Developing countries & Global climate change

Electric Power Options in Korea

Prepared for the Pew Center on Global Climate Change

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Foreword *Eileen Claussen, Executive Director, Pew Center on Global Climate Change*

The Republic of Korea straddles the line between developed and developing countries. Power demand is expanding rapidly—a "business-as-usual" path doubles consumption by 2015—and the economy is driven largely by basic, energy-intensive industries. In addition, Korea imports over 90 percent of its fuel. Because of this, the energy choices Korea makes are complicated and may have ramifications for the global environment that outstrip the nation's size. They could leave Korea's greenhouse gas emissions virtually unchanged—or more than double them.

What will be the likely drivers of the technology choices for the next twenty years of new power generation?

- Economic forces pulling Korea toward additional restructuring of the power sector and reform of industrial policy can reduce emissions of carbon dioxide by 9 percent relative to the baseline, with slightly lower costs per unit of electricity generated. Increasing the supply of natural gas and reducing import tariffs on that fuel have similar impacts.
- Economic concerns also might lead to more widespread adoption of cost-effective energy efficiency measures and, by reducing demand for power by 15 percent, could also reduce carbon and sulphur dioxide emissions by almost 25 percent.
- Further tightening of local environmental requirements might shift technology choices toward natural gas and nuclear and achieve reductions in the emissions of sulphur dioxide (59 percent) and carbon dioxide (28 percent), with only a small increase in costs.

Developing Countries and Global Climate Change: Electric Power Options in Korea is the second in a series examining the electric power sectors in developing countries, and will be followed by four more case studies of India, China, Brazil, and Argentina. The report's findings are based on a lifecycle cost analysis of several possible alternatives to current projections for expanding the power system.

The Pew Center on Global Climate Change was established in 1998 by the Pew Charitable Trusts to bring a new cooperative approach and critical scientific, economic, and technological expertise to the global climate change debate. The Pew Center believes that climate change is serious business and a better understanding of circumstances in individual countries helps achieve a serious response.

Executive Summary

Korea[2] occupies a unique place in energy use and climate change. A member of the Organization for Economic Cooperation and Development since 1996, the country is similar to developed nations in per capita income and energy use, but is counted among the developing countries by the United Nations Framework Convention on Climate Change. The energy choices Korea makes may influence the global response to climate change out of proportion to Korea's geographic size. Korea's leadership potential can be seen in its electric power sector—a microcosm of the climate change dilemma faced by developing countries.

Korea's economy has sustained three consecutive decades of rapid economic growth. GDP per capita averages over $10,000, several times that of most developing nations and comparable to some European countries. Korea also now ranks tenth in the world in total energy consumption. Electricity use per capita is twice Argentina's and four times China's, though only 40 percent that of the United States. Yet power demand in Korea, like that of a developing country, is expanding even faster than the economy. Indeed, Korea plans to double its power supply over the next 15 years.[3]

Whether Korea chooses coal, gas, nuclear, or renewable energy will directly affect the economic competitiveness of the nation and consumer pocketbooks. Korea's choices will also affect the local and global environment. Depending on the energy technologies it chooses, doubling power supply could leave the power sector's greenhouse gas emissions unchanged, or more than double them. Further, control of the power system is being shifted from state-owned monopolies to competing private electricity supply companies. How this mix of policy, growth, and technology will affect investment costs and the local and global environment is the subject of this report.

A. Energy Choices

The Korean power industry depends heavily on centralized planning, though steps are being taken to create a competitive market. Social and industrial policies provide massive subsidies to an otherwise non-competitive domestic coal sector, heavy investment in nuclear power, and rapid growth in the use of imported liquefied natural gas (LNG).

Free of greenhouse gas emissions, nuclear power is the largest source of electric power in Korea and is likely to remain so for at least another decade. This is true despite the fact that nuclear power is no cheaper for the end user than coal, oil, or gas-fired power. Capital costs range from three to four times that of natural gas and oil-fired systems, offsetting the significantly lower fuel costs that nuclear power enjoys. The dominance of nuclear power is a policy choice of the central government, which regulates the power sector closely and reflects a concern for energy security and air pollution control. As a result, Korea may be paying a premium for power in order to enhance its security. A scenario modeled in this report simulating an expanded role for nuclear power indicates that total energy costs would rise 4 percent, although carbon dioxide (CO_2) and sulfur dioxide (SO_2) emissions would fall significantly.

Korean coal resources are limited, expensive, and unlikely to be the fuel of choice among cost-sensitive, market-oriented producers. Imported coal is the cheapest source of power, however, and in a unregulated market would likely be the cheapest option. Coal-fired plants using imported coal are likely to form the second largest source of power generation in Korea over the next decade unless environmental policy alters the economics.

If Korean power generation becomes competitive and if reductions in sulfur, nitrogen, and particulate emissions are imposed, LNG will probably become the fuel of choice. The capital cost for LNG-fired power plants is low and efficiency very high, a combination that would beat the competition. Petroleum-fired, combined-cycle power plants may also be used, partly to diversify energy sources. These are also relatively low in greenhouse gas emissions. Modeling results show that a restructured power sector would reduce carbon emissions by 9 percent by 2015 and slightly lower costs per unit of electricity generated.

Hydropower and wind energy are limited and expensive in Korea, and thus noncompetitive in the near term. However, these resources may be effective tools for providing environmental protection and energy security in the future.

B. Study Results

The report evaluates trends in the Korean power sector to estimate the size and cost of alternative energy strategies and their effect on the nation's greenhouse gas emissions. Simple levelized cost analysis (lifecycle costing) and linear programming is used to test alternative scenarios for the planned expansion of the power system using nuclear, coal, and liquefied natural gas (LNG) fuels.

This analysis produced the following results:

- Korea's electricity consumption will likely double by 2015 from the 1998 level. In the baseline scenario, consumption of LNG would triple, while coal use would grow even more. The least-cost power capacity mix for the baseline in 2015 includes coal, LNG, nuclear, oil, and hydro at 37, 27, 20, 10, and 6 percent, respectively. But in terms of electrical output, coal and nuclear account for the 41 and 27 percent, respectively, with LNG and oil supplying 17 and 11 percent.

- Restructuring would shift the mix of power plant capacity from coal to gas-fired plants. Total costs in the power sector would increase by less than 0.5 percent due to greater demand for low-cost power, but they decline in other energy sectors. Carbon dioxide emissions would decline by 9 percent, and sulfur emissions would drop more than 60,000 tons (24 percent) compared to the baseline case. Nuclear power is unlikely to be adopted by private power developers because of high capital costs, siting delays, and the scale of investment required. Private power developers would prefer the efficiency, low capital costs, and flexibility of small-scale power plants fueled by LNG, which produce less than half as much carbon per unit of delivered electricity as coal. Reforms may enable Korea to improve economic efficiency, satisfy local environmental concerns, and help mitigate global climate change.

