%	0.5%
Venezuela	21.9	21.6	23.3	24.7	27.5	29.7	30.8	32.3	27.4	27.9	28.9	3.3%	1.2%
Other S. & Cent. America	2.0	2.2	2.1	2.2	2.2	2.3	2.4	2.5	2.1	2.1	2.0	-2.6%	0.1%
Total S. & Cent. America	60.5	60.9	64.5	67.4	73.2	79.1	83.2	88.7	89.4	96.5	100.1	3.7%	4.1%
Denmark	4.0	4.1	4.5	4.9	5.3	6.4	7.9	7.6	7.8	8.1	8.4	3.5%	0.3%
Germany	14.7	14.9	14.9	15.6	16.1	17.4	17.1	16.7	17.8	16.9	17.0	0.9%	0.7%
Hungary	4.3	4.0	4.3	4.1	4.2	4.0	3.7	3.3	2.9	2.7	2.7	1.0%	0.1%
Italy	17.4	18.2	19.5	20.6	20.4	20.0	19.3	19.0	17.5	16.2	15.5	-4.6%	0.6%
Netherlands	69.0	69.1	70.0	66.4	67.0	75.8	67.1	63.6	59.3	57.3	61.4	7.1%	2.5%
Norway	27.3	29.4	28.9	30.8	31.2	41.0	46.7	47.8	51.0	54.0	57.5	6.4%	2.3%
Romania	24.5	21.8	20.6	18.7	18.0	17.2	15.0	14.0	14.0	13.8	12.6	-8.5%	0.5%
United Kingdom	50.6	51.5	60.5	64.6	70.8	84.2	85.9	90.2	99.1	108.3	105.8	-2.3%	4.3%
Other Europe	14.3	14.0	15.1	14.5	14.6	13.3	12.8	12.3	11.6	11.8	11.6	-1.4%	0.5%
Total Europe	226.1	227.0	238.3	240.2	247.6	279.3	275.5	274.5	281.0	289.1	292.5	1.2%	11.9%
Azerbaijan	8.0	7.4	6.3	6.0	6.2	5.9	5.6	5.2	5.6	5.3	5.2	-2.0%	0.2%
Kazakhstan	7.4	7.6	6.2	4.2	5.5	6.1	7.6	7.4	9.3	10.8	10.8	0.3%	0.4%
Russian Federation	599.8	597.4	576.5	566.4	555.4	561.1	532.6	551.3	551.0	545.0	542.4	-0.5%	22.0%
Turkmenistan	78.6	56.1	60.9	33.3	30.1	32.8	16.1	12.4	21.3	43.8	47.9	9.1%	1.9%
Ukraine	22.8	19.6	17.9	17.0	17.0	17.2	17.4	16.8	16.9	16.7	17.1	2.3%	0.7%
Uzbekistan	39.1	39.9	42.0	44.0	45.3	45.7	47.8	51.1	51.9	52.6	53.5	1.8%	2.2%
Other Former Soviet Union	0.6	0.6	0.4	0.4	0.4	0.3	0.3	0.4	0.4	0.4	0.4	-8.7%	♦
Total Former Soviet Union	756.3	728.6	710.2	671.3	659.9	669.1	627.4	644.6	656.4	674.6	677.3	0.4%	27.5%
Bahrain	5.5	6.5	6.9	7.1	7.2	7.4	8.0	8.4	8.7	8.8	8.9	1.4%	0.4%
Iran	25.8	25.0	27.1	31.8	35.3	39.0	47.0	50.0	57.8	60.2	60.6	0.6%	2.5%
Kuwait	0.5	2.6	5.4	6.0	9.3	9.3	9.3	9.5	8.6	9.6	9.5	-1.0%	0.4%
Oman	2.6	2.9	2.8	2.9	4.1	4.4	5.0	5.2	5.5	8.4	13.4	59.7%	0.5%
Qatar	7.6	12.6	13.5	13.5	13.5	13.7	17.4	19.6	22.1	29.1	32.5	11.7%	1.3%
Saudi Arabia	35.2	38.3	40.0	42.8	42.9	44.4	45.3	46.8	46.2	49.8	53.7	7.8%	2.2%
United Arab Emirates	23.8	22.2	23.0	25.8	31.3	33.8	36.3	37.1	38.5	39.8	41.3	3.8%	1.7%
Other Middle East	3.4	4.0	4.2	4.9	5.3	6.0	7.2	7.5	7.9	7.9	8.1	2.0%	0.3%
Total Middle East	104.4	114.1	122.9	134.8	148.9	158.0	175.5	184.1	195.3	213.6	228.0	6.7%	9.3%
Algeria	53.2	55.3	56.1	51.6	58.7	62.3	71.8	76.6	86.0	84.4	78.2	-7.3%	3.2%
Egypt	7.8	8.4	10.0	10.6	11.0	11.5	11.6	12.2	14.7	18.3	21.0	14.4%	0.9%
Libya	5.9	6.1	5.8	5.8	5.8	5.8	6.0	5.8	5.5	5.4	5.4	-	0.2%
Nigeria	3.9	4.3	4.9	4.4	4.8	5.4	5.1	5.1	6.0	10.8	13.4	23.6%	0.5%
Other Africa	1.1	1.1	2.7	2.9	3.0	4.2	4.9	5.0	5.4	5.6	6.0	5.8%	0.2%
Total Africa	71.9	75.2	79.5	75.3	83.3	89.2	99.4	104.7	117.6	124.5	124.0	-0.5%	5.0%
Australia	21.7	23.5	24.5	28.1	29.8	30.6	30.0	30.4	30.6	31.1	32.7	5.3%	1.3%
Bangladesh	5.3	5.7	6.1	6.6	7.4	7.6	7.6	7.8	8.3	10.0	10.8	8.2%	0.4%
Brunei	9.1	9.8	10.3	10.4	11.8	11.7	11.7	10.8	11.2	11.3	11.4	1.0%	0.5%
China	14.9	15.1	16.2	16.6	17.6	19.9	22.2	22.3	24.3	27.2	30.3	11.5%	1.2%
India	14.2	15.9	16.1	17.3	18.8	20.4	20.7	24.6	24.9	26.1	26.4	1.1%	1.1%
Indonesia	51.5	54.3	56.2	62.9	63.8	67.1	67.6	64.7	71.4	67.3	62.9	-6.4%	2.6%
Malaysia	20.4	22.8	24.9	26.1	28.9	33.6	38.6	38.5	40.8	45.3	47.4	4.7%	1.9%
Pakistan	11.1	11.5	12.2	13.3	14.6	15.4	15.6	16.0	17.3	18.9	19.9	5.2%	0.8%
Thailand	7.0	7.5	8.4	9.5	10.1	11.8	14.1	15.5	16.9	17.9	18.1	1.0%	0.7%
Other Asia Pacific	8.7	9.1	9.5	9.5	9.2	10.2	10.8	10.6	11.6	18.6	20.1	8.3%	0.8%
Total Asia Pacific	163.9	175.2	184.4	200.3	212.0	228.3	238.9	241.2	257.3	273.7	280.0	2.4%	11.4%
TOTAL WORLD	2026.8	2039.4	2073.5	2095.7	2136.1	2230.0	2233.0	2284.1	2339.3	2421.8	2464.0	1.7%	100.0%
of which: European Union 15	163.8	165.7	177.0	179.8	187.0	210.4	203.3	202.3	206.4	211.6	212.9	0.6%	8.6%
OECD	871.0	891.5	919.6	960.0	973.8	1024.3	1028.3	1041.5	1045.1	1061.7	1080.4	1.8%	43.8%
Former Soviet Union	756.3	728.6	710.2	671.3	659.9	669.1	627.4	644.6	656.4	674.6	677.3	0.4%	27.5%
Other EMEs	399.6	419.3	443.6	464.4	502.1	536.6	577.0	597.6	638.0	685.6	706.4	3.0%	28.7%

*Excluding gas flared or recycled.

♦Less than 0.05%.

Notes: As far as possible, the data above represents standard cubic metres (measured at 15°C and 1013 mbar); as it is derived directly from tonnes of oil equivalent using an average conversion factor, it does not necessarily equate with gas volumes expressed in specific national terms.

Because of rounding some totals may not agree exactly with the sum of their component parts.

Natural gas production data expressed in billion cubic feet per day is available at www.bp.com/centres/energy/

production*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	459.4	463.1	468.3	487.6	481.4	488.0	488.8	494.3	487.4	490.4	499.9	1.9%	22.5%
Canada	94.8	104.5	112.9	122.3	133.4	138.2	140.6	144.5	146.0	151.0	154.8	2.5%	7.0%
Mexico	25.1	25.0	25.0	25.8	25.3	28.1	30.4	32.9	34.6	33.4	31.3	-6.3%	1.4%
Total North America	579.3	592.6	606.2	635.7	640.1	654.3	659.8	671.7	668.0	674.8	686.0	1.6%	30.9%
Argentina	17.9	18.1	19.4	20.0	22.5	23.9	24.6	26.6	31.1	33.7	34.5	2.6%	1.6%
Bolivia	2.7	2.7	2.7	3.0	2.8	2.9	2.9	2.8	2.3	3.1	3.7	20.5%	0.2%
Brazil	3.5	3.6	4.0	4.1	4.3	5.0	5.4	5.6	6.1	6.1	6.9	13.3%	0.3%
Colombia	3.7	3.6	3.8	3.7	4.0	4.2	5.3	5.6	4.7	5.3	5.5	3.0%	0.2%
Trinidad & Tobago	5.1	5.4	5.3	5.6	5.5	6.4	6.7	7.8	9.8	11.7	11.6	-0.5%	0.5%
Venezuela	19.7	19.5	21.0	22.2	24.8	26.8	27.7	29.1	24.7	25.1	26.0	3.3%	1.2%
Other S. & Cent. America	1.8	2.0	1.9	2.0	2.0	2.0	2.1	2.3	1.9	1.9	1.8	-2.6%	0.1%
Total S. & Cent. America	54.4	54.9	58.1	60.6	65.9	71.2	74.7	79.8	80.6	86.9	90.0	3.7%	4.1%
Denmark	3.6	3.7	4.1	4.4	4.8	5.8	7.1	6.8	7.0	7.3	7.5	3.5%	0.3%
Germany	13.2	13.4	13.4	14.0	14.5	15.7	15.4	15.0	16.1	15.2	15.3	0.9%	0.7%
Hungary	3.8	3.6	3.9	3.7	3.7	3.6	3.3	3.0	2.6	2.4	2.5	1.0%	0.1%
Italy	15.7	16.3	17.5	18.6	18.3	18.0	17.3	17.1	15.7	14.6	13.9	-4.6%	0.6%
Netherlands	62.1	62.2	63.0	59.7	60.3	68.2	60.4	57.2	53.3	51.6	55.2	7.1%	2.5%
Norway	24.6	26.5	26.0	27.7	28.0	36.9	42.0	43.0	45.9	48.6	51.7	6.4%	2.3%
Romania	22.0	19.6	18.5	16.8	16.2	15.5	13.5	12.6	12.6	12.4	11.3	-8.5%	0.5%
United Kingdom	45.6	46.3	54.5	58.2	63.7	75.8	77.3	81.2	89.2	97.4	95.2	-2.3%	4.3%
Other Europe	12.9	12.6	13.6	13.0	13.2	12.0	11.5	11.0	10.5	10.6	10.5	-1.4%	0.5%
Total Europe	203.5	204.2	214.5	216.1	222.7	251.5	247.8	246.9	252.9	260.1	263.1	1.2%	11.9%
Azerbaijan	7.2	6.6	5.7	5.4	5.5	5.3	5.0	4.7	5.0	4.7	4.7	-2.0%	0.2%
Kazakhstan	6.6	6.8	5.6	3.8	5.0	5.5	6.8	6.7	8.4	9.7	9.7	0.3%	0.4%
Russian Federation	539.8	537.6	518.8	509.8	499.9	505.0	479.3	496.2	495.9	490.5	488.2	-0.5%	22.0%
Turkmenistan	70.8	50.5	54.8	30.0	27.1	29.6	14.5	11.2	19.1	39.5	43.1	9.1%	1.9%
Ukraine	20.5	17.6	16.1	15.3	15.3	15.4	15.7	15.1	15.2	15.0	15.4	2.3%	0.7%
Uzbekistan	35.2	35.9	37.8	39.6	40.8	41.1	43.0	46.0	46.7	47.4	48.2	1.8%	2.2%
Other Former Soviet Union	0.5	0.5	0.4	0.3	0.3	0.2	0.3	0.4	0.3	0.4	0.3	-8.7%	*
Total Former Soviet Union	680.6	655.5	639.2	604.2	593.9	602.1	564.6	580.3	590.6	607.2	609.6	0.4%	27.5%
Bahrain	5.0	5.8	6.2	6.4	6.5	6.7	7.2	7.5	7.8	7.9	8.0	1.4%	0.4%
Iran	23.2	22.5	24.4	28.6	31.8	35.1	42.3	45.0	52.0	54.2	54.5	0.6%	2.5%
Kuwait	0.5	2.4	4.9	5.4	8.4	8.4	8.3	8.5	7.8	8.6	8.6	-1.0%	0.4%
Oman	2.4	2.6	2.5	2.6	3.6	3.9	4.5	4.7	4.9	7.6	12.1	59.7%	0.5%
Qatar	6.9	11.4	12.2	12.2	12.2	12.3	15.7	17.6	19.8	26.2	29.3	11.7%	1.3%
Saudi Arabia	31.7	34.4	36.0	38.5	38.6	40.0	40.8	42.1	41.6	44.8	48.3	7.8%	2.2%
United Arab Emirates	21.4	20.0	20.7	23.2	28.2	30.4	32.7	33.4	34.6	35.9	37.2	3.8%	1.7%
Other Middle East	3.1	3.6	3.8	4.4	4.8	5.4	6.5	6.7	7.1	7.1	7.3	2.0%	0.3%
Total Middle East	94.2	102.7	110.7	121.3	134.1	142.2	158.0	165.5	175.6	192.3	205.3	6.7%	9.3%
Algeria	47.9	49.8	50.5	46.5	52.8	56.1	64.6	68.9	77.4	76.0	70.4	-7.3%	3.2%
Egypt	7.0	7.6	9.0	9.5	9.9	10.4	10.5	11.0	13.2	16.5	18.9	14.4%	0.9%
Libya	5.3	5.5	5.2	5.2	5.2	5.2	5.4	5.2	5.0	4.9	4.9	-	0.2%
Nigeria	3.5	3.8	4.4	4.0	4.4	4.9	4.6	4.6	5.4	9.8	12.1	23.6%	0.5%
Other Africa	1.0	1.0	2.4	2.6	2.7	3.8	4.4	4.5	4.9	5.1	5.4	5.8%	0.2%
Total Africa	64.7	67.7	71.5	67.8	75.0	80.4	89.5	94.2	105.9	112.3	111.7	-0.5%	5.0%
Australia	19.5	21.1	22.0	25.3	26.8	27.5	27.0	27.3	27.5	28.0	29.4	5.3%	1.3%
Bangladesh	4.8	5.2	5.5	6.0	6.6	6.8	6.8	7.0	7.5	9.0	9.7	8.2%	0.4%
Brunei	8.2	8.8	9.3	9.4	10.6	10.5	10.5	9.7	10.1	10.2	10.3	1.0%	0.5%
China	13.4	13.6	14.6	14.9	15.8	17.9	20.0	20.1	21.9	24.5	27.3	11.5%	1.2%
India	12.8	14.3	14.5	15.6	16.9	18.4	18.6	22.2	22.4	23.5	23.7	1.1%	1.1%
Indonesia	46.4	48.9	50.6	56.6	57.4	60.4	60.8	58.2	64.3	60.5	56.6	-6.4%	2.6%
Malaysia	18.3	20.5	22.4	23.5	26.0	30.3	34.8	34.6	36.8	40.7	42.7	4.7%	1.9%
Pakistan	10.0	10.3	10.9	12.0	13.1	13.8	14.0	14.4	15.6	17.0	17.9	5.2%	0.8%
Thailand	6.3	6.8	7.6	8.6	9.1	10.6	12.7	13.9	15.3	16.1	16.3	1.0%	0.7%
Other Asia Pacific	7.9	8.2	8.5	8.5	8.3	9.2	9.7	9.5	10.4	16.7	18.1	8.3%	0.8%
Total Asia Pacific	147.6	157.7	165.9	180.4	190.6	205.4	214.9	216.9	231.8	246.2	252.0	2.4%	11.4%
TOTAL WORLD	1824.3	1835.3	1866.1	1886.1	1922.3	2007.1	2009.3	2055.3	2105.4	2179.8	2217.7	1.7%	100.0%
of which: European Union 15	147.4	149.2	159.3	161.8	168.3	189.3	183.0	182.1	185.7	190.4	191.6	0.6%	8.6%
OECD	783.9	802.4	827.6	864.0	876.4	921.8	925.5	937.3	940.5	955.5	972.3	1.8%	43.8%
Former Soviet Union	680.6	655.5	639.2	604.2	593.9	602.1	564.6	580.3	590.6	607.2	609.6	0.4%	27.5%
Other EMEs	359.7	377.4	399.2	418.0	451.9	483.0	519.3	537.9	574.2	617.1	635.8	3.0%	28.7%

*Excluding gas flared or recycled.

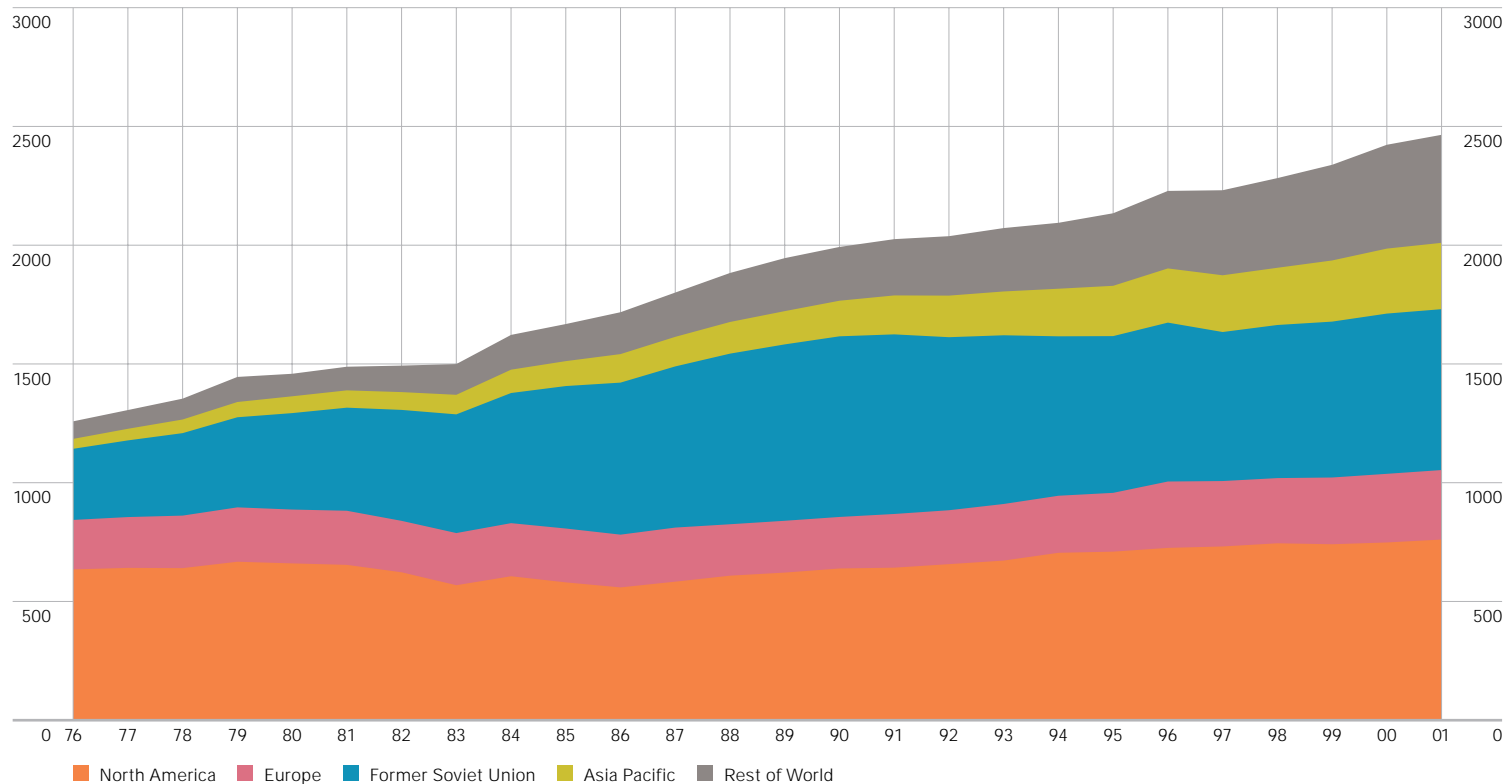
*Less than 0.05%.

Note: Because of rounding some totals may not agree exactly with the sum of their component parts.

natural gas

production by area

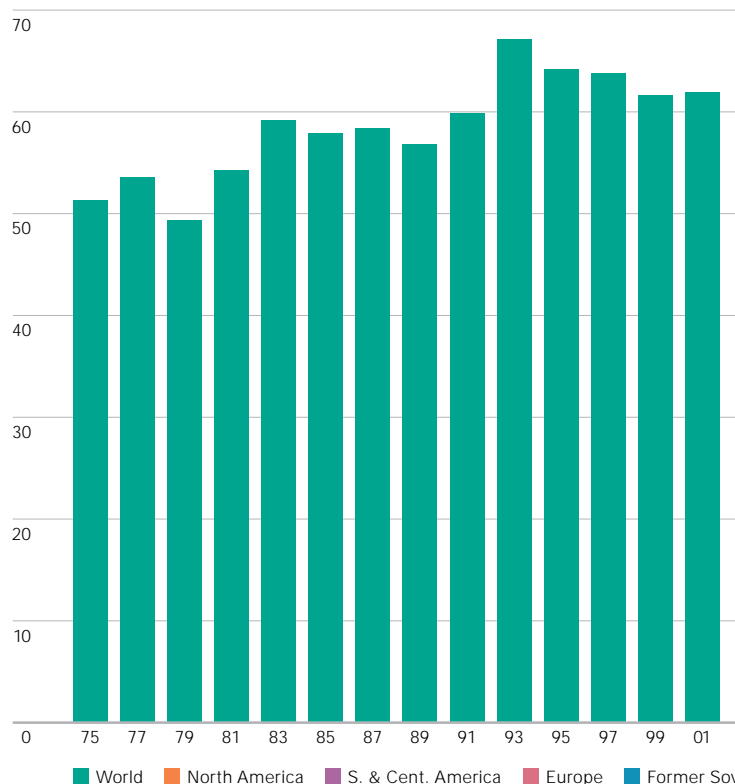
Billion cubic metres



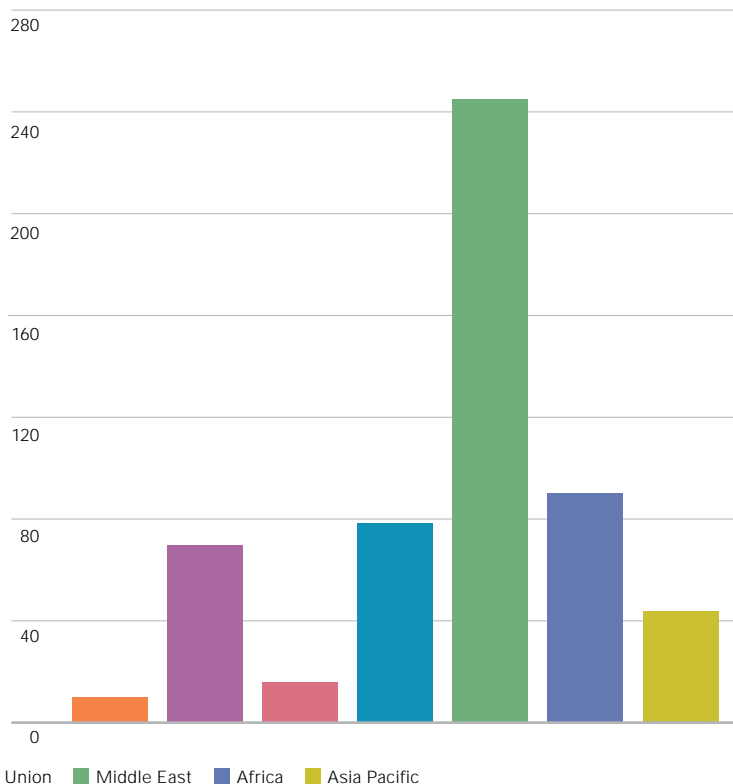
The rate of gas production growth halved in 2001 relative to a very strong 2000. However, the unbroken growth trend of the previous decade was maintained.

R/P ratios

World – Reserves to production ratio



2001 by area – Reserves to production ratio



The world's gas R/P ratio increased to 61.9 at the end of 2001, leaving it two years higher than a decade earlier. Large reserve increases in major LNG exporting countries (Indonesia, Qatar and Australia) outweighed a 1.7% increase in global production.

consumption

Billion cubic metres	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	549.0	563.7	583.2	596.1	620.6	631.7	630.9	614.3	621.7	647.1	616.2	-4.8%	25.6%
Canada	63.0	66.8	68.4	70.8	70.9	74.3	74.8	70.3	72.7	77.5	72.6	-6.4%	3.0%
Mexico	27.7	27.7	28.2	29.4	29.7	31.0	31.7	34.4	33.8	34.9	33.7	-3.3%	1.4%
Total North America	639.7	658.2	679.8	696.3	721.2	737.0	737.4	719.0	728.2	759.5	722.5	-4.9%	30.0%
Argentina	22.1	22.3	23.6	24.3	27.0	28.6	28.5	30.5	32.4	33.2	33.2	♦	1.4%
Brazil	3.9	4.0	4.5	4.5	4.8	5.5	6.0	6.3	7.1	9.1	10.9	19.3%	0.5%
Chile	1.5	1.7	1.6	1.7	1.6	1.7	2.8	3.3	4.6	5.2	5.6	6.5%	0.2%
Colombia	4.1	4.0	4.2	4.2	4.4	4.7	5.9	6.2	5.2	5.9	6.1	2.6%	0.3%
Ecuador	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-	♦
Peru	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.4	0.4	0.3	0.4	7.1%	♦
Venezuela	21.9	21.6	23.3	24.7	27.5	29.7	30.8	32.3	27.4	27.9	28.9	3.3%	1.2%
Other S. & Cent. America	6.5	6.8	6.8	7.3	7.3	8.2	8.9	9.7	10.3	11.2	11.8	5.2%	0.5%
Total S. & Cent. America	60.5	60.9	64.5	67.2	73.1	78.9	83.2	88.8	87.5	92.9	97.0	4.1%	4.0%
Austria	6.1	6.0	6.4	6.5	6.8	7.3	7.7	7.6	7.7	7.3	7.4	0.6%	0.3%
Belgium & Luxembourg	10.0	10.0	11.0	10.8	11.8	13.1	12.5	13.8	14.7	14.9	14.7	-1.4%	0.6%
Bulgaria	5.0	4.3	4.1	4.1	5.0	5.2	4.1	3.4	3.0	2.9	2.6	-9.3%	0.1%
Czech Republic	5.9	5.8	5.9	6.3	7.3	8.4	8.5	8.5	8.6	8.3	8.9	7.0%	0.4%
Denmark	2.3	2.4	2.8	3.0	3.5	4.1	4.4	4.8	5.0	4.9	5.1	4.4%	0.2%
Finland	2.6	2.7	2.8	3.1	3.2	3.3	3.2	3.7	3.7	3.7	4.1	8.5%	0.2%
France	30.6	31.4	32.3	30.9	32.9	36.1	34.6	37.0	37.7	39.7	40.7	2.5%	1.7%
Germany	62.9	63.0	66.4	67.9	74.4	83.6	79.2	79.7	80.2	79.5	82.9	4.3%	3.4%
Greece	0.1	0.1	0.1	†	†	†	0.2	0.8	1.4	1.9	1.9	1.1%	0.1%
Hungary	9.6	8.2	9.0	9.4	10.2	11.4	10.8	10.9	11.0	10.7	11.9	11.1%	0.5%
Iceland	-	-	-	-	-	-	-	-	-	-	-	-	-
Republic of Ireland	2.1	2.1	2.4	2.4	2.6	3.0	3.1	3.1	3.3	3.8	4.0	4.3%	0.2%
Italy	46.2	45.7	46.8	45.3	49.9	51.5	53.2	57.2	62.2	64.9	64.5	-0.6%	2.7%
Netherlands	38.1	36.7	37.9	36.9	37.8	41.7	39.1	38.7	37.9	39.2	39.3	0.2%	1.6%
Norway	2.4	2.6	2.7	2.9	2.9	3.2	3.7	3.8	3.6	4.0	4.5	10.6%	0.2%
Poland	8.8	8.7	9.0	9.2	9.9	10.6	10.5	10.6	10.3	11.1	11.4	2.7%	0.5%
Portugal	-	-	-	-	-	-	0.1	0.8	2.3	2.4	2.5	7.6%	0.1%
Romania	24.7	25.4	25.2	24.2	24.0	24.2	20.0	18.7	17.2	17.1	17.5	2.3%	0.7%
Slovakia	5.4	5.5	5.2	5.0	5.7	6.2	6.3	6.4	6.4	6.5	7.4	14.3%	0.3%
Spain	6.1	6.5	6.5	7.2	8.3	9.3	12.3	13.1	15.0	16.9	18.2	7.7%	0.8%
Sweden	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.9	0.8	0.7	0.8	4.8%	♦
Switzerland	2.0	2.1	2.2	2.2	2.4	2.6	2.5	2.6	2.7	2.7	2.8	4.2%	0.1%
Turkey	4.4	4.5	5.0	6.5	6.8	9.0	9.4	9.9	12.0	14.1	15.5	9.7%	0.6%
United Kingdom	56.6	56.4	64.2	66.1	70.5	82.1	83.8	87.2	92.5	96.0	95.4	-0.6%	4.0%
Other Europe	6.7	6.0	5.0	4.0	4.2	6.0	6.1	5.9	5.3	5.6	6.1	7.8%	0.3%
Total Europe	339.3	336.8	353.7	354.7	380.9	422.8	416.1	429.1	444.5	458.8	470.1	2.4%	19.5%
Azerbaijan	15.1	11.8	8.7	8.1	8.0	5.9	5.6	5.2	5.6	5.4	8.4	55.2%	0.3%
Belarus	14.5	16.8	15.6	13.6	12.3	13.0	14.8	15.0	15.3	16.2	16.1	-0.6%	0.7%
Kazakhstan	13.2	13.5	13.0	10.3	10.8	9.0	7.1	7.3	7.9	9.7	10.1	3.8%	0.4%
Lithuania	5.4	3.0	1.7	2.0	2.3	2.5	2.6	2.3	2.4	2.7	2.8	3.8%	0.1%
Russian Federation	431.1	417.3	416.0	390.9	377.8	379.9	350.4	364.7	363.6	377.2	372.7	-1.2%	15.5%
Turkmenistan	9.6	9.3	9.3	10.2	8.0	10.0	10.1	10.3	11.3	12.6	12.9	2.2%	0.5%
Ukraine	121.5	103.5	92.9	81.3	76.2	82.5	74.3	68.8	70.6	68.5	65.8	-4.0%	2.7%
Uzbekistan	37.1	37.3	40.7	41.3	42.4	43.3	45.4	47.0	49.3	47.1	51.1	8.5%	2.1%
Other Former Soviet Union	18.2	15.7	11.1	9.3	9.1	7.9	8.8	9.2	7.9	7.6	8.6	13.4%	0.4%
Total Former Soviet Union	665.7	628.2	609.0	567.0	546.9	554.0	519.1	529.8	533.9	547.0	548.5	0.3%	22.8%
Iran	22.7	25.0	26.6	31.8	35.2	38.9	47.1	51.8	59.8	63.0	65.0	3.2%	2.7%
Kuwait	0.5	2.6	5.4	6.0	9.3	9.3	9.3	9.5	8.6	9.6	9.5	-1.0%	0.4%
Qatar	7.6	12.6	13.5	13.5	13.5	13.7	14.6	14.8	14.0	15.1	16.0	6.0%	0.7%
Saudi Arabia	35.2	38.3	40.0	42.8	42.9	44.4	45.3	46.8	46.2	49.8	53.7	7.8%	2.2%
United Arab Emirates	20.4	18.8	19.6	21.7	24.8	27.2	29.0	30.4	31.4	32.9	34.3	4.2%	1.4%
Other Middle East	11.6	13.3	13.9	14.9	16.1	17.3	19.6	20.5	21.5	22.3	23.0	2.9%	1.0%
Total Middle East	98.0	110.6	119.0	130.7	141.8	150.8	164.9	173.8	181.5	192.7	201.5	4.5%	8.4%
Algeria	17.0	17.8	18.6	19.6	21.0	21.4	20.2	20.9	21.2	21.0	21.6	2.7%	0.9%
Egypt	7.7	8.4	9.7	10.4	11.0	11.3	11.6	12.0	14.3	18.3	21.0	14.4%	0.9%
South Africa	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Africa	10.5	11.2	11.6	11.9	12.8	14.3	14.4	14.9	14.6	16.2	17.6	8.4%	0.7%
Total Africa	35.2	37.4	39.9	41.9	44.8	47.0	46.2	47.8	50.1	55.5	60.2	8.2%	2.5%
Australia	17.0	16.9	17.4	19.4	19.5	19.9	19.6	20.3	19.8	21.3	22.5	6.0%	0.9%
Bangladesh	5.3	5.7	6.1	6.6	7.4	7.6	7.6	7.8	8.3	10.0	10.8	8.2%	0.4%
China	14.9	15.1	16.2	16.6	17.7	17.7	19.3	19.3	21.4	24.5	27.7	12.9%	1.2%
China Hong Kong SAR	-	-	-	-	†	1.7	2.6	2.5	2.7	2.5	2.5	0.9%	0.1%
India	14.1	15.8	16.3	17.4	19.6	20.6	21.3	24.2	24.8	26.0	26.3	1.3%	1.1%
Indonesia	21.7	22.6	23.9	27.3	30.1	31.4	31.9	27.8	31.8	30.6	29.7	-2.9%	1.2%
Japan	54.7	56.0	56.3	60.3	61.2	66.1	65.1	69.5	74.6	76.2	79.0	3.7%	3.3%
Malaysia	9.0	10.6	13.0	13.6	13.7	15.9	16.7	17.4	18.5	20.3	21.6	6.2%	0.9%
New Zealand	4.6	4.9	4.7	4.4	4.2	4.7	5.1	4.5	5.2	5.5	5.7	5.1%	0.2%
Pakistan	11.1	11.5	12.2	13.3	14.6	15.4	15.6	16.0	17.3	18.9	20.1	6.1%	0.8%
Philippines	-	-	-	†	†	†	†	†	†	†	0.1	>100.0%	♦
Singapore	-	1.1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.7	2.5	43.3%	0.1%
South Korea	3.9	5.1	6.4	8.5	10.2	13.5	16.4	15.4	18.7	21.0	23.1	9.8%	1.0%
Taiwan	3.0	3.2	3.1	4.0	4.3	4.5	5.1	6.4	6.2	6.9	7.5	9.7%	0.3%
Thailand	7.0	7.5	8.4	9.5	10.0	11.8	14.6	15.9	17.4	20.5	21.1	3.0%	0.9%
Other Asia Pacific	2.5	2.7	3.1	3.3	3.4	3.7	4.2	4.5	4.8	4.9	4.9	0.2%	0.2%
Total Asia Pacific	168.8	178.7	188.6	205.7	217.4	236.0	246.6	253.0	273.0	290.8	305.1	5.0%	12.7%
TOTAL WORLD	2007.2	2010.8	2054.5	2063.5	2126.1	2226.5	2213.5	2241.3	2298.7	2397.2	2404.9	0.3%	100.0%
of which: European Union 15	264.4	263.7	280.4	280.9	302.5	336.0	334.2	348.4	364.4	375.8	381.5	1.5%	15.9%
OECD	1022.8	1042.2	1084.0	1111.3	1164.0	1228.6	1229.5	1229.8	1265.5	1316.7	1296.7	-1.5%	53.9%
Former Soviet Union	665.7	628.2	609.0	567.0	546.9	554.0	519.1	529.8	533.9	547.0	548.5	0.3%	22.8%
Other EMEs	318.7	340.4	361.5	385.2	415.2	443.9	464.9	481.7	499.3	533.5	559.7	4.8%	23.3%

† Less than 0.05.

♦ Less than 0.05%.

Notes: The difference between these world consumption figures and the world production statistics on page 22 is due to variations in stocks at storage facilities and liquefaction plants, together with unavoidable disparities in the definition, measurement or conversion of gas supply and demand data.

As far as possible, the data above represents standard cubic metres (measured at 15°C and 1013 mbar); as it is derived directly from tonnes of oil equivalent using an average conversion factor, it does not necessarily equate with gas volumes expressed in specific national terms.

Natural gas consumption data expressed in billion cubic feet per day is available at www.bp.com/centres/energy/

natural gas

consumption

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	494.1	507.3	524.9	536.5	558.5	568.5	567.8	552.8	559.6	582.4	554.6	-4.8%	25.6%
Canada	56.7	60.2	61.6	63.8	63.8	66.9	67.3	63.3	65.4	69.8	65.4	-6.4%	3.0%
Mexico	24.9	24.9	25.4	26.5	26.7	27.9	28.5	30.9	30.4	31.4	30.4	-3.3%	1.4%
Total North America	575.7	592.4	611.9	626.8	649.0	663.3	663.6	647.0	655.4	683.6	650.4	-4.9%	30.0%
Argentina	19.9	20.1	21.2	21.9	24.3	25.7	25.7	27.5	29.1	29.9	29.9	♦	1.4%
Brazil	3.5	3.6	4.0	4.1	4.3	5.0	5.4	5.6	6.4	8.2	9.8	19.3%	0.5%
Chile	1.3	1.5	1.4	1.5	1.5	1.5	2.5	2.9	4.1	4.7	5.0	6.5%	0.2%
Colombia	3.7	3.6	3.8	3.7	4.0	4.2	5.3	5.6	4.7	5.3	5.5	2.6%	0.3%
Ecuador	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-	♦
Peru	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.4	0.4	0.3	0.3	7.1%	♦
Venezuela	19.7	19.5	21.0	22.2	24.8	26.8	27.7	29.1	24.7	25.1	26.0	3.3%	1.2%
Other S. & Cent. America	5.8	6.1	6.1	6.5	6.5	7.4	8.0	8.8	9.3	10.1	10.6	5.2%	0.5%
Total S. & Cent. America	54.4	54.8	58.0	60.4	65.9	71.1	74.9	80.0	78.8	83.7	87.2	4.1%	4.0%
Austria	5.4	5.4	5.7	5.8	6.1	6.6	6.9	6.8	6.9	6.6	6.6	0.6%	0.3%
Belgium & Luxembourg	9.0	9.0	9.9	9.7	10.6	11.8	11.3	12.4	13.3	13.4	13.2	-1.4%	0.6%
Bulgaria	4.5	3.9	3.7	3.7	4.5	4.6	3.7	3.1	2.7	2.6	2.3	-9.3%	0.1%
Czech Republic	5.3	5.2	5.3	5.7	6.5	7.6	7.7	7.7	7.7	7.5	8.0	7.0%	0.4%
Denmark	2.1	2.2	2.5	2.7	3.1	3.7	3.9	4.3	4.5	4.4	4.6	4.4%	0.2%
Finland	2.4	2.5	2.6	2.8	2.9	3.0	2.9	3.3	3.3	3.4	3.7	8.5%	0.2%
France	27.5	28.3	29.0	27.8	29.6	32.5	31.2	33.3	33.9	35.7	36.6	2.5%	1.7%
Germany	56.6	56.7	59.8	61.1	67.0	75.2	71.3	71.7	72.1	71.5	74.6	4.3%	3.4%
Greece	0.1	0.1	0.1	†	†	†	0.2	0.7	1.2	1.7	1.8	1.1%	0.1%
Hungary	8.6	7.4	8.1	8.4	9.2	10.2	9.7	9.8	9.9	9.6	10.7	11.1%	0.5%
Iceland	-	-	-	-	-	-	-	-	-	-	-	-	-
Republic of Ireland	1.9	1.9	2.2	2.2	2.3	2.7	2.8	2.8	3.0	3.4	3.6	4.3%	0.2%
Italy	41.5	41.1	42.1	40.8	44.9	46.4	47.9	51.5	56.0	58.4	58.0	-0.6%	2.7%
Netherlands	34.2	33.0	34.1	33.2	34.0	37.5	35.2	34.9	34.1	35.3	35.3	0.2%	1.6%
Norway	2.2	2.3	2.4	2.6	2.7	2.9	3.3	3.4	3.2	3.6	4.0	10.6%	0.2%
Poland	7.9	7.8	8.1	8.2	8.9	9.5	9.4	9.5	9.3	10.0	10.2	2.7%	0.5%
Portugal	-	-	-	-	-	-	0.1	0.7	2.0	2.1	2.3	7.6%	0.1%
Romania	22.3	22.8	22.7	21.8	21.6	21.8	18.0	16.8	15.5	15.4	15.8	2.3%	0.7%
Slovakia	4.9	4.9	4.6	4.5	5.1	5.5	5.6	5.7	5.8	5.8	6.7	14.3%	0.3%
Spain	5.5	5.9	5.8	6.5	7.5	8.4	11.1	11.8	13.5	15.2	16.4	7.7%	0.8%
Sweden	0.6	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.8	0.7	0.7	4.8%	♦
Switzerland	1.8	1.9	2.0	2.0	2.2	2.4	2.3	2.4	2.4	2.4	2.5	4.2%	0.1%
Turkey	4.0	4.1	4.5	5.9	6.2	8.1	8.5	8.9	10.8	12.7	14.0	9.7%	0.6%
United Kingdom	51.0	50.7	57.8	59.5	63.5	73.9	75.4	78.5	83.2	86.4	85.9	-0.6%	4.0%
Other Europe	6.0	5.4	4.5	3.6	3.8	5.4	5.5	5.3	4.8	5.1	5.5	7.8%	0.3%
Total Europe	305.3	303.2	318.2	319.2	342.9	380.5	374.6	386.1	399.9	412.9	423.0	2.4%	19.5%
Azerbaijan	13.6	10.6	7.8	7.3	7.2	5.3	5.0	4.7	5.0	4.9	7.6	55.2%	0.3%
Belarus	13.0	15.1	14.0	12.3	11.1	11.7	13.3	13.5	13.8	14.6	14.5	-0.6%	0.7%
Kazakhstan	11.8	12.2	11.7	9.2	9.7	8.1	6.4	6.5	7.1	8.7	9.1	3.8%	0.4%
Lithuania	4.9	2.7	1.5	1.8	2.1	2.3	2.4	2.1	2.2	2.5	2.5	3.8%	0.1%
Russian Federation	388.0	375.5	374.4	351.8	340.0	341.9	315.3	328.3	327.3	339.5	335.4	-1.2%	15.5%
Turkmenistan	8.6	8.4	8.4	9.2	7.2	9.0	9.1	9.2	10.2	11.3	11.6	2.2%	0.5%
Ukraine	109.3	93.2	83.6	73.2	68.6	74.2	66.8	61.9	63.6	61.6	59.2	-4.0%	2.7%
Uzbekistan	33.4	33.6	36.6	37.2	38.1	39.0	40.9	42.3	44.3	42.4	46.0	8.5%	2.1%
Other Former Soviet Union	16.4	14.1	10.0	8.4	8.2	7.1	7.9	8.3	7.1	6.8	7.7	13.4%	0.4%
Total Former Soviet Union	599.0	565.4	548.0	510.4	492.2	498.6	467.1	476.8	480.6	492.3	493.6	0.3%	22.8%
Iran	20.5	22.5	23.9	28.6	31.7	35.0	42.4	46.6	53.8	56.7	58.5	3.2%	2.7%
Kuwait	0.5	2.4	4.9	5.4	8.4	8.4	8.3	8.5	7.8	8.6	8.6	-1.0%	0.4%
Qatar	6.9	11.4	12.2	12.2	12.2	12.3	13.2	13.3	12.6	13.6	14.4	6.0%	0.7%
Saudi Arabia	31.7	34.4	36.0	38.5	38.6	40.0	40.8	42.1	41.6	44.8	48.3	7.8%	2.2%
United Arab Emirates	18.3	16.9	17.7	19.5	22.3	24.4	26.1	27.4	28.3	29.6	30.8	4.2%	1.4%
Other Middle East	10.4	12.0	12.5	13.4	14.5	15.6	17.7	18.5	19.4	20.1	20.7	2.9%	1.0%
Total Middle East	88.3	99.6	107.2	117.6	127.7	135.7	148.5	156.4	163.5	173.4	181.3	4.5%	8.4%
Algeria	15.3	16.0	16.7	17.6	18.9	19.3	18.1	18.8	19.1	18.9	19.4	2.7%	0.9%
Egypt	6.9	7.5	8.7	9.4	9.9	10.2	10.4	10.8	12.9	16.5	18.9	14.4%	0.9%
South Africa	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Africa	9.5	10.1	10.5	10.7	11.5	12.9	12.9	13.4	13.1	14.6	15.8	8.4%	0.7%
Total Africa	31.7	33.6	35.9	37.7	40.3	42.4	41.4	43.0	45.1	50.0	54.1	8.2%	2.5%
Australia	15.3	15.2	15.7	17.5	17.6	17.9	17.6	18.3	17.8	19.1	20.3	6.0%	0.9%
Bangladesh	4.8	5.2	5.5	6.0	6.6	6.8	6.8	7.0	7.5	9.0	9.7	8.2%	0.4%
China	13.4	13.6	14.6	14.9	15.9	15.9	17.4	17.4	19.3	22.1	24.9	12.9%	1.2%
China Hong Kong SAR	-	-	-	-	†	1.5	2.4	2.2	2.4	2.2	2.2	0.9%	0.1%
India	12.7	14.3	14.7	15.7	17.7	18.5	19.1	21.8	22.3	23.4	23.7	1.3%	1.1%
Indonesia	19.5	20.3	21.5	24.6	27.0	28.2	28.7	25.0	28.7	27.5	26.7	-2.9%	1.2%
Japan	49.2	50.4	50.7	54.3	55.0	59.5	58.6	62.5	67.1	68.6	71.1	3.7%	3.3%
Malaysia	8.1	9.5	11.7	12.3	12.4	14.3	15.0	15.7	16.7	18.3	19.4	6.2%	0.9%
New Zealand	4.2	4.4	4.3	4.0	3.7	4.3	4.6	4.0	4.7	4.9	5.2	5.1%	0.2%
Pakistan	10.0	10.3	10.9	12.0	13.1	13.8	14.0	14.4	15.6	17.0	18.1	6.1%	0.8%
Philippines	-	-	-	†	†	†	†	†	†	†	0.1	>100.0%	♦
Singapore	-	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.6	2.3	43.3%	0.1%
South Korea	3.5	4.6	5.7	7.6	9.2	12.2	14.8	13.8	16.8	18.9	20.8	9.8%	1.0%
Taiwan	2.7	2.8	2.7	3.6	3.9	4.0	4.6	5.7	5.6	6.2	6.8	9.7%	0.3%
Thailand	6.3	6.8	7.6	8.6	9.0	10.7	13.1	14.3	15.6	18.4	19.0	3.0%	0.9%
Other Asia Pacific	2.3	2.4	2.7	2.9	3.0	3.4	3.8	4.1	4.4	4.4	4.4	0.2%	0.2%
Total Asia Pacific	152.0	160.8	169.7	185.4	195.5	212.4	221.9	227.6	245.9	261.6	274.7	5.0%	12.7%
TOTAL WORLD	1806.4	1809.8	1848.9	1857.5	1913.5	2004.0	1992.0	2016.9	2069.2	2157.5	2164.3	0.3%	100.0%
of which: European Union 15	237.8	237.5	252.3	252.8	272.2	302.5	300.9	313.5	327.8	338.2	343.3	1.5%	15.9%
OECD	920.4	938.1	975.6	1000.3	1047.5	1105.9	1106.6	1106.5	1138.7	1184.9	1167.2	-1.5%	53.9%
Former Soviet Union	599.0	565.4	548.0	510.4	492.2	498.6	467.1	476.8	480.6	492.3	493.6	0.3%	22.8%
Other EMEs	287.0	306.3	325.3	346.8	373.8	399.5	418.3	433.6	449.9	480.3	503.5	4.8%	23.3%

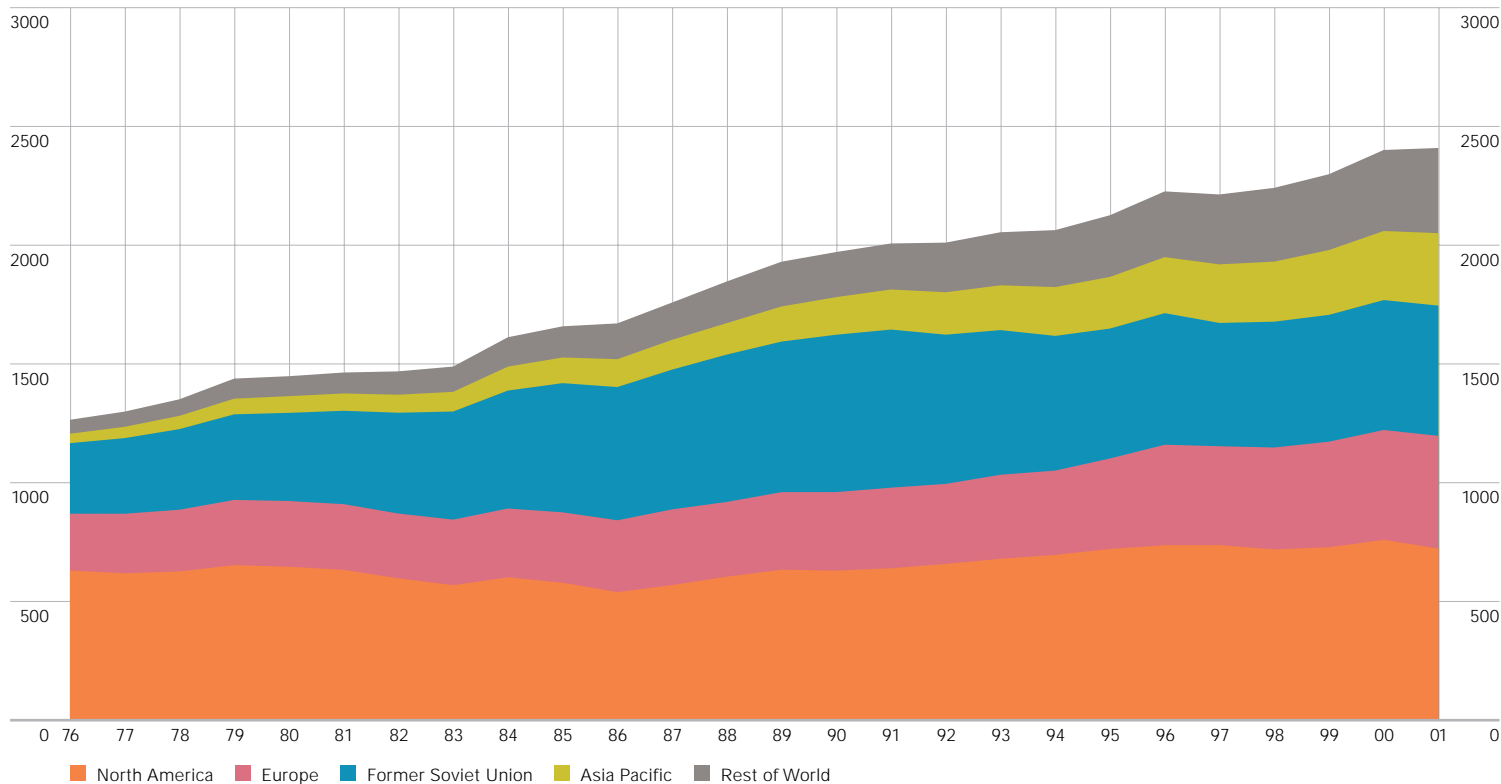
†Less than 0.05.

♦Less than 0.05%.

Note: The difference between these world consumption figures and the world production statistics on page 23 is due to variations in stocks at storage facilities and liquefaction plants, together with unavoidable disparities in the definition, measurement or conversion of gas supply and demand data.

consumption by area

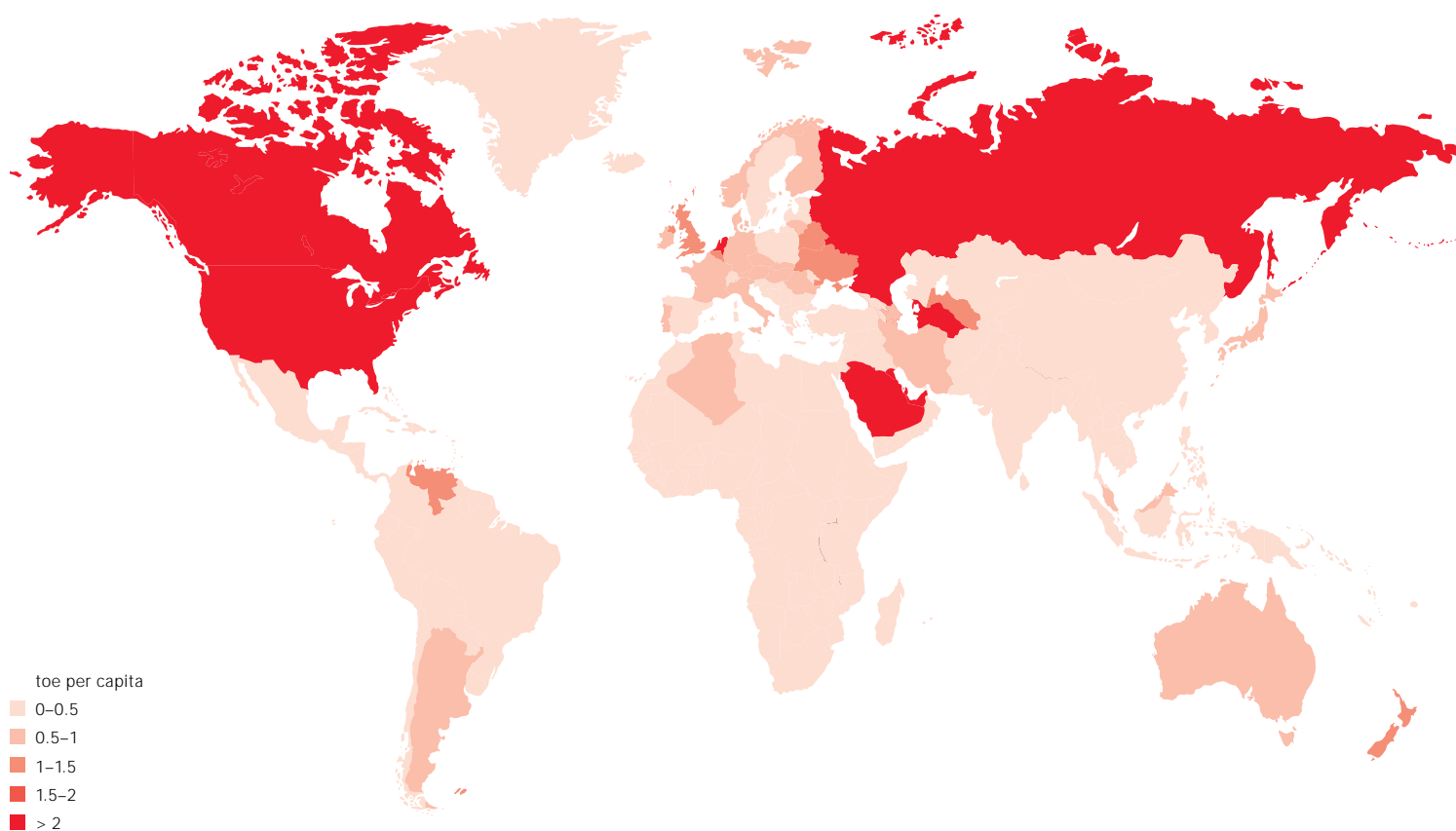
Billion cubic metres



Global gas consumption grew by a weak 0.3% in 2001, following an exceptionally strong 2000 during which consumption grew by well over 4%. Falling US demand was the main factor, with growth in most other regions remaining robust.

consumption per capita

Tonnes oil equivalent



natural gas

trade movements 2001 – by pipeline

Billion cubic metres				From																Total imports
To	USA	Canada	Mexico	Argentina	Bolivia	Denmark	France	Germany	Netherlands	Norway	UK	Russian Fed.	Turkmenistan	Iran	Algeria	Indonesia	Malaysia	Myanmar		
North America																				
USA	–	109.02	0.65	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	109.67	
Canada	4.87	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4.87	
Mexico	4.28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4.28	
S. & C. America																				
Brazil	–	–	–	0.50	2.50	–	–	–	–	–	–	–	–	–	–	–	–	–	3.00	
Chile	–	–	–	4.60	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4.60	
Uruguay	–	–	–	0.07	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.07	
Europe																				
Austria	–	–	–	–	–	–	–	0.32	–	0.50	–	5.22	–	–	–	–	–	–	6.04	
Belgium	–	–	–	–	–	–	–	0.19	7.60	5.12	0.31	–	–	–	–	–	–	–	13.22	
Bulgaria	–	–	–	–	–	–	–	–	–	–	–	2.90	–	–	–	–	–	–	2.90	
Croatia	–	–	–	–	–	–	–	–	–	–	–	1.08	–	–	–	–	–	–	1.08	
Czech Republic	–	–	–	–	–	–	–	–	–	1.70	–	7.50	–	–	–	–	–	–	9.20	
Finland	–	–	–	–	–	–	–	–	–	–	–	4.54	–	–	–	–	–	–	4.54	
France	–	–	–	–	–	–	–	–	5.80	12.87	1.29	11.18	–	–	–	–	–	–	31.14	
Germany	–	–	–	–	–	2.20	–	–	20.20	19.89	3.26	33.20	–	–	–	–	–	–	78.75	
Greece	–	–	–	–	–	–	–	–	–	–	–	1.48	–	–	–	–	–	–	1.48	
Hungary	–	–	–	–	–	–	0.90	1.12	–	–	–	7.95	–	–	–	–	–	–	9.97	
Ireland	–	–	–	–	–	–	–	–	–	–	3.42	–	–	–	–	–	–	–	3.42	
Italy	–	–	–	–	–	–	–	–	7.10	1.10	–	19.50	–	–	21.85	–	–	–	49.55	
Luxembourg	–	–	–	–	–	–	–	0.40	0.40	–	–	–	–	–	–	–	–	–	0.80	
Netherlands	–	–	–	–	–	–	–	–	–	5.50	7.50	0.13	–	–	–	–	–	–	13.13	
Poland	–	–	–	–	–	–	–	0.50	–	0.40	–	7.50	–	–	–	–	–	–	8.40	
Portugal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.20	–	–	–	2.20	
Romania	–	–	–	–	–	–	–	0.20	–	–	–	2.80	–	–	–	–	–	–	3.00	
Slovakia	–	–	–	–	–	–	–	–	–	–	–	7.90	–	–	–	–	–	–	7.90	
Slovenia	–	–	–	–	–	–	–	–	–	–	–	0.68	–	–	0.36	–	–	–	1.04	
Spain	–	–	–	–	–	–	–	–	–	1.22	–	–	–	–	6.54	–	–	–	7.76	
Sweden	–	–	–	–	–	0.90	–	–	–	–	–	–	–	–	–	–	–	–	0.90	
Switzerland	–	–	–	–	–	–	0.30	1.75	0.60	–	–	0.40	–	–	–	–	–	–	3.05	
Turkey	–	–	–	–	–	–	–	–	–	–	–	10.93	–	0.11	–	–	–	–	11.04	
United Kingdom	–	–	–	–	–	–	–	–	0.50	2.20	–	–	–	–	–	–	–	–	2.70	
Others	–	–	–	–	–	–	–	–	–	–	–	1.97	–	–	–	–	–	–	1.97	
Middle East																				
Iran	–	–	–	–	–	–	–	–	–	–	–	–	4.20	–	–	–	–	–	4.20	
Africa																				
Tunisia	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1.20	–	–	–	1.20	
Asia Pacific																				
Singapore	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1.00	1.50	–	2.50	
Thailand	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1.75	1.75	
TOTAL EXPORTS	9.15	109.02	0.65	5.17	2.50	3.10	1.20	4.48	42.20	50.50	15.78	126.86	4.20	0.11	32.15	1.00	1.50	1.75	411.32	

Note: Flows are on a contractual basis and may not correspond to physical gas flows in all cases.

Source: Cedigaz.

trade movements 2001 – LNG*

Billion cubic metres	From														Total imports
To	USA	Trinidad & Tobago	Oman	Qatar	UAE	Algeria	Libya	Nigeria	Australia	Brunei	Indonesia	Malaysia	Taiwan		
North America															
USA	–	2.62	0.34	0.64	–	1.84	–	1.08	0.07	–	–	–	–	6.59	
S. & C. America															
Puerto Rico	–	0.58	0.05	–	–	–	–	–	–	–	–	–	–	0.63	
Europe															
Belgium	–	–	–	–	–	2.32	–	0.08	–	–	–	–	–	2.40	
France	–	–	–	0.15	–	9.80	–	0.50	–	–	–	–	–	10.45	
Greece	–	–	–	–	–	0.50	–	–	–	–	–	–	–	0.50	
Italy	–	–	–	–	–	2.25	–	3.00	–	–	–	–	–	5.25	
Portugal	–	–	–	–	–	–	–	0.26	–	–	–	–	–	0.26	
Spain	–	0.45	0.91	0.78	0.02	5.20	0.77	1.71	–	–	–	–	–	9.84	
Turkey	–	–	–	–	–	3.63	–	1.20	–	–	–	–	–	4.83	
Asia Pacific															
Japan	1.79	–	0.83	8.30	6.89	–	–	–	10.05	8.20	22.74	15.27	–	74.07	
South Korea	–	–	5.30	6.67	0.17	–	–	–	0.08	0.80	5.36	3.04	0.41	21.83	
Taiwan	–	–	–	–	–	–	–	–	–	–	3.70	2.60	–	6.30	
TOTAL EXPORTS	1.79	3.65	7.43	16.54	7.08	25.54	0.77	7.83	10.20	9.00	31.80	20.91	0.41	142.95	

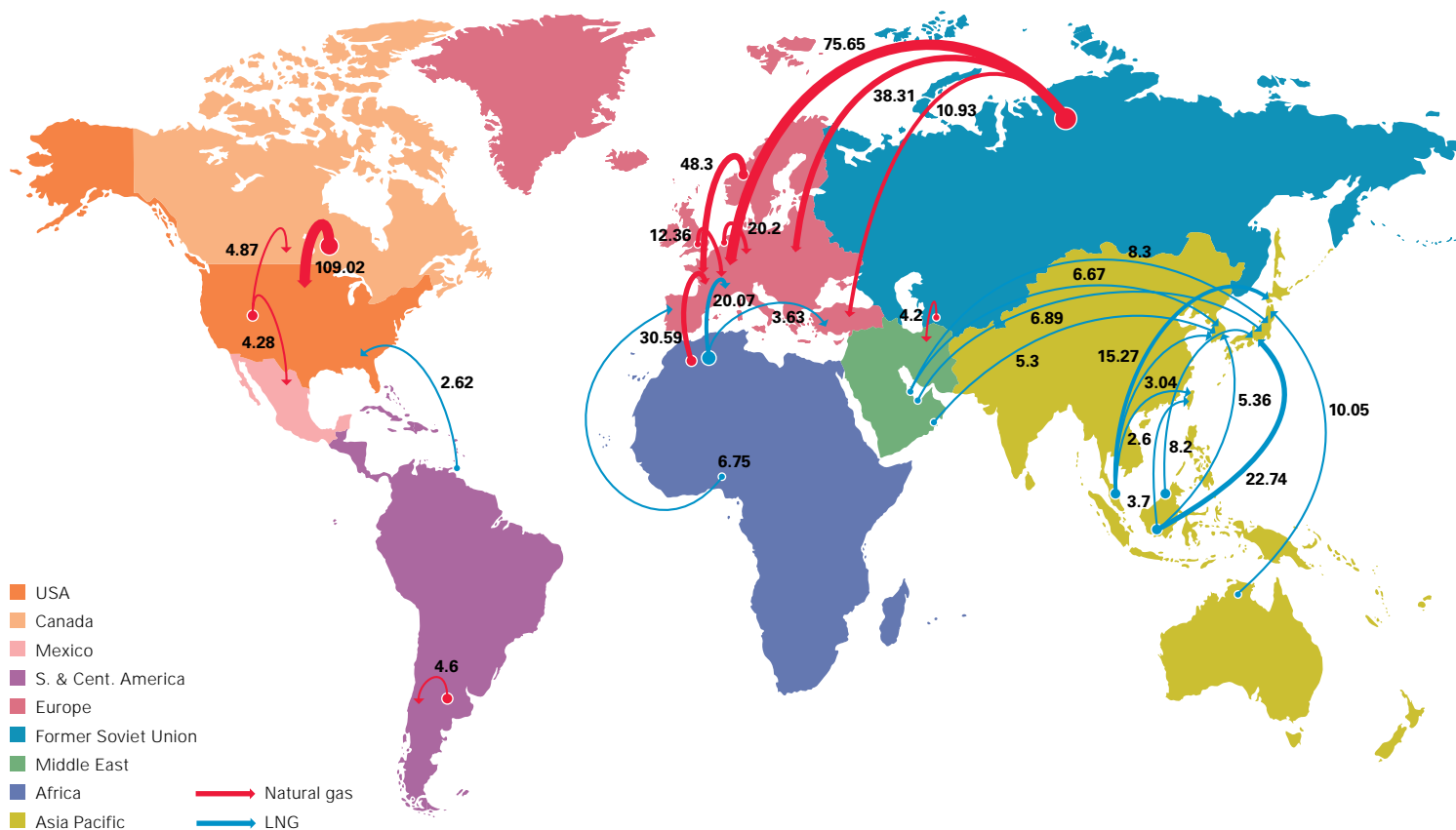
*Liquefied Natural Gas.

Source: Cedigaz.

Note: Flows are on a contractual basis and may not correspond to physical gas flows in all cases.

major trade movements

Trade flows worldwide (billion cubic metres)



prices

US dollars per million Btu	LNG Japan cif	European Union cif	Natural gas UK (Heren NBP index)†	USA Henry Hub‡	Canada (Alberta)‡	Crude oil OECD countries cif
1984	–	3.76	–	–	–	5.00
1985	5.23	3.83	–	–	–	4.75
1986	4.10	3.65	–	–	–	2.57
1987	3.35	2.59	–	–	–	3.09
1988	3.34	2.36	–	–	–	2.56
1989	3.28	2.09	–	1.70	–	3.01
1990	3.64	2.82	–	1.64	1.05	3.82
1991	3.99	3.18	–	1.49	0.89	3.33
1992	3.62	2.76	–	1.77	0.98	3.19
1993	3.52	2.53	–	2.12	1.69	2.82
1994	3.18	2.24	–	1.92	1.45	2.70
1995	3.46	2.37	–	1.69	0.89	2.96
1996	3.66	2.43	1.85	2.76	1.12	3.54
1997	3.91	2.65	2.03	2.53	1.36	3.29
1998	3.05	2.26	1.92	2.08	1.42	2.16
1999	3.14	1.8	1.64	2.27	2.00	2.98
2000	4.72	3.25	2.68	4.23	3.75	4.83
2001	4.64	4.19	3.22	4.07	3.61	4.06

†Source: PH Energy.

‡Source: Natural Gas Week.

Note: cif = cost+insurance+freight (average prices).

coal

proved reserves at end of 2001

Million tonnes	Anthracite and bituminous	Sub-bituminous and Lignite	Total	Share of total	R/P ratio
USA	115891	134103	249994	25.4%	246
Canada	3471	3107	6578	0.7%	93
Mexico	860	351	1211	0.1%	101
Total North America	120222	137561	257783	26.2%	234
Brazil	–	11929	11929	1.2%	*
Colombia	6267	381	6648	0.7%	157
Venezuela	479	–	479	♦	59
Other S. & Cent. America	992	1704	2696	0.3%	*
Total S. & Cent. America	7738	14014	21752	2.2%	381
Bulgaria	13	2698	2711	0.3%	96
Czech Republic	2114	3564	5678	0.6%	86
France	22	14	36	♦	15
Germany	23000	43000	66000	6.7%	326
Greece	–	2874	2874	0.3%	43
Hungary	–	1097	1097	0.1%	80
Poland	20300	1860	22160	2.3%	136
Romania	1	1456	1457	0.1%	44
Spain	200	460	660	0.1%	29
Turkey	278	3411	3689	0.4%	54
United Kingdom	1000	500	1500	0.2%	47
Other Europe	584	16949	17533	1.8%	337
Total Europe	47512	77883	125395	12.7%	167
Kazakhstan	31000	3000	34000	3.5%	431
Russian Federation	49088	107922	157010	15.9%	*
Ukraine	16274	17879	34153	3.5%	407
Other Former Soviet Union	1000	3812	4812	0.5%	*
Total Former Soviet Union	97362	132613	229975	23.4%	*
South Africa	49520	–	49520	5.0%	220
Zimbabwe	502	–	502	0.1%	101
Other Africa	5149	196	5345	0.5%	*
Middle East	1710	–	1710	0.2%	*
Total Africa & Middle East	56881	196	57077	5.8%	246
Australia	42550	39540	82090	8.3%	261
China	62200	52300	114500	11.6%	105
India	82396	2000	84396	8.6%	246
Indonesia	790	4580	5370	0.5%	58
Japan	773	–	773	0.1%	242
New Zealand	33	539	572	0.1%	141
North Korea	300	300	600	0.1%	6
Pakistan	–	2265	2265	0.2%	*
South Korea	78	–	78	♦	20
Other Asia Pacific	227	1600	1827	0.2%	47
Total Asia Pacific	189347	103124	292471	29.7%	147
TOTAL WORLD	519062	465391	984453	100.0%	216
of which: OECD	211084	234686	445770	45.3%	215
Former Soviet Union	97362	132613	229975	23.4%	*
Other EMEs	210616	98092	308708	31.4%	150

*More than 500 years.

♦Less than 0.05%.

Notes:

Proved reserves of coal – Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions.

Reserves/Production (R/P) ratio – If the reserves remaining at the end of the year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level.

Source of reserves data – World Energy Council.

prices

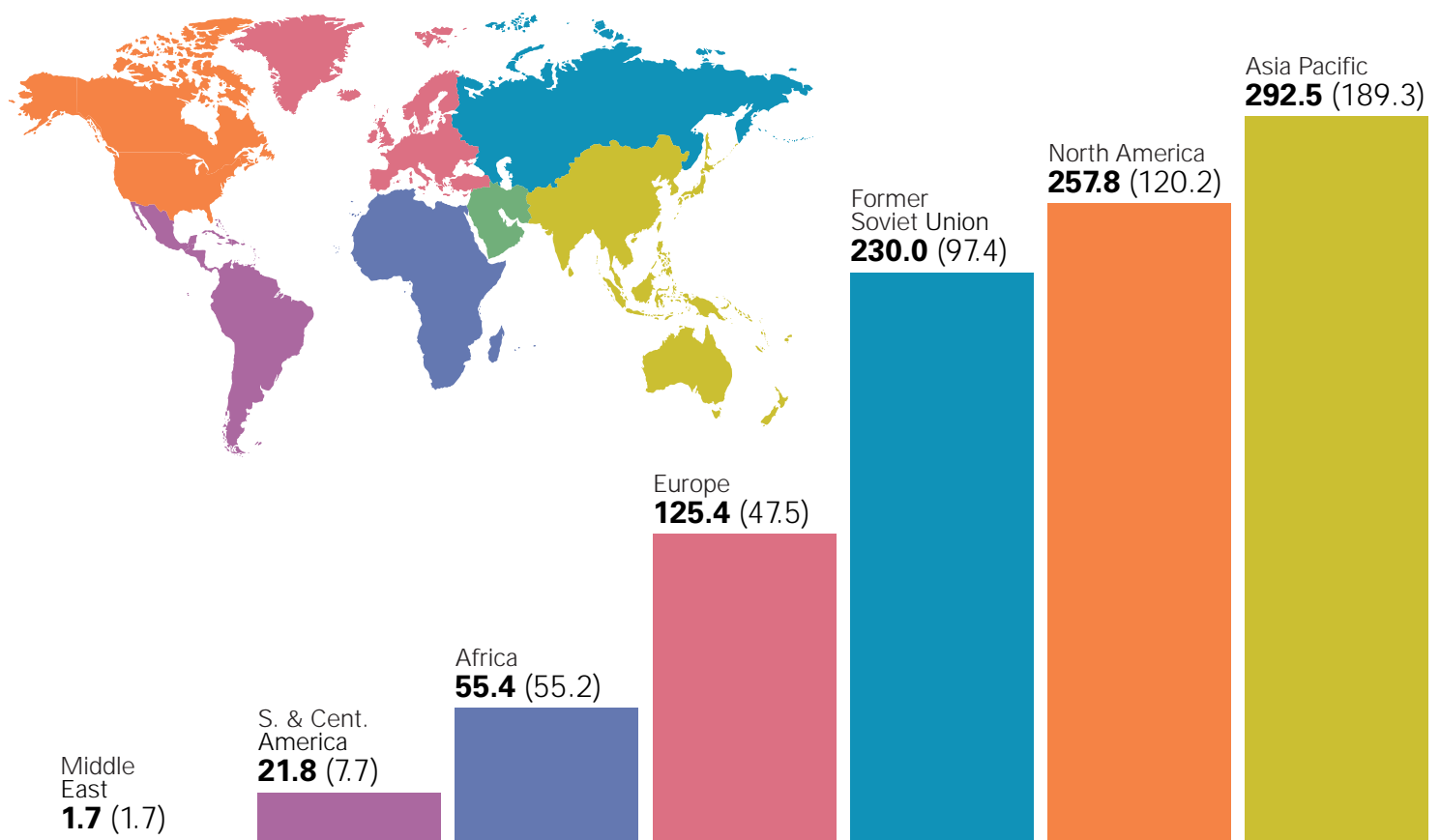
US dollars per tonne	Marker Price (basis Northwest Europe)*	Price of US coal receipts at steam-electric utility plants	Japan coking coal import cif price	Japan steam coal import cif price
1987	31.30	35.09	53.44	41.28
1988	39.94	33.77	55.06	42.47
1989	42.08	33.21	58.68	48.86
1990	43.48	33.57	60.54	50.81
1991	42.80	33.10	60.45	50.30
1992	38.53	32.35	57.82	48.45
1993	33.68	31.51	55.26	45.71
1994	37.18	30.88	51.77	43.66
1995	44.50	29.78	54.47	47.58
1996	41.25	29.16	56.68	49.54
1997	38.92	28.83	55.51	45.53
1998	32.00	28.31	50.76	40.51
1999	28.79	27.35	42.83	35.74
2000	35.98	26.99	39.69	34.58
2001	39.29	27.68	41.33	37.96

*Source of Marker Price: McCloskey Coal Information Service.

Note: cif = cost+insurance+freight (average prices).

