International Energy Outlook 2004

Electricity

Electricity consumption nearly doubles in the IEO2004 projections. Developing nations in Asia are expected to lead the increase in world electricity use.

World net electricity consumption is expected nearly double to over the next two decades, according to the *International Energy Outlook 2004* (*IEO2004*) reference case forecast. Total demand for electricity is projected to increase on average by 2.3 percent per year, from 13,290 billion kilowatthours in 2001 to 23,072 billion kilowatthours in 2025 (Figure 60 and Table 14).

Figure 60. World Net Electricity Consumption, 2001-2025

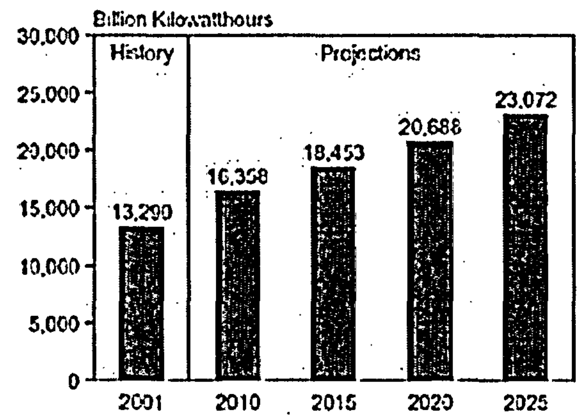

Figure Data

Much of the growth in new electricity demand is expected to come from the countries of the developing world. At present, developing countries, with more than 75 percent of the world's population, account for only about one-third of the world's electricity consumption (Figure 61). Access to reliable supplies of electricity among the emerging economies will be necessary to fuel the robust economic growth projected for the region as a whole. Many governments of developing countries have recognized the need to increase their citizens' access to electricity. They have implemented strategies such as privatization to increase investment in the electricity sector, enacting government policies to encourage investment from potential foreign participants, and introducing rural electrification schemes aimed at bringing electricity to rural communities, both to improve standards of living and to increase the productivity of rural societies.

Figure 61. World Net Electricity Consumption by Region, 2001-2025

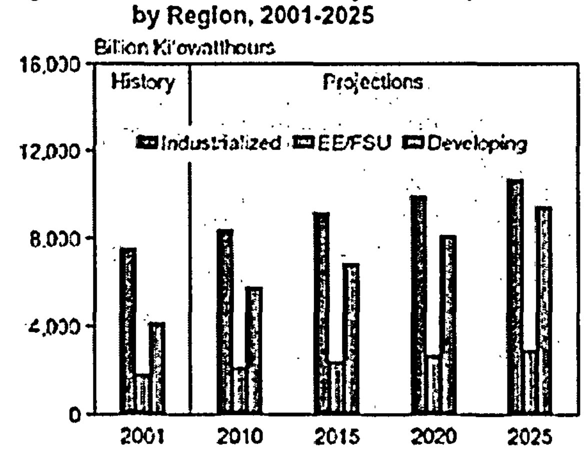

Figure Data

Electricity use in the industrialized nations is expected to increase more slowly than in the developing world, averaging 1.6 percent per year in the *IEO2004* reference case, compared with 3.5 percent per year for the developing world. In the industrialized world, the electricity sector is well established, and equipment efficiency gains are expected to temper the growth in electricity demand. In addition, populations in Japan and Western Europe are expected either to remain at current levels or to decline slightly toward the end of the forecast period, and as a result it is unlikely that demand for electricity in the residential sector will increase substantially.

Electricity demand among the transitional economies of Eastern Europe and the former Soviet Union (EE/FSU) is expected to increase at an average annual rate of 2.0 percent over the 2001-2025 period—higher than the 1.5-percent average annual increase over the past 30 years, mostly as a result of the precipitous drop in electricity use that followed the fall of the Soviet regime in the early 1990s. Net electricity consumption in the EE/FSU fell by 24 percent between 1989 and 1998. Although demand has been on the rise since 1998, it is not expected to return to its 1989 level until after 2010. The region as a whole has shown positive economic growth since 1998 (and Eastern Europe alone since 1993), but upgrades to generating equipment have improved efficiency so that electricity generation has not increased at the same pace as gross domestic product (GDP).

This chapter begins with a discussion of the present fuel mix used for electricity generation and how the mix might change over the forecast period. Next, regional electricity markets are reviewed, considering legislation and policies that could affect their mid-term development, with particular attention to privatization, efforts to increase fuel diversity, and policies in place to improve rural electrification among the developing nations of the world.

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. In contrast, in conjunction with the high world oil prices brought on by the oil price shocks after 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 *IEO2004* 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 moderated somewhat by a 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. New reactors are expected to be built mainly in the developing world. Generation from hydropower and other renewable energy sources is projected to grow by 57 percent over the next 24 years, but their share of total electricity generation is projected to remain near the current level of 20 percent (Figure 62).

Figure 62. Fuel Shares of World Electricity Generation, 2001-2025

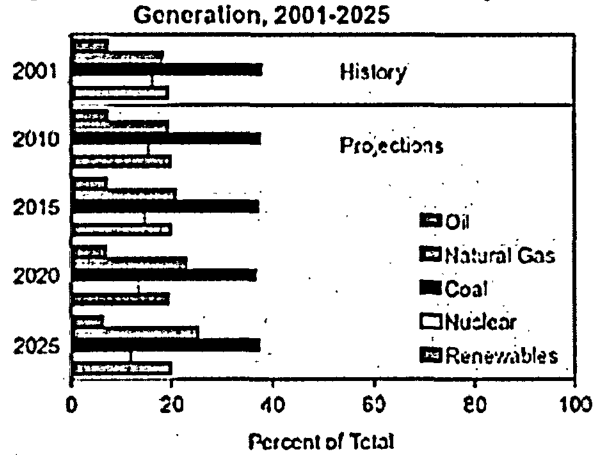

Figure Data

Coal

Coal is an important source of electricity generation in a number of the world's regional markets. Not surprisingly, the countries with the largest coal reserves have electricity markets dominated by coal. For instance, the United States—with the largest share of the world's recoverable coal reserves—generates about one-half of its total electricity from coal. China, India, Germany, Poland, South Africa, and Australia all have substantial coal reserves, and in each case coal-fired generation accounts for more than one-half of electric power production. In both China and India, coal's market share in the electricity sector exceeds 75 percent.

Russia has the world's second largest coal reserves and uses coal to produce one-third of its electricity at present. Russia has been able to diversify its electricity markets somewhat more than other coal-rich nations, because it also has ample natural gas and hydroelectric resources and a mature nuclear power program; but because the FSU also has significant coal resources, coal is expected to retain its importance in the region's electric power supply. Coal's share of the electric power market in the FSU is projected to increase slightly, from 23 percent in 2001 to 24 percent in 2025, as nuclear generation decreases.

Competition from natural gas may erode coal's market share in some key countries, but coal's dominance is not likely to decline precipitously. Many of the countries of Western Europe are expected to reduce their use of coal for power generation, with increases in natural-gas-fired generation, renewables, and, in the case of France, nuclear power. Most notably, in Germany, coal's share of energy use for electricity generation was 49 percent in 2001 but is projected to drop rapidly as natural-gas-fired generation and, to a lesser extent, renewable energy use continue to be added for new electric power capacity. As Eastern European electricity markets begin to integrate with Western European markets with the expansion of the European Union (EU), coal use for electricity is also expected to decline. Coal's share of electricity generation in Eastern Europe is projected to fall from 58 percent in 2001 to 44 percent in 2010 and to 24 percent in 2025.

In markets where coal has not been a particularly important contributor to electricity generation, there are unlikely to be significant increases in coal use. Canada, Mexico, Central and South America, and the Middle East all use coal for less than 20 percent of their total electricity generation. Canada and Central and South America rely heavily on hydroelectric power for their electricity supplies, and Mexico and the Middle East rely on oil and natural gas. In each of those markets, coal is projected to account for less than 20 percent of electricity generation in 2025.

Natural Gas

Electricity markets of the future are expected to depend increasingly on natural-gas-fired generation. Industrialized nations are increasing their use of combined-cycle gas turbines, which usually are cheaper to construct and more efficient to operate than other fossil-fuel-fired generation. Natural gas is also seen as a much cleaner fuel than other fossil fuels. Worldwide, natural gas use for electricity generation is projected to be more than twice as great in 2025 as it was in 2001, as technologies for natural-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, most notably in Central and South America, where heavy reliance on hydroelectric power has led to shortages and blackouts during periods of severe drought.

Natural gas has proven to be a popular choice for electricity generation in many countries. Worldwide, consumption of natural-gas-fired electricity increased by an average of 6.9 percent per year from 1970 to 2001—second only to nuclear power's average annual growth rate of 17.5 percent over the same period. In some cases, governments have tried to slow the growth of natural gas use for power generation. In the 1970s, the U.S. Government passed legislation that effectively barred utilities from expanding their use of natural gas (as well as petroleum) [*1*]. The Energy Supply and Environmental Coordination Act of 1974 allowed the Federal Government to prohibit electric utilities from burning gas or oil. Nonutility generators were largely responsible for the increase in gas-fired power generation in the United States during the 1990s, until electricity deregulation, the belief that sufficient natural gas reserves existed, and the perceived environmental advantages of natural gas over coal resulted in a relaxation of the restrictions on natural gas.

In the United Kingdom, natural gas use for electric power grew rapidly in the 1990s and was characterized by some analysts as the "dash for gas." The fast-paced growth alarmed the U.K. government, both because of the fear that there would not be sufficient supplies of natural gas to meet the growing demand of electric power companies and because the government wished to allow the country's coal industry to be competitive with natural gas [2]. As a result, the government issued a moratorium on construction of new natural gas capacity in 1998, which was in place until November 2000 [*3*]. Immediately after the restrictions were revoked, plans were announced to construct five new electricity generators fueled by natural gas.

Natural gas has been an important fuel for electricity generation among the countries of the FSU for the past three decades, accounting for between 40 and 50 percent of their total natural gas use. Dependence on natural gas for electricity generation is expected to remain strong in the FSU: in 2025, gas-fired generation is projected to account for 51 percent of the FSU's total electricity supply.

Oil

The role of oil in the world's electricity generation market is generally expected to diminish over the next two decades in much of the world. Energy security concerns, as well as environmental considerations, have already led many nations to reduce their use of oil for electricity generation. In the Middle East, however, oil holds a significant share of the generation fuel market. With much of the world's oil resources, the Middle East is expected to continue to generate a large share of its electricity with oil. In other parts of the developing world, where many countries still rely on traditional fuels (such as wood and animal dung) as energy sources, oil use for electricity may increase somewhat as nations switch to diesel-fired generators until their populations are able to be connected to national grids.

Nuclear Power

In the *IEO2004* reference case, the nuclear share of the world's total electricity supply is projected to fall from 16 percent in 2001 to 12 percent in 2025. The reference case assumes that the currently prevailing trend away from nuclear power in the industrialized countries will not be reversed, and that retirements of existing plants as they reach the end of their designed operating lifetimes will not be balanced by the construction of new nuclear power capacity in those countries. In contrast, rapid growth in nuclear power capacity is projected for some countries in the developing world.

For the most part, and under most economic assumptions, nuclear power is a relatively expensive option for electricity generation when compared with natural gas or coal, particularly for nations with access to inexpensive sources of fossil fuels, and without world compliance with carbon emission reduction policies, such as the Kyoto Protocol. In addition, there is strong public sentiment against nuclear power in many parts of the world, based on concerns about plant safety, radioactive waste disposal, and the proliferation of nuclear weapons. The economics of nuclear power may be more favorable in countries where other energy fuels (mostly imported) are relatively expensive.

Nineteen countries depended on nuclear power for at least 20 percent of their electricity generation in 2002 (Figure 63). In absolute terms, the world's total nuclear power capacity is projected to increase from 353 gigawatts in 2001 to 385 gigawatts in 2025 in the reference case (Table 15). The largest additions of nuclear capacity are expected in Asia (China, India, Japan, and South Korea) and in Russia. China is projected to add nearly 19 gigawatts of nuclear capacity in the *IEO2004* reference case, South Korea 15 gigawatts, Japan 11 gigawatts, India 6 gigawatts, and Russia 6 gigawatts. (Japan and Russia are also expected to retire 5 gigawatts and 7 gigawatts of existing nuclear capacity, respectively, between 2001 and 2025.)