- Carbon and sulfur emissions would fall by 21 and 25 percent, respectively, if Korea were to utilize cost-effective energy efficiency options. Greater use of cogeneration, district heating, and performance contracting combined with the elimination of subsidies to energy-intensive heavy industry could help reduce Korea's energy use per unit of GDP to that of Japan's by 2015. The country would save almost $8 billion in constructing and operating power plants and significantly reduce energy imports.

- Liberalizing natural gas imports would make gas-fired power generation the most cost-competitive option. Such a scenario would result in 36 percent of power capacity fueled by natural gas while bringing costs down slightly from the baseline (by reducing import tariffs). Installed capacity of gas-fired units would increase to 30 gigawatts by 2015. Sulfur dioxide and carbon dioxide emissions would drop by 64,000 (25 percent) and 5.5 million tons (11 percent), respectively.

- Including the shadow environmental externality costs in the planning of electricity significantly alters the power mix in 2015 and makes coal more expensive than natural gas or nuclear. While total costs would rise about $2.3 billion over the baseline scenario, sulfur and carbon emissions would decline by 59 and 28 percent, respectively. Windpower, if resources are available, would become competitive in this scenario by 2010.

- Nuclear power becomes the cheapest alternative only if capital costs fall to about $1,200 per kilowatt, about one-third less than the cost today. If nuclear costs were reduced as a result of research, development, and deployment (RD&D), carbon dioxide and sulfur dioxide emissions would decline sharply by 23 million tons (46 percent) and 157,000 tons (61 percent), respectively. Total installed nuclear capacity in this case would reach 35 gigawatts in 2015. However, when more realistic capital costs are assumed, nuclear power is not competitive.

C. Recommendations

- Korea could boost economic performance, improve environmental quality, and ensure greater energy security by accelerating energy efficiency efforts. To accomplish this, the country will need to reduce subsidies to heavy industry and support even greater development of demand-side management, cogeneration, district heating, and energy service companies.

- Korea could improve least-cost power planning by considering the full economic and environmental impacts of electricity generation options.

- Reducing the taxes and duties on LNG imports could make combined-cycle power plants, which have lower emissions, more competitive. Importing pipeline natural gas from Russia would further lower the cost of power from combined-cycle plants.

- Korea's economy and environment could benefit from advanced technologies such as fuel cells and wind power if research and development is accelerated and capital costs decline as a result.

I. The Korean Energy Picture

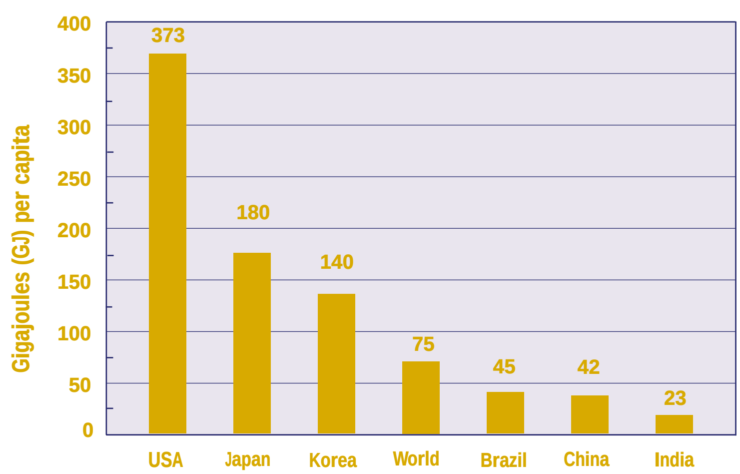
A. Energy's Role in Korea's Economy

Korean electric power—and the nation's energy system—are characterized by rapid demand growth and heavy dependence on imported fuels. Industry currently accounts for half of the country's energy use; buildings and transportation split the other half. Oil and liquefied natural gas provide two-thirds of total energy supply. Coal and nuclear add one-fifth and one-tenth of supply, respectively. Almost all fuel is imported, except for a small amount of coal. Electric power generation uses about one-third of total primary energy (that used in direct applications), and is fueled by uranium, coal, gas, and petroleum, in order of importance. Current trends presage continuing growth, especially for electricity.

Rapid economic growth stemming from expansion of heavy industry has driven Korean energy demand growth for the last two decades.[4] Overall energy use has grown more than 8 percent annually for the past two decades, tripling energy use per capita as personal incomes surged. Koreans use twice as much energy per capita as Argentinians and about the same as Italians, but only 40 percent as much as people in the United States. (See Figure 1.)

Figure 1

Primary Energy Use in Korea and Selected Countries, 1998

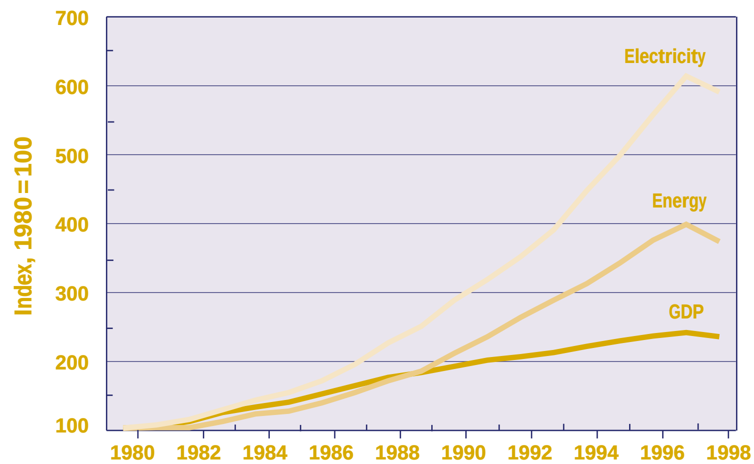


Source: *BP Amoco Statistical Review of Energy 1999.*

Korea's economy is relatively energy intensive and becoming increasingly so. Energy intensity (defined as energy consumption per unit of economic output in constant currency) improved in the early 1980s, but has risen by one-fifth since 1985. Korean energy demand has grown 30 percent faster than its economy.[5] (See Figure 2.) Korea's rising demand contrasts with that of Japan, China, and the United States where, during comparable periods of rapid industrial modernization, energy use grew more slowly than economic output.[6] The rising trend can be explained partly by Korea's economic structure, which emphasizes energy-intensive industries, such as chemicals and steel, rather than services and light manufacturing. Indeed, the industrial sector consumes over one-half of all energy used in Korea, compared to one-third or less in Europe and North America.[7] (See Table 1.) One startling example is Korea's petrochemical sector, which consumes over one-fifth of the country's entire energy.