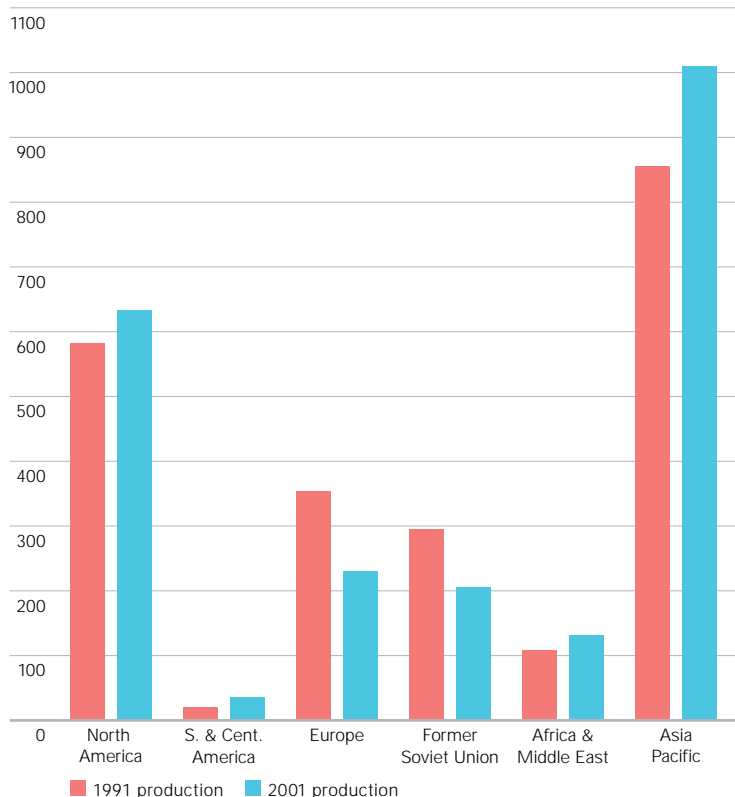
proved reserves at end 2001

Thousand million tonnes (share of anthracite and bituminous coal is shown in brackets)



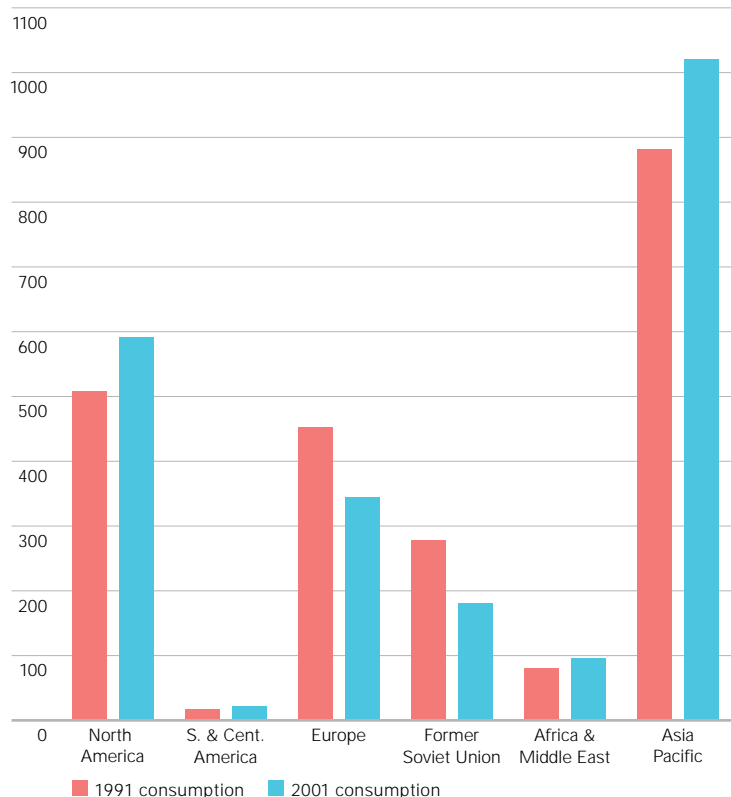
production

Million tonnes oil equivalent



consumption

Million tonnes oil equivalent



Global coal production and consumption have been broadly flat over the last decade, with declines in Europe and the Former Soviet Union offset by gains in North America, Asia and the Rest of the World.

coal

production*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	539.9	540.7	506.2	552.8	550.7	567.1	580.3	598.4	579.7	565.6	590.7	4.4%	26.3%
Canada	39.7	35.1	37.5	39.4	40.8	41.6	43.0	40.8	39.2	37.0	37.6	1.6%	1.7%
Mexico	3.1	2.9	3.1	4.3	4.1	4.6	4.5	4.8	4.9	5.4	5.7	5.8%	0.3%
Total North America	582.7	578.7	546.8	596.5	595.6	613.3	627.8	644.0	623.8	608.0	634.0	4.3%	28.2%
Brazil	2.1	1.8	1.8	2.0	2.0	1.8	2.1	2.0	2.1	2.1	2.1	0.5%	0.1%
Colombia	13.8	15.3	14.1	14.7	16.7	19.5	21.0	19.6	21.3	24.8	27.6	11.3%	1.2%
Venezuela	1.8	1.8	2.9	3.2	3.2	3.1	3.9	4.7	4.8	5.7	5.9	2.8%	0.3%
Other S. & Cent. America	2.0	1.5	1.2	1.4	1.3	1.2	1.1	0.4	0.5	0.6	0.6	-1.4%	♦
Total S. & Cent. America	19.7	20.4	20.0	21.3	23.2	25.6	28.1	26.7	28.7	33.2	36.2	8.9%	1.6%
Bulgaria	4.8	5.1	4.9	4.8	5.2	5.2	4.9	5.0	4.3	4.5	4.7	3.9%	0.2%
Czech Republic	33.9	31.4	30.8	28.1	27.3	27.0	27.9	26.0	23.1	25.2	25.8	2.3%	1.1%
France	7.4	6.8	6.3	5.4	5.1	5.0	4.1	3.4	3.1	2.1	1.5	-32.4%	0.1%
Germany	102.0	93.3	83.7	77.8	74.6	70.0	66.9	61.3	59.4	56.7	54.2	-4.3%	2.4%
Greece	6.9	7.0	7.2	7.4	7.5	7.2	7.7	8.1	8.2	8.5	9.0	6.3%	0.4%
Hungary	3.9	3.6	2.8	2.9	2.6	3.2	3.3	3.0	3.0	2.9	2.8	-2.1%	0.1%
Poland	90.7	89.2	89.2	89.3	91.1	94.5	92.1	79.6	77.1	72.0	72.5	0.7%	3.2%
Romania	7.4	8.5	8.9	9.1	9.3	9.6	7.4	5.7	5.1	6.4	7.3	13.4%	0.3%
Spain	11.2	11.4	11.0	10.6	10.2	10.0	9.8	9.3	8.6	8.2	8.0	-3.2%	0.4%
Turkey	11.8	12.1	11.7	12.1	12.1	12.3	13.1	13.9	13.3	13.0	12.9	-0.1%	0.6%
United Kingdom	55.8	50.0	40.3	28.3	31.8	30.2	29.4	25.0	22.5	19.0	19.6	3.1%	0.9%
Other Europe	17.9	16.6	15.3	12.2	12.9	12.3	13.7	14.2	11.0	11.9	12.1	1.3%	0.5%
Total Europe	353.7	335.0	312.1	288.0	289.7	286.5	280.3	254.5	238.7	230.4	230.4	♦	10.2%
Kazakhstan	66.9	65.0	57.3	53.5	42.6	39.3	37.3	36.0	30.0	38.5	40.6	5.4%	1.8%
Russian Federation	154.8	148.4	135.1	121.2	118.5	114.4	109.3	103.9	112.0	115.8	120.8	4.3%	5.4%
Ukraine	69.1	68.4	59.4	48.5	44.2	39.1	39.8	39.9	42.8	42.1	43.6	3.5%	1.9%
Other Former Soviet Union	3.7	2.5	2.0	1.6	1.2	1.1	1.1	1.1	1.1	0.9	1.0	9.2%	♦
Total Former Soviet Union	294.5	284.3	253.8	224.8	206.5	193.9	187.5	180.9	185.9	197.3	206.0	4.4%	9.2%
Total Middle East	0.6	0.6	0.6	0.8	0.7	0.7	0.6	0.6	0.7	0.6	0.5	-18.0%	♦
South Africa	102.2	100.0	103.5	111.1	116.9	116.9	124.6	127.1	125.6	126.5	126.7	0.1%	5.6%
Zimbabwe	3.6	3.6	3.4	3.5	3.6	3.3	3.4	3.5	3.2	2.8	3.2	13.2%	0.1%
Other Africa	1.4	1.4	1.3	1.4	1.4	1.3	1.2	1.4	1.3	1.2	1.1	-2.1%	0.1%
Total Africa	107.2	105.0	108.2	116.0	121.9	121.5	129.2	132.0	130.1	130.5	131.0	0.4%	5.8%
Australia	113.3	119.6	121.4	122.5	128.5	133.9	147.8	151.3	155.8	153.3	168.1	9.7%	7.5%
China	545.1	559.9	580.7	619.4	650.9	691.5	665.5	619.7	523.9	501.8	548.5	9.3%	24.4%
India	112.6	119.2	123.5	126.9	135.2	145.7	149.6	150.3	147.4	157.0	161.1	2.6%	7.2%
Indonesia	8.5	13.8	17.0	20.2	25.7	31.0	33.7	38.3	45.3	47.4	56.9	20.2%	2.5%
Japan	4.4	4.2	4.0	3.8	3.4	3.6	2.4	2.0	2.2	1.7	1.8	2.2%	0.1%
New Zealand	1.5	1.7	1.8	1.8	2.1	2.2	2.0	2.0	2.2	2.2	2.5	15.7%	0.1%
Pakistan	1.3	1.3	1.4	1.4	1.4	1.5	1.4	1.5	1.5	1.4	1.5	2.5%	0.1%
South Korea	6.8	5.4	4.2	3.3	2.6	2.2	2.0	2.0	1.9	1.9	1.7	-8.0%	0.1%
Other Asia Pacific	62.6	64.2	66.7	66.2	66.4	67.5	68.5	65.0	64.2	66.2	68.1	2.8%	3.0%
Total Asia Pacific	856.1	889.3	920.7	965.5	1016.2	1079.1	1072.9	1032.1	944.4	932.9	1010.2	8.3%	44.9%
TOTAL WORLD	2214.5	2213.3	2162.2	2212.9	2253.8	2320.6	2326.4	2270.8	2152.3	2132.9	2248.3	5.4%	100.0%
of which: OECD	1035.0	1016.6	963.2	991.1	995.9	1015.6	1038.1	1032.5	1005.7	976.4	1016.8	4.1%	45.2%
Former Soviet Union	294.5	284.3	253.8	224.8	206.5	193.9	187.5	180.9	185.9	197.3	206.0	4.4%	9.2%
Other EMEs	884.8	912.5	945.4	997.3	1051.6	1111.0	1100.9	1057.4	960.5	959.2	1025.4	6.9%	45.6%

*Commercial solid fuels only, i.e. bituminous coal and anthracite (hard coal), and lignite and brown (sub-bituminous) coal.

♦Less than 0.05%.

Note: Because of rounding some totals may not agree exactly with the sum of their component parts.

Coal production data expressed in million tonnes is available at www.bp.com/centres/energy/

consumption*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	478.8	482.7	498.1	502.3	504.7	528.2	540.9	546.0	546.3	565.3	555.7	-1.7%	24.6%
Canada	25.5	26.2	23.7	24.5	25.2	25.7	26.8	28.1	27.8	29.4	28.9	-1.6%	1.3%
Mexico	3.3	3.4	3.8	4.5	5.0	5.7	5.7	5.9	6.0	6.2	6.3	2.4%	0.3%
Total North America	507.6	512.3	525.6	531.3	534.9	559.6	573.4	580.0	580.1	600.9	590.9	-1.7%	26.2%
Argentina	0.8	0.8	0.7	1.2	0.9	0.9	0.8	0.7	0.7	0.7	0.7	-3.4%	♦
Brazil	10.2	9.9	10.2	10.2	10.7	11.2	11.4	11.2	11.7	12.8	14.0	9.6%	0.6%
Chile	2.0	1.8	1.8	2.2	2.4	3.2	4.2	3.7	3.5	3.9	4.0	2.1%	0.2%
Colombia	3.7	3.6	3.7	3.6	3.4	3.2	3.1	2.8	2.1	2.2	2.4	8.6%	0.1%
Ecuador	-	-	-	-	-	-	-	-	-	-	-	-	-
Peru	0.3	0.3	0.4	0.4	0.4	0.3	0.4	0.4	0.5	0.5	0.6	7.6%	♦
Venezuela	-	†	†	0.1	†	†	†	†	0.1	†	†	-	♦
Other S. & Cent. America	0.4	0.5	0.5	0.4	0.4	0.5	0.4	0.5	0.5	0.6	0.7	18.0%	♦
Total S. & Cent. America	17.4	16.9	17.3	18.1	18.2	19.3	20.3	19.3	19.1	20.7	22.4	7.8%	1.0%
Austria	3.6	2.8	2.4	2.5	2.4	2.7	3.1	3.0	3.2	3.2	2.7	-16.3%	0.1%
Belgium & Luxembourg	10.8	10.2	8.7	8.5	9.8	7.6	7.5	7.9	6.9	7.6	7.1	-5.9%	0.3%
Bulgaria	7.5	7.3	8.2	7.6	7.8	8.4	7.8	8.2	6.6	6.6	6.1	-7.9%	0.3%
Czech Republic	30.4	25.4	23.7	23.2	23.5	23.6	22.8	20.5	19.0	20.7	21.3	2.8%	0.9%
Denmark	8.4	6.7	7.2	7.8	6.6	9.0	6.7	5.6	4.7	4.0	4.2	3.9%	0.2%
Finland	3.6	2.7	3.1	4.1	3.1	4.0	4.5	3.4	3.6	3.5	3.9	10.6%	0.2%
France	20.1	17.9	14.7	13.7	14.5	15.4	13.4	16.1	14.3	13.8	10.9	-20.9%	0.5%
Germany	113.3	104.4	97.9	95.6	90.6	89.9	86.8	84.8	80.2	84.9	84.4	-0.6%	3.7%
Greece	7.8	8.4	7.9	8.4	8.2	7.8	7.6	8.8	9.1	9.2	9.5	3.1%	0.4%
Hungary	5.8	4.6	4.0	3.6	3.6	3.7	3.7	3.4	3.4	3.2	3.1	-3.1%	0.1%
Iceland	0.1	†	†	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.1%	♦
Republic of Ireland	2.2	2.0	1.9	1.9	1.9	1.9	2.0	1.9	1.6	2.0	2.1	5.0%	0.1%
Italy	13.7	12.4	10.0	10.7	12.5	11.2	11.0	11.6	11.6	13.0	13.9	6.9%	0.6%
Netherlands	8.2	7.7	8.2	9.0	9.8	9.3	9.5	9.4	7.7	8.6	8.4	-1.9%	0.4%
Norway	0.4	0.4	0.5	0.6	0.7	0.6	0.6	0.7	0.7	0.7	0.6	-11.2%	♦
Poland	77.6	73.0	74.0	72.3	71.7	73.2	70.1	63.8	61.0	57.6	57.5	-0.2%	2.5%
Portugal	3.0	3.0	3.3	3.4	4.2	3.9	3.6	3.6	3.6	3.6	3.6	-2.3%	0.2%
Romania	9.6	10.3	9.5	9.4	9.7	9.5	8.4	7.0	6.7	7.0	7.7	8.8%	0.3%
Slovakia	6.3	6.2	5.6	5.0	5.1	5.0	4.7	4.5	4.3	4.0	4.1	1.7%	0.2%
Spain	18.8	19.1	18.2	18.0	18.5	15.5	17.7	17.7	20.5	21.6	19.5	-10.0%	0.9%
Sweden	2.4	2.2	2.1	2.1	2.1	2.4	2.1	2.0	2.0	1.9	2.0	4.4%	0.1%
Switzerland	0.3	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	-1.7%	♦
Turkey	16.8	19.0	18.7	17.6	17.5	20.7	22.3	22.5	20.8	22.3	20.4	-8.5%	0.9%
United Kingdom	65.1	61.2	53.3	49.7	47.5	44.4	39.6	39.7	35.6	36.9	40.3	9.0%	1.8%
Other Europe	17.3	16.6	14.7	11.8	12.1	11.6	12.2	13.6	11.0	11.8	10.6	-9.8%	0.5%
Total Europe	453.1	423.7	397.9	386.8	383.7	381.5	367.9	359.9	338.3	347.9	344.1	-1.2%	15.3%
Azerbaijan	0.1	-	-	-	-	-	-	-	-	-	-	-	-
Belarus	1.1	0.7	0.6	0.2	0.3	0.5	0.6	0.4	0.3	0.3	0.3	-	♦
Kazakhstan	38.2	39.9	36.4	34.5	27.5	25.9	22.4	22.9	19.8	23.2	24.7	6.5%	1.1%
Lithuania	0.6	0.5	†	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-6.4%	♦
Russian Federation	165.6	154.7	140.8	126.4	119.4	115.7	109.7	102.8	109.4	110.4	114.6	3.9%	5.1%
Turkmenistan	0.3	0.1	-	†	†	†	-	-	-	-	-	-	-
Ukraine	62.1	63.9	56.3	46.3	42.1	33.2	38.0	36.9	38.5	38.8	39.0	0.6%	1.7%
Uzbekistan	4.0	2.9	1.9	1.8	1.4	1.2	1.2	1.2	0.9	1.0	1.1	2.4%	♦
Other Former Soviet Union	5.7	2.8	2.7	2.1	1.8	2.1	2.5	1.7	1.0	0.8	0.6	-26.2%	♦
Total Former Soviet Union	277.7	265.5	238.7	211.4	192.6	178.7	174.5	166.0	170.0	174.6	180.4	3.3%	8.0%
Iran	1.1	1.2	1.3	1.3	1.4	1.2	0.9	1.0	1.0	1.1	0.8	-25.6%	♦
Kuwait	-	-	-	-	-	-	-	-	-	-	-	-	-
Qatar	-	-	-	-	-	-	-	-	-	-	-	-	-
Saudi Arabia	-	-	-	-	-	-	-	-	-	-	-	-	-
United Arab Emirates	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Middle East	2.5	3.1	3.5	3.8	4.1	5.0	5.4	5.8	5.7	6.2	7.2	15.6%	0.3%
Total Middle East	3.6	4.3	4.8	5.1	5.5	6.2	6.3	6.8	6.7	7.3	8.0	9.5%	0.4%
Algeria	0.7	0.6	0.6	0.6	0.6	0.5	0.3	0.5	0.5	0.6	0.6	5.3%	♦
Egypt	0.7	0.8	0.9	1.0	0.7	0.9	0.9	0.9	0.9	0.9	0.9	-	♦
South Africa	70.1	67.3	69.8	73.6	77.4	81.7	84.3	83.4	82.3	81.9	80.6	-1.6%	3.6%
Other Africa	6.0	6.1	6.8	6.5	6.7	6.7	6.9	6.9	6.5	6.1	6.5	7.2%	0.3%
Total Africa	77.5	74.8	78.1	81.7	85.4	89.8	92.4	91.7	90.2	89.5	88.6	-0.9%	3.9%
Australia	37.4	39.0	36.4	38.7	41.2	43.9	45.4	45.9	45.5	47.5	47.6	0.3%	2.1%
Bangladesh	0.1	0.1	†	†	0.3	0.2	0.3	0.1	†	0.1	0.1	-	♦
China	534.9	549.5	570.3	606.4	635.7	676.9	649.3	616.8	512.7	493.7	520.6	5.4%	23.1%
China Hong Kong SAR	5.9	6.3	7.3	5.2	5.6	4.2	3.5	4.4	3.9	3.7	4.9	32.6%	0.2%
India	116.2	123.3	128.0	133.9	142.8	154.4	160.2	159.9	158.1	171.4	173.5	1.2%	7.7%
Indonesia	4.1	4.1	4.0	4.8	5.7	6.9	8.2	9.3	11.6	13.7	16.7	21.9%	0.7%
Japan	79.0	78.0	79.2	82.0	86.2	88.3	89.8	88.4	91.5	98.9	103.0	4.2%	4.6%
Malaysia	1.3	1.3	1.3	1.1	1.5	1.5	1.6	1.7	1.8	1.9	2.4	26.3%	0.1%
New Zealand	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.2	1.1	1.3	15.0%	0.1%
Pakistan	2.0	2.1	2.2	2.2	2.2	2.2	2.1	2.1	2.1	2.0	2.0	-1.9%	0.1%
Philippines	1.3	1.1	1.3	1.3	1.4	2.0	2.4	2.7	2.9	4.3	4.5	5.8%	0.2%
Singapore	-	-	-	-	-	-	-	-	-	-	-	-	-
South Korea	24.5	23.6	25.9	26.7	28.1	32.2	34.8	36.1	38.2	43.0	45.7	6.2%	2.0%
Taiwan	12.2	14.3	15.6	16.6	17.1	19.4	21.9	23.8	24.9	28.9	30.9	6.9%	1.4%
Thailand	4.5	4.8	5.4	6.1	7.1	8.7	8.7	7.3	7.9	7.8	8.8	12.7%	0.4%
Other Asia Pacific	56.5	57.3	59.1	58.7	58.9	58.7	59.3	56.5	55.8	57.9	58.7	1.4%	2.6%
Total Asia Pacific	881.1	906.1	937.2	984.9	1035.0	1100.7	1088.7	1056.1	958.1	975.9	1020.7	4.6%	45.3%
TOTAL WORLD	2218.0	2203.6	2199.6	2219.3	2255.3	2335.8	2323.5	2279.8	2162.5	2216.8	2255.1	1.7%	100.0%
of which: European Union 15	281.0	260.7	238.9	235.4	231.7	225.0	215.1	215.5	204.6	213.8	212.5	-0.7%	9.4%
OECD	1068.4	1043.7	1033.8	1037.9	1045.7	1077.2	1084.1	1082.6	1070.5	1113.9	1108.2	-0.5%	49.1%
Former Soviet Union	277.7	265.5	238.7	211.4	192.6	178.7	174.5	166.0	170.0	174.6	180.4	3.3%	8.0%
Other EMEs	871.9	894.4	927.1	970.0	1017.0	1079.9	1064.9	1031.2	922.0	928.3	966.5	4.1%	42.9%

*Commercial solid fuels only, i.e. bituminous coal and anthracite (hard coal), and lignite and brown (sub-bituminous) coal.

†Less than 0.05.

♦Less than 0.05%.

nuclear energy

consumption*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	145.9	147.4	145.4	152.6	160.4	160.7	149.8	160.5	173.5	179.6	183.2	2.0%	30.5%
Canada	19.2	18.2	21.3	24.4	22.1	21.0	18.7	16.2	16.6	16.5	17.4	5.4%	2.9%
Mexico	1.0	0.9	1.1	1.0	1.9	1.8	2.4	2.1	2.3	1.9	2.0	5.9%	0.3%
Total North America	166.1	166.5	167.8	178.0	184.4	183.5	170.9	178.8	192.4	198.0	202.6	2.3%	33.7%
Argentina	1.8	1.6	1.8	1.9	1.6	1.7	1.8	1.7	1.6	1.4	1.6	14.2%	0.3%
Brazil	0.3	0.4	0.1	†	0.6	0.5	0.7	0.7	0.9	1.3	3.2	>100.0%	0.5%
Chile	-	-	-	-	-	-	-	-	-	-	-	-	-
Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-
Ecuador	-	-	-	-	-	-	-	-	-	-	-	-	-
Peru	-	-	-	-	-	-	-	-	-	-	-	-	-
Venezuela	-	-	-	-	-	-	-	-	-	-	-	-	-
Other S. & Cent. America	-	-	-	-	-	-	-	-	-	-	-	-	-
Total S. & Cent. America	2.1	2.0	1.9	1.9	2.2	2.2	2.5	2.4	2.5	2.7	4.8	82.4%	0.8%
Austria	-	-	-	-	-	-	-	-	-	-	-	-	-
Belgium & Luxembourg	9.7	9.8	9.5	9.2	9.4	9.8	10.7	10.5	11.1	10.9	10.7	-2.1%	1.8%
Bulgaria	3.0	2.6	3.2	3.5	3.9	4.1	4.0	3.8	3.6	4.5	4.5	0.3%	0.7%
Czech Republic	2.7	2.8	2.9	2.9	2.8	2.9	2.8	3.0	3.0	3.1	3.3	8.5%	0.6%
Denmark	-	-	-	-	-	-	-	-	-	-	-	-	-
Finland	4.4	4.3	4.5	4.4	4.3	4.4	4.8	5.0	5.3	5.1	5.2	1.4%	0.9%
France	75.0	76.6	83.3	81.5	85.4	89.9	89.5	87.8	89.2	94.0	94.9	1.0%	15.8%
Germany	33.4	35.9	34.7	34.2	34.9	36.6	38.5	36.6	38.5	38.4	38.7	0.9%	6.4%
Greece	-	-	-	-	-	-	-	-	-	-	-	-	-
Hungary	3.1	3.2	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	-0.4%	0.5%
Iceland	-	-	-	-	-	-	-	-	-	-	-	-	-
Republic of Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Italy	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands	0.8	0.9	0.9	0.9	0.9	0.9	0.5	0.9	0.9	0.9	0.9	1.2%	0.1%
Norway	-	-	-	-	-	-	-	-	-	-	-	-	-
Poland	-	-	-	-	-	-	-	-	-	-	-	-	-
Portugal	-	-	-	-	-	-	-	-	-	-	-	-	-
Romania	-	-	-	-	-	0.3	1.2	1.2	1.2	1.2	1.2	-0.2%	0.2%
Slovakia	2.6	2.5	2.7	2.7	2.6	2.6	2.4	2.6	3.0	3.7	3.9	3.3%	0.6%
Spain	12.6	12.6	12.7	12.5	12.5	12.7	12.5	13.4	13.3	14.1	14.4	2.3%	2.4%
Sweden	17.4	14.4	13.9	16.6	15.8	16.6	15.8	15.9	16.6	13.0	16.4	26.4%	2.7%
Switzerland	5.2	5.3	5.3	5.5	5.6	5.7	5.8	5.8	5.6	6.0	6.1	1.4%	1.0%
Turkey	-	-	-	-	-	-	-	-	-	-	-	-	-
United Kingdom	16.0	17.4	20.2	20.0	20.1	21.4	22.2	22.5	21.5	19.3	20.4	5.9%	3.4%
Other Europe	1.1	0.9	0.9	1.0	1.1	1.0	1.1	1.1	1.1	1.1	1.2	10.5%	0.2%
Total Europe	187.0	189.2	197.8	198.1	202.5	212.1	215.0	213.3	217.1	218.5	225.0	3.0%	37.4%
Azerbaijan	-	-	-	-	-	-	-	-	-	-	-	-	-
Belarus	-	-	-	-	-	-	-	-	-	-	-	-	-
Kazakhstan	0.1	0.1	0.1	0.1	†	†	0.1	†	-	-	-	-	-
Lithuania	3.8	3.3	2.8	1.7	2.7	3.2	2.7	3.1	2.2	1.9	2.6	35.0%	0.4%
Russian Federation	27.2	27.1	27.0	22.1	22.5	24.7	24.5	23.6	27.1	29.5	30.9	4.6%	5.1%
Turkmenistan	-	-	-	-	-	-	-	-	-	-	-	-	-
Ukraine	17.0	16.7	17.0	15.6	16.0	18.0	18.0	17.0	16.3	17.5	17.2	-1.7%	2.9%
Uzbekistan	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Former Soviet Union	-	-	-	-	0.1	0.5	0.4	0.4	0.5	0.4	0.5	8.2%	0.1%
Total Former Soviet Union	48.1	47.2	46.9	39.5	41.3	46.4	45.7	44.1	46.1	49.3	51.2	3.6%	8.5%
Iran	-	-	-	-	-	-	-	-	-	-	-	-	-
Kuwait	-	-	-	-	-	-	-	-	-	-	-	-	-
Qatar	-	-	-	-	-	-	-	-	-	-	-	-	-
Saudi Arabia	-	-	-	-	-	-	-	-	-	-	-	-	-
United Arab Emirates	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Middle East	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Middle East	-	-	-	-	-	-	-	-	-	-	-	-	-
Algeria	-	-	-	-	-	-	-	-	-	-	-	-	-
Egypt	-	-	-	-	-	-	-	-	-	-	-	-	-
South Africa	2.2	2.2	1.7	2.3	2.7	2.8	3.0	3.2	3.1	3.1	2.6	-17.6%	0.4%
Other Africa	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Africa	2.2	2.2	1.7	2.3	2.7	2.8	3.0	3.2	3.1	3.1	2.6	-17.6%	0.4%
Australia	-	-	-	-	-	-	-	-	-	-	-	-	-
Bangladesh	-	-	-	-	-	-	-	-	-	-	-	-	-
China	-	0.1	0.4	3.1	2.9	3.2	3.3	3.4	3.4	3.8	4.0	4.4%	0.7%
China Hong Kong SAR	-	-	-	-	-	-	-	-	-	-	-	-	-
India	1.2	1.4	1.4	1.1	1.7	1.9	2.3	2.6	2.9	3.6	4.4	21.9%	0.7%
Indonesia	-	-	-	-	-	-	-	-	-	-	-	-	-
Japan	47.4	49.3	56.3	58.7	65.1	67.3	72.8	74.0	71.9	72.3	72.7	0.5%	12.1%
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
New Zealand	-	-	-	-	-	-	-	-	-	-	-	-	-
Pakistan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	†	0.3	0.5	82.1%	0.1%
Philippines	-	-	-	-	-	-	-	-	-	-	-	-	-
Singapore	-	-	-	-	-	-	-	-	-	-	-	-	-
South Korea	12.7	12.8	13.2	13.3	15.2	16.7	17.4	20.3	23.3	24.7	25.4	2.9%	4.2%
Taiwan	8.0	7.7	7.8	7.9	8.0	8.6	8.2	8.3	8.7	8.7	8.0	-7.8%	1.3%
Thailand	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Asia Pacific	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Asia Pacific	69.4	71.4	79.2	84.2	93.0	97.8	104.1	108.7	110.2	113.4	115.0	1.4%	19.1%
TOTAL WORLD	474.9	478.5	495.3	504.0	526.1	544.8	541.2	550.5	571.4	585.0	601.2	2.8%	100.0%
of which: European Union 15	169.3	171.9	179.7	179.3	183.3	192.3	194.5	192.6	196.4	195.7	201.6	3.1%	33.6%
OECD	409.1	414.3	431.0	443.6	462.2	474.2	469.8	480.3	498.8	506.7	518.8	2.4%	86.3%
Former Soviet Union	48.1	47.2	46.9	39.5	41.3	46.4	45.7	44.1	46.1	49.3	51.2	3.6%	8.5%
Other EMEs	17.7	17.0	17.4	20.9	22.6	24.2	25.7	26.1	26.5	29.0	31.2	7.8%	5.2%

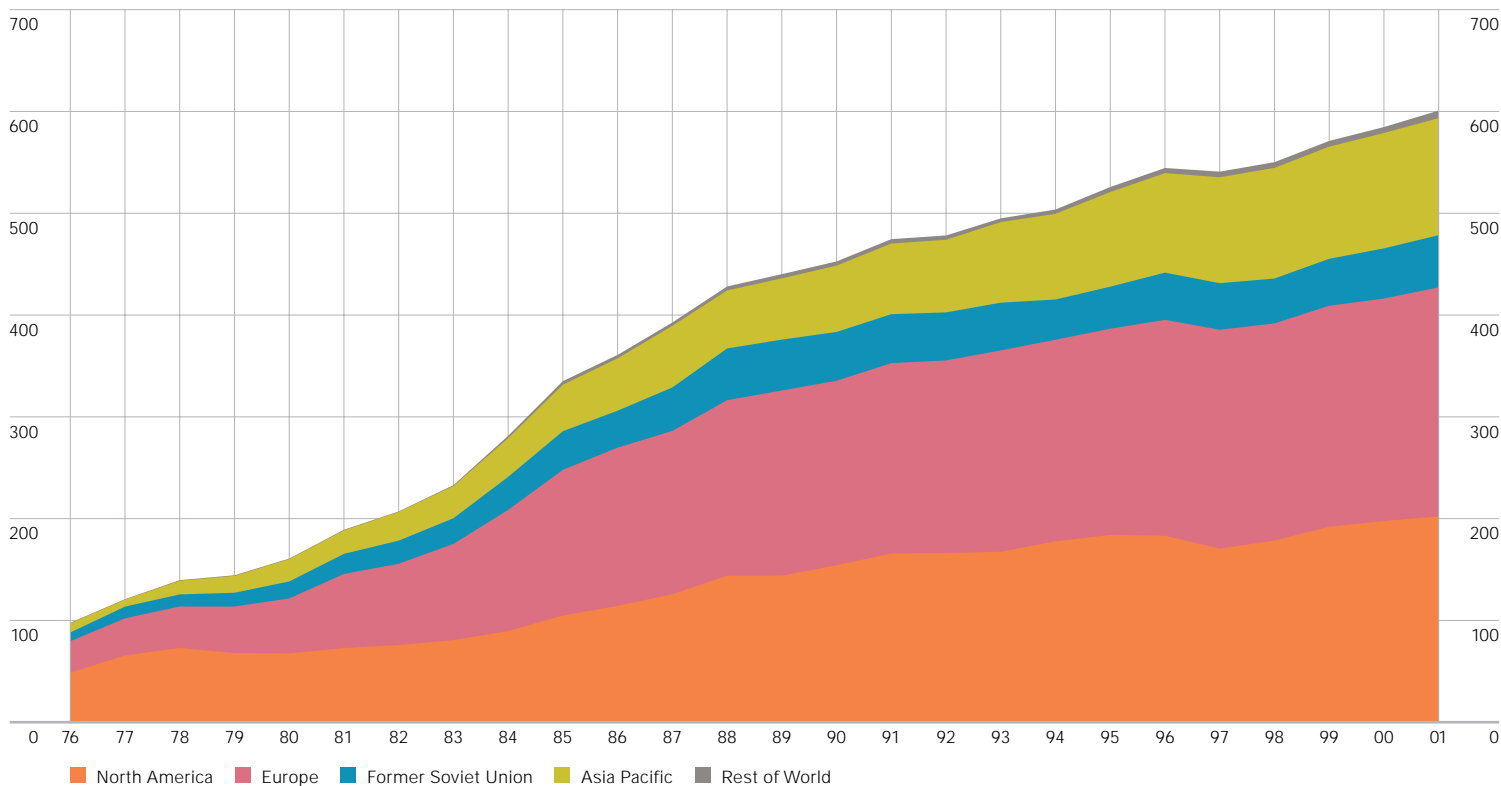
*Converted on the basis of thermal equivalence assuming 38% conversion efficiency in a modern thermal power station.

†Less than 0.05.

Note: Nuclear energy data expressed in terawatt-hours is available at www.bp.com/centres/energy/

consumption by area

Million tonnes oil equivalent

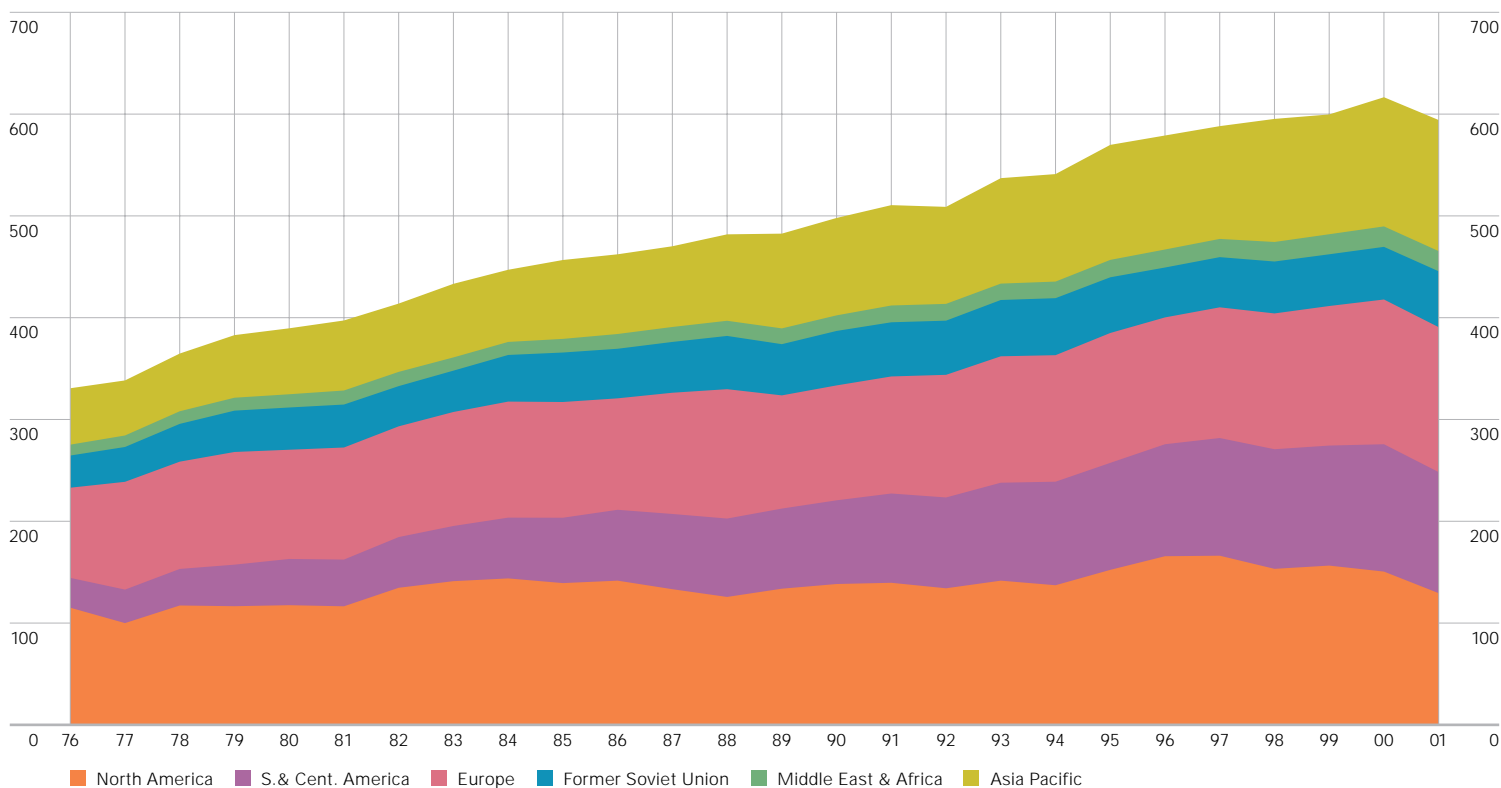


Nuclear energy maintained its record of steady growth during 2001, registering a 2.8% increase, somewhat ahead of the 10-year annual average of 2.4%.

hydroelectricity

consumption by area

Million tonnes oil equivalent



Major falls in North American and Brazilian output resulted in a steep drop in hydroelectric generation during 2001, breaking a 10-year growth trend.

hydroelectricity

consumption*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	65.1	56.9	63.2	58.7	70.5	78.7	81.1	72.9	71.6	62.4	48.3	-22.7%	8.1%
Canada	69.8	71.6	72.8	74.2	75.9	80.2	79.4	75.1	77.8	81.0	75.0	-7.4%	12.6%
Mexico	5.0	6.0	6.0	4.6	6.2	7.1	6.0	5.6	7.4	7.5	6.4	-14.1%	1.1%
Total North America	139.9	134.5	142.0	137.5	152.6	166.0	166.5	153.6	156.8	150.9	129.7	-14.1%	21.8%
Argentina	3.7	4.4	5.5	6.2	6.1	5.2	6.4	6.0	4.9	6.5	8.0	23.0%	1.3%
Brazil	49.3	50.5	53.2	54.9	57.5	60.1	63.1	66.0	66.3	69.6	61.4	-11.7%	10.3%
Chile	3.0	3.8	3.9	3.9	4.2	3.8	4.3	3.6	3.0	4.3	4.8	12.9%	0.8%
Colombia	6.3	5.1	6.3	7.3	7.3	8.0	7.1	6.9	7.6	6.9	7.1	2.6%	1.2%
Ecuador	1.2	1.2	1.3	1.5	1.2	1.4	1.5	1.5	1.6	1.7	1.6	-9.0%	0.3%
Peru	2.5	2.2	2.6	2.9	2.9	3.0	3.0	3.1	3.1	3.7	4.0	8.9%	0.7%
Venezuela	10.1	10.7	10.7	11.6	11.6	12.2	13.0	13.1	13.7	14.2	13.7	-3.9%	2.3%
Other S. & Cent. America	11.6	11.3	12.7	13.4	14.3	16.3	17.2	17.3	17.7	18.2	18.3	0.8%	3.1%
Total S. & Cent. America	87.7	89.2	96.2	101.7	105.1	110.0	115.6	117.5	117.9	125.1	118.9	-4.9%	20.0%
Austria	7.4	8.2	8.6	8.4	8.7	8.1	8.4	8.8	9.4	9.9	9.8	-0.2%	1.7%
Belgium & Luxembourg	0.4	0.4	0.3	0.4	0.5	0.5	0.5	0.6	0.5	0.6	0.6	2.9%	0.1%
Bulgaria	0.6	0.5	0.4	0.3	0.5	0.7	0.7	0.8	0.7	0.7	0.8	6.7%	0.1%
Czech Republic	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.6	11.5%	0.1%
Denmark	†	†	†	†	†	†	†	†	†	†	†	-14.3%	♦
Finland	3.0	3.4	3.1	2.7	2.9	2.7	2.7	3.3	2.9	3.3	3.0	-8.1%	0.5%
France	13.9	16.4	15.4	18.3	17.2	15.9	15.3	14.9	17.4	16.4	18.1	10.8%	3.0%
Germany	4.2	4.8	4.9	5.1	5.5	4.9	4.7	4.8	5.3	5.9	5.8	-0.6%	1.0%
Greece	0.7	0.5	0.6	0.7	0.9	1.0	0.9	0.9	1.1	0.9	0.5	-45.5%	0.1%
Hungary	†	†	†	†	†	†	0.1	†	†	†	†	5.0%	♦
Iceland	1.0	1.0	1.0	1.0	1.1	1.1	1.2	1.3	1.4	1.4	1.5	3.5%	0.3%
Republic of Ireland	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.3	0.2	0.3	0.2	-23.5%	♦
Italy	10.3	10.4	10.1	10.8	9.5	10.7	10.6	10.7	11.7	11.5	12.5	8.2%	2.1%
Netherlands	†	†	†	†	†	†	†	†	†	†	†	-18.8%	♦
Norway	25.0	26.5	27.1	25.5	27.7	23.5	25.1	26.3	27.6	32.2	27.4	-14.9%	4.6%
Poland	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	2.5%	0.2%
Portugal	2.1	1.1	2.0	2.4	1.9	3.4	3.0	3.0	2.9	2.9	2.9	-0.9%	0.5%
Romania	3.2	2.6	2.9	3.0	3.8	3.6	4.0	4.3	4.1	3.3	3.4	1.0%	0.6%
Slovakia	0.4	0.5	0.9	1.0	1.2	1.0	1.0	1.0	1.1	1.1	1.1	-4.5%	0.2%
Spain	6.4	4.7	5.8	6.5	5.5	9.4	8.5	8.8	7.0	8.3	11.6	40.5%	2.0%
Sweden	14.4	16.9	17.1	13.4	15.3	11.7	15.6	16.7	16.2	17.8	17.9	0.8%	3.0%
Switzerland	7.6	7.7	8.3	9.0	8.1	6.7	8.0	7.8	9.3	8.7	9.7	11.7%	1.6%
Turkey	5.1	6.0	7.7	6.9	8.0	9.2	8.8	9.6	7.8	7.0	5.4	-22.3%	0.9%
United Kingdom	1.4	1.6	1.3	1.5	1.4	1.1	1.3	1.5	1.9	1.8	1.5	-17.5%	0.2%
Other Europe	6.6	5.9	5.3	5.8	6.3	7.8	6.4	6.6	7.1	6.8	7.1	4.1%	1.2%
Total Europe	115.0	120.5	124.2	124.3	127.6	124.6	128.4	133.4	137.1	142.2	142.4	0.1%	23.9%
Azerbaijan	0.4	0.4	0.5	0.4	0.4	0.3	0.4	0.4	0.3	0.3	0.3	-15.4%	♦
Belarus	†	†	†	†	†	†	†	†	†	†	†	-	♦
Kazakhstan	1.6	1.6	1.7	2.1	1.9	1.7	1.5	1.4	1.4	1.6	1.7	2.5%	0.3%
Lithuania	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	8.9%	♦
Russian Federation	38.0	39.1	39.6	39.8	40.1	34.9	35.6	35.9	36.4	37.4	39.8	6.4%	6.7%
Turkmenistan	0.2	0.2	-	-	-	-	-	-	-	-	-	-	-
Ukraine	2.7	1.8	2.5	2.8	2.3	2.0	2.3	3.6	2.6	2.7	3.0	11.0%	0.5%
Uzbekistan	1.4	1.4	1.7	1.6	1.4	1.5	1.3	1.3	1.3	1.0	1.3	24.2%	0.2%
Other Former Soviet Union	8.8	8.6	9.2	9.1	8.4	8.4	8.0	8.2	8.6	8.6	8.6	0.1%	1.4%
Total Former Soviet Union	53.2	53.2	55.3	56.0	54.7	49.0	49.3	51.0	50.8	51.7	54.9	5.7%	9.2%
Iran	1.6	2.0	2.2	1.8	1.9	1.8	1.3	1.7	1.2	1.1	0.8	-30.4%	0.1%
Kuwait	-	-	-	-	-	-	-	-	-	-	-	-	-
Qatar	-	-	-	-	-	-	-	-	-	-	-	-	-
Saudi Arabia	-	-	-	-	-	-	-	-	-	-	-	-	-
United Arab Emirates	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Middle East	0.5	0.7	0.6	0.8	0.9	1.1	1.1	1.1	0.7	0.8	0.7	-6.6%	0.1%
Total Middle East	2.1	2.7	2.8	2.6	2.8	2.9	2.4	2.8	1.9	1.9	1.5	-20.5%	0.3%
Algeria	0.2	0.1	0.3	0.1	0.2	0.1	0.1	0.2	†	†	†	33.3%	♦
Egypt	2.3	2.3	2.4	2.5	2.6	2.7	2.7	3.1	3.4	3.2	3.0	-6.5%	0.5%
South Africa	0.9	0.5	0.3	0.6	0.4	0.8	1.1	0.9	0.8	0.9	0.8	-7.2%	0.1%
Other Africa	11.0	10.9	10.3	10.5	11.1	11.2	11.6	12.2	13.6	14.1	14.5	2.8%	2.4%
Total Africa	14.4	13.8	13.3	13.7	14.3	14.8	15.5	16.4	17.8	18.2	18.3	0.7%	3.1%
Australia	3.7	3.5	3.9	3.7	3.5	3.6	3.5	3.8	4.0	3.7	3.9	4.3%	0.7%
Bangladesh	0.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	5.6%	♦
China	28.3	30.0	32.7	37.8	42.2	42.3	42.5	44.9	44.1	55.0	58.3	5.9%	9.8%
China Hong Kong SAR	-	-	-	-	-	-	-	-	-	-	-	-	-
India	16.7	15.9	16.0	18.2	17.2	15.6	15.9	18.9	18.6	17.4	16.1	-7.5%	2.7%
Indonesia	1.3	1.9	1.8	1.6	1.7	1.8	1.2	2.2	2.1	2.1	2.1	-	0.4%
Japan	23.4	20.0	23.8	17.4	19.9	19.7	21.2	23.6	21.0	20.7	20.4	-1.1%	3.4%
Malaysia	1.0	1.0	1.1	1.5	1.4	1.2	0.9	1.1	1.7	1.7	1.7	-	0.3%
New Zealand	5.1	4.7	5.3	5.8	6.2	5.8	5.3	5.5	5.3	5.5	5.0	-10.3%	0.8%
Pakistan	4.1	4.5	5.0	4.9	5.1	5.6	4.2	5.5	4.9	4.0	4.0	-0.6%	0.7%
Philippines	1.2	1.0	1.1	1.3	1.4	1.6	1.4	1.1	1.8	1.8	1.6	-9.3%	0.3%
Singapore	-	-	-	-	-	-	-	-	-	-	-	-	-
South Korea	1.1	1.1	1.4	0.9	1.2	1.2	1.2	1.4	1.4	1.3	0.9	-26.1%	0.2%
Taiwan	1.2	1.9	1.5	2.0	2.0	2.0	2.2	2.4	2.0	2.0	2.1	3.4%	0.3%
Thailand	1.0	1.0	0.8	1.0	1.5	1.7	1.6	1.2	0.8	1.4	1.4	4.6%	0.2%
Other Asia Pacific	10.3	8.6	9.1	9.3	9.6	9.7	9.5	9.1	9.8	10.1	11.1	10.0%	1.9%
Total Asia Pacific	98.6	95.3	103.6	105.6	113.0	112.0	110.8	120.9	117.7	126.9	128.8	1.5%	21.7%
TOTAL WORLD	510.9	509.2	537.4	541.4	570.1	579.3	588.5	595.6	600.0	616.9	594.5	-3.7%	100.0%
of which: European Union 15	64.4	68.6	69.4	70.5	69.5	69.6	71.7	74.3	76.5	79.6	84.4	6.4%	14.2%
OECD	277.8	275.3	292.0	280.5	300.4	308.8	315.0	309.6	313.7	313.5	291.0	-7.1%	49.0%
Former Soviet Union	53.2	53.2	55.3	56.0	54.7	49.0	49.3	51.0	50.8	51.7	54.9	5.7%	9.2%
Other EMEs	179.9	180.7	190.1	204.9	215.0	221.5	224.2	235.0	235.5	251.7	248.6	-1.3%	41.8%

*Converted on the basis of thermal equivalence assuming 38% conversion efficiency in a modern thermal power station.

†Less than 0.05.

♦Less than 0.05%.

Note: Hydroelectricity data expressed in terawatt-hours is available at www.bp.com/centres/energy/

primary energy

consumption*

Million tonnes oil equivalent	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Change 2001 over 2000	2001 share of total
USA	1949.6	1976.6	2020.9	2059.9	2101.8	2172.7	2187.6	2196.0	2239.9	2287.4	2237.3	-2.2%	24.5%
Canada	246.5	253.0	256.5	265.3	266.8	275.9	277.4	269.4	274.8	284.8	274.6	-3.6%	3.0%
Mexico	104.6	106.3	107.3	114.4	111.3	116.4	120.0	125.6	126.9	131.0	127.7	-2.5%	1.4%
Total North America	2300.7	2335.9	2384.7	2439.6	2479.9	2565.0	2585.0	2591.0	2641.6	2703.2	2639.6	-2.4%	28.9%
Argentina	45.5	46.5	48.7	50.6	52.4	53.9	55.9	57.9	57.3	58.8	59.2	0.7%	0.6%
Brazil	122.3	126.5	130.4	135.0	142.3	151.0	160.5	166.8	171.1	177.3	173.6	-2.1%	1.9%
Chile	13.1	14.4	15.1	16.4	17.7	19.1	22.3	21.6	22.4	24.6	25.8	4.8%	0.3%
Colombia	23.3	23.0	24.7	25.7	26.4	27.7	27.9	27.3	25.0	24.9	24.8	-0.3%	0.3%
Ecuador	6.0	5.8	6.2	6.8	6.4	7.2	8.1	8.2	7.7	7.7	7.6	-0.3%	0.1%
Peru	8.5	8.4	9.1	9.9	10.7	11.0	10.8	11.3	11.4	11.7	11.7	-0.3%	0.1%
Venezuela	48.4	49.8	51.1	53.4	56.4	58.0	61.1	63.8	59.8	61.9	61.9	♦	0.7%
Other S. & Cent. America	62.7	64.0	66.5	70.5	74.0	78.1	80.9	83.2	84.7	86.3	87.2	1.0%	1.0%
Total S. & Cent. America	329.8	338.4	351.8	368.3	386.3	406.0	427.5	440.1	439.4	453.2	451.8	-0.3%	5.0%
Austria	28.1	27.7	28.2	27.9	28.5	29.1	30.3	30.9	31.6	31.5	31.6	0.4%	0.3%
Belgium & Luxembourg	56.3	56.6	54.8	54.7	56.7	59.1	60.3	63.0	64.1	66.4	63.9	-3.6%	0.7%
Bulgaria	21.5	20.3	21.7	20.8	22.3	23.3	20.7	20.7	18.0	18.9	18.2	-3.3%	0.2%
Czech Republic	45.9	40.5	39.1	39.3	41.3	43.0	41.7	39.9	38.5	39.8	41.6	4.6%	0.5%
Denmark	19.5	17.9	19.2	20.7	20.2	24.1	21.7	20.6	19.9	18.8	18.9	0.5%	0.2%
Finland	23.9	23.3	23.1	24.3	23.1	24.5	25.1	25.6	25.7	26.0	26.3	1.1%	0.3%
France	231.1	233.7	233.5	229.5	235.7	244.7	241.0	247.2	251.4	254.8	256.4	0.6%	2.8%
Germany	340.6	336.2	333.6	331.1	333.1	344.0	337.8	334.5	328.5	330.5	335.2	1.4%	3.7%
Greece	24.4	25.1	25.2	25.9	26.7	27.0	27.2	28.6	30.1	31.8	31.1	-2.1%	0.3%
Hungary	25.6	23.3	22.9	23.4	23.6	24.2	23.8	23.8	23.7	23.0	23.9	3.8%	0.3%
Iceland	1.6	1.7	1.8	1.8	1.9	1.9	2.1	2.2	2.3	2.4	2.5	3.0%	♦
Republic of Ireland	9.2	9.2	9.5	10.0	10.2	10.8	11.6	12.4	13.2	13.9	14.6	5.1%	0.2%
Italy	158.0	158.3	154.9	154.7	162.4	162.4	163.9	168.5	173.7	176.4	177.2	0.4%	1.9%
Netherlands	79.1	78.1	79.6	79.5	82.7	85.2	84.7	84.5	83.2	86.5	88.6	2.5%	1.0%
Norway	36.3	38.2	39.5	38.4	40.7	37.1	39.3	40.4	41.5	45.9	41.7	-9.2%	0.5%
Poland	101.2	95.2	97.0	96.2	96.4	100.8	98.6	94.1	91.1	88.4	87.7	-0.9%	1.0%
Portugal	16.5	17.0	17.3	17.9	19.0	19.4	20.4	22.4	24.0	23.6	23.9	1.3%	0.3%
Romania	50.7	48.5	47.3	45.4	48.6	48.2	45.2	41.3	36.9	37.0	38.2	3.1%	0.4%
Slovakia	18.6	18.1	17.1	16.6	17.3	17.5	17.1	17.6	17.5	18.1	19.1	5.2%	0.2%
Spain	92.7	95.1	93.9	96.9	100.5	104.8	111.7	118.1	122.7	129.2	134.6	4.2%	1.5%
Sweden	50.3	50.5	49.9	49.8	50.1	48.8	50.4	51.6	51.6	48.6	52.6	8.4%	0.6%
Switzerland	27.8	28.3	28.1	29.4	27.9	27.1	28.9	29.1	30.1	29.4	31.4	6.9%	0.3%
Turkey	48.0	52.5	57.8	56.2	60.1	67.7	69.6	70.6	68.9	73.7	70.2	-4.7%	0.8%
United Kingdom	215.9	214.5	216.6	213.6	214.4	224.8	219.8	223.1	221.9	222.2	224.0	0.8%	2.5%
Other Europe	47.9	41.7	38.8	35.3	37.0	41.1	41.6	43.4	40.7	41.0	41.1	0.2%	0.5%
Total Europe	1770.7	1751.5	1750.4	1739.3	1780.4	1840.6	1834.5	1854.1	1850.8	1877.8	1894.5	0.9%	20.8%
Azerbaijan	22.3	19.1	16.6	15.8	16.1	12.6	11.4	12.6	12.8	11.4	12.5	9.1%	0.1%
Belarus	38.1	37.1	28.6	25.3	23.6	21.4	23.5	22.2	20.9	21.0	20.7	-1.4%	0.2%
Kazakhstan	73.5	74.1	65.6	58.2	51.2	45.9	40.7	39.1	35.0	40.5	43.1	6.4%	0.5%
Lithuania	17.6	11.0	8.3	7.3	8.2	9.0	8.6	9.2	7.8	7.0	8.1	16.5%	0.1%
Russian Federation	862.2	820.8	770.4	702.8	668.1	647.2	614.3	614.2	626.4	640.3	643.0	0.4%	7.0%
Turkmenistan	14.1	13.6	11.6	12.9	11.1	12.0	12.1	12.0	12.7	13.6	14.0	2.6%	0.2%
Ukraine	248.6	218.3	184.3	157.7	147.8	141.6	138.9	133.7	133.7	132.6	131.1	-1.1%	1.4%
Uzbekistan	49.8	47.0	48.3	47.8	47.6	49.0	50.1	51.8	53.6	50.9	54.8	7.8%	0.6%
Other Former Soviet Union	49.1	38.4	31.1	25.7	23.8	22.3	23.8	23.6	21.7	21.0	22.1	5.1%	0.2%
Total Former Soviet Union	1375.3	1279.4	1164.8	1053.5	997.5	961.0	923.4	918.4	924.6	938.3	949.4	1.2%	10.4%
Iran	72.2	75.7	78.3	85.2	93.3	98.5	103.7	105.2	113.4	115.0	114.3	-0.6%	1.3%
Kuwait	4.1	7.9	9.9	11.6	14.8	14.6	15.3	17.7	18.1	19.0	19.1	0.4%	0.2%
Qatar	7.7	12.2	13.0	13.0	13.1	13.4	14.3	14.5	13.7	14.7	15.7	7.1%	0.2%
Saudi Arabia	87.0	85.8	88.1	92.0	90.1	93.7	96.1	101.0	102.5	107.2	111.0	3.5%	1.2%
United Arab Emirates	34.9	33.8	34.9	37.7	40.3	42.3	42.4	39.2	41.3	43.8	45.2	3.0%	0.5%
Other Middle East	58.4	64.8	69.3	72.9	77.6	80.3	85.2	88.0	88.8	90.6	91.9	1.4%	1.0%
Total Middle East	264.3	280.2	293.5	312.4	329.2	342.8	357.0	365.6	377.8	390.3	397.2	1.8%	4.4%
Algeria	25.3	25.9	26.6	27.0	28.1	27.9	26.5	27.7	27.8	28.0	28.8	3.0%	0.3%
Egypt	33.3	33.3	33.7	34.4	36.4	38.4	40.0	42.1	45.0	47.8	49.0	2.5%	0.5%
South Africa	89.8	87.2	89.8	95.3	100.5	106.0	109.4	108.8	107.9	108.4	107.0	-1.3%	1.2%
Other Africa	71.8	74.9	76.8	79.2	81.2	83.6	85.5	88.2	90.7	92.7	95.8	3.4%	1.1%
Total Africa	220.2	221.3	226.9	235.9	246.2	255.9	261.4	266.8	271.4	276.9	280.6	1.4%	3.1%
Australia	87.2	88.5	88.6	93.9	97.5	101.3	103.6	105.0	105.4	108.1	109.9	1.7%	1.2%
Bangladesh	6.7	7.2	7.8	8.4	9.9	10.0	10.6	11.0	11.1	12.6	13.4	6.2%	0.1%
China	694.5	722.2	758.4	811.8	857.4	912.7	898.0	872.8	786.6	804.7	839.7	4.3%	9.2%
China Hong Kong SAR	12.2	14.4	15.6	14.1	15.1	15.0	15.1	15.4	15.6	15.6	16.6	6.6%	0.2%
India	205.8	216.9	222.8	236.2	252.4	269.8	280.8	290.0	297.1	313.3	314.7	0.5%	3.4%
Indonesia	57.1	61.4	64.9	67.9	73.5	79.4	84.0	80.0	89.1	93.8	97.9	4.4%	1.1%
Japan	451.1	455.2	461.8	479.8	493.8	503.6	507.4	502.2	508.7	515.9	514.5	-0.3%	5.6%
Malaysia	24.2	25.9	29.6	32.3	33.1	36.0	37.7	37.4	40.5	42.3	42.1	-0.4%	0.5%
New Zealand	15.3	15.6	16.0	16.5	16.9	17.2	17.3	16.8	17.4	17.8	17.6	-1.0%	0.2%
Pakistan	27.7	29.5	31.7	33.7	36.4	38.3	37.4	39.6	40.8	42.1	43.4	3.2%	0.5%
Philippines	13.6	15.8	16.5	17.5	19.6	21.1	22.6	22.9	22.7	22.6	22.7	0.5%	0.2%
Singapore	23.7	25.7	28.1	32.0	33.3	31.6	33.8	34.7	32.9	35.0	39.1	11.7%	0.4%
South Korea	101.8	114.4	125.4	135.5	148.6	163.8	179.6	165.5	180.5	191.1	195.9	2.5%	2.1%
Taiwan	51.7	55.1	57.9	62.3	65.7	68.9	72.9	77.5	81.1	85.6	85.4	-0.1%	0.9%
Thailand	33.2	36.1	40.6	45.5	52.4	58.4	61.2	58.2	59.7	62.4	63.0	1.0%	0.7%
Other Asia Pacific	80.4	80.9	84.3	84.9	86.4	88.2	90.0	88.0	89.0	93.0	95.8	3.0%	1.0%
Total Asia Pacific	1886.2	1964.8	2050.0	2172.3	2292.0	2415.3	2452.0	2417.0	2378.2	2455.9	2511.7	2.3%	27.5%
TOTAL WORLD	8147.2	8171.5	8222.1	8321.3	8511.5	8786.6	8840.8	8853.0	8883.8	9095.6	9124.8	0.3%	100.0%
of which: European Union 15	1345.6	1343.2	1339.3	1336.5	1363.3	1408.7	1405.9	1431.0	1441.6	1460.2	1478.9	1.3%	16.2%
OECD	4606.7	4650.6	4719.1	4803.1	4909.2	5078.9	5119.9	5129.2	5208.8	5317.0	5274.5	-0.8%	57.8%
Former Soviet Union	1375.3	1279.4	1164.8	1053.5	997.5	961.0	923.4	918.4	924.6	938.3	949.4	1.2%	10.4%
Other EMEs	2165.2	2241.5	2338.2	2464.7	2604.8	2746.7	2797.5	2805.4	2750.4	2840.3	2900.9	2.1%	31.8%

*In this Review, primary energy comprises commercially traded fuels only. Excluded, therefore, are fuels such as wood, peat and animal waste which, though important in many countries, are unreliably documented in terms of consumption statistics.

♦Less than 0.05%.

primary energy

consumption by fuel*

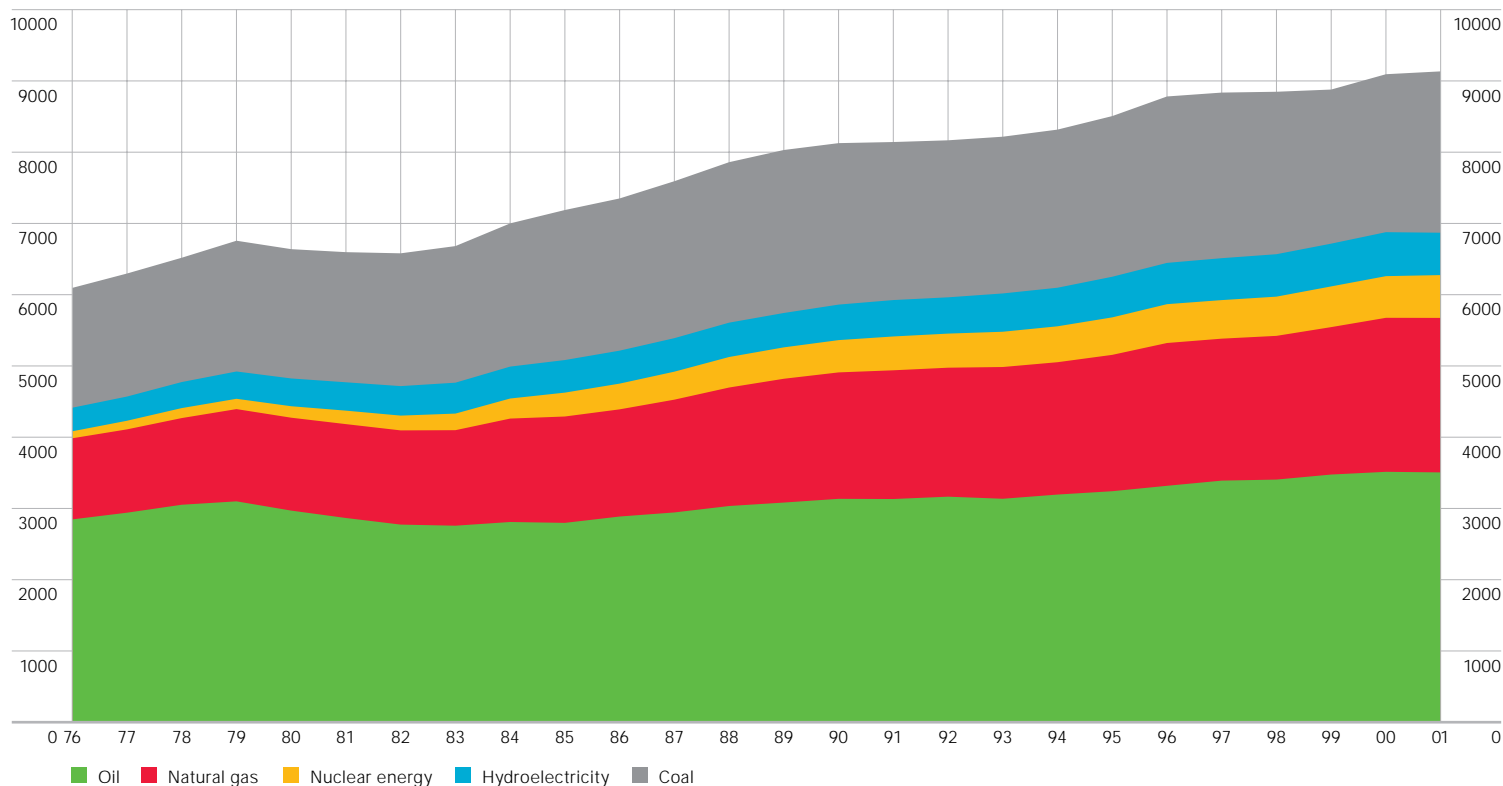
Million tonnes oil equivalent	2000						2001					
	Oil	Natural gas	Coal	Nuclear energy	Hydro-electricity	Total	Oil	Natural gas	Coal	Nuclear energy	Hydro-electricity	Total
USA	897.6	582.4	565.3	179.6	62.4	2287.4	895.6	554.6	555.7	183.2	48.3	2237.3
Canada	88.1	69.8	29.4	16.5	81.0	284.8	88.0	65.4	28.9	17.4	75.0	274.6
Mexico	84.1	31.4	6.2	1.9	7.5	131.0	82.7	30.4	6.3	2.0	6.4	127.7
Total North America	1069.8	683.6	600.9	198.0	150.9	2703.2	1066.3	650.4	590.9	202.6	129.7	2639.6
Argentina	20.3	29.9	0.7	1.4	6.5	58.8	19.0	29.9	0.7	1.6	8.0	59.2
Brazil	85.4	8.2	12.8	1.3	69.6	177.3	85.1	9.8	14.0	3.2	61.4	173.6
Chile	11.8	4.7	3.9	–	4.3	24.6	12.0	5.0	4.0	–	4.8	25.8
Colombia	10.5	5.3	2.2	–	6.9	24.9	9.9	5.5	2.4	–	7.1	24.8
Ecuador	5.8	0.1	–	–	1.7	7.7	5.9	0.1	–	–	1.6	7.6
Peru	7.3	0.3	0.5	–	3.7	11.7	6.8	0.3	0.6	–	4.0	11.7
Venezuela	22.5	25.1	†	–	14.2	61.9	22.2	26.0	†	–	13.7	61.9
Other S. & Cent. America	57.4	10.1	0.6	–	18.2	86.3	57.5	10.6	0.7	–	18.3	87.2
Total S. & Cent. America	221.0	83.7	20.7	2.7	125.1	453.2	218.4	87.2	22.4	4.8	118.9	451.8
Austria	11.8	6.6	3.2	–	9.9	31.5	12.4	6.6	2.7	–	9.8	31.6
Belgium & Luxembourg	33.9	13.4	7.6	10.9	0.6	66.4	32.3	13.2	7.1	10.7	0.6	63.9
Bulgaria	4.5	2.6	6.6	4.5	0.7	18.9	4.6	2.3	6.1	4.5	0.8	18.2
Czech Republic	7.9	7.5	20.7	3.1	0.5	39.8	8.3	8.0	21.3	3.3	0.6	41.6
Denmark	10.4	4.4	4.0	–	†	18.8	10.1	4.6	4.2	–	†	18.9
Finland	10.7	3.4	3.5	5.1	3.3	26.0	10.5	3.7	3.9	5.2	3.0	26.3
France	94.9	35.7	13.8	94.0	16.4	254.8	95.8	36.6	10.9	94.9	18.1	256.4
Germany	129.8	71.5	84.9	38.4	5.9	330.5	131.6	74.6	84.4	38.7	5.8	335.2
Greece	19.9	1.7	9.2	–	0.9	31.8	19.4	1.8	9.5	–	0.5	31.1
Hungary	6.8	9.6	3.2	3.2	†	23.0	6.8	10.7	3.1	3.2	†	23.9
Iceland	0.9	–	0.1	–	1.4	2.4	0.9	–	0.1	–	1.5	2.5
Republic of Ireland	8.2	3.4	2.0	–	0.3	13.9	8.7	3.6	2.1	–	0.2	14.6
Italy	93.5	58.4	13.0	–	11.5	176.4	92.8	58.0	13.9	–	12.5	177.2
Netherlands	41.7	35.3	8.6	0.9	†	86.5	43.9	35.3	8.4	0.9	†	88.6
Norway	9.4	3.6	0.7	–	32.2	45.9	9.7	4.0	0.6	–	27.4	41.7
Poland	20.0	10.0	57.6	–	0.9	88.4	19.0	10.2	57.5	–	1.0	87.7
Portugal	14.9	2.1	3.6	–	2.9	23.6	15.2	2.3	3.6	–	2.9	23.9
Romania	10.0	15.4	7.0	1.2	3.3	37.0	10.1	15.8	7.7	1.2	3.4	38.2
Slovakia	3.4	5.8	4.0	3.7	1.1	18.1	3.4	6.7	4.1	3.9	1.1	19.1
Spain	70.0	15.2	21.6	14.1	8.3	129.2	72.7	16.4	19.5	14.4	11.6	134.6
Sweden	15.2	0.7	1.9	13.0	17.8	48.6	15.6	0.7	2.0	16.4	17.9	52.6
Switzerland	12.2	2.4	0.1	6.0	8.7	29.4	13.1	2.5	0.1	6.1	9.7	31.4
Turkey	31.6	12.7	22.3	–	7.0	73.7	30.4	14.0	20.4	–	5.4	70.2
United Kingdom	77.9	86.4	36.9	19.3	1.8	222.2	76.1	85.9	40.3	20.4	1.5	224.0
Other Europe	16.3	5.1	11.8	1.1	6.8	41.0	16.8	5.5	10.6	1.2	7.1	41.1
Total Europe	755.8	412.9	347.9	218.5	142.2	1877.8	760.2	423.0	344.1	225.0	142.4	1894.5
Azerbaijan	6.2	4.9	–	–	0.3	11.4	4.6	7.6	–	–	0.3	12.5
Belarus	6.1	14.6	0.3	–	†	21.0	5.9	14.5	0.3	–	†	20.7
Kazakhstan	7.0	8.7	23.2	–	1.6	40.5	7.7	9.1	24.7	–	1.7	43.1
Lithuania	2.4	2.5	0.1	1.9	0.1	7.0	2.8	2.5	0.1	2.6	0.2	8.1
Russian Federation	123.5	339.5	110.4	29.5	37.4	640.3	122.3	335.4	114.6	30.9	39.8	643.0
Turkmenistan	2.3	11.3	–	–	–	13.6	2.4	11.6	–	–	–	14.0
Ukraine	12.0	61.6	38.8	17.5	2.7	132.6	12.7	59.2	39.0	17.2	3.0	131.1
Uzbekistan	6.4	42.4	1.0	–	1.0	50.9	6.5	46.0	1.1	–	1.3	54.8
Other Former Soviet Union	4.4	6.8	0.8	0.4	8.6	21.0	4.7	7.7	0.6	0.5	8.6	22.1
Total Former Soviet Union	170.3	492.3	174.6	49.3	51.7	938.3	169.6	493.6	180.4	51.2	54.9	949.4
Iran	56.1	56.7	1.1	–	1.1	115.0	54.2	58.5	0.8	–	0.8	114.3
Kuwait	10.4	8.6	–	–	–	19.0	10.5	8.6	–	–	–	19.1
Qatar	1.2	13.6	–	–	–	14.7	1.4	14.4	–	–	–	15.7
Saudi Arabia	62.4	44.8	–	–	–	107.2	62.7	48.3	–	–	–	111.0
United Arab Emirates	14.2	29.6	–	–	–	43.8	14.3	30.8	–	–	–	45.2
Other Middle East	63.5	20.1	6.2	–	0.8	90.6	63.3	20.7	7.2	–	0.7	91.9
Total Middle East	207.8	173.4	7.3	–	1.9	390.3	206.4	181.3	8.0	–	1.5	397.2
Algeria	8.5	18.9	0.6	–	†	28.0	8.8	19.4	0.6	–	†	28.8
Egypt	27.2	16.5	0.9	–	3.2	47.8	26.2	18.9	0.9	–	3.0	49.0
South Africa	22.5	–	81.9	3.1	0.9	108.4	23.0	–	80.6	2.6	0.8	107.0
Other Africa	57.9	14.6	6.1	–	14.1	92.7	59.0	15.8	6.5	–	14.5	95.8
Total Africa	116.1	50.0	89.5	3.1	18.2	276.9	117.0	54.1	88.6	2.6	18.3	280.6
Australia	37.7	19.1	47.5	–	3.7	108.1	38.1	20.3	47.6	–	3.9	109.9
Bangladesh	3.4	9.0	0.1	–	0.2	12.6	3.4	9.7	0.1	–	0.2	13.4
China	230.1	22.1	493.7	3.8	55.0	804.7	231.9	24.9	520.6	4.0	58.3	839.7
China Hong Kong SAR	9.7	2.2	3.7	–	–	15.6	9.5	2.2	4.9	–	–	16.6
India	97.5	23.4	171.4	3.6	17.4	313.3	97.1	23.7	173.5	4.4	16.1	314.7
Indonesia	50.4	27.5	13.7	–	2.1	93.8	52.3	26.7	16.7	–	2.1	97.9
Japan	255.4	68.6	98.9	72.3	20.7	515.9	247.2	71.1	103.0	72.7	20.4	514.5
Malaysia	20.4	18.3	1.9	–	1.7	42.3	18.6	19.4	2.4	–	1.7	42.1
New Zealand	6.3	4.9	1.1	–	5.5	17.8	6.2	5.2	1.3	–	5.0	17.6
Pakistan	18.8	17.0	2.0	0.3	4.0	42.1	18.9	18.1	2.0	0.5	4.0	43.4
Philippines	16.6	†	4.3	–	1.8	22.6	16.5	0.1	4.5	–	1.6	22.7
Singapore	33.5	1.6	–	–	–	35.0	36.9	2.3	–	–	–	39.1
South Korea	103.2	18.9	43.0	24.7	1.3	191.1	103.1	20.8	45.7	25.4	0.9	195.9
Taiwan	39.8	6.2	28.9	8.7	2.0	85.6	37.7	6.8	30.9	8.0	2.1	85.4
Thailand	34.8	18.4	7.8	–	1.4	62.4	33.8	19.0	8.8	–	1.4	63.0
Other Asia Pacific	20.6	4.4	57.9	–	10.1	93.0	21.5	4.4	58.7	–	11.1	95.8
Total Asia Pacific	978.2	261.6	975.9	113.4	126.9	2455.9	972.7	274.7	1020.7	115.0	128.8	2511.7
TOTAL WORLD	3519.0	2157.5	2216.8	585.0	616.9	9095.6	3510.6	2164.3	2255.1	601.2	594.5	9124.8
of which: European Union 15	632.8	338.2	213.8	195.7	79.6	1460.2	637.1	343.3	212.5	201.6	84.4	1478.9
OECD	2197.4	1184.9	1113.9	506.7	313.5	5317.0	2189.6	1167.2	1108.2	518.8	291.0	5274.5
Former Soviet Union	170.3	492.3	174.6	49.3	51.7	938.3	169.6	493.6	180.4	51.2	54.9	949.4
Other EMEs	1151.3	480.3	928.3	29.0	251.7	2840.3	1151.4	503.5	966.5	31.2	248.6	2900.9

*In this Review, primary energy comprises commercially traded fuels only. Excluded, therefore, are fuels such as wood, peat and animal waste which, though important in many countries, are unreliably documented in terms of consumption statistics.