Figure 63. Nuclear Shares of National Electricity Generation, 2002

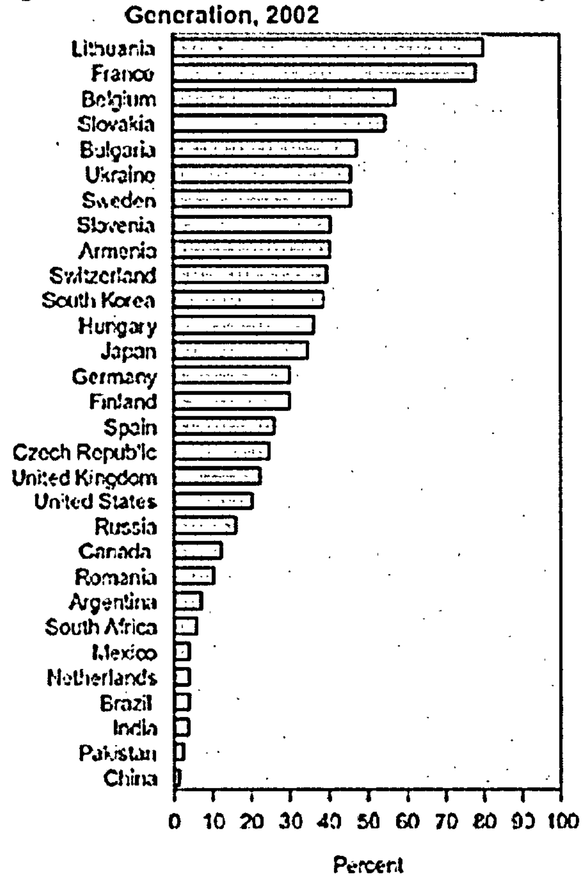

Figure Data

In other parts of the world, life extensions, higher capacity factors, and capacity uprates are expected to offset some of the capacity lost through plant retirements. For example, life extensions and higher capacity factors are expected to play a major role in sustaining the U.S. nuclear industry. Thus, despite a declining share of global electricity production, nuclear power is projected to continue in its role as an important source of electric power.

At the end of 2003 there were 441 nuclear power reactors in operation around the world [*4*], and another 34 were under construction. Two new nuclear power plants began operation in China in 2003, and four were permanently shut down in the United Kingdom. Construction on North Korea's nuclear reactor program was suspended in November 2003, pending the outcome of the ongoing six-party negotiations (North Korea, China, Japan, Russia, South Korea, and the United States) over North Korea's nuclear weapons program [*5*].

Recently, significant improvements in operating and safety performance have improved the image of nuclear power and its future global prospects. For instance, the world's average nuclear power plant availability factor improved from 73 percent in 1990 to 84 percent in 2002, and average U.S. capacity factors improved from 71 percent in 1992 to 91 percent in 2002 [6]. Greater capacity utilization allowed the U.S. nuclear power industry to increase net generation by 19 percent between 1991 and 2001, despite a nearly 2-percent decrease in operable nuclear capacity over the same period. At the same time, both overseas and in the United States, nuclear plant safety measures have improved considerably. Nuclear power has also been advocated as a desirable option for reducing greenhouse gas emissions.

Nowhere is the decision to build nuclear power capacity left entirely to corporations or utilities that would base their decisions solely on economic grounds. In general, government policy (with an eye to public opinion) guides the development of nuclear power. National policies have evolved considerably since the first nuclear power reactors were connected to the grid in the United Kingdom, United States, and Soviet Union during the 1950s. Shortly after the first oil crisis exposed the vulnerability of world economies to petroleum price shocks, nations attempted to increase their access to more secure sources of fuel, and subsequent oil price shocks tended to reinforce their desires. As a result, many nations pursued nuclear power programs aggressively during the 1970s, in most cases with strong public support.

Subsequently, however, accidents at Three Mile Island in the United States in 1979 and at Chernobyl in the Soviet Union in 1986 pushed public opinion and national energy policies away from nuclear power as a source of electricity. In the United States, massive cost overruns and repeated construction delays—both caused in large part by regulatory reactions to the accident at Three Mile Island—essentially ended U.S. construction of nuclear power plants. Similarly, both before and after the Chernobyl accident, several European governments had announced their intentions to withdraw from the nuclear power arena. Sweden committed to a phaseout of nuclear power in 1980 after a national referendum. Both Italy and Austria have abandoned nuclear power entirely, and Austria has also been a strong opponent of nuclear power programs in Eastern Europe that it considers to be unsafe. Belgium, Germany, and the Netherlands have committed to gradual phaseouts of their nuclear power programs, although in some cases such commitments have proven difficult to carry through. Given the periodic changes in political leadership that can shift official government positions on nuclear power, it is difficult to assess the degree to which current commitments for or against nuclear power will be maintained.

Many issues still may impede the expansion of the nuclear power industry. Nuclear waste disposal remains a key concern. High-level nuclear waste must be stored for thousands of years, and there is general consensus that stable, deep, geological formations are the best locations for waste repositories. The greatest concern over the storage of high-level nuclear waste is that over such a long period of time, the containers in which the waste is stored could eventually leak. Although most nations have identified potential underground storage sites and have conducted geological and geophysical tests as to their suitability, no underground storage site has progressed beyond the planning stage. In the United States, which is perhaps the farthest advanced in the planning stage, President Bush in February 2002 authorized the construction of a nuclear waste repository at Yucca Mountain in Nevada [*7*].

Another potential drawback to nuclear power is the fear that reactors might be used for purposes of developing nuclear weapons. The events that have unfolded in North Korea over the past several years underscore the concern that can arise over the possibility of nuclear proliferation. For many years, North Korea insisted that it would not use its Yongbyong nuclear power reactor to create weapons-grade plutonium; then, in 2003, the government announced that it possessed nuclear weapons [*8*]. Nuclear programs in other countries, such as Iran and Libya, have also recently come under scrutiny by the world community. After Libya agreed to dismantle its nuclear program—which involved the purchase of nuclear power designs from Pakistani scientist Abdul Qadeer Khan—the International Atomic Energy Agency announced that finding out whether other countries had acquired nuclear weapons technology was "an important and urgent concern for us" [*9*]. Khan also admitted selling nuclear secrets to Iran and North Korea.

In the wake of the events in Libya, North Korea, and Iran, the Bush Administration proposed several new initiatives for curbing the spread of nuclear weapons materials and expertise [*10*]. Under the proposal, the Nuclear Suppliers Group—comprising 40 member countries with nuclear technologies—would refuse to sell enrichment and reprocessing equipment to any state that does not already possess full-scale, functioning equipment and reprocessing plants. The proposal also would expand the effort to intercept suspected weapons of mass destruction on ships, through cooperation with Interpol and other law enforcement mechanisms, and would require that all nations sign the International Atomic Energy Agency's

"Additional Protocol," expanding the agency's authority to investigate clandestine nuclear activities.

Hydroelectricity and Other Renewables

In the *IEO2004* reference case, moderate growth in the world's consumption of hydroelectricity and other renewable energy resources is projected over the next 24 years. Most renewable energy sources are not expected to compete economically with fossil fuels in the mid-term forecast. In the absence of significant government policies, such as those aimed at reducing the impacts of carbon-emitting energy sources on the environment, it will be difficult to extend the use of renewables on a large scale. *IEO2004* projects that consumption of renewable energy for electricity production worldwide will grow by 57 percent, from 32 quadrillion Btu in 2001 to 49 quadrillion Btu in 2025 (Table 16).

Much of the projected growth in renewable generation is expected to result from the completion of large hydroelectric facilities in developing countries, particularly in developing Asia, where the need to expand electricity production often outweighs concerns about environmental impacts and the relocation of populations to make way for large dams and reservoirs. China, India, and other countries in developing Asia are constructing or planning new, large-scale hydroelectric facilities. The first electricity generating units of China's 18,200-megawatt Three Gorges Dam hydropower project began generating power in mid-2003, and India's 1,500-megawatt Nathpa Jhakri hydropower project was commissioned in October 2003.

Many nations of Central and South America also have plans to expand their already well-established hydroelectric resources. Brazil, Peru, and even oil-rich Venezuela have plans to increase hydroelectric capacity over the next decade. Brazil alone anticipates tenders for 17 hydroelectric projects in 2004, with a combined installed capacity of 4,149 megawatts, despite a crippling drought in 2000-2001 that resulted in electricity rationing and threatened brownouts. Many of Brazil's new hydroelectric projects will be located in the northeastern part of the country, which was not as severely affected by the drought. In general, however, the nations of Central and South America are not expected to expand hydroelectric resources dramatically but instead are expected to invest in other sources of electricity—particularly natural-gas-fired capacity—that will allow them to diversify electricity supplies and reduce their reliance on hydropower.

Hydroelectric capacity outside the developing world is not expected to grow substantially. Among the industrialized nations, only Canada has plans to construct any sizable hydroelectric projects over the forecast period. Hydro Québec alone is planning to add some 6,000 megawatts of additional hydroelectric capacity within the next decade. In the EE/FSU countries, most additions to hydroelectric capacity are expected to come from repair or expansion of existing plants. In the industrialized and EE/FSU regions, most hydroelectric resources either have already been developed or lie far from population centers.

Wind power has shown the fastest growth of all renewable energy sources in recent years. In many countries of the developing world, small wind and wind-hybrid installations are an effective method for bringing electric power to rural areas that cannot be connected to national grids (see discussion on "Small Wind Power"). In the industrialized world, particularly strong growth in wind power has been seen in recent years in Western Europe. Germany, Spain, and Denmark were all among the top five wind installers in 2002; Germany added the most wind capacity in 2002, installing 3,247 megawatts to bring the country's total installed wind capacity to 12,000 megawatts [*11*]. The United States installed 687 megawatts of new wind capacity in 2002, after a record year of 1,695 megawatts of new wind capacity in 2001. U.S. wind capacity additions in 2003 were expected to be even stronger, totaling an estimated 1,664 megawatts, in view of the December 31, 2003, expiration of a production tax credit for wind power; although a provision in proposed U.S. energy legislation includes a bipartisan plan for extending the tax credit through 2006, the U.S. Senate has not yet passed the bill.

The *IEO2004* projections for hydroelectricity and other renewable energy resources include only on-grid renewables. Non-marketed (noncommercial) fuels from plant and animal sources are an important source of energy, particularly in the developing world, and the International Energy Agency has estimated that some 2.4 billion people in developing countries depend on traditional biomass for heating and cooking [*12*]. Comprehensive data on the use of non-marketed fuels are not available, however, for inclusion 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, also because there are few comprehensive sources of international data on their use.

Regional Developments

North America

United States

In the United States, electricity demand is projected to increase by 1.8 percent per year on average, from 3,386 billion kilowatthours in 2001 to 5,207 billion kilowatthours in 2025 (Figure 64). Demand for electricity has slowed in the United States over the past several decades, owing to increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. In the forecast, growth in demand for office equipment and personal computers is offset by slowing or reduced demand for space heating and cooling, refrigeration, water heating, and lighting.

Figure 64. Net Electricity Consumption in North America by Country, 2001-2025

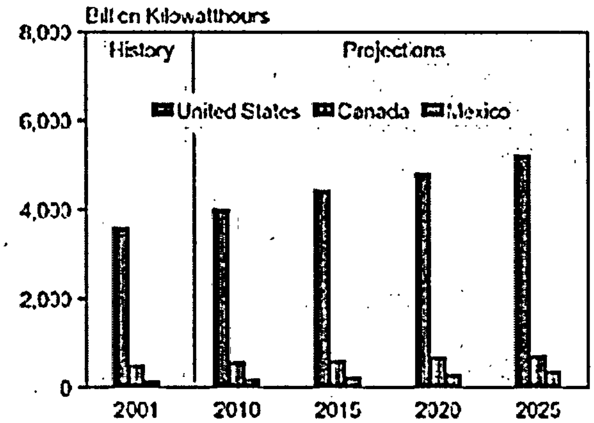

Figure Data

The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 18 percent in 2001 to 20 percent in 2025, lower than the 29 percent forecast for 2025 in last year's report. The coal share of generation is projected to increase from 49 percent in 2001 to 52 percent in 2025 as rising natural gas prices improve the cost competitiveness of coal-fired technologies. Some 112 gigawatts of new coal-fired generating capacity is expected to be constructed by 2025.

Nuclear generating capacity in the *IEO2004* forecast is projected to increase from 98.2 gigawatts in 2001 to 102.6 gigawatts in 2025, including uprates of existing plants equivalent to 3.9 gigawatts of new capacity by 2025. This is a change from last year's forecast, where total nuclear capacity reached a projected peak of 100.4 gigawatts in 2006 before declining to 99.6 gigawatts in 2025. In contrast to the *IEO2003* forecast, no existing U.S. nuclear units are retired in the *IEO2004* reference case. The forecast assumes that the Browns Ferry nuclear plant will begin operation in 2007 but projects that no new nuclear facilities will be built before 2025, based on the relative economics of competing technologies.

Renewable technologies are projected to grow slowly because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies in the competition for new capacity. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. Eleven States (California, Nevada, Arizona, New Mexico, Texas, Iowa, Wisconsin, Maine, Massachusetts, Connecticut, and Pennsylvania) currently have renewable portfolio standards in place. In addition, Minnesota and Illinois have set renewable goals but not renewable portfolio standards [*13*].

Total renewable generation, including combined heat and power generation, is projected to increase from 291 billion kilowatthours in 2001 to 519 billion kilowatthours in 2025, at an average annual growth rate of 2.4 percent. U.S. renewable energy use grows more quickly in the *IEO2004* reference case than in last year's report, where renewable generation was projected to grow by only 2.1 percent per year from 2001 to 2025.

Canada

Electric power in Canada is constitutionally the responsibility of the provinces, except for electricity traded across provincial or international borders. The electricity sectors are, for most of the country's 10 provinces, largely province-owned, although there are some privately-owned utilities and some independent power producers operating in the country. Canada's three largest electric utilities are Ontario Power Generation, Hydro-Québec, and British Columbia Hydro.