Figure 2

Korean **Economic and Energy Growth** 1980-98



Source: *Korea Energy Review Monthly.*

During the financial crisis of 1997-98, International Monetary Fund economists criticized Korea's industrial policy, which allocates capital to heavy industry through the *chaebol* system of interlocking enterprises.[8] Korea's economy contracted by 6 percent during 1998, but growth surged in 1999. With economic recovery, pressure for reform has diminished.[9]

The buildings sector, which includes residential and commercial buildings, accounts for about one-quarter of Korea's final energy demand. More than 85 percent of Koreans now live in cities, which are relatively modern, and occupy modest apartment-style housing much like in Japan. Korean housing is in marked contrast with the energy-intensive, single-family homes of North America. Direct use of coal for heating and cooking, which causes severe air pollution in China and elsewhere, has been largely replaced in Korea by relatively clean natural gas and electricity.

Fuel use in the transportation sector has grown most dramatically in Korea, particularly for gasoline to fuel private automobiles.[10] Koreans own one car for every four persons, and car ownership has increased in this decade by 15-20 percent per year. Car ownership rose from 2 million cars in 1990 to more than 6 million in 1996, and is expected to reach 11 million by 2000. Oil consumption increased more rapidly than any other type of energy use over the past two decades, growing more than 13 percent annually between 1985 and 1995.

Table 1

Final Energy Consumption by End-Use Sector, Percent of Total

	1981	1997
Industrial, Total	45	52
Primary Metallurgical	13	11
Non-Metals	6	5
Petro-Chemicals	12	21
Other	14	15
Buildings	40	23
Transportation	10	23
Public Sector & Others	5	2

Source: KEEI, *Yearbook of Energy Statistics*, 1998.

Liquefied natural gas, first introduced in 1987, has grown to almost 9 percent of primary energy supply, with power generation the largest single use for this premium fuel. Nuclear energy increased its share of primary energy supply from 2 percent in 1980 to 11 percent in 1997. Nuclear power stations now generate just over one-third of Korea's electric power.

B. Energy Sources and Technologies for Power Generation

Korea's power generation depends primarily on imported fuels. Foreign crude oil and petroleum products accounted for about 82 percent of total energy imports in 1997. Anthracite coal is the most abundant domestic energy resource, but ten times as much bituminous coal is imported from China and Australia for power generation and industrial uses.[11] Both domestic anthracite and imported bituminous coal are expensive, ranging from $35-50 per ton, but still competitive compared to other fuels. The Asian financial crisis helped depress coal prices, and lower costs are likely to persist in the near future, even while Korean demand rises to its previous levels.[12] Korea is concerned about expanding coal-fired power generation due to the high levels of carbon dioxide and other emissions, but coal may have a direct cost advantage too strong for policy-makers to resist.

Korea manufactures high-quality, supercritical boiler-turbines[13] that generate power using coal. Most of these plants are relatively efficient and reliable—even if they lose 60 percent of the available energy in the process of converting coal to electricity. Such plants can be fitted with flue gas desulfurization (FGD) equipment, which removes up to 90 percent of the harmful sulfur dioxide emissions, but also results in slightly lower plant efficiency.

Alternative coal-fired plants, including pressurized fluidized bed combustion and integrated gasification combined-cycle (IGCC) facilities, have been under development for several decades. The technology is improving slowly, but plants are still very complex and saddled with high costs. Korea is unlikely to use these advanced coal technologies in a commercial setting before 2015.

Korea has limited hydropower resources. Most have been developed into standard and pumped-storage sites already. (Pumped-storage plants, though expensive, are used for stabilizing the grid and meeting sharp peaks in power demand.) The small share (less than one-twelfth) of electricity generated from hydropower will decline after the remaining planned plants are constructed.

Korea has no domestic natural gas supplies, and no long-distance pipelines have been constructed to deliver natural gas to Korean markets. The potential for pipeline gas imports is great, however. Large quantities of gas are being developed off Sakhalin Island in Russia to the northeast and near Irkutsk to the northwest. Korea currently relies on LNG for power generation, residential use, and industrial applications. It is shipped from Indonesia, Malaysia, and, increasingly, other new producers.

While LNG prices have been relatively high to date and require long-term, take-or-pay contracts, this situation is changing. The cost of building new LNG supply plants has dropped by up to 40 percent in the 1990s, and new facilities have recently or will soon come on line in Australia, Nigeria, Oman, Qatar, and Trinidad and Tabago.[14] Competition among these facilities is expected to keep international prices down. Due to the financial crisis, demand for LNG has fallen. It remains to be seen if international LNG prices will continue to decline, but it appears that new opportunities are developing for spot markets and short-term contracts in some countries.[15]

Compared to coal-based technologies, natural gas turbines have lower capital costs, fewer pollutants, and shorter construction lead times, as well as greater efficiency and modularity. Higher efficiency and lower capital costs often offset the price advantage coal has over gas. Combustion turbines operating in a single cycle have efficiencies up to 42 percent. However, combined-cycle gas turbines (CCGT), which first burn natural gas in a turbine and then use the waste heat to run a steam turbine, have efficiencies approaching 60 percent. CCGTs have become the cheapest, cleanest technology for power production in many countries this decade. Current mid-size and large CCGTs have installed capital costs ranging from $400-$700 per kilowatt. Operation and maintenance (O&M) costs are generally lower than those related to coal-fired units. One of the benefits of combined-cycle systems is that economies of scale are not strongly dependent on large systems; even small units have relatively low capital costs. Eight facilities in Korea currently use the CCGT system.

Petroleum accounts for a little more than 20 percent of the share of power generation. Sixteen heavy oil-fired plants (accounting for 4.6 gigawatts of capacity) are planned by 2015, reflecting greater demand for heavy oil. However, heavy oil power plants produce damaging emissions of sulfur dioxide and rely on less efficient steam turbine technologies.

An attractive alternative to burning heavy oil is combusting light distillates, condensates, and No. 2 fuel oil in combined-cycle gas turbines. These fuels are more expensive than their predecessors but can be burned in combined-cycle units at much higher efficiencies. Additionally, operators can switch from one fuel to another easily depending on market prices.

Korea has consistently promoted nuclear power as a reliable source of domestic electricity and operates some of the world's most modern and productive plants. Nuclear power plants avoid many of the environmental problems associated with coal combustion and reduce reliance on sometimes-expensive imported fuels. High-level waste disposal and the risk of accidents, however, present environmental challenges of a different magnitude.

Korea has 12 nuclear power units with a total capacity of 10,317 megawatts (MW). Officially, 18 new plants (18,600 megawatts) are planned to be constructed by 2015. Six other plants with a combined capacity of 5,400 megawatts are under construction. Currently most plants use pressurized, light water reactors (PWR), except for two Canada Deuterium Uranium (CANDU) plants, which use heavy water reactors. The standard Korean reactor is a 1,000 megawatt PWR, though a 1,300 megawatt model is planned for 2001. Korea intends to standardize the reactor type to accumulate experience, cope with accidents, secure long-term fuel supply, and reduce construction costs.