†Less than 0.05.

world consumption

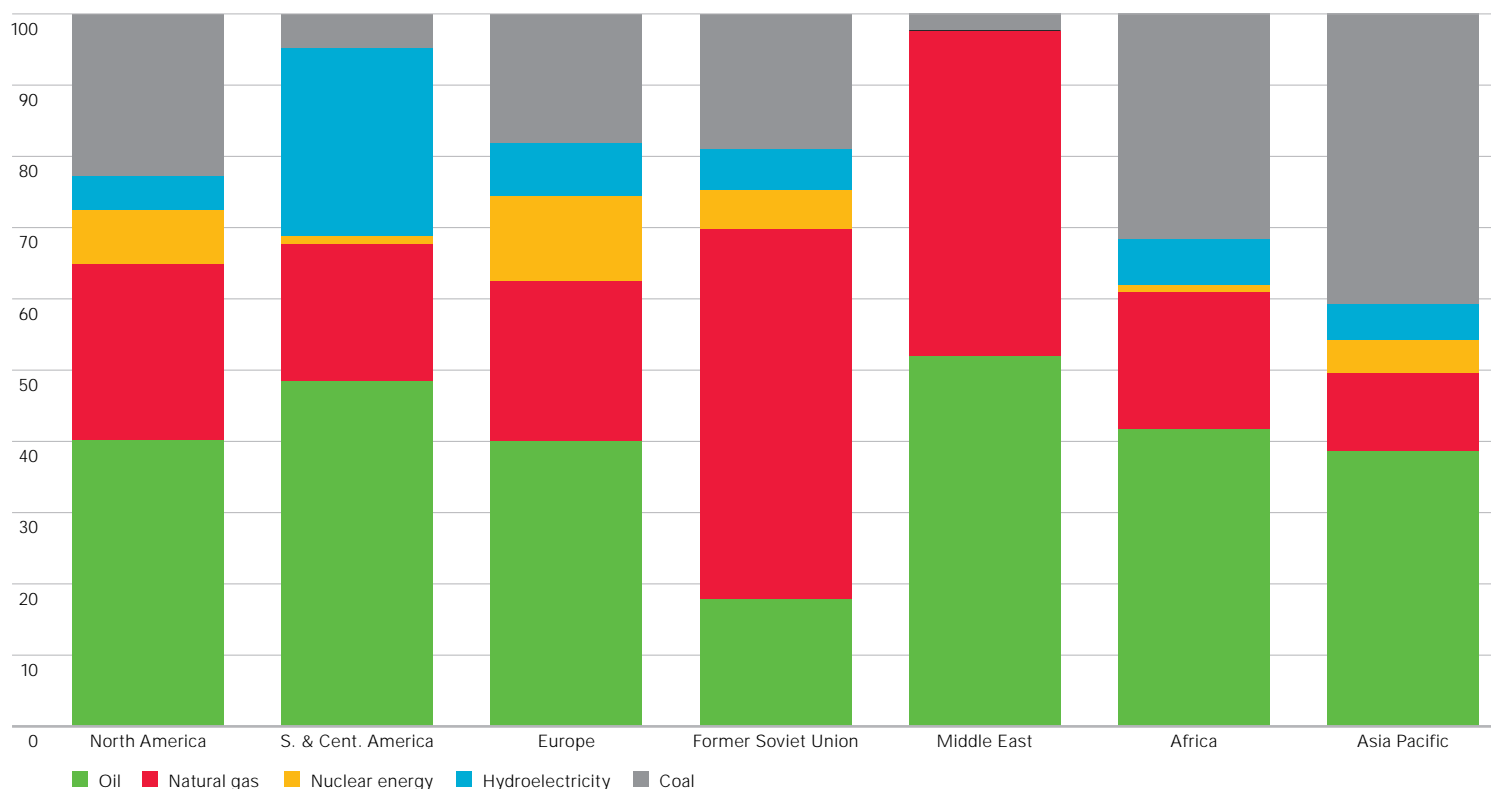
Million tonnes oil equivalent



Primary energy consumption grew by less than 0.5% in 2001, marking the third year of virtually zero growth in the last four. Nuclear and coal were the fastest-growing fuels, with hydroelectricity showing a steep fall. Coal increased its share of the overall energy market for only the second time since 1985.

regional consumption pattern 2001

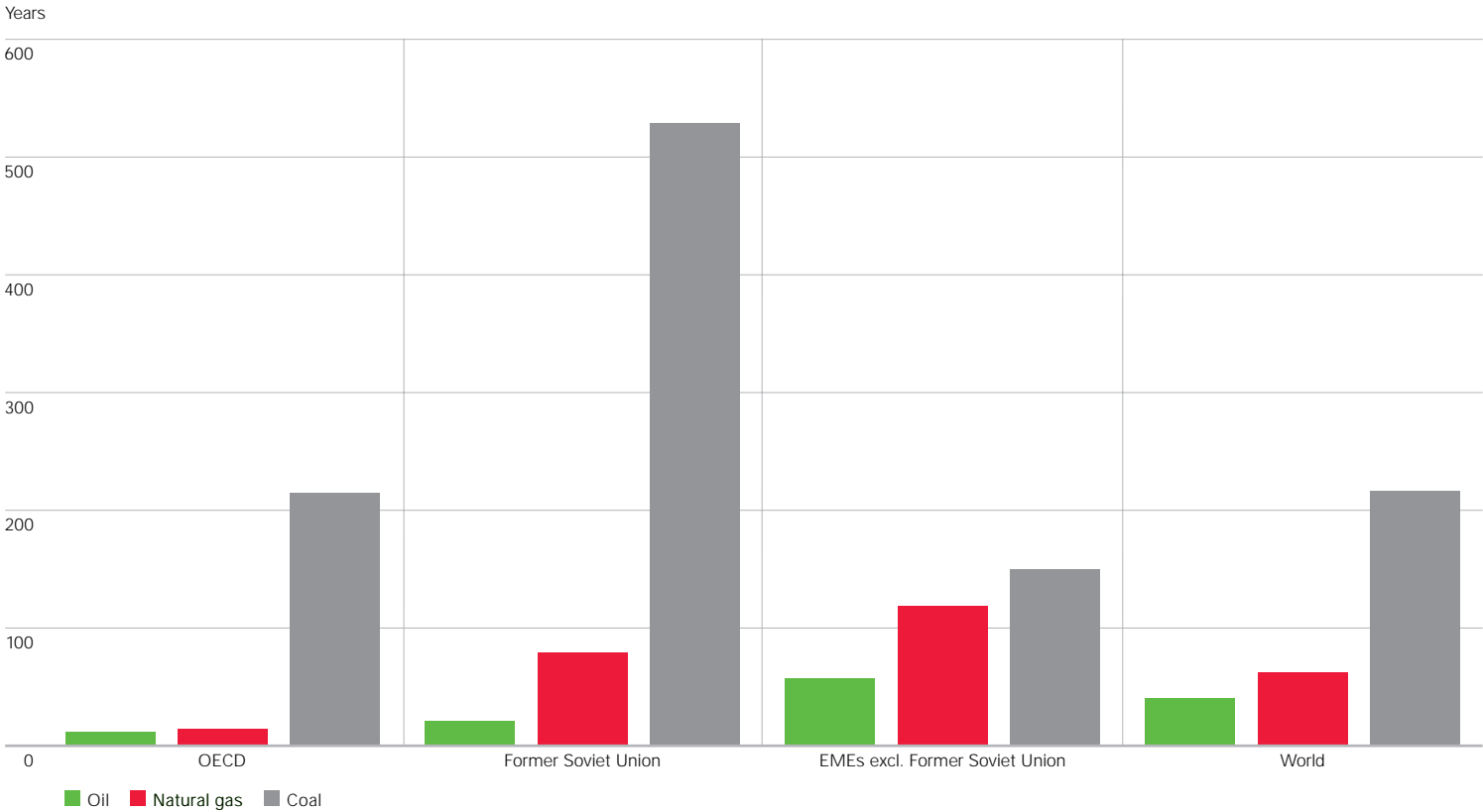
Percentage



Oil remains the largest single source of energy in most parts of the world. The exceptions are the Former Soviet Union, where gas dominates, and Asia Pacific, where coal moved marginally ahead of oil during 2001.

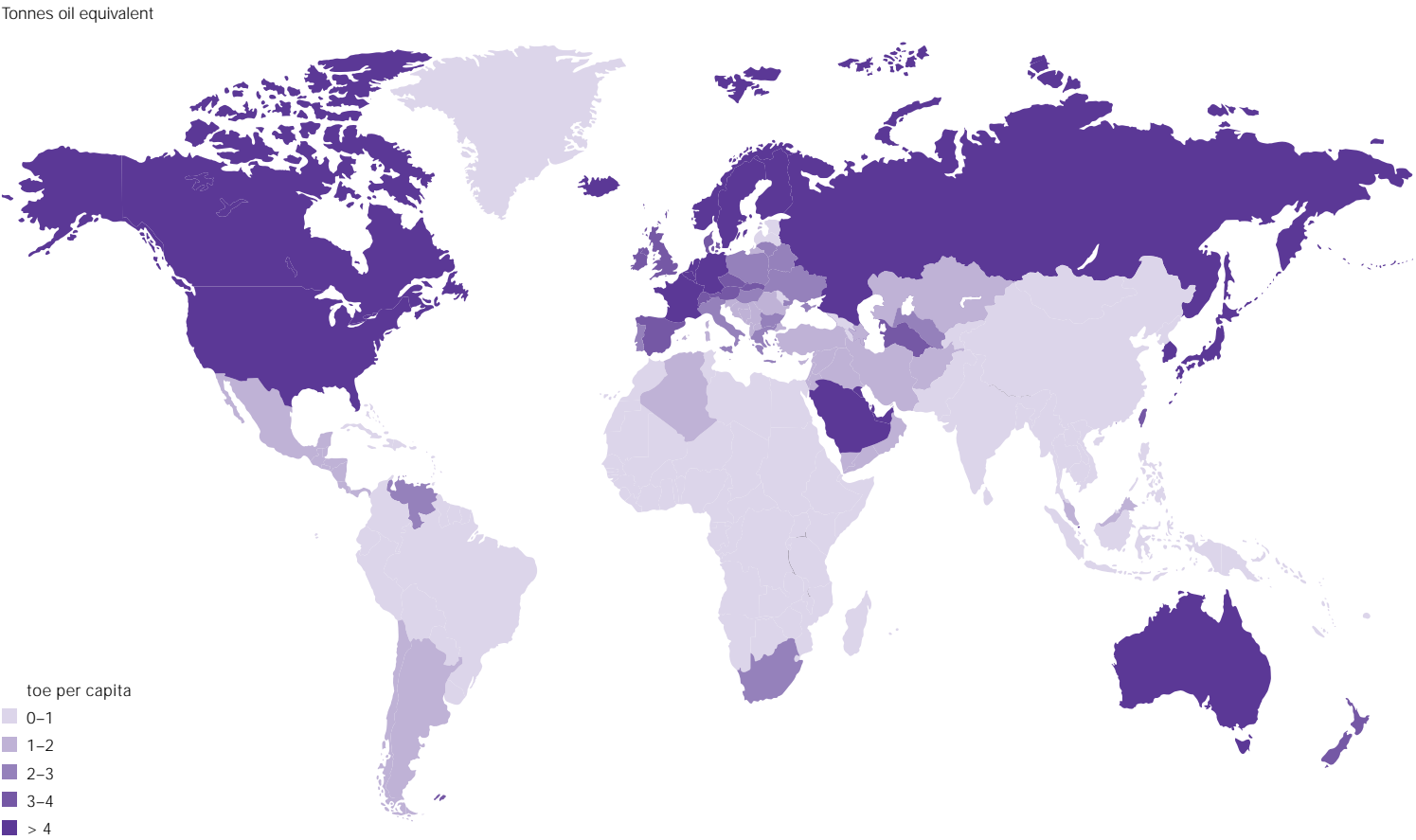
primary energy

fossil fuel R/P ratios at end 2001



The world's reserves-to-production ratio for coal is nearly six times that for oil and four times that for natural gas. Coal's dominance in R/P ratio terms is particularly pronounced in the OECD and the Former Soviet Union.

energy consumption per capita



appendices

approximate conversion factors

crude oil*

	To tonnes (metric)	kilolitres	barrels	US gallons	tonnes/ year
From	Multiply by				
Tonnes (metric)	1	1.165	7.33	307.86	–
Kilolitres	0.8581	1	6.2898	264.17	–
Barrels	0.1364	0.159	1	42	–
US gallons	0.0032	0.0038	0.0238	1	–
Barrels/day	–	–	–	–	49.8

*Based on worldwide average gravity.

products

	To convert barrels to tonnes	tonnes to barrels	kilolitres to tonnes	tonnes to kilolitres
From	Multiply by			
LPG	0.086	11.6	0.542	1.844
Gasoline	0.118	8.5	0.740	1.351
Kerosene	0.128	7.8	0.806	1.240
Gas oil/diesel	0.133	7.5	0.839	1.192
Fuel oil	0.149	6.7	0.939	1.065

natural gas and LNG

	To billion cubic metres NG	billion cubic feet NG	million tonnes oil equivalent	million tonnes LNG	trillion British thermal units	million barrels oil equivalent
From	Multiply by					
1 billion cubic metres NG	1	35.3	0.90	0.73	36	6.29
1 billion cubic feet NG	0.028	1	0.026	0.021	1.03	0.18
1 million tonnes oil equivalent	1.111	39.2	1	0.805	40.4	7.33
1 million tonnes LNG	1.38	48.7	1.23	1	52.0	8.68
1 trillion British thermal units	0.028	0.98	0.025	0.02	1	0.17
1 million barrels oil equivalent	0.16	5.61	0.14	0.12	5.8	1

units

1 metric tonne = 2204.62 lb.
= 1.1023 short tons
1 kilolitre = 6.2898 barrels
1 kilocalorie (kcal) = 4.187 kJ = 3.968 Btu
1 kilojoule (kJ) = 0.239 kcal = 0.948 Btu
1 British thermal unit (Btu) = 0.252 kcal = 1.055 kJ
1 kilowatt-hour (kWh) = 860 kcal = 3600 kJ = 3412 Btu

Calorific equivalents

One tonne of oil equivalent equals approximately:

Heat units	10 million kilocalories
	42 gigajoules
	40 million Btu
Solid fuels	1.5 tonnes of hard coal
	3 tonnes of lignite
Gaseous fuels	See natural gas and LNG table
Electricity	12 megawatt-hours /3?

One million tonnes of oil produces about 4000 gigawatt-hours of electricity in a modern power station.



definitions

Statistics published in this Review are taken from government sources and published data. No use is made of confidential information obtained by BP in the course of its business.

North America

USA (excluding Puerto Rico), Canada and Mexico.

South and Central America

Caribbean (including Puerto Rico), Central and South America.

Europe

European members of the OECD plus Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Former Yugoslav Republic of Macedonia, Gibraltar, Malta, Romania, Slovenia, Yugoslavia.

Former Soviet Union

Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine, Uzbekistan.

Middle East

Arabian Peninsula, Iran, Iraq, Israel, Jordan, Lebanon, Syria.

North Africa

Territories on the north coast of Africa from Egypt to Western Sahara.

West Africa

Territories on the west coast of Africa from Mauritania to Angola, including Cape Verde.

East and Southern Africa

Territories on the east coast of Africa from Sudan to Republic of South Africa. Also Botswana, Madagascar, Malawi, Namibia, Uganda, Zambia, Zimbabwe.

Asia Pacific

Brunei, Cambodia, China, China Hong Kong SAR*, Indonesia, Japan, Laos, Malaysia, Mongolia, North Korea, Philippines, Singapore, South Asia (Afghanistan, Bangladesh, India, Myanmar, Nepal, Pakistan and Sri Lanka), South Korea, Taiwan, Thailand, Vietnam, Australia, New Zealand, Papua New Guinea and Oceania.

*Special Administrative Region.

Australasia

Australia, New Zealand.

Country groupings are made purely for statistical purposes and are not intended to imply any judgement about political or economic standings.

OECD members

Europe: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Republic of Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, United Kingdom.

Other member countries: Australia, Canada, Japan, Mexico, New Zealand, South Korea, USA.

OPEC members

Middle East: Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates (Abu Dhabi, Dubai, Ras-al-Khaimah and Sharjah). North Africa: Algeria, Libya. West Africa: Nigeria. Asia Pacific: Indonesia. South America: Venezuela. (Since Ecuador and Gabon have withdrawn from OPEC, they are excluded from all OPEC totals.)

European Union members

Austria, Belgium, Denmark, Finland, France, Germany, Greece, Republic of Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, UK.

Other EMEs (Emerging Market Economies)

South and Central America, Africa, Middle East, Non-OECD Asia and Non-OECD Europe.

Other terms

Tonnes: Metric tons.

Percentages: Calculated before rounding of actuals. All annual changes and shares of totals are on a weight basis except on pages 12, 16 and 18.

Rounding differences: Because of rounding, some totals – including the 2001 share of total – may not agree exactly with the sum of their component parts.

US processing gain: In previous years we have deducted processing gain from volumetric consumption levels. From this year in order to retain consistency across regions we will no longer be deducting US processing gain.



Questions on data

BP regrets it is unable to deal with enquiries about the data in the Statistical Review of World Energy.

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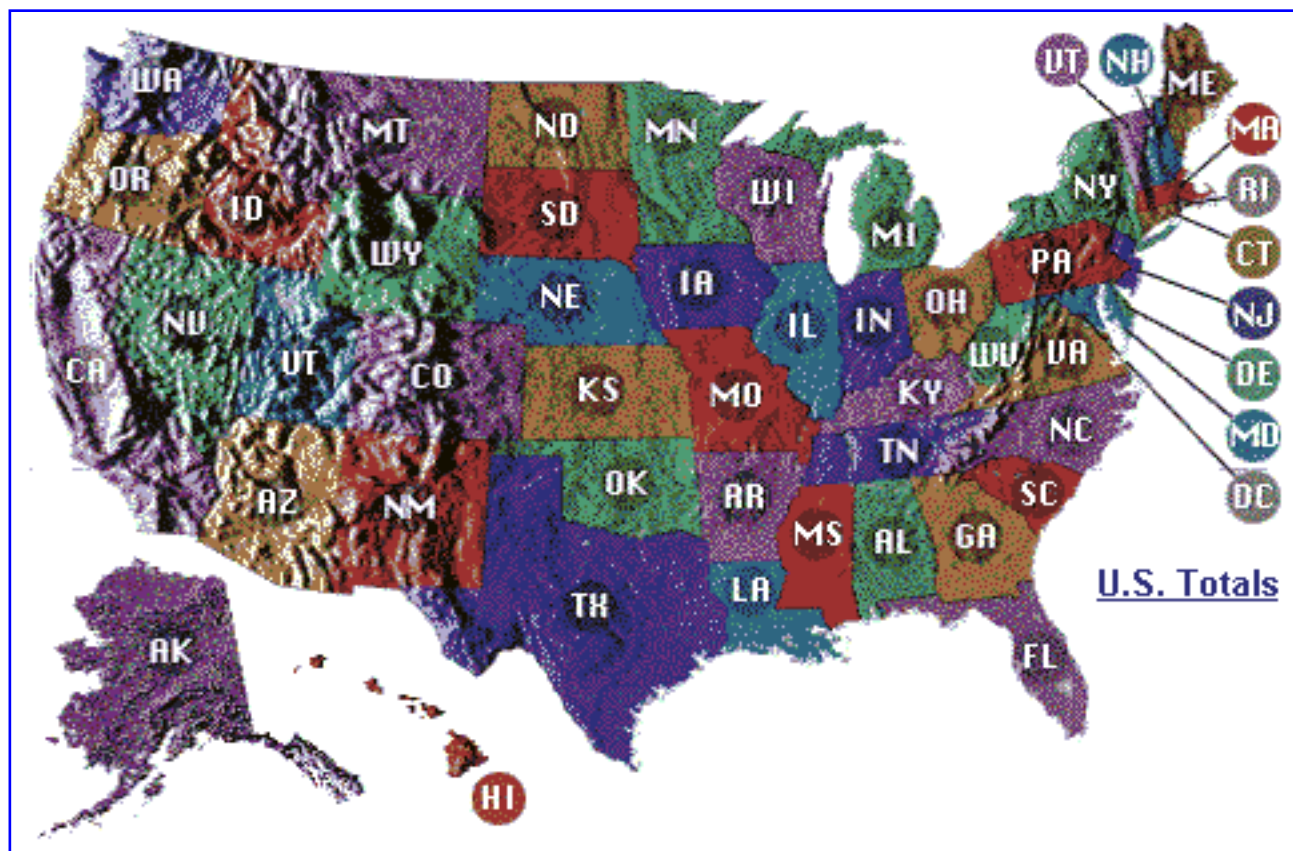
November 2002

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| [Links](#)

United States of America

The United States of America is the world's largest energy producer, consumer, and net importer. It also ranks twelfth worldwide in reserves of oil, sixth in natural gas, and first in coal.

Information contained in this report is the best available as of November 2002 and is subject to change. For the latest monthly U.S. outlook by the Energy Information Administration, please see the ["Short-Term Energy Outlook"](#).



GENERAL BACKGROUND

As of early November 2002, the U.S. economy appeared to be growing slowly and uncertainly. On November 6, 2002, the U.S. Federal Reserve cut its interest rate target by a half-percentage point in an effort to stimulate an economic recovery. The move came following data in September and October indicating an increase in the unemployment rate (from 5.6% to 5.7%), slower-than-expected economic growth (3.1% in the third quarter, following a 1.3% gain in the second quarter), a decline in job creation, a sharp decrease in consumer confidence, and a reduction in consumption spending. Among other factors which appear to be slowing the U.S. economy are fears (since 9/11 in particular) over possible terrorism, worries over the situation in the Middle East (and the potential for an increase in oil prices), and a sharp decline in U.S. equity markets. On the positive side, the Labor Department reported on November 7 that U.S. productivity grew at a rapid, 4% rate during the third quarter of 2002, the fastest growth in this indicator since the first quarter of the year.

The recent difficulties experienced by the U.S. economy follow a period

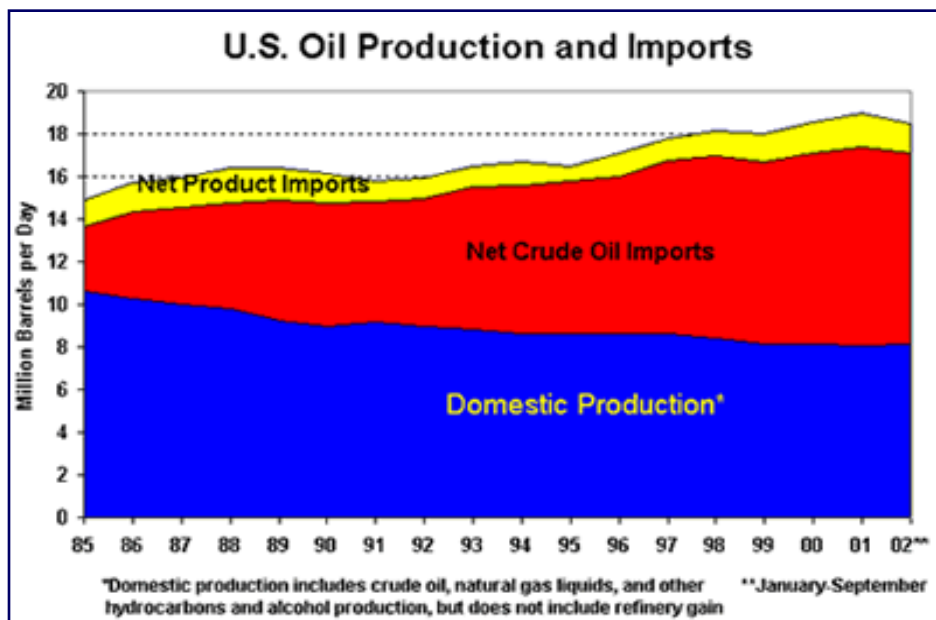
during the mid- and late-1990s of strong growth, low inflation, low unemployment, rapid productivity growth, and a booming stock market. Real (inflation adjusted) U.S. gross domestic product (GDP) growth for 2002 now is expected at 2.3%, up from 0.3% growth in 2001.

For Fiscal Year (FY) 2002, the federal unified budget ran an estimated deficit of \$180 billion after running a surplus of around \$127 billion in 2001. The turn from surplus to deficit has come about as a consequence of several factors, including economic slowdown, tax rebates and cuts, and increased government spending. Meanwhile, the U.S. merchandise trade deficit is estimated at \$478 billion for 2002. This deficit mainly reflects the relative strength of the U.S. economy compared to major U.S. trading partners. The current account deficit now is running at over 4% of GDP, compared to 1.7% in 1997.

In mid-May 2001, the Bush administration issued a series of energy policy recommendations as part of its new [National Energy Policy Report](#), developed by a task force led by Vice President Dick Cheney. In August 2001, the U.S. House of Representatives passed an energy bill (the "Securing America's Future Energy" -- SAFE -- Act of 2001) which contained many of the energy plan's recommendations. In April 2002, the U.S. Senate passed its own version of an energy bill, which must be reconciled with the House version.

OIL

The United States had 22.0 billion barrels of proved oil reserves as of January 1, 2002, twelfth highest in the world. These reserves are concentrated overwhelmingly (over 80%) in four states -- Texas (25% including the state's reserves in the Gulf of Mexico), Alaska (24%), California (21%), and Louisiana (14% including the state's reserves in the Gulf of Mexico). U.S. proven oil reserves have declined by around 20% since 1990, with the largest single-year decline (1.6 billion barrels) occurring in 1991.



During 2002, the United States is estimated to be producing around 8.2 million barrels per day (MMBD) of oil, of which 5.9 MMBD is crude oil, and the rest natural gas liquids and other liquids. U.S. total oil production in 2002 is down sharply (around 2.4 MMBD, or

23%) from the 10.6 MMBD averaged in 1985. U.S. crude oil production, which declined following the oil price collapse of late 1985/early 1986, leveled off in the mid-1990s, and began falling again following the sharp decline in oil prices of late 1997/early 1998. With the rebound in world oil prices since March 1999, U.S. crude production basically leveled off once again in 2000 and 2001, rising slightly in 2002. Despite this increase, U.S. crude production remains near 50-year lows.

In 2000, there were around 534,000 producing oil wells in the United States, the vast majority of which are considered "marginal" or "stripper" wells, generally producing only a few barrels per day of oil. During the first half of 2002, top oil producing areas included the Gulf of Mexico (1.6 million bbl/d), Texas onshore (1.2 million bbl/d), Alaska's North Slope (989,000 bbl/d), California (712,000 bbl/d), Louisiana onshore (282,000 bbl/d), Oklahoma (184,000 bbl/d), and Wyoming (153,000 bbl/d).

Domestic oil exploration and development spending by U.S. major oil companies rebounded during 2001 from the deep cuts made during the oil price collapse of 1997/1998. Improved technology and new or increased offshore production in the Gulf of Mexico (including at deepwater areas beyond the continental shelf) also could help matters. In 2000, deepwater production in the Gulf of Mexico for the first time surpassed shallow water production. In January 2000, Chevron and Shell -- the largest producer in the

Gulf of Mexico -- signed an agreement to share drilling rigs and to drill exploratory wells jointly in the deep-water Gulf of Mexico. In August 2002, a U.S. government lease sale for the western Gulf of Mexico produced bids totaling \$182 million. Bidders included Amerada Hess, Kerr-McGee, Dominion Exploration and Production, Shell, and Nexen.

Overall, production from deepwater areas of the Gulf of Mexico has been increasing rapidly, with deepwater wells accounting for about two-thirds of total U.S. Gulf output. Large fields include ExxonMobil's \$1.1 billion Hoover-Diana development (which started up in May 2000 and is producing 80,000 bbl/d), plus several by BP: the \$2 billion Atlantis project (scheduled to come online in 2005); Crazy Horse (the largest single field ever discovered in the Gulf of Mexico), Crosby, Holstein, King, King's Peak, Mad Dog, Marlin, and Nakika fields. BP has stated that it plans to accelerate its deepwater Gulf of Mexico production plans, possibly including construction of a \$1-billion deep-sea pipeline, and to increase its production from 200,000 bbl/d currently to 750,000 bbl/d in 2007. This will require billions of dollars worth of investment.

Crude oil production in the lower 48 states is expected to fall by about 130,000 bbl/d in 2003, while Alaskan crude production remains flat. Alaskan production, which accounts for around 17% of the U.S. total, is down about 50% from the 2.0 MMBD reached during the peak year of 1988. Most of Alaska's oil output comes from the giant Prudhoe Bay Field, and is transported via the Alyeska pipeline. A new oilfield, known as Alpine (owned 78% by Phillips Petroleum, 22% by Anadarko), began production in November 2000. Alpine represents the largest North American onshore oil discovery in a decade, and was producing 80,000 bbl/d of high quality, light crude oil by the end of 2000. Production at Alpine could rise to 120,000 bbl/d with tie-ins to the Nanuk and Fiord satellite fields. Phillips has been the largest oil producer in Alaska since acquiring Arco's Alaska fields in early 2000. In November 2000, two oil and natural gas lease sales conducted by the State of Alaska drew bids worth \$11 million for offshore tracts in the Beaufort Sea and onshore in the North Slope.

In other news from Alaska, the critical Trans-Alaska Pipeline System (TAPS) shut down briefly in early November 2002 due to an earthquake. In October 2001, TAPS also was shut down for a short time after being punctured by a gunshot.

In early 2000, the Energy Information Administration (EIA), in response to a Congressional request, issued a report on potential oil reserves and production from the Arctic National Wildlife Refuge (ANWR). The report, which cited a 1998 U.S. Geological Survey study of ANWR oil resources, projected that for the mean resource case (10.3 billion barrels technically recoverable), ANWR peak production rates could range from 1.0 to 1.35 MMB/D, with initial ANWR production possibly beginning around 2010, and peak production 20-30 years after that.

According to Baker Hughes Inc., which has tallied weekly U.S. drilling activity since 1940, domestic oil and natural gas drilling has rebounded sharply since the low point of 488 reached in late April 1999 following the oil price collapse of late 1997. In mid-October 2001, for instance, the U.S. weekly "rig count" reached the 1,141 mark (933 for natural gas and 208 for oil), close to the highest number since late 1990. Since then, however, the U.S. "rig count" has fallen, reaching 843 (703 gas rigs and 137 oil rigs) as of mid-October 2002. Natural gas rigs outnumber oil rigs in the United States by more than five-fold. Historically, U.S. drilling activity peaked in 1981, with a total of 91,553 wells (43,598 oil, 20,166 natural gas, 27,789 dry wells) drilled in that year. For 2001, a total of 34,139 wells (22,083 natural gas wells, 8,060 oil wells, and nearly 4,000 dry wells) were drilled in the United States, up from the low point of 18,377 total wells drilled in 1999. For the first nine months of 2002, total wells drilled were down sharply -- 30% -- from the same period a year earlier.

Twenty-two major energy companies reported overall net income (excluding unusual items) of \$5.5 billion on revenues of \$141 billion during the second quarter of 2002 (Q202). This level of net income represented a 55% decrease

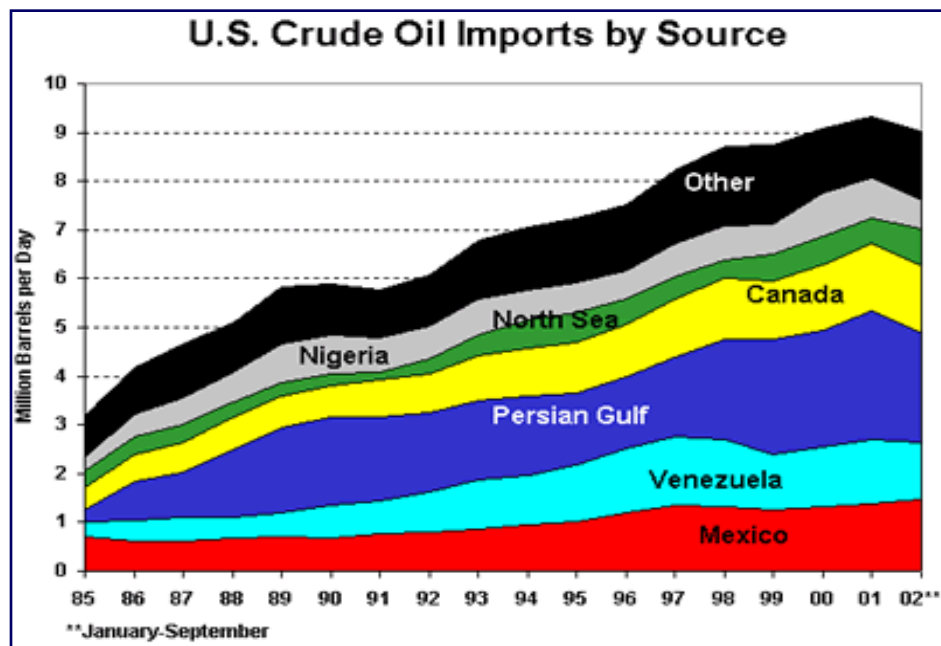
relative to the second quarter of 2001 (Q201) (see EIA's "[Performance Profiles for Major Energy Producers 2000](#)"). Domestic upstream oil and natural gas production operations accounted for \$3.2 billion of net income, followed by foreign upstream oil and natural gas production operations (\$2.7 billion) and worldwide downstream natural gas and power operations (\$1.0 billion). Besides the major energy companies, independent oil and natural gas producers, oil field companies and refiner/marketers also reported declines in net income (down 42%) during Q202 compared to Q201. As with the majors, this decline in net income was due to sharp drops during that period in the price of natural gas, combined with weak demand for electricity and a decline in oil and gas drilling activity (see below).

Consumption/Marketing

The United States is estimated to be consuming an average of about 19.7 MMBD of oil in 2002. Of this, 8.9 MMBD (or 45% of the total) is motor gasoline, 4.8 MMBD (24%) "other oils," 3.8 MMBD (19%) distillate fuel oil, 1.7 MMBD (8%) jet fuel, and 0.7 million bbl/d (3%) residual fuel oil. U.S. oil demand is expected to increase by about 3% (670,000 bbl/d) in 2003. Following the September 11 terrorist attacks, U.S. jet fuel demand fell sharply. For the first nine months of 2002, U.S. jet fuel consumption was down 6% compared to the same period in 2001.

Imports/Exports

The United States averaged *total gross oil* (crude and products) imports of an estimated 11.2 MMBD during the first nine months of 2002, representing around 57% of total U.S. oil demand. Around two-fifths of this oil came from OPEC nations, with Persian Gulf sources accounting for about one-fifth of total U.S. oil imports. Overall, the top suppliers of oil to the United States during the first nine months of 2002 were Canada (1.9 MMBD), Saudi Arabia (1.5 MMBD), Mexico (1.5 MMBD), and Venezuela (1.4 MMBD).



U.S. Energy Sanctions Issues

The United States maintains energy sanctions against several countries, including Iran, Iraq, and Libya (an oil embargo against Serbia was lifted by President Clinton on October 12, 2000). Iraq remains under comprehensive sanctions

imposed after its invasion of Kuwait in August 1990. Iran and Libya are affected by the Iran-Libya Sanctions Act (ILSA), passed unanimously by the U.S. Congress and signed into law by President Clinton in August 1996. ILSA imposes mandatory and discretionary sanctions on non-U.S. companies which invest more than \$20 million annually (lowered in August 1997 from \$40 million) in the Iranian oil and natural gas sectors. The passage of ILSA was not the first U.S. sanction against Iran. In early 1995, President Clinton signed two Executive Orders which prohibited U.S. companies and their foreign subsidiaries from conducting business with Iran. The Orders also banned any "contract for the financing of the development of petroleum resources located in Iran." On March 13, 2001, President Bush, citing threats posed by Iran to U.S. national security, extended Clinton's two Executive Orders on Iran for another 6 months. On August 3, 2001, President Bush signed into law the ILSA Extension Act of 2001. This Act provides for a 5-year extension of ILSA with amendments that affect certain of the investment provisions.

Attempts by the United States to implement ILSA have run into opposition from a number of foreign governments. The European Union (EU) opposes the enforcement of ILSA sanctions on its members, and on November 22, 1996 passed resolution 2271 directing EU members to not comply with ILSA. On May 18, 1998, the EU and the U.S. reached an agreement on a package of

measures to resolve the ILSA dispute at the EU/U.S. Summit in London, but the Summit deal is contingent upon acceptance by the U.S. Congress before full implementation may take place.

On April 5, 1999, following the Libyan handover of two suspects in the 1988 bombing of Pan Am flight 103 to stand trial before a Scottish Court in the Netherlands, the United States modified its Libya sanctions on April 28, 1999 to allow shipments of donated clothing, food and medicine for humanitarian reasons (trade in informational materials such as books and movies is also allowed). However, all other U.S. sanctions against Libya remain in force. On February 1, 2001, one suspect was convicted by the Scottish court, while another was acquitted. The U.S. and British governments both said that they still expected Libya to accept responsibility for the murders, which Libya has said it would not do.

Refining

The United States experienced a steep decline in refining capacity between 1981 and the mid-1990s. Between 1981 and 1989, for instance, the number of U.S. refineries fell from 324 to 204, representing a loss of 3 MMBD in operable capacity, while refining capacity utilization increased from 69% to 86%. Much of the decline in U.S. refining capacity resulted from the 1981 deregulation (elimination of price controls and allocations), which effectively removed the major prop from underneath many marginally profitable, often smaller, refineries.

Since the mid-1990s, U.S. refinery capacity has increased, from 15.0 MMBD in 1994 to 16.8 MMBD in 2002. As of November 2002, utilization of operating capacity at U.S. refineries reportedly was averaging around 88%-92%. Although financial, environmental, and legal considerations make it unlikely that new refineries will be built in the United States, expansion at existing refineries likely will increase total U.S. refining capacity in the long-run.

Since the mid-1980s, several U.S. refiners have joined with foreign

(especially Venezuelan) companies in various joint venture arrangements. In 1986, for instance, Venezuela's state oil company PdVSA acquired a 50% interest in Citgo's U.S. refining operation. In 1988, Texaco and Saudi Aramco created Star Enterprise, an integrated refining and marketing operation with three refineries and a network of Texaco gasoline stations. Unocal and PdVSA followed suit in 1989, forming Uno-Ven Co. (in 1997, PdVSA bought out Unocal's share). In late October 1997, Mobil signed an agreement with a PdVSA subsidiary on joint ownership of the 170,000-bbl/d refinery in Chalmette, Louisiana.

Strategic Petroleum Reserve (SPR)

The SPR was officially established on December 22, 1975, when then-President Ford signed the Energy Policy and Conservation Act (EPCA). EPCA declared it to be U.S. policy to establish a petroleum reserve of up to 1 billion barrels. In order to store the reserve oil, the U.S. government in April 1977 acquired several salt caverns along the Gulf of Mexico coastline. The first crude oil was delivered to the SPR on July 21, 1977, and stored at the West Hackberry storage site near Lake Charles, LA. Other major storage sites include: Bryan Mound and Big Hill in Texas; and Bayou Choctaw, the St. James Terminal in Louisiana, with a total storage capacity of 700 million barrels.

The volume of oil stored in the SPR peaked at 592 million barrels in 1994. Approximately \$327 million worth of SPR oil was sold off in 1996, and an additional \$220 million in 1997. On September 22, 2000, President Clinton authorized the release of 30 million barrels of oil from the SPR over 30 days in an attempt to bolster U.S. oil supplies and to alleviate possible shortages of heating oil during the upcoming winter. The release took the form of a "swap" (bidding results were announced on October 4) in which crude oil volumes drawn from the SPR is to be replaced by the recipients at a later date.

In mid-November 2001, President Bush directed the Department of Energy (DOE) to fill the SPR to its capacity of 700 million barrels in order to "maximize long-term protection against oil supply disruptions." Under the

DOE plan, the SPR is to be filled with "royalty in kind" (RIK) oil. As of November 12, 2002, the SPR contained around 590 million barrels of oil -- the largest emergency oil stockpile in the world. The SPR has a maximum drawdown capability of 4.3 million bbl/d for 90 days, with oil beginning to arrive in the marketplace 15 days after a presidential decision to initiate a drawdown. The SPR drawdown rate declines to 3.2 million bbl/d from days 91-120, to 2.2 million bbl/d for days 121-150, and to 1.3 million bbl/d for days 151-180.

Under EPCA, there is no preset "trigger" for withdrawing oil from the SPR. Instead, the President determines that drawdown is required by "a severe energy supply interruption or by obligations of the United States" under the International Energy Agency. EPCA defines a "severe energy supply interruption" as one which: 1) "is, or is likely to be, of significant scope and duration, and of an emergency nature;" 2) "may cause major adverse impact on national safety or the national economy" (including an oil price spike); and 3) "results, or is likely to result, from an interruption in the supply of imported petroleum products, or from sabotage or an act of God."

Should the President decide to order an emergency drawdown of the SPR, oil would be distributed mainly by competitive sale to the highest bidder(s). This would be accomplished in a 4-step process, including a "Notice of Sale," receipt of bids, selection of bidders, and finally delivery of oil. Today, the SPR can withdraw oil at a maximum sustained rate of 4.1-4.2 MMBD for a 90-day period (lower after that).

Oil Mergers and Acquisitions

Pushed in part by low oil prices during 1998 and into early 1999, but also by the desire for oil reserves, cost cutting, and higher refining/marketing shares, merger activity in the oil business accelerated sharply during 2000 and 2001 (before slowing considerably in 2002). The largest merger/acquisition announcements came from BP and Amoco, Exxon and Mobil, BP Amoco and ARCO, and, most recently, Chevron and Texaco. BP and Amoco completed their \$53-billion merger on December 31, 1998, a day after the deal received

regulatory approval from the U.S. Federal Trade Commission (FTC), subject to certain conditions.

In September 2002, U.S. regulators approved the purchase of Pennzoil-Quaker State Co. by Shell Oil Co. The deal, first reported in March 2002, was for \$1.8 billion (with Shell also assuming \$1.1 billion of Pennzoil-Quaker State debt). The transaction combines Shell's 3% share of the U.S. market for passenger car motor oil with Pennzoil-Quaker State's 35% share, making Shell the No. 1 U.S. lubricants company. Shell also adds Pennzoil-Quaker State's 46,200 barrels-per-day Shreveport, Louisiana refinery and more than 2,000 Jiffy Lube outlets. In October 2002, Shell announced that it would close or sell seven U.S. blending and packaging plants as part of its ongoing merger.

On November 19, 2001, the *Wall Street Journal* reported that [Phillips Petroleum](#) and [Conoco Inc.](#) agreed to merge in a \$15.2 billion transaction. This transaction was completed in August 2002, creating a new company called ConocoPhillips. ConocoPhillips ranks as the sixth-largest oil and gas company in the world, the largest U.S. refiner, and the third-largest U.S.-based energy company.

Another major oil industry merger/acquisition was announced in October 2000, this time between Chevron and Texaco. According to the announcement, Chevron is to buy Texaco for \$35 billion in stock, creating the world's fourth largest energy company (behind ExxonMobil, Shell, and BP). The deal received regulatory approval in early October 2001, and was approved by shareholders of the two companies on October 9, 2001, creating ChevronTexaco.

In November 2000, Russia's Lukoil announced that it intended to purchase Getty Petroleum Marketing for \$71 million. Lukoil eventually intends to switch Getty's 1,300 retail outlets in the Northeastern and Middle Atlantic states to the Lukoil brand name. The purchase represents the first takeover of a publicly traded U.S. company by a Russian firm. In late January 2001, Getty

shareholders approved the the buyout.

On April 13, 2000, the FTC approved the \$27.6 billion BP Amoco-ARCO deal. This followed the March 15, 2000 announcement by Phillips Petroleum that it had agreed to purchase ARCO's assets in Alaska for \$6.5 billion. The sale was made as part of an effort to secure approval from the FTC. On the same day, the FTC announced that it had suspended its antitrust lawsuit seeking to block the merger, citing progress in talks with the companies involved. Among other issues, the FTC was concerned that the BP Amoco-ARCO merger would control about 75% of Alaskan North Slope crude oil output and over 70% of the critically important TAPS line, potentially hurting consumers on the U.S. west coast. BP Amoco agreed to sell some pipeline and oil storage holdings in Cushing, Oklahoma. The new company (now called BP) will rank in the top three private oil companies in the world, along with ExxonMobil and Royal Dutch/Shell.

Meanwhile, the \$81 billion merger between Exxon and Mobil, which formed the world's largest privately owned petroleum company (in terms of revenues), was approved by the FTC on December 1, 1999, subject to the divestiture of 2,400 service stations and other assets (on December 3, 1999, 1,740 of these stations were sold to Tosco, the largest U.S. independent oil refiner). In a related development, in April 2000, Duke Energy said that it had agreed to acquire Mobil's European natural gas trading and marketing business. The sale of Mobil's natural gas operations in Europe was required by the European Commission as part of its approval of the ExxonMobil merger.

Besides these large mergers, several defensive mergers among smaller, independent oil companies also have been unveiled recently, including Kerr-McGee Corp.'s (KMG) \$1.86 billion takeover of Oryx Energy Co. (ORX), and an agreement between Seagull Energy Corp. (SGO) and Ocean Energy Inc. (OEI) to merge in a \$1.1-billion deal. On July 14, 2000, Anadarko Petroleum announced the closing of its merger transaction with the Union Pacific Resources Group. Union Pacific became a wholly owned subsidiary of

Anadarko, creating one of the largest U.S. independent oil and natural gas companies. In January 2001, Amerada Hess announced that it was withdrawing a \$3.5-billion offer to purchase Britain's Lasmo P.L.C., a move which would have created a "super-independent" oil company. Instead, Lasmo was purchased by Italy's ENI for \$4 billion.

Due to low profitability in the refining/marketing line of business, U.S. integrated major energy companies began a process during the 1990s of selective refining/marketing divestiture, and numerous U.S. refineries were shut down. Among independent refiners, growth largely has been concentrated in the following group of companies: Citgo/PDV America, Clark Refining and Marketing, Diamond Shamrock (merged with Ultramar during 1996, creating Ultramar Diamond Shamrock), Koch Industries, Tesoro Petroleum, Ultramar, and Valero Energy. In May 2001, Valero agreed to acquire Ultramar Diamond Shamrock for \$6 billion. Another company, Tosco Corporation, was purchased by Phillips Petroleum for \$7.5 billion in September 2001, creating the second largest refining group in the United States, behind ExxonMobil.

NATURAL GAS

As of January 1, 2002, the United States had estimated proven natural gas reserves of 177 trillion cubic feet (Tcf), or 3.2% of world reserves (6th in the world). For all of 2002, U.S. production of dry natural gas is estimated at 19.2 Tcf. Natural gas consumption is estimated at 21.6 Tcf, and net imports at around 3.5 Tcf, mainly from Canada. Overall, the United States depends on natural gas for about 23% of its total primary energy requirements (oil accounts for around 39% and coal for 22%).

Natural gas wellhead prices reached record highs of nearly \$10.00 per thousand cubic feet (mcf) in late 2000/early 2001, but fell sharply soon thereafter to around \$2.50 per mcf. Early cold weather in October 2002, particularly in the Midwest and Northeast, raised natural gas prices even as storage levels remained at relatively high levels. With natural gas storage levels well above 3 billion cubic feet (Bcf) at the end of October, further large

price increases are not expected in the near term. The current level of storage is only slightly higher than last year but about 6% higher than the previous 5-year average. Assuming normal weather for the remainder of the 2002/2003 heating season, winter natural gas wellhead prices are expected to average \$3.54 per mcf, or \$1.12 per mcf above last winter's price. For all of 2002, the average natural gas wellhead price is projected to be \$2.92 per mcf compared to over \$4.00 per mcf last year. In 2003, wellhead prices are projected to average \$3.37 per mcf.

Natural Gas Production and Storage

September hurricanes in the Gulf of Mexico temporarily shut in some natural gas production, causing spot prices at the Henry Hub and elsewhere to rise above the \$4.00 per million btu mark for most of October 2002. Early cold weather in October, particularly in the Midwest, also helped raise prices even as storage levels remained relatively high. With storage levels well above 3 Tcf at the end of October, further large price increases are not expected in the near term, unless the weather turns abnormally cold for a prolonged period. A level of 3-3.2 tcf of working gas in storage by November 1, 2002 is considered sufficient to ensure adequate natural gas supplies for the winter. The current (end of October) storage level for working gas is 3.15 tcf, about the same level as year ago, when the wellhead price was \$2.45 per thousand cubic feet, and about 5% higher than the previous 5-year average.

Domestic dry natural gas production is projected to increase by about 2.7% in 2003 after falling by about 1.3% in 2002. U.S. natural gas production and net imports are likely to increase sharply over the next two decades in response to strong demand, abundant reserves, and improved unconventional and offshore recovery technology. Increased natural gas production is expected to come mainly from onshore sources, although offshore Gulf of Mexico production also is forecast to grow significantly. In August 2001, for instance, ExxonMobil began production at its \$330 million Mica natural gas project in the deepwater Gulf of Mexico. Alaska's North Slope fields also represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas reserves. Alaska's Governor Tony Knowles has stated that he supports a \$17.2

billion natural gas pipeline running from the North Slope along the Alaska Highway into Alberta and on to markets in the U.S. Midwest (another option would be to route the pipeline via the MacKenzie Delta in northern Canada). Increased natural gas production likely will come mainly from lower 48 sources, with increased use of cost-saving technologies expected to result in continuing large natural gas finds, including in the deep waters of the Gulf of Mexico but also in conventional onshore fields. Currently, top natural-gas-producing states (in descending order) include Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Colorado, Kansas, Alaska, California, and Alabama.

Natural Gas Demand

From 1990 through 2001, natural gas consumption in the United States increased by about 14%, and this growth is likely to continue in coming years. Greater use of natural gas as an industrial and electricity generating fuel can be attributed, in part, to its relatively clean-burning qualities in comparison with other fossil fuels. Lower costs resulting from greater competition and deregulation in the natural gas industry and an expanding transmission and distribution network have also helped expand its acceptance and use. In 2001, natural gas consumption fell by over 1.1 Tcf, after a 0.9 Tcf increase in 2000. During 2001, natural gas consumption by electric utilities fell sharply, to 2,675 billion cubic feet (Bcf), down 368 Bcf from 2000. Natural gas is consumed in the United States mainly in the industrial (42%), residential (22%), commercial (15%), and electric utility (13%) sectors (note: EIA generally places consumption of natural gas for power generation by nonutilities, including natural gas used for industrial cogeneration, in the "industrial" category).

Total natural gas demand for the first half of 2002 fell by 610 bcf. That translates into a decline of 5.2% from 2001 levels, although nearly 50% of the first-half decline in total demand was due to weather effects in the residential and commercial sectors. Second-half strength in the residential and commercial sectors, fed by weather-related increases in the fourth quarter, remains highly probable. Total natural gas demand growth for 2002 is expected to be 1.1%. Weakness in the industrial sector prevents the growth

rate from being more substantial.

U.S. natural gas consumption and imports, largely from Canada -- and to a far lesser extent from liquefied natural gas, or LNG, from Trinidad, Algeria, Qatar, and others -- are expected to expand substantially in coming decades, with the fastest volumetric growth resulting from additional natural-gas-fired electric power plants. In particular, new combined-cycle facilities furnished with more efficient natural gas turbines will help lower the cost of natural-gas-generated electricity to levels competitive with coal-fired plants. Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure -- \$1.5 trillion over the next 15 years according to the National Petroleum Council. The largest natural gas pipeline project currently under construction is the \$1.2 billion Gulf Stream pipeline, which will run 564 miles from Alabama to Florida.

Mexico could potentially become a significant natural gas exporter to the United States in the long term. One U.S.-Mexican natural gas pipeline proposal currently on the table is the \$230 million, 220-mile North Baja line connecting southeastern California and Tijuana, Mexico. Companies involved in this project include Sempra Energy, PG&E, and Mexico's Proxima Gas. The project began service in September 2002, with initial capacity of 200 million cubic feet per day (Mmcfd). This should rise to 500 Mmcfd shortly, with completion of the pipeline's compressor station.

Domestic and Import Pipelines

On November 1, 1993, FERC issued Order No. 636, which decoupled the various stages of the natural gas industry between wellhead and end-user. This order has led to significant restructuring of the interstate natural gas pipeline industry, including moves towards unbundled services, diversification into other energy sectors, and development of mega-pipeline systems.

During the past decade, interstate natural gas pipeline capacity has increased substantially. From January 1996 through August 1998 alone, at least 78

projects were completed adding approximately 11.7 billion cubic feet per day of capacity, and much more will be needed in coming years. Recently completed pipelines include the Pony Express project and the Trailblazer system expansion, providing access from the Wyoming and Montana production regions. Also, the Transwestern and El Paso natural gas pipeline expansions have increased capacity from New Mexico's San Juan Basin.

On December 1, 2000, the \$2.9-billion, 1.3-Bcf/day Alliance Pipeline from western Canada (Fort St. John, British Columbia) to the Chicago area entered service. Another pipeline, the Independence Pipeline (\$678 million) received FERC approval in July 2000, but was cancelled in June 2002 due to lack of customer interest.

Columbia Gas System's Millennium project (\$700 million), which is to connect Canadian natural gas sources to New York and Pennsylvania, received FERC go-ahead on September 19, 2002. When complete, Millennium will transport up to 700 million cubic feet of natural gas per day, providing an environmentally preferred option for generating electricity. According to the Millennium Pipeline consortium's Web site, more than 90% of the pipeline's 425-mile overland route uses existing utility corridors, with about 224 miles of the project replacing and upgrading a 50-year-old pipeline system owned and operated by Columbia Gas Transmission Corp. That existing system serves several major gas end-users, utilities and their customers in New York's Southern Tier region.

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. The U.S. and Canadian natural gas grids are highly interconnected and Canadian natural gas has become an increasingly important component of the total natural gas supply for the United States. This is especially true for certain U.S. regions such as the Northeast, Midwest, and Pacific, which depend on Canadian natural gas for significant amounts of their supply. Overall, the United States received about 2.2 Tcf of natural gas (net) from Canada during the first seven months of 2002, about the same year-over-year as in 2001. Mexico is a small

net importer of natural gas from the United States.

There has been considerable progress in recent years on natural gas interconnections between Canada and the United States. The Northern Border Pipeline, an extension of the Nova Pipeline, came onstream in late 1999 and connects to Chicago through the upper Midwest. The Maritimes and Northeast Pipeline came onstream in January 2000, running from Sable Island to New England, with further extensions into New England planned (Phase III construction is set to begin in the fall of 2002). In February 2002, Enbridge shelved plans to build a pipeline connection between Sable Island and Quebec.

The \$2.5-billion Alliance Pipeline, at 1,875 miles, is the longest pipeline ever built in North America, and is designed to carry about 1.3 billion cubic feet per day (Bcf/d) of gas from western Canada (Fort St. John, British Columbia) to the Chicago area. The pipeline began commercial service on December 1, 2000. The U.S. utility Pacific Gas & Electric imports natural gas from British Columbia via the Alliance pipeline.

The Millennium Pipeline remains in the regulatory approval stage of development; it is slated to connect Canadian sources to southern New York and Pennsylvania. Indecision over the final route of the pipeline in New York currently is stalling progress.

On October 12, 2001, the U.S. Coast Guard lifted the ban on LNG tankers from Boston harbor. The ban, in effect since September 26 (two weeks after the terrorist attacks in New York and Washington, DC), was established in response to security and safety concerns about the ships that bring LNG to the import facility of Distrigas of Massachusetts (a Division of Tractebel, Inc.). The decision enabled the reopening of the Distrigas facility in Everett, Massachusetts, which received 45 shipments containing 99 Bcf of natural gas in 2000, mostly from Trinidad, accounting for 44% of total LNG imports into the United States that year. The Distrigas facility is one of three currently active LNG facilities in the United States. The other two active facilities are

located in Lake Charles, Louisiana, and the recently reopened facility in Elba Island, Georgia. An additional LNG facility, in Cove Point, Maryland, is currently used as a storage and peak shaving facility, but is being upgraded into the nation's largest LNG facility. In August 2002, Williams announced that was selling Cove Point (including an 87-mile pipeline) for \$217 million to a subsidiary of Dominion Resources.

Overall, there is growing interest in LNG to supply natural gas for U.S. electric power generation and provide supply flexibility. EIA expects that LNG imports to the United States will increase at an average 8.6% annual rate, to 830 Bcf by 2020.

Natural Gas Mergers, Acquisitions, Bankruptcies

As with oil, a number of major natural gas market participants are engaging in various forms of corporate combinations, such as mergers, acquisitions, and strategic alliances. The value of mergers and acquisitions within the natural gas industry quadrupled from \$10.4 billion in 1990 to \$39 billion in 1997. This increase parallels an enormous surge in corporate combinations (mergers, acquisitions, joint ventures and strategic alliances) across the energy sector. In August 2001, Devon Energy announced the acquisition of Mitchell Energy for \$3.1 billion, forming the second largest independent natural gas producing company in the United States, behind Anadarko Petroleum Corp. In late January 2001, El Paso Energy completed its \$24-billion merger with Coastal, creating the fourth-largest U.S. energy company by market capitalization (after BP, ChevronTexaco, and Enron at the time). The October 1999 merger between El Paso Energy Corporation and Sonat had created the largest transporter of natural gas in the country.

On December 2, 2001, Enron, formerly the world's largest electricity and natural gas trading company, filed for Chapter 11 bankruptcy in the Southern District of New York for 14 affiliated entities, including Enron, Enron North America, Enron Energy Services, Enron Transportation Services, Enron Broadband Services, and Enron Metals & Commodity Corporation. Enron had been the seventh-largest publicly-traded energy company in the

world. Also in early December 2001, Enron filed a \$10 billion lawsuit against Dynegy, alleging breach of contract, in connection with Dynegy's November 28 termination of its proposed merger with Enron. On November 9, 2001, Enron had agreed to an all-stock takeover by former competitor Dynegy. ChevronTexaco, a 27% stakeholder in Dynegy, was to inject \$1.5 billion of cash immediately into Enron, and an additional \$1 billion into the combined entity. The merged company was to be called Dynegy Inc., and Dynegy executives were to occupy all top positions. On November 28, 2001, however, Dynegy withdrew from the merger deal.

On January 2, 2002, the U.S. Department of Justice confirmed that a criminal probe of Enron had been launched. A task force was formed to investigate whether the former giant energy company defrauded investors by deliberately withholding or falsifying crucial financial information. The U.S. Securities and Exchange Commission has been investigating Enron since October 2001. A number of civil suits already have been filed against Enron. In October 2002, the Justice Department filed a criminal complaint against Enron's former CFO, Andrew Fastow, alleging multiple counts of financial fraud.

COAL

The United States is forecast to produce 1,089 million short tons (Mmst) of coal in 2002, down from 1,121 Mmst in 2001. Also in 2002, the United States is expected to consume 1,063 Mmst (up from 1,051 Mmst in 2001) and to export (net) 24 Mmst. Led by Wyoming, the West is the leading U.S. coal-producing region (with about half of the U.S. total), overwhelmingly from surface mines. Appalachia (led by West Virginia and Kentucky) accounts for about 37% of total U.S. coal production, mainly from underground mines.

Around three-fifths of U.S. coal production is bituminous, one-third subbituminous, and about one-tenth lignite (brown coal). Around 80,000 miners work in the \$20 billion U.S. coal industry, down from a peak of 700,000 in 1923, when U.S. coal production was half what it is today. Major U.S. coal companies include Peabody Energy (the largest in terms of production), Arch Coal (the second largest coal producer); and Kennecott

Energy.

During 2002, coal production is expected to fall in all regions of the United States, particularly Appalachia. Low-sulfur western coal production surpassed relatively higher-cost, higher-sulfur, Appalachian coal for the first time in 1998, following strong increases since 1994, prompted largely by Phase 1 of the Clean Air Act Amendments of 1990 (CAAA). CAAA originally took effect during 1995, and required lower sulfur emissions from coal combustion. In response, Wyoming increased its coal production sharply, particularly low-sulfur, low-ash (and low cost) coal from the Powder River Basin, where coal is strip-mined.

The electric power sector (utilities and nonutilities) accounts for the vast majority (around 90%) of U.S. coal consumption, with independent power producers (IPPs) and manufacturing taking nearly all the rest. This pattern is expected to continue through 2020 at least, with coal maintaining a fuel cost advantage over oil and natural gas, and coal demand reaching 1,365 Mmst. As sulfur dioxide emissions standards are tightened (in 2000, for instance, Phase 2 of CAAA took effect), the share of low-sulfur coal in the U.S. coal consumption mix is expected to increase. In 1999, low and medium-sulfur coals had approximately the same share of the U.S. coal market, with high-sulfur coal far behind.

U.S. coal exports have fallen precipitously since 1995 due mainly to lower world coal prices and increased competition from other coal-producing nations (i.e., Australia, South Africa, China, Venezuela, Colombia), plus natural gas -- especially in Europe. In 2001, total U.S. coal exports dropped to the lowest level since 1978, largely due to 1) a strong U.S. dollar, which gave an edge to other coal-exporting countries; and 2) the tight supply market in the United States, which resulted in increased spot prices of coal, influencing some producers to shift their output to the domestic market. Metallurgical coal exports experienced the greatest decline in 2001, accounting for 75% of the total decline. Export markets for metallurgical coal have been declining over the past few years because of the

expansion of new steel-making technologies requiring less high-grade coking coal. Consequently many U.S. metallurgical coal operations have closed, and increased amounts of metallurgical coal have been sold into the domestic utility steam coal market. The U.S. coal industry is expected to continue to face strong competition from other coal-exporting countries, with limited or negative growth in import demand in Europe and the Americas. Given this, it is likely that the U.S. share of world coal exports will decline in coming years.

U.S. gross coal imports, at 16.5 Mmst, are expected to be about 17% lower in 2002 than they were in 2001. The rise in imports is attributable to both the heightened demand for low-sulfur coal to meet the stricter sulfur emission requirements of Phase II of the CAAA, and to the tight coal supply market that existed for most of 2001.

ELECTRICITY

In 2001, the United States generated 3,779 billion kilowatthours (Kwh) of electricity, including 2,661 billion Kwh at electric utilities plus an additional 1,116 billion Kwh at nonutility producers. For utilities, coal-fired plants accounted for 60% of generation, nuclear 20%, natural gas 10%, hydroelectricity 7%, oil 3%, geothermal and "other" 0.1%. For non-utilities, natural gas plants accounted for around 32% of generation, coal 32%, nuclear 21%, "geothermal and other" (including geothermal, wind, solar, wood and waste) about 8%, oil 5%, hydroelectric at 2%, and "other gaseous fuels" (including refinery still gas and liquefied petroleum gases) 1%.

During the first 6 months of 2002, total U.S. net generation of electricity was 1,836 billion Kwh (1,235 billion Kwh from utilities and 600 billion kwh from nonutilities), about the same as for the corresponding period in 2001. Roughly half of this generation was accounted for by coal-fired power plants. This was followed by 21% from nuclear, 17% percent from natural gas, 8% from hydroelectricity, 3% from renewables, and 2% from petroleum.

Natural gas-fired power plants have been gaining share rapidly over the past

few years. Coal-fired power plants generally have been less attractive than natural-gas-fired plants due to relatively high capital costs, longer construction periods, and lower efficiencies than natural gas combined-cycle plants, and has been losing share. Nuclear power has been growing only slowly, far behind the rate of natural gas-fired power.

On a national level, the price of electricity sold by utilities during the first half of 2002 averaged 7.06 cents per Kwh, about the same as during the first half of 2001. Electricity prices in the United States fell every year between 1993 and 1999, but this trend reversed in 2000 and 2001.

As of 2001, U.S. total net summer electric generating capacity was 854.7 gigawatts (GW). Of this total, 37% was coal-fired, 16% natural-gas-fired capacity, 11% nuclear; 9% hydroelectric, 4% petroleum, and 2% "renewables" (geothermal, solar, wind). The amount and geographical distribution of capacity by energy source is a function of availability and price of fuels and/or regulations. Capacity by energy source generally shows a geographical pattern such as: significant petroleum-fired capacity in the East, hydroelectric in the West, and natural-gas-fired capacity in the Coastal South.

Total annual electricity demand (retail sales plus industrial generation for own use and other direct sales) is expected to show growth of 2.2% for all of 2002. Abnormally high summer temperatures and high cooling demand increased electricity demand sharply in the third quarter of 2002. Based on Edison Electric Institute data on weekly electricity output, U.S. electricity production rose 6.5% for the third quarter 2002 compared to the year-earlier level. EIA's estimate for third-quarter 2002 growth in total demand has been revised to 5.0%. Total U.S. electricity demand is expected to be 3.5% higher this winter than it was last winter, due to the slowly rising economy and assumptions of normal temperatures for the remainder of the winter, which would imply 13% colder conditions this winter than last, contributing to higher heating-related electricity demand. In 2003, while the economy is expected to continue to recover, electricity demand is expected to grow by a relatively subdued rate of about 1% since little or no net summer demand growth would be expected

under normal levels of cooling degree-days.

Over the long term, U.S. power demand is increasing steadily (although well below average economic growth), with EIA forecasting 1.8% average annual growth in electricity sales through 2020. This increase will require a significant addition in generating capacity, with EIA forecasting that 1,300 new power plants will be needed over the next 20 years. Whether these plants are natural-gas-fired, coal-fired, "renewable," or nuclear depends on a mix of factors, including economics and government policy, but if recent trends continue, it is likely that the vast majority of new plants will be natural-gas-fired, with oil accounting for less than 1% of power generation by 2020.

The changing structure of the U.S. electric power industry has resulted in many electric utilities restructuring their companies and selling their generating assets, primarily to nonutility companies. During 1999, approximately 55,070 MW of capacity was sold to nonutility companies. On March 31, 1998, retail customers of investor-owned utilities in California (approximately three-fourths of the state's customers) were allowed direct access to an alternative energy (electricity) service provider. Also during 1998, Massachusetts and Rhode Island opened their retail electricity markets. Meanwhile, legislatures and/or public utility commissions in 18 other states (plus the District of Columbia) also have approved or implemented plans to move toward retail competition (although California's problems have caused many of these states to take a second look. On April 2, 2001, Entergy and the FPL Group called off a proposed \$7.6-billion merger which would have created the largest power distribution company in the United States. This follows the collapse in 2000 of a proposed \$3.3-billion merger between Connecticut's Northeast Utilities and New York's Consolidated Edison Co.

During much of 2000 and early 2001, California confronted a major power problem, with intermittent "rolling blackouts" and "Stage 3" (the highest level) alerts. Causes of this situation included: 1) sharply increased (11%) power demand in California over the past decade as a result of a surging economy and low power costs to consumers; 2) stagnant supply over the same

period; 3) low hydropower output levels in the Northwest due to below-normal rainfall; 4) California's heavy reliance on out-of-state capacity and power imports; 5) high natural gas prices and lingering problems from the August 2000 El Paso natural gas pipeline explosion; 6) significant problems stemming from California's Electric Utility Industry Restructuring Act of 1996; and 7) serious financial problems at utilities (PG&E, SCE). Serious problems, however, were largely avoided during the summer of 2001 due to conservation, a downturn in California's economy (and hence power demand), the addition of power generating capacity, and higher power prices. On September 24, 2001, as required by law, the CPUC effectively put an end to deregulation of retail electricity in California. Although California for the most part avoided power blackouts or other major problems this past summer, financial difficulties continue at utilities like Pacific Gas & Electric (PG&E, in bankruptcy) and Southern California Edison (close to bankruptcy). On October 22, 2001, the US Department of Energy, in partnership with PG&E, announced that it would spend \$300 million to upgrade Path 15, a series of power transmission lines connecting northern and southern California. As of November 2002, California had excess power generation and minimal risk of power outages.

In March 2001, the Energy Secretaries of Canada, Mexico, and the United States met to discuss a common energy strategy for the three countries, including integration of the three countries' power grids and creation of a US-Mexican working group to focus on promoting cross-border electricity trade. At present, power trade between Mexico and the United States is severely limited by infrastructure constraints, including inadequate power transmission capability (there are only two cross-border transmission lines: San Diego-Tijuana and El Paso-Matamoros). In January 2001, a small (50-MW), natural-gas-fired power plant in Baja California began exporting power to California. Canada exported about 42.9 bkwh of electricity to the United States in 1999, mostly from Quebec, Ontario, and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Washington state, Minnesota, California, and Oregon. There is considerable reciprocity between the Canadian and U.S. power markets, as the United

States also exports smaller volumes of electricity to Canada.

Nuclear

In 2001, U.S. nuclear power generation reached a record 769 billion kWh, or about 20% of total U.S. electricity generation, second only to coal in the U.S. electricity generation mix (for the first half of 2002, nuclear production was up about 1% from the same period in 2001). Nuclear power's share of U.S. utility electric generating capacity in 2001 was highest in the New England region (69% of utility generation), followed by the Middle Atlantic (37%), the South Atlantic (29%), the Pacific Coast (24%), the East South Central (20%), the West South Central (17%), the West North Central (16%), the East North Central (12%), and the Mountain region (10%). Approximately one-fourth of U.S. nuclear output was provided by just three states: Illinois, Pennsylvania, and South Carolina. The average capacity factor for all nuclear units nationwide increased from 88.1% in 2000 to 89.7% in 2001, an all-time record high utilization rate. Following the September 11, 2001 terrorist attacks on the United States, security at nuclear power plants around the United States was increased dramatically.

Nuclear power in the United States grew rapidly after 1973, when only 83 billion kWh of nuclear power was produced. As of 2001, nuclear power had grown nine-fold, with 104 licensed nuclear power units generating 769 billion kWh of electricity. This rapid growth in nuclear power generation, however, obscures serious underlying problems in the U.S. nuclear industry. After 1974, many planned units were canceled, and since 1977, there have been no orders for any new nuclear units, and none are currently planned. The 1979 Three Mile Island accident greatly increased concerns about the safety of nuclear power plants in the United States. The regulatory reaction to those concerns contributed to the decline in the number of planned nuclear units. In late March 2000, the Nuclear Regulatory Commission (NRC), in a positive signal to the U.S. nuclear power industry, granted the first-ever renewal of a nuclear power plant's operating license. The 20-year extension (until 2034 and 2036 for two reactors) went to the 1,700-MW Calvert Cliffs plant in Maryland. As of March 2002, Exelon and Dominion Resources reportedly

were looking at sites to build the first new nuclear power plants in the United States in two decades.

After a period of heightened concern for the availability of nuclear generation this past summer, the prospect for normal operations appears likely. Upon discovery of corrosion in a major component in a nuclear plant in Ohio, the Nuclear Regulator Commission ordered the submission of safety information on 68 other units, implying the possible need for shutdowns for inspections. It now appears the problem is confined to one unit and the cause is being investigated. The temporary loss of this capacity is offset by increases in capacity at several reactors due to NRC-approved upgrades ranging from 2% to 20% and totaling several hundred megawatts in each year of the projection. Total nuclear generation is expected to rise by 0.4% from the 2001 level in 2002 and by an additional 0.9% in 2003.

On July 9, 2002, the U.S. Congress voted to formally approve Yucca Mountain, located 100 miles north of Las Vegas, as the nation's permanent nuclear waste depository. Studies on Yucca Mountain as a possible nuclear power plant waste site have been going on for over two decades, with concerns centering on the dangers of transporting nuclear materials to the site via rail or highway. Nuclear utilities have complained that they are running out of nuclear waste storage capacity at their nuclear plants, with many being forced to resort to "dry cask" storage of spent fuel assemblies after water-storage pools reached capacity.

On November 7, 2002, South Carolina's Governor-elect, Mark Sanford, announced that he "would be inclined" to drop a legal suit against the Energy Department regarding plutonium shipments to the Savannah River nuclear site. The plutonium would be shipped from other nuclear weapons sites across the United States.

Hydroelectricity/Other "Renewables"

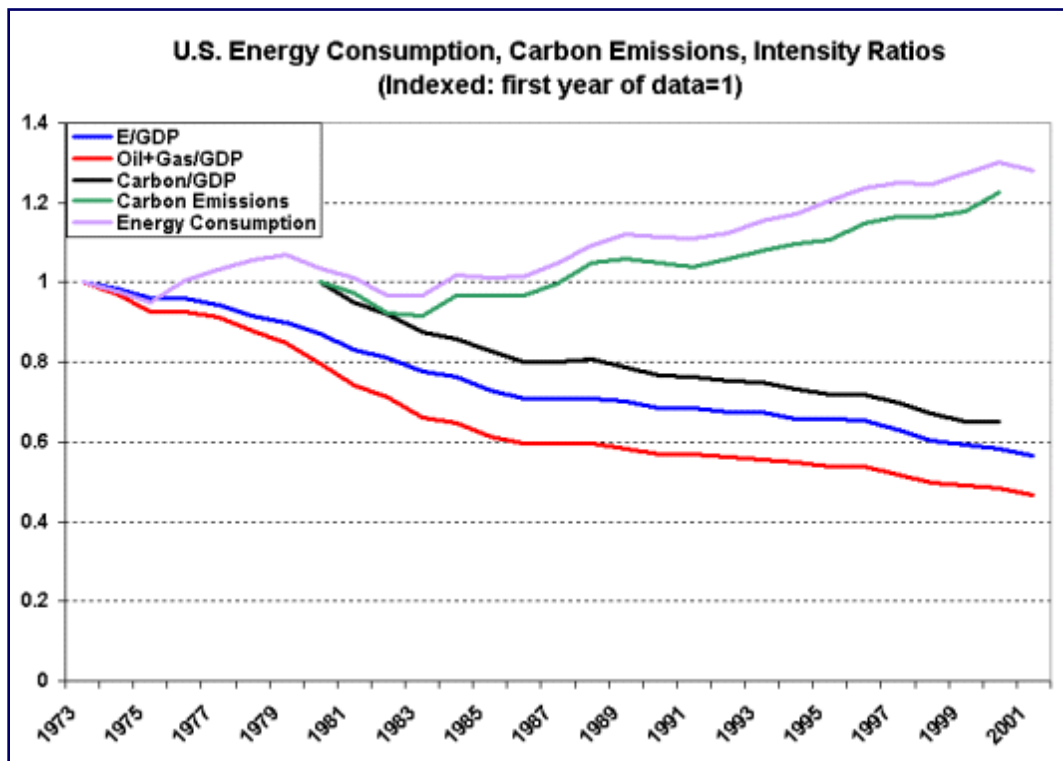
The United States consumed 6.2 quadrillion Btu of renewable energy in 2001, about 6% of total domestic gross energy demand, with the largest component

used for electricity production. Hydropower made up around 39% of total U.S. renewable consumption in 2001, with biofuels (including wood and waste), solar, wind, and geothermal making up most of the remainder. In 2001, total hydropower generation was down to lows not seen since 1966. In the summer of 2002, the U.S. Northeast experienced a serious drought, calling into question the adequacy of hydroelectricity supplies during the summer cooling season. As of early November, however, the drought had eased significantly following heavy rains in much of the region. Overall, total hydro generation rose by around 24% during the first half of 2002 compared to the same period in 2001. For 2002 as a whole, total hydropower generation is expected to rise by 29% as normal precipitation returns to the Pacific Census Division (Washington, Oregon and California), the main region affected by drought.

Wind, solar, biomass, and geothermal power, although growing, still supply only a tiny fraction of U.S. energy needs. In January 2000, however, the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) released a report which said that the domestic photovoltaic (PV) industry could provide up to 15% of "new U.S. peak electricity capacity expected to be required in 2020." Wind, geothermal, and biomass energy sources also have significant potential in the United States.

In 2001, 1,694 MW of wind power was installed in the United States, more than twice the previous record of 732 MW installed in 1999, according to the American Wind Energy Association (AWEA). This increase was driven in part by a federal wind Production Tax Credit, or PTC, of 1.7 cents per Kwh (lowered to 1.5 cents per Kwh in the two-year renewal signed into law on March 9, 2002). The PTC, among other factors, has helped boost total U.S. installed wind generating capacity to 4,258 MW (as of January 2002), with wind turbines now located in 26 states. During the first half of 2002, wind power production increased 37% from the same period in 2001, the fastest growing power source in the United States in percentage terms, but trailing far behind natural gas and nuclear power in absolute terms. The first U.S. offshore windmill park reportedly is scheduled to be built off the Cape Cod

coast, with 170 windmills to be installed beginning in 2004. The project could power more than 200,000 homes in Cape Cod.



ENVIRONMENT

The United States, with the world's largest economy, is also the world's largest single source of anthropogenic (human-caused) greenhouse gas emissions.

Quantitatively, the most important anthropogenic greenhouse gas

emission is carbon dioxide, which is released into the atmosphere when fossil fuels (i.e., oil, coal, natural gas) are burned. Current projections indicate that U.S. emissions of carbon (mainly in the form of carbon dioxide) will reach 1,694 million metric tons in 2005, an increase of 357 million metric tons from the 1,337 million metric tons emitted in 1990, and around one-fourth of total world energy-related carbon emissions. At the December 1997 global warming summit in Kyoto, Japan, the U.S. delegation agreed to reduce U.S. carbon emissions 7% from 1990 levels by 2008-2012. Given current EIA projections, it is unlikely that this goal will be met.

In February 2002, the Bush Administration released its proposed alternative to the Kyoto Treaty, calling for significant reductions in emissions of various pollutants (mercury, nitrogen oxide, sulfur dioxide). The program, known as the "Clear Skies Initiative," would utilize a "cap and trade" system which would allow companies to trade emissions credits. In addition, the Bush Administration envisions reductions in U.S. "greenhouse gas intensity" -- the amount of greenhouse gases emitted per dollar of GDP -- by 18% over 10

years. As the graph here shows, U.S. carbon emissions per dollar of GDP have been declining steadily since at least 1980.

U.S. energy-related carbon emissions have been increasing in recent years for three main reasons. First, the U.S. economy experienced strong economic growth during the 1990s, which in combination with generally low oil prices for most of the period (until recently), caused energy consumption to increase. Second, the energy "efficiency gains" of the 1980s, which were prompted largely by the oil price spikes of the 1970s, have been leveling off for several years now, particularly since the 1985/86 oil price collapse. Sales of sport-utility vehicles, minivans, and small trucks, for instance, all of which are less fuel efficient than small cars, have increased sharply in recent years. Third, nuclear power generation (which emits no carbon), has now stagnated and is expected to decline after expanding rapidly during the 1970s and 1980s. Hydroelectricity, the other major non-fossil energy source in the United States, also has not been growing.