The provinces of Alberta and Ontario have introduced legislation to deregulate and privatize their power sectors. Alberta was the first province to introduce privatization legislation in 1995, and in January 2001 retail customers were allowed to choose their own electricity suppliers [*14*]. Ontario introduced privatization legislation in 1998 and deregulation began there in 2002. The process slowed substantially, however, in the aftermath of California's energy crisis. In Ontario, sharp price increases after deregulation was implemented led the government to intervene and impose a retail electricity price cap of 4.3 cents per kilowatthour (Canadian) for residential and other small consumers in November 2002. The new Liberal government, upon taking office in late 2003, became concerned about the financial implications of the cap for Ontario Power Generation and for the government deficit. As an interim measure, the cap will be raised in April 2004 to 4.7 cents per kilowatthour for the first 750 megawatthours and 5.5 cents per kilowatthour for consumption above that. This pricing regime is to remain in place until May 2005, by which time the Ontario Energy Board is to develop a new pricing system [*15*].

Net electricity consumption in Canada is expected to increase by 1.6 percent per year between 2001 and 2025, from 500 billion kilowatthours to 728 billion kilowatthours. Hydroelectric power provides about 60 percent of Canada's generation, and although its share slips slightly over the forecast period, hydropower is projected to continue dominating the electric power fuel mix in Canada through 2025. In the *IEO2004* reference case, hydropower's share of total energy use for electricity generation falls to 58 percent in 2025.

There are plans to expand hydroelectric capacity in Canada. In particular, Hydro Québec has more than 6,000 megawatts of hydroelectric capacity either under construction or planned in Québec Province, including the 3,880-megawatt Saint Marguerite facility (to be completed by the end of 2004); 1,480-megawatt Eastmain (2008); 220-megawatt Grande Mere (2005); 526-megawatt Tolnustoouc (2005); and 385-megawatt Peribonka (2008) [*16*].

There are currently 17 nuclear power reactors operating in Canada. Although no new nuclear reactors are under construction, there are plans to bring four units of Ontario Province's Pickering reactors back into operation over the next several years, adding 2,060 megawatts of nuclear capacity by 2007. This follows the reconnection of the 790-megawatt Bruce 4 reactor to the Ontario electricity grid in December 2003 and the reconnection of the 750-megawatt Bruce 3 unit in January 2004 [*17*]. Both Bruce units had been shut down since 1998. The return of the two units will mean, when the temporarily suspended Bruce 8 unit is brought back on line, that Bruce Power will be able to meet the needs of 20 percent of Ontario's electric power demand with the six nuclear units [*18*]. Canada's nuclear capacity is projected to increase from 10,018 megawatts in 2001 to 15,207 megawatts in 2020 before beginning to decline to 12,351 megawatts at the end of the *IEO2004* forecast in 2025.

The return of the Bruce and Pickering nuclear units in Ontario should help the provincial government in its efforts to eliminate coal-fired generation in the province by 2007 [*19*]. In 2003, Ontario had around 8,000 megawatts of coal-fired capacity [*20*]. The Electricity Conservation and Supply Task Force was organized to determine how Ontario's electricity sector should evolve to both phase out coal-fired generation and at the same time ensure a secure supply of electricity. The task force suggested that a combination of nuclear power improvements and uprates, along with additional nonhydropower renewable energy sources, could allow Ontario to meet its target for coal's removal; however, it also warned that removing the province's five baseload coal generators could put reliability at risk in the short term. In addition, the task force recommended that electricity demand growth rates be reduced to 0.5 percent per year, from the 1.7 percent per year growth experienced over the past decade, and that the province consider importing hydroelectric power from Manitoba, Québec, and Labrador for "intermediate and peaking purposes." It also cautioned that constructing the necessary transmission lines "would be costly, and would take time" [*21*].

Ontario's recently elected Liberal government has approved a renewable portfolio standard (RPS) that sets aggressive targets and time frames for increasing the amount of renewable capacity in the province [*22*]. The RPS calls for 300 megawatts of new wind capacity by 2005 and 2,000 megawatts by 2010. In addition, it calls for the development of about 700 megawatts of small hydropower and biomass projects.

Other provinces are also seeing interest in developing renewable energy resources, particularly wind. In 2003, a 75-megawatt wind project was completed in Alberta, near Fort Macleod. Construction on the $76 million McBride Lake Wind Farm began in November 2002, and the first electricity from the project was generated in February 2003 [*23*]. The last of the 114 wind turbines was installed in June 2003. The project was supported by Canada's $196 million Wind Power Production Incentive program, whose goal is to increase the amount of wind power in Canada by an estimated 500 percent [*24*]. The government of Canada is expected to contribute approximately $25 million to the McBride facility over a 10-year period.

The Canadian company Suncor Energy began construction of a 30-megawatt wind project in southern Alberta in September 2003 [*25*]. The $35 million project, a joint venture between Suncor and EHN Wind Power Canada, will be located about 4 miles west of Magrath. It is scheduled for completion by the end of 2004. Suncor Energy also completed an 11-megawatt, $17 million wind project in Saskatchewan in 2002. In addition, Hydro Québec is planning to purchase 1,000 megawatts of wind power over the next 10 years, mostly from independent power producers in the Gaspésie region [*26*].

Mexico

In Mexico, the electric power sector remains largely under state control. Electric power generation is currently the only segment of the electricity sector that allows some private-sector participation, the result of a 1992 amendment to Mexico's Electricity Law [*27*]. Private companies are allowed to generate electricity for areas not considered "public service." They include generating electricity for export and generating electricity for public service during an emergency. Self- or cogenerators and small producers may generate electricity for their own use, and independent power producers are permitted to sell excess power to the Federal Electricity Commission (CFE) under long-term contracts.

CFE and Luz y Fuerza Centro (LFC) are Mexico's two state-owned electricity companies. CFE generates about 90 percent of the country's electricity and LFC about 2 percent, with 4 percent coming from the Mexican state-owned oil company Pemex and the remainder from private-sector generators. The Mexican Energy Secretariat has estimated that an additional 13,000 megawatts of new capacity will be needed between 1999 and 2005 to meet demand. The Fox Administration proposed reforming Mexico's electricity sector as a way of meeting growing electricity demand, but the Mexican Congress has not adopted the reforms to date.

Net electricity consumption in Mexico is projected to more than double in the *IEO2004* forecast, from 150 billion kilowatthours in 2001 to 379 billion kilowatthours in 2025. Much of the country's generation is currently produced from fossil fuels. Oil accounts for about 50 percent of generation, natural gas about 23 percent, and coal a very modest amount. Fossil fuels are expected to dominate the sector in the mid-term, with a continuing switch from oil to natural gas both for environmental reasons and to diversify the sector.

Mexico has two nuclear power plants at Laguna Verde, Veracruz, each with a 680-megawatt installed capacity. There are no plans for Mexico to add nuclear power over the projection period. The country also has around 10,000 megawatts of installed hydroelectric capacity and plans to expand the use of hydropower. In March 2003, a contract was awarded by the federal government for construction of the 750-megawatt El Cajón hydropower project, to be built in the northwest state of Nayarit at Tepic [*28*]. El Cajon is one of the largest public infrastructure projects undertaken by the Mexican government in several years, with completion scheduled for 2008.

Western Europe

Among the countries of Western Europe, mature electricity infrastructures and slow population growth are expected to translate into relatively slow growth in demand for electric power over the 24-year projection period. Western Europe's electricity demand is projected to increase by an average of 1.3 percent per year, from 2,246 billion kilowatthours in 2001 to 3,029 billion kilowatthours in 2025 (Figure 65).

The summer of 2003 was marked by several widespread power failures in some of the largest economies of the Western European region. An unusually severe heat wave occurred during the summer months, testing many nations' electricity infrastructures. Nuclear power plants were forced to curb operations in Germany and in France when water temperatures exceeded legal limits and the nuclear power plants could not dispose of the water used to cool nuclear core elements. In addition, a lack of wind resulted in weaker performance of installed wind generation in Germany.

Figure 65. Net Electricity Consumption in Western Europe, 2001-2025

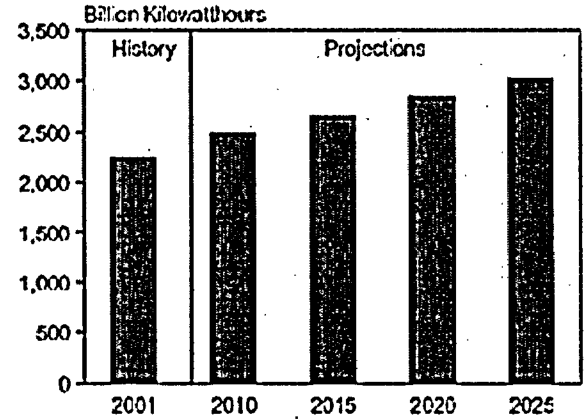

Figure Data

In August 2003, London experienced an electric power outage that affected 400,000 customers during rush hour [*29*]. However, the U.K. natural gas and power market regulator, Ofgem, determined that the failure—and another one that followed a week later—were not caused by insufficient grid investment. Instead, the outage was caused by the wrong type of fuse installed on backup protection equipment. In September 2003, a power failure caused by falling tree limbs cut off power to 55 million people in Italy for 18 hours, attributed, at least in part, to the slow reaction of ETRANS (the Swiss firm that coordinates participation in Europe's grid) to inform Italian grid operator Gestore della Rete di Trasmissione [*30*]. Denmark and Sweden, with integrated electricity systems, suffered their worst blackout in 20 years when the 1,135-megawatt nuclear power plant at Oskarshamn in Sweden was shut down, triggering an automatic closure at Sweden's 1,800 megawatt Ringhals nuclear power plant [*31*]. The shutdown at Oskarshamn was attributed to a fault on the transmission line. Lack of investment in the Scandinavian power grid has been cited as a key reason for the massive failure.

The number and severity of the power failures that hit Western Europe in 2003 have raised concerns about the liberalization of electricity markets in the region. In the case of the United Kingdom, Sweden, and Denmark, governments are questioning whether the power failures resulted from a lack of investment in the national grids, which is less profitable to companies than is investment in new capacity. In Italy, on the other hand, the government has moved to speed up the process of liberalization in the wake of the widespread power outages, by expediting legislation on an energy reform bill that would make it easier for companies to construct new generation capacity [*32*]. In the short term, the government passed an emergency decree at the end of August 2003 that allowed the Industry Ministry to let power producers ignore temperature limits on the waters they discharge [*33*].

The EU, after many years of negotiation, passed directives in 2003 that establish deadlines for opening electricity and natural gas markets. The directives require that markets for nonresidential consumers be opened to competition by July 2004 and for all consumers throughout the EU by July 2007 [*34*]. The directives also require the separation of distribution wires from other parts of the electricity industry and the institution of energy sector regulators. The directives are not expected to result in radical shifts in EU electricity markets in the near term.

The 2003 EU directives on electricity and natural gas follow from the original 1996 agreement that began forcing EU member countries to open their electricity markets for competition [*35*]. The market opening imposed rules upon member countries according to a timetable that allowed each country to define its own pace of market liberalization, somewhere between the European Commission minimum requirements and full immediate opening. Introducing competition into the EU markets was expected to result in increased energy efficiency and lower prices for consumers.

In the countries that have instituted mandated opening of their electricity markets as a result of the 1996 agreement, customer prices have generally declined. In Germany, wholesale and retail competition opened in 1999, and power prices in 2000 were around 26 percent lower than in 1995. Residential sector power prices fell by 8 percent, even with the additional costs of the country's ecological tax and laws supporting renewable energy use and combined heat and power (CHP) [*36*]. In the United Kingdom, electricity prices for industrial and commercial consumers fell by between 20 and 25 percent from October 1998 to 2003 [*37*].

Markets in Spain began opening to competition in 1999, and although the terms of the EU directive on electricity required only that one-third of Spain's total electricity sales be liberalized by 2003, the country has already surpassed this requirement [*38*]. Between 1996 and 2001, electricity prices fell by 29 percent in real terms, primarily due to reductions in tariffs rather than as a result of competition in the electricity sector.

France has been the slowest in liberalizing its electricity markets. It has opened 30 percent of its electricity market to competition, but only 5 percent of the country's power companies have third-party access agreements. Further, state-owned Electricité de France (EdF) supplies 87 percent of all French electricity demand today and owns the entire national grid, making competition difficult [*39*]. In January 2004, however, the French Commission de Regulation de l'Energie announced that French electricity (and natural gas) distributors must start testing their computer systems by April 2004 in preparation for open retail markets [*40*]. Commercial and industrial customers are scheduled to be able to pick their electricity suppliers by July 2005 and residential customers by 2007.

Liberalization and the commitments of EU member countries to enact policies aimed at reducing greenhouse gases, as specified under the Kyoto Protocol, are expected to have an impact on the fuel mix for electricity generation in Western Europe. Oil is expected to become less important to the mix, particularly in countries where it has historically been high, notably Italy. Natural gas—with its efficiency and environmental advantages over other fossil fuels—is projected to gain share throughout the region, as is renewable energy, given widespread government programs to support its expansion. Coal is expected to continue to lose market share in Western Europe, as it has for much of the past decade.

With plans for uprates and extending the operating lives of many nuclear reactors, nuclear power generation is projected to increase somewhat over the next decade, but planned retirements and few plans for new generating units are projected to reduce the potential for nuclear power after 2010. As a result, electricity generation from nuclear power is expected to decline precipitously from 2010 to 2025. Finland and France are the only Western European countries expected to construct new nuclear power plants in the *IEO2004* reference case. Other European countries are expected to begin to retire nuclear capacity by the end of the forecast. Both Belgium and Germany have passed laws that require their nuclear power plants to be phased out.