II. Current Dynamics

A. From Dynasty to Competition

The electric power business in Korea dates to 1898, the end of the Chosun Dynasty, when the Seoul Electric Company was formed. Power development has faced many obstacles over the last century, notably a difficult transition following the end of Japanese rule in 1945, abrupt severance of power supply from North Korea in 1949, and the Korean War in the early 1950s.

The industry has evolved over the past 40 years through consolidation, nationalization, and now the beginning of privatization. In 1961, Seoul Electric and two other power companies, Korea Electric and South Korea Electric, merged to form the Korea Electric Company, Ltd. (KECO). KECO grappled with power demand growth that outpaced economic growth, and was converted to a public corporation in 1961. Thereafter, the company expanded power supply rapidly and evolved into the Korea Electric Power Corporation (KEPCO), a state-owned monopoly. Korean policy now is to create a competitive private power sector. In the first step toward implementing that policy, the government sold 21 percent of KEPCO's shares to the public in 1989. The government aims to break KEPCO up into competing generating companies by 2002, start instituting competition among generators (but not retail distributors) in 2003, and begin implementing retail competition by 2009.[16]

While the Korean government plans to remain a majority owner of KEPCO, its current monopoly would be limited to power transmission. Generation companies would be private and open to foreign participation and even ownership. Two large coal-fired complexes and several combined-cycle cogeneration plants are scheduled to be privatized soon. Independent power producers would be guaranteed grid access. The large nuclear industry most likely will not be privatized, but operate as a separate, state-owned generating company.

Electric power prices, currently based on costs plus a "fair" rate-of-return, are regulated by a host of players. To change power rates, KEPCO must apply to the Ministry of Commerce, Industry, and

Energy (MOCIE), which consults with the Ministry of Finance and Economy (MOFE). These ministries then ask the Price Stabilization Committee to consider KEPCO's application. The Price Stabilization Committee is an advisory body, consisting of cabinet-level and expert groups. Ultimately, the President of Korea approves any price increases. To facilitate reform, a regulatory body will be created to ensure competition and coordination of supply, transmission, and distribution through the 10-year transition period. Nuclear power will probably require a two-step price mechanism in which markets set the prices and nuclear suppliers either meet them, are provided credits to compensate for "stranded" costs (investments in non-competitive power plants that cannot be recovered as planned), or receive a subsidy to meet national security or environmental needs.[17]

B. Rapid Development

Korea has achieved remarkable growth in its power supply system. In 1961, the nation had only 367 megawatts of installed capacity, equal to just one mid-sized plant by today's standards and barely enough power to supply 150,000 American homes. By 1968, Korean power capacity had reached only 1,000 megawatts, the size of a typical large plant. Today, Korea has nearly 44,000 megawatts of capacity. India, in comparison, has twice as much capacity as Korea, but 20 times as many people.[18]

Korean power consumption—the kilowatt-hours (kWh) generated by available capacity and sold to consumers—has also risen rapidly, growing annually at the staggering rate of 12.1 percent. (See Table 2.) Simply stated, Korean electric power use has tripled over the past decade. While industrial and household electric consumption has expanded at about 11 percent per year, commercial sector demand has exploded at 17.5 percent annually.[19] Korean experts believe that per capita electricity consumption will reach Japanese or Western European levels within two decades.[20] They note that per capita consumption still remains considerably below that of the richest countries.

The industrial sector, the major electricity consumer, accounted for 58 percent of electricity use in 1997, although the ratio fell from 66 percent in 1987. Commercial sectors have had the fastest growth rate in electricity consumption over the past decade, but absolute demand is far smaller than in the industrial sectors. In particular, the increase of power consumption in the service industry has been remarkable during the last decade. As a result of rapid growth, the share of commercial power consumption rose from 16 percent in 1987 to 26 percent in 1997.

Table 2

Power Consumption by Sector

	1987		1997		1987-97 Annual Growth Rate
	TWh	Share (%)	TWh	Share (%)	
Residential	11.5	17.9	32.5	16.2	10.9
Commercial	10.3	16.1	51.8	25.8	17.5
Public	2.3	3.6	6.8	3.4	11.4
Service	8.0	12.5	45.0	22.4	18.7
Industrial	42.4	66.0	116.4	58.0	10.6
Agriculture	0.8	1.3	4.2	2.1	18.0
Mining	1.0	1.5	1.0	0.5	0.0
Manufacturing	40.6	63.2	111.2	55.4	10.6
Total	64.2	100.0	200.8	100.0	12.1

Source: KEEI, *Yearbook of Energy Statistics*, 1998.

Demand for electricity in Korea has risen along with the level of economic output and living standards. Total electricity consumption increased from 64 terawatt-hours (TWh) in 1987 to 201 terawatt-hours in 1997. During this period, per capita use climbed from 1,545 kilowatt-hours per year to 4,365 kilowatt-hours. Remarkably, the GDP elasticity of electricity demand, defined as the ratio of the growth rate of electricity consumption to the GDP growth rate, rose from 1.2 in 1987 to 2.0 in 1997, with an annual average of 1.5. This means that electricity demand has grown 50 percent faster than the economy. Even in the United States, the elasticity of electricity demand is 1.0 or less. In China, it is 0.7-0.8.[21]

Peak demand growth in the recent past has outstripped supply capacity, an imbalance that has sometimes produced low and unstable reserve margins.[22] Total installed capacity increased from 19 gigawatts in 1987 to almost 44 gigawatts in 1998—an average annual growth rate of less than 8 percent, far below the 12 percent demand growth rate during the same period. (See Table 3.) While the capacity reserve margin was an excessive 72 percent in 1987, it fell to 15 percent in 1997, with tremendous variations during the decade. Capacity additions were intentionally slowed during the mid-1980s to reduce the high reserve margin. It appears that in the late 1980s, power planners misjudged demand growth and thus helped create a power supply shortfall. An unusually hot summer in 1994 raised demand unexpectedly and cut reserves to an uncomfortably low level of about 8 percent. KEPCO's difficulties in securing construction funds and plant sites also impeded long-term power development plans. While power demand fell sharply during the 1997-98 financial crisis, generation facilities continued to be installed as previously planned.[23] Consequently, the reserve margin increased to 32 percent in 1998.

Korea's economy appears to be recovering from the "IMF" crisis. As a result, power demand is expected to accelerate. Consequently, the Korean government is continuing with its plan to double today's level of power generating capacity by 2015.

Table 3

Power Capacity and Generation in Korea, 1987-1998

Year	Installed Capacity (GW)	Growth Rate (%)	Reserve Margin (%)	Power Generation (TWh)	Growth Rate (%)
1987	19.0	—	72.3	74.0	
1988	19.9	4.7	46.0	85.5	15.5
1989	21.0	5.5	39.4	94.5	10.5
1990	21.0	—	21.8	107.7	14.0
1991	21.1	0.5	10.4	118.6	10.1
1992	24.1	14.2	18.0	131.0	10.5
1993	27.7	14.9	25.1	144.4	10.2
1994	28.7	3.6	7.7	165.0	14.3
1995	32.2	12.2	7.7	184.7	11.9
1996	35.7	10.9	10.6	205.5	11.3
1997	41.0	14.8	14.5	224.4	9.2
1998	43.4	5.8	32.0	215.3	-4.1

Sources: KEEI, *Yearbook of Energy Statistics*, 1998; KEPCO, *Managerial Statistics*, 1999.