Since taking office on January 20, 2001, the Bush Administration has taken a series of actions related to energy and the environment. On February 28, 2001, EPA Administrator Christine Todd Whitman directed her agency to move ahead with a rule issued by President Clinton that will require U.S. refiners to reduce sulfur in diesel fuel from 500 parts per million currently, to 15 parts per million by 2006. On March 13, 2001, President Bush declared that his administration would not seek to regulate power plants' emissions of carbon dioxide, citing an EIA study that regulating these emissions could result in higher electricity prices. On March 27, the Bush administration declared that the United States had "no interest" in implementing or ratifying the Kyoto treaty, saying it would be too harmful to the U.S. economy, and that it would pursue other ways of addressing the climate change issue. On April 10, the EPA asked the U.S. Court of Appeals in Washington, DC to uphold a Clinton administration plan to regulate mercury pollution from coal-fired power plants, beginning in 2004. On April 12, the White House affirmed Clinton administration-approved energy efficiency standards for washing machines and water heaters. Under these standards, clothes washers would

become 22% more efficient by 2004 and 35% more by 2007. The next day (April 13), the Department of Energy announced that it would require air conditioners to be 20% more energy efficient by 2006. The Clinton administration had mandated a 30% energy efficiency increase for air conditioners. In June 2001, President Bush announced that the federal government would lead an effort to reduce the use of energy by machines not in use (known as standby power, or "vampire," devices). In July 2001, the Interior Department announced that it would greatly reduce the scope of proposed oil leases in the Gulf of Mexico, and also would keep oil rigs at least 100 miles from the state's beaches. In January 2002, Energy Secretary Spencer Abraham announced an initiative, known as "Freedom CAR," to help automakers produce fuel-cell-powered electric vehicles.

COUNTRY OVERVIEW

President: George W. Bush (since January 20, 2001)

Legislative Branch: Bicameral Congress (Senate, House of Representatives)

Judicial Branch: Supreme Court

Independence: July 4, 1776

Population (July 2001E): 285 million

Location/Size: North America, between Canada and Mexico/9,629,091 sq. km (3,717,792 sq. miles), the third largest country in the world, behind Russia and Canada

Major Cities: Washington, DC (capital), New York, Los Angeles, Chicago, Houston, Miami, Philadelphia, etc.

Languages: English, Spanish (spoken by a sizable minority)

Ethnic Groups (8/1/2000): White (82.2%), Black (12.8%), Asian (4.1%), Native American (0.9%). Note: Hispanics, who can be of any race, made up 11.8% of the U.S. population as of 8/1/2000.

Religions (1997): Protestant (58%), Roman Catholic (26%), Jewish (2%), other (6%), none (8%)

Defense (8/98): Army, 479,400; Navy, 380,600; Air Force, 370,300; Marine Corps, 171,300 (the United States also has nearly 1.35 million reservists)

ECONOMIC OVERVIEW

Currency: Dollar (\$)

Exchange Rates, per Dollar (11/6/2002): British Pound (0.6397); Canadian Dollar (1.557); Euro (0.9999); Japanese Yen (121.85)

Gross Domestic Product (GDP) (2002E): \$10.5 trillion

Real GDP Growth Rate: (2001E): 0.3% **(2002E):** 2.3% **(2003F):** 3.0%

Inflation Rate (GDP implicit price deflator) (2001E): 2.4% **(2002E):** 1.3% **(2003F):** 2.5%

Unemployment Rate (2001E): 4.8% **(2002E):** 5.8% **(2003F):** 5.9%

Current Account Balance (2001E): -\$393 billion **(2002E):** -\$510 billion **(2003F):** -\$535 billion

Merchandise Exports (2001E): \$719 billion **(2002F):** \$693 billion

Merchandise Imports (2001E): \$1,146 billion **(2002F):** \$1,171 billion

Merchandise Trade Balance (2001E): -\$427 billion **(2002F):** -\$478 billion

Major Exports: Capital goods, automobiles, industrial supplies and raw materials, consumer goods, agricultural products

Major Imports: Crude oil and refined petroleum products, machinery, automobiles, consumer goods, industrial raw materials, food and beverages

Major Trading Partners: Canada, Japan, European Union, Mexico

Federal Budget Surplus (2001E): \$127 billion **(2002E):** -\$180 billion **(2003F):** -\$255 billion

ENERGY OVERVIEW

Secretary of Energy: Spencer Abraham (as of January 20, 2001)

Proven Oil Reserves (1/1/02E): 22.0 billion barrels

Oil Production (January-September 2002E): 8.1 million barrels per day (bbl/d), of which 5.8 million bbl/d was crude oil (NOTE: Including "refinery gain," US oil production in 2002 is estimated at 9.1 million bbl/d)

Oil Consumption (January-September 2002E): 19.6 million bbl/d

Net Oil Imports (January-September 2002E): 10.3 million bbl/d

Gross Oil Imports (January-September 2002E): 11.25 million bbl/d (of which, 8.96 million bbl/d was crude oil and 2.28 million bbl/d were petroleum products)

Crude Oil Imports from the Persian Gulf (January-August 2002E): 2.3 million bbl/d (around 26% of total U.S. crude oil imports)

Top Sources of U.S. Crude Oil Imports (January-August 2002E): Saudi Arabia (1.49 million bbl/d); Mexico (1.46 million bbl/d); Canada (1.37 million bbl/d); Venezuela (1.14 million bbl/d)

Value of Oil Imports (January-August 2002E): \$64 billion (down from \$74 billion during the same period in 2001)

Crude Oil Refining Capacity (2002E): 16.8 million bbl/d (153 operable refineries)

Oil Stocks (9/02E): 1.57 billion barrels (including about 585 million barrels in the U.S. Strategic Petroleum Reserve)

Oil Wells Drilled (January-September 2002E): 3,689 (down from 6,210 during the same period in 2001)

Operating Oil and Natural Gas Rotary Rigs (10/02E): 852 (709 for natural gas and 140 for oil)

Natural Gas Reserves (1/1/02E): 177 trillion cubic feet (Tcf)

Dry Natural Gas Production (2001E): 19.5 Tcf **(2002F):** 19.2 Tcf

Natural Gas Consumption (2001E): 21.4 Tcf **(2002F):** 21.6 Tcf

Net Natural Gas Imports (2001E): 3.65 Tcf (over 90% from Canada) **(2002F):** 3.46 Tcf

Natural Gas Wells Drilled (2001E): 21,224 (up from 15,598 in 2000)

Recoverable Coal Reserves (12/31/98): 275.1 billion short tons (54% lignite and subbituminous; 46% anthracite and bituminous)

Coal Production (2001E): 1,121 million short tons (Mmst) **(2002F):** 1,089 Mmst

Coal Consumption (2001E): 1,050 Mmst **(2002F):** 1,063 Mmst

Gross Coal Exports (2001E): 49 Mmst **(2002F):** 41 Mmst

Primary and Secondary Coal Stocks (closing; 2002F): 159 Mmst (down from 170 Mmst in 2001)

Electric Generation Capacity (2001E): 855 gigawatts (37% coal-fired, 16% natural-gas, 11% nuclear; 9% hydroelectric, 4% petroleum, and 2% "renewables")

Electric Net Generation by Utilities (2002F): 2,579 billion kilowatthours (of which coal-fired 59%, nuclear 20%, natural gas 10%, hydroelectricity 10%, oil 2%, geothermal and "other" 0.1%)

Non-utility Power Production (2002F): 1,275 billion kilowatthours (of which natural gas-fired 35%, coal 30%, nuclear 21%, "geothermal and other" 8%, oil 3%, hydroelectric 2%, and "other gaseous fuels" 2%)

Total Electricity Generation (2001E): 3,758 billion kilowatthours **(2002F):** 3,854 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Administrator of the U.S. Environmental Protection Agency: Christine Todd Whitman

Total Energy Consumption (2001E): 97.1 quadrillion Btu (25% of world total energy consumption) **(2002F):** 97.8 quadrillion Btu

Energy-Related Carbon Emissions (2001E): 1,540 million metric tons of carbon (about 25% of world total carbon emissions)

Per Capita Energy Consumption (2000E): 348.9 million Btu

Per Capita Carbon Emissions (2000E): 5.7 metric tons of carbon

Energy Intensity (2001E): 10,530 Btu/\$1996

Carbon Intensity (2000E): 0.17 metric tons of carbon/thousand \$1996

Sectoral Share of Energy Consumption (2001E): Industrial (35%), Transportation (26%), Residential (21%), Commercial (18%)

Fuel Share of Energy Consumption (2001E): Oil (39%), Natural Gas (23%), Coal (23%), Renewables (6%)

Fuel Share of Carbon Emissions (2000E): Oil (42%), Coal (37%), Natural Gas (21%)

Renewable Energy Consumption (2001E): 6,173 trillion Btu (about 39% of which was conventional hydroelectric power)

Number of People per Motor Vehicle (2000E): 1.3

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified October 15th, 1992). Under the negotiated Kyoto Protocol (signed on November 12th, 1998 not yet ratified), the United States agreed to reduce greenhouse gases 7% below 1990 levels by the 2008-2012 commitment period.

Major Environmental Issues: Air pollution resulting in acid rain in both the US and Canada; the US is the largest single emitter of carbon dioxide from the burning of fossil fuels; water pollution from runoff of pesticides and

fertilizers; very limited natural fresh water resources in much of the western part of the country require careful management; desertification.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Antarctic-Environmental Protocol, Antarctic Treaty, Climate Change, Endangered Species, Environmental Modification, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified, Air Pollution-Persistent Organic Pollutants, Air Pollution-Volatile Organic Compounds, Biodiversity, Desertification, Hazardous Wastes.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

ENERGY INDUSTRY

Major U.S. Oil Companies (2002): ExxonMobil, ChevronTexaco, ConocoPhillips, Anadarko, Occidental, Apache, Burlington Resources, Unocal, Devon, Marathon

Major U.S. Coal Companies (2000): Peabody Holding Co., Inc.; Arch Coal; Kennecott Energy Co.; Consol Energy; RAG American Coal Holding; AEI Resources; A.T. Massey; Vulcan Partners

Oil Pipelines (2001E): Around 2 million miles **Natural Gas Pipelines (2000E):** 278,000 miles

Major Ports: Baltimore, Chicago, Hampton Roads, Houston, Los Angeles, New Orleans, New York, Philadelphia

Sources for this report include: Associated Press; Christian Science Monitor; Dallas Morning News; Dow Jones; DRI/WEFA; EIU Viewswire; Energy

Daily; Energy Report; Financial Times; Financial Times Energy Newsletters; Gas Daily; Houston Chronicle; Los Angeles Times; Megawatt Daily; New York Times; Oil and Gas Journal; Oil Daily; Petroleum Intelligence Weekly; Pipeline and Gas Journal; Platts Oilgram News; PR Newswire; Reuters; U.S. Energy Information Administration (numerous publications -- see links); USA Today; Washington Post; Weekly Petroleum Argus; World Gas Intelligence; World Markets Online; World Oil.

LINKS

For more information on U.S. energy, see these other sources on the EIA web site:

[EIA - Short-Term Energy Outlook](#)

[EIA - Annual Energy Outlook 2002](#)

[EIA - Monthly Energy Review](#)

[EIA - Petroleum Page](#)

[EIA - Natural Gas Page](#)

[Natural Gas Annual 2000](#)

[EIA - Nuclear Page](#)

[EIA - Coal Page](#)

[EIA - Electricity Page](#)

[Electric Power Annual: 2000](#)

[EIA - Renewable Fuels Page](#)

[EIA - Energy Supply Security Page](#)

[EIA - Financial Page](#)

[EIA - Links Page](#)

Links to other U.S. government sites:

[2002 CIA World Factbook - U.S.](#)

[U.S. Department of Energy's Office of Fossil Energy Home Page](#)

[U.S. Department of Energy Home Page](#)

[U.S. Nuclear Regulatory Commission](#)

[Federal Energy Regulatory Commission](#)

[National Association of State Energy Officials](#)

[National Renewable Energy Laboratory \(NREL\)](#)

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[National Petroleum Refiners Association](#)

[American Gas Association](#)

[National Mining Association](#)

[Electric Power Research Institute](#)

[Edison Electric Institute](#)

[North American Electric Reliability Council](#)

[Nuclear Energy Institute](#)

[Gas Research Institute](#)

[Global Climate Coalition](#)

[Resources for the Future](#)

[Export Council for Energy Efficiency](#)

[Alliance to Save Energy](#)

[American Solar Energy Society](#)

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[Geothermal Energy Association](#)

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April 2002

Russia

Russia is important to world energy markets because it holds the world's largest natural gas reserves, the second largest coal reserves, and the eighth largest oil reserves. Russia is also the world's largest exporter of natural gas, one of the largest oil exporters, and the third largest energy consumer.

Note: Information contained in this report is the best available as of April 2002 and is subject to change.



GENERAL BACKGROUND

After a banner year in 2000, when Russia's real gross domestic product (GDP) grew by 8.3%, Russia's economic growth slowed in 2001. Nevertheless, Russia's economy grew by a healthy 5.1%, and the country's economy is in the best shape it has been in since the breakup of the Soviet Union in 1991.

Russia's rate of inflation slowed from 20.2% in 2000 to 18.5% in 2001, and Russia's currency, the

ruble, continued to strengthen in 2001, prolonging its remarkable rebound from the country's August 1998 financial crisis and devaluation.

Since energy accounts for approximately 40% of Russia's exports and 13% of the country's real GDP, Russia's economy is extremely sensitive to global energy price fluctuations. As a result, the decline in world oil prices in 2001 put the brakes on Russia's economic recovery, which was fueled by high world oil prices in 1999-2000 and the increased competitiveness of Russian exports in the aftermath of the 1998 financial crisis. Although the windfall in oil export revenues in 1999-2000 stimulated increases in other industrial sectors and helped the Russian government pay down some of its \$154 billion foreign debt, structural reforms slowed in the euphoria of the oil revenues.

The drop in world oil prices after September 11, 2001, resulted in members of the Organization of Petroleum Exporting Countries ([OPEC](#)) requesting Russia and other [non-OPEC](#) members to cut their oil exports in order to boost prices. Russia agreed with OPEC in December 2001 to cut its oil exports by 150,000 bbl/d during the first quarter of 2002. Despite heavy lobbying by Russian oil companies to end the cut and to increase exports, Russia, whose state budget for 2002 is based on an average oil price of \$23 per barrel and a minimum price of \$18 per barrel, decided in March 2002 to continue its self-imposed cuts by 150,000 bbl/d through June 2002.

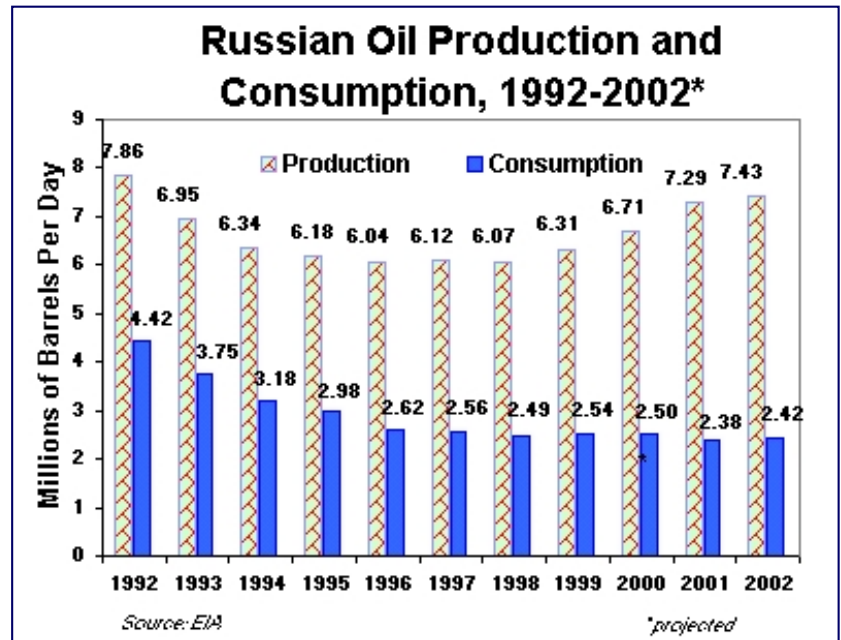
Although reforms have been slow in coming, [restructuring and liberalizing the energy sector](#) and making the Russian economy less dependent on [oil and natural gas exports](#) is a stated priority for Russian President

Vladimir Putin and the Russian government. Plans to break up the monopoly positions of both Gazprom and Unified Energy Systems, the Russian natural gas and electricity monopolies, have been approved. Similarly, the Russian government has pledged to improve the investment climate in Russia, but Russia's unstable tax and legal codes have kept many foreign energy companies from investing in Russia's energy sector. Russia has plans for a number of [new oil and natural gas pipelines](#), and massive infrastructure investments will be needed to develop several planned [international oil and gas projects](#).

OIL

After several years of production declines following the collapse of the Soviet Union, Russia's oil industry has bounced back over the past few years, posting strong profits and healthy increases in production. Russia is one of the world's biggest oil producers, but from 1992 to 1998, the country's oil production plummeted 23% due to decreased domestic industrial demand and a decline in drilling and capital investment.

Buoyed by high world oil prices in 1999-2000, Russian oil companies reinvested much of their generous profits into ramping up crude production. Since 1998, when production bottomed out at 6.07 million bbl/d, Russia's oil production, including condensates, has increased 20%, with overall production of 7.29 million bbl/d in 2001.



Despite Russia's pledge to OPEC to shave 150,000 bbl/d off its oil exports in the first half of 2002, Russian oil production is still forecast to post a 1.9% year-on-year increase--reaching 7.43 million bbl/d--in 2002. Russian oil production actually increased in the first few months of 2002, with average oil production of 7.49 million bbl/d in February 2002. Although Russian government officials have attempted to limit the country's oil exports, new export channels, such as the [Baltic Pipeline System](#), have provided a powerful disincentive to Russian oil producers to reduce their output. As a result of [Saudi Arabia's](#) OPEC-mandated production cut (and that country's better compliance with its pledged cuts), Russia's oil production surpassed Saudi Arabia's in February 2002 for the first time since the Soviet era, making Russia the world's leading oil producer, if only temporarily.

Russia has proven oil reserves of 48.6 billion barrels, but aging equipment and poorly developed fields are making it difficult to develop these reserves. In addition, Russia's rate of oil production is exceeding its rate of discovery of new reserves by a significant margin. The Russian oil industry faces the depletion of existing oilfields, deterioration in transport infrastructure, and an acute shortage of investment due to the confusing tax and legal environment. In order to sustain and to increase Russia's oil production from current levels, large amounts of capital will be needed to develop new fields and to extend the life of existing oilfields with exhausted and low-yield reserves.

However, the sharp rise in oil prices during 1999-2000 provided Russian oil companies with a windfall in revenues, and many have begun to upgrade decaying oil infrastructure and to undertake new exploratory drilling. In addition to further development of the West Siberia region, where most of Russia's oil comes from currently, Russian oil producers are conducting more exploration in the Russian sector of the [Caspian Sea](#), and teaming up with foreign oil producers to develop [oil projects in the Arctic region, Eastern Siberia, and Sakhalin Island](#) in Russia's Far East. Russia's future level of oil production will be defined by the

ability of oil companies to develop these new deposits, which will require a massive amount of infrastructure investment (including [new export pipelines](#)) in order to deliver this oil to customers.

Oil Sector Reform

Russia [reorganized its state-run oil industry](#) into a number of vertically-integrated oil companies in the early 1990s, and the state has divested itself of large stakes in most of these companies. Nonetheless, foreign investment in the industry has been minimal due to economic and political instability, a poor record of corporate governance, and the unstable legislative framework.

In order to create a more stable investment climate, potential investors have called upon the Russian government to undertake further reform, including the establishment of cohesive production-sharing agreement (PSA) framework legislation. Although the political and economic situation has stabilized since the August 1998 financial crisis, and high world oil prices in 1999-2000 enticed some investors into Russia, others are still awaiting the passage of a new Russian PSA regime and tax code.

Oil Exports

Despite problems surrounding the transition to a market economy and the lack of foreign investment in its oil sector, [Russia remains one of the world's top oil exporters](#). After Russian oil exports slumped in the mid-1990s, exports rebounded after the ruble devaluation of August 1998 reduced production costs sharply for Russian oil producers, and the climb in world oil prices in 1999-2000 made exports even more profitable for Russian oil companies. With domestic consumption of 2.38 million bbl/d in 2001, Russia's increased its net oil exports in 2001 to 4.91 million bbl/d, making Russia the world's second largest oil exporter, behind only Saudi Arabia.

Russia is not a member of OPEC, but in recent years it has frequently attempted to coordinate its export strategy with OPEC. Although Russia agreed to reduce its oil exports by 150,000 bbl/d in the first quarter of 2002, Russian oil companies' compliance with these export cuts has been questionable at best, with preliminary data showing that Russian crude oil exports actually increased during the first quarter of 2002. Russian government officials levied higher export tariffs and set crude oil export quotas in order to limit the country's oil exports, but Russian oil companies increased their oil product exports instead. For 2002 as a whole, Russia's net oil exports are projected to increase to 5.01 million bb/d.

Oil Pipelines

Russia's oil exports could be even higher if they were not restricted by a lack of spare capacity in existing export pipelines. Despite Russia's pledged export cuts, the country's main export pipeline, the 1.2-million-bbl/d-capacity Druzhba pipeline, still is operating close to its highest capacity in years. In addition, many of the country's oil pipelines are in a state of disrepair, and Russian Energy Ministry figures indicate that almost 5% of crude oil produced in Russia is lost through illegal tapping of Russia's pipelines.

With a windfall in oil export tariffs in the past several years, Transneft, the state oil transport monopoly, has taken steps to upgrade the country's pipeline system, with an emphasis on building [new export pipelines](#) to increase and diversify export routes for oil exporters. In addition to constructing the [Baltic Pipeline System](#) and a possible [pipeline to China](#), Transneft is seeking to lure additional [transit oil](#) from [Azerbaijan](#), [Kazakhstan](#), and [Turkmenistan](#).

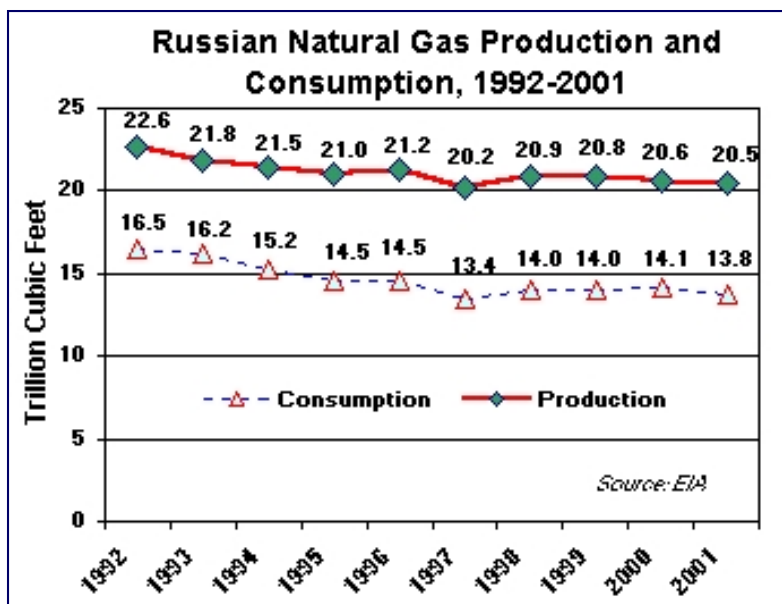
Downstream/Refining

Russia has 42 oil refineries--many of which are inefficient, aging, and in need of modernization--with a total processing capacity of 6.9 million bbl/d. With Russian domestic demand of 2.38 million bbl/d in 2001, refining capacity far outstrips demand for refined products. In addition, because a barrel of crude oil on the Russian market typically sells for just over half the world crude oil price, many Russian oil companies prefer to export their crude oil rather than to refine it in Russia. When Russian oil producers do not export their crude oil--often because of the constraints of Russia's pipeline system or the government's limits on each company's exports--many choose to supply their own refineries rather than sell the oil on the open market.

Russia's decision to go along with OPEC oil supply cuts in the winter of 2001-2002 has led to a glut of oil on the Russian market. As a result, Russian oil companies have channeled more oil into domestic refineries, and with refineries awash in crude, the domestic crude price collapsed, falling from about \$13.70 per barrel at the wellhead in November 2001 to just \$4.48 per barrel in January 2002. With many Russian refineries undergoing renovations or efficiency upgrades, Russia's refineries have not been able to handle so much crude oil at once. Preliminary data indicates that Russia's exports of refined products increased in the first quarter of 2002, and surplus refined products such as fuel oil, gasoline, and kerosene went into storage.

NATURAL GAS

Russia contains over 1,700 trillion cubic feet (Tcf) in proven reserves of natural gas, the world's largest. Gazprom, the state-run natural gas monopoly, produces nearly 94% of Russia's natural gas, operates the country's 90,000-mile natural gas pipeline grid and 43 compressor stations, and holds nearly one-third of the world's natural gas reserves while employing approximately 38,000 people. Often referred to as a "state within a state," Gazprom also is Russia's largest earner of hard currency, and the company's tax payments account for around 25% of federal government tax revenues.



Russia's natural gas production also is the largest in the world. Natural gas also accounts for over 54% of Russia's energy consumption, but the country still has plenty of natural gas available for export. According to Russia's State Statistics Committee, in 2001 Russia consumed 13.8 Tcf of natural gas while it produced 20.5 Tcf. With 6.7 Tcf in net [natural gas exports](#), Russia is the world's largest natural gas exporter. In 2002, Russia is planning to increase natural gas production to 21.2 Tcf, while the country projects domestic natural gas consumption to increase to 14.6 Tcf.

In addition to its main producing areas in the Yamal-Nenets region of northern West Siberia at the Urengoy and Yamburg fields, Gazprom is responsible for future development of giant Bovanenkovskoye field on the Yamal Peninsula and other fields in the Yamal-Nenets region, including the the giant Pestsovoye and Zapolyarnoye fields to the north in the Ob-Taz Gulf area. Through its subsidiary Rosshelf, Gazprom also is responsible for development of the Shtokmanskoye field in the Barents Sea and other fields in the North Caucasus, Precaspian, Timan-Pechora, and the Volga-Urals.

Many analysts doubt Russia's ability to raise its natural gas production in the face of Gazprom's declining budget and the low levels of investment to the sector in recent years. Although Russia's natural gas sector has not been as hard hit as other sectors of the energy industry during the transition to a market economy (production is down just 9% since 1992), low investment in the sector has raised concerns about future production levels. Production in the Urengoy and Yamburg natural gas fields is declining, while the planned development of new fields continues to be delayed as a result of lack of investment resources. In February 2002, Gazprom scaled back its 2002 investment program for field exploration to \$453 million from the \$499 million invested in 2001.

Sectoral Problems

According to the Russian Gas Law of 1999, Gazprom must supply the Russian natural gas market, regardless of profitability, at regulated prices. Thus, the company is forced by the Russian government to

sell natural gas to domestic users for approximately \$16 per 1,000 cubic meters (35,300 cubic feet)--less than it costs the company to produce, and only about one-tenth of the export price of \$140-\$150 per 1,000 cubic meters.

In addition, Gazprom continues to be hurt by chronic non-payments by consumers (although this situation has improved recently). In 1999, Russian consumers paid only 39% of their bills for natural gas in cash, but by 2001, Gazprom was paid in cash for 83% of the natural gas it sold domestically. Still, only 29 of Russia's 89 regions are up to date with their natural gas payments, and the multi-billion dollar debt of domestic natural gas consumers has hindered Gazprom's ability to invest adequately in new fields, many of which need major infrastructure investments.

The only investment in new natural gas production that Gazprom has made recently is the development of Zapolyarnoye, which was brought onstream in October 2001 to offset the decline in the company's production. Although Gazprom has enough undeveloped natural gas reserves in its portfolio to ensure future supplies, Zapolyarnoye is the last of the so-called "easy-to-develop" giant fields. Development of future fields, most of which are located in the more remote regions that lack infrastructure to deliver the natural gas to consumers, will require much higher levels of investment. Developments like Prirazlomnoye and Shtokmanskoye are provisionally budgeted to cost \$1 billion and \$15 billion to \$20 billion, respectively.

Restructuring the Natural Gas Sector

While Gazprom is looking to establish [partnerships with foreign investors to develop several natural gas production projects](#), restrictions on foreign investment in the company, along with [allegations of asset stripping](#) by senior managers of Gazprom, has limited Russia's investments in new natural gas developments. In addition, Gazprom's control over Russia's natural gas trunk-line system, forcing other producers to sell their natural gas to Gazprom on its terms, has proven a disincentive to increased natural gas production. The lack of access to Russia's natural gas pipelines has meant that Russian oil companies prefer to flare their associated natural gas instead of treating it and selling it to Gazprom.

In an attempt to spur increased investment in the industry and to raise production levels, President Putin is taking steps to end Gazprom's monopoly position and to [restructure the natural gas sector](#). On November 9, 2000, the government ordered Gazprom to give other companies the right to use up to 15% of its pipeline capacity, and in May 2001, Gazprom's Board of Directors ousted long-time chief Rem Vyakhirev and replaced him with Aleksei Miller, an ally of Putin.

A restructuring plan currently under consideration would [break Gazprom's upstream operations into separate producing companies](#) in order to foster competition on the Russian domestic market, while the government would take control of Gazprom's transmission pipelines, offering [equal access to all natural gas producers](#), thereby giving incentive to Russia's oil companies to treat the associated natural gas they develop. In addition, the Russian government is paying heed to Gazprom's minority shareholders, curtailing Gazprom's mysterious relationship with natural gas trader Itera and attempting to loosen restrictions on the purchasing of Gazprom shares by foreign investors.

Natural Gas Exports

The Russian government's determination to keep domestic natural gas prices artificially low means that [the country's natural gas industry is heavily dependent on exports](#) to finance its production. In 2001, Russia totaled 6.7 Tcf of net natural gas exports, the majority of which were piped to customers outside the Commonwealth of Independent States (CIS). Gazprom supplies [Europe](#) with 25% of its natural gas, and with [several new export pipelines](#) planned or already under construction, Russia hopes to increase this percentage in the next decade.

In order to offset its own declining production and maintain its export level, Gazprom, via natural gas trader Itera, contracted to buy 353 billion cubic feet (Bcf) of gas from Turkmenistan in 2002. As

Kazakhstan, Turkmenistan, and [Uzbekistan](#) continue to develop their natural gas industries and increase their production, senior Russian officials--including President Putin--have called for a Eurasian alliance to offset the impact of [European natural gas market liberalization](#). According to Putin, the so-called "Gas OPEC," uniting Russia with the three big natural gas-producing countries in [Central Asia](#), would "bring an element of stability into the transportation of natural gas on a long-term basis." Analysts have criticized the alliance proposal as a Russian attempt to exercise control over Central Asian natural gas exports.

Natural Gas Export Pipelines

In an effort to diversify its export routes and reach new markets, Russia is planning to build several [new natural gas export pipelines](#). The [Blue Stream pipeline](#) to [Turkey](#) is the centerpiece of Russia's export diversification strategy. The pipeline, which will supply Turkey with 565 Bcf of natural gas via twin pipelines laid on the bottom of the Black Sea, is nearing completion, and should be operational by the fall of 2002. The December 2001 resolution of the dispute between Russia and Ukraine over Ukraine's unsanctioned removal of natural gas has caused Gazprom to drop plans to build a "[Ukraine bypass](#)" [pipeline](#), but plans for the second branch of the [Yamal-Europe pipeline](#)--to Europe via [Belarus](#)--are in development. In addition, Russia is looking eastwards, with several potential [natural gas pipelines to China](#) currently under consideration.

COAL

With 173 billion short tons in proven coal reserves, Russia holds the world's second largest coal reserves, behind only the [United States](#). However, years of poor management during the Soviet era, combined with a sharp decline in demand for coal during the early 1990s, significantly undermined the Russian coal sector's viability in the early 1990s. By 1993, Russian government subsidies to the coal sector became unsustainably high, exceeding 1% of the country's GDP, according to the World Bank. As production began to slump, Russia initiated a [comprehensive restructuring of the coal sector](#) in the mid-1990s.

As a result of the restructuring, the state coal company, RosUgol, has been phased out, production subsidies have ended, and mines with no economic future are being closed. With over \$1.3 billion in financial assistance provided by the World Bank, the restructuring efforts are paying off, and the transition of Russia's coal sector from a massively-subsidized industry into a streamlined, profitable operation is almost complete. After years of decline, which saw Russian coal production decrease by 41%--from 406 million short tons (Mmst) in 1992 to 241 Mmst in 1998--in 1999, the reformed coal sector increased its production to 259 Mmst. EIA preliminary data for 2000 shows that Russia's coal production increased to 281 Mmst, and Russia's State Statistics Committee reports that the country's coal production rose again in 2001. Russia's Ministry of Energy has projected a 0.3% coal production increase in 2002.

Many of Russia's major coal basins are in West Siberia, and in 2001, the region's coal mines accounted for 48% of Russia's overall coal production. Kuzbassrazrezugol and Krasnoyarskugol, both located in West Siberia, were Russia's largest coal producers in 2001, with output of 36.3 Mmst and 35.3 Mmst, respectively. In addition, through the first seven months of 2001, Russia's State Statistics Committee reported that Russia's coal exports increased during the same time period by 30% year-on-year, including a 41.5% increase in exports to countries outside the CIS and [Baltics](#).

With Russia's determination to increase its [oil and natural gas exports](#), Russia's coal consumption is slated to rise. Although coal accounted for just 16% of Russia's domestic energy consumption in 1999, the government is committed to increase that percentage to as high as 28%. Russia consumed 298 Mmst of coal in 2000, but the country's energy strategy calls for coal production to climb to 335 Mmst in 2010, and then to 430 Mmst in 2020.

Nevertheless, the Russian Trade Union of Coal Miners complained in March 2002 of a lack of demand for Russian coal. Despite the sector's increased productivity, the Union's chairman, Ivan Mokhnachuk, said that coal deliveries to power-generation facilities fell by 4.4 Mmst in 2001, while coal stocks in depots increased by 33% over the previous year. At the same time, he noted, Russia imported 28.4 Mmst of coal

from Kazakhstan. The Russian Trade Union of Coal Miners has accused both Kazakhstan and China of dumping coal on the Russian market, reducing demand for Russian-produced coal.

ELECTRICITY

Russia's mammoth power sector, which includes over 440 thermal and hydropower plants, plus 29 [nuclear reactors](#), has a total electric generation capacity of 203 gigawatts (GW). With 139 GW of production capacity, thermal power (oil-, gas-, and coal-fired plants) accounts for 68% of the country's power generation capacity, while hydropower plants account for an additional 44 GW (21.5% of total installed power capacity). Russia's electricity sector is dominated by Unified Energy Systems (UES), which is 52%-owned by the Russian government. UES, headed by former privatization minister Anatoly Chubais, controls approximately 70% of the country's distribution system and oversees Russia's 72 regional electricity companies, called *energос*.

Russia shut down several nuclear reactors during the 1990s, leading to a drop in the country's power-generating capacity during the last decade from 213 GW in 1992. Nonetheless, Russia still has sufficient power production potential to supply domestic consumers, as well as [export power](#) to other countries. In 1999, Russia's total electricity generation broke a decade-long downward trend by inching up from 788 billion kilowatt-hours (Bkwh) produced in 1998 to 801 Bkwh, followed by a jump to 836 Bkwh of electricity produced in 2000.

Similarly, the economic recovery after the August 1998 financial crisis resulted in an increase in the country's total electricity consumption, from 715 Bkwh in 1998 to 767 Bkwh in 2000. Increased industrial demand for electricity also has forced power stations to operate at higher capacity, straining power companies' ability to procure fuel supplies at a time when Gazprom is continuing to reduce natural gas supplies to UES. A lack of fuel supplies at power stations has already led to periodic power outages.

Electricity Sector Restructuring

Russia's aging power sector is in serious need of investment and reform. Much of the sector is obsolete by Western standards, and Russia lacks the money to pay for necessary maintenance. UES estimates that between \$20 billion and \$35 billion in investment will be needed over the next 10 years for maintenance and modernization efforts, but the company currently only has about \$1 billion per year to invest. Analysts have estimated that if rates of investment stay at present levels, 32% of the current stock of electricity generating equipment will be out of commission by 2005, prompting a crisis in electricity production that may lead to widespread regional power shortages.

In an effort to entice foreign electricity companies to invest in Russia's power sector, numerous reform plans have been debated over the past decade, to no avail. However, the severe power outages in Russia's Far East during the winter of 2000-2001 made power sector restructuring a high priority, and in May 2001, the Russian government approved a [blueprint for electricity sector restructuring](#). The restructuring plan will break the UES monopoly into separate generation and distribution units, then split up the generation assets further. Russian government officials hope this will pave the way for privatization of independent power-generating companies and thereby attract much needed investment to the sector.

Electricity Exports

UES has begun to focus on electricity exports in order to increase its cash flow to allow it to procure fuel supplies, as well as to invest in maintenance and modernization projects. In October 2000, UES began to supply electricity to Europe as part of an international project to create an "East-West energy bridge." UES is participating in the Baltrel program to create an energy ring with power companies in the Baltic states, and it has also signed contracts to export power to Turkey via [Georgia](#). In addition, in August 2001 the Ukrainian and Russian electricity grids were re-connected, allowing Russia to export electricity via Ukraine to [Moldova](#), as well as to access the [Romanian](#), [Bulgarian](#), and [Balkan](#) markets.

In March 2002, during a joint meeting of the CIS Electric Power Council and the Union of the Electric Industry (Eurelectric) in Warsaw, UES Chairman Anatoly Chubais appealed to European colleagues to

"destroy the iron curtain" between the energy systems of the East and the West. The first steps towards synchronization of energy systems have already been taken, as the Union for the Coordination of Transmission of Electricity (UCTE), of which 20 European countries are members, has entered into discussions with its eastern colleagues over the technological and operational aspects of amalgamating their systems.

Nuclear

With the opening of the 1,000-megawatt (MW) Rostov-1 reactor in March 2001, Russia now operates 30 nuclear reactors at 10 locations, all west of the Ural Mountains. The country has a total installed nuclear capacity of 22 GW, and in 1999 Russia's nuclear plants generated 111 Bkwh of power, accounting for 14% of the country's total electricity generation. However, Russia's nuclear power plants are aging, and the nuclear power industry has been hard hit by Russia's transition to a market economy. Russia already has shut down four reactors that were over 30 years old (the maximum prescribed service life for a reactor), but 15 of the country's 29 operating units are over 20 years old, and by 2005, seven of those reactors will have been in service for 30 years.

With Russia's plans to [export additional natural gas](#) to the West, the country's energy strategy is to increase its use of nuclear power over the next 20 years to meet domestic electricity needs. In order to do so, additional capacity will be needed, but the nuclear industry's lack of money has forced Minatom, the government agency responsible for overseeing the country's nuclear power plants, to focus on extending the service life of existing units instead of building new ones. Safety issues are an ongoing concern, especially with regard to the 16 relatively old reactors of the RBMK design used at Chernobyl. Older RBMK units at Kursk and St. Petersburg are scheduled to be overhauled and equipped with stopgap safety improvements to prolong their lives for another three decades.

Minatom is hoping to complete construction on five nuclear reactors that have been under construction since the 1980s, as well as to build 25 new reactors during the next 20 years. In February 2001, Russia's Deputy Minister of Atomic Energy, Bulat Nigmatulin, said the ministry would finance most of the \$1.5 billion necessary to complete the construction of the five reactors by 2005. Although the Rostov-1 reactor is now operational, both the 1,000-MW Kalinin-3 reactor and the 1,000-MW Kursk-5 reactor are still under construction. In addition, Western nuclear experts have expressed serious doubts that Russia can finance the construction of 25 additional reactors on its own.

To increase its ability to finance domestic nuclear projects, in October 2000 Russia announced plans to market nuclear power plants to countries in Asia and Africa. The first of such plants, a \$1.2-billion project for two 1,000-MW reactors, was sold to [India](#), to be installed near Chennai by 2008. Russia also negotiated a similar deal with [Iran](#) to build the Bushehr nuclear power plant, and in November 2001, Russia delivered the first reactor body to Iran. According to the International Atomic Energy Agency, Russian-designed reactors would not be licensable in Western countries because they do not have all of the mandatory safety features, such as a containment dome.

ENVIRONMENT

After years of neglect under the Soviet Union, the [environment](#) has become a pertinent issue in today's Russia. Soviet policies that encouraged rapid industrialization and development left a legacy of air pollution and nuclear waste with which Russia now is struggling to contend. Although environmental awareness in Russia is rising, the cost of remediating the country's environmental hot spots is high, and the newly created Ministry of Natural Resources has a limited budget. As a result, cleanup has been slow, and environmental protection has not been a top priority for the Russian government.

The economic contraction in the aftermath of the Soviet Union's collapse caused a drop in industrial production, resulting in less energy consumption and a drop in Russia's carbon emissions. However, energy and carbon intensities in Russia remain high, and although per capita carbon emissions have fallen over the past 12 years, Russia will need to pursue more sustainable environmental policies in order to maintain this trend, especially with the rebound in industrial production since the August 1998 financial crisis. Russia

has abundant fossil fuel resources, but the country will need to pursue more renewable energy options and cleaner environmental technologies in order to preserve its natural wonders and protect its environment for future generations.

COUNTRY OVERVIEW

President: Vladimir Vladimirovich Putin (acting president since December 31, 1999; president since May 7, 2000)

Prime Minister: Mikhail Mikhaylovich Kasyanov (since May 7, 2000)

Independence: August 24, 1991 (from Soviet Union). National holiday: Independence Day, June 12, 1990

Population (7/01E): 145.5 million

Location: Eurasia

Size: 6,592,850 sq. mi., slightly more than 1.8 times the size of the United States

Major Cities: Moscow, St. Petersburg, Yekaterinburg, Irkutsk, Murmansk, Yakutsk, Vladivostok

Languages: Russian, others

Ethnic Groups: Russian 81.5%, Tatar 3.8%, Ukrainian 3%, Chuvash 1.2%, Bashkir 0.9%, Belorussian 0.8%, Moldovan 0.7%, other 8.1%

Religions: Russian Orthodox, Muslim, other

ECONOMIC OVERVIEW

Minister of Economic Development and Trade: German Oskarovich Gref

Minister of Finance: Aleksey Leonidovich Kudrin

Currency: Ruble

Market Exchange Rate (4/25/02): \$1 = 31.19 rubles

Nominal Gross Domestic Product (GDP) (2001E): \$301.5 billion; **(2002E):** \$327 billion

Real GDP Growth Rate (2001E): 5.1%; **(2002E):** 3.2%

Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 18.5%; **(2002E):** 12.8%

Official Unemployment Rate (2001E): 8.8%; **(2002E):** 8.6%

Current Account Balance (2001E): \$34.3 billion; **(2002E):** \$27.1 billion

Major Trading Partners (1999): Germany, Ukraine, U.S., Belarus, Italy, Netherlands, Kazakhstan

Merchandise Exports (2001E): \$102.7 billion; **(2002E):** \$103.7 billion

Merchandise Imports (2001E): \$53.1 billion; **(2002E):** \$60.0 billion

Merchandise Trade Balance (2001E): \$49.6 billion; **(2002E):** \$43.7 billion

Major Exports: Petroleum and petroleum products, natural gas, wood and wood products, metals, chemicals, and a wide variety of civilian and military manufactures

Major Imports: Machinery and equipment, consumer goods, medicines, meat, grain, sugar, semifinished metal products

External Debt (2001E): \$154 billion

ENERGY OVERVIEW

Deputy Prime Minister (for Energy Issues): Viktor Borisovich Khristenko

Minister of Energy: Igor Khanukovich Yusufov

Minster of Atomic Energy: Aleksandr Yuryevich Rumyantsev

Proven Oil Reserves (1/1/02E): 48.6 billion barrels

Oil Production (2001E): 7.29 million bbl/d (of which 7.05 million bbl/d was crude); **(2002E):** 7.43 million bbl/d

Oil Consumption (2001E): 2.38 million bbl/d; **(2002E):** 2.42 million bbl/d

Net Oil Exports (2001E): 4.91 million bbl/d; **(2002E):** 5.01 million bbl/d

Major Oil Customers: Europe, Commonwealth of Independent States

Crude Refining Capacity (1/1/02E): 6.6 million bbl/d

Proven Natural Gas Reserves (1/1/02E): 1,700 trillion cubic feet (Tcf)

Natural Gas Production (2001E): 20.5 Tcf

Natural Gas Consumption (2001E): 13.8 Tcf

Net Natural Gas Exports (2001E): 6.7 Tcf

Coal Reserves (1/1/01E): 173 billion short tons

Coal Production (2000E): 281 million short tons (Mmst)

Coal Consumption (2000E): 298 Mmst

Electric Installed Capacity (2000E): 203 gigawatts (68% thermal, 21.5% hydro, 10.5% nuclear)

Electricity Generation (2000E): 836 billion kilowatt-hours (Bkwh)

Electricity Consumption (2000E): 767 Bkwh

Net Electricity Exports (2000E): 69 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Natural Resources: Vitaliy Grigoryevich Artyukhov

Total Energy Consumption (1999E): 26.0 quadrillion Btu* (6.8% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 400.1 million metric tons of carbon (6.5% of world carbon emissions)

Per Capita Energy Consumption (1999E): 176.7 million Btu (vs. U.S. value of 355.9 million Btu)

Per Capita Carbon Emissions (1999E): 2.7 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)

Energy Intensity (1999E): 72,133 Btu/\$1990 (vs U.S. value of 12,638 Btu/\$1990)**

Carbon Intensity (1999E): 1.1 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.20 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1997E): Industrial (64.3%), Residential (17.9%), Transportation (17.1%), Commercial (0.7%)

Sectoral Share of Carbon Emissions (1997E): Industrial (64.8%), Transportation (17.8%), Residential (17.4%)

Fuel Share of Energy Consumption (1999E): Natural Gas (54.3%), Oil (19.3%), Coal (16.0%)

Fuel Share of Carbon Emissions (1998E): Natural Gas (50.8%), Coal (26.2%), Oil (22.9%)

Renewable Energy Consumption (1997E): 2,482 trillion Btu* (1% increase from 1996)

Number of People per Motor Vehicle (1997): 6.5 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 28th, 1994). Under the negotiated Kyoto Protocol (signed on March 11th, 1999, but not yet ratified), Russia has agreed to stabilize greenhouse gases at 1990 levels by the 2008-2012 commitment period.

Major Environmental Issues: air pollution from heavy industry, emissions of coal-fired electric plants, and transportation in major cities; industrial, municipal, and agricultural pollution of inland waterways and sea coasts; deforestation; soil erosion; soil contamination from improper application of agricultural chemicals; scattered areas of sometimes intense radioactive contamination; ground water contamination from toxic waste.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Wetlands and Whaling. **Has signed, but not ratified:** Climate Change, Air Pollution-Sulphur 94.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999

ENERGY INDUSTRY

Organization: Russia's energy sector is overseen by the Ministry of Energy, except for nuclear power, which is administered by the Ministry of Atomic Energy (Minatom).

Russia's Oil Sector is dominated by large joint-stock companies, although smaller independent producers also produce oil. The major vertically integrated companies include Lukoil, Yukos, Surgutneftegaz, Tyumen Oil (TNK), Tatneft, Sibneft, Slavneft, and Rosneft. Transneft has a monopoly over crude oil

transport, while Transnefteprodukt transports petroleum products.

Russia's Natural Gas Sector is dominated by the joint-stock company Gazprom, which is 38% owned by the Russian government. Gazprom produces over 90% of the country's natural gas and also controls Russia's pipeline network. Itera has gained a foothold in the natural gas sector as Russia's second-largest natural gas exporter.

Russia's Coal Sector, formerly operated by RosUgol, a government-owned holding company that was organized along regional lines, has been restructured, with many unprofitable mines closed down, RosUgol eliminated, and the remaining efficient mines privatized. Kuzbassrazrezugol and Krasnoyarskugol were Russia's biggest coal producers in 2001.

Russia's Electricity Sector is operated by the joint-stock company Unified Energy Systems (UES), which is majority state-owned. UES controls approximately 70% of the country's distribution system, 21 thermal power plants, 8 nuclear power plants, and oversees the country's 72 regional electricity companies, known as *energós*.

Major Producing Oil Fields: Samotlor, Romashkino, Mamontov, Fedorov, Lyantor, Arlan, Krasnolenin, Vatyegan, Sutormin

Major Oil Terminals: Novorossiisk (Black Sea), Tuapse (Black Sea), Primorsk (Baltic Sea); Russia also uses ports at Ventspils (Latvia), Odesa (Ukraine), Klaipeda (Lithuania), and Butinge (Lithuania)

Major Oil Export Pipelines outside the Commonwealth of Independent States: Friendship (Druzhba) (1.2 million bbl/d nominal capacity)

Major Oil Refineries (1/1/02E) (Capacity in bbl/d): Omsk (566,000), Angarsk (441,000), Nizhniy Novgorod (438,000), Grozny (390,000), Kirishi (388,000), Novo-Ufa (380,000), Ryazan (361,000), Novo-Kuibishev (309,000), Yaroslavl (290,000), Perm (279,000), Ufaneftekhim (251,000), Salavatnefteorgsintez (247,000), Moscow (243,000), Ufa (235,000), Syzran (211,000), Volgograd (200,000), Saratov (177,000), Orsk (159,000), Samara-Kuibishev (154,000), Achinsk (147,000), Ukhta (127,000), Nizhnekamsk (120,000), Komsomolsk (108,000)

Major Foreign Oil Company Involvement: Agip, BP, British Gas, ChevronTexaco, Statoil, Conoco, ExxonMobil, Neste Oy, Norsk Hydro, Marathon, McDermott, Mitsubishi, Mitsui, Royal Dutch/Shell, and TotalFina Elf.

Major Producing Natural Gas Fields: Urengoy, Yamburg, Medvezh, Orenburg, Severo Urengoy, Vyngapurov

Major Natural Gas Export Pipelines outside the Commonwealth of Independent States (Capacity): Brotherhood (*Bratrstvo*), Progress, and Union (*Soyuz*) (to Europe, via Ukraine) (1 Tcf each); Northern Lights (0.8 Tcf) (to Europe, via Belarus and Ukraine), Volga/Urals-Vyborg (to Finland) (0.1 Tcf); Yamal (to Europe, via Belarus) (1.0 Tcf); Blue Stream (0.56 Tcf) (to Turkey, under construction)

Major Coal Producing Basins: Chelyabinsk, Kansk-Achinsk, Kuznetsk, Lena, Moscow, Pechora, Raychikhinsk, South Yakutia, Taymyr, Zyryanka

Sources for this report include: Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring International Reports, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, Current Digest of the Post-Soviet Press, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, Energy Day, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Gas Connections, Hart's European Fuel News, Interfax News Agency, The International Herald

Tribune, International Petroleum Finance, ITAR-TASS News Agency, Mining & Metals Report, The Moscow Times, Oil and Gas Journal, Petroleum Economist, Petroleum Report, Platt's International Coal Report, Platt's Oilgram News, Polish News Bulletin, PR Newswire, Project Finance, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, Warsaw Business Journal, World Gas Intelligence, and World Markets Online.

Links

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Brief

December 2001

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Germany

Germany is one of the world's largest energy consumers. Because it has limited indigenous energy resources (except for coal), Germany imports most of its energy. Although the country is a major coal producer, it is a net coal importer.

The information contained in this report is the best available as of December 2001 and is subject to change.



GENERAL BACKGROUND

Germany is one of the largest economies in the world, a founding member of the European Union (EU), a North Atlantic Treaty Alliance (NATO) member, and a member of the Group of Seven (G-7) industrialized nations. It joined the common European currency, the euro, on January 1, 1999, and Frankfurt is the seat of the European Central Bank. The German mark will disappear in the first few

months of 2002 as people trade in their marks for the new euro coins and currency.

Germany experienced slower economic growth during 2001 as compared to 2000, and may be on the verge of a slight contraction, according to a report published in October 2001 by Germany's top six economic research institutes. The events of September 11 had a negative effect on the entire world economy, and recent German government estimates are that growth in 2001 may be just 0.75%. In September, business confidence in Germany fell to its lowest level since 1993. Export-led growth has been diminished as the global economy, and that of the United States in particular, loses momentum. Unemployment, a major issue in German politics in recent years, has decreased slightly since its high point in 1998. However, the current economic slowdown indicates that unemployment likely will not fall any further in the next 12 months.

Energy in Germany

Germany has relatively insignificant domestic energy sources and is heavily import-reliant to meet its energy needs. Coal accounted for 47% of domestic energy production in 1999, nuclear power 30%, natural gas 14%, renewable sources (including hydro) 6%, and oil 2%. However, oil accounted for 41% of consumption.

Energy policy in Germany is influenced heavily by EU regulations. The EU requires privatization and competition in member countries' energy markets, and Germany has been a leader in developing competitive energy markets.

Following reunification of the country in 1990, the major task of German energy policy was to merge successfully the radically different energy sectors of the East and West. West Germany had a diversified and mainly privately-owned system of energy supply with a high standard of energy efficiency and a commitment to environmental protection. In contrast, East Germany's energy sector was highly centralized, predominantly state-owned, and mainly dependent upon relatively "dirty" lignite (brown coal) as its primary fuel. To date, a great deal of progress has been made in conforming the former East Germany's energy sector to the standards of the West in the areas of privatization and environmental regulation.

OIL

Germany consumed about 2.8 million barrels per day (bbl/d) of oil in 2000, nearly all of which it imported, making Germany the third-largest oil importer in the world. German oil imports in 2000 came primarily from Russia (29%), Norway (18%), United Kingdom (13%), and the Libya (11%). German imports from Russia have remained unchanged in recent years. However, OPEC's share of German imports has decreased, while the share of North Sea oil from Norway and the United Kingdom has increased. For the first six months of 2001, preliminary estimates show Russian crude oil maintaining the same level as 2000, but imports from OPEC declining from 26% to 22% of total imports into Germany.

Germany produced around 64,000 bbl/d of crude oil in 2000, of which 16,000 bbl/d came from the German North Sea. Higher world oil prices in 2000 spurred a small increase in domestic crude oil production. Veba Oel is Germany's largest upstream company, with interests in 13 countries, including Germany, and production of about 160,000 barrels of oil equivalent per day.

Germany's oil consumption was essentially unchanged in 2000 as compared to 1999. With the aid of hefty federal taxes on gasoline consumption, Germany had decreased its oil consumption in recent years, with lower consumption in 1999 than in any year since unification. For instance, Germans pay about four times more for motor gasoline than Americans, despite having the most competitive retail gasoline market in Europe. German refinery throughput increased 1% in 2000, and refinery capacity utilization was at 95%.

The German downstream sector is in the process of completing two large mergers. In April 2001, Royal Dutch Shell and one of Germany's largest energy companies, RWE, agreed to form a new 50:50 venture called Shell & Dea Oil. The new company is managed by Shell, and in 2004 Shell's share will increase to 51%, and Shell will have the option to buy the remaining 49%, which it is expected to do. The new company will have about a 23% market share for gasoline stations and is poised to become Germany's largest refinery operation with capacity of about 460,000 bbl/d. However, in July 2001, BP acquired a majority stake (51%) in Veba Oel from E. On. Veba Oel, in addition to upstream assets valued at \$2 billion, owns the Aral network of gasoline stations, which has a 25% market share, and refinery capacity of about 300,000 bbl/d. In return, BP gave E. On a majority stake (51%) of its 25.5% holding (through holding company Gelsenberg) of German gas distributor Ruhrgas, \$1.63 billion in cash, and agreed to assume debts of \$950 million. BP and E. On have the option to acquire the remaining stakes in Veba and Gelsenberg, respectively. When the second deal was announced, both deals came under increasing scrutiny by EU and German officials. The European Commission has endorsed a preliminary finding of risk of "collective dominance" by the German cartel office, to which it has delegated

responsibility for assessing the downstream market effects. The European Commission is retaining responsibility for a 4-month investigation launched in late August on the effect of the mergers on the petrochemical industry.

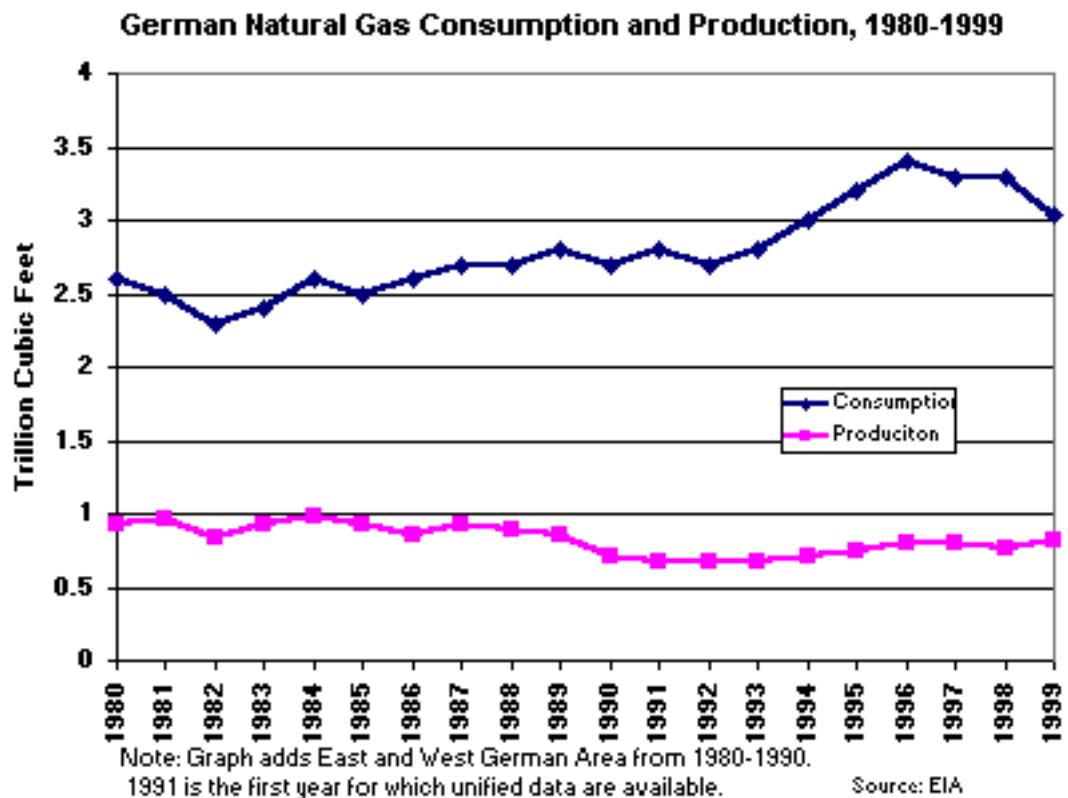
NATURAL GAS

Germany is the European Union's second largest consumer of natural gas, after the United Kingdom. Germany produces insufficient natural gas to satisfy domestic consumption and satisfies most of its demand through imports. In 1999, the country produced 0.82 trillion cubic feet (Tcf) of natural gas from proven reserves of 11.5 Tcf, while consuming 3.0 Tcf (a decline of 300 billion cubic feet (Bcf) from 1998). This decline appears to have continued into 2000, as natural gas import prices rose steadily, and German gas suppliers instead drew down stored natural gas that had been purchased at cheaper prices. Although overall natural gas consumption fell 1.2% from 1998 to 1999, power sector usage fell a much larger 7%. E. On, Germany's second-largest largest utility, has asserted that power sector usage of natural gas fell even further in 2000, as it became cheaper to import electricity and maximize output from coal-fired facilities. In 1999, residential and other non-commercial consumers accounted for 53% of total demand, industry for 38%, and power stations, 9%. In 2000, Russia provided 37% of Germany's consumption, the Netherlands 26%, Norway 14%, and Denmark 1%. Natural gas consumption accounted for about 21% of total energy consumption in Germany in 1999. This share is expected to rise over the decade, especially for electric power generation as nuclear power is phased out. In September 2000, the *Deutsches Nordseekonsortium* (German North Sea Consortium), which is made up of Wintershall (40%, operator), BEB Erdgas und Erdoel (40%), BASF (12%), and RWE-DEA (7%), began production. The first offshore natural gas project in the German North Sea, the field is located about 190 miles from the German coast. New pipelines will transmit the anticipated 3.3 million cubic meters (116.5 million cubic feet) per day of production. The field is expected to produce for 16 years.

Ruhrgas remains Germany's dominant natural gas transmission company, accounting for about 60% of all natural gas sales. Years of Ruhrgas's monopolistic control of Germany's natural gas market have left Germany with a highly developed

gas infrastructure. E. On, which already owns 42% of Ruhrgas through the deal with BP mentioned above and through E. On's partial ownership of another holding company of Ruhrgas, Bergemann, announced in November 2001, that it intends to buy the remaining shares of Bergemann, lifting E. On's share of Ruhrgas to 60%. E. On also sells to 35% of Germany's natural gas customers through its stakes in smaller companies Contigas and Thuga. E. On's ownership of Ruhrgas is already being investigated by the German cartel office, but perhaps more problematic is the fact that the outstanding shares of Bergemann are controlled by German coal group RAG, which is part-owned by E. On's rival company RWE. RWE may attempt to block the deal unless E. On gives RWE a larger share of RAG, of which E. On also is part-owner. Ruhrgas itself announced in October 2001, that it plans to bid for the gas division of Hungary's state-owned oil and gas group MOL.

Competition in Germany's natural gas market has developed slowly. Ruhrgas's main competitor, Wingas, was formed in 1993 by a joint venture between BASF's Wintershall (65%) and Russia's Gazprom (35%). Now, with its own domestic pipelines and links to export supply lines, Wingas has gained market share (19%), while Ruhrgas's share has decreased. Eni of Italy



and Energie Baden-Württemberg (EnBW) may also bring more competition to the German gas market through their partnered acquisition of a majority stake in Gasversorgung Süddeutschland (GVS). GVS currently gets 85% of its supply from Ruhrgas and 15% from Wingas, but the new Eni-EnBW holding company would likely have Eni supplying Libyan and Algerian gas to GVS. This acquisition of GVS is not yet certain, as there are remaining political and business obstacles.

Although Germany has one of the most liberalized energy sectors in the EU, full liberalization of the German natural gas market has not emerged as expected. According to EU law, member countries' natural gas transmission systems had to be open to third party access as of August 2000. While a German law was in place confirming a legal right for third party access, in practicality, new entrants have had difficulty gaining access. The creation of an independent regulator by the government is seen as key to making the market more accessible.

Pipelines

Germany is both a major destination point and major transit center for Europe's natural gas pipelines. Germany has five major pipelines on land, three from the North Sea to its coast, and several in the construction and planning stages. Pipelines from the [Czech Republic](#) transport Russian natural gas. The existing pipelines include: 1) The MEGAL pipeline from the Czech Republic to France through Germany, with annual capacity of 777 billion cubic feet (Bcf), 2) the TENP pipeline from the Netherlands to Germany and onward to Switzerland and Italy, with an annual capacity of 247 Bcf, 3) the STEGAL pipeline from the Czech Republic to Germany, with an annual capacity of 283 Bcf, 4) the NETRA pipeline from Etzel/Wilhelmshaven to Steinitz/Bernau, with an annual capacity of 706 Bcf and 5) the MIDAL pipeline from the port of Emden to Ludwigshafen with an annual capacity of 459 Bcf. The pipelines that bring Norwegian natural gas ashore are Norpipe, which lands at Emden, and Europipe I & II, which land at Dornum. From the Dornum receiving station, the natural gas is linked to either the NETRA pipeline or the metering station at Emden, where the MIDAL pipeline begins.

The TENP pipeline can also bring in UK gas by way of the Netherlands. Wingas, which already owns the MIDAL and STEGAL pipelines, is planning to construct a pipeline with a capacity of 353-424 Bcf per year from Heppenheim in Southwest Germany to the states of Baden-Wurttemberg and Bavaria in Southeastern Germany. Ruhrgas is the largest shareholder in the MEGAL, TENP, and NETRA pipelines, though it has a majority stake only in the TENP pipeline. Ruhrgas, Fortum of Finland, and Wingas agreed in April 2001, to jointly develop plans to build a natural gas pipeline from Russia to Germany via the Baltic Sea.

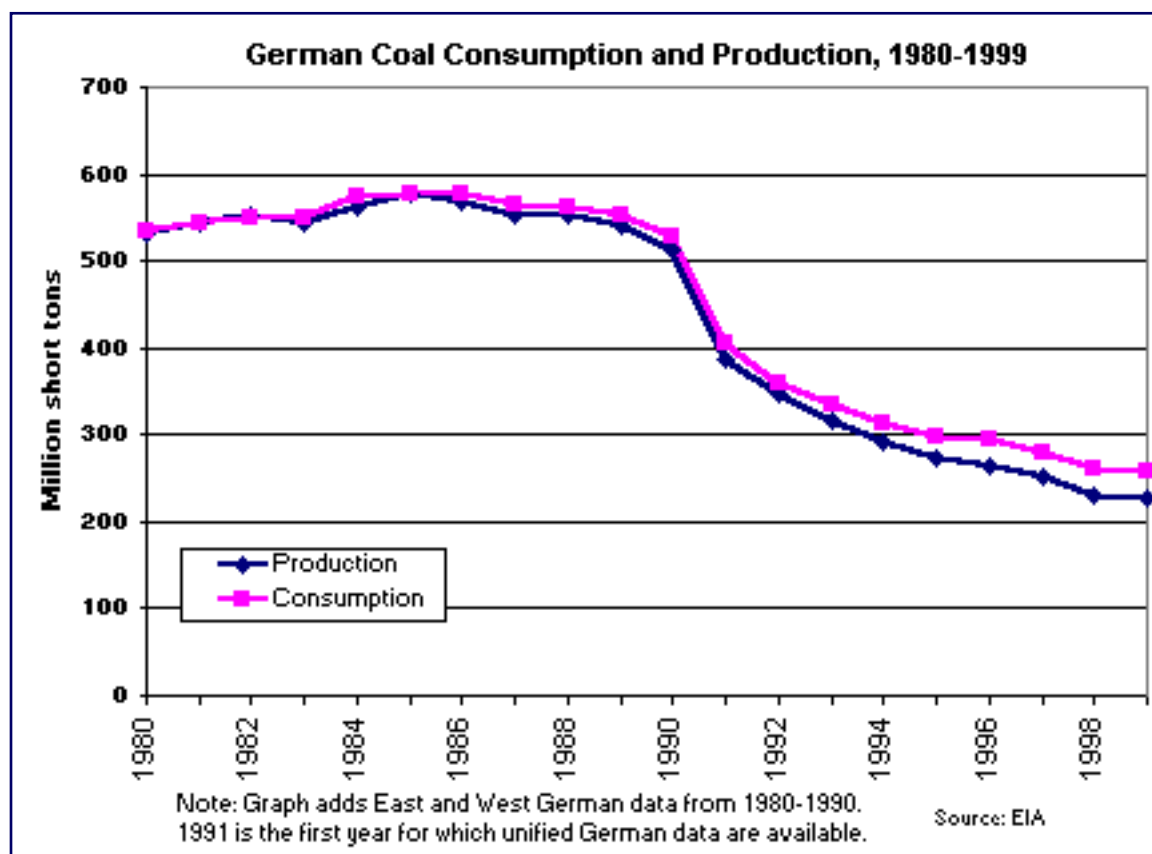
The large volumes of natural gas entering Germany, particularly on the Northwest coast around Emden, have given rise to efforts to establish Europe's third major natural gas hub at Bunde near the Dutch border. This is the point where the pipeline system of Gasunie of the Netherlands links up to the German networks of Ruhrgas, Wingas, and BEB. Spot trading by about a dozen companies is already occurring in this area, although volumes are small so far. Its location is in close proximity to where very large volumes of natural gas come into Germany, combined with European Commission proposals to unbundle integrated gas companies in the EU make the formation of an important hub likely. A conference was held in May 2001, on the subject of fostering natural gas trade at Bunde, which was attended by 40 companies, including all of Germany's major players.

COAL

Coal is Germany's only major domestic fuel source, accounting for 23% of energy consumption in 1999. Over 75% of German coal production is used for electricity generation, and coal accounts for over 50% of electricity generation. Hard coal production is expensive in Germany relative to other major coal producers, because German coal is located deep underground. Hard coal production has remained a viable industry only through heavy subsidization, which is being reduced, but not ended. Lignite, or "brown coal," production, however, is inexpensive in Germany. Germany is the world's largest lignite producer, with about one-fifth of global output, though output of lignite, most of which comes from the former East Germany, has

fallen by about 40% since reunification.

In March 1997, the German government, the mining industry, and the unions reached an agreement on the future structure of subsidies to the German hard coal industry. Subsidies to the industry are to be reduced from over DM10 billion (\$5.5 billion) in 1997 to DM5.5 billion (\$3 billion) by 2005. The agreement called for closure of 7-8 of Germany's 19 hard coal mines, resulting in an estimated decline in employment from 76,000 miners in 1997 to 36,000 by 2005. As of December 2000, 12 hard coal mines in Germany were still in operation.



In October 2000, the EC Energy Commissioner Loyola de Palacio demanded that Germany rework this subsidization scheme or risk legal action. The EC claimed that too much of

that amount will be spent on subsidizing continuing production, and not enough devoted to ending production. This dispute was resolved in November 2000, by allocating part of the annual coal subsidy volume to a different category of coal aid, namely, to "mines that will definitely be closed at some point." In July 2001, the EC set out new proposals to maintain a significant coal industry in the EU (for reasons of energy security) that will allow Germany to provide billions of euros in aid over the coming years. Specifically, under the proposals German aid would fall to 2.8 billion euros in

2005, which does not differ greatly from the domestic agreements of 1997. The most recent aid package of 2 billion euros from January 1, 2002 to July 23, 2002, was approved by the EC in October 2001.

Decreasing coal production has brought about changes in the industry's organization. Two major producers, Saarbergen and Ruhrkohle Bergbau, merged to form Deutsche Steinkohle (DSK), which accounts for 96% of German production. DSK is part of the larger RAG group, which intends to diversify its holdings and focus less on coal as the sector shrinks in coming years. RAG is itself owned by E. On, RWE, Thyssen, and two holding companies.

As domestic production declines, Germany is emerging as a significant coal importer. Imports of hard coal, coke, and briquettes increased by 8.5% in 1999-2000, and are estimated to have increased even more in the first few months of 2001. The largest supplier is Poland, followed by Australia, South Africa, and Colombia, among others. The Federation of German Coal Importers expects German hard coal imports to exceed domestic production in 2001 or 2002, and to double over the next 20 years, as nuclear power is phased out and domestic production declines.

Germany's lignite production is separate from hard coal production. Lignite was the most important fuel in the former East Germany, and East Germany had been producing about three times as much lignite as West Germany in the years prior to reunification. Since reunification, wasteful and environmentally damaging mining methods practiced during Communist rule have been reformed. The industry also has been privatized. Lignite production in Germany fell from 308 million short tons (Mmst) in 1991 to 178 Mmst in 1999. Rheinbraun, a subsidiary of RWE, is responsible for most of German lignite production, and most of its lignite is used to produce electricity in RWE's power generation plants.

RAG has founded a new company called Minegas to exploit the mine gas from operational and closed mines for electricity generation. Minegas has

already formed a consortium with several other German companies and a partnership with RWE. The target is to generate 450 gigawatts (GW) per year from mine gas.

ELECTRICITY

Germany has Europe's largest electricity market. In 1999, Germany generated 531.4 billion kilowatt hours (bkwh) of electricity, two-thirds of which came from fossil fuels (mostly coal), with the other other third coming mostly from nuclear power along with small amounts of hydropower and other renewable sources. Although Germany produced more electricity than it consumed, the country was a small net electricity importer, because of transmission losses, proximity to foreign sources of generation, etc. Germany has about 2,800 power plants and considerable excess generation capacity. The International Energy Agency predicts slow power demand growth in coming years. Major electricity companies recently have announced intentions to decrease generation capacity and output, and new power plant construction is at record lows. There is a new gas-fired, combined-cycle power plant with a capacity of 400 megawatts (MW) that was inaugurated by Kraftwerke Mainz-Wiesbaden near Frankfurt in March 2001.

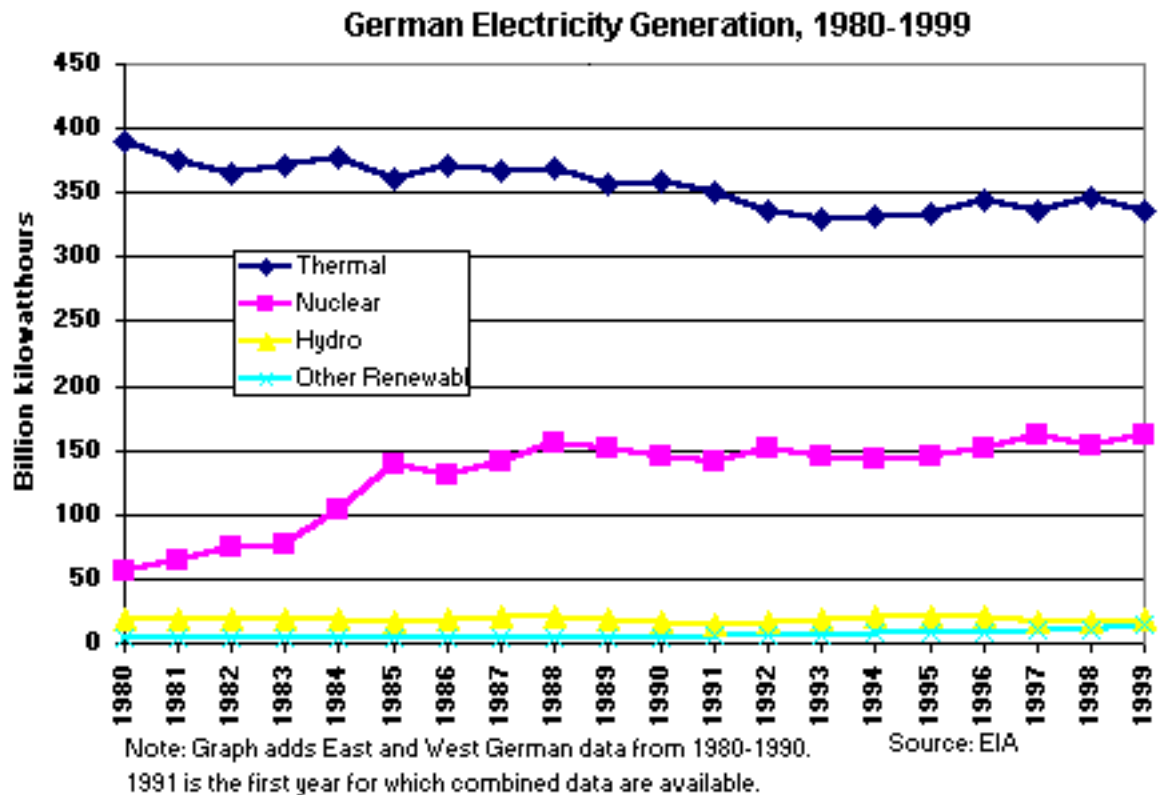
The industry is undergoing changes in fuel mix and in organization. Efforts continue to phase out nuclear power and to increase reliance on renewable energy sources, most notably wind power, and on natural gas. RWE is developing fuel cell technology for electricity generation that it hopes to have functioning by 2004.

Sector Organization

In step with EU legislation, the German power market has become one of the most competitive in Europe. Liberalization of the electricity

sector has progressed via agreements among major participants in the market and is not overseen by any regulatory body (like the natural gas sector). Some German market groups and the European Commission have called for an energy regulator, but so far the government has only created a six-member division of the cartel office dedicated to handling complaints about the electricity sector. About one million of Germany's 40 million electricity customers have switched to competitive suppliers. About 1,000 terrawatthours were traded in 2000. Liberalization has resulted in lower consumer prices and decreased employment in the industry, and is now sparking a wave of consolidation.

Six major electricity generation companies have dominated the German market in recent years, accounting for about 80% of generation. Major mergers are re-shaping the industry, potentially reducing the number of major players from six to three. RWE, the largest electricity company in Germany, has acquired VEW, the country's sixth-largest electricity producer. E. On, Germany's second largest electricity company, is set to acquire UK energy provider Powergen in a \$16.9 billion deal. Powergen owns U.S. utility LG&E Energy, so when the deal is complete E. On will be world's second-largest



energy provider after Electricite de France, and will have a significant presence in the U.S. E. On and Verbund of Austria agreed in July 2001, to combine their hydroelectric generation assets into one company, European Hydro Power, which would own about 200 plants with a total of 9,600 MW. In June 2001, the formation of Germany's third-largest energy company was announced by Hamburgische Electricitaets-Werke (HEW). A new holding company is being formed that is expected to be complete by 2003 that will control HEW, Berlin utility BEWAG, eastern German generation group VEAG, and lignite-mining company LAUBAG. Through a series of acquisitions, the company will be owned by HEW, Vattenfall of Sweden, and Mirant of the United States

The utility market is highly fragmented in Germany, with about 70 regional utilities and 900 municipal utilities, which together account for about 20% of power generation and about two-thirds of distribution. The Deutsche Verbundgesellschaft (DVG), which groups the main supra-regional utilities and deals with national and international interconnections issues, and the Vereinigung Deutscher Elektrizitaetswerke (VDEW), which deals with economic and other technical issues. The regional utilities are grouped in the Arbeitsgemeinschaft Regionaler Energie Versorgungsunternehmen (ARE), the Stadtwerke are grouped in the Verband Kommunalen Unternehmen (VKU), and industrial producers are in the Vereinigung Industrielle Kraftwirtschaft (VIK).