Electricity generation from renewable energy sources other than hydroelectricity (which is already substantially developed in the countries with appropriate resources) is expected to continue fast-paced growth among the countries of Western Europe. The governments in the region offer support for nonhydropower renewable power sources, most notably wind, in the form of subsidies or requirements that utilities purchase a certain amount of power from "green" energy sources. Germany, Spain, and Denmark remain the fastest growing wind producers in the world, and the United Kingdom, Ireland, and Portugal all are experiencing a surge in installed wind capacity.

In 2003, Ireland's Airtricity began installation of the first phase of the 25.2-megawatt Arklow wind farm [*41*]. The $59 million project, located 6.3 miles off Ireland's east coast. consists of seven 3.6-megawatt turbines. It is scheduled to begin generating electricity by the end of 2004. Airtricity has proposed to eventually expand the site to up to 200 turbines, making it the largest offshore wind project in the world.

Portugal had about 200 megawatts of installed wind capacity at the beginning of 2003, and its wind capacity is expected to more than double to 450 megawatts before 2008 [*42*]. Two new facilities are projected to begin operation in 2004, one at Lomba da Seixa II near the northern Portuguese cities of Braga, Vila Real, and Porto, and one at Senhora da Vitoria in the central western part of the country near Nazaré. They will add a combined 24 megawatts of wind power to the grid of Portugal's largest utility, Electricidade de Portugal.

Germany

In Germany, there has been a shift away from coal-fired generation since the reunification of the country in 1990. Coal use for electricity generation fell from 3.5 quadrillion Btu in 1990 to 2.6 quadrillion Btu in 2001, largely reflecting the reduction in coal use in the eastern half of the country. This trend is expected to continue over the projection period, as natural gas and renewable energy resources displace the use of coal for electricity. Nuclear power is expected to be phased out in Germany, in accordance with German law that retires reactors after an average lifespan of 32 years. No new nuclear units are expected to be built in Germany as a result of the government's commitment to phase out nuclear power.

Germany remains one of the fastest-growing markets for wind power, setting national and world records for the installation of wind capacity in the past several years. German energy policy has set a target of doubling the renewable share of total energy use between 2001 and 2006, according to the Erneuerbare Energien Gesetz (Renewable Energies Act) of 2000 [*43*]. In early 2003, the German government announced it would extend the target deadline to 2010, and it would also extend the deadline for installing subsidized offshore wind power to 2010 [*44*]. The government has announced its goal to install 500 megawatts of offshore wind capacity by 2006 and 3,000 megawatts of offshore wind capacity by 2010. In 2002, wind power accounted for 4.7 percent of Germany's total electricity generation, up from 3.0 percent in 2001. The German Electricity Feed-In Law has helped support the increase in wind power by requiring utilities to purchase renewable-generated electricity at above-market rates [*45*].

France

France remains heavily reliant on nuclear power for its electricity generation, and this is expected to remain the case throughout the forecast period. Nearly 80 percent of France's electricity consumption is attributed to nuclear power, and although its share is projected to fall slightly from 2001 to 2025, nuclear clearly will dominate the French electricity market for years to come. In the *IEO2004* reference case projection, few French nuclear reactors are expected to be retired over the forecast period, and two new reactors are expected to be built. Further, the operating lives of most reactors are expected to be increased to 50 years, and significant capacity uprates are expected.

Natural gas use for electricity generation in France is projected to grow substantially in the forecast, while renewable energy use remains fairly flat. The French National Assembly passed an electricity feed-in law in 2001 that guarantees wind power producers reimbursement of about 9.8 cents per kilowatthour during the first 5 years of operation [*46*]. At present, France has 185 megawatts of installed wind capacity, including a 20-megawatt wind facility that began operating in June 2003 at Pays de la Loire, about 28 miles south of Nantes on the Atlantic coast.

United Kingdom

In the United Kingdom, coal is the dominant fuel source for electricity generation, at 37 percent of total energy use for electricity generation in 2001, followed by natural gas at 28 percent of the total. The mix is projected to shift so that, in 2025, natural gas will be the dominant resource in the U.K. electricity market. Coal's share is projected to drop precipitously as gas use climbs. Oil's role in the U.K. electricity market has been declining steadily over the past several decades and contributes very little to electricity generation in the *IEO2004* forecast.

Nuclear power currently accounts for about 23 percent of the United Kingdom's electric power supply. In the mid-term future, however, 8,879 megawatts of installed nuclear capacity is expected to be lost by 2025, as nuclear power reactors are shut down and no new reactors are expected to replace them. British Energy has had difficulty competing in the deregulated environment of the U.K. electricity market, supporting the expectation of a decline in nuclear power (see discussion on "Deregulated Electric Power Markets and Operating Nuclear Power Plants"). The United Kingdom has not ruled out future expansion of its nuclear industry, however, and government policies that affect the costs of fossil fuels in the future could help to bolster the U.K. nuclear program.

On April 1, 2002, the Renewables Obligation, which requires licensed electricity suppliers to provide a specific portion of their total electricity sales from eligible renewable sources, became law in the United Kingdom [*47*]. The government estimates that the law will provide around $1.8 billion in support for the U.K. renewable industry. The British government passed legislation in 2003 that set a target to generate 10 percent of the country's electricity from renewable energy sources by 2010 and 20 percent by 2020 [*48*]. In addition, the legislation required that the Renewables Obligation percentage be increased to 15 percent by 2015. This is expected to have a profound impact on the installation of wind capacity over the mid-term. Although in the past it has been difficult to site wind facilities because of considerable local resistance, the

Crown Estate (which controls British public lands) awarded leasing rights of up to 50 years for 15 wind sites in December 2003 [*49*]. The electricity from these projects is expected to begin flowing in 2007. When completed, it is expected to provide up to 7,000 megawatts of electric capacity. At the end of 2002, the United Kingdom had 552 megawatts of installed wind capacity.

Italy

In Italy, oil has been an important source of energy for electric power generation over the past several decades. With the opening of the country's electricity markets to competition, this is expected to change. If the government is successful in passing legislation that would expedite the liberalization of Italian energy markets, natural gas use is expected to increase markedly, given its competitive advantages over oil. Italy relies on imported electricity to meet nearly one-fifth of its domestic electricity demand. The Italian government is concerned about improving its domestic electricity supply for energy security reasons and is expected to promote the use of natural-gas-fired generation, as opposed to oil-fired generation that would increase the country's reliance on Middle Eastern oil imports.

Renewable energy sources are also expected to grow in importance. The Italian government has set a goal of doubling electricity production from hydropower and other renewable energy resources by 2012, which would add more than 7,000 megawatts of installed renewable electricity capacity [*50*]. In total, Italy has set a target to generate 25 percent of its electricity from renewable resources by 2010. While the *IEO2004* reference case projection does not expect this goal to be achieved, renewable generation in Italy is projected to double by 2025 from the 2001 level. In a 1987 referendum, Italy voted to stop the use of nuclear power. Although there are four inactive nuclear power reactors in the country, all of them are being dismantled, and there are no plans to resume the use of nuclear power.

Former Soviet Union

The FSU region has had several years of positive economic growth, raising the demand for secure supplies of electric power. Electricity demand is projected to continue to grow in the FSU, by an average of 2.0 percent per year from 2001 to 2010 and another 1.9 percent per year from 2010 to 2025, reaching 2,202 billion kilowatthours per year in 2025 from the 2001 level of 1,397 billion kilowatthours (Figure 66).

Figure 66. Net Electricity Consumption in Eastern Europe and the Former Soviet Union, 2001-2025

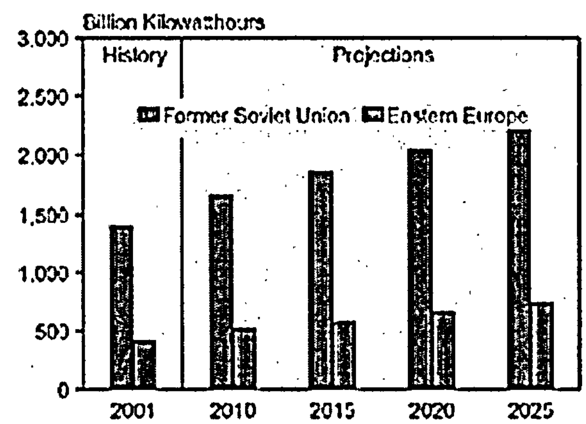

Figure Data

Electricity generation from fossil fuels, mostly natural gas and coal, dominates the electric power sector in most of the countries of the region where resources are available, and its on natural gas and coal is expected to increase over the projection period. Nuclear power and oil-fired generation are expected to become less important while renewable energy sources retain their shares of electric power supply. Four countries in the region— Armenia, Lithuania, Russia, and Ukraine—currently generate a portion of their electric power with nuclear generators. Lithuania generates nearly 80 percent of its electricity from its two Iglanina nuclear power reactors. Much of the increase in renewable energy use in the FSU region is expected to involve the refurbishment, repair, or expansion of existing sites that fell into neglect under the Soviet regime, rather than construction of new, greenfield projects.

The FSU countries are increasingly looking toward western electricity markets as models for reform. In Russia, for example, the electricity market is expected to be fully deregulated by 2006 [*51*]. In 2003, the Russian government opened a new wholesale spot market, where electricity can be traded at free market prices. Initially, electricity trade on the new exchange is limited to between 5 and 15 percent of a generator's total output. Furthermore, purchasers of electricity are limited to supplying no more than 30 percent of their electricity needs from the deregulated exchange and must purchase the rest from Russia's regulated power market, Forem.

Russia's Unified Energy System (UES), the state-majority-owned electric utility, has submitted a draft plan to the Russian government for improving the infrastructure of the country's electric power sector. The investment plan requests about $953 million for 2004, and a final ruling on the proposal was expected by the end of November 2003 [*52*]. Even if approved, the proposal falls short of the total investment of $55 billion that UES estimates will be needed over the next decade to ensure the operation of the Russian power sector [*53*]. Plans to privatize and overhaul the Russian electric power sector are aimed at gaining private and foreign investment in the sector over the longer term.

Additional Russian reforms to the electricity sector include the privatization of 10 new generating companies formed from UES, which now owns some 70 percent of the total Russian electricity market, as well as the creation of an independent high-voltage transmission system operator. The transmission system operator would remain under government control, as would all hydroelectric power generators, until at least 2008. The country's nuclear power generating capacity is expected to remain under state ownership for the foreseeable future. However, five new electricity generating companies that own fossil-fuel-fired power plants are scheduled to be privatized by 2006.

The Russian electricity fuel mix remains heavily dependent on natural gas. According to an estimate by Cambridge Energy Research Associates (CERA), the gas share of total thermal generation exceeds 60 percent, largely encouraged by many years of price capping [*54*]. Coal and oil use for electricity has declined over the past decade. The Russian government is concerned about over-reliance on natural gas and has proposed increasing investment in nuclear power and hydroelectricity. The country has also recognized the need to expand and enhance its transmission grid. There are plans to interconnect the Siberian, European, and Far Eastern Russian power systems.

The Russian government has proposed doubling the amount of energy generated by nuclear power before 2020 and plans to construct 40 new nuclear reactors by 2030. The first unit at Rostov nuclear power plant—the first nuclear power reactor to be completed in Russia since the fall of the Soviet Union—came on line in early 2001. Another reactor, the 1,000-megawatt Kalinin unit 3 is scheduled for completion by the end of 2004. Although the *IEO2004* reference case does not reflect the fast-paced development of nuclear power that the Russian government has announced, several new units are projected to become operational over the forecast period. As a result, no decline in Russia's electricity production from nuclear power is expected until after 2015.

As in most of the other FSU nations, Russia's expansion of hydroelectric resources is expected, in part, to be accomplished by the upgrading and repair of existing facilities. For instance, the St. Petersburg-based utility Lenenergo is planning to refurbish three of its hydroelectric plants, Narva, Lesogorsk, and Svetogorsk [*55*]. The Narva hydroelectric plant, located near the Russian-Estonian border, would be used to export electricity to Estonia. Narva began operating in 1955 and has never had a major overhaul of its generating capacity; Lenenergo has estimated that the refurbishment of the plant would cost about $17 million and would take 8 years to complete. The Lesogorsk and Svetogorsk plants are located at the Finnish border and have been in almost continuous service since 1945. Most of the electricity generated at the two plants, which have a combined installed capacity of 192 megawatts, is exported to Finland. An overhaul of the plants will cost an estimated $52 million.

There has been some progress in constructing new hydroelectric capacity in Russia, and the 2,000-megawatt Bureya hydroelectric plant began operating in Russia in June 2003 [*56*]. The plant, located in the Russian Far East, is expected to alleviate the frequent blackouts and high power prices that consumers in the region have been experiencing for the past several years. Power shortages were responsible for a number of deaths in the winter of 2000-2001 and are widely believed to have been the impetus for the recent electricity sector reform.

There are efforts to introduce some nonhydropower renewable energy projects in Russia, as well as in other FSU countries, particularly in niche areas that cannot be served by national transmission grids. For example, the European Bank for Reconstruction and Development is funding a feasibility study to add substantial wind power in the Chukotka region of northeastern Russia [*57*]. The project consists of the construction of 14 wind hybrid projects with a total installed capacity of 34.4 megawatts. The wind turbines would be provided with backup supply systems using diesel generators, fuel cells, or other suitable power sources. Chukotskenergo, the local power utility, has already installed and is successfully operating seven wind turbines with a total installed capacity of 2.5 megawatts, under a federal scheme introduced to reduce central government fuel subsidies. The power needs of the coastal area currently are met by diesel generators located in each of the region's scattered ethnic settlements, serving mines and various isolated industrial centers. An interconnected power supply system, which would be needed to minimize the reserve capacity requirements, was never developed because of the arctic climate, large distances, and limited road links between settlements.