C. Government Ownership and Barriers to Entry

The Korean power industry depends much more on centralized planning than on the market. KEPCO, the government-owned, vertically integrated electric utility, owns and operates more than 90 percent of the installed capacity. The government controls KEPCO's power plant construction, finance, fuel mix, demand-side management, and other major managerial aspects. KEPCO is also required to implement various policies indirectly related to the power business, including subsidizing small and medium-sized business, and buying and burning domestic coal. Government intervention in KEPCO has resulted in a lack of managerial discretion and efficiency. In addition, KEPCO's monopoly position does not assure adequate customer service.

The Korean power industry subsidizes several primary energy sources, as well as local district heating. KEPCO is also required to help balance demand for LNG, which is delivered from foreign suppliers in steady volumes, but is used in Korea in large seasonal fluctuations. The company's role as a swing-consumer interferes with economical "dispatch," that is, choosing the cheapest available power source. KEPCO also has to build power plants suited for expensive domestic coal. Further, the Electricity Enterprise Act, enacted in 1990, requires KEPCO to buy wholesale power from hydropower plants operated by the Korea Water Resources Development Corporation. KEPCO also indirectly subsidizes nuclear energy development with large research and development expenditures. All these mandatory cross-subsidies severely restrict KEPCO's operational flexibility.

D. Supply Technology Policy

Korea reacted to the 1974 oil crisis by diversifying its energy supply. The country embarked on a program to develop nuclear power, imported coal, and LNG, and many oil-fired plants have since been replaced with one of these power systems. Although domestic hydroelectric and coal resources do exist, both are limited. Hydropower has been exploited nearly to its full potential, and as mentioned previously, low-quality domestic coal is very expensive.

Korea has added over 26,000 megawatts of new electric generating capacity over the last 11 years. About 45 percent was from LNG-fired combined-cycle, 30 percent from coal-fired and 25 percent from nuclear facilities. Most of the remainder came from new hydroelectric capacity. (See Table 4.)

Table 4

Power Capacity Added in Korea (MW), 1988-1998

	Nuclear	Coal	Combined-Cycle	Gas Turbine	Hydro	Total
Total	6,300	7,751	11,480	147	918	26,596

Note: Does not include new oil-fired capacity.

Source: KEPCO at http://www.kepco.co.kr

Combined-cycle gas turbine plants burning LNG can be installed quickly in small increments. These characteristics reduce the burden of long-range planning, compared to the decade or more required to plan and build coal and nuclear-powered plants. Recently, combined-cycle plants have been commonly used for baseload power generation.[24]

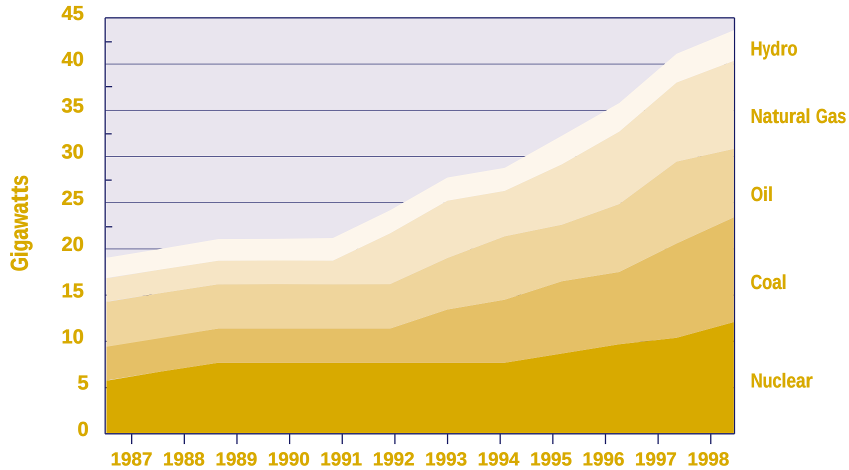
Despite the shift in capacity toward LNG, Korea relied much more on nuclear and coal-fired facilities between 1987 and 1998 for actual power generation. (See Figures 3 and 4.) The latter are typically baseload plants, operated continuously at or near full capacity, while LNG-fired units are operated intermittently to meet fluctuating peak demand. In 1997, nuclear provided the largest share of power at 34 percent of all kilowatt-hours generated, followed by coal (30 percent) and oil (20 percent). LNG provided only about 14 percent and hydro 2.4 percent.[25]

Korea inaugurated its first nuclear power plant in 1978, and nuclear power generation has grown at a rate of 20 percent per year. In the late 1980s nuclear power accounted for more than half of total power generation.

Oil-fired thermal power generation has plummeted from 84 percent in 1974 to 19 percent in 1997, while coal-fired generation jumped from 4 percent in 1974 to 30 percent in 1997. LNG, primarily a means of meeting peak demand, provides additional fuel diversity. The government's effort to expand nuclear and LNG generation capacity has—as was intended—eased environmental problems from fossil fuel use. KEPCO has also achieved overall thermal efficiency improvement and reduction of transmission and distribution losses.

Figure 3

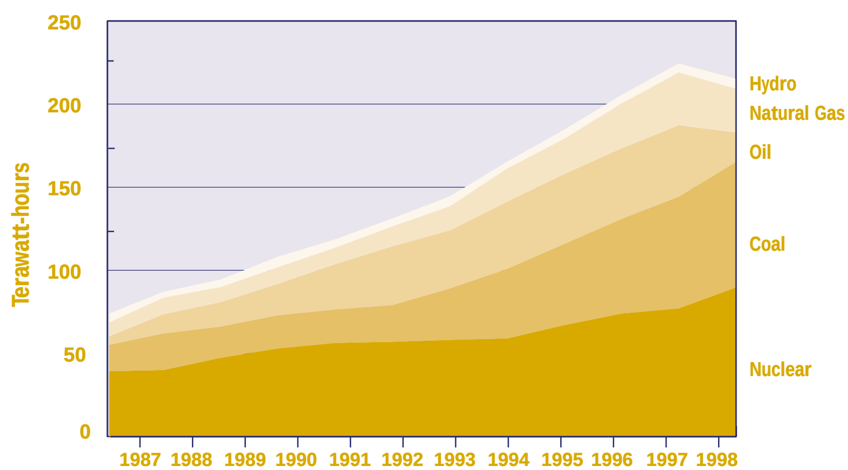
Generation Capacity by Fuel Type



Sources: KEEI, *Yearbook of Energy Statistics, 1998;* KEPCO at http://www.kepco.co.kr/en/static.html.