Despite the overall success of liberalization, third party access to transmission networks remains a contentious issue. The *Verbandervereinbarung* that determines access to the grid system was first agreed in May 1998 and left transmission control mostly in the hands of the six major companies. After much criticism, a new *Verbandervereinbarung* was agreed in December 1999. This agreement has encountered even more criticism than its predecessor, and EU competition authorities have expressed concern. The most criticized aspects of the agreement include a lack of price transparency and the division of the German market into two distinct trading zones.

The German government has been critical of EU member governments that have not taken steps to open their power sectors in accordance with EU law. Currently, German electricity companies do have the right to block electricity imports from countries that deny access to foreign companies. The Minister of Economics, Werner Mueller, has proposed that German energy law be amended to extend the right to invoke bans, known to the government as "reciprocity clauses." However, the European Association of Transmission System Operators (ETSO) is urging Germany to adopt its policy of socializing network access costs such that costs of flows of electricity between grids is passed on to all users to promote exchange. Germany wants to pass export costs on to just exporters. If Germany does not agree to ETSO's policy, there is the possibility of Germany being excluded from the system. A decision will have to be taken by ETSO by the end of the year.

Nuclear Power

Currently, Germany ranks fourth worldwide in installed nuclear capacity, behind the United States, France, and Japan. Germany's 19 nuclear plants comprise about 21% of Germany's electric generation capacity, and about 30% of actual generation. E. On, RWE, HEW, and EnBW own nuclear generation capacity, with E. On holding stakes in 11 of Germany's 19 nuclear power reactors.

Nuclear power has become controversial since the September 1998 elections. The Greens, the environmental party that is part of the ruling alliance, are staunchly opposed to the continued use of nuclear power. Chancellor Schroeder had decided to close all 19 nuclear reactors in 2005, but he has since amended his position. The government formally signed an agreement with utility companies in June 2001 to gradually phase out nuclear power. Each nuclear plant is allowed to produce a finite amount of electricity, and plants will have a life span of 32 years. The deal could see the total elimination of nuclear power by 2021, as the newest nuclear plant opened in 1989. Generation volumes are transferable; if an older plant closes before reaching its production ceiling, its remaining allowable production can be transferred to a new plant.

There are few economically viable alternatives to quickly replace such a significant portion of the fuel mix, especially in the wake of power-sector liberalization. As European markets become more liberalized and more price-sensitive, replacing the mostly amortized plants will prove difficult. Over the longer term, however, high costs (high fixed costs, long depreciation periods and long annual operating times) associated with nuclear generation could work to decrease nuclear generation's role in Germany's power sector. Nuclear installations currently are initiating programs to reduce production costs and waste disposal costs in order to become more price-competitive. In October 2000, E. On and RWE announced intentions to close a number of their less competitive (in terms of price) nuclear power plants. Some executives in Germany's nuclear industry have claimed that the June 2001 agreement is not irreversible, and that an electricity shortage and a change in the political climate might lead to a renewal of nuclear energy.

ENVIRONMENT

Germany has a strong commitment to protecting its environment. It has actively promoted the use of renewable energy, both under the Kohl government with the Electricity Feed Law, and now under Schroeder's government with eco-taxes. In Germany's eco-tax regime, energy tax (energy taxes are slated to increase 10% over the next three years) revenue is used to fund renewable projects. However, in late October 2001, the Chancellor's chief economic advisor indicated that these ecological taxes may be suspended for a year or two as a way to provide a stimulus to economy.

In 1999, Germany emitted 236.9 million metric tons of carbon from the consumption of fossil fuels. Germany ranks third in total carbon emissions within the G-7, after the United States and Japan. Germany signed the Framework Convention on Climate Change in Rio de Janeiro in June 1992 and ratified it on December 9, 1993. Signers of the agreement pledged to stabilize per capita CO₂ emissions in the year 2000 and beyond at 1990 levels. Under the Kyoto Protocol of December, 1997, Germany would have to

go even further by reducing carbon emissions 8% by 2008-2012. This will be made more achievable given the sharp drop in total German carbon emissions since 1990, due mainly to decreased consumption of energy overall (and in particular lignite) in the former East Germany.

Sources for this report include: CIA World Factbook; Dow Jones; Economist Intelligence Unit ViewsWire; Petroleum Intelligence Weekly; Financial Times; Economist; Petroleum Economist; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

President: Johannes Rau (elected May 1999)

Chancellor: Gerhard Schroeder (elected September 1998)

Independence: January 18, 1871 (reunification of West and East Germany took place on October 3, 1990)

Population (2001E): 83 million

Location/Size: Central Europe, bordering the Baltic Sea and the North Sea, between the Netherlands and Poland, south of Denmark/137,821 square miles (slightly smaller than Montana)

Major Cities: Berlin (national capital since 10/3/90), Hamburg, Munich, Cologne, Frankfurt, Essen, Dortmund, Stuttgart

Language: German

Ethnic Groups: German 91.5%, Turkish 2.4%, other 6.1% (made up largely of Serbo-Croatian, Italian, Russian, Greek, Polish, Spanish)

Religions: Protestant 38%, Roman Catholic 34%, Muslim 1.7%, unaffiliated or other 26.3%

Defense (8/98): Army, 230,600; Navy, 26,700; Air Force, 76,200 (including conscripts)

ECONOMIC OVERVIEW

Finance Minister: Hans Eichel

Currency: Deutsche Mark (DM)

Exchange Rate (12/02/01): 1 US Dollar = 2.1981 DM

Gross Domestic Product (GDP, nominal, 2000E): \$1.87 trillion (2001E):

\$1.89 trillion

Real GDP Growth Rate (2000E): 3.0% (2001E): 1.1%

Inflation Rate (consumer prices, 2000E): 1.9% (2001E): 2.7%

Unemployment Rate (2000E): 9.6% (2001E): 9.5%

Exports of Goods (2000E): \$549 billion

Imports of Goods (2000E): \$492 billion

Major Trading Partners (2000): France, U.S., U.K., Italy, Netherlands

Major Export Products (2000): Machinery and transport equipment, manufactured goods, chemicals

Major Import Products (2000): Machinery and transport equipment, manufactured goods, other finished goods, fuels

ENERGY OVERVIEW

Minister of Economics: Werner Mueller

Proven Oil Reserves (1/1/01E): 380 million barrels

Oil Production (2000E): 139,000 barrels per day (bbl/d), of which 64,000 bbl/d was crude oil

Oil Consumption (2000E): 2.76 million bbl/d

Net Oil Imports (1999E): 2.7 million bbl/d

Natural Gas Reserves (1/1/01E): 11.5 trillion cubic feet (Tcf)

Natural Gas Production (1999E): 0.82 Tcf

Natural Gas Consumption (1999E): 3.0 Tcf

Coal Reserves (12/31/96E): 73.9 billion short tons

Coal Production (1999E): 226 million short tons (Mmst)

Coal Consumption (1999E): 258 Mmst

Net Coal Imports (1999E): 32 Mmst

Electric Generation Capacity (1/1/99E): 108 gigawatts

Electricity Production (1999E): 531.4 billion kilowatthours

ENVIRONMENTAL OVERVIEW

Minister for Environment: Juergen Trittin

Total Energy Consumption (1999E): 13.9 quadrillion Btu* (3.6% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 229.9 million metric tons of

carbon (3.7% of world total carbon emissions)

Per Capita Energy Consumption (1999E): 170.4 million Btu (vs U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 2.8 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)

Energy Intensity (1999E): 7,280 Btu/ \$1990 (vs U.S. value of 12,638 Btu/ \$1990)**

Carbon Intensity (1999E): 0.12 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (41.9%), Residential (24.2%), Transportation (21.5%), Commercial (12.3%)

Sectoral Share of Carbon Emissions (1998E): Industrial (37.4%), Transportation (25.6%), Residential (24.5%), Commercial (12.5%)

Fuel Share of Energy Consumption (1999E): Oil (41.4%), Coal (23.2%), Natural Gas (21.2%)

Fuel Share of Carbon Emissions (1999E): Oil (45.1%), Coal (36.3%), Natural Gas (18.6%)

Renewable Energy Consumption (1998E): 395 trillion Btu* (5% increase from 1997)

Number of People per Motor Vehicle (1998): 1.9 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 9th, 1993). Under the negotiated Kyoto Protocol (signed on April 29th, 1998, but not yet ratified), Germany, as a member of the European Union, has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.

Major Environmental Issues: Emissions from coal-burning utilities and industries and lead emissions from vehicle exhausts (the result of continued use of leaded fuels) contribute to air pollution; acid rain, resulting from sulfur dioxide emissions, is damaging forests; heavy pollution in the Baltic Sea from raw sewage and industrial effluents from rivers in eastern Germany; hazardous waste disposal.

Major International Environmental Agreements: A party to Conventions

on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands, Whaling . Has signed, but not ratified, Air Pollution-Persistent Organic Pollutants.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

ENERGY INDUSTRIES

Major Energy Companies: *Oil:* Deutsche Shell, Esso, Ruhr Oel; *Natural Gas:* Ruhrgas, Wintershall/Wingas; *Coal:* DSK, RAG; *Electricity:* RWE, Viag, Veba

Major Refineries (crude capacity, bbl/d): Karlsruhe (285,800), Bayernoil (258,000), Schwedt (230,000), Gelsenkirchen (227,000), Leuna (214,000), Wilhelmshaven (225,000), Godorf (170,000), Wesseling (140,000), Esso Ingolstadt (105,000)

LINKS

For more information from EIA on Germany, please see:

[EIA - Country Information on Germany](http://www.eia.doe.gov/emeu/cabs/germany.html)

Links to other U.S. Government sites:

[CIA World Factbook - Germany](#)

[U.S. Department of Energy's Office of Fossil Energy's International section - Germany](#)

[U.S. Department of Energy on German Nuclear Sector](#)

[U.S. State Department's Consular Information Sheet - Germany](#)

[U.S. State Department's Country Commercial Guide - Germany](#)

[U.S. State Department Background Notes on Germany](#)

[U.S. Embassy in Germany](#)

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[Germany's Nuclear Energy Policy Briefing Paper](#)

[European Commission Directorate General XVII \(Energy\)](#)

[International Energy Agency's Germany 1998 Review](#)

[Wingas](#)

[Wintershall](#)

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Regional Indicators: European Union (EU)

The European Union, with increasingly integrated economies and energy sectors, is the world's second-largest energy consumer (behind the United States). EU members include: [Austria](#), [Belgium](#), [Denmark](#), [Finland](#), [France](#), [Germany](#), [Greece](#), [Ireland](#), [Italy](#), [Luxembourg](#), [the Netherlands](#), [Portugal](#), [Spain](#), [Sweden](#), and the [United Kingdom](#).

Note: Information contained in this report is the best available as of October 2002 and is subject to change.



BACKGROUND

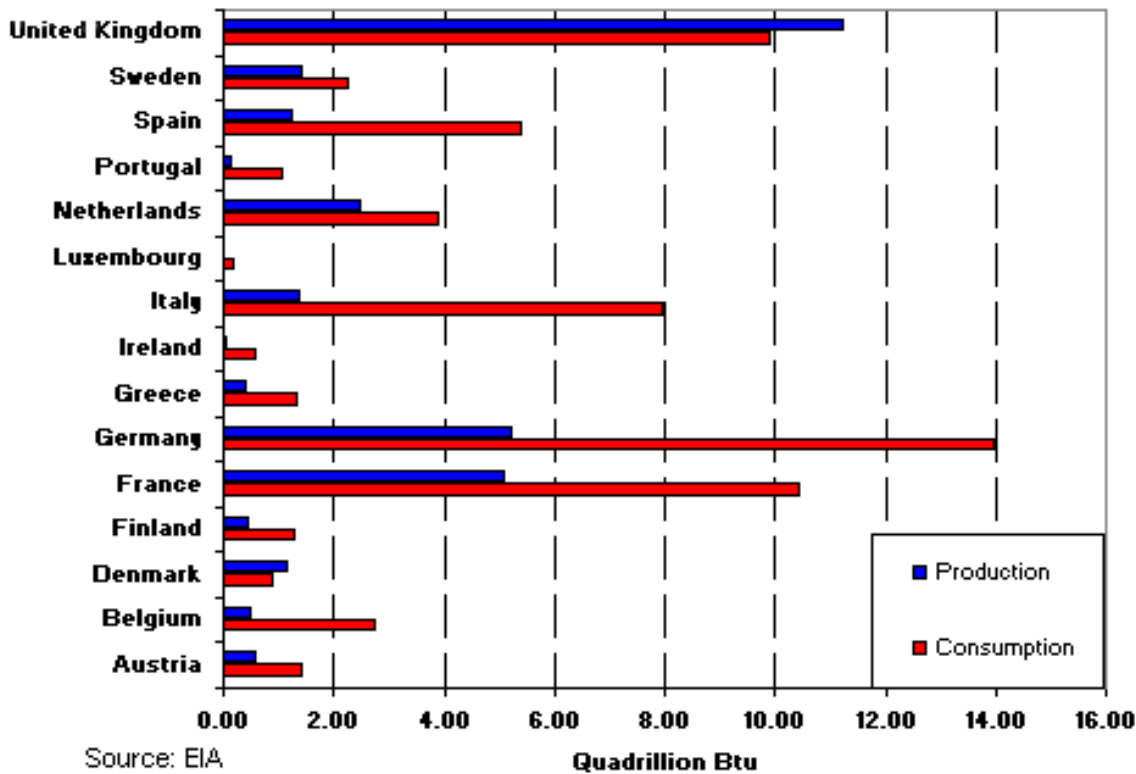
The European Union (EU) was founded as the European Economic Community (EEC) by the Treaty of Rome in 1957 to promote economic and political integration in Europe. The founding of the EEC followed the creation of the European Coal and Steel Community, established after World War II as a means of promoting integration among former enemies. The EEC has expanded from its original six members (Belgium, France, the Federal Republic of Germany, Italy, Luxembourg, and the Netherlands) to include the United Kingdom, Ireland, and Denmark in 1973; Greece in 1981; Spain and Portugal in 1986; and Austria, Finland, and Sweden (former members of the European Free Trade Association) in 1995.

All 15 member states delegate a degree of sovereignty to the EU's network of institutions. National governments are represented in the Council of the European Union, while citizens of the member states are elected to the European Parliament. In 1993, the Maastricht Treaty (which renamed the EEC as the European Union), created European citizenship, strengthened the power of the European Parliament, laid out plans for the Economic and Monetary Union (EMU), as well as committed members to negotiate for expansion of the EU to include Central and Eastern European countries. As part of EMU, 12 EU member countries (Belgium, France, Germany, Greece, Italy, Spain, Portugal, Finland, Austria, the Netherlands, Ireland and Luxembourg) adopted a new common European currency, called the "euro". The Euro currency entered into general circulation in January 2002. Monetary policy is overseen by the European Central Bank, which works in conjunction with the national central banks of the 12 euro zone countries.

In 2001, the Treaty of Nice was signed by member governments. This treaty changed the way the institutions of the EU operate in order to make possible the admission of new member states in the future. At its next scheduled meeting in December 2002, the EU Council of Ministers is expected to nominate Poland, the Czech Republic, Slovakia, Hungary, Estonia, Latvia, Lithuania, Slovenia, Malta, and Cyprus for entry in to the EU in 2004. Many other countries also aspire to EU membership, including Romania and Bulgaria, which are expected to join in 2007.

The combined economies of the EU are slightly smaller than the U.S. economy (\$9.2 trillion purchasing power parity gross domestic product for the EU in 2001 versus \$9.9 trillion for the United States), while the EU population of 376.8 million significantly exceeds the U.S. population of 278 million. The United States has extensive trade relations with the EU. In 2001, 22% of U.S. exports (\$159 billion) went to EU members, and 19% of U.S. imports (\$220 billion) originated in EU countries.

EU Energy Production and Consumption, 2000



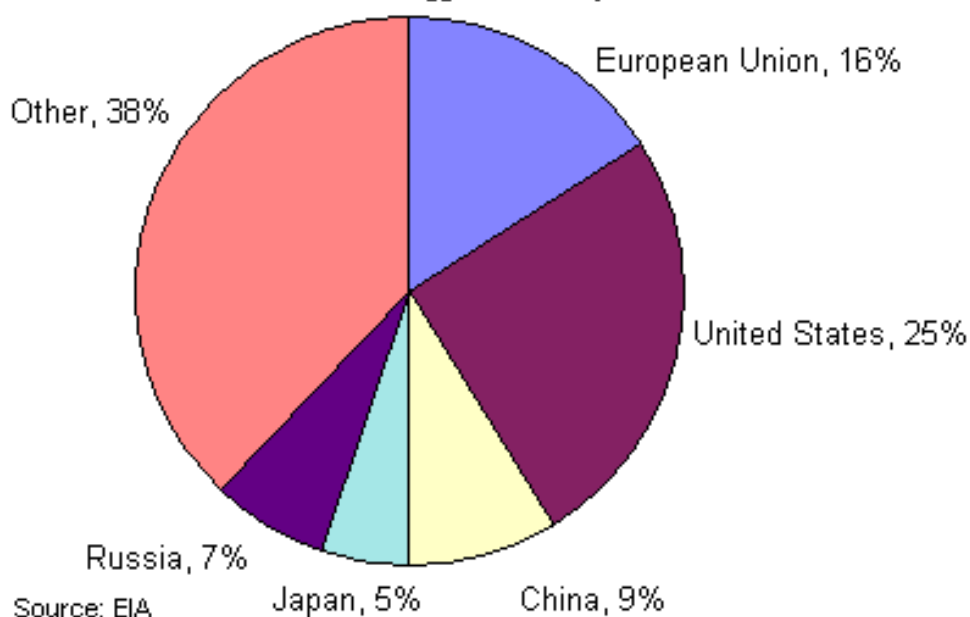
ENERGY

On the whole, the members of the European Union are net energy importers. Import dependency is forecast to grow in the future, as the European Commission estimates that the EU could be forced to import 70% of its total energy, and up to 90% of its oil in the next 20 to 30 years if no new measures are taken.

Germany, Italy, and France are the EU's largest net importers of energy; the United Kingdom is the only significant net exporter (see graph). EU oil is imported primarily from the Persian Gulf region, Norway, Russia, and North Africa. Russia also exports significant amounts of natural gas to the EU countries.

EU members possess only about 0.7% of the world's proven reserves of oil and 2.5% of the world's natural gas reserves (see [Table 3](#)). However, they have 7.3% of proven coal reserves, 16% of the world's capacity for refining crude oil into petroleum products, and 17% of the world's electric generating capacity. In 2000, they produced 4.5% of the world's crude oil, 9% of the world's natural gas, and 7% of the world's coal.

2000 World Energy Consumption



Energy Consumption

In 2000, the 15 EU countries consumed 63.3 quadrillion British thermal units (Btu) of energy, which represents 16% of the world's total energy consumption and is 35.5 quadrillion Btu's less than the United States energy consumption for the year. EU members consumed about 33% of the world's nuclear power, 19% of the world's oil, 16% of the world's natural gas, and 9% of the world's coal in 2000.

Oil is the dominant fuel, (see [Table 2](#)), accounting for 43% of total EU energy consumption in 2000, followed

by natural gas at 23%. Over the past decade, natural gas has been the fastest growing fuel source in the EU, mainly at the expense of coal, whose share has declined sharply. This is in part due to environmental considerations, but also due to increased availability of natural gas supplies because of pipelines from Algeria, Norway, and Russia. By 2010, natural gas is expected to account for 26% of EU energy consumption.

Nuclear power generation has grown only slightly over the past decade. Eight EU member states are currently operating nuclear power plants, and five of these (Sweden, Spain, the Netherlands, Germany, and Belgium) have announced moratoriums. In May 2002, however, the Finnish Parliament approved plans to build a new nuclear reactor, marking the first expansion of nuclear power in the EU in over ten years. Hydroelectric power consumption has grown by almost 20% over the past decade and accounted for approximately 5% of total EU power consumption in 2000. Other "renewables" (geothermal, biomass, solar, and wind) quadrupled between 1991 and 2000, but still constituted only 1% of total EU energy consumption in 2000. Renewable energy and natural gas are expected to be the two fastest growing fuels in the EU over the next 20 years.

Energy Policy and the Internal Market

Although energy policy was not stipulated in the original treaties establishing the modern European Union, the political and economic policies governed by the EU have found a natural confluence in energy policy. Moreover, many of the EU countries share a similar energy profile, and could face significant import dependency problems in the coming years.

In November of 2000, a [European Commission Green Paper on Energy Security](#) outlined the EU's unified energy strategy. The paper identifies four main principles of European energy policy: 1) security of supply, 2) completion of the internal market, 3) environmental responsibility and 4) promoting renewable energy and demand management. To these ends, the European Union has acted over the years to coordinate the member countries' energy policies and the infrastructure that links them.

Community energy policy is developed and implemented by the Energy and Transport Directorate-General, which has its headquarters in Brussels. The Energy and Transport Directorate-General reports to the European Commission, which in turn drafts legislative proposals for the European Parliament. The Parliament then works

with the Council of the European Union, (which is made up of government officials from the member states) to amend, and eventually adopt energy legislation for the entire EU.

Integrating the energy sectors of EU members is a work-in-progress. Incremental steps toward enjoining member countries' energy sectors have been taking place since the early 1990s. Because existing treaties already govern the coal and nuclear sectors, and the oil industry was considered to be sufficiently open, most of the EU's recent energy legislation has focused on electricity and natural gas.

In 1996, after years of deliberations, the EU Directive on Electricity was passed, stipulating the deregulation of the production and transport of electricity in EU member states, and setting a schedule for the opening of member countries' markets to free competition. The Electricity Directive originally called for incremental market liberalization, with 32% of the market to be open to free competition by 2003 (Greece, Belgium and Ireland were granted waivers). In 1998, the E.U. Natural Gas Directive was passed with similar provisions, calling upon the member countries to adapt national law to facilitate market opening, and setting a similar schedule of annual market-liberalization benchmarks (with Greece, Belgium, and Ireland again granted waivers).

Energy market liberalization has gained unprecedented support recently as the European Council in March 2000 called upon the European Commission to expedite the opening of energy markets. In March 2001, the Commission advanced the timetables to achieve full market liberalization by 2005. In March 2002, EU leaders at the Barcelona Summit confirmed their commitment to opening up natural gas and electricity markets, declaring that access to business and commercial customers will be completely open by 2004. The European Parliament has passed a draft resolution on opening electricity and natural gas markets, which will go before EU member energy ministers in November. Approving market opening for residential customers has proven much more contentious, with no deadline set as of yet.

The Energy and Transport Directorate-General also oversees efforts to increase the role of renewable energy sources in the EU fuel mix, as well as demand management programs. The promotion of renewable energy and energy efficiency are handled by the EU's [Altener](#), and [SAVE](#) programs respectively. The two programs have been in place since the early 1990s, and in April of 2002 were renewed under the European Commission's proposal, "Intelligent Energy for Europe (2003-2006)." Currently, renewable energy accounts for 5.6% of EU energy consumption. The EU aims to derive 12% of the group's energy consumption from renewable fuels by 2010.

In September 2002, the European Commission proposed that EU member states make arrangements to hold an additional 40 days worth of strategic oil stocks in a joint European reserve pool. These proposed reserves would supplement each state's individual reserves, which are supposed to amount to 90 days worth of consumption. Currently, the EU member states are estimated to hold on average 115 days worth of oil, depending on the country. The Commission aims to raise strategic oil stocks across the EU to 120 days worth of consumption by 2007.

ENERGY USE AND CARBON EMISSIONS

In 2000, EU members generated 896 million metric tons of energy-related carbon emissions, representing 14% of the world total for that year. Of the EU countries, Germany emitted the most carbon (220 Mmt), followed by the United Kingdom (148 Mmt), Italy (117 Mmt) and France (109 Mmt), with each of the countries showing a decline in carbon emissions since last year. Under the December 1997 Kyoto Protocol, the EU is obligated to reduce its greenhouse gas emissions 8% from 1990 levels (in that year, the EU emitted 913 Mmt of carbon) by 2008-2012. All EU member states signed the Kyoto Protocol on April 29, 1998. On June 17, 1998, the EU agreed on how it would meet the 8% reduction. Under this agreement, different EU member states are assigned varying degrees of

emission cuts, ranging from a 4% increase in the case of Sweden, to a reduction of 28% in the case of Luxembourg, with other countries somewhere in between.

Table 1. Economic and Demographic Indicators for EU Countries

	Gross Domestic Product (GDP) (purchasing power parity)				Population, 2001E (Millions)
	2001E (Billions of U.S. Dollars)	Real GDP Growth Rate		Per Capita, 2001E(U.S. Dollars)	
		2001 Estimate	2002 Projection		
Austria	\$223.6	1.0%	1.0%	\$27,300	8.2
Belgium	\$286.7	1.0%	1.0%	\$27,800	10.3
Denmark	\$151.2	1.0%	1.4%	\$28,500	5.3
Finland	\$132.8	0.7%	1.2%	\$25,500	5.2
France	\$1,483	1.8%	1.1%	\$25,000	59.0
Germany	\$2,113.6	0.7%	0.4%	\$25,700	82.4
Greece	\$184.9	4.1%	3.8%	\$17,400	10.6
Ireland	\$123.2	5.9%	3.4%	\$32,400	3.8
Italy	\$1,414	1.8%	0.4%	\$24,500	57.8
Luxembourg	\$23.5	3.5%	2.7%	\$58,700	0.4
Netherlands	\$420.7	1.1%	0.7%	\$26,300	16
Portugal	\$178.8	1.7%	0.8%	\$17,900	10.0
Spain	\$804.8	2.7%	2.0%	\$20,400	39.5
Sweden	\$222.1	1.1%	1.6%	\$25,000	8.8

United Kingdom	\$1,462.9	1.9%	1.6%	\$24,600	59.5
Total	\$9,225.8	1.6%	1.0%	\$27,100	376.8

Sources: DRI-WEFA World Economic Outlook, World Bank.

Table 2. Energy Consumption and Carbon Emissions in EU Countries, 2000

	Energy Consumption								Carbon Emissions (Million metric tons)
	Total (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Renewable Electricity	Net Electricity Imports	
Austria	1.41	39%	20%	10%	0%	31%	1%	-1%	18
Belgium	2.75	45%	23%	12%	17%	0.2%	0.4%	1.6%	40
Denmark	0.88	51%	23%	19%	0%	0.03%	7%	1%	16
Finland	1.30	32%	12%	11%	17%	12%	7%	9%	13
France	10.41	40%	15%	6%	39%	7%	0.4%	-7%	109
Germany	13.98	41%	22%	23%	12%	1%	1%	0.1%	220
Greece	1.33	63%	6%	28%	0%	3%	0.7%	0.0%	27
Ireland	0.59	60%	26%	13%	0%	1%	0.5%	0.2%	11
Italy	7.96	49%	32%	6%	0%	6%	2%	6%	117
Luxembourg	0.19	50%	15%	3%	0%	1%	0.4%	31%	2
Netherlands	3.91	45%	39%	8%	1%	0.04%	1%	5%	64
Portugal	1.08	64%	8%	14%	0%	11%	2%	1%	17
Spain	5.40	57%	12%	14%	11%	5%	1%	1%	81

Sweden	2.25	30%	1%	4%	24%	36%	2%	2%	13
United Kingdom	9.88	35%	36%	15%	10%	1%	1%	1%	148
Total	63.32	43%	23%	13%	14%	5%	1%	0.7%	896

Source: Energy Information Administration *Note: Percentages may not add to 100% due to independent rounding.*

Table 3. Energy Supply Indicators--EU Countries

	Fossil Fuel Proved Reserves			Fossil Fuel Production, 2000			Electric Generating Capacity, 1/1/00 (Million kilowatts)	Crude Oil Refining Capacity, 1/1/02 (Thousand barrels/day)
	Crude Oil, 1/1/02 (Million barrels)	Natural Gas, 1/1/02 (Trillion cubic feet)	Coal (Million short tons)	Oil (Crude, liquids, and processing gain; Thousand barrels/day)	Natural Gas (Trillion cubic feet)	Coal (Million short tons)		
Austria	86	0.9	28	22	0.1	1.4	14	209
Belgium	0	0.0	0.0	12	0.0	0.4	14	791
Denmark	1,113	2.7	0.0	367	0.3	0.0	13	176
Finland	0	0.0	0.0	0	0.0	0.0	16	239
France	140	0.4	40	79	0.1	5.2	110	1,896
Germany	364	12	72,753	144	0.8	225.3	109	2,259
Greece	9	0.2	3,168	9	0.0	69.5	10	407
Ireland	0	0.7	15	1	0.0	0.0	4	71
Italy	622	8.1	37	155	0.6	0.0	67	2,283
Luxembourg	0	0.0	0.0	0	0.0	0.0	0	0
Netherlands	107	62.5	548	89	2.6	0.0	21	1,206

Portugal	0	0.0	40	2	0.0	0.0	11	304
Spain	21	18	728	19	0.0	25.8	46	1,294
Sweden	0	0.0	1	0	0.0	0.0	34	424
U.K.	4,930	26	1,653	2,553	3.8	35.3	72	1,784
Total	7,392	131.5	79,011	3,452	8.2	362.9	541	13,343

Sources: Energy Information Administration, *Oil & Gas Journal*.

Sources for this report include: Energy Information Administration, DRI-WEFA, International Energy Agency; European Union; *Oil and Gas Journal*.

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Germany: Environmental Issues

Introduction

The current German government, elected in September 1998, is headed by the Social Democrat Chancellor Gerhard Schroeder, whose party rules in coalition with the environmentalist party, the Greens. The government's energy and environmental policy objectives include reducing energy-related emissions, phasing out nuclear power, and increasing Germany's reliance on renewable energy. The government has initiated a regime of "eco-taxes" to encourage more environmentally friendly energy use.

The Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety is headed by Green party member Juergen Trittin. This office also coordinates Germany's climate protection policy. While the country's commitment to the environment and reduction in emission of greenhouse gases (GHGs) is well known, Germany remains one of the world's largest carbon emitters.

Following the reunification of the country in 1990, the major task of German energy and environmental policy was to merge successfully the radically different systems of East and West Germany. West Germany had a diversified and mainly privately owned system of energy supply with a high standard of energy efficiency and a deep commitment to environmental protection. In contrast, East Germany's energy sector was highly centralized, predominantly state-owned, and mainly dependent upon relatively "dirty" lignite (brown coal) as its primary fuel. Cleaning up the former East Germany's environment, closing lignite mines in particular, was one of the primary objectives of the unified Germany's new energy and environment policy.

Air Pollution

In the late 1970's and early 1980's it was widely believed that atmospheric pollution was killing the German Black Forest, a belief which contributed to the Green revolution that followed. The use of lignite coal from the former East Germany, the proximity to the highly polluting former Soviet bloc countries, and a very large transportation sector were the main sources of air pollution in Germany. In a 1996 assessment, forests were damaged to the point where only 43% could be considered healthy.

Today, there have been marked improvements in all polluting sectors, with transportation continuing to represent the largest source of German air pollution. Consequently, environmental policy has been tied directly to transportation policy.

According to the environment ministry, air pollution in Germany has decreased over the last ten years because of the widespread fitting of closed-loop three way catalytic converters, the phasing out of leaded

gasoline, better quality fuels and more efficient engineering. Though German cars are known for being the most fuel efficient, the huge growth in the number of cars has cancelled out most of the gains from this sector. There are presently more than 44 million cars and 4.5 million trucks on German roads.

Energy Use and Carbon Emissions

Reduction of carbon emissions has been a major German international and domestic policy objective. In July, the German government hosted the sixth conference of parties (COP 6) of the Framework Convention on Climate Change in Bonn.

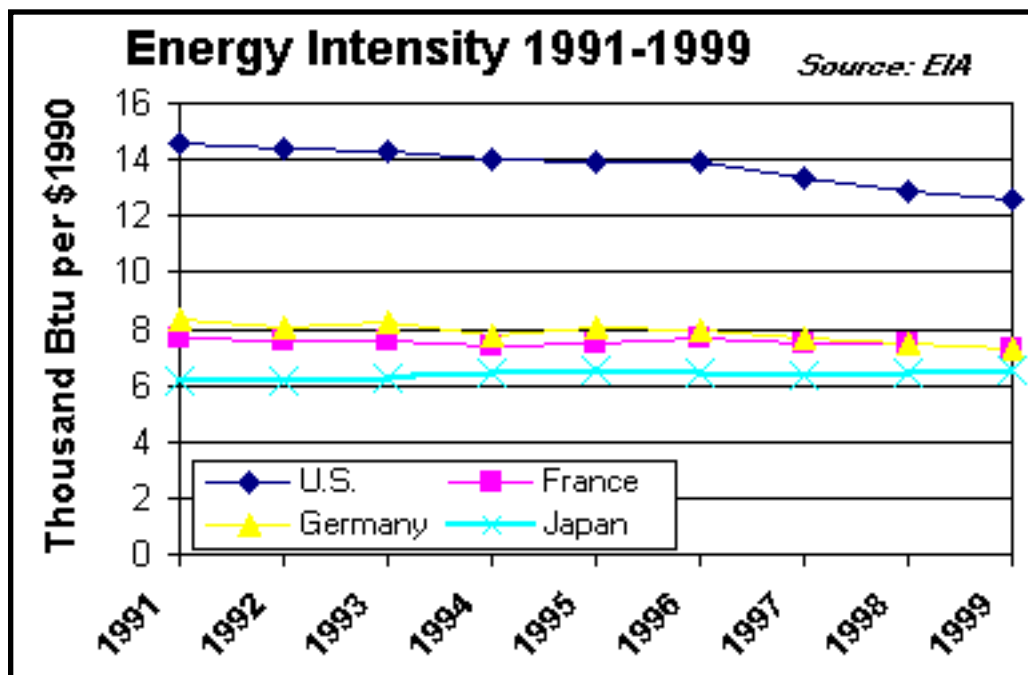
The German government has committed to reducing the country's carbon emissions by 21% below 1990 levels. They are currently 17% below these levels, largely due to dramatic reductions in the former East Germany following German reunification. While overall carbon emissions were down, the environment ministry stated that vehicle emissions had increased by 15% over the same period.

In 2001, Chancellor Schroeder signed an agreement with several different industries in order to reduce greenhouse gas emissions. The transportation industry has set a voluntary target of cutting new car fuel consumption 25% by 2005. In addition, the electricity industry has pledged to cut carbon emissions voluntarily by at least 20 million metric tons (mmt) by 2010. Additionally, the chemical industry (the second largest industrial energy consumer --behind steel in Germany) reduced its carbon emissions by around 30% (21mmt during 1990-1999), despite a 17% increase in production.

The Government and utilities have agreed to reduce carbon emissions by promoting co-generation power plants that produce both heat and electricity by recapturing the heat from natural gas driven power plants and converting it into useable energy. Converting to this type of system is very expensive, and utility companies are being permitted to pass some of these costs on to consumers (expected costs are DM 8 billion -- \$3.5 billion over ten years).

In 1999, Germany's energy related carbon dioxide emissions were 230 mmt of carbon, ranking Germany the sixth largest carbon emitter in the world after the United States (1520 mmt), China (669 mmt), Russia (400 mmt), Japan (307 mmt), and India (243 mmt). German energy consumption in 1999 accounted for 3.7% of the world total (14.0 quadrillion Btus).

Energy and Carbon Intensity

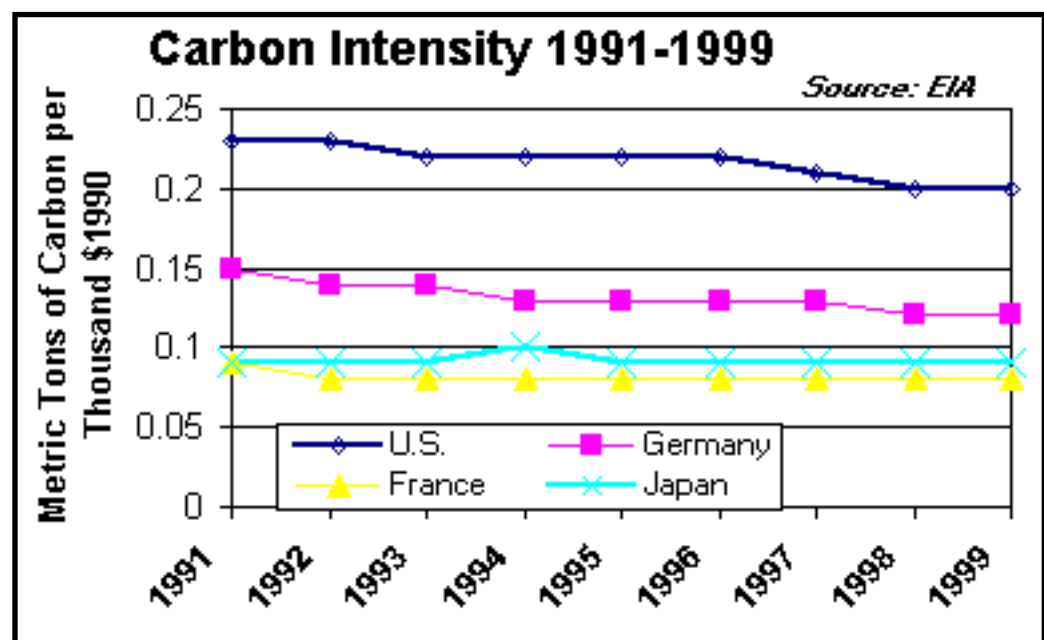


Energy consumed per unit of GDP (energy intensity) in Germany in 1999 was approximately 7.3 thousand Btu per \$1990. Energy intensity was about equal to other industrial Western European countries, above Italy (6.5 thousand Btu per \$1990) and Ireland (6.7), but below Spain (8.7), and about equal to France (7.3). The 1999 energy intensity reflects a 12.6% decrease in energy consumption from 1991 levels despite the country's economic growth over

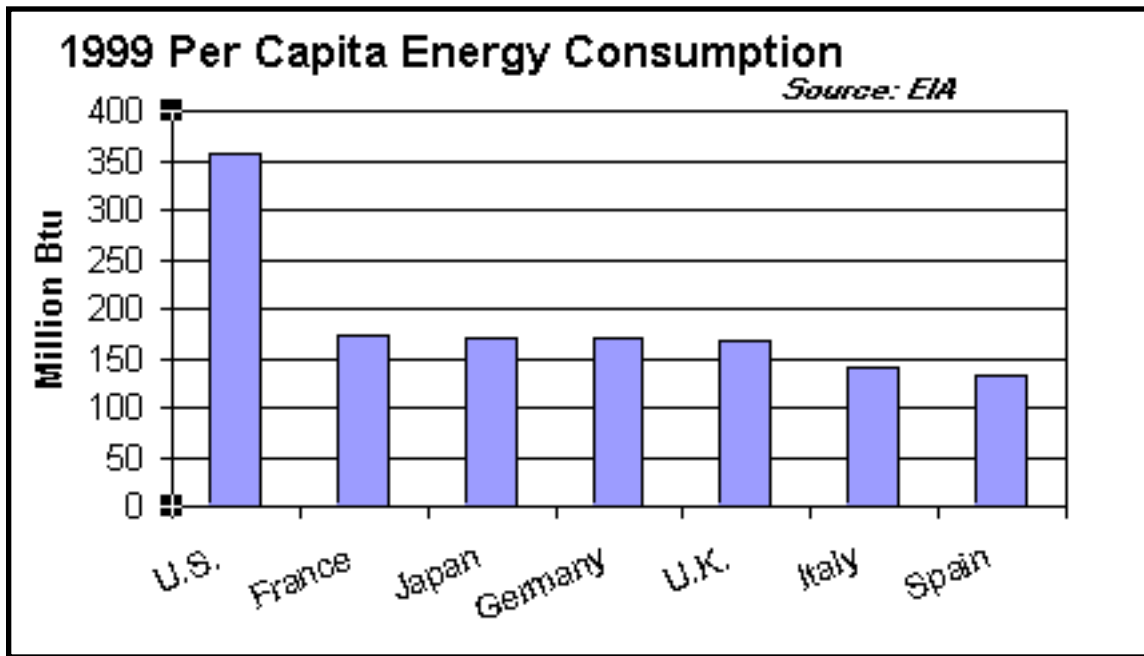
the same period.

Though German carbon intensity remains relatively high, it has declined almost 20% since 1991. Carbon emitted per unit of GDP in 1999 was 0.12 metric tons per \$1990. This level was about equal to industrial Western European countries, and considerably lower than the U.S. level of 0.20 metric tons per \$1990.

In 1999, Germany was the third largest coal consuming country in the world, behind the United States and China. The addition of "clean coal" technologies in former East German coal fired plants has helped to significantly reduce air pollution in Germany. However, coal is the most carbon intense fossil fuel. Some German industry experts believe that though there will be some reduction in the burning of hard coal, domestic lignite will continue to be used as the electricity sector adjusts to the country's planned nuclear phase out.



Per Capita Energy Consumption and Carbon Emissions



German per capita energy consumption was similar to Western Europe and Japan in 1999, at 170.4 million Btu per person. 1999 per capita energy consumption was lower than the United States (355.9 Btu), Canada (410.7 Btu) and Belgium (256.1 Btu).

German per capita carbon emissions in 1999 were 2.8 tons of carbon per

person, higher than France (1.8 tons), Italy (2.1), and the U.K. (2.6), but lower than the United States (5.6) and Canada (4.9).

Nuclear

The phasing out of nuclear power has been one of Chancellor Gerhard Schroeder's main environmental policy objectives while in office. In June 2001, the Chancellor and leading energy companies formally signed an agreement to shut down Germany's 19 nuclear power plants. This new pact limits the lifespan on nuclear plants, which provide close to one third of Germany's electricity, to an average 32 years of operation. Should this pact be enforced, it is likely that the newest plant operating in Germany would be closed by 2021. Germany is the first big industrial country to abandon nuclear energy.

The pact also requires the nuclear industry to construct interim waste-storage sites near the plants to reduce the unpopular transport of nuclear waste, and provides for the termination of spent nuclear fuel reprocessing by 2005. In the interim, plant operators will be required to drastically increase their liability coverage until they go offline.

Renewable Energy

The German government is hoping to use renewable energy sources to compensate for the loss of atomic power through better conservation and new technology, particularly renewable resources. The environment minister has stated that up to 3/5 of nuclear power could be replaced by wind energy by 2030, though only a few of the additional plants have been built yet.

Germany's main renewable resource is wind power. In August 2001, Europe's largest wind farm, with a production capacity of 105 MW, opened in Paderborn in the northwestern part of Germany. The opening of this plant has increased Germany's total wind power capacity to 700 MW. In 1999 wind power already accounted for 2.8% of Germany's total electric power generation, a figure the government hopes to increase to 12.5% by 2010.

As suitable sites for additional wind farms in Germany are running out, the government is looking to build offshore wind power parks.

There are plans in the works to build about 40 wind generators offshore in a small-scale pilot project before 2004.



Outlook

The German government has committed to reduce carbon dioxide emissions by 10 million tons by 2005 and 23 million by 2010. Germany's Environment Minister, Juergen Trittin has forecast that Germany will meet its target of cutting greenhouse gas emissions by 21% below 1990 levels by 2010.

According to the Energy Information Administration's *International Energy Outlook 2001*, Germany's total energy consumption is expected to grow at an annual rate of 0.9% annually through 2020. This figure is lower than projected annual GDP growth for Germany of 2.2% over the same period. Renewable energy sources are expected to increase at an average annual rate of 4.9%, nuclear energy consumption is expected to decrease at a rate of 4.5%, and carbon emissions are expected to decrease at a yearly rate of 1.0% for the reference case outlook.

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Norway

Norway is a major non-OPEC source of oil and was the world's third largest net oil exporter in 2001. Norway is the second-largest natural gas exporter to western Europe.

Note: Information contained in this report is the best available as of September 2002 and is subject to change.



BACKGROUND

Norway's economy is characterized by substantial oil and natural gas revenues, growing government expenditures, a tight labor market, and closer linkage to international oil and gas prices than to the OECD business cycle. Norway is the third largest net oil exporter in the world, and the recent period of high oil prices have made for government budget and current

account surpluses and rising disposable income. The petroleum sector represents over 20% of Norway's gross domestic product (GDP). Norway continues to record large trade surpluses, mostly due to hydrocarbon exports. Real GDP growth for 2002 is forecast at 2.3%, a solid rate. Trade surpluses are expected to decline from about 14% to 8% into the later part of this decade. The consumer price growth forecast is at 1.5% in 2002, though the Norwegian Central Bank recently said that core inflation of 2.7% year-on-year in June had been "somewhat higher" than the bank had projected, so the bank raised interest rates slightly. The phasing-in of revenue from the state Petroleum Fund through additional spending and reduced taxation is expected to stimulate consumer spending. As this change is implemented, the central government's non-oil deficit is expected to rise from 2% of mainland GDP in 2001 to 5.5% by 2010, increasing mainland GDP by 0.4% annually.

Norway has a small industrial base apart from its oil and gas, shipping, and

fishing industries, and its mainland (i.e. excluding oil and natural gas) economy is forecast to grow by 1.2% in 2002. Manufacturing activity was up 1.4% year-on-year for the second quarter of 2002. Norway's government is concerned about its economic welfare once its oil runs out, as is predicted by the end of the first half of the 21st century. Norway makes annual contributions to its Petroleum Fund, a financial safety net for the time when oil revenues decline (and a means of reducing the inflationary impact of oil revenues). The government was able to pay Norwegian krone (Nkr) 53.5 billion (about \$7.1 billion) into the Petroleum Fund in the second quarter of 2002, for a total value of Nkr 605.4 billion.

A new center-right coalition took power in October 2001 after the Labor Party lost seats in the parliamentary election. The coalition consists of Prime Minister Kjell Magne Bondevik's Christian People's Party, the Conservative Party, and the Liberal Party. The government has sought to lessen government involvement in business and to lower taxes, though it remains quite involved in social and environmental policy. The government currently does not have plans to seek membership in the European Union.

Norway is part of the European Economic Area (EEA), but Norwegians have voted in two referenda against joining the European Union (EU). Recent polls have shown some increase in support for joining the EU. Norway has a history of state control over major industry, but this is beginning to change. Norway's reliance on oil revenues in the past resulted in a government preference for keeping Norwegian businesses under Norwegian control.

North Sea Oil and Natural Gas

North Sea oil and natural gas were first discovered in the 1960s. The North Sea did not emerge immediately as a key non-OPEC oil producing area. North Sea production grew as major discoveries continued throughout the 1980s and into the 1990s. Although the region is a relatively high cost oil producer (breakeven is about \$12-\$14 per barrel, vs. \$3-\$4 per barrel in Iran, for example), its political stability and proximity to major European consumer markets have allowed it to play a major role in world oil and gas markets.

Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil - about \$150 billion in annual petroleum trade. Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field. Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 400,000 barrels per day (bbl/d) by 2005, making the Brent price marker increasingly dated. Liquidity has fallen to about 10 cargoes per delivery month compared with 300-400 deals per month in the early 1990s. In response to this, pricing service Platts made a change effective July 10, 2002 allowing for substitution - at seller's option - of UK Forties and Norwegian Oseberg for Brent in an attempt to increase potential volumes and reduce volatility resulting from traders "cornering the market." The change has not been universally accepted, and it remains to be seen whether it will be successful. The International Petroleum Exchange (IPE), which runs the Brent futures market, appears to be waiting to see whether the over-the-counter market adopts Brent-Forties-Oseberg (BFO). The first full BFO contract was sold on August 8.

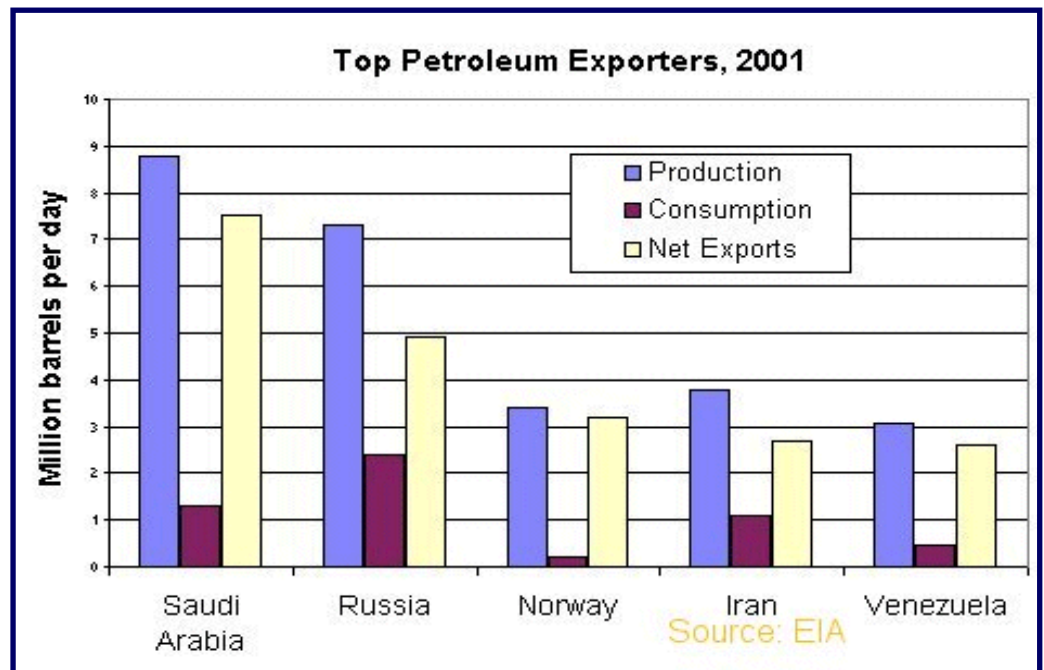
The late 1997-1998 oil price collapse had an adverse effect on North Sea production. In 1997 and 1998, North Sea oil production remained stable, whereas previous years had shown average annual increases of 400,000 bbl/d. The 1999-2000 oil price increase had the opposite effect: North Sea oil and gas production reached new heights in 2000, with oil production exceeding 6 bbl/d for the first time. However, the North Sea area is considered to be increasingly "mature," with few additional large discoveries likely to be made. Some predict that the North Sea will reach peak production of about 7 million bbl/d in the next two or three years, although technology developments could delay this. The average recovery rate for Norwegian fields is expected to eventually reach 44%. Because the North Sea is believed to be nearing its peak production, in both of the major North Sea producing nations, Norway and the United Kingdom (UK), government and industry are

taking steps to restructure their oil and natural gas sectors to make them more internationally competitive and also are increasing cooperation between the two countries. On August 28, 2002, Norway and the UK released a joint plan to increase cooperation, cut costs, and raise output, especially on aging fields. However, taxation rates will remain unharmonized. Norway also signed a cooperation agreement with Russia that same day that opens energy dialogue on the Arctic Barents Sea shared by the two countries.

OIL

Norway has proven oil reserves of 9.44 billion barrels. In 2001, Norway was the world's third largest net oil exporter. Norway consumes very little of the oil it produces, and its oil exports are the country's greatest source of revenue. Norway's oil reserves are located exclusively offshore and mostly in the North Sea, with smaller deposits in the Norwegian Sea. The Barents Sea also is being explored. Oil production was about 3.4 million bbl/d in 2001, an increase of about 100,000 bbl/d over 2000. Production in the first half of 2002 was affected by a production cut agreement with OPEC.

In November 2001, Norway's Energy and Oil Minister announced that Norway would cooperate with OPEC and cut crude oil production for the first half of 2002 in an effort to shore up prices in the face of sagging demand.



Norway later agreed to cut production by 150,000 bbl/d, with target production at 3.02 million bbl/d. Rather than cutting production steadily across the period, Norwegian production cuts were concentrated in the last month of each quarter, i.e., March and June. A preliminary estimate of crude

oil production for the first half of 2002 is 3.06 million barrels per day. In June, it was announced by the Oil and Energy Ministry that "The Norwegian government has decided not to extend the restriction on oil production into the second half of 2002." By this time, Brent prices were some \$5 per barrel higher than they had been in November 2001. In late June, Norway informed operators that they could produce at 13% above field production limits in an effort to reach a government target of 3.02 million bbl/d of crude oil for 2002.

Oil service workers struck from July 5 until August 10, when the Norwegian oil industry association (OLF) and oil union Nopef arrived at a new agreement covering 3500 employees in oil service companies. The oil industry reportedly suffered a loss of more than Nkr 330 million (\$42.2 million) during the strike. A strike began September 10, 2002 by dock workers at Statoil's 205,000-barrels-per-day refinery in Mongstad, Norway, that would curb exports from one of Europe's key gasoline-producing plants. The strike could curb crude production from Norsk Hydro's Troll B and C platforms, which send their output to the terminal at the Mongstad refinery via pipelines.

Oil Sector Restructuring

The Norwegian oil sector has undergone massive restructuring during the past few years. Norway's oil sector had been characterized by extensive public ownership. Its largest oil company, Statoil, was 100% state-owned, while Norsk Hydro, the second largest oil company, was majority state-owned. The only completely privately-held company was Saga Petroleum. In addition, state-owned Statoil managed another entity even larger than itself, the State Direct Financial Interest (SDFI), which represented the state's holdings in 150 offshore oil and natural gas fields and about 40% of total production.

In late 1999, Norsk Hydro completed its acquisition of Saga, reducing its public ownership, originally 51%, to 44%. In April 2001, the Norwegian parliament approved plans to sell between 10% and 25% of Statoil to private investors and to sell 15% of the SDFI to Statoil prior to Statoil's listing on the New York and Oslo stock exchanges. Norsk Hydro (taking the largest share) and eight other Norwegian North Sea operators were sold another 6.5% of the

SDFI in March 2002. The remainder of the SDFI (78.5%) was reorganized into a new state company called Petoro. Petoro is the world's fifth largest oil and gas firm in terms of production, with estimated production of 1.4 million bbl/d of oil, though Petoro functions entirely as a management company, having no operations itself. Statoil completed its purchase of 15% of the SDFI in May 2001 for \$4.24 billion, and on June 18, 2001, Norway sold 17.5% of its holding in Statoil in an initial public offering for \$2.9 billion. These changes should introduce more efficiency into the system, as Statoil was uncompensated for managing the SDFI, and raise more capital for Statoil in order for it to compete globally as the company explores regions such as offshore west Africa and Venezuela.

Norsk Hydro sold two production licenses to Marathon Oil of the United States in July. There is speculation that Norsk Hydro may spin off its oil unit to focus on its aluminum and fertilizers businesses. Statoil is the most likely buyer, which would create a company with production approaching 1 million bbl/d of crude, condensate, and natural gas liquids. Statoil announced in May 2002 that it is selling its 7,000 bbl/d assets in the Danish North Sea to Denmark state oil company DONG for \$127 million in order to concentrate on core areas.

Oil Production

Norway's major Norwegian North Sea production areas include: Ekofisk, Sleipner, Frigg, Statfjord, and Oseberg and Troll. There are also five fields producing in the Norwegian Sea. (The 62nd line of latitude separates the North Sea and the Norwegian Sea.)

Norwegian oil investment was about Nkr 56.9 billion (\$7.5 billion) in 2001, an increase from the \$6.2 billion invested in 2000, but down from the peak of Nkr 80 billion (\$10.6 billion) in 1998. Investment levels reflect expectations that Norway's oil production will remain roughly constant until 2004, and then begin a gradual decline. Oil fields and projects under development include: Fram West, Grane, Tune, and the Valhall Flanks and water injection. Three new offshore oil fields came on stream in the second half of 2001:

Tambar, Glitne, and Huldra. Some important oil discoveries offshore Norway in the past 12 months include: Staerne, near the Norne field, with estimated reserves of 30 million barrels; increased reserves in the Oseberg unit; and additional oil at the Goliat continental oil shelf in the Barents Sea (estimates of 75-107 million barrels increased to 91-250 million barrels). Overall, about 250 million barrels of oil and condensate were added to Norwegian reserves in 2001. A total of 32 blocks were offered at the 17th Norwegian Continental Shelf licensing round in June 2002. Eleven companies will share blocks that comprise six production licenses. This round focused on the Norwegian Sea.

Ekofisk, in the southern North Sea sector, was the first North Sea oil field to be discovered, in the late 1960s, and developed, with production beginning in 1971. Since 1975, oil has been piped from Ekofisk to the UK (Teesside, England). There are currently 29 platforms installed in the area, some of which are in the British North Sea. The most recent phase of development began in 1994, when the Phillips group (the U.S. company that leads the Ekofisk operating consortium, which includes TotalFinaElf, Norsk Agip, Norsk Hydro, and Statoil) installed two new platforms at "Ekofisk II". Ekofisk II came onstream in August 1998. The Phillips license runs through 2028. In December 2001, it was decided by the government that Phillips would remove 14 of the 29 Ekofisk platforms between 2003 and 2018, at an estimated cost of \$1 billion (Nkr 8 billion). About 10% of the removal cost will be paid by Phillips, 72% by the Norwegian government, and the remainder will be paid by the other members of the consortium. Phillips plans to bring the steel structures and the topside of the concrete Ekofisk tank ashore for recycling, to leave the rest of the concrete tank and barrier wall in place, and also to leave about 150 miles of pipelines buried. Ekofisk's production (including Eldfisk, Embla, and Tor) is expected to be about 381,000 barrels per day of crude oil in 2002. The Valhall field's production continues to decline, with expected production in 2002 at 72,000 bbl/d. However, the recently approved Valhall water injection and the Valhall flanks should improve recovery from the field. The Yme field has ceased production.

Sleipner West was discovered in 1974, but Sleipner East went into production first, in 1993. Sleipner West is tied back into Sleipner East, and the fields share the same operations organization. Sleipner is mostly important for natural gas production, including liquids and condensate (2002 condensate production in East and West is estimated at 3.7 million cubic meters), but the Varg field is estimated to produce 8,300 bbl/d crude oil in 2002. Varg is scheduled to cease production within the next few years.

Moving to the northern North Sea sector, the Frigg-Heimdal area is also mostly important as a natural gas producing area, though the Balder and Jotun fields together are expected to produce about 124,000 bbl/d of crude oil in 2002. Balder was proven as early as 1967, though production did not commence until 1999. Shuttle tankers are loaded from a production ship tied to subsea-completed wells. Several structures close to Balder are being developed by Ringhorne platform. Jotun also commenced production in 1999, from a floating production, storage, and offloading vessel (FPSO) that is serviced by shuttle tankers.

The Statfjord area is one of the largest oil producing areas in the North Sea. The Statfjord field itself was discovered by Mobil in 1974, and it extends into the British North Sea. Production began from Statfjord A in 1979, from Statfjord B in 1982, and from Statfjord C in 1985. Production from the Statfjord North and Statfjord East subsea installations are tied back into Statfjord C. Statoil took over the operations from Mobil in 1987. Three large concrete platforms with storage cells have been installed on Statfjord. Britain's 14.5% share goes by pipeline via the Brent field to Scotland. Statfjord's production has exceeded the most optimistic expectations, but all Statfjord fields are now in decline. Norway's share of Statfjord crude oil production in 2002 (including North and East) is expected to be 205,000 bbl/d. Statfjord should continue producing until 2020.

The Snorre field, with production rising, has become the largest single field in the area, with 2002 production estimated to be 228,000 barrels per day. It was discovered in 1979, and production commenced in 1992 (see above).

Norway's third largest field is Gullfaks, which, including West and South, is expected to produce 223,000 bbl/d in 2002. Gullfaks (including West) has declined by over 50% since its peak in 1995, but Gullfaks South (including Rimfaks and Gullveig) has had increasing production since it came online in 1998, to 70,000 bbl/d expected for 2002. Vigdis continues to decline from its peak in 1999, but Visund, which is east of Snorre, has had its production increase, with 2002 expected to be 43,000 bbl/d.

The various Oseberg fields (Oseberg, East, South, West) together are the largest oil producing fields in their area, whereas Troll is the largest gas field in the area. Oseberg began production in 1988, and peaked at about 500,000 bbl/d in 1996, and has declined since to about 176,000 bbl/d (including West), far below the capacity of the three platforms there. The surrounding East and South Oseberg fields have come online in 1999 and 2000, respectively, supplementing the declining production at Oseberg with 130,000 bbl/d expected for 2002. Both East and South peaked in 2001. There is a pipeline from Oseberg to the Sture terminal on the Norwegian coast, with tie-backs from East and South to Oseberg. A thin layer of oil underlies the entire Troll field, but it is only sufficiently thick for commercial recovery in the Troll West region. This is where Troll Phase II is expected to produce 316,000 bbl/d in 2002 - production has been relatively flat since 2000, though Troll achieved a daily record of 440,000 bbl in May 2002. There is a pipeline from Troll West to the Mongstad crude oil terminal on the Norwegian coast.

The Norwegian Sea has seen production increase at a higher rate than North Sea production in recent years, though it is in an earlier stage of development, the first field having come on stream in 1993. Total production for the area for 2002 is predicted to be 725,000 bbl/d. Much of the increase comes from the new Asgard field, which went into production in 1999, and now produces about 148,000 bbl/d. Norne's production also increased in 2001, though a slight decline is predicted for 2002. Heidrun's production has declined to less than that of the Norne field. Draugen's production has been flat in the past two years, but it is still has the highest production at about 200,000 bbl/d. Shuttle tankers are used to take oil from the platforms or production ships, as there is

currently not an oil pipeline from the Norwegian Sea.

NATURAL GAS

Norway holds 44 trillion cubic feet (Tcf) of natural gas reserves. Norway is not a major natural gas consumer, although its consumption is expected to increase in coming years as natural gas-fired power plants come online. It is estimated that just 16% of Norway's gas reserves have been extracted since output began, though Norway produced more gas than it discovered for the first time in 2001, as the increase in reserves was between 700-900 billion cubic feet (Bcf). Natural gas accounts for about 60% of Norway's overall offshore hydrocarbon reserves and is expected to account for an increasing portion of Norway's energy exports. Norway continues to be the second-largest natural gas exporter in Europe, with its growth outpacing that of Europe's largest natural gas exporter, Russia. Exports are forecast to be between 1.9-2.3 Tcf in 2002. Export volumes peaked at about 6.7 Bcf per day in the second quarter of this year, but will have to decline slightly if the forecast is correct. Norway's sub-sea natural gas export network is capable of transporting about 3 Tcf per year.

Natural Gas Exports

Norway, as a member of the European Economic Area (EEA), is bound by certain EU economic directives, and the EU recently has forced Norway to restructure the way it sells natural gas to other European countries. Prior to June 1, 2001, all Norwegian gas was sold through the Gassforhandlingsutvalget (GFU, meaning Gas sales negotiating committee). Although ownership of Norway's gas is held by many different companies and formerly the SDFI, now Petoro, the GFU consisted of just Norsk Hydro and Statoil. The GFU would set a price for all Norwegian gas available for purchase, instead of letting the various producers compete against each other. The EU claimed that this violated fair trading practices and threatened Statoil and Norsk Hydro with huge fines. In July 2002, Norway and the European Commission resolved this long-running dispute over the legality of long-term contracts negotiated by the defunct Gas Sales Negotiating Committee (GFU). The European Commission had threatened to take legal action against Statoil

and Norsk Hydro because long-term contracts already in place that account for about 20% of western Europe's gas imports were negotiated by means of the GFU and because many of these contracts have destination clauses (prohibition of resale). Under the negotiated deal, the Commission relented on its demand to have the long-term contracts revised in return for Statoil and Norsk Hydro agreeing to sell 530 Bcf over a four-year period to new European customers (customers without GFU-era contracts). In May 2002, most natural gas exporting companies agreed to coordinate ownership of their pipeline assets through shares in the new government-backed Gas-Led company. The state-owned company Gassco is the operator on all of Norway's natural gas pipelines (since January 1, 2002), as the partial privatization of the former operator, Statoil, created a conflict of interest.

The effects of all these changes are yet to be seen, though the expectation is that the price of Norwegian natural gas will be reduced, at least in the short to medium run. A major constraint for upstream gas companies competing for sales in the newly deregulated market will be limited infrastructure to take the gas out, because various companies share the same pipeline. Norwegian gas arrives in Europe through the following trunklines: the Europipe I and Statpipe/Norpipe systems to Germany; the Zeepipe trunkline to Zeebrugge in Belgium; the NorFra line to Dunkerque in northern France; and the Europipe II line from Kårstø north of Stavanger to Emden. These Norwegian trunklines provide a combined gas transport capacity of 2.7 Tcf per year. There are also pipelines to the UK, including the new Vesterled pipeline, which opened in October 2001, with volumes at about 138 million cubic feet per day. Marathon is exploring the potential demand for its proposed Symphony natural gas pipeline, which would bring additional Norwegian natural gas to the UK through a link between the Heimdal complex and the Brae/Miller complex in the UK sector.

Statoil expects Norway's share of natural gas deliveries to continental Europe to rise from 14% in 1996 to 20% by 2005. The following companies currently buy Norwegian gas: Ruhrgas, BEB, Meeg, Thyssengas and Verbundnetz Gas (Germany), Gaz de France (France), Gasunie, SEP (the Netherlands),

Distrigaz (Belgium), Enagas (Spain), Austria Ferngas, OMV (Austria), Snam (Italy), Energia (Italy), Polish Oil and Gas Company (Poland), Transgas (Czech Republic), and Centrica (UK). Germany is the largest natural gas market in continental Europe, and about 20% of the gas that Germany currently consumes comes from Norway. Ruhrgas expects Norway to supply 30% of Germany's imports. About half of the gas from the NorFra line transits through France to points in Italy and Spain, while the other half is consumed in France. By 2005, this pipeline is expected to supply one-third of France's total gas consumption.

In July 2001, Stoltenberg and Polish Prime Minister Jerzy Buzak signed a joint declaration for the deliveries of 177 billion cubic feet (Bcf) of natural gas from Norway annually. Existing Polish infrastructure cannot support significant imports from non-Russian sources, so a pipeline across the Baltic through either Sweden or Denmark was being planned, but it now appears unlikely that a natural gas pipeline to Poland will be built because of insufficient demand volumes. There is a competing plan to import liquefied natural gas (LNG) from Norway to a planned LNG terminal on Poland's Baltic Coast. Norway began piping a relatively small amount of gas through Germany in October 2000, based on an earlier contract signed in May 1999, for the delivery of 17.7 Bcf annually, under an agreement between Germany's Ruhrgas and Verbundnetz Gas and Poland's state-held gas monopoly.

The United Kingdom, the largest natural gas market in Europe, will also soon become an importer of Norwegian gas again. Norway had once supplied up to a quarter of British demand in the 1980s, but this dwindled as the Frigg field that supplied the gas was depleted. Vesterled will connect the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gasfields, and from there to other areas of the Norwegian North Sea such as the Ormen Lange gasfield that is scheduled to come on stream in 2006. In July 2001, BP announced a 15-year contract to buy 56.5 Bcf natural gas per year from Statoil. In June 2002, Centrica of the UK signed a 10-year deal with Statoil for the purchase of 483.5 million cubic feet per day, with prices linked to natural gas rather than oil.

Natural Gas Production

The Troll field (East and West) contains over half of Norwegian natural gas reserves and, as Norway's largest natural gas field, Troll produces over 72 Bcf per month. It has a production capacity of 100 million cubic meters (3.5 Bcf) per day, and estimated production in 2002 is expected to be 22.8 billion cubic meters (805 Bcf). The Troll Gas development Phase I in Troll East comprises the Troll A platform, the gas treatment plant at Kollsnes near Bergen, and pipelines linking these two installations. Troll East is thought to contain two-third's of Troll's natural gas reserves. Phase III (under development) will extract gas from Troll West. Troll A is the tallest structure ever moved by humans. Its concrete gravity base structure has been built for a lifetime of 70 years. The division of roles on the field has been controversial. Currently, Statoil and the new Petoro have about three-quarters of the shares and Statoil is the operator, followed by Norsk Hydro, Shell, TotalFinaElf, and Conoco. The gas is taken by the Zeepipe to Zeebrugge and Statpipe/Norpipe to Emden.

Troll is not the only active natural gas field in Norway's North Sea. Gas sales began in 1977 from Ekofisk and Frigg. Ekofisk, in the southern North Sea sector, supplies Ruhrgas, Gaz de France, Gasunie and Distrigaz. Ekofisk has declined from its peak in the late 1970s and a production spike in the 1990s, though it is still expected to produce 5.95 billion cubic meters (210 Bcf) in 2002. Frigg production is sold to British Gas, though Frigg has declined to the point that production is expected to cease sometime this year. Nearby Heimdal's declining production is also set to cease this year. Agreements on selling gas from Statfjord, Gullfaks and Heimdal were signed in 1981 and deliveries began in 1985 to Ruhrgas, BEB, Thyssengas, Gaz de France, Gasunie, Distrigaz, Elf and Meeg. Remaining commitments under these deals average six billion cubic meters per year (212 Bcf). Sleipner, East and West, is expected to produce 13.6 billion cubic meters (479 Bcf) in 2002; this gas is currently sold under the Troll gas sales agreements. Though Sleipner East is declining, most natural gas production is from Sleipner West, which continues to have sharply increasing production. The Norwegian share of gas from the field is piped through the Statpipe/Norpipe system to Emden in

Germany via Kårstø, north of Stavanger.

Huldra commenced production with an unmanned platform in November 2001, with natural gas production steadily rising and already at about 350 million cubic feet per day (total expected production 3.19 billion cubic meters or 113 Bcf for 2002). Huldra also produces condensate and about 28,000 bbl/d of crude oil. The crude and condensate are piped to Veslefrikk B, and the gas is piped to Heimdal.

The Åsgard field on the Halten Bank in the Norwegian Sea is one of Norway's most important new projects. The field has been developed as a chain of four interconnected projects: development of Åsgard itself, construction of the Åsgard Transport gas trunkline from the field to the Kårstø gas treatment plant north of Stavanger, the Kårstø development project, and the Europipe II gas trunkline from Kårstø to Dornum in northern Germany. Gas production from the floating platform began in October 2000, and is expected to be 8.9 billion cubic meters (314 Bcf) in 2001. Statoil is the operator of the project, which is one of Norway's giant offshore developments, on par with Ekofisk and Troll. Subsea production installations in the field are planned to be the most extensive in the world, embracing a total of 51 wells grouped in 17 seabed templates. It will link the Halten Bank area to Norway's gas transport system in the North Sea.



Statoil now is developing the Halten Bank South area of the Norwegian Sea, having taken over as operator in January 2000 (Saga had been the operator). Recoverable reserves of the Halten Bank South fields are estimated

at 140 billion cubic meters (almost 5 Tcf) of gas and about 440 million barrels of oil and condensate - on par with Åsgard. The Kristin field of the Halten Bank has already secured sales of up to 31 billion cubic meters (1.1 Tcf) from 2005 to 2016. ExxonMobil made the largest discovery of 2000 in this area, the Bella Donna field, with estimated reserves between 60 and 125 billion cubic meters (2.1-4.4 Tcf).

In March 2002, the Norwegian parliament approved Statoil's plans to develop the \$5 billion Snohvit project. If it is completed, Snohvit will be the largest sub-sea liquefied natural gas (LNG) project in the world, as well as the most northerly as it is located in the Barents Sea. Approximately 201 Bcf per year of natural gas would be piped to the coast, liquefied, and transported to customers in Spain and the United States by means of four carriers. In June 2002, El Paso of the United States, announced that it had final Norwegian and U.S. government approval for its plans to import 1.8 million metric tons of LNG to the United States from Snohvit. This is over 40% of the project's capacity, and much of the LNG may be delivered to El Paso's Cove Point, Maryland regasification facility. Construction of Snohvit restarted in June as well.

The huge Ormen Lange field in the Norwegian Sea, Norway's second largest natural gas discovery with estimated reserves of 14.1 Tcf, has its blocks divided into three production licenses, with the unusual characteristic that Statoil/SDFI has only a 30% share of one of the licenses, such that non-Norwegian companies are the majority owners of one of the licenses. Norsk Hydro is the operator in the development phase, and Shell will be the operator in the production phase. Gas production is planned to commence in 2007.

COAL

Norway's coal production occurs on Spitsbergen of the Svalbard Islands, off the country's northern coast. This island also has Norway's only coal-fired power plant. In December 2001, the Norwegian Parliament voted to give a \$16.9 million subsidy to state-owned coal monopoly Store Norske Siserbergen Kulkompani. Mining in Svalbard will be expanded and eventually, coal exports are planned. However, Norway is currently a net importer of coal, though overall consumption is small at 1.57 million short tons in 2000.

ELECTRICITY

In 2000, 99% of Norway's electricity generation came from its 27 million kilowatts of installed hydroelectric capacity. Norway has one of the highest rates of per-capita consumption of electricity in the world. In December 2001, state-owned Norwegian electricity company Statkraft purchased independent electricity company Trondheim Energiverk for \$483 million. This makes Statkraft the second-largest electricity supplier in Scandinavia and gives the company over 50% of the Norwegian electricity market. Prime Minister Stoltenberg declared, in January 2001, that "the era of large-scale new hydropower is over" and that several large new hydro projects are to be abandoned, including Beiarn, Bjollaga, and Melfjord. A new hydro plant with greater capacity is being constructed to replace the existing one at Tyin.

Norway is planning to construct three new natural gas-fired power plants. Construction of two natural gas-fired power plants by Naturkraft appears set to go ahead sometime this year. Naturkraft recently asked the government to extend its license to build these plants beyond 2004. This issue, which has not

been completely resolved, is extremely important in Norway, as Prime Minister Bondevik's previous term of office ended in a vote of no confidence that overrode his opposition to the plants. Industrikraft Midt-Norge also plans to build a natural gas-fired plant, and has an allowance to emit 2.2 million tones of carbon dioxide per year. This 2X400 gas-fired combined heat and power plant in Skogn, central Norway is slated to begin construction in 2002. U.S.-based Mirant has bought 40% of five-member industrial consortium IMN, which will build, operate, and own the plant.

Norway has had a surplus of hydroelectric power in the past two years, but in drier years it must import electricity. In January 2001, E.On of Germany, Statkraft, and Elsam of Denmark agreed to free up capacity on key power cables linking the high tension electricity grids of Scandinavian countries to Germany, including the Skaggerrak cable, the only cable connecting western Denmark and Norway.

In May 2002, the European Free Trade Area (of which Norway is a member) informed the government that industry's exemption from taxation on electricity cannot continue. Consumers currently pay a 9% tax on electricity.

ENVIRONMENT

Norway is a proponent of "green power" from renewable sources and has made efforts to make its oil sector as environmentally friendly as possible. Under its Kyoto Protocol commitment, Norway has agreed to limit its carbon emissions to a 1% increase from 1990 levels by the 2008-2012 commitment period. In a dual effort to meet its Kyoto target and to further develop technologies to make oil and gas production less environmentally damaging, Norway has been a leader in alternatives for reducing carbon emissions. As a result of high activity in the oil and gas extraction sectors, Norway is relatively more energy-intensive than most OECD countries, and possesses one of the highest per capita energy consumption levels in the world. Air pollution in Oslo is not as severe as in other major world cities.

Sources for this report include: Economist Intelligence Unit, Financial Times, Hart's European Petroleum Finance Week, International Monetary Fund (IMF), Oil Daily, Norwegian Ministry of Oil and Energy, Petroleum Economist, Petroleum Intelligence Weekly, Platt's Oilgram News, Statoil, The Scotsman, DRI-WEFA, World Markets Energy .