Outside Russia, electricity sector reform has progressed, though with mixed success. Kazakhstan appears to be in the most advanced stage of restructuring in the region. Restructuring of the power sector in Kazakhstan began in 1995 with the unbundling of distribution, transmission, and generation functions [*58*]. By 1998, the government had privatized most of the country's generating capacity, as well as a number of distribution companies, and was allowing direct electricity sales to large end users. Ukraine also began privatizing its regional electricity distribution companies in 1995, but the process has moved slowly, and most of the country's 27 distribution companies still are state-owned. In early 2004, the Ukraine State Property Fund canceled plans to sell its stakes in five regional power utilities, citing opposition to the current administration [*59*].

Nuclear generation remains an important part of the Ukrainian supply mix. In December 2000, the Ukrainian government permanently shut down operations at the 925-megawatt Chernobyl unit 3 plant, the last operating plant at Chernobyl. Although many analysts believe that Ukraine has surplus electric capacity, the government still is working to complete two nuclear power plants begun under the Soviet Union, the Khmelnitsky-2 and Rivne-4 reactors [*60*]. In September 2003, the Ukrainian government announced that it would finish construction of the reactors without financing from the European Bank of Reconstruction and Development, which had repeatedly refused to make a decision to approve a loan for this purpose.

In Lithuania, two electricity distributors, Vakaru Skirstomieji Tinklai (VST) and Rytu Skirstomieji Tinklai (RST) are in the process of being privatized [*61*]. In July 2003, the government announced plans to sell the majority stake in the two distributors, with hopes that the offer would earn more than $261 million for the country. Germany's E.ON, France's EDF, Russia's UES, Finland's Fortum, the U.S. company AES, Poland's Polskie Sieci Elektroenergetyczne (PSE), and NDZ Energija of Lithuania all have expressed interest in purchasing the two Lithuanian power distributors.

Azerbaijan's 1998 Law on Electricity provides a framework by which the state-owned electric company, Azerenerji, will be unbundled, along with the liberalization of the country's generation and distribution companies [*62*]. The Azerbaijan government approved the restructuring of Azerenerji in early 2002, and privatization is expected to progress, albeit slowly. Uzbekistan also approved a program for the partial privatization of the electric power sector in 2001, but again progress has been slow. In Turkmenistan, the electric power sector remains fully under state control.

Eastern Europe

With the accession of five key Eastern European economies (the Czech Republic, Hungary, Poland, Slovakia, and Slovenia) to the EU in May 2004 and Bulgaria and Romania scheduled to join in 2007, Eastern Europe as a whole is restructuring and liberalizing its electricity markets to adhere to EU requirements. This will likely mean a switch from coal- to natural-gas-fired generation and, in several instances, has required acceding nations to release timetables for the dismantling of nuclear power reactors that the EU considers unsafe by western standards. In the *IEO2004* reference case, net electricity consumption in Eastern Europe is projected to increase by 2.4 percent per year on average, from 418 billion kilowatthours in 2001 to 739 billion kilowatthours in 2025. Coal's share of the total energy consumed for electricity generation is projected to fall from nearly 60 percent in 2001 to 44 percent in 2010 and 24 percent in 2025. In contrast, the natural gas share of total generation is expected to increase rapidly, from 10 percent in 2001 to 48 percent in 2025. Oil and nuclear power are projected to lose share in the region's power sector, and the renewable share of electricity generation is projected to grow from 13 to 14 percent.

Hungary's electric power sector already has been largely privatized. Electricity supplies are provided by 12 power generating companies distributed by 6 regional distribution and supply companies [63]. About 40 percent of the country's electricity is provided by the 4-unit PAKS nuclear power project and the rest from fossil fuels. The EU has inspected the PAKS units and determined that they are as safe as western nuclear reactors and in compliance with EU standards. The units were originally planned to have a 30-year lifespan, which is likely to be extended to at least 40 years. Tightening environmental regulations are expected to lead to the replacement of Hungary's coal-fired plants with natural gas; and if plans proceed as expected, only one coal-fired plant, the 800-megawatt Matra plant (which provides about 13 percent of Hungary's electricity), will remain.

The Czech Republic has also opened its electricity markets; however, the state-owned electric power company Ceske Energeticke Zavody (CEZ) still provides nearly three-fourths of the country's electricity supply [64]. The Czech government owns 68 percent of CEZ, but the company is scheduled for privatization by 2006. Electricity markets are in the process of being opened to adhere with EU directives on deregulation. The Czech Republic is a member of the CENTREL system, which links the country's electricity grid to those of Poland, Hungary, and Slovakia. It is also an associate member of the Union for the Coordination of Transmission of Electricity (UTCE), which coordinates the operations of its 16 European transmitters in an effort to guarantee the security and synchronous operation of their power systems.

At present, coal is the most important component of the Czech Republic's power supply, although there are efforts aimed at reducing the country's dependence on coal, or at least improving the pollution controls associated with generating coal-fired electric power. Over the past 10 years, CEZ has implemented an aggressive environmental cleanup program that includes retrofitting flue gas desulfurization scrubbers on existing coal plants. By some estimates, the Czech coal-fired generators now operate more cleanly than some facilities in Western Europe [65].

In addition to environmental upgrades to existing coal facilities, the Czech Republic brought the 1,824-megawatt Temelin nuclear power plant into operation in 2001. This is an important new source of electric power for the country. Temelin and the country's other operating nuclear power reactor at Dukovany account for around 22 percent of the total Czech electricity supply. Temelin has been the source of dispute from some of the Czech Republic's neighbors, particularly Austria, where a petition demanding the closure of the plant was signed by 900,000 Austrians in January 2002, despite a September 2001 agreement between the Austrian and Czech governments that allowed the plant to begin operation [66].

Poland's electricity sector is even more reliant on coal-fired capacity than is the Czech Republic's, with coal accounting for more than 97 percent of its generation [67]. The dependence on coal is not expected to moderate substantially over the next decade, with few plans to introduce natural-gas-fired generation and no plans to introduce nuclear power. There are plans to begin to increase the amount of biomass and solid waste use for electricity generation, particularly biomass co-fired with coal.

Liberalization of Poland's electricity sector began in 1997 with the passage of the Energy Law Act of 1997 to meet the requirements for EU membership. Current plans would allow all electricity consumers to choose their own energy suppliers by the end of 2005 [68]. Third-party access to the national grid has already been granted to large electricity customers that consume at least 40,000 megawatthours per year.

The Polish electricity grid is already well integrated with those of its neighboring countries. Poland is a member of the CENTREL transmission system, which was connected to Western Europe's system in 1995, with 2,000 megawatts of capacity allowed through the system in both directions. Construction of a high-voltage power link between Poland and Lithuania began in 2001, with plans for completion by 2008.

Bulgaria's membership in the EU is under consideration for 2007, and the country is in the process of restructuring its electricity sector. In 1998, the Bulgarian parliament began liberalization of the country's power sector by unbundling the generation, transmission, and distribution activities of the state-owned power company, Natsional Elektricheska Kompania (NEK) [69]. In line with recommendations made by the International Monetary Fund, the unbundling was accomplished by the summer of 2000. In June 2003, 10 of the country's largest power-consuming companies were allowed to negotiate their electricity supplies and prices directly with generators. Also, as a precondition to EU membership, Bulgaria agreed to shut down four of its oldest nuclear reactors. At the end of December 2002, the country permanently shut down

Kozloduy units 1 and 2, which the EU considered unsafe. Units 3 and 4 are scheduled for closure in 2008 and 2010. The Bulgarian government has announced plans to complete construction of the 1,000-megawatt Belene 1 and 2 nuclear power plants in an effort to compensate for installed capacity lost with the closure of the Kozloduy units [*70*].

The Bulgarian electricity sector is fairly diversified: 40 percent of the country's electricity is generated from nuclear power, 50 percent from fossil fuels, and 10 percent from hydropower. In addition, there have been some efforts to add alternative, nonhydropower renewable resources. A 20-turbine wind farm in northeastern Bulgaria, at Kavarna on the Black Sea, is expected to be completed by the end of 2004 [*71*]. It will be the country's first wind project. A second wind project in nearby Balchik is also under construction but has been delayed pending the results of an environmental inquiry into potential impacts on birds that migrate on the Via Pontica.

Bulgaria has been aggressively attempting to establish a regional power market. As the leading Balkan electricity producer, Bulgaria has ample installed capacity and has been an important source of electricity for its neighbors, having signed electricity supply contracts with Serbia, Montenegro, Albania, and Greece [*72*]. The heat wave and drought that created shortages in many countries of Central and Western Europe in the summer of 2003 helped to strengthen Bulgaria's role as an exporter of electric power. Romania's electricity distributor, Electrica, began negotiations with the Bulgarian state-owned power company, Natsional Elektricheska Kompania when the Cernavoda nuclear power plant was forced to shut down in August because of low water levels, removing 10 percent of Romania's generating capacity from service [*73*].

Industrialized Asia

The three countries of industrialized Asia (Japan, Australia, and New Zealand) all have mature electric power sectors. Japan has the region's largest installed electric capacity, at 235,000 megawatts, as compared with 43,000 megawatts in Australia and 9,000 megawatts in New Zealand. Net electricity consumption in the region is projected to grow by 1.2 percent per year on average, from 1,014 billion kilowatthours in 2001 to 1,354 billion kilowatthours in 2025. Australia and New Zealand combined are expected to see more rapid growth in electricity demand than Japan, where an aging population and the highest prices for residential electricity in the world are expected to result in only modest growth in the mid-term. Annual growth in Japan's electricity demand is projected to average only 1.0 percent over the forecast period, compared with 1.8 percent average annual growth projected for Australia and New Zealand (Figure 67).

Figure 67. Net Electricity Consumption in Industrialized Asia, 2001-2025

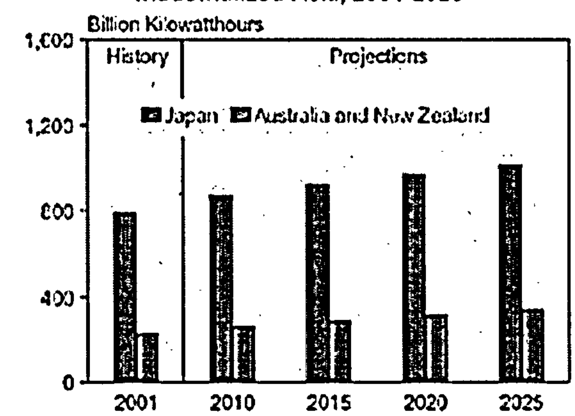

Figure Data

The Japanese electric power sector is already privatized. However, 10 privately owned regional utilities produce 75 percent of the country's electricity and control the regional transmission and distribution infrastructure [*74*], discouraging competition from independent power producers and offering little incentive for price competition. With the lack of competition, strict government regulation, scarcity of indigenous natural resources, and high land and operating costs, Japanese electricity prices have remained high. The Japanese government has, however, begun the process of liberalizing electricity trading for large electricity consumers. The Electricity Utilities Law (passed in 1995) deregulated electricity retailing to large-scale consumers in March 2000. In April 2004, 18 companies will launch a wholesale electricity market, which will be opened only to large-scale industrial users.

Japan's electricity is produced largely from fossil fuels and nuclear power. In 2001, about 33 percent of its electricity was generated by nuclear power plants. A scandal hit the Japanese nuclear power industry in 2002, when it was disclosed that the country's largest nuclear power company, Tokyo Electric Power

Company (Tepco), had filed falsified inspection documents for 13 reactors [*75*]. At the end of 2002, in the aftermath of the scandal, Tepco was forced to suspend operations at a total of 17 nuclear power plants, only 7 of which had returned to operation as of March 2004. With the loss of such a substantial amount of capacity, more generation was switched to fossil fuels. According to the *Petroleum Intelligence Weekly*, a 2.2-percent increase in Japan's oil consumption in 2003 resulted almost entirely from an 18-percent increase in demand for fuel oil for electric power generation [*76*].

In spite of the recent problems in its nuclear power industry, Japan plans to build more nuclear capacity in the future and has announced plans to construct 13 nuclear power plants, with a combined capacity of 13,000 megawatts, by 2010 [*77*]. In the *IEO2004* reference case, Japan's nuclear capacity is projected to increase from 43,245 megawatts in 2001 to 56,882 megawatts in 2020 before declining to 54,281 megawatts in 2025 as several older units reach the end of their operating lives.

In recent years there has been increasing interest in the development of renewable energy resources in Japan, particularly wind and solar power. In April 2002, the Japanese government passed legislation for establishing a renewable portfolio standard [*78*], and by the end of the year installed wind capacity had reached 340 megawatts, well above the 1999 total of 20 megawatts. The government has set a target of installing 3,000 megawatts of wind capacity by 2010. Among the projects currently under construction is the 30-megawatt Rokkashomura wind project at Rokkashomura, on the eastern part of the Aomori Prefecture [*79*]. Upon completion, the project will be one of Japan's largest wind installations, providing power to the Tohuku Electric Power Company under a long-term contract.