Figure 4

Power Generation by Fuel Type



Sources: KEEI, *Yearbook of Energy Statistics, 1998;* KEPCO at http://www.kepco.co.kr

E. Pricing

The primary objective of Korea's electricity policy is to secure a reliable supply at an affordable cost. Electricity prices have declined dramatically in real terms over the last two decades. While overall consumer prices rose at an average annual rate of 4.2 percent, the price of power rose at an annual rate of only 1.5 percent. The central government regulates prices on the basis of generation costs plus a fair rate of return on investment (currently set at 8 percent). Rates vary as a function of consumption level, time of day, and supply voltages. Rates also reflect concerns about demand-side management, industrial competitiveness, and consumer equity.

Price controls have led to inadequate funding for long-term electricity development, since current average electricity prices are below the long-run marginal cost of generation. Deregulation is intended, in part, to rectify this situation. As in the United States, large industrial users pay less for power than residential and commercial users. (See Table 5.)

F. Environmental Policy

Table 5

Relative Electricity Prices by User
(% of weighted average price), 1980-97

Year	Average	Large Industry	Small Industry/ Commercial	Agriculture	Residential	Street Lighting
1980	100	83	155	44	117	126
1990	100	85	125	64	130	91
1997	100	78	133	60	141	86

Source: KEEI, *Yearbook of Energy Statistics*, 1998.

Korea's rapid economic growth, coupled with industrialization, urbanization, and population growth, has brought increasing concern about environmental problems in the last 20 years. Although Korea has made some progress towards balancing its environmental and economic objectives, there is substantial room for improvement.

The government is paying particular attention to sulfur dioxide, particulate emissions, and water pollution in major rivers and lakes. Limiting greenhouse gas emissions is an especially difficult task for countries like Korea that use relatively new industrial technologies, rely heavily on nuclear power, and deserve economic growth opportunities without the onus of controlling carbon emissions. Many new policies currently underway address the problem indirectly by attempting to reduce energy intensity.[26] Included in these policy measures are energy conservation targets and energy efficiency labeling for major appliances.

Power generation accounts for a considerable fraction of Korea's total sulfur dioxide, particulate, and carbon dioxide emissions. (See Table 6.) These emissions have increased since 1990. In response, the government requires new or renovated thermal power plants to be equipped with high-efficiency electrostatic precipitators to control particulate emissions. Most thermal power plants also must be equipped with flue gas desulfurization (FGD) facilities by 1999-2000. After 1999, SO_x emissions from power plants are expected to decrease by as much as 30 percent from the 1996 level if FGD facilities come online as scheduled. Carbon dioxide emissions increased at over 9 percent annually between 1991-1996.

Table 6

Air Emissions by Sectors (thousands of tons per year)

		SO_2	NO_x	TSP	CO	HC	CO_2
1996	Heating	119	70	10	79	3	21,300
	Industry	689	381	161	19	3	38,800
	Transport	323	616	95	975	146	24,200
	Electricity	369	191	157	16	2	27,000
	Total	1,500	1,258	423	1,089	154	111,300

Note: TSP means total suspended particulates, CO means carbon monoxide, HC means hydrocarbons.

Source: KEEI, *Yearbook of Energy Statistics*, 1998.

Nuclear power plant operations have displaced power plants with much dirtier emission profiles. Each year a typical nuclear reactor produces 3.6 and 5.7 thousand tons fewer sulfur dioxide and nitrogen oxide (NO_x) emissions compared to a coal-fired plant, while carbon dioxide emissions decline by 4.8 million tons.[27] Solid waste from coal ash is likewise reduced by almost one-half million tons each year. Offsetting this benefit, to some degree, are nuclear wastes accumulating on power plant sites due to the absence of permanent disposal facilities. A combination of the waste problem and the limited number of publicly acceptable new plant sites could limit the expansion of nuclear power generation. Also, the issue of nuclear plant decommissioning has not been considered in official cost analyses.

Although Korea tightened some emissions limits in 1999 (especially SO_x), limits for other pollutants are lenient compared to those of developed countries. (See Table 7.) As a result, Korea plans to reduce sulfur dioxide and nitrogen oxide emissions from coal-fired power plants from 1995 levels of 330,000 tons and 185,000 tons, respectively, to 120,000 and 156,000 tons by 2005. Particulate emissions, meanwhile, would be limited to 15,000 tons by 2000.[28] Wastewater would be treated to meet the national water quality standard, and coal ash recycling would increase from about 20 percent today to 50 percent by 2010. Most of these reductions will require the use of more advanced technologies and cleaner fuels.

Table 7

Air Emission Limits for Power Plants

Substance	Plant Type	Fuel Type	Korea 1995	Korea 1999	USA	Japan	Germany
SO_x (PPM)	Old Plant	Liquid Fuel	540-1,200	150-180	350	70-140	140
		Solid Fuel	500-1,200	150-270	—	180-1,060	—
	New Plant	Liquid Fuel	—	120	—	—	—
		Solid Fuel	—	120	—	—	—
NO_x (PPM)	Old Plant	Liquid Fuel	250-1,400	250-950	170-250	130	75-220
		Solid Fuel	350	350	230-300	200	100-320
		Gaseous Fuel	400-500	400-500	140	60	50-220
	New Plant	Liquid Fuel	250	250	170-280	60-90	75-150
		Solid Fuel	350	350	230-300	100-200	100-200
		Gaseous Fuel	400	400	140	30-60	50-100
Particulates (mg/Nm^3)	All Plants	Liquid Fuel	60	40	40	40-50	50
		Solid Fuel	100	50	35	50-100	—
		Gaseous Fuel	—	—	40	30-50	—

Note: PPM means parts per million. mg means one-millionth of a gram. Nm^3 means Newton meters cubed.
Source: KEPCO, *Yearbook of Energy Statistics*, 1998.

III. Comparing Alternatives

A. Methodology

To analyze the cost and environmental impacts of different power sector policies in Korea, the authors developed a simple linear programming (LP) model.[29] (See Box 1.) This model allows analysts to capture detailed characteristics of the technologies used in the power sector, an important consideration over the relatively short time scale considered. Macroeconomic general equilibrium modeling would have been a preferred analytical method if Korea's power sector were part of a more market-oriented economy.[30] Market-based models do not simulate heavily distorted markets well. However, any model simulating Korea's electricity sector is subject to uncertainty, because consumer prices are subsidized and specific fuel costs are affected by cross-subsidies.

The LP model developed first calculates levelized costs[31] for each type of power generation option based on capital, fuel, operation and maintenance, and, if applicable, environmental costs. The model then determines the optimal combination of new plants needed to meet given levels of power demand, which is entered exogenously (from outside sources). The model also allows constraints that mimic policy measures and sets reasonable limits over which values can be obtained.