COUNTRY OVERVIEW

Head of State: King Harald V

Prime Minister: Kjell Magne Bondevik (since October 2001)

Independence: October 26, 1905 (from Sweden)

Population (2001E): 4.5 million

Location/Size: Northern Europe, bordering the North Sea and the North Atlantic Ocean, west of Sweden/123,843 square miles (slightly larger than New Mexico)

Capital City: Oslo

Language: Norwegian (small Lapp- and Finnish-speaking minorities)

Ethnic Groups: Germanic (Nordic, Alpine, Baltic), Lapps (Sami) 20,000

Religions: Evangelical Lutheran 87.8% (state church), other Protestant and Roman Catholic 3.8%, none 3.2%, unknown 5.2%

Defense (8/98): Army, 28,900; Navy, 6,100; Air Force, 6,700 (including 16,500 conscripts)

ECONOMIC OVERVIEW

Finance Minister: Per-Kristian Foss

Minister of Trade and Industry: Ansgar Gabrielsen

Currency: Norwegian Krone (NKR)

Exchange Rate (9/09/02): 1 US Dollar = 7.52 Kroner

Gross Domestic Product (GDP, 2001E): \$163.7 billion

Real GDP Growth Rate (2001E): 1.4% **(2002F):** 2.3%

Inflation Rate (consumer prices, 2001E): 3.0% **(2002F):** 1.5%

Unemployment Rate (2001E): 3.6% **(2002F):** 4%

Merchandise Exports (2001E): \$58.6 billion

Merchandise Imports (2001E): \$33.6 billion

Merchandise Trade Surplus (2001E): \$25 billion

Major Trading Partners: UK, Germany, Sweden, Denmark, United States, other EU members

Major Exports: Fuels and other energy products; food and beverages; manufactured materials

Major Imports: Machinery and transport equipment, miscellaneous manufactures, food, beverages, and tobacco

ENERGY PROFILE

Minister of Petroleum and Energy: Einar Steensnaes

Proven Oil Reserves (1/1/02E): 9.4 billion barrels

Oil Production (2001E): 3.4 million barrels per day (bbl/d), of which 3.1 million bbl/d was crude oil

Oil Consumption (2001E): 0.2 million bbl/d

Net Oil Exports (2001E): 3.3 million bbl/d

Crude Oil Refining Capacity (1/1/02E): 310,000 bbl/d

Natural Gas Reserves (1/1/02E): 44 trillion cubic feet (Tcf)

Natural Gas Production (2000E): 1.81 Tcf

Natural Gas Consumption (2000E): 0.087 Tcf

Net Natural Gas Exports (2000E): 1.7 Tcf

Electrical Generation Capacity (1/1/00E): 27.2 gigawatts

Electricity Generation (2000E): 141 billion kilowatthours (bkwh)

Electricity Consumption (2000E): 112 bkwh

Recoverable Coal Reserves (12/31/99E): 1 million short tons (Mmst)

Coal Production (2000E): 0.55 Mmst

Coal Consumption (2000E): 1.57 Mmst

Major Systems: Statfjord, Oseberg, Gullfaks, Ekofisk

Major Companies: BP, ConocoPhillips, ExxonMobil, TotalFinaElf, Norsk Hydro, Shell, Statoil, Chevron, Petoro

ENVIRONMENTAL OVERVIEW

Minister of Environment: Borge Brende

Total Energy Consumption (2000E): 1.8 quadrillion Btu* (0.5% of world

total energy consumption)

Energy-Related Carbon Emissions (2000E): 10.3 million metric tons of carbon (0.2% of world total carbon emissions)

Per Capita Energy Consumption (2000E): 399.6 million Btu (vs. U.S. value of 348.9 million Btu)

Per Capita Carbon Emissions (2000E): 2.3 metric tons of carbon (vs. U.S. value of 5.7 metric tons of carbon)

Energy Intensity (2000E): 10,619 Btu/\$1995 (vs U.S. value of 10,390 Btu/\$1996)**

Carbon Intensity (2000E): 0.06 metric tons of carbon/thousand \$1995 (vs U.S. value of 0.17 metric tons/thousand \$1996)**

Sectoral Share of Energy Consumption (1998E): Industrial (52.1%), Residential (21.7%), Transportation (13.1%), Commercial (13.1%)

Sectoral Share of Carbon Emissions (1998E): Industrial (57.0%), Transportation (37.9%), Residential (2.6%), Commercial (2.5%)

Fuel Share of Energy Consumption (2000E): Oil (21.9%), Natural Gas (5.3%), Coal (2.2%)

Fuel Share of Carbon Emissions (2000E): Oil (72.7.1%), Natural Gas (16.7%), Coal (10.6%)

Renewable Energy Consumption (1998E): 1,248 trillion Btu* (5% increase from 1997)

Number of People per Motor Vehicle (1998): 2.0 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (July 9th, 1993).

Signatory to the Kyoto Protocol (signed April 29th, 1998- not yet ratified).

Under the Protocol, Norway has agreed to a 1% increase from 1990 emissions levels of a basket of greenhouse gases.

Major Environmental Issues: Water pollution; acid rain damaging forests and adversely affecting lakes, threatening fish stocks; air pollution from vehicle emissions.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds,

Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

LINKS

For more information from EIA on North Sea, please see:

[EIA - Country Information on Norway](#)

Links to other U.S. government sites:

[CIA World Factbook - Norway](#)

[U.S. Department of Energy's Office of Fossil Energy's International section - Norway](#)

[U.S. State Department Consular Information Sheet - Norway](#)

[U.S. State Department Background Notes - Norway](#)

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[International Energy Agency Norway 1997 Review](#)

[The Washington Times International Supplement on the North Sea](#)

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September 2001

United Kingdom

With its significant North Sea reserves, the United Kingdom is a major European oil and natural gas producer. It is also one of the largest energy consumers in Europe.

Information contained in this report is the best available as of September 2001 and is subject to change.



BACKGROUND

The United Kingdom (official name: United Kingdom of Great Britain and Northern Ireland, abbreviated: UK) is a major political and economic world power and a close ally of the United States. It is also the world's fourth-largest economy. The country joined the European Union (EU) in 1973 (confirmed by referendum in 1975), but has no plans to join the common European currency, the euro, in the immediate future. Despite the UK's lack of participation in the euro, the country has continued to attract foreign direct investment (FDI) - about \$517 billion total at the end of 2000, second in the world after the United States. The UK is an even larger exporter of capital - outward FDI at the end of 2000 totaled \$902 billion, also second to the United States. The UK maintains a smaller public sector than many of its EU counterparts.

The UK, like most of the OECD, has seen growth rates decline in 2001. GDP growth in the UK is expected to decline to 2% in 2001, and will decline further still if the economy of the United States approaches a mild recession, as the UK economy is the second-closest linked to that of the United States of all the countries of the EU. This slowdown is also expected to decrease external demand, raising the trade deficit for 2001. Despite this, unemployment fell to a 26-year low in July 2001.



Given low inflation (under the government's target of 2.5% for 28 consecutive months) and the prospect of slackening growth (especially in the manufacturing sector), the Bank of England has cut interest rates four times in 2001, most recently in

August.

The United Kingdom is by far the largest petroleum producer and exporter in the EU (Norway is not a member of the EU). It also is the largest producer and an important exporter of natural gas in the EU. Most of the UK's oil and gas reserves and production are located off the coast of Scotland, with the Scottish city of Aberdeen considered to be the oil and gas capital of the United Kingdom. The International Petroleum Exchange (IPE), the second-largest energy futures exchange in the world, is located in London. The second and third-largest publicly traded energy companies in the world in terms of market value, Royal Dutch/Shell and BP, respectively, are based in the UK (Royal Dutch/Shell is also based in the Netherlands). Because major UK energy companies are private, the imminent decline in British oil and gas production most likely will translate to an increase in UK companies' involvement abroad, mitigating the effect in the overall UK economy, though Scottish employment is particularly sensitive to North Sea production levels. The oil and gas industry represented about 12% of industrial capital investment, and 2% of total capital investment in 2000. The energy industry overall represents about 4% of GDP. The UK has high taxes on petroleum products, making for among the highest prices in the EU. High fuel prices caused protests and blockades in September 2000.

In July 1999, a Scottish Parliament met for the first time in almost 300 years. "Devolution" gives the Scottish Parliament the ability to tax its own citizens, plus jurisdiction over local issues such as education, health, transport, and agriculture. It has no effect on the economic and industrial structure of the United Kingdom, which remains a single market. Devolution has had no effect on North Sea oil and gas.

North Sea Oil and Gas

North Sea oil and gas reserves were first discovered in the 1960s. The North Sea did not emerge immediately as a key non-OPEC oil producing area, but North Sea production grew as major discoveries continued throughout the 1980s and into the 1990s. Although the region is a relatively high cost producer, its high quality crude oil, political stability, and proximity to major European consumer markets have allowed it to play a major role in world oil and gas markets.

Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil. (Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field.) Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 450,000 bbl/d by 2005, but discussions are reported to be underway on building a pipeline spur from the Statfjord system to the Shell-run Brent pipeline to Sullom Voe. The increased throughput would support trade in the increasingly dated Brent price marker, extending its life as a price marker and reducing volatility in the 15-day Brent forward market, where liquidity has fallen to about 10 cargoes per delivery month compared with 300-400 deals per month in the early 1990s.

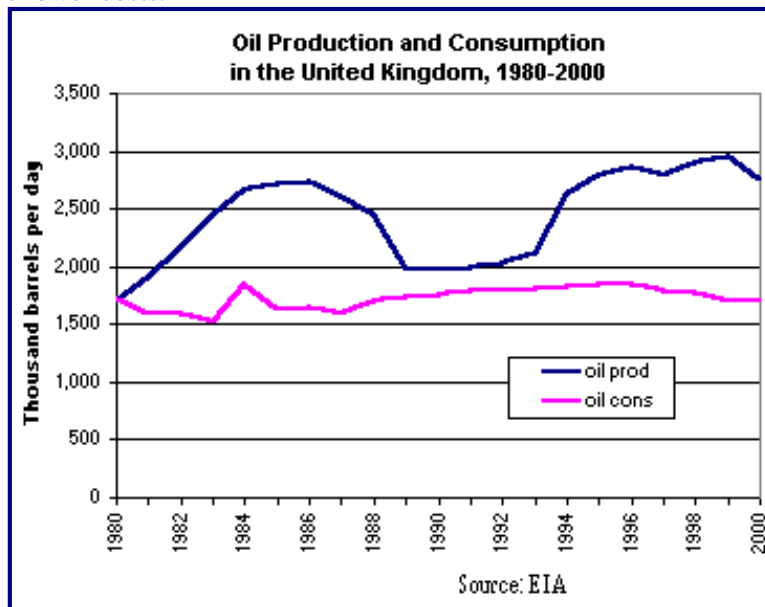
The North Sea is considered a "mature" area, with few large discoveries likely to be made. Only a few frontier areas hold the possibility of further discoveries of large oil and gas fields. In both of the major North Sea producing nations, Norway and the UK, government and industry are taking steps to restructure their oil and gas sectors to make them more internationally competitive.

OIL

The UK holds about 5 billion barrels of proven oil reserves, almost all of which is located in the North Sea. Most of the country's production comes from basins east of Scotland in the central North Sea.

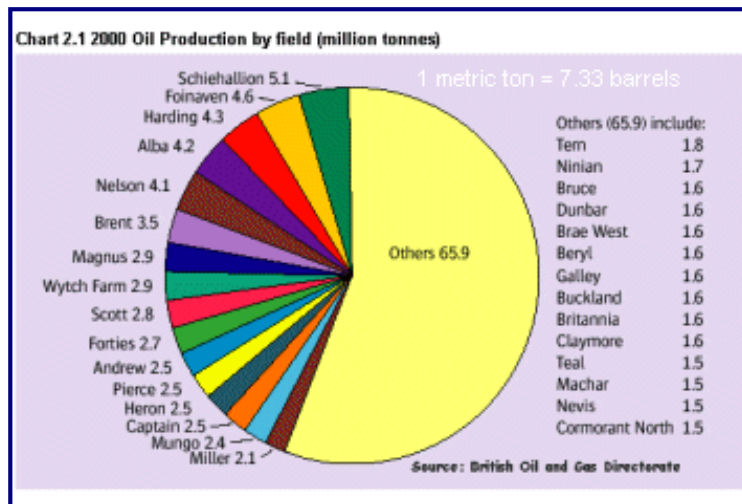
The northern North Sea (east of the Shetland Islands) also holds considerable reserves, and smaller deposits are located in the North Atlantic Ocean, west of the Shetland Islands. There are over 100 oil and gas fields currently onstream, and several hundred companies are active in the area. In 2000, the United Kingdom's production declined to 2.75 million barrels per day (bbl/d), down from a historical high of 2.95 million bbl/d in 1999. Production is expected to decline by 85,000 bbl/d in 2001. Most of the UK's crude oil production ranges in gravity from 30° to 40° API. Most high quality crude is exported, while cheaper, lower quality (mainly from the Middle East) crude oils are imported for refining. Unit costs for UK oilfields averaged just above \$15 per barrel in 2000, though fields that started production in the 1990s have lower costs.

The domestic UK oil and gas industry is expected to decline as reserves are depleted in the coming decade. The British Oil and Gas Industry Task Force was set up in 1998 to bring together government departments and oil and gas industry representatives (the oil and gas industry is 100% in the hands of the private sector) to discuss the future of the industry. A successor body to the Task Force, known as "PILOT", now has been created to oversee the execution of Task Force recommendations and future developments. Government and industry are interested in collaborating to facilitate a "gentle decline" in British North Sea production, a component of which involves shifting focus from small numbers of very large projects to larger numbers of smaller projects.



Production

The number of fields under development or in production in the UK at the end of 2000 was 264. Just two fields ceased production, Bladen and Blenheim. Oil production from six offshore fields commenced in 2000: Bittern, Cook, Guillemot West, Guillemot North West, Shearwater (condensate), and Keith. In 2001, as of July, four new offshore oil fields were approved for development by the British Oil and Gas Directorate: Halley, Hannay, Kestrel, and Otter; and the Angus field was approved for redevelopment.



In December 2000, the British government gave approval to four new projects that will result in \$1.5 billion in new investment in the British North Sea: (1) a £320 million gas pipeline from the Shetland Islands to the Magnus oil field that takes surplus gas from Sullom Voe oil terminal on the Shetland Islands to be reinjected for enhanced recovery in the Magnus field; (2) a floating platform to drill for oil in the Leadon field which was discovered in 1979, but so far undeveloped, that is expected to yield 50,000 bbl/d of oil equivalent (see below); (3) further development by BP of

the Foinaven oil field; and (4) Ranger Oil's (subsidiary of Canadian Natural Resources Limited) production in the Kyle field, which started in April 2001 at 7,000 bbl/d, in addition to gas production. Total investment spending in the UK continental shelf in 2000 was about £3 billion, though continued high oil prices make it likely that investment will increase for 2001. Most new developments will be subsea, using existing infrastructure, instead of new platforms.

As noted above, production commenced in April 2000 from the Bittern, Guillermot West, and Guillermot North West fields by means of the Amerada-Hess operated Triton FPSO. About 78% of the content is British, and the three fields have reserves of about 140 million barrels of oil and 180 billion cubic feet (Bcf) of gas. Expected field life is 13 years and daily production is 60,000 bbl/d. Another development is the £350-million expansion Area B to Texaco's Captain field completed in December 2000 allows production to increase by 25,000 bbl/d to 85,000 bbl/d and will extend the field's life to beyond 2015.

Some of the smaller projects planned for the British North Sea include development of the Jade and Blake fields. In January 2000, the British subsidiary of Phillips Petroleum (operator) and its partners British Gas, Texaco, Agip, and OMV received approval from DTI to develop the Jade field. The field is expected to produce 15,000 bbl/d of crude oil and 200 million cubic feet per day (Mmcf/d) of natural gas after it comes onstream in late 2001. The BG-operated Blake field represents the opening up of the Outer Moray Firth for new discoveries and developments. It has a subsea tie-back to the existing Bleo Holm FPSO, and will extend the life of the existing Ross field. Production is expected to start in third-quarter 2001.

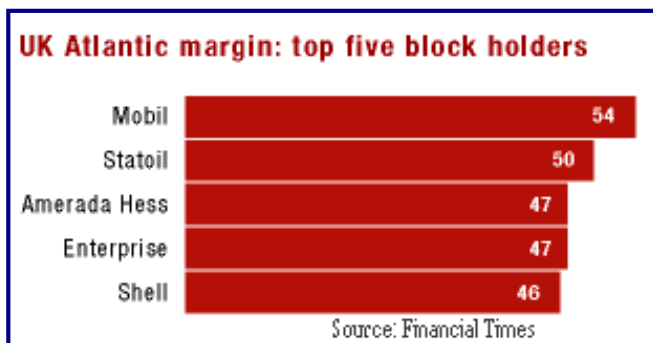
Another important development is the Skene field, which is being developed by operator ExxonMobil as a subsea tie-back to the Beryl Alpha platform. This field has a complex mix of hydrocarbons, including crude oil and condensate, that is estimated to be about 100 million barrels of oil equivalent. Only the implementation of the latest technology using a heated flowline bundle has made recovery possible. It is expected to come online in April 2002.

A larger project that was given approval in 2000 is the development of the Leadon field. It was discovered in 1979, but became economically viable with the discovery of a northern extension of the field. The Canadian company Kerr-McGee-operated field is expected to commence production in early 2002, and will peak at 40,000 bbl/d of crude oil.

Europe's largest on-shore oilfield is Wytch Farm. Estimated reserves are 500 million barrels. Egdon Exploration is active in the area, and it is hoped that even smaller fields can be economically viable as they are on-shore. Other smaller on-shore fields are clustered in east-central England.

Industry Structure

Industry reorganization that started with BP's 1998 merger with Amoco continues. The merged BP Amoco, (now simply BP) already one of the world's largest petroleum companies, announced in April 1999 its intentions to take over Los Angeles-based Atlantic Richfield (Arco), which was completed in April 2000. The merged company is truly global and is the world's third-largest publicly traded oil and gas company. Most of the majors have a share of UK North Sea production, including BP, Chevron, Conoco, ENI, ExxonMobil, Royal Dutch/Shell, Texaco, and TotalFinaElf. Amerada Hess, Enterprise, and Statoil also have large shares. The graphic shows the number of blocks held by each top-ranking company in 2000.



BP Exploration is managed from Aberdeen, Scotland (as are most other companies that are active in the British North Sea). BP produces oil and gas and brings ashore 40% of the UK's total production through the Forties Pipeline System to Grangemouth, Scotland. BP Amoco has producing fields in the North Sea and, since the end of 1997, in the North Atlantic, west of the Shetland

Islands. It operates the Sullom Voe oil terminal in the Shetlands, which is Europe's largest oil terminal. The 206,000-bbl/d oil refinery and petrochemical complex at Grangemouth represents one of Scotland's largest industrial complexes.

British independent oil companies, important in the North Sea oil scene, were particularly hard hit by the oil price collapse of 1998. As a result, the major five independents at the time, Enterprise, Lasmo, Premier, British-Borneo, and Cairn, were hesitant to approve new investment and development in 1999-2000, though Enterprise has now begun more investment and development. The consolidation sweeping the oil majors has affected the independents. Enterprise, the largest British independent, unsuccessfully attempted to take over the second largest, Lasmo, in the spring of 1999. Enterprise's UK production was 164,907 barrels of oil equivalent per day in 2000. In 2000, Italian oil and gas giant ENI began to acquire British independents, British-Borneo in March 2000, and Lasmo in February 2001. This gives ENI a presence in the North Sea, and increases its worldwide oil and gas assets, particularly in Asia. Regarding the remaining two independents, Premier is heavily focused outside of the UK, and Cairn's production and reserves are very small, even for an independent.

Downstream

The UK's crude oil refining capacity is approximately 1.77 million barrels per day, just slightly more than the country's consumption. However, the UK imports and exports refined products because British refineries produce an excess of some grades and products and insufficient quantities of others for local demand. Additionally, demand for gasoline varies seasonally. The largest refinery is ExxonMobil's (Esso's) 311,240-bbl/d Fawley refinery in Southampton, one of the largest in Europe and marine tanker accessible. It also has a pipeline to the on-shore Wytch Farm field. The 100,000-bbl/d Port Clarence Phillips-Imperial Petroleum refinery at North Tees is connected by pipeline to the Phillips Consortium Ekofisk Oil Terminal at Seal Sands, giving it a direct feed from the North Sea. The Grangemouth refinery is also directly connected to the North Sea through the Forties Pipeline System.

Petroleum products represented 45% of final energy consumption in 2000. The retail gasoline market is dominated by Esso (ExxonMobil), BP, Shell, TotalFinaElf, Texaco, and Conoco, which together account for 58% of gasoline sales. Supermarkets now account for 8% of retail sales. Total retail sales were 28 billion liters (7.4 billion gallons) in 2000. The transport sector consumed 74% of petroleum products in 2000, whereas the energy industry consumed just 7%. Fuel oil use has declined 30% since 1998, as industrial and home-heating demand has dropped in favor of gas.

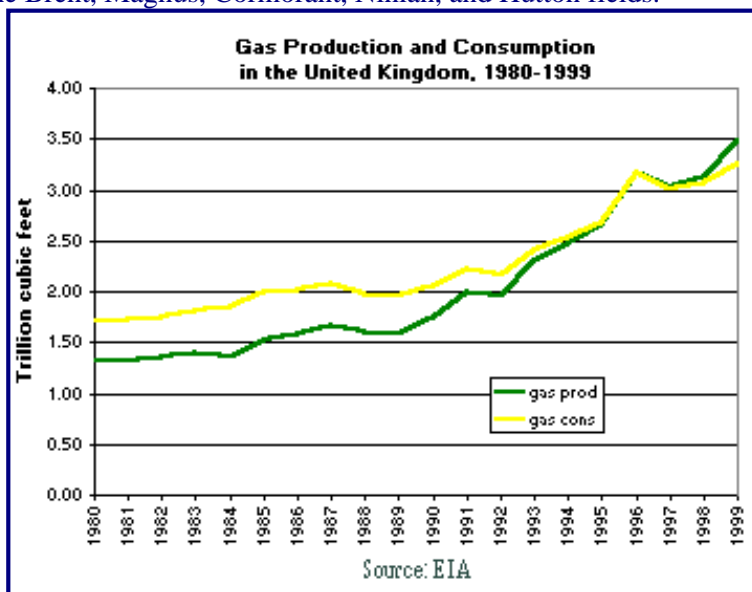
NATURAL GAS

The UK contains an estimated 26.8 trillion cubic feet (Tcf) of natural gas reserves, most of which are in non-associated gas fields located off the English coast in the Southern Gas Basin, adjacent to the Dutch North Sea sector. The UK shares the declining Frigg field with Norway (39.18% to the UK), which is expected to be shut down in 2002, and has small share of the 0.44-Tcf Statfjord field (14.53%). There are a few small fields on-shore. The Irish Sea contains the large Morecambe and Hamilton fields. Morecambe alone accounts for up to 20% of British natural gas production. Key producing gas fields in the North Sea include BP's 5.7-Tcf Leman, Chevron and Conoco's 3-Tcf Britannia, Shell's 1.7-Tcf Indefatigable and 0.8-Tcf Clipper, and TotalFinaElf's 0.85 Tcf Elgin. Key pipelines are the Scottish Area Gas Evacuation (SAGE) system to the St Fergus Terminal, which

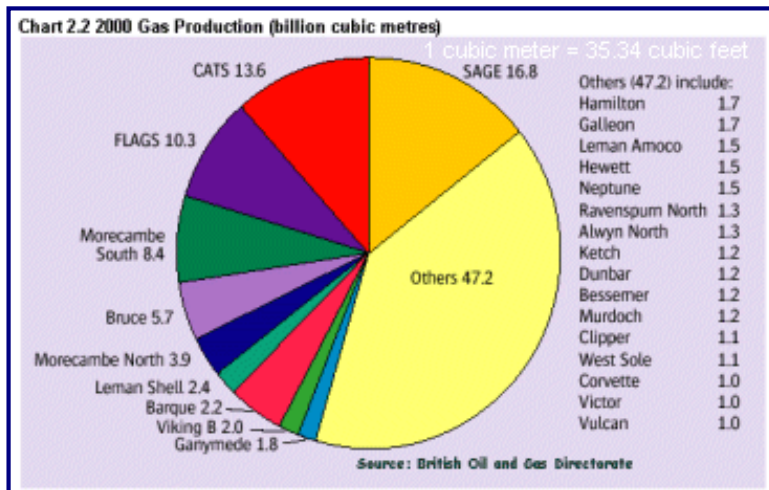
handles gas produced from a number of North Sea fields, including Britannia, the Beryl and Brae areas, and others in the central/northern North Sea, the Central Area Transmission System (CATS) that also goes to the Central North Sea, and takes gas from several fields, including Everest, Judy, and Jade, and others, and the Far North Liquids and Associated Gas System (FLAGS) that takes gas from the northern North Sea, including the Brent, Magnus, Cormorant, Ninian, and Hutton fields.

The largest project to come online in 2001 (in March) in the British North Sea is the TotalFinaElf-operated Elgin/Franklin platform, which might prove to be the last big North Sea production platform. It is the world's largest high-pressure, high temperature development. The Elgin/Franklin platform has extensive processing facilities, unlike most North Sea platforms. The \$2.3-billion platform is expected to last for 22 years in its location in the central North Sea, in the Graben area, off the coast of Scotland. It is to

produce 700 million barrels of oil equivalent, about half condensate and half natural gas. This equates to peak production of 350 million cubic feet per day (Mmcf/d) of natural gas. The export pipelines are shared with the Shearwater field, and include a 294-mile gas pipeline to Bacton and a 24-mile condensate pipeline to the Marnock platform. The Shell-operated Shearwater field in the central North Sea was inaugurated in September 2000, and has reserves of 0.71 Tcf natural gas and 110 million barrels of condensate. Gas production is expected to peak at 375 Mmcf/d.



The Brigantine cluster is the most important recent development in the Southern Gas Basin. It is three fields with two platforms using extended reach horizontal wells to get at reserves of 0.27 Tcf. Shell is the operator, and production of 130 Mmcf/d commenced in the first quarter of 2001. There is a 12-mile pipeline to the Corvette platform, which is connected indirectly with Bacton.



British Gas was the monopoly supplier to the interruptible market until the passage of the 1995 Gas Act, which split the company into supply and shipping (British Gas Trading Limited) and while other functions remained with British Gas, including transport subsidiary Transco. In 1997, Centrica was demerged from British Gas, and British Gas was renamed BG. Centrica is the holding company for British Gas Trading, British Gas Services, the Retail Energy Centers, and is the producer in the Morecambe fields. BG retained Transco, along with exploration and production, international downstream, R&D and properties. In October 2000, BG again split, with Transco becoming part of a separate holding company Lattice Group. Independent Gas suppliers entered the firm (non-tariff) market in 1990, but the larger interruptible market (smaller customers) brought in competition in 1995. The consumer gas market was deregulated by region from October 1997 to June 1998, such that all residential and commercial customers could choose their supplier at the end of this process. At the end of 2000, suppliers other than British Gas Trading had captured 20-30% of the market in many

regions of the UK. In July 2001, Houston-based Dynegy purchased BG Storage from what remains of BG for \$590 million, acquiring gas production wells and platforms, salt caverns, pipelines, and a natural gas processing terminal.

The UK's gas and electricity regulatory body is the Office of Gas and Electricity Markets (Ofgem). Ofgem has proposed reforming price controls on Transco's pipeline usage fees. The privatization of the UK's gas industry, leading to an increased gas supply and reduced prices, has helped gas to replace much of the UK's reliance on coal as a source for electricity generation. The natural gas share of utility fuels was 1% in 1988 and is expected to increase to almost 50% by 2010. Privatization in the UK has progressed well in advance of EU requirements.

In 1998, the UK-Continent Gas Interconnector pipeline was opened, with terminals at Bacton, England and Zeebrugge, Belgium. This is the first natural gas pipeline linking the United Kingdom to the European continent. A new pipeline to connect Ireland to Scottish gas sources in the Corrib field was approved in November 1999, and a plan to connect Ireland to England via Wales was announced in April 2000. A pipeline would run from Manchester, England, underground to Wales, and then under the Irish Sea to just north of Dublin. There is currently one pipeline linking Britain and Ireland, connecting Ireland to Scottish gas sources. Despite these pipeline projects, the UK will remain a much smaller natural gas exporter than North Sea neighbor Norway, and will eventually become a net importer as the UK begins to import Norwegian gas again. Norway had once supplied up to a quarter of British demand in the 1980s, but this dwindled as the Frigg field that supplied the gas was depleted. The new Vesterled gas pipeline, set to begin operations October 1, 2001, will be one of the ways Norwegian gas may enter the UK. Vesterled will connect the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gasfields, and from there to other areas of the Norwegian North Sea such as the Ormen Lange gasfield that is scheduled to come on stream in 2006. In July 2001, BP announced a 15-year contract to buy 56.5 billion cubic feet (Bcf) natural gas per year from Statoil. However, Statoil has indicated that it would not import large volumes of gas through Vesterled unless Britain changed its pricing system for bringing gas onshore from North Sea fields. Statoil officials have asserted that the UK's system of auctioning entry capacity, or access rights to the national pipeline system, had produced volatile, very high prices.

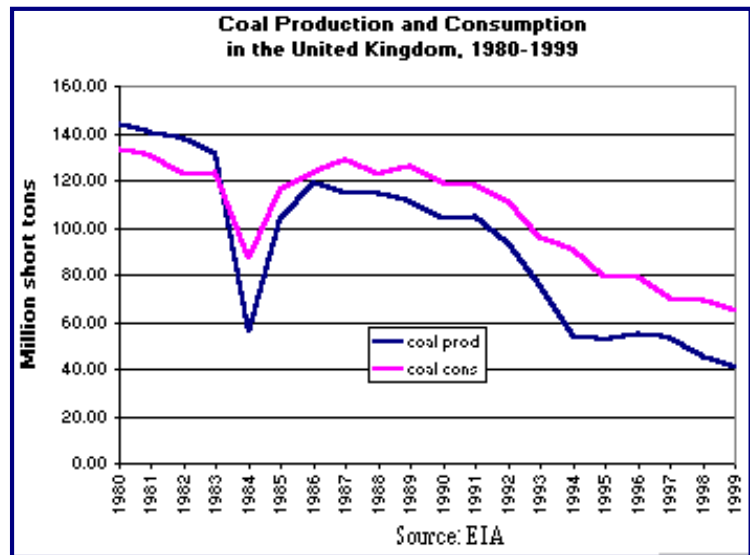
COAL

Coal production and consumption in the United Kingdom have decreased dramatically since 1986. UK coal production fell from 119 million short tons (Mmst) in 1986 to 40.9 Mmst in 1999. Production fell again in 2000, but demand rose, increasing imports. In 2000, steam coal accounted for 80% of coal demand, coking coal for 15%, and anthracite for 5%. Electricity demand accounted for 95% of demand for steam coal and 46.5% of demand for anthracite. In the late 1980s, coal accounted for about two-thirds of the United Kingdom's thermal electricity production. Currently, less than half of UK thermal electricity is coal-fired, and the figure is expected to fall below one-third by the end of the decade. Coal mines are located primarily in central and northern England and southern Wales, with some coal mines also found in southern Scotland. The UK produced 40.5 million tons of bituminous coal and 409 thousand tons of anthracite coal in 1999. The UK also produces coke-oven coke in quantities such that it is self-sufficient. Nevertheless, net imports of coal in 1999 were 23.9 million tons.

Between 1984 and 1985, the British coal miners' union staged a year-long strike. The strike dramatically altered energy production and consumption patterns in the United Kingdom for that year and precipitated the longer term decline of the industry (see graph).

Employment in the industry has plummeted since the late 1980s. The United Kingdom began liberalizing its electricity market in 1989, and this liberalization is one of the major reasons for the decline of the country's coal industry. Prior to the privatization of electricity,

the cost of domestic coal to electric utilities had far exceeded the cost of coal traded in international markets. The Central Electricity Generation Board (CEGB) had been the primary purchaser of British coal. The CEGB largely subsidized the British coal industry, purchasing domestic coal at above world market prices and then passing on those costs to consumers. This ended when National Power and PowerGen, two private electricity generation companies, were formed in the early 1990s, weakening the bargaining power of British Coal, the national coal company.



In 1992, the British coal industry reached a turning point. Growing competition from increasingly available natural gas, the imminent removal of the regional electricity companies' captive franchise supply markets, and newly-enacted pollution abatement goals all worked to initiate the steady decline of the industry. The industry was privatized in 1994, at which point RJB Mining bought the major British Coal assets and became the country's major producer. Mining Scotland and Celtic Energy are the other two remaining companies. The UK coal industry had not received any subsidies since 1995, but in November 2000 the European Commission approved a modernization plan and aid scheme. The aid would go toward mines/production units that have long-term economic viability on the world market, but are having temporary difficulties as they restructure in an effort to reduce production costs. The total amount of aid will not exceed £110 million, and two disbursements of £25 million and £21 million have been made so far. Production costs over the period 1992 to 1999 already fell 35%, and the expectation is that these costs can fall further still before the aid scheme expires in July 2002.

New EU environmental directives are expected to further increase British coal production costs, leading some analysts to predict an end to the United Kingdom's coal industry in the early 2000s. RJB Mining is more optimistic about the future of British coal. RJB maintains that foreign coal prices will increase, making British coal more competitive, and that clean coal technology will allow power stations to burn increased amounts of coal without increased greenhouse gas emissions. Higher natural gas prices, gas-fired power plant outages for maintenance and repair, and reduced nuclear power led to a 14% increase in coal consumption by power producers in 2000.

ELECTRICITY

The United Kingdom has 70 million kilowatts of installed electric capacity, about 80% of which is thermal, 18% nuclear, and 2% hydropower. The country generated 342.8 billion kilowatt hours (bkwh) of electricity in 1999, making it the third-largest electricity market in Europe (behind Germany and France).

Electricity privatization began in the early 1990s, and the final phase of transition ended in May 1999. Initially, all non-nuclear state-owned power stations were privatized and four major generating companies -- PowerGen and National Power in England and Wales, and ScottishPower and Hydro-Electric in Scotland -- were formed to operate the stations. The grid distribution system in England and Wales became the property of the National Grid Company. Regional Electricity Boards were

privatized as separate distribution companies. Large customers were the first to be able to choose their suppliers, with all small customers (below 100 kW peak load) being able to choose by May 1999.

The number of electric generation companies in the United Kingdom has increased to 27 as a result of the liberalization process, according to DTI, such that 40% of the UK's electricity was generated by these new companies in 2000. In March 2001, the structure of the electricity industry changed yet again. Under the former system, generators and suppliers in England and Wales traded electricity through the electricity pool, which was regulated by the National Grid Company, owner of the transmission network. The New Electricity Trading Arrangements (NETA) changed this to a system based on bilateral trading between generators, suppliers, traders, and customers. The system includes forwards and futures markets, a balancing mechanism to enable the National Grid Company to balance the system, and a settlement process. Dallas-based TXU purchased United Utilities' retail electricity and natural gas business, Norweb Energi, for \$465 million in August 2000. This, added to TXU's European retail business Eastern Energy, creates the UK's largest electricity retailer, with over 5.6 million customers. Powergen, with 2.6 million retail customers as well as 14% of electricity generation in England and Wales, merged with Louisville-based LG&E Energy in December 2000.

In Scotland, the two main companies, Scottish Power and Scottish and Southern Energy, cover the full range of electricity provision. Ofgem has made proposals to further reform the Scottish power market. Northern Ireland, part of the United Kingdom but not part of Great Britain, is served by Northern Ireland Electricity, one of the largest companies in Northern Ireland and part of the Viridian Group. Northern Ireland has a separate electricity and gas regulatory body, Ofreg. The grids of Northern Ireland and the Republic of Ireland are connected for electricity import/export.

Nuclear

In 1995, the government announced that it would privatize its more modern nuclear stations while retaining ownership of older stations. In 1996, more modern stations were privatized and British Energy became the holding company of Nuclear Electric and Scottish Nuclear, which merged in 1998 to form British Energy Generation, the nation's largest private nuclear generator and the world's first wholly privatized nuclear utility. British Energy operates eight nuclear power stations in the UK (as well as several in the U.S. through its AmerGen subsidiary that is jointly owned with PECO). Each station consists of two advanced gas-cooled reactors, except Sizewell B, which is a modern pressurized-water reactor. Nuclear power stations were not privatized simultaneously with non-nuclear stations. No new plants have been built since 1995, but because of limited domestic coal and gas reserves in the long run, new construction is under discussion, at least to maintain nuclear's market share as older nuclear plants are retired. Of the UK's 33 reactors, 26 are of the old Magnox design. Six of the Magnox reactors are being decommissioned, as well as the Dounreay prototype fast reactor. The remaining Magnox plants are run by the state-owned British Nuclear Fuels. British Nuclear Fuels operates the Sellafield reprocessing plant, and is one of only two companies in the world that provides reprocessing and recycling technologies. The British nuclear industry is regulated by the Department of Trade and Industry's Nuclear Directorate.

ENVIRONMENT

With a reduction in sulfur dioxide and carbon dioxide emissions, environmental conditions in the United Kingdom have improved over the past couple of decades. Some of these environmental improvements, such as a reduction in [air pollution](#), can be attributed to the United Kingdom's [energy use](#) choices. Partially as a result of deregulation and the elimination of coal subsidies, coal's share of total primary energy consumption is gradually being replaced by natural gas.

Improvements in energy efficiency have led to a gradual reduction in both [energy and carbon intensity](#). In 1980, energy intensity in the United Kingdom registered 11.70 thousand Btu per \$1990, decreasing to 8.37 thousand Btu per \$1990 in 1999, a 27% decline. Similarly, carbon intensity in 1999 registered 0.13 metric tons of carbon per thousand \$1990, a 45% decrease from 1980 levels. [Per capita](#) energy consumption, at 167.8 million Btu in 1999, is rising gradually.

As the United Kingdom enters the [21st century](#), many energy and environment-related policies reflect the country's awareness of climate change issues. With introduction of the Climate Change Levy in 2001, and its exemption for [renewable](#) energy resources like solar and wind, these alternative sources of energy are beginning to gain more attention. For example, the United Kingdom hopes to increase the share of electricity generated by renewables from the current 2%, to 10% by 2010.

Sources for this report include: Aberdeen Press & Journal; CIA World Factbook; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Hart's European Offshore Petroleum Newsletter; Oil & Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; The Scotsman; U.K. Department of Trade and Industry; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

Head of State: Queen Elizabeth II

Prime Minister: Anthony (Tony) Blair, re-elected June 2001

Population (2000E): 59.5 million

Location/Size: Western Europe, islands including the northern one-sixth of the island of Ireland between the North Atlantic Ocean and the North Sea, northwest of France/244,820 sq km (slightly smaller than Oregon)

Capital City: London

Language: English

Ethnic groups: English 81.5%, Scottish 9.6%, Irish 2.4%, Welsh 1.9%, Ulster 1.8%, West Indian, Indian, Pakistani, and other 2.8%

Religions: Anglican 27 million, Roman Catholic 9 million, Muslim 1 million, Presbyterian 800,000, Methodist 760,000, Sikh 400,000, Hindu 350,000, Jewish 300,000 (1991 est.)

Defense (8/98): Army, 113,900; Navy, 44,500; Air Force, 52,540

ECONOMIC OVERVIEW

Chancellor of the Exchequer: Gordon Brown

Currency: Pound sterling

Exchange Rate (9/04/01): 1 US Dollar = 0.69 pounds

Gross Domestic Product (GDP, 2000E): \$1,415 billion

Real GDP Growth Rate (2000E): 3.0% **(2001F):** 2.0%

Inflation Rate (consumer prices, 2000E): 2.9% **(2001F):** 2.0%

Unemployment Rate (2000E): 3.7% **(2001F):** 3.4%

Merchandise Exports (2000E): \$283 billion

Merchandise Imports (1999E): \$327 billion

Major Trading Partners: United States, Germany, France, Netherlands

Major Exports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

Major Imports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

ENERGY PROFILE

Secretary of State for Trade and Industry: Patricia Hewitt

Minister of State for Industry and Energy: Brian Wilson

Proven Oil Reserves (1/1/01): 5 billion barrels

Oil Production (2000): 2.75 million bbl/d, of which 2.48 million bbl/d was crude oil

Oil Consumption (2000): 1.7 million bbl/d

Crude Oil Refining Capacity (1/1/01): 1.77 million bbl/d

Net Oil Exports (2000): 1.05 million bbl/d

Natural Gas Reserves (1/1/01): 26.8 trillion cubic feet (Tcf)

Natural Gas Production (1999E): 3.49 Tcf

Natural Gas Consumption (1999E): 3.26 Tcf

Natural Gas Net Exports (1999E): 0.02 Tcf

Major Systems: Brent, Ninian, Forties, Flotta, Fulmar

Major Fields: E. Brae, Brent, Forties, Magnus, Miller, Scott

Oil and Gas Companies: Amerada Hess, BP Amoco, BHP, Chevron, ExxonMobil, Kerr-McGee, Phillips, Ranger Oil, Shell, Texaco

Recoverable Coal Reserves (12/31/96E): 1.65 billion short tons

Coal Production (1999E): 40.9 million short tons (Mmst)

Coal Consumption (1999E): 64.8 Mmst

Electrical Generation Capacity (1/1/99): 69.9 gigawatts (79.7% thermal, 2.1% hydro, 18% nuclear, 0.2% other)

Electricity Generation (1999E): 342.8 billion kilowatt hours (bkwh)

Electricity Consumption (1999E): 333 bkwh

ENVIRONMENTAL OVERVIEW

Secretary of State for the Environment, Food, and Rural Affairs: Margaret Beckett

Total Energy Consumption (1999E): 9.9 quadrillion Btu* (2.6% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 152.4 million metric tons of carbon (2.5% of world carbon emissions)

Per Capita Energy Consumption (1999E): 167.8 million Btu (vs. U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 2.6 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)

Energy Intensity (1999E): 8,365 Btu/\$1990 (vs U.S. value of 12,638 Btu/\$1990)**

Carbon Intensity (1999E): 0.13 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (37.0%), Residential (25.4%), Transportation (26.1%), Commercial (11.5%)

Sectoral Share of Carbon Emissions (1998E): Industrial (33.7%), Transportation (31.3%), Residential (24.3%), Commercial (10.6%),

Fuel Share of Energy Consumption (1999E): Oil (35.0%), Natural Gas (34.9%), Coal (15.7%)

Fuel Share of Carbon Emissions (1999E): Oil (41.2%), Natural Gas (33.4%), Coal (25.5%)

Renewable Energy Consumption (1998E): 137 trillion Btu* (15% increase from 1997)

Number of People per Motor Vehicle (1998): 2.3 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change. Under the negotiated Kyoto Protocol (signed on April 29th, 1998 - not yet ratified), the UK has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.

Major Environmental Issues: Sulfur dioxide emissions from power plants contribute to air pollution; some rivers polluted by agricultural wastes and coastal waters polluted because of large-scale disposal of sewage at sea.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Links

For more EIA information on the United Kingdom:

[EIA - Country Information on the United Kingdom](#)

[Electricity Restructuring and Privatization in the United Kingdom](#)

Links to other U.S. Government sites:

[CIA World Factbook - United Kingdom](#)

[U.S. State Department Country Commercial Guides: Europe](#)

[U.S. State Department Consular Information Sheet](#)

[U.S. Geological Survey, map of the United Kingdom including oil fields](#)

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[Energy Links for the UK from Online Energy Services](#)

[International Petroleum Exchange](#)

[Grampian Oil and Gas Directory \(an online database of companies operating in Scotland\)](#)

[Scottish Enterprise Energy Group](#)

[RJB Mining](#)

[Electricity Association](#)

[National Power](#)

[PowerGen](#)

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[National Grid](#)

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[British Energy \(nuclear generator\)](#)

[British Nuclear Fuels](#)

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[Ofgem](#)

[Ofreg](#)

[Department of Trade and Industry](#)

[Department of Environment, Transport and the Regions](#)

[British Embassy in Washington, D.C.](#)

[Scottish Parliament](#)

[International Energy Agency United Kingdom 1998 Review](#)

[Royal Institute of International Affairs, Energy and Environmental Programme](#)

[European Commission Directorate General XVII \(Energy\)](#)

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Libya

Libya is a major oil exporter, particularly to Europe. With the suspension of U. N. sanctions against Libya following its extradition of two men suspected in the 1988 bombing of Pan Am flight 103 over Lockerbie, Scotland, oil companies are eager to resume and/or expand operations in Libya.

Note: Information contained in this report is the best available as of July 2002 and can change.



GENERAL BACKGROUND

Oil export revenues, which account for about 95% of Libya's hard currency earnings (and 75% of government receipts), were hurt severely by the dramatic decline in oil prices during 1998, as well as by reduced oil exports and production - in part as a result of U.S. and U.N. sanctions. With higher oil prices since 1999, however, Libyan oil export revenues have increased sharply, to \$11.0 billion in 2001 and \$10.6 billion forecast for 2002, up from only \$6.0 billion in 1998.

As a result of strong oil export revenues, Libya's fiscal situation is now significantly in surplus.

Libya has experienced strong economic growth over the past three years. Real gross domestic product (GDP) grew by around 6.5% in 2000 and 3.1%-4.3% in 2001. For 2002, real GDP growth of 3.6%-4.5% is expected. Despite this strong economic growth, Libya's unemployment rate remains high, and inflation remains under control (note: the Economist Intelligence Unit in April 2002 stated that Libya actually was in the midst of "significant deflation," although Libyan economic statistics are somewhat unreliable). Libya's relatively poor infrastructure (i.e. roads and logistics), unclear legal structure, often-arbitrary government decisionmaking process, a bloated public sector (as much as 60% of government spending goes towards paying public sector employees' salaries), and various structural rigidities all have been impediments to foreign investment and economic growth. There are signs that the country now is moving towards a variety of economic reforms and a reduction in the state's direct role in the economy.

In January 2002, Libya devalued the official exchange rate on its currency, the dinar, by 51% as part of a move towards unification of the country's multi-tier foreign exchange system. The devaluation also aims to increase the competitiveness of Libyan firms and to help attract foreign investment into the country. Besides the official dinar exchange rate, which is used for state transactions (i.e., imports of goods by the government), Libya has a commercial rate and a black market rate. Also in January 2002, Libya cut its customs duty rate by 50% on most imports in part to help offset the effects of its currency devaluation.

On April 5, 1999, more than 10 years after the 1988 bombing of Pan Am flight 103 over Lockerbie, Scotland that killed 270 people, Libya extradited two men suspected in the attack. In response, the United Nations suspended economic and other sanctions against Libya which had been in place since April 1992. US sanctions, including the Iran-Libya Sanctions Act (ILSA) of 1996 (which covers foreign companies that make new investments of \$40

million or more over a 12-month period in Libya's oil or gas sectors) remain in effect. On July 27, 2001, the US Congress voted to extend ILSA for five more years. UN sanctions since 1992 reportedly have cost Libya billions of dollars in lost income, and have made it more difficult for Libya to develop its energy sector. A full lifting of sanctions can occur 90 days after the UN certifies that Libya has met all requirements, including renunciation of support for terrorist acts. On July 9, 1999, the UN Security Council issued a statement saying that while it "welcomed the significant progress" which Libya had made in complying with UN demands, that at the same time Libya would need to do more (i.e., cooperate with court proceedings, pay compensation to families if the suspects are convicted) before sanctions were lifted permanently. In late May 2002, Libya was reported to be offering \$2.7 billion in compensation to families of Pan Am flight 103, with money to be released as UN and US sanctions are lifted. However, a Libyan government spokesman denied the offer, according to the state news agency (JANA).

Libya is hoping to reduce its dependency on oil as the country's sole source of income, and to increase investment in agriculture, tourism, fisheries, mining, and natural gas. Libya's agricultural sector is a top governmental priority. Hopes are that the Great Man Made River (GMR), a five-phase, \$30-billion project to bring water from underground aquifers beneath the Sahara to the Mediterranean coast, will reduce the country's water shortage and its dependence on food imports. Libya also is attempting to position itself as a key economic intermediary between Europe and Africa, has become more involved in the Euro-Mediterranean process, and has pushed for a new African Union. In April 2001, members of the [Arab Maghreb Union](#) (Algeria, Libya, Mauritania, Morocco, and Tunisia) agreed to encourage intra-regional cooperation on trade, customs, banking, and investment issues.

OIL

Libya's oil industry is run by the state-owned National Oil Corporation (NOC), along with smaller subsidiary companies. As of 2000, NOC had an estimated total oil production capacity of around 810,000 bbl/d, accounting for over half the country's total. Several international oil companies are

engaged in exploration/production agreements with NOC. The leading foreign oil producer in Libya is Italy's Agip-Eni, which has been operating in the country since 1959. Two US oil companies (Exxon and Mobil) withdrew from Libya in 1982, following a US trade embargo begun in 1981. Five other US companies (Amerada Hess, Conoco, Grace Petroleum, Marathon, and Occidental) remained active in Libya until 1986, when President Reagan ordered them all to cease activities there. Conoco, Amarada Hess and Occidental made up the "Oasis Group," which was producing around 850,000 bbl/d in 1986.

In December 1999, US oil company executives from Oasis plus Marathon traveled to Libya, with US government approval, to visit their old oil facilities in the country. The former head of NOC, Abdullah al-Badri, has stated that if US companies return to Libya, they will return to the fields they used to operate in the country. However, in the first part of 2001, Libya contacted the US companies and indicated that, given its desire to develop their fields, Libya was considering transferring them to European companies. In September 2001, Libya stated that the US companies must either make use of their concessions within a year or risk losing them. In March 2002, the US State Department said that it would permit Marathon Oil to hold discussions with Libyan officials while sanctions remain fully in place.

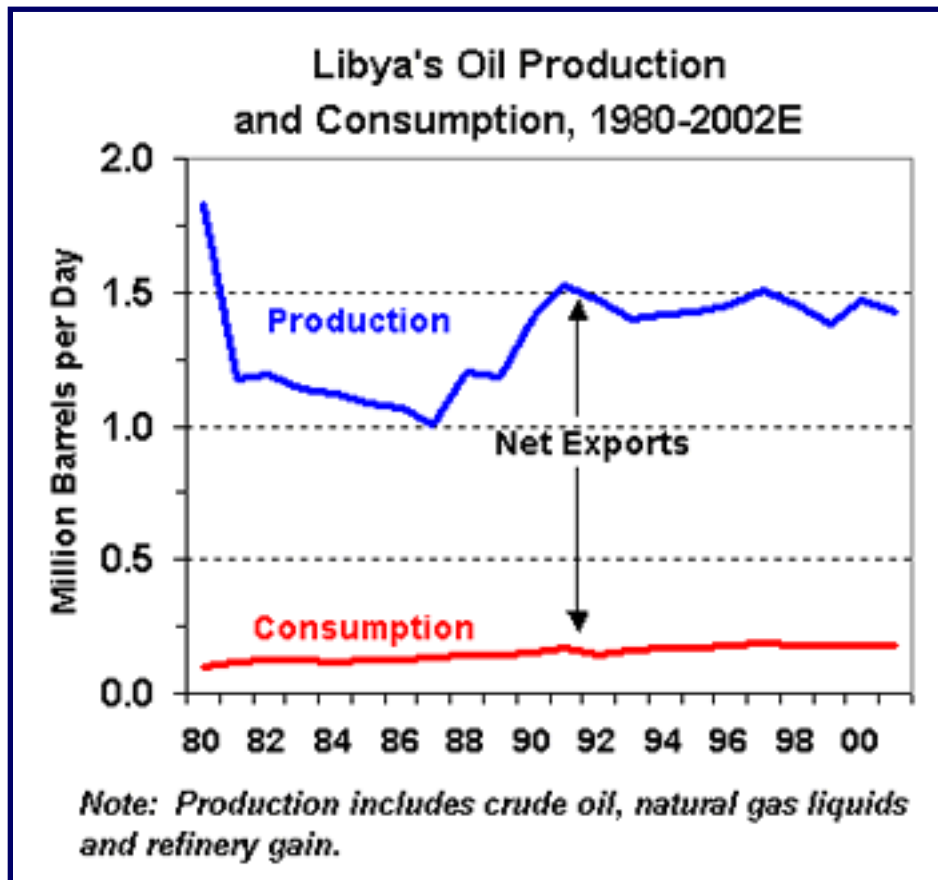
Overall, Libya would like foreign company help to increase the country's oil production capacity from 1.5 million bbl/d at present to 2 million bbl/d over the next five years. This would restore Libya's oil production capacity to the level of the early 1970s. During the 1970s, the country's revolutionary government imposed tough terms on producing companies, leading to a slide in oilfield investments and oil production. In May 2000, Libya invited around 50 foreign oil and gas companies to a meeting to discuss exploration and production sharing agreements. In order to achieve its oil sector goals, Libya will require as much as \$10 billion in foreign investment through 2010. Around \$6 billion of this is to go towards exploration and production, with the rest going towards refining and petrochemicals. In addition, NOC has earmarked \$1.5 billion for oil infrastructure investment. In January 2002,

NOC appointed Abdel-Hafez Zleitni as its new chairman, with the specific mission to work on attracting foreign investment into the country's oil sector.

Currently, Libya has 12 oil fields with reserves of 1 billion barrels or more each, and two others with reserves of 500 million-1 billion barrels. Libya's onshore oil (where most production currently takes place) is found mainly in three geological trends of the Sirte Basin: 1) the western fairway, which includes several large oil fields (Samah, Beida, Raguba, Dahra-Hofra, and Bahi); 2) the north-center of the country, which contains the giant Defa-Waha and Nasser fields, as well as the large Hateiba gas field; and 3) an easterly trend, which has such giant fields as Sarir, Messla, Gialo, Bu Attifel, Intisar, Nafoora-Augila, and Amal. Despite years of oil production, Libya retains a large untapped oil and gas potential, with only around 25% of Libya's area covered by agreements with oil companies. This potential is due largely to lack of investment mainly as a result of stringent fiscal terms imposed by Libya on foreign oil companies. NOC priorities for exploration include new areas in the Sirte (i.e., Blocks 25 and 36), Ghadames (i.e., Block 20), and Murzuq basins, plus unexplored areas such as Kufra and Cyrenaica. NOC also hopes to apply modern Enhanced Oil Recovery (EOR) techniques to existing oil fields.

Libya has a relatively narrow continental shelf and slope in the Mediterranean and Gulf of Sirte, which widens in the west in the Gulf of Gabes. The northern part of the Gulf of Gabes, also known as the November Seventh concession, lies on the Libyan-Tunisian border and is rich in oil and gas. As part of a 1988 settlement to a long-standing territorial dispute, the area (which contains an estimated 3.7 billion barrels of oil and nearly 12 trillion cubic feet -- Tcf -- of natural gas) is set to be exploited by the Libyan-Tunisian Joint Oil Company (JOC), a 50-50 venture of Libya's NOC and Tunisia's ETAP. The Libyan side of the zone contains the Omar structure, which is estimated to contain more than 65% of the zone's total oil and gas reserves. On February 1, 1997, JOC awarded the entire block to a consortium consisting of Saudi Arabia's Nimr Petroleum (55%) and Malaysia's Petronas (45%). The companies have a \$30-million, 5-year commitment to explore the block. Full

development of the concession could cost more than \$1 billion.



Production, Exports, and Reserves

Libya produces high-quality, low-sulphur ("sweet") crude oil at very low cost (as low as \$1 per barrel at some fields).

Libyan oil is priced off of Dated Brent, and main export grades include Es Sider (36-37° API), El Sharara (44° API), Zueitina (42° API), Bu Attifel (41° API), Brega (40° API), Sirtica

(40° API), Sarir (38° API), Amna (36° API), and El Bouri (26° API). Most Libyan oil is sold on a term basis, including to the country's Oilinvest marketing network in Europe; to companies like Agip, OMV, Repsol YPF, Tupras, CEPSA, and TotalFinaElf; and small volumes to Asian and South African companies.

During the first quarter of 2002, Libyan oil production was estimated at just over 1.3 million bbl/d, only about two-fifths of the 3.3 million bbl/d produced in 1970. Libya would like to boost oil output, and the suspension of UN sanctions, along with possible changes to Libya's 1955 hydrocarbons legislation, could be helpful in this regard. Sanctions had caused delays in a number of field development and EOR projects, and had deterred foreign capital investment to an extent. Suspension of sanctions means that Libya now can resume purchases of oil industry equipment.

With reserve replacement slipping since the 1970s, Libya's challenge is maintaining production at mature fields (Brega, Sarir, Sirtica, Waha, Zuetina) while at the same time bringing new fields like Murzuq/El Sharara (online in December 1996; reserves of 2 billion barrels; main operator Repsol-YPF, along with Austria's OMV and TotalFinaElf) and Mabruk online. Libya currently exports about 1.2 million bbl/d of oil. Nearly all (about 90%) of this is sold to European countries like Italy (507,000 bbl/d in 2001), Germany (208,000 bbl/d in 2001), France (70,000 bbl/d in 2001), Spain and Greece.

With state-operated oil fields undergoing a 7%-8% natural decline rate, Libya depends heavily on foreign companies and workers. Major foreign companies include Spain's Repsol-YPF (150,000-200,000 bbl/d of output, mainly at the El Sharara field, plus exploration at blocks NC-186, NC-187, and North-A), Italy's Agip (82,000 bbl/d mainly from Bu Attifel, plus exploration on block NC-174 and in the el-Bouri offshore field), Austria's OMV, Germany's Veba (50,000 bbl/d, mainly from its Amal field in Block NC-12), Wintershal, and multinational TotalFinaElf. Production from Block NC-115 of the Murzuq basin, being developed by Repsol-YPF, TotalFinaElf, and OMV (with 75% of output going to Libya's NOC), increased to around 75,000 bbl/d in early 1998, and 160,000 bbl/d as of October 2001. In January 1999, Repsol (now Repsol-YPF) said that it had found an "important" petroleum deposit of light, sweet (low sulfur) oil in the Block. In December 2001, Repsol-YPF (along with OMV, TotalFinaElf and Saga Petroleum) announced that it had discovered a significant new oil deposit in Block NC-186 of Murzuq. Also, in April 2002, the same Repsol-YPF consortium announced its first discovery in in the NC-190 block of Murzuq, in the Hawaz formation.

Libya is actively courting foreign oil companies, and is considered a highly attractive oil province due to its low cost of oil recovery, its proximity to European markets, and its well-developed infrastructure. European companies reportedly are growing frustrated over the slow pace of progress in awarding Libyan oil concessions, including the 130 exploration blocks offered since UN sanctions were lifted in 1999. As of March 2002, only five packages reportedly had been awarded. In April 2002, Libya signed an

agreement with China to offer Chinese companies a wider role in the Libyan oil sector.

Of NOC's subsidiaries, the largest oil producer is the Waha Oil Company (WOC), created in 1986 to take over operations from Oasis Oil Co., a joint venture of NOC, Conoco, Marathon, and Amarada Hess. WOC has been among the companies most adversely affected by the US embargo. This is due to the fact that its oilfields are equipped mainly with old US equipment, for which WOC cannot now acquire needed spare parts. As a result, production at WOC's giant Waha field has fallen sharply despite an emergency maintenance program begun in 1992.

After Waha, the next largest NOC subsidiary is the Arabian Gulf Oil Company (Agoco), with production coming mainly from the Sarir, Nafoora/Augila, and Messla fields.

Two other large NOC subsidiaries are the Zueitina Oil Company (ZOC), which operates the five Intisar fields in Block 103 of the Sirte Basin, and the Sirte Oil Company (SOC), originally created in 1981 to take over Exxon's holdings in Libya. In 1986, SOC took over the assets of Grace Petroleum, one of the five US companies forced by the US government to leave Libya in 1996. SOC operates the Raguba field in the central part of the Sirte Basin. The field is connected by pipeline to the main line between the Nasser field and Marsa el-Brega. Nasser is one of the largest oilfields in Libya, with production of about 50,000 bbl/d of oil, down from 70,000 bbl/d in 1992. Besides Nasser, SOC is in charge of two other gas fields -- Attahaddy and Assumud -- plus the Marsa el-Brega liquefied natural gas (LNG) plant.

Libya's oilfields are connected to Mediterranean terminals by an extensive network of pipelines. Libya's main crude oil pipelines, all owned by NOC, are: Sarir-Marsa el Hariga (Tobruk); Messla-Ras Lanuf; Waha-Es Sider; Hammada El Hamra-Az Zawiya; Amal-Ras Lanuf; Intisar-Zueitina; Nasser (Zelten)-Marsa El Brega. NOC also has six oil terminals and storage facilities (Marsa El Hariga, Zueitina, Marsa el-Brega, Ras Lanuf, Es Sider,

Zawiya), and is considering bids for a \$150 million-\$300 million expansion of the oil terminal and refinery facility at Az Zawiya.

Exploration and Development

Oil exploration in Libya began in 1955, the key national Petroleum Law No. 25 was enacted in April 1955. Libya's first oil fields were discovered in 1959 (at Amal and Zelten -- now known as Nasser), and oil exports began in 1961. After years of little activity due in part to sanctions, Libya now is attempting to attract foreign companies with improved incentives and production terms. Libya has legislation pending which would grant foreign firms better terms, including access to exploration acreage, small field developments, large field incremental production opportunities, and adoption of international competitive bidding practices. Currently, only around 25% of the country's oil fields have been granted to foreign operators (although Libya does plan to open up some 40 blocks in the Sirte basin and other areas to foreign investment). In July 2000, NOC said that it would open up around 70% of its land to exploration, and that it would bundle exploration blocks into three packages, with the first package to include blocks in the oil-rich Murzuq basin.

The major component of Libya's expansion plans is development of the el-Bouri offshore oilfield off Libya's western coast, the largest producing oilfield in the Mediterranean Sea (at around 60,000 bbl/d). Italy's Agip-Eni is the developer of the field, discovered in 1976 at a depth of 8,700 feet and estimated to contain 2 billion barrels in proven recoverable crude oil reserves. The first phase of field development, costing \$2 billion, was completed in 1990, with el-Bouri producing about 150,000 bbl/d in 1995, with a sharp decline thereafter. This decline was due largely to an inability to import EOR equipment under UN sanctions, and possibly could be reversed with an infusion of investment. Besides oil, el-Bouri also contains large amounts (2.5 Tcf) of associated gas.

Since the discovery of the giant, 2-billion barrel el-Bouri field, Agip-Eni has reported a series of oil finds in its various blocks, as have other oil companies

in the country. The most significant of these is in the Murzuq basin, in the Sahara south of Tripoli. El Bouri was purchased by Repsol in 1993 for \$65 million. Repsol-YPF currently is leading a European consortium, which also consists of OMV and TotalFinaElf. Original expectations were that Murzuq/El Sharara's output of light (44° API), sweet (less than 0.6% sulphur content) crude production would reach 200,000 bbl/d by the end of 1998, but various problems, including difficulties with the pipeline to the port of Az Zawiya, delayed achievement of this target. Currently, oil from Murzuq/El Sharara is being processed by the Az Zawiya refinery.

In October 1997, an international consortium led by British company Lasmo (with a 33.3% stake), along with Agip-Eni (33.3%) and a group of five South Korean companies (led by Korea National Oil Corp., replacing Pedco, and including Hyundai), announced that it had discovered large recoverable crude reserves (around 700 million barrels) at the NC-174 Block, 465 miles south of Tripoli, in the remote Murzuq basin. Lasmo has estimated that production from the field, which it has named Elephant, will cost around \$1 per barrel (Repsol-YPF's Murzuq/El Sharara field, with its 30-inch pipeline to the coast, is located only 40 miles to the north). According to Lasmo, appraisal drilling in 1998 has confirmed recoverable reserves of around 560 million barrels. Elephant originally was due to begin production late in 2000 at around 50,000 bbl/d, and to utilize an existing 30-inch pipeline located 42 miles to the north. Production startup now has been delayed, reportedly due to bureaucratic obstacles, at least until the end of 2002. Production at Elephant is expected to reach 150,000 bbl/d within a year or two of startup.

Other foreign companies active in Libya include: Lundin Oil, a Swedish independent, along with its affiliate Red Sea Oil of Canada, has discovered an estimated 84 million barrels of oil at the En Naga North and West fields on block NC-177 in the Sirte basin (in December 1999, Red Sea announced that testing on the block had been suspended); TotalFinaElf, whose Mabruk field is producing around 18,000 bbl/d; and Canadian Occidental, which controls but has not yet developed a potential 200-million-barrel field in Block NC-101 in the Murzuq basin. In June 2001, Petro-Canada agreed to purchase

Lundin's interest in the En Naga block. In November 2001, TotalFinaElf reportedly was negotiating with NOC to increase production at Mabruk, possibly to 30,000 bbl/d.

Refining/Marketing

Libya has three domestic refineries, with a combined nameplate capacity of approximately 343,400 bbl/d, nearly twice the volume of domestic oil consumption (182,000 bbl/d; the rest is exported). Libya's refineries include: 1) the Ras Lanuf export refinery, completed in 1984 and located on the Gulf of Sirte, with a crude oil refining capacity of 220,000 bbl/d; 2) the Az Zawiya refinery, completed in 1974 and located in northwestern Libya, with crude processing capacity of 120,000 bbl/d; and 3) Brega, the oldest refinery in Libya, located near Tobruk with crude capacity of 8,400 bbl/d. In February 2001, bids were submitted by engineering and construction firms on a \$400 million project to upgrade Az Zawiya (including construction of a new 120,000-bbl/d refinery). In May 2002, Libya signed a \$280 million contract with South Korea's LG Petrochemicals to upgrade the refinery. Ras Lanuf also is slated for upgrading, although that project appears to have been delayed. In March 2002, Ras Lanuf was shut down for several days after a fire broke out at an ethylene storage tank on March 19.

In addition to its domestic refineries, Libya also has operations in Europe. Libya is a direct producer and distributor of refined products in Italy, Germany, Switzerland, and (since early 1998) Egypt. In Italy, Tamoil Italia, based in Milan, controls about 5% of the country's retail market for oil products and lubricants, which are distributed through nearly 2,100 Tamoil service stations. Sanctions have constrained Libya's ability to increase the supply of oil products to European markets, however, as Libya's refineries are badly in need of upgrading, especially in order to meet stricter EU environmental standards in place since 1996. In Egypt, Libya is planning to build gasoline stations on the coastal road linking the two countries as well as in other areas of Egypt. The stations are to be run by Libya's foreign oil investment arm Oilinvest, which maintains 300,000 bbl/d of refining capacity in Europe.

Libya's refining sector reportedly was hard hit by UN sanctions, specifically UN Resolution 883 of November 11, 1993, which banned Libya from importing refinery equipment. Libya is seeking a comprehensive upgrade to its entire refining system, with a particular aim of increasing output of gasoline and other light products (i.e. jet fuel). Possible projects include a new 20,000-bbl/d refinery in Sebha (for which Libya is seeking foreign investment), which would process crude from the nearby Murzuq field, and a 200,000-bbl/d export refinery in Misurata.

NATURAL GAS

Continued expansion of natural gas production remains a high priority for Libya for two main reasons. First, Libya has aimed (with limited success) to use natural gas instead of oil domestically, freeing up more oil for export. Second, Libya has vast natural gas reserves and is looking to increase its gas exports, particularly to Europe. Libya's proven natural gas reserves in 2002 are estimated at 46.4 Tcf, but the country's actual gas reserves are largely unexploited (and unexplored), and thought by Libyan experts to be considerably larger, possibly 50-70 Tcf. Major producing fields include Attahadi, Hatiba, Zelten, Sahl, and Assumud. To expand its gas production, marketing, and distribution, Libya is looking to foreign participation and investment. In recent years large new discoveries have been made in the Ghadames and el-Bouri fields, as well as in the Sirte basin. Libya also produces a small amount of liquefied petroleum gas (LPG), most of which is consumed by domestic refineries.

Libyan natural gas development projects currently underway include as-Sarah and Nahoora, Faregh, Wafa, offshore block NC-41, abu-Attifel, Intisar, and block NC-98. In May 2000, NOC reportedly came out with a framework for gas exploration in the country, under which NOC would have first priority to the foreign company's gas share at an agreed discount. In December 2000, NOC announced that it had discovered a 472-Bcf gas field in the Sirte basin, northwest of Assumud.

Potential exists for a large increase in Libyan gas exports to Europe, although at present the only customer for Libyan gas is Spain's Enagas. A joint venture between Eni and NOC on the Western Libyan Gas Project (WLGP), a \$4.6 billion plan aimed at developing and exporting large volumes of natural gas to Italy, is moving ahead. In June 2002, for instance, Eni affiliate Saipem was awarded a \$500-\$550 million contract to build and install an offshore natural gas platform northwest of Tripoli. In February 2002, \$1 billion worth of engineering, procurement and construction contracts were awarded to a consortium led by Japan's JGC and including France's Sofregaz and Italy's Technimont. The consortium will work on oil and natural gas infrastructure in the Wafa Desert and near Melitah on the Mediterranean coast.

Overall, the WLGP calls for Libya to export 8 billion cubic meters (280 Bcf) per year of natural gas from a processing facility at Melitah to Italy and France over 24 years, beginning in 2004, via a 370-mile underwater pipeline (called "Green Stream") under the Mediterranean to southeastern Sicily and the Italian mainland. To date, Italy's Edison Gas has committed to taking around half (140 Bcf) of this gas, and to use it mainly for power generation in Italy. Besides Edison, Italy's Energia Gas and Gaz de France have each committed to taking around 70 Bcf of Libyan gas. As part of the overall WLGP, Agip-ENI is set to develop huge Libyan gas reserves in offshore Block NC-41 in the Gulf of Gabes, as well as in the Wafa onshore gas (and oil) field on the Algerian border. Feasibility studies have been completed on Wafa and NC-41, and gas is expected to begin flowing by mid-2004. The project also is expected to produce condensates estimated at around 70,000 bbl/d oil equivalent.

Agip-ENI also has promoted linking the reserves of both Egypt and Libya to Italy by pipeline. An agreement in principle to link Egypt and Libya's natural gas grids was reached in June 1997, following a visit to Libya by Egyptian President Hosni Mubarak. In early May 2002, Egypt's Oil Minister said that ground work on a double pipeline to carry Egyptian natural gas to Libya (for power generation, water desalination, and possible export) and another to carry Libyan oil to Alexandria, Egypt for refining and consumption there).

Yet another proposal is to build a nearly 900-mile pipeline from North Africa to southern Europe. Such a pipeline could transport natural gas from Egypt, Libya, Tunisia and Algeria, via Morocco and into Spain (a pipeline between Morocco and Spain already exists). Also, Tunisia and Libya agreed in May 1997 to set up a joint venture which will build a natural gas pipeline from the Mellita area in Libya to the southern Tunisian city and industrial zone of Gabes. In late 1998, Tunisia and Libya signed an agreement for around 70 Bcf of gas per year to be delivered from Libyan gas fields to Cap Bon, Tunisia beginning in 2003.

In 1971, Libya became the second country in the world (after Algeria in 1964) to export liquefied natural gas (LNG). Since then, Libya's LNG exports have generally languished, largely due to technical limitations which do not allow Libya to extract LPG from the LNG, thereby forcing the buyer to do so. Libya's LNG plant, at Marsa El Brega, was built in the late 1960s by Esso and has a capacity of 124 billion cubic feet per year, but due to technical limitations only about one-third of this is available for export, mainly to Enagas of Spain. Work to refurbish and upgrade the El Brega LNG plant in order to deal with the LPG separation problem has been delayed since 1992. If completed, Libyan LNG exports could triple, with likely customers including Spain, Turkey and Italy. On February 1, 2002, Libya joined the Gas Exporting Countries Forum (GECF), formed in 2001 to promote cooperation in the world natural gas industry. Members of the GECF account for around three-fourths of world natural gas reserves and three-fifths of exports.

ELECTRIC POWER

Libya currently has electric power production capacity of about 4.6 gigawatts. Power demand is growing rapidly (around 6% annually), and Libya has plans to more than double installed capacity by 2010 at a cost of over \$3.5 billion. As of July 2002, however, little progress has been made towards achieving this goal, nor does Libya have any plans at present to privatize its power sector.

Most of Libya's existing power stations are oil-fired, though several have been converted to natural gas. Plans to utilize natural gas include the 600-megawatt (MW) Western Mountain Power Project (Italy's Enelpower has been announced as the preferred bidder), an 800-MW power plant in Zuwara on the west coast, a 1,400-MW power plant to be located on the coast between Benghazi and Tripoli (Enelpower is bidding on this plant as well), and the 1,200-MW "Gulf Stream" combined power and desalination complex in Sirte (France's Alstom appears to be the lead bidder). In February 2002, Russia's Tekhnopromexport signed a \$600 million deal with Libya to build a 650-MW power plant.

Libya's state-owned General Electricity Company (GEC) has hinted at the possibility of allowing private investment in the country's power generation and distribution. The country's power sector requires substantial investment, and officials are looking at alternatives to public financing, but despite this, it remains unlikely that Libya will undertake any large-scale power privatization or allow independent power projects (IPPs) anytime soon. Meanwhile, the Export-Import Bank of South Korea reportedly has guaranteed \$99 million of the \$299 million cost of an expansion and upgrading project at the 450-MW Benghazi North power plant. The project would double the plant's capacity and convert it to combined cycle. GEC's biggest current project is to expand Libya's network of power substations, which are concentrated mainly in Benghazi, Sebha, and Tripoli. In other news, Libya, Egypt, and Tunisia have finished linking their power grids.

COUNTRY OVERVIEW

President (Chief of State): Mu'ammar Qadhafi (since September 1, 1969)

Independence: December 24, 1951 (from Italy)

Population (2001E): 5.2 million

Location/Size: North Africa/1,775,500 sq km (685,524 sq mi), slightly larger than Alaska

Major Cities: Tripoli (capital), Benghazi, Misurata

Languages: Arabic; Italian and English widely understood in major cities

Ethnic Groups: Arab (97%)

Religions: Sunni Muslim (97%)

Defense (1998E): Army (35,000), Air Force (22,000), Navy (8,000)

ECONOMIC OVERVIEW

Secretary of the Gen. People's Committee for Economy and Trade:

Shukri Muhammad Ghanim

Currency:Libyan Dinar (LD)

Official Exchange Rate (1/1/02): US\$1=1.30 LD **Parallel Market**

Exchange Rate (April 2002): around US\$1=1.57 LD

Gross Domestic Product (GDP) (2001E; official exchange rate): \$31.2 billion (2001E: parallel market exchange rate): \$11.6 billion

Real GDP Growth Rate (2001E): 3.1%-4.3% (2002E): 3.6%-4.5%

Inflation Rate (consumer prices, 2001E): -8.5% (1Q2002E): 5%

Unemployment Rate (1998E): around 30%

Current Account Balance (2001E): \$2.0 billion

Main Destinations of Exports (2000E): Italy (42%), Germany (19%), Spain (13%), France (6%)

Main Origins of Imports (2000E): Italy (25%), Germany (10%), Tunisia (8%), UK (7%)

Merchandise Exports (2001E): \$7.5 billion (2002E): \$8.0 billion

Merchandise Imports (2001E): \$4.5 billion (2002E): \$4.9 billion

Merchandise Trade Balance (2001E): \$3.0 billion (2002E): \$3.1 billion

Major Export Products: Crude oil, refined petroleum products, natural gas

Major Import Products: Manufactured goods, food and primary products

Total External Debt (non-military) (2001E): \$4.4 billion

International Reserves (12/01E): \$14.8 billion (17 months worth of import cover)

ENERGY OVERVIEW

Chairman of the National Oil Company: Abdel-Hafez Zleitni

Proven Oil Reserves (1/1/02): 29.5 billion barrels

OPEC Crude Oil Production Quota (effective 1/1/02) : 1.162 million bbl/d

Oil Production Capacity (2Q 2002E): 1.5 million bbl/d

Oil Production (2001E): 1.43 million barrels per day (bbl/d), of which 1.37 million bbl/d was crude oil, and 60,000 bbl/d was natural gas liquids

Oil Consumption (2001E): 182,000 bbl/d

Net Oil Exports (2001E): 1.25 million bbl/d

Major Oil Customers (2000E): Italy, Germany, Spain, and France combined account for around three-quarters of Libya's oil exports; other customers include Austria, Greece, Britain, and Switzerland

Crude Oil Export Revenues (2000E): \$12.9 billion **(2001E):** \$12.5 billion

Oil Export Revenues/Total Export Revenues (2000E): 98%

Crude Oil Refining Capacity (1/1/02E): 343,400 bbl/d

Natural Gas Reserves (1/1/02): 46.4 trillion cubic feet (Tcf)

Natural Gas Production (2000E): 0.21 Tcf

Natural Gas Consumption (2000E): 0.18 Tcf

Electric Generation Capacity (2000E): 4.6 gigawatts (all thermal)

Electricity Generation (2000E): 19.4 terawatthours

ENVIRONMENTAL OVERVIEW

Total Energy Consumption (2000E): 0.58 quadrillion Btu* (0.15% of world total energy consumption)

Energy-Related Carbon Emissions (2000E): 10.9 million metric tons of carbon (0.2% of world carbon emissions)

Per Capita Energy Consumption (2000E): 109.6 million Btu (vs U.S. value of 348.9 million Btu)

Per Capita Carbon Emissions (2000E): 2.1 metric tons of carbon (vs U.S. value of 5.7 metric tons of carbon)

Energy Intensity (2000E): 18,412 Btu/\$1995 (vs U.S. value of 10,919 Btu/\$1995)**

Carbon Intensity (2000E): 0.35 metric tons of carbon/thousand \$1995 (vs U.S. value of 0.17 metric tons/thousand \$1995)**

Sectoral Share of Energy Consumption (1998E): Transportation (48.4%), Industrial (45.8%), Residential (5.8%), Commercial (0.0%)

Sectoral Share of Carbon Emissions (1998E): Transportation (53.7%), Industrial (40.6%), Residential (5.6%), Commercial (0.0%)

Fuel Share of Energy Consumption (2000E): Oil (65.5%), Natural Gas

(34.5%)

Fuel Share of Carbon Emissions (1999E): Oil (67.8%), Natural Gas (32.1%)

Renewable Energy Consumption (1998E): 66.5 trillion Btu* (1,278% increase from 1997)

Number of People per Motor Vehicle (1998): 4.8 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified June 14th, 1999). Not a signatory to the Kyoto Protocol.

Major Environmental Issues: Desertification; very limited natural fresh water resources; the Great Manmade River Project, the largest water development scheme in the world, is being built to bring water from large aquifers under the Sahara to coastal cities.