Solar power has also advanced strongly in Japan, bolstered by government incentives and high residential electricity prices [*80*]. According to a study by CERA, demand for photovoltaics (PV) in Japan has grown by more than 40 percent per year over the past decade, from 19 megawatts in 1992 to nearly 860 megawatts at the end of 2003. With government incentives expected to continue to support the photovoltaic industry, solar power is likely to continue its fast-paced expansion. CERA has estimated that photovoltaic installations might reach as much as 7,000 megawatts by 2010.

In Australia, rich in domestic coal resources, almost 70 percent of electric power is generated from coal. Coal's share of electric power generation in Australia/New Zealand is projected to falls slightly in the *IEO2004* forecast, to 63 percent in 2025, and the natural gas share is projected to increases from 10 percent in 2001 to 19 percent in 2025, largely displacing oil and, to a lesser extent, coal.

Australia has been attempting to introduce competition in regional markets that already have an integrated transmission infrastructure. In 2001, the National Electricity Market announced that the states of Victoria, New South Wales, and Queensland had achieved a "fully contestable" power market, and plans are underway to extend competition to South Australia and Tasmania [*81*].

Although much of the growth in electric power markets is expected to be based on natural gas, Australia has also made several moves to increase the use of renewable energy. In 1997, the government established a Renewable Energy Equity Fund to provide capital for small renewable energy projects. The government's Renewable Energy Act, passed in 2000, requires power producers to increase the renewable share of their electricity mix by 2 percent by 2010 [*82*]. A total of 3,900 megawatts of renewable energy capacity is already under construction, including the 80.5-megawatt Lake Bonney wind project near Millicent in South Australia, which is scheduled to be completed by 2005 [*83*].

Developing Asia

The electricity sectors of the countries in developing Asia are expected to be the fastest-growing in the world. In the region as a whole, net electricity consumption is projected to increase at an average rate of 3.7 percent per year from 2001 to 2025 in the *IEO2004* reference case. In China alone, the projected average growth rate for electricity demand is 4.3 percent per year (Figure 68). Over the next two decades, electricity demand more than doubles in the

IEO2004 reference case, growing from 2,650 billion kilowatthours in 2001 to 6,274 billion kilowatthours in 2025. Much of the increase in demand is projected for the residential sector, where robust growth in personal income is expected to increase demand for newly purchased home appliances for air conditioning, refrigeration, cooking, and space and water heating.

Figure 68. Net Electricity Consumption in Developing Asia, 2001-2025

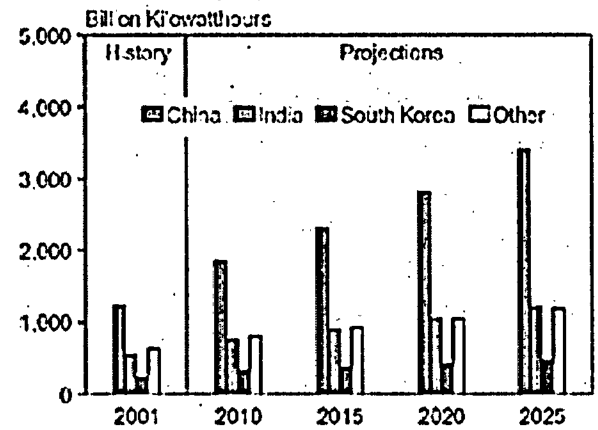

Figure Data

China

With high rates of annual GDP growth, electricity demand in China has grown substantially over the past decades. Over the past 5 years alone, China's net electricity consumption has grown by an average of 7.2 percent annually. Until recently China had a surplus of installed generating capacity as a result of the construction of power plants along the country's east coast during the 1990s [*84*]. Beginning in 1998, however, the Chinese government began trying to reduce the amount of surplus capacity by shutting down small, mostly coal-fired, power plants and discouraging new plant construction. A number of new plants were completed, however, and supply was largely able to keep up with demand until the past year or two. By some estimates, at the end of 2003 China was facing a deficit in capacity of more than 10 percent.

China's strong economic performance in 2003—fueling strong electricity demand in the industrial sector—and a particularly hot summer resulted in blackouts across the east and south portions of the country [*85*]. The problem was exacerbated further by low water levels, which reduced supplies of hydroelectric power in seven provinces [*86*]. There were some fears that the electricity shortage would worsen in the winter, and the Chinese government responded by requiring shopping centers and department stores in all major urban areas of the country to turn off their central heating for 2 hours each morning. In addition, large energy-consuming industries, such as steel, aluminum, and chemicals, were asked to shut down or operate only from 10 p.m. to 5 a.m., and peak power prices for residential consumers were raised fivefold in an effort to cut demand during the evening hours.

Because of the need to expand capacity to meet the strong growth in electricity demand, China has begun the process of restructuring to allow private investment in its electric power sector. In December 2002 the State Power Corporation was divided into five generating units and two transmission companies, with regulatory functions assigned to the China Electricity Regulatory Commission [*87*]. Although there have been efforts to introduce some privatization in the electric power sector, China's two largest privatized electric power generators, Huaneng Power and Beijing Datang Power, are still majority-owned by the government.

There have also been efforts to liberalize the electricity sector by introducing limited price competition. China began a simulated electricity price competition in early January 2004 as part of its effort to set up regional power markets. The government hopes that introducing price competition at the regional level will help to end provincial trading barriers and increase the reliability of supply. The northeast part of China was chosen for the test case, because it still has a power surplus and experience with a largely unsuccessful competitive pricing model in 1999. About 26 power generators, affiliated with 5 state-owned utilities in the northeast and eastern Inner Mongolia, began to sell power to distributors through a bidding process [*88*].

China's electric power fuel mix remains heavily reliant on coal; however, there are projects underway to increase hydropower, nuclear, and natural gas capacity, and their shares of electricity generation are expected to increase over the forecast period. Coal still is expected to remain the dominant fuel for electric power supply, with a projected 72-percent share of total energy use for electric power generation in 2025, compared with 76 percent in 2001.

China's 18,200-megawatt Three Gorges Dam project is scheduled to be fully operational in 2009, supplying 10 percent of current demand for electricity. In addition, China's Hydro Electric Corporation is presently developing 25 hydroelectric plants over a 570-mile portion of the Yellow River, which would add 15,800 megawatts of installed capacity. In addition, the 5,400-megawatt Longtan hydroelectric project on the Hongshui River is scheduled for completion in 2009 [*89*]. Plans have also been proposed for a 14,000-megawatt hydroelectric facility at Xiluodo and a 6,000-megawatt facility at Xiangjiaba.

There are also plans to increase China's nuclear power capacity. As of March 2004, nine nuclear reactors were operating in China, with a combined capacity of 6,199 megawatts. Two additional reactors are under construction, scheduled for completion before 2005. They will add another 2,000 megawatts of installed nuclear capacity [*90*]. The government is considering another 26 nuclear units for future development, with a total combined capacity of 23,000 megawatts, but it is unlikely that those units will become operational before 2025 [*91*]. The *IEO2004* reference case projects an increase in China's nuclear capacity of 18,626 megawatts from 2001 to 2025, reaching 20,793 megawatts at the end of the projection period.

China also has plans to construct six 320-megawatt natural-gas-fired generators in Guangdong province and to replace existing coal-fired capacity in Beijing with natural gas in time for the 2008 Olympics [*92*]. In light of growing electric power shortages, however, the government has begun to promote the construction of new coal-fired plants, along with the gas-fired facilities being constructed in Beijing, Shanghai, and a few other coastal cities [*93*]. Of the 30 new power projects approved for construction, most are coal-fired plants.

China remains concerned about improving rural electrification, and there are a number of renewable energy projects underway toward that end. Construction of the 150-megawatt Huitengxile wind power project in Inner Mongolia, is slated to begin in August 2004 [*94*]. Power generated by the wind project will be purchased by Inner Mongolia Electric Power Corporation, the regional utility based in Hohhot, and will be distributed through the electricity grid system to consumers throughout Inner Mongolia. Under the country's "Brightness Program," aimed at extending electrification to remote villages through solar-powered electricity, 78,000 rural households in Xinjiang province have already been supplied with solar modules, each with a capacity of 2.4 megawatts [*95*]. In December 2003, Shell Solar GmbH was awarded a contract by the Chinese government to supply another 26 villages in Yunnan and Xinjiang with solar-powered electricity.

India

Among the countries of developing Asia, India has the second largest installed electricity capacity, next to China's. India is expected to experience fast-paced growth in demand over the forecast, with strong economic growth of 5.2 percent per year projected between 2001 and 2025. Net electricity consumption is projected to grow by 3.3 percent per year, to 1,216 billion kilowatthours in 2025, more than double its 2001 level of 554 billion kilowatthours.

India is already running about an 8-percent deficiency in needed electricity supply. Increasing the capacity through foreign investment will be difficult, even though private investment in the electric power sector is allowed, because many foreign investors find the country's bureaucracy onerous. State electricity boards are in control of most of India's electricity sales and over half of the country's capacity [*96*]. There also are problems with distribution losses, caused in large part by theft, which has been estimated to be as high as 50 percent in New Delhi, Orissa, and Jammu-Kashimir. With federal and state governments unwilling to increase prices to improve service, extensive foreign investment in India's electricity sector is not expected in the short term.

India's electric power sector is dominated by coal, which accounts for 78 percent of its total generation. Hydroelectricity provides another 13 percent, and nuclear, oil, and natural gas provide the remainder. The government has plans to increase the use of hydroelectric, nuclear, and natural gas in the electric power sector over the mid-term. There are 13 nuclear power reactors operating in the country today, with a combined installed capacity of 2,460 megawatts. Another 8 reactors are currently under construction, and the government has set a goal of increasing the country's nuclear capacity to 20,000 megawatts by 2020 [*97*]. The *IEO2004* reference case projects total installed nuclear capacity in India of 8,923 megawatts in 2025.

The Indian government is pressing forward with aggressive plans to expand the country's hydroelectric capacity. In May 2003, the Indian Prime Minister Atal Bihari Vajpayee launched an initiative to add 50,000 megawatts of hydroelectric power by 2012 [*98*]. Several large-scale hydroelectric projects are under construction in India, including the 2,400-megawatt Tehri hydroelectric project. The first unit of the 1,500-megawatt hydroelectric project at Nathpa Jhakri was commissioned in October 2003 [*99*]. The Tehri project was scheduled for completion in mid-2003, but legal challenges delayed those plans [*100*].

There are also efforts to increase electricity imports to meet India's growing demand. In 2003, the government signed a memorandum of understanding to purchase hydropower from Bhutan's 870-megawatt Punatsangchhu project [*101*]. India also has plans to import electricity from the proposed 360-megawatt Mangdechhu project and 1,050-megawatt Tala project in Bhutan, both scheduled for completion in 2005. India also imports substantial amounts of electricity from hydroelectric projects in Nepal.

Other Developing Asia

In the other countries of developing Asia, including South Korea, demand for electricity is expected to grow by about 2.8 percent per year between 2001 and 2025, from 859 billion kilowatthours to 1,648 billion kilowatthours. About one-third of the region's electric power sector is fueled with coal, followed by natural gas (21 percent), oil (17 percent), and nuclear power and renewables (both about 14 percent). Over the projection period, natural gas and nuclear power are expected to gain shares of the electricity fuels mix, displacing mostly coal and, to a lesser extent, oil and hydropower.

South Korea's energy sector is well established, with a diversified fuel mix and adequate capacity to meet demand. Coal and nuclear power account for about 40 percent of generation each, and natural gas, diesel, and renewables account for the remainder. The South Korean government initiated restructuring and privatization of the electric power sector in 1993, when 8 percent of the state-owned Korea Electric Power Corporation (KEPCO) was offered for sale to foreign investors [*102*]. The country's restructuring plan included a gradual phase-in of liberalization, with wholesale competition not fully integrated until after 2009.

In contrast to South Korea's electricity sector, Indonesia's state-owned Perusahaan Listrik Negara (PLN) has had several difficult years. In the early 1990s, the Indonesian government signed contracts for 27 independent power projects, all of which were suspended during the country's 1998 economic crisis [*103*]. Although electricity demand has recovered from the crisis, which lasted through 1999, PLN has been unable to raise funds necessary to keep up with demand. Investors have been hesitant to return to the Indonesian market because of difficulties in resolving payment disputes in the wake of the economic collapse.

The Indonesian government enacted the Electricity Business Act in September 2002, in an effort to satisfy foreign investors' desire for reform in the sector. The legislation will eventually end the state monopoly over power generation and sales and will allow the separation of generation, transmission, and distribution functions [*104*]. According to the law, competition can begin any time after 2007.

Middle East

In the countries of the Middle East, high rates of population growth are expected to lead to rapid growth in demand for electricity over the next two decades. In the *IEO2004* reference case, net electricity consumption is projected to grow by 2.8 percent per year on average, from 476 billion kilowatthours in 2001 to 926 billion kilowatthours in 2025 (Figure 69).

For the countries of the region with large reserves of petroleum and natural gas, those fuels are expected to dominate electricity generation. The two largest regional electricity consumers, Saudi Arabia and Iran, use oil and natural gas to generate almost all their electricity. Turkey and Israel rely heavily on coal for their electric power supplies, although both countries also use substantial amounts of oil for electricity generation. Most of the major energy consumers in the region have plans to increase natural-gas-fired generating capacity over the forecast period. In Saudi Arabia, replacing oil-fired capacity with gas-fired capacity will allow the country to monetize their oil through export. In Turkey and Israel, adding gas-fired capacity is a way to diversify electricity supplies away from coal, and in Iran away from oil.