All modeling has limitations. Optimization models like this one have finite ability to mirror the reality of consumer behavior. Furthermore, although they provide realistic technical and performance characteristics, they tend to overestimate the impact of the single cheapest alternative. Finally, optimization models can neither account for investor preference, such as risk mitigation or financial guarantees, nor ensure that energy security and diversity issues are addressed without input from the modeler. Still, the model can be a useful tool to weigh policy alternatives.

Box 1

A Guide to Linear Programming for Power Sector Analysis

Analysts use linear programming (LP) models to optimize combinations of inputs whose values are valid only over specific ranges. For example, power planners and electric utilities use LP models to determine the types of power plants required to meet least-cost power demand over time while meeting limitations in pollution emissions, energy sources, and manufacturing capacity. Models can help planners analyze alternatives, but non-quantitative factors must also be considered when designing real-life systems.

Researchers use two classes of models to analyze energy systems. LP models are often called "bottom-up" models because they contain detailed information about technology and costs. They have rich engineering detail and rely on user input to simulate broader economic conditions. "Top-down" models, on the other hand, begin from a higher level of economic reality by simulating the interaction of supply and demand in the main sectors of an economy. While top-down models have less detailed information about energy technologies and costs, they capture the reality of consumer behavior better than bottom-up models. Some models, like MARKAL-MACRO, try to integrate the economic reality of top-down models with the engineering detail of bottom-up models.

Researchers at Battelle created a generic LP model that each of the country teams in this series modified to analyze least-cost power options according to the conditions in their specific countries. The model can choose among 17 different types of power plants (coal, petroleum, natural gas, nuclear, hydroelectric, and renewable) to meet power demand. The model divides the country into as many as five regions to capture the variation in energy availability, fuel cost, and environmental limitations. Simulation begins with a base year (1995) and then determines the amount of new capacity from each type of power plant needed to meet demand over 5-year intervals.

After analysts enter technology and cost characteristics of the power plant options, the model calculates the levelized, or lifecycle, costs of power generation. Levelized cost analysis accounts for all the costs of building, fueling, operating, and controlling pollution from power systems and spreads them out over the economic life. In this way, the costs of delivering power to users from nuclear plants (with high construction and low fuel costs) can be compared directly with the costs of providing power from combined-cycle plants (low construction costs and high fuel costs). Analysts also need to enter the power demand over time and regions. These values are calculated separately according to estimates of economic growth and power demand intensity.

The actual linear program will then find the minimum cost combination of power plants needed to meet the demand. Additional constraints can include emission caps on pollutants such as sulfur dioxide, manufacturing limitations for power generation equipment such as nuclear reactors, energy supply limitations such as hydropower capacity, and transmission line characteristics that limit the amount of power that can be sent from one region to another. For a given time period, the LP will choose the cheapest power source available and continue to use that technology until a constraint prevents its use. LP models need expert input to define when constraints are needed to simulate reality.

Comparing alternative sources of power generation is done in three steps. First, the analysis develops a framework that includes a baseline projection of power demand and a model to integrate supply and demand to evaluate costs. Second, the model reviews power generation technologies for capital, fuel, operations, and associated environmental costs, and converts these to costs per kilowatt-hour. Third, the analysis tests alternative policies for their impact on average generation costs and especially for changes in greenhouse gas emissions relative to the present and to the baseline. The results indicate increased or reduced economic cost compared to the baseline, along with changes in power plant capacity, utilization, and emissions.

Five power generation technologies are included in the analysis: coal-fired power plants with scrubbers (FGD), oil-fired combined-cycle units, gas-fired combined-cycle units, nuclear power plants, and hydropower plants. (See Table 8.) The model also includes integrated gasification combined-cycle (IGCC) plants, none of which have been built in Korea.

Various renewable technologies such as wind, biomass, and geothermal technologies are included in the model as options, but they do not compete with the other technologies in the majority of scenarios analyzed. In the last scenario of this section, however, the analysis considers how far costs for renewable and other advanced energy technologies like fuel cells would have to decline before becoming competitive.

The modeling here is not an attempt to forecast power plant construction schedules or even the necessary power capacity. Rather, it serves as a tool to compare the impact of different policy options on technology choices and environmental quality.

Table 8

Costs and Technical Characteristics for Generation Technologies in 1998

Technology	Capital Costs ($ per kilowatt)	O&M Costs ($ per kilowatt-year)	Efficiency (%)	Construction time (years)
Coal-fired units with sulfur scrubbers	1,050	38	41	4.0
Integrated gasification combined-cycle	1,700	42	43	4.0
Gas-fired combined-cycle	550	20	54	3.0
Petrol-fired combined-cycle	570	23	53	3.0
Nuclear	1,715	44	34	8.0
Large hydropower	1,360	45	—	5.5
Wind	1,100	13	—	2.0

1) Exchange rate of 1,100 won per USD applied.

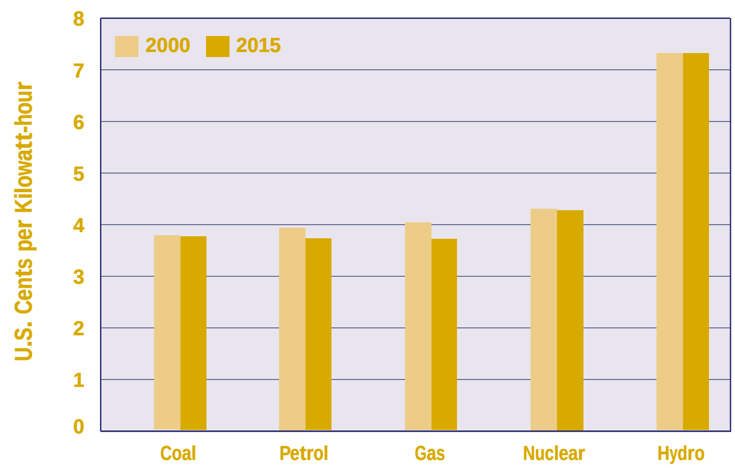
2) The model considers baseload and peaking gas-fired combined-cycle plants separately.

Source: See Appendix 2.

Before turning to the scenarios, a look at levelized costs is instructive. Korea's reliance on nuclear power is striking considering that it ranks as the most expensive energy alternative, except for hydropower. (See Figure 5.) A national security preference of about 15 percent in the cost of nuclear power would be required to make that source competitive in price. The nuclear option might still be hampered, however, by large scale and perceived investor risk. There is also the possibility that Korea could significantly reduce the cost of nuclear power by increasing domestic content, and the model tests the impact of using a lower capital cost assumption in a sensitivity case. Levelized cost analysis demonstrates that coal is slightly cheaper than either oil or gas plants. However, even a small environmental preference for cleaner fuels would place coal, the second largest fuel source for electric power in Korea, at a competitive disadvantage.

Figure 5

Levelized Power Generation Costs in Korea, 2000 and 2015



Source: Authors' calculations.