Major International Environmental Agreements: A party to Conventions on Desertification, Marine Dumping, Nuclear Test Ban and Ozone Layer Protection. Has signed, but not ratified, Biodiversity, Climate Change and Law of the Sea.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

OIL AND GAS INDUSTRIES

State Oil Companies: *Libyan National Oil Company* (NOC) - Manages the state-owned oil industry and controls over 70% of Libya's oil production, *Oilinvest* - Manages all international investments

Foreign Energy Company Involvement: Agip (Italy), Canadian Occidental, Eni (Italy), Husky Oil (Canada), Lasmo (UK), Lundin Oil (Sweden), Nimr Petroleum (Saudi Arabia), OMV (Austria), PanCanadian; Pedco (South

Korea), Petrobras (Brazil), Petro-Canada (Canada), Petronas (Malaysia), Red Sea Oil Corp. (Canada), Repsol-YPF (Spain), Saga (Norway), Shell; TotalFinaElf (France), Veba (Germany), Wintershall (Germany)

Major Oil Ports: Es Sider, Zuetina, Tripoli

Major Oil and Gas Fields: Amal, el-Bouri, Bu Attifel, Defa-Waha, Elephant, Kabir, Mabruk, Murzuq, Nasser, Omar, Sarah, Zueitina

Major Pipelines: Amal-Ras Lanuf; Defa-Nasser; Hammada el Hamra-Az Zawiya; Intisar-Zueitina; Intisar -Hatiba; Messla-Ras Lanuf; Nasser-Hatiba; Nasser (Zelten)-Marsa el Brega; Sarir-Marsa el Hariga; Waha-Es Sider

Major Refineries (crude oil capacity): Ras Lanuf (220,000 bbl/d), Az-Zawiya (115,000 bbl/d), Brega (8,400 bbl/d)

Sources for this report include: Africa News; Africa Oil and Gas; AFX European Focus; Agence France Presse; AP Worldstream; BBC Summary of World Broadcasts; Canada NewsWire; CIA World Factbook 2001; Dow Jones Interactive; Dow Jones Newswires; DRI/WEFA; Economist Intelligence Unit ViewsWire; Energy Day; Financial Times Energy Newsletters; The Guardian; Hart's Africa Oil and Gas; Hart's E & P Daily; Les Echos; Middle East Economic Digest (MEED); Middle East Economic Survey (MEES); Oil Daily; Oil and Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; Platt's Oilgram News; Reuters; U.S. Energy Information Administration; Washington Post; World Gas Intelligence; World Markets Online; World Oil.

LINKS

For more information on Libya, please see these other sources on the EIA web site:

[EIA - Historical Energy Data on Libya](#)

[OPEC Revenues Fact Sheet](#)

Links to other U.S. government sites:

[2001 CIA World Factbook - Libya](#)

[U.S. Treasury Department's Office of Foreign Assets Control](#)

[Iran-Libya Sanctions Act Extension](#)

[U.S. State Department's Consular Information Sheet - Libya](#)

[Library of Congress Country Study on Libya](#)

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April 2002

North Central Europe

North Central Europe is important to world energy markets because it is a significant producer and exporter of coal and an important transit point for Russian oil and natural gas pipelines

Note: Information contained in this report is the best available as of March 2002 and is subject to change.



GENERAL BACKGROUND

[Poland](#), the [Czech Republic](#), the [Slovak Republic](#) (commonly referred to as Slovakia), and [Hungary](#) are all the members of the [Visegrad Group](#) and share certain common characteristics in addition to being geographical neighbors. The Czech Republic and Slovakia were the single country of Czechoslovakia formed from the former Austro-Hungarian Empire in 1918 (with an interruption during the Second World War) until Czechoslovakia's peaceful dissolution into the independent states of the Czech Republic and the Slovak Republic in 1993. Hence, the Visegrad group was known as the Visegrad Troika when it was formed February 15, 1991 in Visegrad, Hungary. Hungary, Poland, and Czechoslovakia had all been Communist states and members of the Warsaw Pact during the years following World War II until 1989-1990. All three states had developed heavy industry that was characterized by being very energy intensive and polluting. Poland is much larger than the other states of the Visegrad Group in area and population, having a greater population than the other three combined. Hungary's main ethnic group is not Slavic in origin, unlike the other two (now three) states.

Hungary and Slovakia have large minority populations, with both having large populations of Roma, and Slovakia having a significant Hungarian minority. The issue of ethnic Hungarians living outside Hungary has become an important issue for the current Hungarian government, which passed a law granting economic, cultural, and educational benefits to ethnic Hungarians in neighboring countries. This has caused some friction with Slovakia, which sees the law as having an extraterritorial nature.

All four countries have successfully transitioned to democracy and have made great strides in moving to market-based economies. Slovakia was slower to change than the other three, especially in the area of democracy, and is unlikely to be among the first group of former Communist countries to enter the [European Union \(EU\)](#), although the country has made great strides of late. Poland remains a more rural society than the Czech Republic or Hungary. All four countries have applied for membership in the EU, with Poland, the Czech Republic, and Hungary probably acceding in 2004 or 2005. In 1999, Hungary, Poland, and the Czech Republic became the first former-Warsaw Pact countries to join the [North Atlantic Treaty Organization \(NATO\)](#). Slovakia is a member of NATO's Euro-Atlantic Partnership Council. The Czech Republic became a member of the [Organization for Economic Co-operation and Development](#) in 1995, Hungary and Poland joined in 1996, and Slovakia in 2001. As members of the Visegrad Group, the four countries are

also members of the [Central European Free Trade Agreement \(CEFTA\)](#). There is a customs union between the Czech and Slovak Republics, and most products have no tariffs or quotas for trade amongst the other countries, with the exception of agriculture. CEFTA was founded by the Visegrad Troika, but [Slovenia](#), [Romania](#), and [Bulgaria](#) have since joined.

The Visegrad countries are dependent on trade with the EU and in particular with [Germany](#).

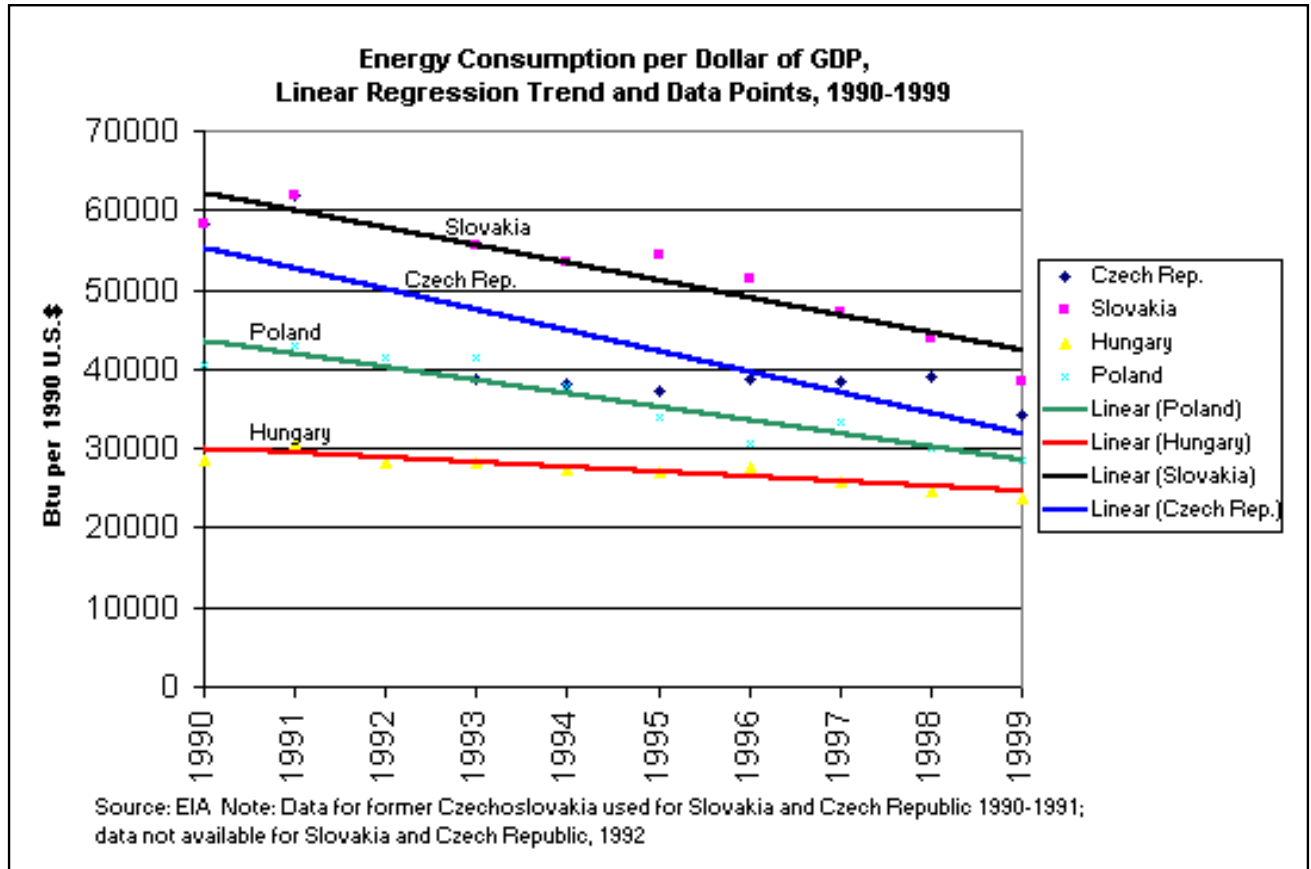
Continuing economic challenges that these countries share include: technologically backward agricultural sectors that will find it difficult to compete internationally; industries that are still more energy intensive than their counterparts

in western Europe (though energy intensity is on a declining trend as these economies become more similar to their western counterparts; see chart); costs from heavily-polluting industries and clean-up costs; the challenge of increasing standards of industries and services to the levels of the EU.

REGIONAL ENERGY ISSUES

Coal is the only fossil fuel of abundance in the region, and only Poland and the Czech Republic have substantial quantities of hard coal. Poland is the largest hard coal producer and exporter in absolute terms by far, though the Czech Republic exports over one-third of its production, whereas Poland only exports about one-fifth of its coal output. Of strategic importance is the fact that most of the crude oil and natural gas from [Russia](#) that is piped to western Europe passes through the Visegrad region, with the four countries only taking a small part of this for domestic consumption. Crude oil consumption in the region is small -- only about 56% of that of [Spain](#) alone. Not only is the region's total natural gas consumption (1.4 trillion cubic feet - Tcf) smaller than its neighbor Germany (over 3 Tcf), but Poland and Hungary each satisfied more than one third of their natural gas consumption from domestic sources in 2000. Preliminary estimates of imports of Russian natural gas into the region during January-November 2001 show Hungary importing 257.8 billion cubic feet (Bcf), the Czech Republic 243.7 Bcf, Poland 240.1 Bcf, and Slovakia about 236 Bcf.

The Czech Republic and Poland export coal to each other, and both countries have import quotas for the other. Unions in Poland have campaigned to have the quota for Czech imports lowered, whereas industries in the Czech Republic have campaigned to have the quota for Polish imports raised. Polish coal has become cheaper than Czech coal in the



Czech Republic, but Polish unions claim that Czech coal is "dumped" in Poland. Neither government has changed its quotas so far.

Oil Transit

The northern branch of the 1-million-barrel-per-day capacity Druzhba ("Friendship") pipeline from [Russia](#) through [Belarus](#) brings oil to Poland which then can be transited onward to Germany. The 1.2-million-barrel-per-day capacity southern branch of the Druzhba pipeline runs from Russia through [Ukraine](#) into Slovakia. In August 2001, the Yuzhnyy-Brody pipeline was officially opened in Ukraine. This allows [Caspian](#) region oil that is piped to Black Sea ports to be shipped across the Black Sea to Yuzhnyy's Pivdenny terminal (near Odessa) and then transported in a new pipeline to Brody, where it connects with the southern Druzhba pipeline for shipment to Slovakia, Hungary, and onward. There is discussion of extending the Yuzhnyy-Brody pipeline north to Plotz in Poland where the pipeline could tie into the Druzhba northern route and/or an existing line to the Polish Baltic Sea port of Gdansk and allow imports of Caspian crude oil to Poland, Germany, and other Baltic states. The southern Druzhba pipeline splits in Ukraine just before it reaches the borders of Slovakia and Hungary. Some of the oil imported into Hungary transits onward to [the former Yugoslavia](#) and the Croatian port of Omisalj on the Adriatic.

Natural Gas Transit

The region is extremely important as a transit center for Russian natural gas exports to western Europe. The Yamal pipeline from Russia will deliver about 1.1 Tcf per year into Poland by 2005 under current contracts. Most of this natural gas transits onward to Germany. Yamal is the only route that bypasses [Ukraine](#). The Russians have considered adding additional routes that bypass Ukraine for their natural gas exports to Europe, partially because Russia has accused Ukraine of stealing natural gas transiting through the country and because of Ukraine's nearly \$2 billion in debt to Russia for natural gas. The planned Yamal II pipeline would link Yamal with the Southern pipeline to make for an additional source for the pipelines in Slovakia that currently take natural gas transiting through Ukraine. Yamal II has not been formally approved yet and there are still disagreements about its route in Poland. Germany and Russia appear to favor a route that is more southerly, as that is where Germany has more natural gas demand, but Poland favors a more northerly route that could provide some natural gas to its industries as the pipeline passes through to Germany. A possible entirely new natural gas pipeline from Russia to Slovakia by way of Belarus and Poland appears to have been cancelled by Gazprom in February 2002. This pipeline differed from the planned Yamal II in that it would have had a new source pipeline in Russia, instead of just feeding off of existing Russian pipelines and would only have transited through the region to western Europe; it would not have provided natural gas to the intermediary countries. In March 2002, Poland's state auditor NIK urged the Polish government to renegotiate its long-term supply deal with Russia.

The Brotherhood (Druzhba), Progress, and Soyuz natural gas pipelines that go through Ukraine to Slovakia have annual capacities of about 1 Tcf each. There is still some excess capacity in the pipelines. From Slovakia, the natural gas transits to Austria and the Czech Republic. The natural gas that passes through Slovakia represents about 25% of the natural gas consumed in western Europe and about 70% of the Russian natural gas exported to western Europe. The Druzhba pipeline splits in the Ukraine, with one part going to Hungary. Hungary takes some of the natural gas, and the rest continues on to the Balkans. At a meeting of the Visegrad Group's Economic Forum in September 2001, the possibility of providing Polish natural gas imports from Norway and/or Denmark to Slovakia and/or Hungary was discussed, with favorable statements by leaders. The region's leaders worry about being too dependent on Russia.

Regional Integration

There have been attempts by various energy companies in the region to merge in order to compete with larger rivals from the west and from Russia. The two largest oil companies in the region, Nafta Polska's PKN Orlen of Poland and MOL of Hungary have been in so-far unsuccessful talks to sell a 17.58% share of PKN Orlen for some time. OMV of

Austria has now been permitted to be involved in these talks by the new Polish government, which have been extended now to April 15, 2002. The result of such a sell-off likely would create a loosely-tied regional oil company. MOL did purchase a 36.2% share of Slovakian oil company Slovnaft in 2001, which is the only integration of the region's oil companies so far, though MOL in particular continues to look for ways to expand in the region.

The region shares the CENTREL electricity system, which links the Czech Republic, Slovakia and Hungary. In 1995, the CENTREL system was connected with Western Europe's system. Poland also has electricity connections with Ukraine and Belarus. Currently, both north-south and east-west connections are being expanded, as part of the EU's [Trans-European Energy Network](#) project, including a new link to Lithuania. The four countries of the region are also members of European electricity transmission system [Union for the Coordination of Transmission of Electricity \(UCTE\)](#). UCTE coordinates the interests of transmission system operators in 20 European countries.

There has been some interest in a regional energy exchange market, but rivalries over where it would be based as well as the regions's eventual integration into the EU that might make such a market superfluous have delayed this idea. Poland and the Czech Republic are developing electricity exchanges, while such exchanges are still in the planning stages in Hungary and Slovakia. Hungary imports a large amount of electricity from Slovakia, and is the region's only net power importer. Much of Poland and the Czech Republic's electricity exports go to western markets, Germany in particular.

POLAND

Poland was one of the first of the former Soviet satellite countries to hold free elections and to successfully introduce market reforms (1989). A new constitution was approved by a national referendum in May 1997. On September 23, 2001, Poland held legislative elections in which no party won an outright majority. In October 2001, a coalition government was formed by the Democratic Left Alliance (the former Communist Party) that won 41% of the popular vote, but was still 15 seats short of an absolute majority. After joining with the Polish Peasants Party in a coalition, Leszek Miller of the Democratic Left Alliance became prime minister on October 19, 2001. The new coalition has called for a relaxing of monetary policy by Poland's Central Bank in order to promote economic growth and to reduce the country's high (over 16%) unemployment rate. Poland's real GDP growth rate slowed from 4% in 2000 to 1.3% in 2001. It is estimated that Poland's high rate of foreign direct investment (\$10.6 billion in 2000) fell considerably in 2001. The economic downturn has also reduced government revenue, to as little as 49% of the target for January-July 2001. The budget deficit was estimated by the previous government to be about \$7 billion, or 4% of GDP, in July 2001. The current government has taken measures, including a new tax, to ensure that the budget deficit does not exceed \$9.4 billion, especially in light of continuing low economic growth rates. Poland's inflation rate is at a recent historical low.



Poland is planning to enter the EU in the group's next expansion, and the country is in the midst of reforms necessary to meet membership criteria. Coal and steel industry restructuring is expected to be completed by the end of 2001, and the energy sector will be open to competition by about 2004. Many Polish farmers are opposed to joining the EU, as they believe it will entail agricultural reforms that will render them unable to compete with imports. Poland has a current account deficit and is working to make its exports more competitive. On balance, EU membership is expected to benefit Poland, decreasing trade barriers with key trade partners such as Germany and enhancing political stability. In turn, Poland is a key to EU expansion plans, as Poland is by far the largest country, in terms of both population and gross domestic product, among the twelve states that have begun discussion of accession to the EU.

Energy

In April 1997, the Polish government passed a new [Energy Act](#), which required the Government Economic Committee to pass "Guidelines on Poland's Energy Policy Through 2020." The document spells out long-term energy forecasts and action plans for the Polish government. The key objectives include: increased security of energy supplies, (including diversification of sources); increased competitiveness for Polish energy sources in domestic and international markets; [environmental protection](#); improving energy efficiency; and reducing energy-related carbon emissions. Coal is Poland's most important domestic energy source. While coal production is declining and will continue to decline over the coming years, it will remain a key energy source. In 2001, the Supreme Board of Inspection (NIK) released a report stating that energy sector reform is moving too slowly. The report cited insufficient privatization in the oil sector, a halt in natural gas sector restructuring due to a dispute with the regulator, and problems with coal sector reforms. Poland will have to have a 90-day oil reserve by 2008 as part of its EU agreements.

Oil

With proven oil reserves of only 115 million barrels, Poland relied on imports for 97% of its 2001 oil consumption. Poland's oil demand is expected to increase by as much as 50% by 2020. Polish oil production increased from 10,000 barrels per day (bbl/d) in 2000 to 14,000 bbl/d in 2001, but this is still a small fraction of oil demand (434,000 bbl/d). Polish oil production comes primarily from fields in southern and western Poland, with the southern reserves nearly exhausted. However, the Barnówko - Mostno - Buszewo "BMB" field discovered in 1996 in the Polish part of the Permian Basin (near the German border directly east of Berlin) has potential reserves of about 73 million barrels and the Miedzychod field is estimated to have even more, so Poland should be able to increase its production as these fields come on line.

Poland's oil and gas industries were consolidated in 1981 into a single entity, the state-owned Polish Oil and Gas Company (PGNiG), which dominates the natural gas and upstream oil industries. In 1996, PGNiG became a joint-stock company. The company is slated for privatization after restructuring is completed, bringing the country into line with EU regulations. While a specific privatization plan remains forthcoming, major components of the company are expected to become independent from each other, rather than having a single holding company. There could be one upstream company; one company responsible for gas trade, transmission and storage; and four regional gas distribution companies. The upstream company and the four distribution companies would be privatized first, while the transmission and storage company could remain state-owned for longer.

Oil imports from Russia through the Druzhba ("Przyjazn" in Polish) pipeline traditionally have been the main Polish oil source. Following the breakup of the Soviet Bloc, Poland attempted to diversify its oil sources and to reduce its dependence on Russian oil. For this reason, the "Naftoport" oil terminal at Gdansk was constructed in the 1990s, with a capacity to receive about 600,000 bbl/d. However, Russian oil has remained relatively inexpensive, and economic factors have resulted in Poland actually increasing its imports of Russian oil. In addition, Poland imports oil from Russia's Kaliningrad enclave through the Naftoport.

Russian oil is not imported through direct agreements with Russian suppliers. Rather, there is a complex network of middlemen, the most important of which is the J&S Company of Cyprus. In 2000, 60% of the crude oil purchased by PKN Orlen and 70% of the oil purchased by Rafineria Gdansk (RG) was from J&S. It is estimated that J&S supplies between 60% and 70% of all crude oil processed by Polish refineries. To the Russians, these middlemen are referred to as "operators" and because of a host of regulations, important documents, and licenses, the operators do all the paperwork and financial transfers. Some Polish politicians have questioned this system.

Poland and Ukraine reached an agreement in February 1999 to complete jointly an extension of the 500,000-bbl/d [Odesa-Brody pipeline](#) for Caspian Sea oil to go through Ukraine to Poland.

In July 2000, Germany-based EuroGas, Inc. won ten concessions to explore and develop oil and natural gas deposits in southeast Poland. The company believes that the area, the Karpaten Flysch oil province near the city of Sanok, potentially has a 350-million-barrel oil field, or an equivalent quantity of natural gas, which would represent one of the larger oil and gas discoveries in the region. In November 2000, EuroGas signed an agreement with PGNiG to jointly develop the area through EuroGas' subsidiary. As part of the agreement, PGNiG acquired 30% of EuroGas' Polish subsidiary, EuroGas Polska.

Downstream

Most of Poland's refineries, which were built in the 1960s and 1970s, need modernization in order to meet the current shift in demand towards lighter products such as gasoline and diesel fuel. Refinery capacity also will need to expand to meet growing oil demand. PKN Orlen's 260,000-bbl/d Plock refinery has had some improvements done and others are planned in its efforts to eventually conform to EU standards.

The state's oil companies are held through Nafta Polska, a state holding company and privatization vehicle. Nafta Polska's PKN Orlen controls about 60% of the wholesale and about 40% of the retail fuel markets. In September 2001, the sale of 75% of the 90,000-bbl/d Gdansk refinery to Rotch Energy of the United Kingdom was approved. Rotch paid about \$250 million for its stake and agreed to invest \$600-\$700 million in expansion over the next few years to boost the refinery's capacity to about 150,000 bbl/d.

Gasoline and diesel demand has fallen slightly in recent months, due to higher prices and an economic slowdown. However, the demand for heating oil (which is sometimes used as a vehicle fuel) and liquefied petroleum gas (LPG) has risen sharply, and about 530,000 vehicles in Poland are capable of using LPG, with many vehicles being converted every year.

Natural Gas

Poland has an estimated 5.1 trillion cubic feet (Tcf) of natural gas reserves. The country imported over 65% of its 442-billion cubic feet (Bcf) consumption in 1999. Natural gas production remained fairly stable throughout the 1990s, hovering between 150 Bcf and 180 Bcf, and was about 183 Bcf in 2001. This rate of production is expected to continue into the 21st century, as new exploration takes the place of depleting reserves. FX Energy, a U.S.-based company active in Poland with a 49% stake in the Fences gasfield (51% is owned by PGNiG), began production at its Kleska well in March 2001 at an initial rate of 2 million cubic feet per day. PGNiG is planning to launch 200 new drilling sites in 2002 at a cost of Zl 700-800 million and invest Zl 600 million in domestic oil and natural gas exploration. The company also plans to liquidate 1,500 old and exploited drilling sites within the next five years.

The outlook for natural gas imports into Poland is problematic over the next few years. Despite the fact that Poland's real GDP has grown by about 21% since 1997, natural gas demand has remained flat and is predicted to remain so over the next decade. Even optimistic unofficial Polish government forecasts estimate demand in 2005 to be between

484 and 572 Bcf. Much of the reason for this is that natural gas is simply uneconomical for power generation in Poland compared with coal. Yet, at the same time, diversification of natural gas sources is a high priority for Poland, and those traders with diversified sources will have priority. Russia supplied over 60% of all Polish natural gas in 2000, with smaller amounts coming from or through Germany as well as over 30% from domestic sources. Poland and Russia disagree about the route of the proposed extension of the Yamal pipeline (Yamal II). Poland's contracts with Gazprom are for imports to increase to 441 Bcf per year by 2010. However, in January 2002, Polish Economy Minister Jacek Piechota stated that the contract with Russia as well as the specifics of the extension of the Yamal pipeline will have to be renegotiated.

PGNiG recently has reached agreements to import Danish and [Norwegian](#) natural gas. In July 2001, an agreement was signed with Dansk Olie og Naturgas (DONG) of Denmark to import 16 billion cubic meters (565 Bcf) over eight years, starting in 2003. This would be done through the planned \$330-million, 186-mile BalticPipe pipeline, scheduled to be constructed beginning in the summer of 2002. The pipeline's capacity, 283 Bcf per year, is four times the volume that PGNiG will import from DONG annually, prompting some to question whether the pipeline will be financially viable. In September 2001, PGNiG and Norway's (now defunct) Gas Negotiating Committee (GFU) agreed to the delivery of 74 billion cubic meters (2.6 Tcf) over 16 years. This replaces the previous contract with Norway for 500 million cubic meters (18 Bcf) per year until 2006. These deliveries would not start until 2008, and would gradually increase over the first three years. Norwegian exports to Poland would require the construction of the \$1.1-billion, 683-mile Austerled pipeline. Given probable increasing domestic natural gas production and flat demand, it will be very difficult for Poland to maintain its Russian, Danish, and Norwegian contracts in their present state. The new government already has signaled that it will probably amend or even cancel some or all of these contracts.

Poland needs to increase its [environmental standards](#) as part of its application to achieve member status in the EU. Increased consumption of natural gas, as an alternative to coal, is considered to be a key component of Poland's plan to meet the stricter regulations. The Polish government forecasts that about 14% of electricity will be generated from natural gas by 2020, up from just 2% in 2000, but still a relatively small share. Poland also will need to liberalize at least 28% of its natural gas market by August 2003, according to EU directives.

The Yamal pipeline connecting Poland to Siberian natural gas sources, began operations in September 1999. The \$35-billion pipeline was designed to carry natural gas supplies from the Yamal (West Siberia) field in Russia to Germany and other Western European countries through Belarus and Poland. Under a 25-year contract signed in October 1996, annual throughput capacity of the pipeline is slated to increase to 32 billion cubic meters (about 1.1 Tcf) by 2005. The Polish section is operated by EuroPol Gaz and is 48% owned by PGNiG and Gazprom each, with the remaining 4% owned by a consortium of Polish firms called Gas Trading. Russia is seeking to link this new pipeline with the Southern pipeline, which would allow additional Russian gas to reach Western European markets while bypassing Ukraine (Yamal II). The exact route was discussed at senior-level Russo-Polish talks in January 2002, though no decision has been taken. Also in January 2002, Gazprom and PGNiG announced that feasibility tests will begin soon for the second stretch of the pipeline. Gazprom estimates that when all sections of the Yamal pipeline as well as two new compressor stations are complete, the total capacity will be 2.26 Tcf. Plans for an entirely new natural gas pipeline from Russia through Belarus and Poland to Slovakia appear to have been put aside indefinitely by Gazprom following friction between the Polish, Ukrainian, and Russian governments over the issue. There was some worry by Polish officials of damaging relations with Ukraine, because the diversion will cost Ukraine transit fees.

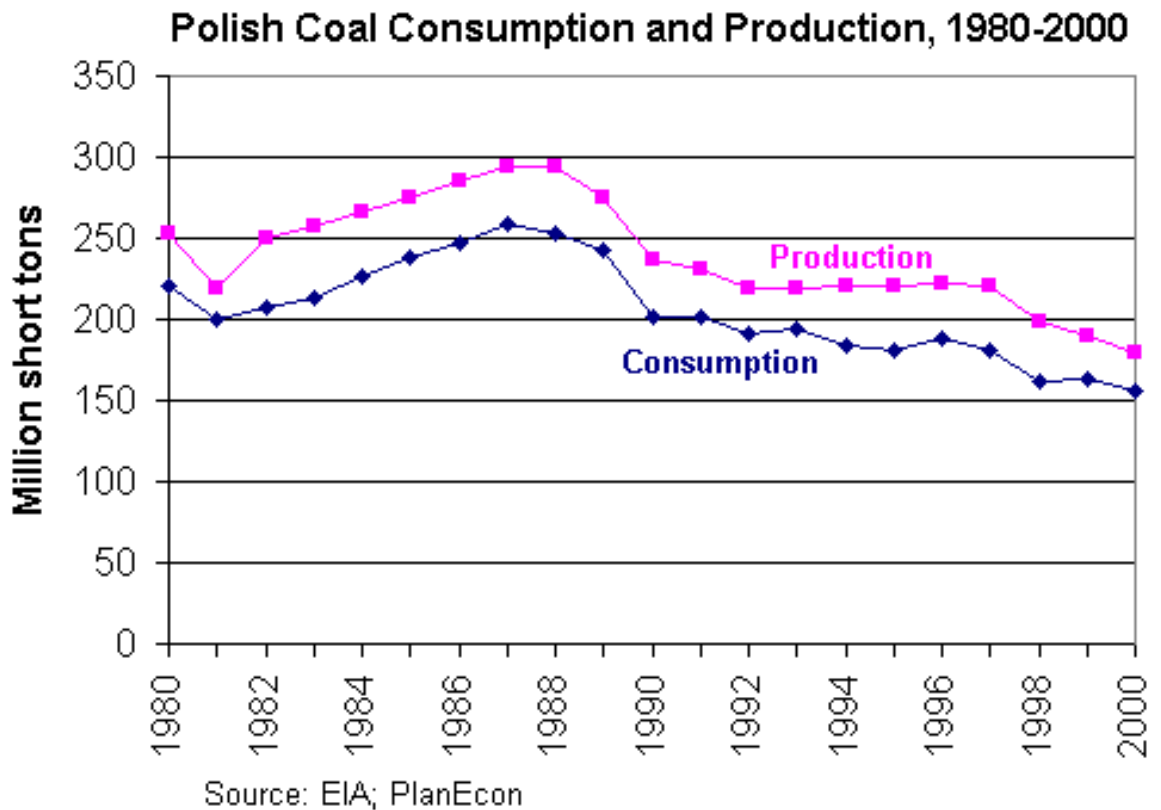
PGNiG is undertaking a program to add more than 6,200 miles to its gas distribution network by 2010. The company is also planning to invest \$670 million over the next three years to upgrade its transmission system. PGNiG is appealing a ruling by the government gas regulatory agency that the company cannot raise its rates. PGNiG believes that raising rates for some customers is vital to its restructuring.

Coal

Although coal represents only 2% of Poland's total GDP, it is by far the dominant fuel in the country's economy, accounting for 95% of primary energy production in 2000. Polish coal, though of high quality, has various geological features that make it difficult to mine. Hard coal (mostly bituminous) provides about 65% of electricity generation, with brown coal (lignite) providing nearly all of the rest of the fuel consumed in Poland's power plants (many of which provide heat and hot water as well as

electricity). Poland is the world's ninth-largest coal exporter, with coal going primarily to customers in Europe and the former Soviet Union. These exports historically have represented a major source of foreign exchange.

There are currently seven state-owned coal holding companies. They are: Bytomska Spolka Weglowa (six mines); Rudaska Spolka Weglowa (4); Gliwicka Spolka Weglowa SA (5); Katowicki Holding Weglowy (9); Nadwislanska Spolka Weglowa (5); Rybnicka Spolka Weglowa (5); and Jastrzebska Spolka Weglowa (5), for a total of 39 operating mines. Weglokoks is the country's largest coal exporter. The company was created in 1993 as the successor to the state-owned coal monopoly; it is owned by the State Treasury. The other coal exporting company is Kopex, which may merge with Weglokoks in the future.



Coal Yards at Port of Gdansk

In May 1998, Poland announced a comprehensive restructuring program for its coal industry aimed at maximizing efficiency and paying off some of the industry's \$4.5-billion debt. Before Poland's democratization, the industry had been heavily subsidized. In 2000, Poland closed 22 coal mines and partially closed seven others, with about 16,000 miners leaving the industry. This reduced production by about 10.3 million metric tons (11.4 million short tons), but the coal mining industry became profitable for the first time, and has continued to be profitable in 2001, though this has been attributed to a write-off of part of the industry's debt. Production rose very slightly, 0.5%, to 103.9 million metric tons (114.5 million short tons).

Privatization of Polish coal mines is just beginning, with the Bogdanka mine, one of Poland's most profitable, approved for a 45% sale to Management Bogdanka, a private company that is a consortium of investors. The fully private Jadwiga mine in Zabrze is expected to begin functioning February or March 2002. PricewaterhouseCoopers is

advising the Ministry of the Economy on further privatization and restructuring, and three tentative plans have been drawn up that vary in the degree that the size of the sector that is maintained and the degree of subsidies and privatizations that would be put in place. A new plan proposed by the current government would create a new holding company called Polish Coal (PW) that would take over the shares of the seven state-owned companies and act as the manager until the coal sector is fully privatized. Another aim of this plan is to control the price of coal in Poland so as to avoid regional disparities that make imports cheaper in some parts of the country. It is estimated that various mining reform programs will cost \$2.26 billion through 2006.

The changes brought about by the coal restructuring program have had some positive economic and environmental implications, which are important for Poland's accession to the EU. Despite this, Polish coal miners have been extremely resistant to the changes, and have held protests and strikes in opposition. The Polish coal industry is one of the country's most important employers and has a powerful union, so there are important political considerations to all reforms of the sector, as well as commensurate efforts to find employment for displaced miners.

Electricity

With installed electric capacity of over 30 million kilowatts in 1999, and electric generation of 134 billion kilowatt hours (bkwh), the Polish power generation sector is the largest in Central and Eastern Europe. As noted above, most of Poland's electricity comes from coal-fired plants, which are highly [polluting](#) and operate with outdated technology. The Polish government expects electricity demand to grow by over 50% by 2020. Poland produces more electricity than it consumes and exports the excess to neighboring countries. Polenergia, a new company, was established by Polish grid operator PSE, a German distributor, and a private Polish company, to sell privatized electricity, including electricity from Russia, to Western European markets.

Poland's electricity is produced by a combination of independent power producers that sell to the state-owned grid operator PSE SA, as well as by PSE itself. There are 17 power plants and 19 power and heating (CHP) plants. PSE transfers power to 33 local distributors, of which the G8 Group is the largest. PSE is in the process of initiating an hourly balancing market for Poland. There has been some consolidation of producers, the most important of which is Poludniowy Koncern Energetyczny (PKE) with total capacity of 4,640 MW. It is expected that only consolidated producers will be able to compete with Western companies as the Polish market continues to open.

Poland's status as an EU applicant makes it more important that efficiency and environmental goals are met in a timely fashion. In November 1998, Poland ambitiously committed to adapting its electricity market regulations to EU standards within four years. Renovation of the sector is expected to cost about \$15 billion by 2010. For these reasons, Poland's power generation is in need of investment. Multilateral lending institutions, most notably the World Bank and the European Bank for Reconstruction and Development, are involved heavily in financing and participating in projects ranging from building new, non-coal facilities to providing cleaner technologies for existing coal-fired plants.

Privatization is seen as the key to modernization and efficiency of the electricity sector. In September 1996, a law was passed that laid the foundation for de-monopolization and privatization of the industry. Plans called for reducing the number of generating companies from 35 to 7 and for privatizing power generation by the end of 2001. A law that took effect in December 1997 sets the groundwork for third-party access to the power grid and vests authority in an independent Energy Regulatory Office. However, the privatization has been delayed. According to the head of the Energy Regulatory Office, it will be two to four years until Poland's energy market is truly competitive. Outstanding long-term supply contracts between power generators and the national grid company, PSE, need to be resolved before market pricing can take effect. Currently, companies consuming more than 40 gigawatthours (GWh) of electricity annually can legally choose between suppliers, but this has yet to be fully implemented. Regulations are still seen as insufficiently defining PSE's position in the new system, such that as PSE continues to regulate itself, the opening up of the grid is restricted.

Electricite de France (EdF) is one of the larger investors in the Polish electricity sector thus far. It has a 57.9% share of the El. Krakow CHP plant and a 11.5% share of the ZEW Kogeneracja CHP plant. Working with Gaz de France, EdF in June 2000 won a tender to buy a 45% stake of the cogeneration company Zespól Elektrociepłownia Wybrzeże (ZEcW), which serves Gdansk. EdF already owns a controlling stake in Elektrociepłownia Krakow, serving Krakow, and a smaller stake in a cogeneration group in Wrocław. In November 2001, EdF's Zecw Group in Poland and Dalkia, a subsidiary of French multinational Vivendi, reached an agreement to purchase 45% of two thermal electric power plants at Toruń. EdF is looking to invest in the distribution side as well. Sweden's Vattenfall has already invested in the distribution side, owning 32% of the large southern GZE distribution group as well as 55% of Warsaw's district heating plant in Siekierki. Vattenfall plans to gain majority shares as soon as possible. Belgium's Tractebel recently acquired a 25% stake in the Polaniec power plant, which is Poland's fourth-largest power generator. In August 2001, the Polish government granted Spanish utility Iberdrola the exclusive right to negotiate the acquisition of 25% of the G8 Group electricity distributor. In southern Poland, a new coal-fired plant is under construction by a subsidiary of U.S.-based PSEG. This will replace the Chorzów plant, now over 100 years old. American utility PSEG signed a deal to purchase 35% of the Skawina power plant for \$24.8 million in January 2002. PSEG plans to invest \$56 million in the plant, part of which will be used to make the plant compliant with stricter environmental regulations.

Environment

As the transition to democracy proceeds in Poland, [environmental issues](#) have become increasingly important. During the 1980s, Poland was one of the most polluted countries in Europe, and while democratic reforms have brought about reductions in the level of [air pollution](#), there remains much room for improvement. In fact, as Poland negotiates with the European Union (EU) for membership, the EU has spotlighted Poland's environmental record, making the country's accession to the exclusive group contingent on improvements in Poland's environmental record.

Similar to the pattern seen in other transition countries, Poland's [energy consumption](#) has decreased in the past 10 years as inefficient factories and industries were closed down. However, unlike the majority of the former Eastern Bloc, production has rebounded in Poland. Although the country's [carbon emissions](#) have dropped since 1989, Poland's dependence on coal, along with the explosion in private automobile use among Poles, correlates to high levels of [energy and carbon intensity](#) in Poland.

Poland's [renewable energy](#) sector is small, with only a few hydroelectric power plants. However, as Poland enters the [21st century](#), the country is beginning to shift away from non-ecological coal mining and related industries towards a more service-oriented, less pollution-intensive economy. In November 2001, Poland's Southern Energy Concern (PKE SA) announced plans to start up two 12-MW wind farms on the coast and in the southern mountains.

CZECH REPUBLIC

The Czech Republic saw its second straight year of positive economic growth in 2001 following three years of recession. The country's real gross domestic product (GDP), which had been in decline since 1997 following an economic boom during the mid-1990's, rose 2.9% in 2000 and 3.5% in 2001. Growth forecasts for 2002 have been cut back to 3.3% because of continued low demand for Czech exports in the European Union (EU) as growth there has remained slow. Trade with the EU represents about 69% of the Czech Republic's overall foreign trade. The Czech Republic is highly dependent on trade, with exports of goods and services being about 70% of GDP. Increasing exports are making a substantial contribution to growth, but imports have increased even faster, so that the current account deficit is estimated to have increased by \$1.1 billion from 2000 to 2001. Foreign direct investment in the Czech Republic peaked in 1999 at \$4.9 billion, and remained high in 2000 at \$4.6 billion, but declined in 2001, with just \$2.3 billion invested in the first three quarters of the year. The slowdown in exports has widened the current account deficit to about \$2.9 billion, though there is a surplus in the capital account that makes this sustainable.



Since the end of the Communist era in 1989, when 100% of industries were state-owned, the Czech Republic has made great progress in privatization. It is estimated that only 10% of Czech industry was state-owned at the start of 2001. The government has plans for further privatizations in the chemical, energy and mining, telecommunications, and steel sectors. The structural reforms and economic rebound have strengthened the Czech Republic's fast-track status for membership in the EU, which is currently slated for 2003-2005.

The Czech Republic's unemployment figure, at about 8.5%, is about the European average, is expected to remain steady over the next two years. In late 2001, growth in industrial production began to slow in response to falling demand in key foreign markets, especially Germany, though domestic demand remains fairly strong. Czech inflation is low, falling to an annual rate of 4.1% in December 2001.

Following an October 1999 European Commission report which warned that the Czech Republic was lagging behind other so-called "firstwave" countries in the introduction of European Union (EU) laws and structural reforms, the opposition Civic Democrats and the ruling Social Democrats (the country's two major parties) agreed to make approval of EU legislation a priority and to speed up the pace of reforms and the stalled privatization process. One issue to be dealt with for the Czech Republic's accession to the EU is the need for further restructuring of the country's energy sector and the end of energy subsidies. The energy chapter was included in the accession talks between the Czech Republic and the EU in November 1999, and while the Czech Republic applied for a phase-in period that would postpone full liberalization of its electricity market until 2005 and of its natural gas market until 2008, the EU called on the Czech Republic to look for ways of re-evaluating its application. In addition, it is estimated that achieving environmental compliance with EU standards by 2004 will cost about \$15 billion. The Czech Republic became a member of the International Energy Agency (IEA) in 2001.

The decision in October 2000 by Czech authorities to activate the controversial, Soviet-era Temelin nuclear power plant in southern Bohemia led to a diplomatic confrontation with neighboring Austria, which argues that the plant is unsafe. A compromise was reached between Austria and the Czech Republic that allowed EU inspectors to assess the plant in December 2000, before it began operating commercially. In November 2001, the premiers of Austria and the Czech Republic came to an agreement to make certain bilateral duties in regards to the Temelin plant part of the Czech Republic's accession process to the EU in return for Austria not blocking the Czech Republic's accession. The other members of the EU must agree to this unusual step of having a protocol attached to the accession treaty. (See Electricity section for more on the Temelin plant.)

Oil

The Czech Republic has very limited oil reserves, and therefore relies almost exclusively on imported oil for its consumption need. Domestic oil production, which is extracted by the firm Moravske naftove doly (MND), reached 6,400 barrels per day (bbl/d) in 2001. In January 2002, Czech oil company Ceska Naftarska Spolecnost made a discovery at its Breclav block in southern Moravia, near the Vienna Basin. Oil is flowing from a test well, but estimates of production from the field are not set yet. Also in January, Australian-based Carpathian Resources discovered a natural flow of crude oil at its Postorna 1 Well in the Vienna Basin.

Czech oil consumption, which totaled 172,000 bbl/d in 2001, is projected to remain about the same in 2002. Oil imports are piped primarily from Russia, via the Druzhba pipeline, and Germany, via the Mero pipeline, which allows the land-locked Czech Republic to import crude oil from the Italian port of Trieste via the Trans-alpine pipeline network.

The Druzhba pipeline, with a capacity of 73 million barrels per year (200,000 bbl/d) to the Czech Republic, historically has been the source of the majority of the country's foreign oil. The completion of the Mero pipeline, which has the same capacity as the Druzhba, allows the Czech Republic to reduce its reliance on Russian oil. As the country continues to re-orient its economy to the West, imports of oil from Russia are declining while oil imports from the EU are rising. Overall, however, the Czech Republic's desire is to reducing its dependence on oil imports by reducing its consumption. High world oil prices in 2000 meant that the Czech Republic's increase in oil imports was slight in 2000, but imports may increase more in 2001 due to relatively lower world oil prices. In April 2001, the EU agreed to the Czech Republic's request to extend the transition period for building a 90-day state oil reserve until December 2005. Mero CR, which operates the Czech oil pipelines, is constructing three storage tanks, each with a capacity of 786,000 barrels, as part of the plan to raise reserves to comply with the EU directive. Completion is expected in 2004.

Refining

The Czech Republic has two major refineries, at Litvinov and Kralupy. The refineries, which have been privatized and are now owned and operated by Ceska Rafinerska, have a combined capacity of 178,000 bbl/d. These refineries supply slightly less than 50% of the gasoline and diesel market in the Czech Republic. Ceska Rafinerska is owned by holding company Unipetrol, which is 63% owned by the government. There are four companies that are still competing for the 63% government share when full privatization occurs, which is expected sometime in 2002. Ceska Rafinerska began producing gasoline and diesel fuel from a new, czech koruna-8-billion cracking unit at Litvinov in April 2001. The added capacity will raise the production of light products, mainly petrols and diesel oil, while the production of heavier fuel oils, the demand for which is decreasing, will be reduced. Ceska Rafinerska sold about 1.1 million barrels of processed fuels to Poland in 2000, and plans to export about 1.9 million barrels in 2001.

There also is a smaller refinery in Pardubice owned by Paramo, A.S. It has a capacity to refine about 20,000 bbl/d.

Natural Gas

As the Czech Republic strives to meet EU membership criteria, natural gas is becoming increasingly important to the country's energy mix. With the need to improve its environmental conditions, the Czech Republic is turning to cleaner-burning natural gas for its energy needs rather than coal. As a result, natural gas consumption has increased by 30% since 1993, from 259 billion cubic feet (Bcf) in 1993 to 337.3 Bcf in 1999. The Energy Regulation Office (ERU) has announced that household natural gas prices will rise 5%-10% in January 2002.

The Czech Republic relies almost exclusively on imports for its natural gas consumption (approximately 98% of consumption). Most of the limited domestic gas production that does occur is carried out by a British company, Ramco Energy's Medusa Oil & Gas, near the Austrian border. MND also extracts a small amount of natural gas. The vast majority of gas consumed is imported from Russia. According to the Czech Statistical Office, in 1999 the Czech Republic imported approximately 78% of its natural gas from Gazexport, Russia's Gazprom subsidiary, with about 15% of its gas coming from [Norway](#), 6% from Germany, and only about 1% from Slovakia. The percentage coming from Norway is expected to increase in the coming years, at the expense of Russian exports.

Transgas, the major gas utility in the Czech Republic, is responsible for purchasing natural gas for Czech consumption. Although the Czech natural gas industry was restructured in 1994, Transgas remained state-owned and operated until January 2002. On January 29, 2002, the National Property Fund of the Czech Republic and RWE Gas of Germany signed a contract for the sale of 97% of the shares of Transgas for koruna 117.3 billion. Transgas currently sells natural gas to eight regional gas distribution companies, the largest of which is Jihomoravska Plynarenska in southern Moravia. For an additional koruna 16 billion, RWE has acquired shares between 46% and 58% in these regional suppliers. The deal is contingent on final approval by the Czech and German anti-monopoly offices and the European Commission. RWE will become Europe's fifth-largest integrated natural gas company and the Czech Republic's largest foreign investor. Reforms have increased Transgas' profitability, from koruna 1.8 billion in 2000 to about koruna 3.8 billion in 2001. Transgas sold 346 Bcf of natural gas in 2001.

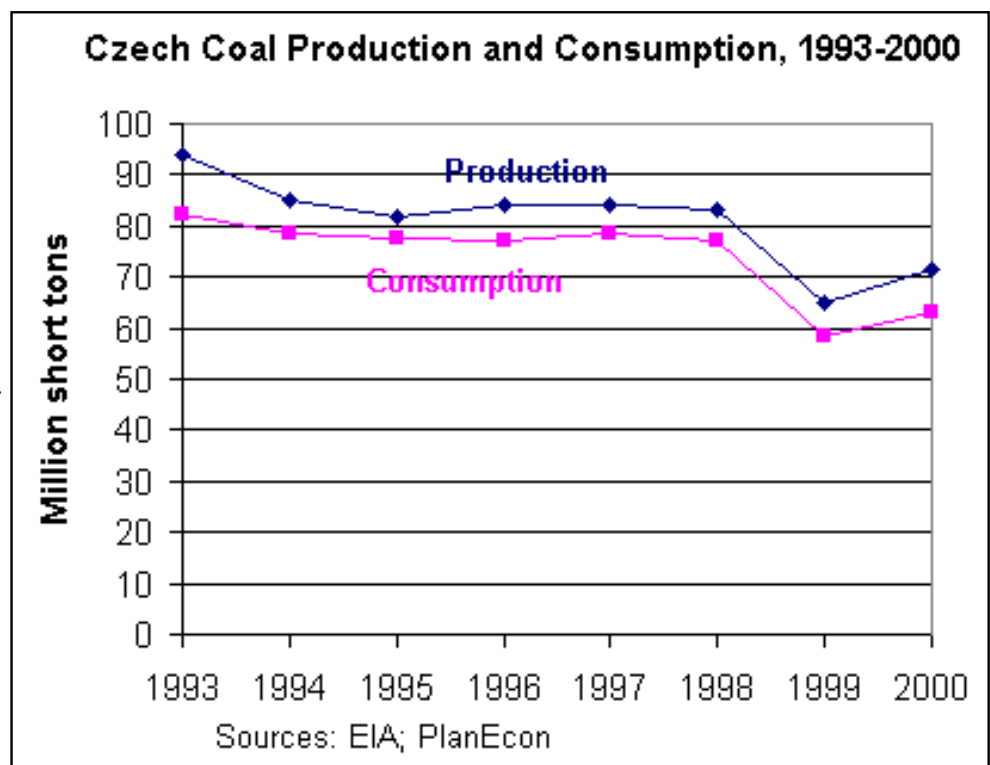
Pipelines

With nearly 32,000 miles of natural gas pipelines, the Czech Republic is a major transit center for Russian gas. Transgas is responsible for transporting Russian natural gas for export to Western Europe. Natural gas is piped to two points on the Czech-German border: Waidhaus, the main point, which delivers gas to Bavaria and points west and south; and Hora Svata Kateriny, on the border with eastern Germany, from which gas travels to Berlin and northern European destinations. The pipelines have been utilized at capacity levels since 1997.

At the beginning of November 1999, Transgas concluded with Gazexport a long-term contract for the transit of Russian natural gas across the territory of the Czech Republic until the year 2020. Until the year 2008, the contract guarantees the current volume of conveyed natural gas at the level of 28 billion cubic meters per year (91.9 Bcf). After 2009, however, the contract guarantees the conveyance of only 13 billion cubic meters (42.7 Bcf) annually. The reduction is connected with the start of the Yamal gas pipeline across Poland, which bypasses both the Czech Republic and Slovakia.

Coal

The Czech Republic's coal mining industry, which used to be one of the traditional pillars of the domestic economy, has experienced a thorough restructuring and paring down of activities over the past few years. The reasons behind this include a reduced demand for coal for electric power generation as the industry moves away from coal-fired power plants, the use of more environment-friendly fuels (such as natural gas) by domestic industry, and competition from cheaper imported coal. Coal mining production has fallen almost by half since 1989, and by 28.8 million short tons during the period 1993-1999. Coal's share of energy consumption has fallen to under 50% over the 1990s, to 43.9% in 1999.



A program for restructuring the Czech coal industry was approved by the government in December 1992. On the basis of this program, former state-owned coal mining companies were transformed into five large and two small commercial mining companies. In addition, the Czech government has reduced the number of inefficient mines in operation, cut the labor force associated with coal mining, and increased awareness of environmental issues related to the industry to bring the country in line with EU standards. The Czech Republic also has stated that it will accept the European Commission's decisions on coal prices in the common market.

As a result, the production of lower-quality brown coal, used mainly by power-producing and heavy industries, has been reduced significantly in the past ten years, especially the production of lignite. According to producer estimates, production of brown coal fell 12% in 2001 to 49.6 million short tons. The launching of operations at the Temelin nuclear power plant in southern Bohemia (see nuclear section, below), probably will cause brown coal mining to fall even more in 2002. Severoekse doly is the largest producer of brown coal, followed by Mostecka uhelna spolecnost and Sokolovska uhelna.

Black or hard coal, mined in particular by the Ostravsko-karvinske doly (OKD) company in northern Moravia, has also experienced a noteworthy decline, but the fall has been not as drastic, and furthermore, black coal continues to have better export markets. In 2000, OKD's production of black coal was 12.3 million short tons. In 1999, Severoceske doly Chomutov accounted for 46% of overall Czech mining production, followed by Mostecka uhelna spolecnost, with a 33% share, and Sokolovska uhelna with 21%. Of late, the domestic market for black coal has improved, and Czech industry, particularly steel, has demanded more than the import quota amount of coal from abroad.

The sharp reduction in coal mining over the last ten years has resulted in total employment in the four largest mining companies falling to less than 40,000. In comparison, OKD alone employed about 100,000 at the beginning of the 1990s. Further cuts in the mining workforce are expected.

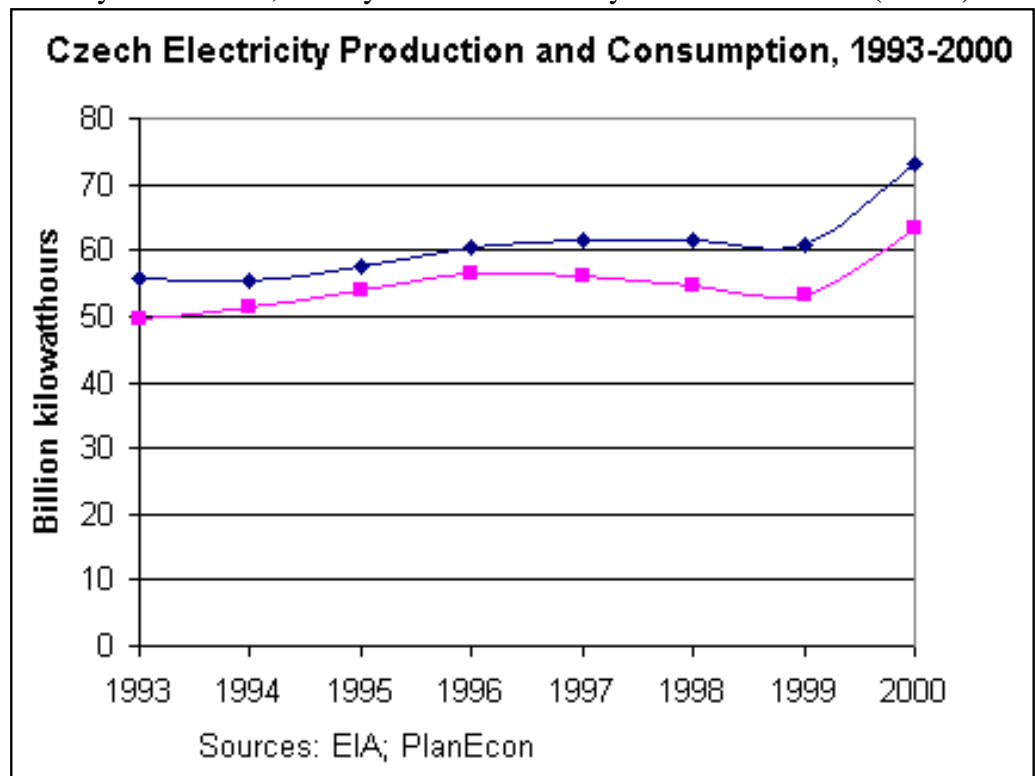
Czech coal consumption has fallen by 28% during the period 1993-1999, as the country switches to other fuels for electricity generation. Net exports of coal were 6.4 million short tons in 1999. Net exports have declined in the past few years, in part because of cheaper Polish coal exports in the region.

Electricity

Both electricity generation and consumption generally have been rising in the Czech Republic. From 1993 to 1999, electricity production in the country rose 9.2%, from 55.6 billion kilowatt-hours (Bkwh) to 60.7 Bkwh. During the same time period, electricity consumption increased 7%, from 49.6 Bkwh to 53.1 Bkwh. By November 2001, it was estimated that the country's consumption was 68.2 Bkwh on an annual basis, though the net figure (excluding consumption of power stations) was 63 Bkwh. The country is a net exporter of electricity, with the annual amount estimated at about 0.73 Bkwh.

Ceske Energeticke Zavody (CEZ) is the Czech Republic's dominant electric power utilities company. The company produces about 70% of the country's electricity, operating 28 power plants, of which 10 run on fossil fuels, 13 are hydroelectric plants, two are wind power stations, two are nuclear power plants, and one is a solar power station. CEZ owns 10,700 MW of generation capacity in the Czech Republic, as well as the national transmission grid, which CEZ operates under control of the company's recently established, wholly-owned subsidiary Ceska Prenosova (CEPS).

In an effort to liberalize its electricity sector to conform with EU standards, the Czech Republic has attempted to privatize CEZ. The privatization of the company, which is 67.6% owned by the state, is to be bundled with majority shares in six distribution companies and total control of the transmission grid company CEPS. In January 2002, the Czech government canceled a tender for the privatization of CEZ. The government stated that the bids submitted by Electricite de France (EdF) and a consortium of Enel and Iberdrola (of Italy and Spain, respectively) failed to meet the conditions of the tender. The companies wanted certain concessions regarding purchasing of brown coal and a state guarantee for the Temelin nuclear power plant, and there were also issues with the prices offered. Another concern for the government was its ability to handle such a large influx of foreign exchange at this time when the sale of Transgas would already bring in about \$3.6 billion.



The largest heat and electric independent power producer (IPP) is Elektrany Opatovice a.s., and there are a number of smaller foreign and domestic IPPs operating in the Czech Republic. In order to enter the EU, the Czech Republic must open up 26.48% of its electricity market to competition. The Energy Act adopted in November 2000 opens up the market gradually from 2002 onward, such that 30% of the electricity market will be subject to competition by 2002, 50% by 2005, and 100% by 2006. Producers with over 10MW of installed capacity and consumers with annual consumption above 40 gigawatthours (about 60 large industrial firms) will be in a competitive market at some point this year. Additionally, subsidies for household electricity prices are to be eliminated by the year 2002, meaning that prices will rise over 10% in January, as announced by regulatory agency ERU recently. However, prices for transmission and distribution services will continue to be regulated by the state due to their monopoly character. Another objective is to increase the share of renewable resources in overall electricity consumption from the current

1.7% to 3%-6% by the year 2010.

Electricity export have become increasingly important for the Czech Republic over the past few years, peaking in the first six months of 2001, when the country exported 6.69 terawatt-hours of electricity. The majority of the electricity was imported by Germany. However, since then exports to Germany have fallen by over 30% as German utility E. On canceled its contract with CEZ on July 1, 2001, due to concerns about the Temelin nuclear power plant and pressure by environmentalists over cheap electricity from polluting power plants being "dumped" on the EU. However, E. On has signalled that it may again become a buyer of Czech electricity by purchasing only non-nuclear-produced electricity. In November 2001, CEZ, along with coal producers Severoceske Doly, Mostecka Uhelna Spolecnost, and Sokolovska Uhelna, and trading company Carbounion Bohemia, formed a new company called Coal Energy that will be essentially a marketing company for CEZ's coal-produced electric power. Coal Energy is looking to expand electricity exports to Serbia, Romania, Slovenia, and other Balkan countries.

Nuclear

The Czech Republic has two operable nuclear power plants, at Dukovany and Temelin. Both are of Soviet design. The plant at Dukovany is equipped with four, 408-MW generators of the relatively new (1980s vintage) VVER-440-213 pressurized water reactor design. Dukovany provides approximately 20% of total Czech electricity output.

After years of delay, the controversial Temelin nuclear power plant, located just 30 miles from the Austrian border in southern Bohemia, was cleared for operations by the Nuclear Safety Authority on October 9, 2000. Although the plant is of Soviet design, Westinghouse was contracted to bring the plant up to Western safety standards during its construction. It consists of two VVER-981V320 generators, each with a capacity of 890-MW. The first reactor was connected to the national grid in December 2000, but was shut down in May 2001, because of circuit and turbine problems and remained closed to allow an EU inspection team time to assess the plant's safety. In August 2001, the EU inspection team found some minor flaws that could be remedied, but declared the plant safe. The first reactor was restarted, but shut down again within a week due to technical problems. Workers claim that the technical problems are not associated with the reactors, hence the plant is safe. The first reactor is currently undergoing tests and its trial operation is expected to be launched in spring 2002. The second reactor is expected to be launched in the beginning of 2003. When the plant is fully operative, it will provide over 20% of the Czech Republic's power needs.

Temelin has been controversial since construction first began in 1986. Opponents have argued that the plant is unnecessary, noting that the Czech Republic already produces more electricity than it consumes, and that additional electricity can be generated by improving the existing distribution network rather than installing new generating capacity. Critics have also accused CEZ of offering to supply energy to other countries at prices that are below production costs (dumping), a practice CEZ has publicly denied.

Although CEZ has stated that Temelin meets and even exceeds EU safety standards for nuclear power plants, Czech and Austrian environmentalists who oppose the project have accused CEZ of failing to conduct adequate safety checks. Ironically, one argument in favour of Temelin is an environmental one; specifically, that it will relieve the northern Czech Republic, whose aging coal-burning stations and extensive strip mines have turned the area into one of Europe's most polluted regions, of continued environmental degradation.

The Czech government is eager to privatize Temelin when it sells its shares in CEZ.

SLOVAK REPUBLIC

Slovakia, unlike the country it was formerly joined with, the Czech Republic, has experienced significant political difficulties in its transition from a Communist state to a market economy seeking to join the European Union. The leader of Slovakia after its dissolution from the Czech Republic in 1993, Prime Minister Vladimir Meciar, was accused during his term of office of thwarting democratic principles and imposing a biased election law. However, the election of Mikulas Dzurinda as Prime Minister in 1998, and Rudolf Shuster as President in 1999 began an era of increasing democracy and integration with the rest of Europe and the possibility of EU and NATO membership. New parliamentary elections are set for the autumn of 2002.



The government began a structural reform program in 1999 that aims to privatize several state-owned companies, control the budget deficit, and reform the healthcare and social security pensions systems. The government has had some success, with budget deficits of 5% of GDP during the Meciar era reduced to 3.7% in 2001 and targeted for 3.5% or less in 2002. Proceeds from privatizations in the steel, energy, telecoms, and financial sectors have also helped reduce the deficit. After growth rates of 1.9% in 1999 and 2.2% in 2000, growth finally went above 3% in 2001 to 3.1%. Slovakia needs solid economic growth to reduce its high unemployment rate, one of the highest in Europe at about 17.5%, but as high as 40% in some areas of eastern Slovakia.

A possible drag on Slovakia's growth in 2002 is continued low growth in the EU, and particularly in Germany, Slovakia's most important trading partner. Trade accounts for about 76% of Slovakia's GDP, and Slovakia's trade deficit grew substantially in 2001, with exports declining 3.7% and imports rising 6.5%. Slovakia's trade deficit has been sustainable because of substantial inward investment flows, but it is unclear whether they will continue. Another drag on the economy has been the recent collapse of BMG Invest, an investment scheme that had 200,000 investors who will most likely not be compensated for their losses.

Slovakia closed the energy chapter of its EU accession talks in November 2001. The country agreed to close the two oldest of four blocks at the Jaslovské Bohunice nuclear power plant. The Economy Ministry sets energy policy.

Oil

Slovakia's oil production is the smallest of the four countries in the Visegrad Group, with production of only about 1,000 bbl/d in 2001. This is an increase over the previous year, with most of the gain coming from Nafta Gbely's Gajary Baden reserves in western Slovakia. Nafta Gbely is one of 18 members of the Nafta Group, Slovakia's oil and natural gas extraction company. Slovakia is a small oil consumer at about 72,000 bbl/d in 2001, and is nearly completely dependent on imports.

Slovakia imports its crude oil from Russia through the Druzhba (Friendship) and Adria oil pipelines. These pipelines have a capacity of about 422,000 bbl/d, but have not been used at full capacity. Transpetrol, the operator of the pipelines in Slovakia, transported about 187,000 bbl/d in 2000, of which about 106,000 bbl/d went to Slovnaft's refinery in Bratislava and the rest was shipped onward to the Czech Republic. Slovnaft is Slovakia's only refinery, and it has a capacity of 115,000 bbl/d. Slovnaft is 36.2% owned by MOL of Hungary.

In December 2001, the Slovak government approved the sale of a 49% stake with managing powers in Transpetrol to Russia's second-largest oil producer, Yukos. Yukos was chosen over domestic company Slovnaft. Yukos plans to use the pipelines' available capacity to supply more oil to western Europe, in particular to Germany through the Druzhba and to Croatia's coast for shipment to Mediterranean countries through the Adria. The Adria pipeline connects to Croatia through Hungary.

Natural Gas

Slovakia, though a very small producer of natural gas, is very important as a transit country. It is estimated that about 25% of the natural gas consumed in western Europe transits through Slovakia. This represents about 70% of the Russian natural gas exported to western Europe. Slovakia produced only about 7 Bcf of natural gas in 1999. However, the country's per capita natural gas consumption was the highest amongst the Visegrad Group countries, as about 80% of Slovak households are connected to the natural gas network. Slovakia's state-owned natural gas monopoly, Slovensky Plynarensky Priemysel (SPP) plans to invest 1.643 billion crowns for additional gas mains in 2002 to connect additional households. In March 2001, a consortium of Gaz de France (GdF), Ruhrgas, and Gazprom submitted a 49% stake in SPP, which is being reviewed by the state's privatization committee. However, ruling Party of the Democratic Left leader Pavel Juncos has since declared that a 49% stake could not be sold for the \$2.69 billion offered, but only a 34% stake. It is reported that the Slovak cabinet has agreed to the consortium's offer, but this has yet to be officially announced.

There are two major natural gas pipeline routes in Slovakia. Both receive natural gas from Russia via Ukraine; one transits onward to the Czech Republic and Germany, the other transits to Austria. The pipelines' Slovak sections are operated by SPP. The pipelines deliver about 3.18 Tcf per year to Western Europe. There are plans to build an extension of the Yamal II natural gas pipeline that would bypass Ukraine and instead transit Belarus and Poland to Slovakia. The planned 373-mile pipeline, 72 miles of which would pass through Slovakia, would have a capacity of 1.06 Tcf per year.

Slovakia's natural gas market is to be liberalized (i.e. customers will be able to choose their supplier) in stages, with liberalization beginning July 2002 for customers with an annual consumption of more than 882 million cubic feet (25 million cubic meters), in 2003 for customers with an annual consumption of more 530 million cubic feet (15 million cubic meters), and in 2008 for customers with an annual consumption of more than 177 million cubic feet (5 million cubic meters).

Coal

Slovakia's coal reserves and production are much smaller than that of the other members of the Visegrad group. Slovakia's coal reserves are estimated at just 190 million short tons, all of which is subbituminous and lignite. Most of the coal is used for electricity production. Production was about 2.5 million short tons in 1999. There are three coal mining companies in Slovakia, all of which are privately owned, and almost all the coal they produce is brown coal. The largest is Hornonitrianske bane Prievidza (HBP), with about 64% of all coal sales. Its main customer is Slovakian electricity company Slovenska Elektrarne (SE), however, HBP has plans to build its own coal-fired power station. The other two companies are Dul Dolina (also known as Bana Dolina) and Bana Zahorie.

Electricity

In 1999, Slovakia's installed electric power generating capacity was about 7.8 million kilowatts, about the same as that of Hungary, despite Slovakia having a smaller population. Slovakia's generating capacity is diversified, with coal, natural gas, hydro, and nuclear power plants each having less than a third of overall capacity in 1999. With two nuclear reactors coming on line in 1998 and 2000, Slovakia has become more reliant on nuclear generation and less reliant on coal and fuel oil (mazut) for electricity generation. Slovakia still has substantial unused hydroelectric

potential. Slovakia generated about 22.6 Bkwh of electricity in 1999, and it is estimated that this total increased in 2000 and 2001. SE alone, which supplies about 85% of Slovakia's electricity, is estimated to have generated about 24.9 Bkwh in 2001. Slovakia was a small net electricity importer in 1999, but it is estimated to have become a net exporter in 2001, as preliminary estimates of electricity consumption in 2001 are about 26.9 Bkwh.

SE is Slovakia's dominant electric power company. It is state-owned, but it is likely to be partially privatized after undergoing organizational and financial restructuring. The government acknowledges that this restructuring will not be completed before the September 2002 elections. SE generates about 85% of Slovakia's electricity, operates the national transmission grid, and trades electricity. Distribution is carried out by three regional companies: Zapadoslovenske Energeticke Zavody (ZSE), Stredoslovenske Energeticke Zavody (SSE), and Vychodoslovenske Energeticke Zavody (VSE). The government has issued tenders for 49% stakes in these companies, and several foreign firms have expressed interest, including CEZ of the Czech Republic.

On January 1, 2002, consumers of more than 100 gigawatthours (Gwh) were supposed to have been allowed to choose their supplier. This covers about 19 large companies that represent some 28% of the market. This liberalization was postponed by the Economy Ministry, however, because an independent electricity regulating agency has not yet been formed and the restructuring of SE is incomplete. Liberalization for customers using more than 40 Gwh is scheduled for 2003, and complete liberalization for 2007.

Nuclear

Slovakia has two nuclear power plants, which generated an estimated 59% of Slovakia's electricity in 2001. All of Slovakia's functioning reactors use the VVER-440 V213 Soviet design and are operated by SE. Slovakia's nuclear plants are regulated and monitored by the Slovak Nuclear Regulatory Authority (UJD). The Jaslovské Bohunice plant at Trnava has four, 408-MW reactors that are functioning, and one decommissioned reactor. The plant's two older reactors are due to be decommissioned in 2006 and 2008 as part of the energy chapter of Slovakia's accession agreement with the EU. An EU study in 1992 determined that the two older functioning reactors at the plant could not be modernized at a reasonable cost. The two newer reactors will require investment of 12.62 billion crowns by 2008 for their modernization, according to the Ministry of the Economy. The modernization is required by the UJD, the International Atomic Energy Agency (IEAA), and legislation. The Mochovce plant has two completed 412-MW reactors that went on line in 1998 and 2000 and two uncompleted reactors whose construction has been halted as government financial support for them has ended.

HUNGARY

Hungary transitioned from a Communist state to a democratic one without violence and held its first free, multi-party parliamentary election in 1990 after the former parliament and Communist Central Committee made a "democracy package" of key reforms in 1989. Hungary emerged from the Communist era with one of the most advanced economies of region, but still not nearly as developed as its neighbor and former partner in the Austro-Hungarian Empire, Austria. Hungary also had significant foreign debt. The first post-

Communist government encountered problems in the transition to a market-based economy, with real GDP falling about 18% from 1990-1993. Industrial output also shrank, and the foreign debt, current account deficit, and budget



deficit rose to high levels. The new government of 1995 instituted an austerity and privatization program as well as a new export-promoting foreign exchange regime to reduce the debt and deficit levels. By 1997, the country's finances were solid and Hungary no longer requires any assistance from the International Monetary Fund (IMF), and has repaid all of its debt to the Fund.

The Federation of Young Democrats (renamed Fidesz-Hungarian Civic Party (MPP) in 1995) captured a plurality of parliamentary seats in the May 1998 elections and forged a coalition with the Smallholders and the Democratic Forum. The head of Fidesz, Viktor Orban, became Prime Minister. The current government is more nationalistic than the previous ones, and has championed the rights of Hungarian minorities living in surrounding countries. The government has also slowed the pace of liberalization in some sectors and has favored more state intervention than the previous government. A parliamentary election is scheduled for spring 2002. Hungary entered NATO in 1999 and has applied to become a member of the EU in 2004 or 2005. Hungary became a member of the International Energy Agency (IEA) in 1997

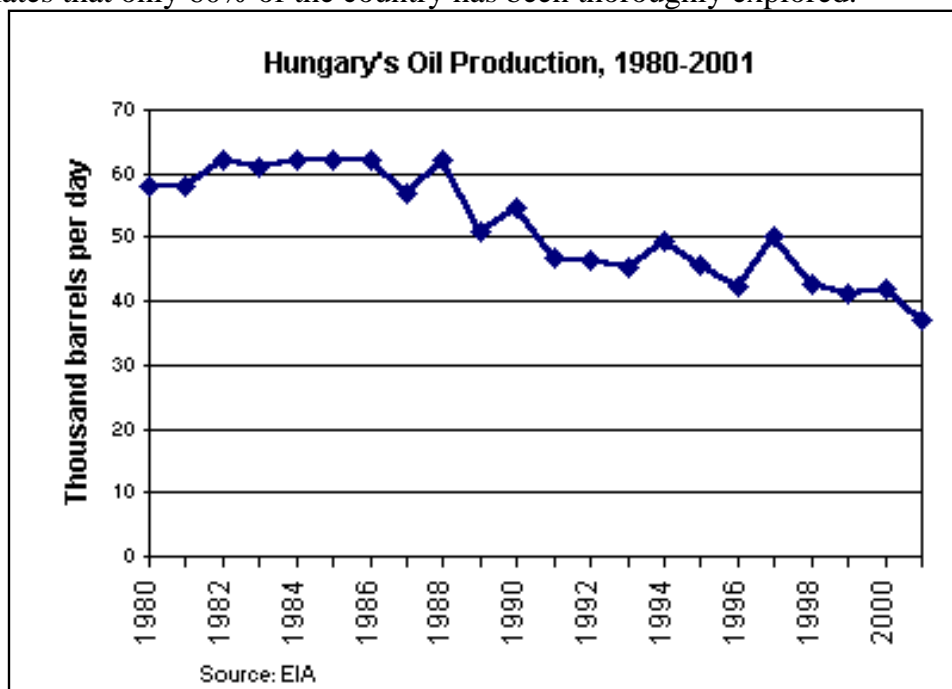
Hungary had strong economic growth of 5.2% in 2000 and this continued into 2001, with a growth rate of 3.8%, despite the global economic slowdown, especially in major trading partners Germany, Italy, and Austria. Hungary has had the strongest economy in the Visegrad group over the past three years. Hungary is dependent on exports for economic growth, and a 13% expansion in exports (especially services) in 2001 was a prime factor driving Hungary's growth and the reduction of Hungary's current account deficit to about 2.1% of GDP. Inflation began to fall in late 2001, and is predicted to be about 6.5% in 2002, the lowest level since Hungary became a market economy. The lower inflation has made it possible for the central bank to cut interest rates 50 basis points in January 2002.

Oil

Hungary is the largest producer of crude oil among the Visegrad Group by far, though still a small producer by international standards. Crude oil production rose very slightly in 2001 to about 27,000 bbl/d, but production of natural gas liquids fell by about 5,000 bbl/d. Hungary's oil production had been declining steadily since its peak in the mid-to-late 1980s of 62,000 bbl/d. Nearly half of Hungary's crude oil comes from the Algyo field in the south central part of the country, and the remainder is produced from numerous fields with production of less than 2,000 bbl/d. Oil reserves are about 110 million barrels. Hungary's oil and natural gas company MOL has undertaken increased domestic exploration, and the company estimates that only 60% of the country has been thoroughly explored.

Hungary consumed about 146,000 bbl/d of oil in 2001, so the country is reliant on imports, mostly from Russia. Consumption has declined steadily from a peak of 244,000 bbl/d in 1980. Russian oil is imported through part of the Druzhba pipeline. A smaller amount of oil is also imported from the Middle East.

Hungarian Oil and Gas Company (MOL) is Hungary's largest company in terms of net revenue, and is dominant in the upstream and downstream oil sectors. The company is responsible for almost all of Hungary's natural gas and oil exploration and production, transmission, stockpiling and wholesale trade. It has an 82% share of the wholesale oil market and a 42% share of the retail market. It was partially



privatized through stock market flotations 1994-1998. The state retains a 25% "golden" share. In 2001 MOL merged its domestic and international upstream activities into one unit and decided to cease all oil exploration abroad with the exception of Yemen. MOL will, however, continue to acquire areas abroad where oil has already been discovered. MOL has attempted to purchase downstream assets in other central European countries, but its only successful purchase so far is a share of Slovakian refiner and retailer Slovnaft. In November 2001, MOL sold its 51% stake in oil storage firm Koolajtarolo to the Crude Oil and Oil Product Storage Association (KKKSz) for 6 billion forints.

In 2001, MOL shut down the crude processing facilities at its 60,000-bbl/d Tiszaújváros and 10,000-bbl/d Zalaegerszeg refineries as part of a cost-cutting move. The Zalaegerszeg refinery will operate as an asphalt plant and the Tiszaújváros refinery will still be used for a small amount of other processing, but the only remaining crude oil refinery in Hungary is MOL's 161,000-bbl/d Százhalombatta refinery. Retail oil products prices and trade were liberalized in the early 1990s.

Natural Gas

Hungary produced about 121 Bcf of natural gas in 2000. Hungarian natural gas production has been declining steadily for many years, though domestic production still accounts for a significant share of consumption. Consumption fell slightly, to an estimated 411 Bcf in 2000 from 437 Bcf in 1999, as both domestic production and imports declined. About 80% of Hungary's natural gas imports are from Russia through part of the Druzhba pipeline. Some Russia gas transits onward to the former Yugoslavia through Hungary. The Győr-Baumgarten natural gas pipeline connects Hungary to Austria and western Europe's natural gas grid. This enables Hungary to import natural gas from GdF and Ruhrgas. Natural gas demand is expected to increase by about 20% by the end of the decade, so Hungary's natural gas imports will increase significantly in light of declining domestic production.