Figure 69. Net Electricity Consumption in the Middle East, 2001-2025

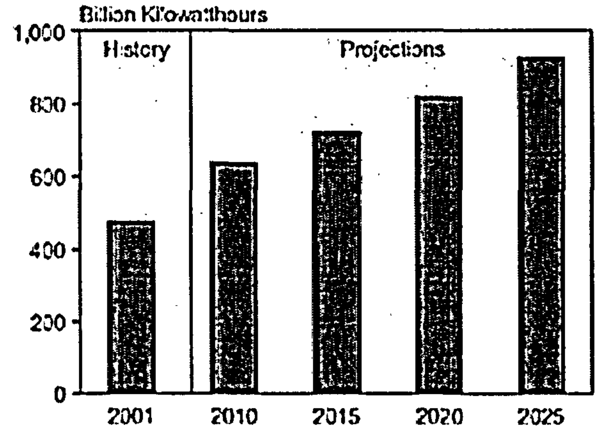

Figure Data

In many countries of the Middle East, the electric power sector is state-owned. Others have begun to consider opening their electricity markets in an effort to attract foreign investment. Saudi Arabia, for instance, began restructuring its electricity sector in the late 1990s, creating the Saudi Electricity Company (SEC) at the end of 1999 [*105*]. The SEC has been incorporated as a joint stock company, and the government has indicated that it will eventually lower its share of the company to 20 percent from 50 percent. There are plans to split the SEC into three divisions, separating generation, transmission, and distribution.

Saudi Arabia is also attempting to boost independent power development. In late 2003, construction began on the country's first independent power project, a 250-megawatt cogeneration plant being constructed in Jubail by U.S.-based CMS Energy and National Power Company (the latter a joint venture of Saudi Arabia's Al Jamil and El-Seif groups) for the Saudi Petrochemical Company [*106*]. The project is scheduled for completion in 2005, at which time CMS is expected to sell its 25-percent share of the project. At the end of 2003, the Saudi Electricity Company retendered three 2,000-megawatt power projects—at Shuaiba on the Saudi western coast and Ras al-Zour and Jubail on the Gulf—that were originally supposed to be part of the Saudi Gas Initiative.

The Saudi state-owned oil company, Saudi Aramco, has also begun efforts to increase power generation through independent power projects. In 2004, the company signed an agreement with U.K.-based International Power to build, own, operate and transfer some 1,074 megawatts of natural-gas-fired cogeneration capacity in the eastern part of Saudi Arabia. The project consists of constructing four plants to supply power to Saudi Aramco under four 20-year agreements. Saudi Aramco will provide the natural gas to the generators. Three of the plants—Ju'aymah, Shedgum, and Uthmaniyah— will have installed electric capacity of 308 megawatts and will produce 569 tons of steam per hour; the fourth, at Ras Tanura, will have an installed electric capacity of 150 megawatts, producing 293 tons of steam per hour.

In Iran, electricity demand grew at an average annual rate of around 8 percent from 1996 to 2001, and strong growth is expected to continue into the future. The Iranian government has set a goal of increasing capacity from 31 gigawatts in 2001 to 40 gigawatts in 2005 to meet the burgeoning demand [*107*]. Most of Iran's electric power is generated with natural gas, which accounts for about 80 percent of the total electric power fuel mix. The remainder is divided between hydropower and oil. The country also has a nuclear power reactor under construction, the 915-megawatt Bushehr 1 power plant, scheduled for completion in 2005.

Iran's electric power sector is regulated through the Energy Ministry's Power Generation and Transmission Management Organization (or TAVANIR) [*108*]. Sixteen regional power suppliers provide the country's generation and distribution. The Iranian government began the process of restructuring the electric power sector in 1998 in an attempt to attract foreign investment for power generation. Privatization of the power sector has moved slowly, however, and it is expected that TAVANIR will retain control over generation and distribution for the foreseeable future.

Iran's electricity fuel mix is likely to remain largely dependent on natural gas. Because the government would prefer to monetize its oil through exports, its plans for new fossil-fired capacity are centered exclusively on natural gas. There are also plans to increase the use of hydroelectric power in Iran, with a goal of adding 8,000 megawatts of new hydroelectric capacity by 2011. Both the environmental benefits of hydropower and the low costs of maintaining and generating electric power once construction has been completed make the energy source a particularly attractive one to the Iranian government.

In October 2003, Iran's largest hydroelectric power plant became operational. The 400-megawatt facility is part of the Karkheh dam project [*109*]. Other hydroelectric projects under various states of development include a 1,000-megawatt power station in Upper Gorvand, the 2,000-megawatt Godar-e Landar hydropower project, and the 3,000 megawatt Karun 3 plant [*110*].

Iran is also interested in importing electricity to help meet its growing power demand, particularly in the northeastern part of the country. In 2003, TAVANIR signed a $48 million contract to import electricity from Turkmenistan through a link-up of the two countries' electricity grids at the border towns of Meshhad, Serakhs, and Gonbad. When completed, the capacity of the transmission lines is expected to reach 700 megawatts. In May 2003, Turkmenistan agreed to export 640 million kilowatthours of power to Iran for the rest of 2003 for $12.8 million.

Electricity demand in the United Arab Emirates (UAE) has also been rapidly increasing in recent years. Between 1996 and 2001, electricity use in the UAE increased by nearly 9 percent per year. It is estimated that the UAE electricity sector will require about $8 billion in investment over the next 8 years to meet demand [*111*], and the government has plans to expand its 9,500 megawatts of installed capacity by more than 50 percent over the next decade.

The governments of the various emirates have chosen to handle their roles in the country's electric utility sectors in different ways. In Abu Dhabi, the electricity sector has been restructured by splitting the state-owned utility into private companies that separately handle generation, transmission, and distribution. The government will retain major stakes in the companies, with the Abu Dhabi Water and Electricity Authority serving as a regulatory body. Abu Dhabi has also attracted foreign investment in its electricity sector by allowing independent water and power projects, three of which are currently under development. Three emirate-owned utilities serve the electricity needs of the other emirates: the Dubai Electricity and Water Authority, the Sharjah Electricity and Water Authority, and the federal Ministry of Electricity and Water.

Turkey is another Middle Eastern country that will require extensive investment in its infrastructure if it is to meet future electricity demand. The country is expected to experience fast-paced population growth and healthy economic expansion in the mid term as it recovers from its economic recession of 2000-2001, accompanied by an increase in electricity demand.

Turkey is largely dependent on hydropower to meet its electricity needs, and 40 percent of its total installed capacity is hydroelectric [*112*]. A drought in 2001 underscored the need to diversify the electric power sector fuel mix. The country has been increasing its use of thermal generation, mostly in the form of natural gas and some coal, and it is expected to continue doing so in the mid-term. In the short term, generation from oil is expected to increase sharply to meet peak demand, because oil-fired generators can be built quickly with minimal infrastructure, compared to greenfield gas-fired power projects that require gas pipelines and other infrastructure.

Turkey's ample hydroelectric resources are expected to support an expansion of hydropower as well. The GAP hydroelectric and irrigation project in southeast Anatolia is currently under development. When completed, it will add some 7,500 megawatts of electric power capacity. Portions of the $32 billion project have already been completed, including the 2,400-megawatt Ataturk facility, the 1,800-megawatt Karakaya facility, and the 200-megawatt Batman and 200-megawatt Karkamis facilities. Power imports are also expected to play an increasing role in Turkey's electricity supply. At present, the country imports electric power from Russia, Iran, Bulgaria, and (for the first time in 2003) Turkmenistan. Imports from those countries are expected to continue increasing in the forecast [*113*].

The Turkish government has been keenly aware of the need to expand electricity and transmission capacity to meet demand. Efforts to bring new power projects into the country include build-own-transfer (BOT) projects in the mid-1980s and build-own-operate (BOO) projects in the mid-1990s. Efforts to restructure and liberalize the electric power sector culminated in the passage of the Electricity Market Law in February 2001 [*114*]. All of those efforts have had only limited success, however. The BOT agreements have encountered approval problems, mostly due to questions about their constitutional legality. In addition, because of Turkey's agreement with the International Monetary Fund to limit foreign debt in the wake of the 2000-2001 economic crisis, the Turkish government announced it would no longer be able to offer guarantees to finance BOT power projects. Finally, a corruption scandal at Turkiye Elektrik AS (TEAS) in early 2001 led to delays in the implementation of electric power sector reforms [*115*]. TEAS has since been separated into state-owned companies for electricity generation (Turkiye Elektrik Uretim AS), transmission (Turkiye Elektrik Iletim AS), distribution (Turkiye Elektrik Dagitim AS), and trading (Turkiye Elektrik Ticaret ve Taahhut AS).

Three of the BOO projects that were proposed in 1997 neared final approval at the end of 2003, but no schedule for their completion has been released. The three plants are a 777-megawatt plant at Adaparzi, a 1,524-megawatt plant at Izmir, and a 1,554-megawatt plant at Gebze. Their construction is expected to cost a combined $2 billion. The Turkish government is now promoting a Transfer of Operating Rights (TOR) model that would allow existing power plants to be licensed to private investors, in the hope that it will encourage efficiency upgrades. In June 2003, the Turkish Energy Ministry transferred 27 coal-fired and hydroelectric stations to the country's privatization agency, with the aim of completing privatization in 2004. Nineteen power distribution grids are also supposed to be privatized by the end of 2004 [*116*].

For some countries of the Middle East region, electricity theft is a major problem, with detrimental impacts on their efforts to attract much-needed foreign investment in electricity projects. In Lebanon, for example, efforts to draw foreign investment in the electricity sector included plans to privatize the country's electric utility Electricite du Liban (EdL). The plan originally anticipated that privatization would begin in 2003 with the sale of a 40-percent share of the utility; but those plans have been delayed indefinitely [*117*]. EdL is almost $3 billion in debt, and it costs the Lebanese Treasury about $200 million per year to purchase new fuel supplies. Electricity theft is the major cause of the problem, with a reported 25 percent of the electricity supplied by EdL per year being stolen by unauthorized taps on power cables.

The Lebanese government has also proposed raising electricity rates to attempt to reduce EdL's debt, but opponents argue that this would merely punish those customers who are already paying their electricity bills, without addressing the problem of theft. Moreover, even if the government were able to reduce electricity theft, the utility would continue to have financial difficulties because it is heavily reliant on oil-fired generation, and world oil prices have remained high. Alternative plans have included switching from oil to natural gas for generation electricity or for the country to participate in a power grid that supplies Jordan, Syria, Turkey, and Egypt.

Africa

For much of Africa, connecting populations to electric power supplies remains a primary goal. Problems with political corruption and a lack of transparency, domestic unrest and warfare in a number of countries, and the AIDS epidemic have strained the economies of many nations in the region. As a result, attracting investment into the region has been difficult. In many African countries, only a small percentage of the population has access to electricity. Nevertheless, efforts have continued in several countries, both to attract international investment in the electric power sector in general and to expand access to the power grid through rural electrification programs. In the *IEO2004* reference case, net electricity consumption in Africa more than doubles over the projection period, from 384 billion kilowatthours in 2001 to 808 billion kilowatthours in 2025 (Figure 70).

Figure 70. Net Electricity Consumption in Africa, 2001-2025

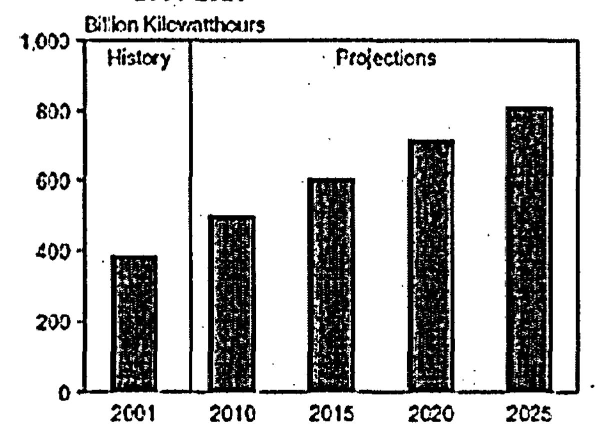

Figure Data

There is a move among some countries to initiate privatization in an effort to attract investment in the electric power sector infrastructure and help indebted state-run utilities become fiscally tenable. In Nigeria, the government has begun the process of restructuring its state-owned electric power company, the National Electric Power Authority (NEPA), by unbundling the utility into 18 separate companies, which are scheduled to be privatized. The government has estimated that some $1.4 billion would have to be invested in each of the companies to make the power sector reliable [*118*]. NEPA is already burdened with a debt of $3 billion in stranded costs making privatization essential for raising the needed funds. Privatization is scheduled to be completed by 2005.

The Nigerian electricity sector is dominated by thermal generation, mostly natural gas, followed by hydroelectric power. There are, however, efforts to introduce nonhydropower renewable energy sources. Renewable energy sources have proven to be a useful way to bring electricity to Africa's rural populations, especially in areas where difficult terrain makes it prohibitively expensive to extend national grids. In Nigeria, for instance, the first part of a $340,000 solar electrification project has been completed in several rural communities [*119*]. The project was initiated in conjunction with the U.S. Solar Electrification Fund (SELF) to assist rural communities in obtaining access to electricity. About $215,000 was expended on the pilot project, targeted at providing solar electric light to some designated areas at Wawar Rafi, Guru, Karaftai, and Maradawa villages. More communities are expected to benefit from the project.