MOL is Hungary's only natural gas producer and importer and operates the natural gas pipelines. Natural gas distribution is the responsibility of regional companies. In addition to natural gas' use for electricity generation and industry (60% of total use), about 60% of Hungarian households are supplied with natural gas (40% of total use). Natural gas represented about 41% of energy consumption in Hungary in 1999.

MOL has been losing money for several years now, at a current rate of over \$1 million per day, or about 118 billion forints in 2001. This results mainly from government price caps, which force MOL to sell imported natural gas at a loss. In September 2001, MOL lost a lawsuit against the government in the Constitutional Court. MOL charged that the government was violating laws on natural gas pricing in forcing the company keep natural gas price increases below levels necessary to recover costs. Because of this, MOL has attempted to sell off at least part of its natural gas division. However, the government is not eager to lose control of Hungary's natural gas assets. Hence, despite the interest of several foreign companies, including a local subsidiary of GdF and Ruhrgas, the state-owned Hungarian Development Bank is in exclusive talks to acquire 100% of MOL's natural gas division, effectively re-nationalizing the company and a step backward from the liberalization occurring in the region. Prime Minister Orbán has stated that he wants price controls for natural gas to remain in place for up to eight more years.

Coal

Hungary is a much smaller coal producer than Poland or the Czech Republic, and about 95% of the coal produced is brown coal (including lignite). Nevertheless, coal is an important part of Hungary's energy mix, accounting for 14.6% of energy consumption in 1999 and about 25% of electric power generation. Coal's share is declining, however, and is expected to continue to do so in the next ten years. Hungary produced about 15.6 million short tons of coal in 2000. This is down sharply from about 22.4 million tons produced in 1989, at the end of the Communist era. This reflects a decline in certain energy-intensive heavy industries as well as closures of unprofitable mines that occurred in 1990s as the industry privatized. In addition, domestic lignite with high sulphur content has caused air pollution, and a new coal-fired power plant being built will use imported Russian coal. However, Hungary's lignite (about 85% of reserves) is

inexpensive to produce through open-pit mines in the Matra and Bukk mountains, so there will continue to be a demand for it at older electricity generating plants. Hungary's coal consumption in 2000 was about 16.1 million short tons, down sharply from 25.3 million short tons in 1989.

Electricity

Hungary's electricity sector, like others in the region, is undergoing a process of liberalization and restructuring. Most of the sources of Hungary's capacity and generation are thermal, though Hungary's 4-unit nuclear plant at Paks generates slightly less than 40% of total electricity generated. Hydropower generates less than 1% of Hungary's electricity. It is estimated that Hungary generated about 34.9 Bkwh in 1999 and consumed about 33.5 Bkwh in 1999. Consumption peaked at 37 Bkwh in 1989, but declined in the early 1990s as Hungary's post-Communist economy grew less energy-intensive. Electricity consumption has since increased, but at less than the rate of economic growth. The Hungarian government predicts that electricity consumption will grow an average of 1.45% per year this decade, assuming 5% economic growth. According to the Hungarian government, power generating capacity currently exceeds consumption by about 30%. Nevertheless, Hungary is a net importer of electricity, mostly from Slovakia. Preliminary estimates of 2000 production show it declining, but 2000 consumption was steady, so electricity imports rose in 2000. The electricity sector accounts for about 4% of Hungary's GDP.

For years, the state-owned Hungarian Electricity Works (Magyar Villamos Muvek - MVM) generated most of Hungary's electricity, was the sole importer/exporter, and owned and operated the national electricity grid through subsidiary Mavir. This has changed, however, as Hungary's eight generation companies were unbundled from MVM over the past few years, and Mavir was acquired by the Ministry of Economic Affairs in February 2002, with the state privatization agency APV exercising ownership rights. In return, MVM is to be compensated financially by the government and by APV handing over stakes in a number of power plants to MVM. However, this may be problematic as liberalization proceeds, as no generator will be able to hold more than 30% of total market capacity. MVM already owns the Paks nuclear power plant and the Vertes power company, which are already about 30% of capacity. The eight generating companies (seven thermal and one hydroelectric) have been partially or fully privatized, but hydroelectric power company Tiszaviz Kft will likely be returned to full ownership by MVM as part of the compensation for Mavir by APV. Tiszaviz's two hydroelectric plants are slated to be modernized later this decade. There are also independent power producers (IPPs) in Hungary, which sell their power to distributors under long-term power agreements.

MVM/Mavir has made and continues to make improvements to Hungary's electricity network. In November 2001, MVM completed a 17 billion forint, network control system that connects the system to 166 other power plants and distributors and prepares the Hungarian power industry for the planned market opening in 2003. In September, MVM announced that it plans to restart investment projects on the national grid, including an expansion of the Sandofalva-Bekescsaba powerline for 18 billion forints and an expansion of the line between the southern city of Pecs and the nuclear power plant at Paks. In May 2001, MVM (represented by Mavir) became a member of European electricity transmission system Union for the Coordination of Transmission of Electricity (UCTE) as the result of a 12-year process. Hungary's power and transmission system operates in accordance with the systems of most other European countries, providing increased security of supply according to MVM.

Hungary has passed electric power liberalization legislation set to go into effect beginning in January 2003. It will begin with large consumers (about 200-300 large industrial users with annual consumption above 6.5 Gwh) that represent about 35% of the market. The legislation still requires lower-level regulations that will specify how much electricity these large users can purchase on the open market or from abroad. These regulations will also need to specify how so-called "frozen" costs will be distributed. These are additional costs that arise from the fact that consumers in a free market are unlikely to buy all the power that wholesaler MVM has already purchased through long-term contracts and will have to be reimbursed. Additional liberalization will be phased in gradually, but must

conform with EU regulations by the time that Hungary accedes, as the country has not requested any special exemptions. New power stations were permitted to be built without long-term purchase contracts as of February 2002. Many analysts are skeptical of Hungary's liberalization plans, because Hungary's electricity producers have higher costs than outside European sources, but are protected by long-term contracts with MVM. It is unlikely that the government would simply allow many power plants to go out of business when exposed to competition. Another problem is that MVM is selling below cost to distributors because of price caps, and then being compensated by the government for losses. Currently, the government is considering allowing the large consumers to purchase no more than 50% of their electricity on the open market in 2003. Also, given the small size of Hungary's electricity market and the continuing prevalence of long-term contracts, the creation of a physical spot or short-term market may be difficult. Nevertheless, in June 2001, the European Commission announced its satisfaction with Hungary's regulation of its electricity sector and concluded that the relevant legislation is in line with EU requirements.

Hungary has several new power plants planned or under construction. Central European Steel Group of Russia plans to build a 590-MW coal-fired plant near the border with Ukraine. Higher quality Russian coal will be used as the fuel source, and the plant's construction is expected to begin by the summer of 2002. Fortum Engineering of Finland and Budapest Power Plant plan to build a 110-MW gas-fired, combined cycle power plant in the Kispest area of Budapest. The plant will also produce 120 MW of district heat. E. On of Germany's Hungarian subsidiary built and owns over 90% of a combined-cycle 95-MW power plant in Debrecen that was officially opened in November 2001. The plant is an IPP, having no long-term contract with MVM. AES of the United States has been very active in Hungary, having purchased state-owned power producer Tizai Gorup in 1996. AES at the time promised to make several hundred million dollars in investments in return for long-term contracts with MVM that would support the costs of the investments. In October 2000, AES sued the Hungarian government and MVM and canceled new investment in Hungary because it claimed that MVM had failed to agree to the contracts. In January 2002, AES reached a compromise with the government and MVM that will have MVM obligated to purchase power from AES' 860-MW Tiza II oil and gas-fired plant for 15 years and for two more years from AES' smaller coal-fired power plants, after which the two coal-fired plants will be retired. AES also agreed not to build two new power plants the company had planned. NRG Energy of the United States has also invested in Hungary's power sector, having bought Powergen of the UK's Csepel II 389-MW combined cycle gas turbine power plant in April 2001.

Nuclear

The Paks nuclear power plant at Tolna Megye consists of four Soviet-design, second generation VVER-440/213 reactor units that each have a net generating capacity of 433 MW (the oldest unit has a net capacity of 430 MW). Paks is owned and operated by MVM subsidiary Paks Nuclear Power Plant Co. The Hungarian Atomic Energy Authority (HAEA) regulates the plant. The plant is undergoing a 60-billion-forint multiyear safety upgrade program to be finished at the end of 2002. HAEA is considering a request by the Paks Nuclear Power Plant Co. to extend the lifetime of the four reactors beyond their 30-year design lives and to uprate the power at each unit by about 10%. The four units went online between 1982 and 1987. In June 2001, an accidental fire occurred that caused the plant 1.15 billion forints in losses and 150 million forints in repairs, but the accident did not have to do with the nuclear reactor, so there were no significant safety issues raised. Hungary has bilateral agreements with the other countries of the region for notification and information sharing in the case of an emergency. The EU regards the plant as safe by Western nuclear power plant standards.

Table 1. Economic and Demographic Indicators for North Central Europe

Country	Gross Domestic Product (GDP), 2000E (Billions of U.S. \$)	Real GDP Growth Rate, 2000 Estimate	GDP per capita, 2000 Estimate (U.S. \$)	Population, 2001E (Millions)
Poland	158.3	4.0%	4,097	38.6
Czech Republic	50.8	2.9%	4,943	10.3
Slovak Republic	19.2	2.2%	3,555	5.4
Hungary	46.8	5.2%	4,680	10.0
Total/Weighted Average	275.1	3.9%	4,278	64.3

Source: DRI WEFA

Table 2. Energy Consumption and Carbon Dioxide Emissions in North Central Europe, 2000

Country	Total Energy Consumption (quadrillion Btu, 1999)	Oil (thousand barrels per day, 2001)	Natural Gas (billion cubic feet)	Coal (million short tons, all types)	Electricity (billion kilowatthours)	Energy-Related CO ₂ Emissions (million metric tons of carbon, 1999)
Poland	3.84	431	444.6	155.3	138.8	84.5
Czech Republic	1.54	175	327.4	63.3	63.2	28.5
Slovak Republic	0.70	72	292.3	11.2	27.8	9.2
Hungary	1.07	149	411.2	16.1	38.2	16.2
Total	7.15	827	1,475.5	245.9	268	138.4

Sources: Energy Information Administration; PlanEcon

Table 3. Energy Supply Indicators in North Central Europe

Country	Crude Oil Reserves, Million Barrels, 1/1/02E	Natural Gas Reserves, Trillion Cubic Feet, 1/1/02E	Coal Reserves, Million Short Tons, 1999	Oil Production, Thousand Barrels per day, 2001	Natural Gas Production, Billion Cubic Feet, 2000	Coal Production, All Types, Million Short Tons, 2000	Electricity Generation, Billion Kilowatthours, 2000	Crude Oil Refining Capacity, Thousand Barrels per Day, 1/1/02
Poland	114.9	5.12	15,773	14.2	174.9	179	145.1	382

Czech Republic	15	0.14	6,809	6.4	2.9	71.3	73.1	198
Slovak Republic	9	0.53	190	1	14.1	4.1	29.9	115
Hungary	110.9	1.28	4,917	37.2	121.9	15.6	34.2	161
Total	249.8	7.07	27689	58.8	313.8	270	282.3	856

Sources: Energy Information Administration; PlanEcon

Sources for this report include: BBC; CIA World Factbook; Czech News Agency; DRI WEFA; Economist Intelligence Unit; Financial Times; Hungarian News Agency; PlanEcon; Platts Oilgram; Polish News Bulletin; Prague Business Journal; Slovak Spectator; U.S. Department of Commerce; U.S. Department of Energy and Energy Information Administration; Weekly Petroleum Argus; World Markets Online.

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[U.S. State Department's Consular Information Sheet - Poland](#)

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September 2001

United Kingdom

With its significant North Sea reserves, the United Kingdom is a major European oil and natural gas producer. It is also one of the largest energy consumers in Europe.

Information contained in this report is the best available as of September 2001 and is subject to change.



BACKGROUND

The United Kingdom (official name: United Kingdom of Great Britain and Northern Ireland, abbreviated: UK) is a major political and economic world power and a close ally of the United States. It is also the world's fourth-largest economy. The country joined the European Union (EU) in 1973 (confirmed by referendum in 1975), but has no plans to join the common European currency, the euro, in the immediate future. Despite the UK's lack of participation in the euro, the country has continued to attract foreign direct investment (FDI) - about \$517 billion total at the end of 2000, second in the world after the United States. The UK is an even larger exporter of capital - outward FDI at the end of 2000 totaled \$902 billion, also second to the United States. The UK maintains a smaller public sector than many of its EU counterparts.

The UK, like most of the OECD, has seen growth rates decline in 2001. GDP growth in the UK is expected to decline to 2% in 2001, and will decline further still if the economy of the United States approaches a mild recession, as the UK economy is the second-closest linked to that of the United States of all the countries of the EU. This slowdown is also expected to decrease external demand, raising the trade deficit for 2001. Despite this, unemployment fell to a 26-year low in July 2001.



Given low inflation (under the government's target of 2.5% for 28 consecutive months) and the prospect of slackening growth (especially in the manufacturing sector), the Bank of England has cut interest rates four times in 2001, most recently in

August.

The United Kingdom is by far the largest petroleum producer and exporter in the EU (Norway is not a member of the EU). It also is the largest producer and an important exporter of natural gas in the EU. Most of the UK's oil and gas reserves and production are located off the coast of Scotland, with the Scottish city of Aberdeen considered to be the oil and gas capital of the United Kingdom. The International Petroleum Exchange (IPE), the second-largest energy futures exchange in the world, is located in London. The second and third-largest publicly traded energy companies in the world in terms of market value, Royal Dutch/Shell and BP, respectively, are based in the UK (Royal Dutch/Shell is also based in the Netherlands). Because major UK energy companies are private, the imminent decline in British oil and gas production most likely will translate to an increase in UK companies' involvement abroad, mitigating the effect in the overall UK economy, though Scottish employment is particularly sensitive to North Sea production levels. The oil and gas industry represented about 12% of industrial capital investment, and 2% of total capital investment in 2000. The energy industry overall represents about 4% of GDP. The UK has high taxes on petroleum products, making for among the highest prices in the EU. High fuel prices caused protests and blockades in September 2000.

In July 1999, a Scottish Parliament met for the first time in almost 300 years. "Devolution" gives the Scottish Parliament the ability to tax its own citizens, plus jurisdiction over local issues such as education, health, transport, and agriculture. It has no effect on the economic and industrial structure of the United Kingdom, which remains a single market. Devolution has had no effect on North Sea oil and gas.

North Sea Oil and Gas

North Sea oil and gas reserves were first discovered in the 1960s. The North Sea did not emerge immediately as a key non-OPEC oil producing area, but North Sea production grew as major discoveries continued throughout the 1980s and into the 1990s. Although the region is a relatively high cost producer, its high quality crude oil, political stability, and proximity to major European consumer markets have allowed it to play a major role in world oil and gas markets.

Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil. (Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field.) Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 450,000 bbl/d by 2005, but discussions are reported to be underway on building a pipeline spur from the Statfjord system to the Shell-run Brent pipeline to Sullom Voe. The increased throughput would support trade in the increasingly dated Brent price marker, extending its life as a price marker and reducing volatility in the 15-day Brent forward market, where liquidity has fallen to about 10 cargoes per delivery month compared with 300-400 deals per month in the early 1990s.

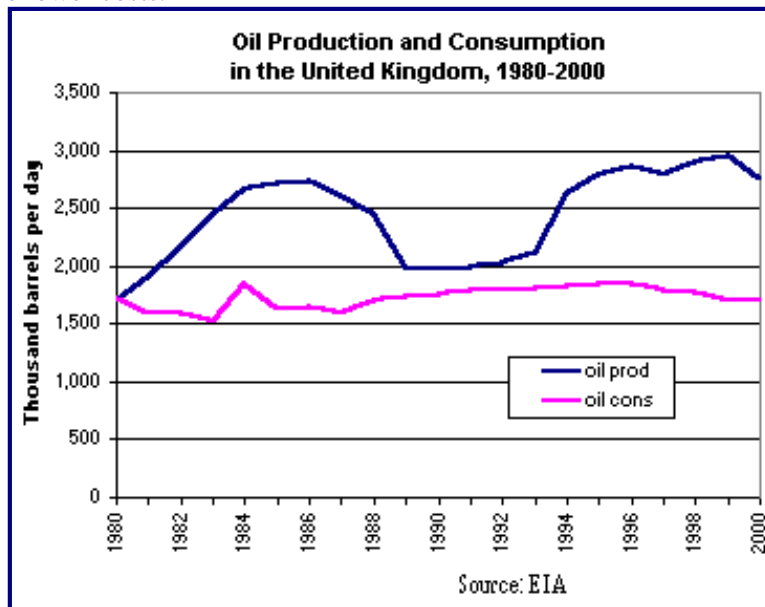
The North Sea is considered a "mature" area, with few large discoveries likely to be made. Only a few frontier areas hold the possibility of further discoveries of large oil and gas fields. In both of the major North Sea producing nations, Norway and the UK, government and industry are taking steps to restructure their oil and gas sectors to make them more internationally competitive.

OIL

The UK holds about 5 billion barrels of proven oil reserves, almost all of which is located in the North Sea. Most of the country's production comes from basins east of Scotland in the central North Sea.

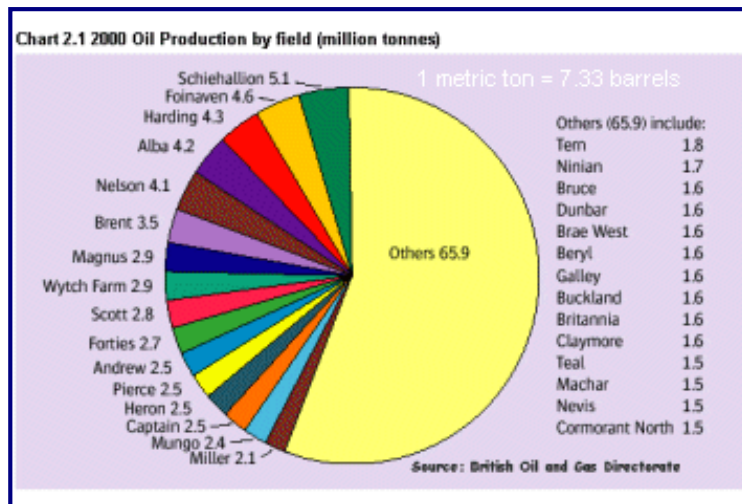
The northern North Sea (east of the Shetland Islands) also holds considerable reserves, and smaller deposits are located in the North Atlantic Ocean, west of the Shetland Islands. There are over 100 oil and gas fields currently onstream, and several hundred companies are active in the area. In 2000, the United Kingdom's production declined to 2.75 million barrels per day (bbl/d), down from a historical high of 2.95 million bbl/d in 1999. Production is expected to decline by 85,000 bbl/d in 2001. Most of the UK's crude oil production ranges in gravity from 30° to 40° API. Most high quality crude is exported, while cheaper, lower quality (mainly from the Middle East) crude oils are imported for refining. Unit costs for UK oilfields averaged just above \$15 per barrel in 2000, though fields that started production in the 1990s have lower costs.

The domestic UK oil and gas industry is expected to decline as reserves are depleted in the coming decade. The British Oil and Gas Industry Task Force was set up in 1998 to bring together government departments and oil and gas industry representatives (the oil and gas industry is 100% in the hands of the private sector) to discuss the future of the industry. A successor body to the Task Force, known as "PILOT", now has been created to oversee the execution of Task Force recommendations and future developments. Government and industry are interested in collaborating to facilitate a "gentle decline" in British North Sea production, a component of which involves shifting focus from small numbers of very large projects to larger numbers of smaller projects.



Production

The number of fields under development or in production in the UK at the end of 2000 was 264. Just two fields ceased production, Bladen and Blenheim. Oil production from six offshore fields commenced in 2000: Bittern, Cook, Guillemot West, Guillemot North West, Shearwater (condensate), and Keith. In 2001, as of July, four new offshore oil fields were approved for development by the British Oil and Gas Directorate: Halley, Hannay, Kestrel, and Otter; and the Angus field was approved for redevelopment.



In December 2000, the British government gave approval to four new projects that will result in \$1.5 billion in new investment in the British North Sea: (1) a £320 million gas pipeline from the Shetland Islands to the Magnus oil field that takes surplus gas from Sullom Voe oil terminal on the Shetland Islands to be reinjected for enhanced recovery in the Magnus field; (2) a floating platform to drill for oil in the Leadon field which was discovered in 1979, but so far undeveloped,

that is expected to yield 50,000 bbl/d of oil equivalent (see below); (3) further development by BP of

the Foinaven oil field; and (4) Ranger Oil's (subsidiary of Canadian Natural Resources Limited) production in the Kyle field, which started in April 2001 at 7,000 bbl/d, in addition to gas production. Total investment spending in the UK continental shelf in 2000 was about £3 billion, though continued high oil prices make it likely that investment will increase for 2001. Most new developments will be subsea, using existing infrastructure, instead of new platforms.

As noted above, production commenced in April 2000 from the Bittern, Guillermot West, and Guillermot North West fields by means of the Amerada-Hess operated Triton FPSO. About 78% of the content is British, and the three fields have reserves of about 140 million barrels of oil and 180 billion cubic feet (Bcf) of gas. Expected field life is 13 years and daily production is 60,000 bbl/d. Another development is the £350-million expansion Area B to Texaco's Captain field completed in December 2000 allows production to increase by 25,000 bbl/d to 85,000 bbl/d and will extend the field's life to beyond 2015.

Some of the smaller projects planned for the British North Sea include development of the Jade and Blake fields. In January 2000, the British subsidiary of Phillips Petroleum (operator) and its partners British Gas, Texaco, Agip, and OMV received approval from DTI to develop the Jade field. The field is expected to produce 15,000 bbl/d of crude oil and 200 million cubic feet per day (Mmcf/d) of natural gas after it comes onstream in late 2001. The BG-operated Blake field represents the opening up of the Outer Moray Firth for new discoveries and developments. It has a subsea tie-back to the existing Bleo Holm FPSO, and will extend the life of the existing Ross field. Production is expected to start in third-quarter 2001.

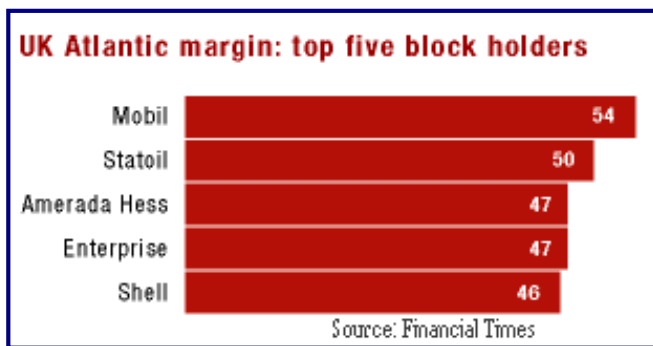
Another important development is the Skene field, which is being developed by operator ExxonMobil as a subsea tie-back to the Beryl Alpha platform. This field has a complex mix of hydrocarbons, including crude oil and condensate, that is estimated to be about 100 million barrels of oil equivalent. Only the implementation of the latest technology using a heated flowline bundle has made recovery possible. It is expected to come online in April 2002.

A larger project that was given approval in 2000 is the development of the Leadon field. It was discovered in 1979, but became economically viable with the discovery of a northern extension of the field. The Canadian company Kerr-McGee-operated field is expected to commence production in early 2002, and will peak at 40,000 bbl/d of crude oil.

Europe's largest on-shore oilfield is Wytch Farm. Estimated reserves are 500 million barrels. Egdon Exploration is active in the area, and it is hoped that even smaller fields can be economically viable as they are on-shore. Other smaller on-shore fields are clustered in east-central England.

Industry Structure

Industry reorganization that started with BP's 1998 merger with Amoco continues. The merged BP Amoco, (now simply BP) already one of the world's largest petroleum companies, announced in April 1999 its intentions to take over Los Angeles-based Atlantic Richfield (Arco), which was completed in April 2000. The merged company is truly global and is the world's third-largest publicly traded oil and gas company. Most of the majors have a share of UK North Sea production, including BP, Chevron, Conoco, ENI, ExxonMobil, Royal Dutch/Shell, Texaco, and TotalFinaElf. Amerada Hess, Enterprise, and Statoil also have large shares. The graphic shows the number of blocks held by each top-ranking company in 2000.



BP Exploration is managed from Aberdeen, Scotland (as are most other companies that are active in the British North Sea). BP produces oil and gas and brings ashore 40% of the UK's total production through the Forties Pipeline System to Grangemouth, Scotland. BP Amoco has producing fields in the North Sea and, since the end of 1997, in the North Atlantic, west of the Shetland

Islands. It operates the Sullom Voe oil terminal in the Shetlands, which is Europe's largest oil terminal. The 206,000-bbl/d oil refinery and petrochemical complex at Grangemouth represents one of Scotland's largest industrial complexes.

British independent oil companies, important in the North Sea oil scene, were particularly hard hit by the oil price collapse of 1998. As a result, the major five independents at the time, Enterprise, Lasmo, Premier, British-Borneo, and Cairn, were hesitant to approve new investment and development in 1999-2000, though Enterprise has now begun more investment and development. The consolidation sweeping the oil majors has affected the independents. Enterprise, the largest British independent, unsuccessfully attempted to take over the second largest, Lasmo, in the spring of 1999. Enterprise's UK production was 164,907 barrels of oil equivalent per day in 2000. In 2000, Italian oil and gas giant ENI began to acquire British independents, British-Borneo in March 2000, and Lasmo in February 2001. This gives ENI a presence in the North Sea, and increases its worldwide oil and gas assets, particularly in Asia. Regarding the remaining two independents, Premier is heavily focused outside of the UK, and Cairn's production and reserves are very small, even for an independent.

Downstream

The UK's crude oil refining capacity is approximately 1.77 million barrels per day, just slightly more than the country's consumption. However, the UK imports and exports refined products because British refineries produce an excess of some grades and products and insufficient quantities of others for local demand. Additionally, demand for gasoline varies seasonally. The largest refinery is ExxonMobil's (Esso's) 311,240-bbl/d Fawley refinery in Southampton, one of the largest in Europe and marine tanker accessible. It also has a pipeline to the on-shore Wytch Farm field. The 100,000-bbl/d Port Clarence Phillips-Imperial Petroleum refinery at North Tees is connected by pipeline to the Phillips Consortium Ekofisk Oil Terminal at Seal Sands, giving it a direct feed from the North Sea. The Grangemouth refinery is also directly connected to the North Sea through the Forties Pipeline System.

Petroleum products represented 45% of final energy consumption in 2000. The retail gasoline market is dominated by Esso (ExxonMobil), BP, Shell, TotalFinaElf, Texaco, and Conoco, which together account for 58% of gasoline sales. Supermarkets now account for 8% of retail sales. Total retail sales were 28 billion liters (7.4 billion gallons) in 2000. The transport sector consumed 74% of petroleum products in 2000, whereas the energy industry consumed just 7%. Fuel oil use has declined 30% since 1998, as industrial and home-heating demand has dropped in favor of gas.

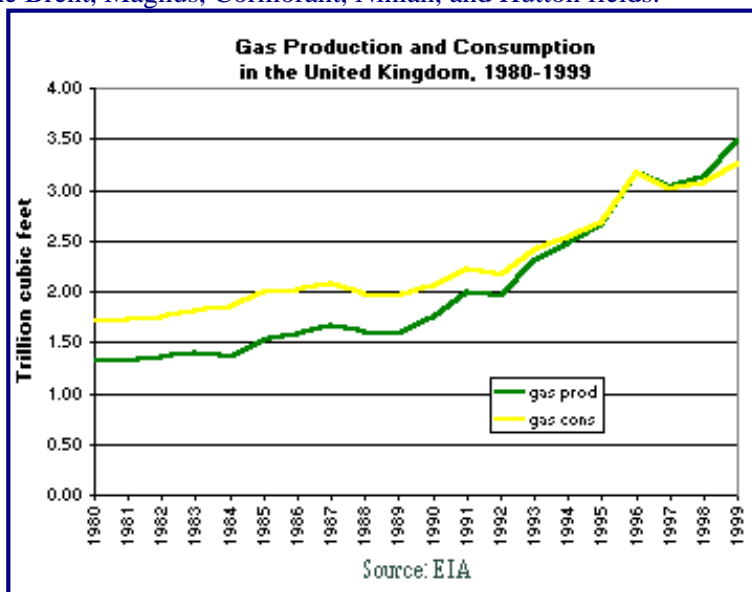
NATURAL GAS

The UK contains an estimated 26.8 trillion cubic feet (Tcf) of natural gas reserves, most of which are in non-associated gas fields located off the English coast in the Southern Gas Basin, adjacent to the Dutch North Sea sector. The UK shares the declining Frigg field with Norway (39.18% to the UK), which is expected to be shut down in 2002, and has small share of the 0.44-Tcf Statfjord field (14.53%). There are a few small fields on-shore. The Irish Sea contains the large Morecambe and Hamilton fields. Morecambe alone accounts for up to 20% of British natural gas production. Key producing gas fields in the North Sea include BP's 5.7-Tcf Leman, Chevron and Conoco's 3-Tcf Britannia, Shell's 1.7-Tcf Indefatigable and 0.8-Tcf Clipper, and TotalFinaElf's 0.85 Tcf Elgin. Key pipelines are the Scottish Area Gas Evacuation (SAGE) system to the St Fergus Terminal, which

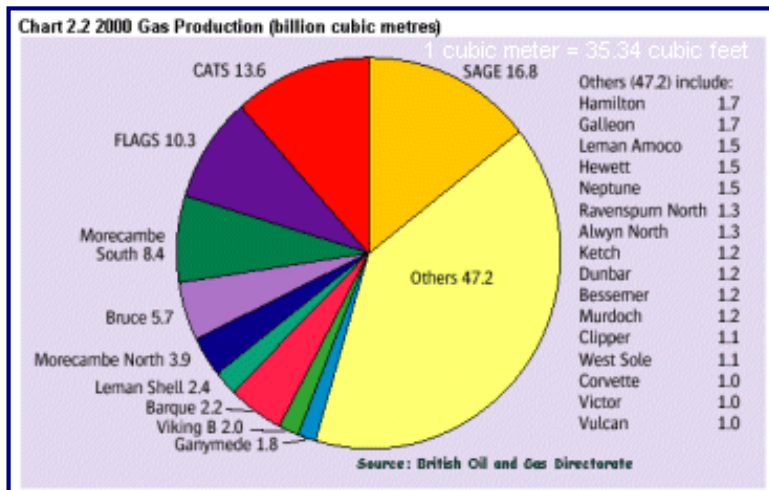
handles gas produced from a number of North Sea fields, including Britannia, the Beryl and Brae areas, and others in the central/northern North Sea, the Central Area Transmission System (CATS) that also goes to the Central North Sea, and takes gas from several fields, including Everest, Judy, and Jade, and others, and the Far North Liquids and Associated Gas System (FLAGS) that takes gas from the northern North Sea, including the Brent, Magnus, Cormorant, Ninian, and Hutton fields.

The largest project to come online in 2001 (in March) in the British North Sea is the TotalFinaElf-operated Elgin/Franklin platform, which might prove to be the last big North Sea production platform. It is the world's largest high-pressure, high temperature development. The Elgin/Franklin platform has extensive processing facilities, unlike most North Sea platforms. The \$2.3-billion platform is expected to last for 22 years in its location in the central North Sea, in the Graben area, off the coast of Scotland. It is to

produce 700 million barrels of oil equivalent, about half condensate and half natural gas. This equates to peak production of 350 million cubic feet per day (Mmcf/d) of natural gas. The export pipelines are shared with the Shearwater field, and include a 294-mile gas pipeline to Bacton and a 24-mile condensate pipeline to the Marnock platform. The Shell-operated Shearwater field in the central North Sea was inaugurated in September 2000, and has reserves of 0.71 Tcf natural gas and 110 million barrels of condensate. Gas production is expected to peak at 375 Mmcf/d.



The Brigantine cluster is the most important recent development in the Southern Gas Basin. It is three fields with two platforms using extended reach horizontal wells to get at reserves of 0.27 Tcf. Shell is the operator, and production of 130 Mmcf/d commenced in the first quarter of 2001. There is a 12-mile pipeline to the Corvette platform, which is connected indirectly with Bacton.



British Gas was the monopoly supplier to the interruptible market until the passage of the 1995 Gas Act, which split the company into supply and shipping (British Gas Trading Limited) and while other functions remained with British Gas, including transport subsidiary Transco. In 1997, Centrica was demerged from British Gas, and British Gas was renamed BG. Centrica is the holding company for British Gas Trading, British Gas Services, the Retail Energy Centers, and is the producer in the Morecambe fields. BG retained Transco, along with exploration and production, international downstream, R&D and properties. In October 2000, BG again split, with Transco becoming part of a separate holding company Lattice Group. Independent Gas suppliers entered the firm (non-tariff) market in 1990, but the larger interruptible market (smaller customers) brought in competition in 1995. The consumer gas market was deregulated by region from October 1997 to June 1998, such that all residential and commercial customers could choose their supplier at the end of this process. At the end of 2000, suppliers other than British Gas Trading had captured 20-30% of the market in many

regions of the UK. In July 2001, Houston-based Dynegy purchased BG Storage from what remains of BG for \$590 million, acquiring gas production wells and platforms, salt caverns, pipelines, and a natural gas processing terminal.

The UK's gas and electricity regulatory body is the Office of Gas and Electricity Markets (Ofgem). Ofgem has proposed reforming price controls on Transco's pipeline usage fees. The privatization of the UK's gas industry, leading to an increased gas supply and reduced prices, has helped gas to replace much of the UK's reliance on coal as a source for electricity generation. The natural gas share of utility fuels was 1% in 1988 and is expected to increase to almost 50% by 2010. Privatization in the UK has progressed well in advance of EU requirements.

In 1998, the UK-Continent Gas Interconnector pipeline was opened, with terminals at Bacton, England and Zeebrugge, Belgium. This is the first natural gas pipeline linking the United Kingdom to the European continent. A new pipeline to connect Ireland to Scottish gas sources in the Corrib field was approved in November 1999, and a plan to connect Ireland to England via Wales was announced in April 2000. A pipeline would run from Manchester, England, underground to Wales, and then under the Irish Sea to just north of Dublin. There is currently one pipeline linking Britain and Ireland, connecting Ireland to Scottish gas sources. Despite these pipeline projects, the UK will remain a much smaller natural gas exporter than North Sea neighbor Norway, and will eventually become a net importer as the UK begins to import Norwegian gas again. Norway had once supplied up to a quarter of British demand in the 1980s, but this dwindled as the Frigg field that supplied the gas was depleted. The new Vesterled gas pipeline, set to begin operations October 1, 2001, will be one of the ways Norwegian gas may enter the UK. Vesterled will connect the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gasfields, and from there to other areas of the Norwegian North Sea such as the Ormen Lange gasfield that is scheduled to come on stream in 2006. In July 2001, BP announced a 15-year contract to buy 56.5 billion cubic feet (Bcf) natural gas per year from Statoil. However, Statoil has indicated that it would not import large volumes of gas through Vesterled unless Britain changed its pricing system for bringing gas onshore from North Sea fields. Statoil officials have asserted that the UK's system of auctioning entry capacity, or access rights to the national pipeline system, had produced volatile, very high prices.

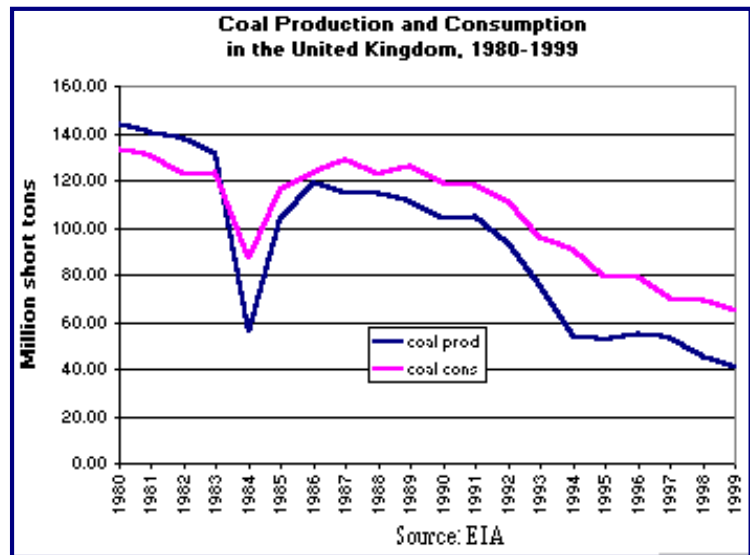
COAL

Coal production and consumption in the United Kingdom have decreased dramatically since 1986. UK coal production fell from 119 million short tons (Mmst) in 1986 to 40.9 Mmst in 1999. Production fell again in 2000, but demand rose, increasing imports. In 2000, steam coal accounted for 80% of coal demand, coking coal for 15%, and anthracite for 5%. Electricity demand accounted for 95% of demand for steam coal and 46.5% of demand for anthracite. In the late 1980s, coal accounted for about two-thirds of the United Kingdom's thermal electricity production. Currently, less than half of UK thermal electricity is coal-fired, and the figure is expected to fall below one-third by the end of the decade. Coal mines are located primarily in central and northern England and southern Wales, with some coal mines also found in southern Scotland. The UK produced 40.5 million tons of bituminous coal and 409 thousand tons of anthracite coal in 1999. The UK also produces coke-oven coke in quantities such that it is self-sufficient. Nevertheless, net imports of coal in 1999 were 23.9 million tons.

Between 1984 and 1985, the British coal miners' union staged a year-long strike. The strike dramatically altered energy production and consumption patterns in the United Kingdom for that year and precipitated the longer term decline of the industry (see graph).

Employment in the industry has plummeted since the late 1980s. The United Kingdom began liberalizing its electricity market in 1989, and this liberalization is one of the major reasons for the decline of the country's coal industry. Prior to the privatization of electricity,

the cost of domestic coal to electric utilities had far exceeded the cost of coal traded in international markets. The Central Electricity Generation Board (CEGB) had been the primary purchaser of British coal. The CEGB largely subsidized the British coal industry, purchasing domestic coal at above world market prices and then passing on those costs to consumers. This ended when National Power and PowerGen, two private electricity generation companies, were formed in the early 1990s, weakening the bargaining power of British Coal, the national coal company.



In 1992, the British coal industry reached a turning point. Growing competition from increasingly available natural gas, the imminent removal of the regional electricity companies' captive franchise supply markets, and newly-enacted pollution abatement goals all worked to initiate the steady decline of the industry. The industry was privatized in 1994, at which point RJB Mining bought the major British Coal assets and became the country's major producer. Mining Scotland and Celtic Energy are the other two remaining companies. The UK coal industry had not received any subsidies since 1995, but in November 2000 the European Commission approved a modernization plan and aid scheme. The aid would go toward mines/production units that have long-term economic viability on the world market, but are having temporary difficulties as they restructure in an effort to reduce production costs. The total amount of aid will not exceed £110 million, and two disbursements of £25 million and £21 million have been made so far. Production costs over the period 1992 to 1999 already fell 35%, and the expectation is that these costs can fall further still before the aid scheme expires in July 2002.

New EU environmental directives are expected to further increase British coal production costs, leading some analysts to predict an end to the United Kingdom's coal industry in the early 2000s. RJB Mining is more optimistic about the future of British coal. RJB maintains that foreign coal prices will increase, making British coal more competitive, and that clean coal technology will allow power stations to burn increased amounts of coal without increased greenhouse gas emissions. Higher natural gas prices, gas-fired power plant outages for maintenance and repair, and reduced nuclear power led to a 14% increase in coal consumption by power producers in 2000.

ELECTRICITY

The United Kingdom has 70 million kilowatts of installed electric capacity, about 80% of which is thermal, 18% nuclear, and 2% hydropower. The country generated 342.8 billion kilowatt hours (bkwh) of electricity in 1999, making it the third-largest electricity market in Europe (behind Germany and France).

Electricity privatization began in the early 1990s, and the final phase of transition ended in May 1999. Initially, all non-nuclear state-owned power stations were privatized and four major generating companies -- PowerGen and National Power in England and Wales, and ScottishPower and Hydro-Electric in Scotland -- were formed to operate the stations. The grid distribution system in England and Wales became the property of the National Grid Company. Regional Electricity Boards were

privatized as separate distribution companies. Large customers were the first to be able to choose their suppliers, with all small customers (below 100 kW peak load) being able to choose by May 1999.

The number of electric generation companies in the United Kingdom has increased to 27 as a result of the liberalization process, according to DTI, such that 40% of the UK's electricity was generated by these new companies in 2000. In March 2001, the structure of the electricity industry changed yet again. Under the former system, generators and suppliers in England and Wales traded electricity through the electricity pool, which was regulated by the National Grid Company, owner of the transmission network. The New Electricity Trading Arrangements (NETA) changed this to a system based on bilateral trading between generators, suppliers, traders, and customers. The system includes forwards and futures markets, a balancing mechanism to enable the National Grid Company to balance the system, and a settlement process. Dallas-based TXU purchased United Utilities' retail electricity and natural gas business, Norweb Energi, for \$465 million in August 2000. This, added to TXU's European retail business Eastern Energy, creates the UK's largest electricity retailer, with over 5.6 million customers. Powergen, with 2.6 million retail customers as well as 14% of electricity generation in England and Wales, merged with Louisville-based LG&E Energy in December 2000.

In Scotland, the two main companies, Scottish Power and Scottish and Southern Energy, cover the full range of electricity provision. Ofgem has made proposals to further reform the Scottish power market. Northern Ireland, part of the United Kingdom but not part of Great Britain, is served by Northern Ireland Electricity, one of the largest companies in Northern Ireland and part of the Viridian Group. Northern Ireland has a separate electricity and gas regulatory body, Ofreg. The grids of Northern Ireland and the Republic of Ireland are connected for electricity import/export.

Nuclear

In 1995, the government announced that it would privatize its more modern nuclear stations while retaining ownership of older stations. In 1996, more modern stations were privatized and British Energy became the holding company of Nuclear Electric and Scottish Nuclear, which merged in 1998 to form British Energy Generation, the nation's largest private nuclear generator and the world's first wholly privatized nuclear utility. British Energy operates eight nuclear power stations in the UK (as well as several in the U.S. through its AmerGen subsidiary that is jointly owned with PECO). Each station consists of two advanced gas-cooled reactors, except Sizewell B, which is a modern pressurized-water reactor. Nuclear power stations were not privatized simultaneously with non-nuclear stations. No new plants have been built since 1995, but because of limited domestic coal and gas reserves in the long run, new construction is under discussion, at least to maintain nuclear's market share as older nuclear plants are retired. Of the UK's 33 reactors, 26 are of the old Magnox design. Six of the Magnox reactors are being decommissioned, as well as the Dounreay prototype fast reactor. The remaining Magnox plants are run by the state-owned British Nuclear Fuels. British Nuclear Fuels operates the Sellafield reprocessing plant, and is one of only two companies in the world that provides reprocessing and recycling technologies. The British nuclear industry is regulated by the Department of Trade and Industry's Nuclear Directorate.

ENVIRONMENT

With a reduction in sulfur dioxide and carbon dioxide emissions, environmental conditions in the United Kingdom have improved over the past couple of decades. Some of these environmental improvements, such as a reduction in [air pollution](#), can be attributed to the United Kingdom's [energy use](#) choices. Partially as a result of deregulation and the elimination of coal subsidies, coal's share of total primary energy consumption is gradually being replaced by natural gas.

Improvements in energy efficiency have led to a gradual reduction in both [energy and carbon intensity](#). In 1980, energy intensity in the United Kingdom registered 11.70 thousand Btu per \$1990, decreasing to 8.37 thousand Btu per \$1990 in 1999, a 27% decline. Similarly, carbon intensity in 1999 registered 0.13 metric tons of carbon per thousand \$1990, a 45% decrease from 1980 levels. [Per capita](#) energy consumption, at 167.8 million Btu in 1999, is rising gradually.

As the United Kingdom enters the [21st century](#), many energy and environment-related policies reflect the country's awareness of climate change issues. With introduction of the Climate Change Levy in 2001, and its exemption for [renewable](#) energy resources like solar and wind, these alternative sources of energy are beginning to gain more attention. For example, the United Kingdom hopes to increase the share of electricity generated by renewables from the current 2%, to 10% by 2010.

Sources for this report include: Aberdeen Press & Journal; CIA World Factbook; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Hart's European Offshore Petroleum Newsletter; Oil & Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; The Scotsman; U.K. Department of Trade and Industry; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

Head of State: Queen Elizabeth II

Prime Minister: Anthony (Tony) Blair, re-elected June 2001

Population (2000E): 59.5 million

Location/Size: Western Europe, islands including the northern one-sixth of the island of Ireland between the North Atlantic Ocean and the North Sea, northwest of France/244,820 sq km (slightly smaller than Oregon)

Capital City: London

Language: English

Ethnic groups: English 81.5%, Scottish 9.6%, Irish 2.4%, Welsh 1.9%, Ulster 1.8%, West Indian, Indian, Pakistani, and other 2.8%

Religions: Anglican 27 million, Roman Catholic 9 million, Muslim 1 million, Presbyterian 800,000, Methodist 760,000, Sikh 400,000, Hindu 350,000, Jewish 300,000 (1991 est.)

Defense (8/98): Army, 113,900; Navy, 44,500; Air Force, 52,540

ECONOMIC OVERVIEW

Chancellor of the Exchequer: Gordon Brown

Currency: Pound sterling

Exchange Rate (9/04/01): 1 US Dollar = 0.69 pounds

Gross Domestic Product (GDP, 2000E): \$1,415 billion

Real GDP Growth Rate (2000E): 3.0% **(2001F):** 2.0%

Inflation Rate (consumer prices, 2000E): 2.9% **(2001F):** 2.0%

Unemployment Rate (2000E): 3.7% **(2001F):** 3.4%

Merchandise Exports (2000E): \$283 billion

Merchandise Imports (1999E): \$327 billion

Major Trading Partners: United States, Germany, France, Netherlands

Major Exports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

Major Imports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

ENERGY PROFILE

Secretary of State for Trade and Industry: Patricia Hewitt

Minister of State for Industry and Energy: Brian Wilson

Proven Oil Reserves (1/1/01): 5 billion barrels

Oil Production (2000): 2.75 million bbl/d, of which 2.48 million bbl/d was crude oil

Oil Consumption (2000): 1.7 million bbl/d

Crude Oil Refining Capacity (1/1/01): 1.77 million bbl/d

Net Oil Exports (2000): 1.05 million bbl/d

Natural Gas Reserves (1/1/01): 26.8 trillion cubic feet (Tcf)

Natural Gas Production (1999E): 3.49 Tcf

Natural Gas Consumption (1999E): 3.26 Tcf

Natural Gas Net Exports (1999E): 0.02 Tcf

Major Systems: Brent, Ninian, Forties, Flotta, Fulmar

Major Fields: E. Brae, Brent, Forties, Magnus, Miller, Scott

Oil and Gas Companies: Amerada Hess, BP Amoco, BHP, Chevron, ExxonMobil, Kerr-McGee, Phillips, Ranger Oil, Shell, Texaco

Recoverable Coal Reserves (12/31/96E): 1.65 billion short tons

Coal Production (1999E): 40.9 million short tons (Mmst)

Coal Consumption (1999E): 64.8 Mmst

Electrical Generation Capacity (1/1/99): 69.9 gigawatts (79.7% thermal, 2.1% hydro, 18% nuclear, 0.2% other)

Electricity Generation (1999E): 342.8 billion kilowatt hours (bkwh)

Electricity Consumption (1999E): 333 bkwh

ENVIRONMENTAL OVERVIEW

Secretary of State for the Environment, Food, and Rural Affairs: Margaret Beckett

Total Energy Consumption (1999E): 9.9 quadrillion Btu* (2.6% of world total energy consumption)

Energy-Related Carbon Emissions (1999E): 152.4 million metric tons of carbon (2.5% of world carbon emissions)

Per Capita Energy Consumption (1999E): 167.8 million Btu (vs. U.S. value of 355.8 million Btu)

Per Capita Carbon Emissions (1999E): 2.6 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)

Energy Intensity (1999E): 8,365 Btu/\$1990 (vs U.S. value of 12,638 Btu/\$1990)**

Carbon Intensity (1999E): 0.13 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (37.0%), Residential (25.4%), Transportation (26.1%), Commercial (11.5%)

Sectoral Share of Carbon Emissions (1998E): Industrial (33.7%), Transportation (31.3%), Residential (24.3%), Commercial (10.6%),

Fuel Share of Energy Consumption (1999E): Oil (35.0%), Natural Gas (34.9%), Coal (15.7%)

Fuel Share of Carbon Emissions (1999E): Oil (41.2%), Natural Gas (33.4%), Coal (25.5%)

Renewable Energy Consumption (1998E): 137 trillion Btu* (15% increase from 1997)

Number of People per Motor Vehicle (1998): 2.3 (vs. U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change. Under the negotiated Kyoto Protocol (signed on April 29th, 1998 - not yet ratified), the UK has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.

Major Environmental Issues: Sulfur dioxide emissions from power plants contribute to air pollution; some rivers polluted by agricultural wastes and coastal waters polluted because of large-scale disposal of sewage at sea.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Links

For more EIA information on the United Kingdom:

[EIA - Country Information on the United Kingdom](#)

[Electricity Restructuring and Privatization in the United Kingdom](#)

Links to other U.S. Government sites:

[CIA World Factbook - United Kingdom](#)

[U.S. State Department Country Commercial Guides: Europe](#)

[U.S. State Department Consular Information Sheet](#)

[U.S. Geological Survey, map of the United Kingdom including oil fields](#)

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[British Petroleum](#)

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[Energy Links for the UK from Online Energy Services](#)

[International Petroleum Exchange](#)

[Grampian Oil and Gas Directory \(an online database of companies operating in Scotland\)](#)

[Scottish Enterprise Energy Group](#)

[RJB Mining](#)

[Electricity Association](#)

[National Power](#)

[PowerGen](#)

[ScottishPower](#)

[National Grid](#)

[Northern Ireland Electricity](#)

[British Energy \(nuclear generator\)](#)

[British Nuclear Fuels](#)

[UK Energy Centre](#)

[Ofgem](#)

[Ofreg](#)

[Department of Trade and Industry](#)

[Department of Environment, Transport and the Regions](#)

[British Embassy in Washington, D.C.](#)

[Scottish Parliament](#)

[International Energy Agency United Kingdom 1998 Review](#)

[Royal Institute of International Affairs, Energy and Environmental Programme](#)

[European Commission Directorate General XVII \(Energy\)](#)

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January 2002

Spain

Spain is one of the fastest growing European economies but has very limited domestic energy resources. As a result, Spain is expected to become an increasingly important energy importer.

Note: The information contained in this report is the best available as of January 2002 and is subject to change.



BACKGROUND

Spain's period of rapid (4% annual growth) economic expansion is slowing. Still, Spain's forecast growth rate of 2.4% in 2002 is still well above the average "eurozone" growth rate forecast of 1.4%. The unemployment rate has decreased significantly (although projected at 12-13% for 2002), and government finances have improved over the past year. Inflation is expected to ease from 3.7% in 2001 to 2.4% in 2002 as unions have recently given priority to job creation over wage increases. Prime Minister Jose Maria Aznar's center-right Popular Party was re-elected with an absolute majority in March 2000. Aznar is continuing his liberalization of Spanish industry. Legislation aimed at getting rid of monopolies (state-held or private) in the energy, telecommunications, and services industries passed in June 2000. Oil, natural gas, and electricity markets are

key targets in Aznar's liberalization program.

The recent economic and political turmoil experienced by Argentina has adversely affected Spanish companies, which invested EUR 45 billion there over the last decade. Five large Spanish companies, including oil company Repsol-YPF and power company ENDESA, that alone account for about three-

quarters of the trading volume on the Madrid stock exchange, are expected to lose billions of euros because of the default on Argentine government debt and the devaluation of the Argentine peso.

Spain's economic growth and accelerated industrialization associated with European Union (EU) membership have fueled energy demand, up 75% since the mid-1970s. Electricity demand is growing at a particularly rapid rate of 6% per year, reflecting a need for greater investment. Spain is highly dependent on imported oil, leaving the country economically vulnerable to world oil price fluctuations. Further energy demand increases are expected to be met largely with natural gas imports. The increasing use of natural gas has created a new dependency on [Algeria](#), from which Spain obtains 60% of its natural gas imports. With an extensive gas network now in place, Spain's demand for natural gas is expected to increase dramatically during the next few years.

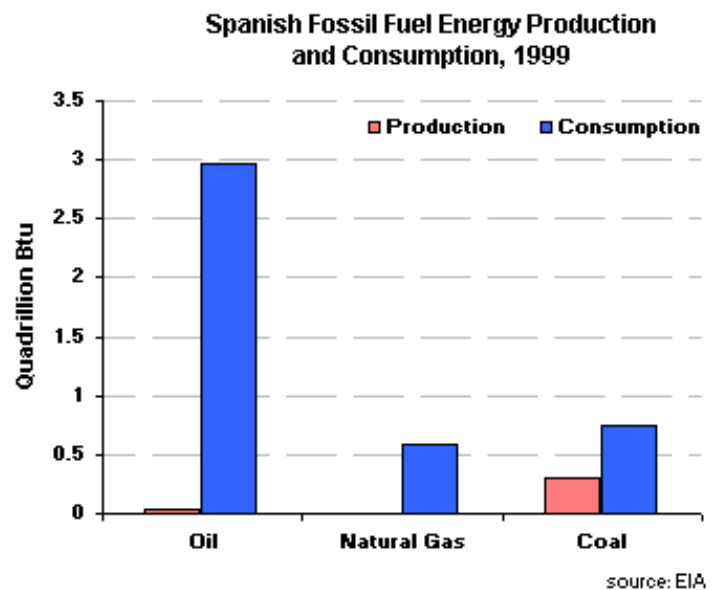
Spain assumed the six-month [European Union \(EU\)](#) presidency in January 2002, and Spanish Finance Minister Rodrigo Rato has announced that Spain will seek to establish a link between progress on the liberalization of energy markets and energy tax harmonization during its term. In December 2001, government energy regulator CNE recommended a EUR 4 billion investment in Spain's natural gas and electricity sectors in order to guarantee supply, to be financed mostly by Red Electrica and Gas Natural's Enagas.

OIL

Oil plays a major (albeit decreasing) role in the Spanish energy sector. In the 1970s, oil accounted for 73% of Spain's primary energy consumption. That percentage has now fallen to less than 60% and is expected to fall further as natural gas becomes an increasingly important fuel source. In 2001, Spain consumed about 1.5 million barrels per day (bbl/d) of oil, 99% of which was imported.

Spain has very limited domestic oil reserves and production. The largest producing area is in the Mediterranean Sea, with the Casablanca complex producing about 4,000 bbl/d. In October 2001, Spain authorized Conoco's UK subsidiary to explore for hydrocarbons off the coast of the southern Mediterranean province of Malaga. The permit for exclusive exploration rights is for six years.

Until 1993, the Spanish oil industry was state-controlled. Today, formerly state-held (now private) Repsol still dominates the Spanish oil sector (and also the Spanish natural gas sector, through a controlling share in the Gas Natural Group). The company acquired the top Argentine oil company, YPF, in 1999, changing the company name to Repsol-YPF. Repsol-YPF is responsible for over 50% of Spain's oil production. Worldwide, the company has reserves of 4.8 billion barrels of oil equivalent and a daily production of about 1 million barrels of oil equivalent per day. The company owns the majority of Spain's refineries, its distribution network (through Compania Logistica de Hidrocarburos, CLH, in which it holds a majority stake), and its gasoline stations (through its trademarks Repsol, Campsa, and Petronor). Divestments in the wake of the merger are working to lessen Repsol-YPF's control in the industry. June 2000 economic liberalization plans also work toward this end; the company's share in CLH must be reduced from 62% to 25%. Repsol-YPF's profits will be much lower for 2001 than the record \$2.10-billion profit achieved in 2000 because of the Argentine economic situation. Repsol-YPF derives 45% of its operating income from Argentina's oil and natural gas fields, and is negotiating a "contribution" to Argentina's government expected to be between \$300 million and \$500 million.



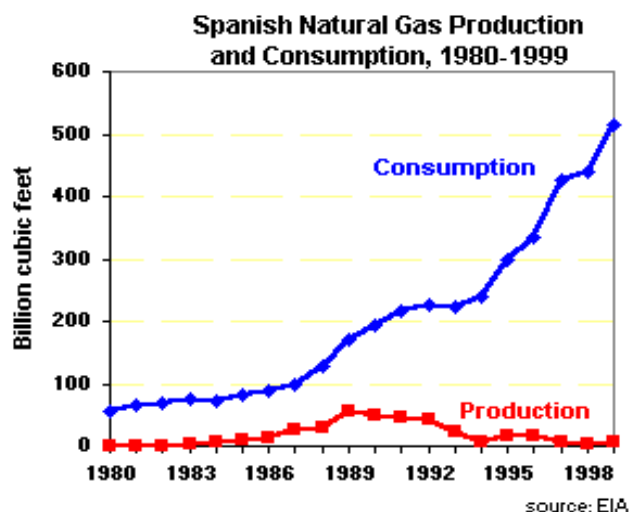
Compania Espanola de Petroleos (Cepsa), established in 1929, is Spain's oldest private oil and gas company. The company has exploration and production activities in Colombia and Algeria. It is the second largest oil group in Spain, with a 25% retail market share. BP Oil is also active in Spain. Repsol, Cepsa, and BP Oil account for almost all of the activity in the Spanish oil sector.

Refining

Spain has nine major refineries. Four are owned by Repsol, and another is owned by a Repsol subsidiary, Petronor, in which Repsol has an 88% stake. Cepsa owns three, and one is owned by BP. Because of state regulation of the industry, Spain has avoided developing the excess refining capacity that characterizes some other countries in southern Europe. Spain's total crude oil refining capacity stands at 1.3 million bbl/d.

NATURAL GAS

Natural gas is expected to account for a much larger share of Spain's total energy consumption in coming years, especially as new pipelines and natural gas-fired power plants come on line. Natural gas consumption has grown from 2% of total energy consumption in the 1970s to more than 11% in 1999. Preliminary estimates of consumption for 2000 are about 611 billion cubic feet (Bcf). Some estimates predict natural gas consumption growing at a 15% annual rate in this decade. Spanish energy company Endesa predicts demand for natural gas rising to about 883 Bcf by 2005. Almost all of this consumption will be satisfied with imports, as Spain has extremely limited natural gas reserves. The country's largest natural gas field went out of production in 1995, and only a very small number of smaller fields remain in production.



The Gas Natural Group (GN) is the leading natural gas conglomerate in Spain, dominating Spain's gas sector with 90%-95% of the market. However, in the market for industrial customers, which was partially opened in 2000, GN's market share was down to 79% by the first half of 2001. Repsol-YPF controls the Group, with 47% of its shares and majority board representation. GN is comprised of Gas Natural SDG, the main natural gas distributor in Spain; Enagás, a transport company; Gas Natural Aprovisionamientos (supplies); Gas Natural Comercializadora (commercialization); Gas Natural Servicios, the services company of the Group; Gas Natural Overseas Trading Company; 14 natural gas distribution companies in Spain; and Gas Natural Internacional, which brings together in a single business unit the interests of GN in Gas Natural BAN (Argentina), Gas Natural ESP (Colombia), Companhia Distribuidora de Gas do Rio de Janeiro-CEG, CEG RIO and Gas Natural SPS (Brazil), in addition to Gas Natural México. Also, GN has minority holdings in three natural gas distribution companies in the region of Aragon and in the Basque Country.

According to liberalization legislation passed in June 2000, no single operator may command over 70% of the Spanish natural gas market by 2004. Since June 2000, large industrial consumers have been able to choose suppliers, and all consumers should be able to choose suppliers by 2003. Several additional regulatory measures were taken in 2001: In July, Spain's Economy Ministry published the terms under which GN must auction off one-third of its 580 Bcf per year Algerian pipeline natural gas imports. In September, Spain's Economy Ministry detailed new natural gas sector regulations that include a revised system for calculating pipeline tariffs and procedures for accessing the national grid. Finally, in October, the government ended GN's monopoly of natural gas imports when a contract for Algerian gas imports equivalent to about 25% of Spain's total annual consumption was awarded to Spain's four largest electricity companies (Endesa, Iberdrola, Union Fenosa, and Hidrocarburo), BP, and Royal Dutch/Shell. This is part of a strategy being pursued by Spanish electricity companies to enter into the natural gas market. As [Algeria](#) supplies about 75% of Spain's imports, these companies now control about 19% of the market. These

companies have until 2004 to sell the natural gas to their industrial clients. The planned sale of 65% of GN subsidiary Enagas cannot be valued until the publication of new natural gas tariffs by the government, expected sometime in 2002.

The Group's Enagás transports natural gas imports to the Iberian Peninsula via gas pipelines connected to international networks (or via methane carriers for liquefied natural gas, discussed below). There are two international gas pipelines in Spain: Lacq-Calahorra in the north and the Pedro Duran Farell pipeline (formerly the Mahgreb-Europe line) in the south. The Lacq-Calahorra gas pipeline is the main Spanish connection to the European network, linking to Norway's North Sea gas sources. The Pedro Duran Farell pipeline, which crosses through Algeria and Morocco and travels under the Strait of Gibraltar, is about 870 miles (1,400 kilometers) long and connects the Algerian deposits with the Spanish gas pipeline network in Córdoba. This pipeline made its first Spanish delivery in 1996. Work is underway to expand the Pedro Duran Farell pipeline's annual capacity from 282.5 Bcf to 388.5 Bcf by adding a compressor station. Completion is expected in late 2003.

There are two new projects underway as well. Spain will have an additional connection with [France](#) via Irun in the Basque Country as a new transfrontier connector is being built with completion expected by the end of 2003. A further extension of the pipeline network coming to and from Irun is planned to be ready between 2005 and 2008. It will have 111 miles in Spain and 93 miles in France, and possess an annual capacity of 144.8 Bcf. In July 2001, Cepsa and Sonatrach of Algeria signed an agreement for the construction of the new Medgaz undersea natural gas pipeline between Algeria and Almeria, Spain, which received political backing in August. A feasibility study is scheduled to be completed in early 2003. The pipeline would have a length of 137 miles and have a capacity of between 282.5 Bcf and 353 Bcf. Natural gas would be allotted in proportion to each shareholder's equity ownership. At present, Sonatrach and Cepsa each hold 20%, while BP, Endesa, Eni, Gaz de France, and TotalFinaElf each hold 12%. Some natural gas from this pipeline may transit through Spain onto other European destinations.

Liquefied Natural Gas

Spain is Europe's second-largest liquefied natural gas (LNG) importer, behind France. Spain has three regasification terminals (Barcelona, Cartagena, and Huelva), the most of any country in Europe. All three are owned and operated by GN. Algeria is Spain's largest LNG supplier. Spain also is involved in long-haul LNG transit, importing LNG from the United Arab Emirates and Qatar. In 1999, Spain began receiving shipments from Trinidad and Tobago and Nigeria. In October 2000, shipments began from Oman, with 17 received through the end of January 2002. In June 2001, GN and Enel of Italy signed an agreement to develop joint marketing and sales negotiations for LNG internationally.

The GN plans to expand its three regasification terminals and its tanker fleet in order to handle increased LNG imports for rising domestic consumption. Spanish electricity generator Union Fenosa signed a firm contract with the Egyptian General Petroleum Corporation in July 2000 for the purchase of LNG from a new liquefaction terminal under construction at Damietta, Egypt. Union Fenosa and Iberdrola, which are constructing the new receiving gasification plant together, had disagreed on the location, but in November 2001 they settled on Fenosa's proposal at the Sagunto port in Valencia. The plant, to be completed in winter 2004, will be able to process 282.5 Bcf per year and will be linked to new combined cycle gas turbine plants being constructed by Fenosa nearby and Iberdrola in Castellon. Some of the natural gas will also transit to other locations.

A new regasification plant is planned for northern Spain. The Bahia de Bizkaia Gas group, a consortium led by BP and including Repsol-YPF, Iberdrola, and EVE (the Basque Energy Authority), will build the new import facility in conjunction with a new power station. The regasification facility is expected to begin operations in 2003.

Seven Spanish companies and Algeria's Sonatrach, forming the Reganosa group, will begin building in 2002 another new LNG import facility. Algerian LNG will supply the new Ferrol terminal in Galicia in northwest Spain for ten years following the terminal's projected 2004 commissioning. In conjunction with the terminal, which will have an initial capacity of 88 Bcf per year, a new pipeline will be constructed to

connect the terminal to power plants located about 60 miles away.

COAL

Coal is Spain's most plentiful indigenous energy source. Production has fallen in recent years, and the decline is expected to continue as Spain works to meet environmental standards. Currently, 95% of coal is used to generate electricity. All of the major coal companies are state-owned.

Spanish coal is too expensive to be competitive in a free energy market, with about 80% of the coal costing at least twice international prices to produce, so the Spanish government subsidizes coal production. According to new EU regulations that will take effect in July 2002, Spain must lower its coal production by 65% over the next ten years. Also, coal mines that do not improve their economic viability will only be able to receive production subsidies until 2008. Spain is one of three EU countries that will be permitted to continue coal production for reasons of economic security, and hence will continue to receive subsidies for more competitive mines. There is increased pressure on coal, however, as the electricity market privatizes, and as electricity generation will no longer be a captive market for domestic coal. Imports of foreign coal already are on the rise, and electricity generators are looking more to natural gas.

The sector now employs only half the number of people as a decade ago. However, most of those employed are in the Asturias region, where the jobs are badly needed. It would be difficult to completely phase out coal mining because of this region's dependence on the industry for employment.

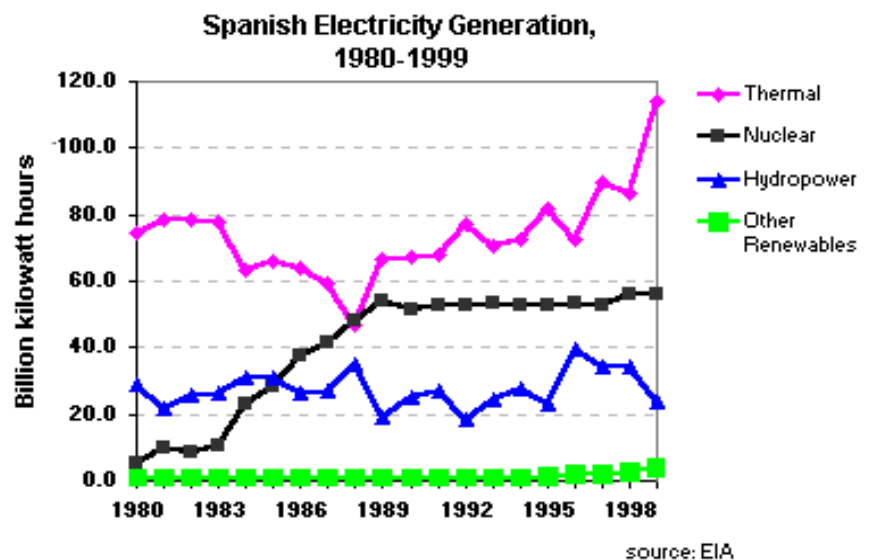
ELECTRICITY

Spain has the fifth largest electricity market in Europe (behind Germany, France, the United Kingdom, and Italy), and it is growing quickly. Electricity demand is estimated to have grown by 5.4% in 2001 to about 205 billion kilowatthours (bkwh). Red Electrica de España (REE), Spain's network operator, invested heavily in the network in 2001, with EUR 78.4 million invested in expanding the electricity network and REE announced plans in October 2001 to invest between EUR

60.2 million and EUR 72.2 million to improve the electricity connection with France. Spain's three largest electricity groups - Endesa, Iberdrola, and Union Fenosa - have announced massive investments planned from August 2001 to 2005 of EUR 34 billion, with much of that in Latin America and other European countries, but nevertheless including EUR 8 billion for new generating plants in Spain.

Endesa announced in July 2001, that it will build a natural-gas-fired, 400-megawatt (MW), combined-cycle generating turbine (CCGT) plant in Huelva by June 2004, in addition to three other gas-fired 400-MW CCGTs the company already has under construction in Spain near Cadiz, Barcelona, and Tarragona. Union Fenosa plans to add 5,000 MW of new capacity by 2005, mostly in Spain, of which 2,800 MW would be natural-gas-fired. Piemsa, an affiliate of Petronor, is planning to construct an 800-MW integrated gasification combined-cycle (IGCC) complex at a refinery near Bilbao that will make use of heavy refinery stocks. The plant will be one of the largest and most advanced of its kind in the world.

Spain's electricity market is privatizing ahead of the schedule mandated by the EU. A 1996 EU directive required that at least 26.48% of electricity sales in member countries be open to competition, beginning in February 1999. This requirement increased to about 28% in February 2000 and will grow to 33% in 2003.



Spain already has surpassed the 2003 requirement.

The Spanish electricity sector is in the midst of restructuring. There are five major utility companies in Spain, in descending order of size: the formerly state-held Endesa, Iberdrola, Union Fenosa, Hidrocantabrico, and the newly independent Viesgo. Viesgo's acquisition by Enel of [Italy](#) from Endesa was completed in January 2002, and Viesgo has a 5% market share. This is part of Enel's strategy of regaining market share abroad after selling its Elettrogen utility at home to Endesa in 2001.

Hidrocantabrico was sold in October 2001 to Electricite de France (EdF) and Eletricidade de Portugal (EdP), after the Spanish government decided to lift the veto on EdF's and EdP's voting rights. Some 60% of Hidrocantabrico will actually be owned by Energie Baden-Wurttemberg (EnBW) of Germany, which is controlled by EdF. The agreement is subject to commitments by the French and Portuguese governments to open up their electricity markets to Spain and subject to France increasing its interconnection with Spain from 1,000 MW to 4,000 MW between 2006 and 2011. This includes a new 1,200 MW line to run along side the planned high-speed rail line between Perpignan and Figueras in Catalonia.

In August 2001, Spain and [Portugal](#) signed an agreement to form a single electricity market by completely unifying their electricity networks. The unification is to be completed by sometime in 2003. There are still several unresolved obstacles to this. One obstacle is that there is minimal separation between transport and distribution activities, which remain monopolies, and production and marketing activities, which are open to competition. Another problem is that in Portugal production is sold to the state-held REN, which transports the electricity, whereas in Spain producers compete to sell electricity, but receive compensation payments for market liberalization called CTCs. The Spanish government in March 2001 reiterated its support for CTCs, but these payments are under investigation by the EU. The opposition PSOE party has called for their end. However, electricity companies have called for an end to tariff privileges enjoyed by several large industrial companies that they believe have made these companies uncompetitive internationally. In addition, electricity companies would like to raise their rates, arguing that prices have fallen 17% in the past five years, while inflation for the period has been 14%. In December 2001, a 1% rate increase was authorized for industrial customers. The Economy Ministry began investigating several electricity companies for alleged restrictive practices in order to raise prices in November 2001, though it has not revealed which companies are under investigation.

As electricity demand has increased rapidly in Spain in the past year combined with flat or low hydroelectric capacity, domestic supply has not been sufficient, and Spain began to import electricity from Morocco for the first time in December 2001 when cold temperatures created a surge in demand. Union Fenosa and Endesa have signed agreements with Moroccan power company ONE. Spain granted ONE the status of an "external operator" in 1998, giving the company the right to deal directly with Spanish electricity companies or on the Spanish spot market. The power exchange between ONE and Spanish companies is through the Spain-Morocco grid interconnection, which became operational in 1998. Two power connections between Algeria and Spain are also planned, one of which will run along side the Medgaz pipeline.

Spanish utilities are becoming increasingly involved in foreign power markets, especially in Latin America. Endesa owns a controlling stake in Chile's largest power provider, Union Fenosa is involved in Guatemala and Panama, and Hidrocantabrico has interests in Mexico. In neighboring France, Endesa acquired a 30% stake in SNET, which owns five coal-fired power plants, and hopes to control the company completely in a few years.

Nuclear Power

Spain is about 27% reliant on nuclear power for its electricity generation. Spain currently has nine nuclear reactors. In 2001 Spain's nuclear plants produced a record 63.6 bkwh, an increase of 2.3% compared to 2000. The Popular Party supports nuclear power, but the PSOE has indicated that it supports a gradual shut-down of Spain's nuclear plants. Currently, the construction of new nuclear plants is not illegal, but companies are unlikely to invest in such plants because of high costs and little government incentive.

COUNTRY OVERVIEW**Head of State:** King Juan Carlos (since November 1975)**Prime Minister:** Jose Maria **Aznar** (since May 1996)**Independence:** 1492 (expulsion of the Moors and unification)**Capital City:** Madrid**Population (July 2001E):** 40 million**Location/Size:** Southwestern Europe, bordering the Bay of Biscay, Mediterranean Sea, North Atlantic Ocean, and Pyrenees Mountains, southwest of France/504,750 sq km (slightly more than twice the size of Oregon)**Language:** Castilian Spanish 74%, Catalan 17%, Galician 7%, Basque 2%**Religion:** Roman Catholic 99%, other 1%**ECONOMIC OVERVIEW****Finance Minister:** Cristobal Montoro**Currency:** Euro (EUR)**Exchange Rate (1/29/2002):** 1 US Dollar = 1.156 EUR Spanish Peseta**Gross Domestic Product (GDP, nominal, 2001E):** \$579 billion**Real GDP Growth Rate (2001E):** 2.6% **(2002F):** 2.4%**Inflation Rate (consumer prices, 2001E):** 3.7% **(2002F):** 2.4%**Unemployment Rate (2001E):** 13.4% **(2002F):** 13.0%**Merchandise Exports (2000E):** \$115.1 billion**Merchandise Imports (2000E):** \$147.8 billion**Merchandise Trade Deficit (2000E):** \$32.7 billion**Major Trade Partners:** France, Germany, Italy, United Kingdom, United States, Portugal**Major Export Products:** Automobiles, tourism, power generation equipment, electrical machinery, petroleum and chemical products, foodstuffs**Major Import Products:** Crude petroleum, vehicle and automobile parts, capital goods, and food**ENERGY OVERVIEW****Proven Oil Reserves (1/1/02E):** 21 million barrels**Oil Production (2001E):** 21,000 barrels per day (bbl/d), of which 7,000 bbl/d was crude oil**Oil Consumption (2001E):** 1.48 million bbl/d**Net Oil Imports (2001E):** 1.46 million bbl/d**Crude Oil Refining Capacity (1/1/02E):** 1.3 million bbl/d**Natural Gas Reserves (1/1/02E):** 18 billion cubic feet (Bcf)**Natural Gas Production (1999E):** 5.1 Bcf**Natural Gas Consumption (1999E):** 513.8 Bcf**Net Natural Gas Imports (1999E):** 508.7 Bcf**Coal Reserves (12/31/96):** 728 million short tons (Mmst)**Coal Production (1999E):** 27 Mmst**Coal Consumption (1999E):** 49 Mmst**Electric Generation Capacity (1999E):** 44.9 million kilowatts**Electricity Generation (1999E):** 197.7 billion kilowatthours (bkwh)**Electricity Consumption (1999E):** 189.6 bkwh**ENVIRONMENTAL OVERVIEW****Minister of Environment:** Jaume Matas**Total Energy Consumption (1999E):** 5.2 quadrillion Btu* (1.4% of world total energy consumption)**Energy-Related Carbon Emissions (1999E):** 81.5 million metric tons of carbon (1.3% of world carbon emissions)**Per Capita Energy Consumption (1999E):** 132.6 million Btu (vs U.S. value of 355.8 million Btu)**Per Capita Carbon Emissions (1999E):** 2.1 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)**Energy Intensity (1999E):** 8,707 Btu/\$1990 (vs U.S. value of 12,638 Btu/\$1990)**

Carbon Intensity (1999E): 0.14 metric tons of carbon/thousand \$1990 (vs U.S. value of 0.19 metric tons/thousand \$1990)**

Sectoral Share of Energy Consumption (1998E): Industrial (43.1%), Transportation (31.6%), Residential (15.0%), Commercial (10.3%)

Sectoral Share of Carbon Emissions (1998E): Industrial (39.3%), Transportation (38.9%), Residential (13.1%), Commercial (8.7%)

Fuel Share of Energy Consumption (1999E): Oil (57.0%), Coal (14.3%), Natural Gas (11.2%)

Fuel Share of Carbon Emissions (1999E): Oil (66.6%), Coal (23.1%), Natural Gas (10.3%)

Renewable Energy Consumption (1998E): 521.4 trillion Btu* (1% increase from 1997)

Number of People per Motor Vehicle (1998): 2.1 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 21st, 1993). Signatory to the Kyoto Protocol (signed April 29th, 1998 - not yet ratified).

Major Environmental Issues: Pollution of the Mediterranean Sea from raw sewage and effluents from the offshore production of oil and gas; water quality and quantity nationwide; air pollution; deforestation and desertification.

Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants, Desertification.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Sources for this report include: CIA World Factbook; DRI/WEFA; Economist; Economist Intelligence Unit; European Union; Financial Times; Gas Natural; Petroleum Economist; Repsol; U.S. Energy Information Administration; World Markets Online.

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