South Africa has, by far, Africa's largest electric power sector, with 43 percent of the entire continent's total installed generating capacity in 2001. The state-owned electric power company Eskom generates nearly all of the country's electric power, with most of the generation produced by coal-fired power plants [*120*]. Eskom also runs the continent's only nuclear power reactor, the 1,930-megawatt Koeberg facility near Cape Town, and a small amount of hydroelectric power is also produced. Natural gas has only begun to be developed as a source of electric power. Gas supplies from Mozambique and Namibia are scheduled to begin flowing into South Africa over the next few years and may facilitate the growth in gas-fired electric power, particularly since Eskom has announced its intention not to construct any new coal-fired capacity.

The South African government is in the final stages of passing legislation on reform and restructuring of the country's electric power sector. A 30-percent share of Eskom is scheduled to be offered to investors by 2006 [*121*]. The government also plans to divest the company of its distribution assets, creating regional electric power distributors.

With enough spare capacity to satisfy domestic demand until at least 2007, South Africa has become a major regional supplier of electric power [*122*]. The country already exports electricity to Botswana, Lesotho, Mozambique, Namibia, Swaziland, and Zimbabwe. South Africa is a member of the South African Power Pool (SAPP, established in 1995) along with Angola, Botswana, Congo (Kinshasa), Lesotho, Malawi, Mozambique, Namibia, Swaziland, Tanzania, and Zimbabwe [*123*]. The SAPP's aim is to integrate the South African power markets, thereby allowing utilities to reduce generation costs and provide reliable electricity supplies to the grids of member nations.

In September 2003, Zambia, Tanzania, and Kenya signed an agreement to construct an electricity grid that would unite the power grids of the three countries [*124*]. The $323 million project would help to enhance development of the SAPP, allowing power swaps and transfers among the three countries and the SAPP power networks, and improve the reliability of power supplies across southern Africa. Construction of the project is scheduled to begin in October 2004 and to be completed by the end of 2006.

After South Africa, Egypt has the second largest installed electricity capacity in Africa. About 80 percent of the country's electricity is from oil- or natural-gas-fired generators, with the remainder largely from hydroelectric power. Egypt plans to add substantial capacity through commissioned buy, own, operate, and transfer schemes within the next decade to meet rapidly growing demand. Much of the new capacity will consist of natural-gas-fired generators. In addition, expansion of the Zafarana wind farm to 600 megawatts is expected to be completed by 2010 [*125*].

The Egyptian government began the process of privatizing the country's electricity sector in 1998 by passing Law 18, which allowed the partial privatization of Egypt's Egyptian Electricity Holding Company and would allow investors to purchase up to 49 percent of the country's electric power generators [*126*]. The government is also encouraging private companies to construct electricity generating plants under buy, own, operate, and transfer agreements to make a more competitive electric power sector.

Ethiopia is a country where the population largely lacks access to the electric power grid. According to state-owned Ethiopian Electric Power Corporation (EEPCO), only 14 percent of the population is connected to the national power grid. In 2003, construction of the 180-megawatt Gilgel Gibe hydroelectric project in Ethiopia neared completion [*127*]. The plant has been under construction, off and on, since 1976. Upon completion, Gilgel Gibe will increase the country's total installed electric capacity to 600 megawatts—an increase of 43 percent. The facility will cost an estimated $247 million, funded by the World Bank, the European Investment Bank, and the Ethiopian government. Gilgel Gibe should help EEPCO reduce the electricity shortages it faced in 2003; however, the shortages were blamed largely on low rainfall, which could also affect Gilgel Gibe. Construction of another hydroelectric project, the $224 million, 300-megawatt Tekeze began in 2002 [*128*]. Tekeze, which is being constructed by a joint venture between EEPCO and the China National Water Resources and Hydropower Engineering Corporation, represents China's largest joint venture in Africa to date. Construction is supposed to be completed by 2007. When both Tekeze and Gilgel Gibe are completed, the two projects will significantly bolster EEPCO's plans to improve rural electrification [*129*].

Uganda is also attempting to improve electric power access. The Ugandan Energy Ministry has set a target date of 2012 to provide 10 percent of the country's population with access to electricity [*130*]. The government has estimated that an investment of at least $450 million will be needed to reach its goal. The country began privatization in an effort to attract foreign investment in its electric power sector, but talks with South Africa's Eskom have not progressed as scheduled, and Uganda may opt to re-tender its electricity services.

The economy of Zimbabwe has been struggling in the face of domestic political problems. The policies enacted by the Mugabe Administration—including the land redistribution program that has seized lands from white farmers and, in many cases, given them to supporters of the regime—have devastated domestic agricultural output. The country is currently facing a food shortage perpetuated by the redistribution program, as well as fuel and electricity shortages [*131*]. Zimbabwe imports substantial amounts of electricity from South Africa to help sustain its electricity sector, and in late January 2004 South Africa's Eskom cut power supplies for 2 days because of chronic nonpayment. At the same time, Mozambique reduced electricity supplies to Zimbabwe by 40 percent from 2003 levels [*132*]. In 2003, the Zimbabwe Electricity Supply Authority (ZESA) stated that it had signed a new agreement with Congo (Kinshasa) to supply 100 megawatts of additional power capacity, added to the 150 megawatts of capacity it had already agreed to import [*133*].

Zimbabwe has begun the process of privatization, and two of the country's two major electric power generating plants, the Hwange and Kariba facilities, were being prepared for sale at the end of 2003 [*134*]. Two South African firms, Standard Corporate & Merchant Bank and Fieldstone Africa, were chosen as finalists to oversee the sale of the two facilities. ZESA is currently $200 million in debt and is hoping to gain $600 million by selling a 50-percent stake in each plant. Although the economic and domestic problems the country is still experiencing would make any investment in Zimbabwe risky, South Africa's Eskom has regional ambitions to dominate Africa's electricity network by obtaining generation assets.

Congo (Brazzaville) has a very small electric power sector, and virtually the entire electric power supply is from hydropower. The country has rich hydroelectric resources that have been largely underutilized, particularly after the sector was damaged during the country's civil war. There are, however, a number of hydroelectric power projects underway, including the 120-megawatt Imboulou project. Construction of the project, which is located on the Lefini River 133 miles north of Brazzaville, began in 2003 [*135*]. The $280 million facility is being built by Chinese companies CMEC and CIEMCO. Upon completion in 2009, it will provide power to Brazzaville and other cities in the northern part of the country and will double Congo's installed generating capacity.

Central and South America

Net electricity consumption among the nations of Central and South America is projected to grow by 3.2 percent per year in the *IEO2004* reference case projection, from 668 billion kilowatthours in 2001 to 1,425 billion kilowatthours in 2025 (Figure 71). The region relies heavily on renewable energy sources, largely hydroelectric power, to meet its electricity needs. Hydropower and other renewables account for nearly three-fourths of the total energy consumed for electricity generation in Central and South America today, and they are expected to be an important component of the region's fuel mix in the future; however, their share is projected to fall to 57 percent in 2025, giving up some of the market to natural gas.

Figure 71. Net Electricity Consumption in Central and South America, 2001-2025

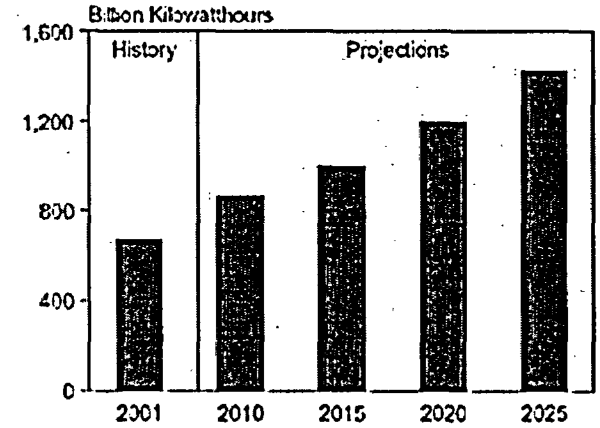

Figure Data

As a result of their dependence on hydroelectric power, many nations of the region are concerned with diversification of their electric power fuel mixes. Low rainfall can have significant detrimental impacts on the region's ability to meet electricity demand. Most recently, drought in Brazil, the region's largest economy, in 2001 to 2002 resulted in brownouts and electricity rationing. In response to the crisis, Brazil pledged to increase thermal generation—especially natural-gas-fired units—in the country; however, when the drought ended and water levels returned to normal, many of the planned projects were suspended. Brazil, along with several other countries in the region, including oil-rich Venezuela, has plans to expand hydroelectric capacity over the next decade.

Another issue of importance to the countries of Central and South America is rural electrification. While the electricity infrastructures of many of the region's nations are adequate to supply urban areas, there are parts of the region that do not have access to national electricity grids. Programs aimed at increasing rural electrification to improve the standards of living of the population and allow productivity to improve are underway in several countries.

Brazil

The electricity shortages in Brazil in 2001-2002 that resulted from drought, economic crisis, and the election of Worker's Party president Lula de Silva, have resulted in the implementation of changes to the country's power sector. Restructuring and privatization of the electricity sector in Brazil was started under the Cardoso Administration in 1995. A wholesale electricity market, the Mercado Atacadista de Energia Elétrica (MAE) was established, and at present some 60 percent of electric power distribution is in the private sector.

The economic and energy troubles in Brazil in 2001-2002 were in large part responsible for slowing privatization efforts. Foreign investors were hesitant to make commitments to energy projects given the economic difficulties facing the country in the wake of the devaluation of the national currency, the real. The election of Lula de Silva, at least in the months immediately following, further dampened private investors' interest in entering the Brazilian market, because the Worker's Party was thought to be unfriendly to business.

The Lula da Silva Administration has, however, made changes to the electricity sector that are expected to help improve security of the system and increase capacity. In September 2003, the government decided to provide a $1 billion aid package to Brazil's struggling electricity distribution companies [*136*]. The aim of the package is to help the companies reduce their short-term debt and allow them to resume investments in the sector. The government has also introduced legislation that would replace the MAE, which has performed poorly, with a new electricity pool and would allow independent power producers and large consumers to trade on a spot market [*137*]. The proposed legislation would also remove federally owned generators from the national privatization plan. The government believes that the removal of these generators from the privatization plan will make it easier to authorize increased investment by private companies [*138*]. Although the Brazilian Chamber of Deputies approved the government legislative proposals, the Senate postponed voting on the reforms in February 2004 [*139*].

Rural electrification is an important issue for Brazil. In November 2003, the Lula da Silva Administration announced a plan to invest $2.4 billion to provide electricity to 13 million people in rural areas of Brazil [*140*]. The "Light for All" project aims, in its first phase, to provide electricity to 7 million people by 2006. By 2008, 13 million Brazilians who do not currently have access to the national grid are expected to gain access as part of the plan. The program is expected to benefit states in the northeastern part of the country, which have the lowest levels of electrification in the country.

The plans for reform and rural electrification may increase opportunities for fossil-fired generators in Brazil, particularly natural gas. The country is concerned that a lack of investment in thermal power may result in electricity shortages over the next few years, as electricity demand growth—which declined after the shortages of 2001-2002—returns to normal. Under the terms of the electricity reform, distributors must contract for all their power needs, providing the guarantees necessary to finance thermal projects [*141*]. Because prices for thermal generation are somewhat higher than inexpensive hydroelectric prices, distributors would, in the past, look at the spot market for discounts when there was surplus hydroelectric capacity, making it impossible for thermal projects to compete effectively [*142*].

Along with the hopes for investment in thermal capacity in Brazil, there are also plans to expand hydroelectric capacity. The Brazilian government has announced that it anticipates the revival of 17 hydroelectric projects in 2004, with a combined installed capacity of 4,149 megawatts [*143*]. Brazil also has two operating nuclear power facilities, Angra 1 and Angra 2. The partially completed Angra 3 unit is not expected to be completed in the *IEO2004* reference case forecast.

Argentina

Argentina, like many countries in Central and South America, began the process of restructuring and privatizing its electricity sector in the 1990s in order to attract foreign investment. In Argentina, the 1992 Energy Regulation Act established guidelines for restructuring and privatizing the country's electric power sector. With the exception of its two nuclear power plants, hydroelectric projects that are jointly owned with other countries, and some provincial utilities, most electricity companies in Argentina have been privatized.

The economic problems Argentina experienced in the early 2000s discouraged private investment in the country's electricity sector. The Argentine peso was devalued in January 2002, and the government ended the ability of utilities to peg their rates to the U.S. dollar, forcing them to bill clients in pesos. As a result, many companies were unable to meet their debt payments [*144*]. In addition, price controls on utility tariffs were frozen at pre-devaluation rates, and the Argentine government would not allow utilities to reduce their services. The tariffs have not been raised since January 2002, and utilities argue that the freeze has made it impossible for them to make needed investments in electricity infrastructure [*145*].

References

Electricity Tables

Released: April 2004

EIA Home
Contact Us

Page last modified on Mon May 24 08:42:27 MDT 2004.
URL: http://www.eia.doe.gov/oiaf/ieo/electricity.html