There is a caveat to these cost results. They are based on a discount rate of 9 percent—low, but reflective of the cost of money to Korea's electric power sector. A market-based approach would increase the cost of capital and create a disadvantage for systems with long lead times or high capital costs. Because fuel use is not financed with plant construction, systems with relatively high fuel costs would not suffer from such a disadvantage. Using a higher discount rate would thus make gas- and oil-fired systems more attractive, driving nuclear and hydroelectric costs out of reach.[32]

B. KEPCO's Baseline

The KEPCO baseline plan is an interesting starting point because it provides a detailed and insightful projection of Korea's electric power future. KEPCO's baseline does not incorporate the sharp setback of the recent financial crisis or the potential impact on demand of economic reform and restructuring measures. The Korean economy, however, has already shown strong signs of recovery, and power demand has risen sharply, suggesting that KEPCO's projection is fundamentally sound.

KEPCO's long-term plan (developed in August 1998) anticipates electricity demand growth of 4.1 percent annually from 1998 to 2015. This projection is driven by assumptions that the Korean economy will grow by 6, 5, and 4 percent in 2000-2005, 2005-2010, and 2010-2015, respectively.[33] Population would grow to almost 52 million people from the current 46 million. The price of electricity would remain stable, and manufacturing's share of economic activity would remain virtually unchanged. This baseline scenario departs from the past only in the assumption of stable electricity prices, which have declined steadily in real terms over the past two decades, and a modest slowing of GDP growth. The authors verified these projections by using their own linear regression analysis.[34]

The KEPCO projection assumes that electricity demand growth will stabilize gradually after 2004 and decrease to match current growth rates in major developed countries by 2009. Demand would grow to approximately 220 billion kilowatt-hours in 2000, 300 billion kilowatt-hours in 2005, and 390 billion kilowatt-hours in 2015.[35] (See Table 9.) Therefore, power demand in 2015 would be double that of 1998. Peak power demand would climb from 40 gigawatts in 2000, to 70 gigawatts in 2015.

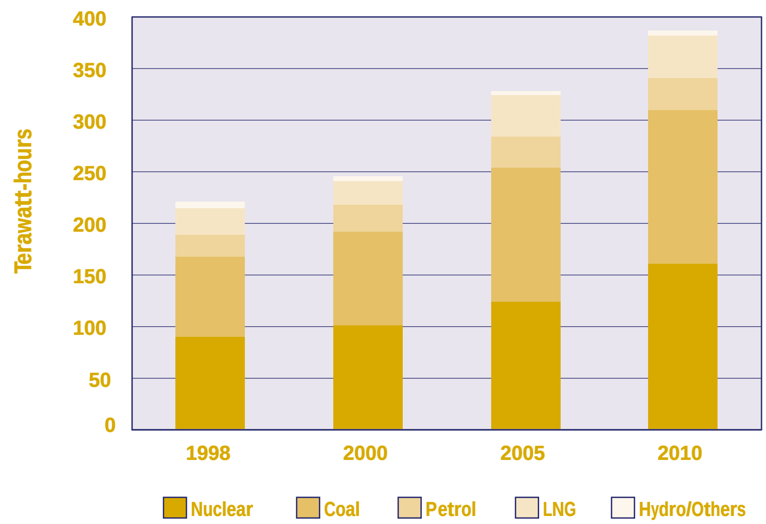
Table 9

Baseline Scenario: The KEPCO Electricity Demand and Supply Forecast

	1998	2000	2005	2010	2015
Total Net Demand (billion kWh)	197	221	295	350	390
Total Installed Capacity (MW)	43,773	50,000	63,500	74,500	81,000
Peak Demand (MW)	35,243	39,500	52,500	62,200	69,600
Reserve Margin (%)	21	22	18	17	16

Source: "The Fourth Long-Term Power Development Plan," KEPCO.

Figure 6
KEPCO's Forecast of **Electricity Generation** by Source



Source: "The Fourth Long-Term Power Development Plan," KEPCO.

Comparing KEPCO plans for adding capacity and for capacity utilization reveals an important peculiarity with significance for climate change. While coal-fired plants would account for 30 percent of new capacity by 2010, coal would account for 40 percent of planned power generation in that year.[36] (See Figure 6.) Coal's share in generation would thus increase by one-third, while overall power consumption is also increasing vigorously. When it comes to actual power generation, nuclear and coal would supply 80 percent of power demand in the year 2010, in roughly equal proportions. In other words, plant usage matters for climate policy as much as power plant construction.

The baseline scenario in this report uses the same demand forecast as KEPCO's and preserves as much of the basic structure as possible. There are at least two main differences, however. First, capital cost estimates for coal and nuclear power are higher to capture the full economic costs. Second, the model assumes that clean petroleum will slowly replace heavy oil in power generation. A more complete discussion of assumptions used in the modeling work follows.

C. Assumptions

The analysis performed here made several assumptions to simplify the modeling. Baseload and peaking plants are separated, and peaking plants are not included in the optimization process. However, their costs, fuel requirements, and environmental emissions are tracked. Capacity factors for nuclear and coal-fired plants, which averaged 89 and 71 percent, respectively, in 1995, will slowly fall as plants age. The authors use capacity factors of 85 and 70 percent in the levelized cost analysis. Heavy oil-fired steam turbines will be gradually retired and replaced with combined-cycle systems capable of burning distillates, condensates, or light fuel oil. No new heavy oil steam turbines will be added.

An average exchange rate of 1,100 won per U.S. dollar was used. The won-dollar exchange rate was relatively stable for most of the 1990s at 850-900 won per U.S. dollar. However, the financial crisis that began in December 1997 reduced the value to 1,800 won per dollar at the end of 1997. The rate has since improved and was stabilizing at the time of this writing. Choosing an appropriate exchange rate for the 20 years this study covers is important because it affects the relative cost of some technologies more than others. Coal plants, for example, are built almost entirely within Korea, so costs do not vary with the exchange rate. Some components of gas turbines and nuclear reactors, however, are imported. When exchange rates are high, as in 1998, components for these units become much more expensive. Likewise, the prices of coal, petroleum, and LNG imports vary directly with the exchange rate. In 1998, the devaluation of the Korean won made LNG-fired power generation very expensive.

The assessment also assumes that fossil fuel costs will continue to decline slowly from their 1995 values due to oversupply of petroleum, LNG, and coal, and also to domestic reforms, which will reduce the price power generators pay. (See Table 10.) Oversupply of fossil fuels is due to lower demand resulting from the financial crisis and increased output largely resulting from improved technologies. LNG costs in Korea have already declined significantly from the high levels in the mid-1990s. (See Natural Gas scenario for more details.)

Table 10

Fuel Prices Paid by Power Generators

	Unit	1995 (Actual)	2015 (Estimated)
Bituminous Coal	$/ton	38	36
Light, Clean Petrol	$/GJ	4.3	4.1
Liquefied Natural Gas	$/GJ	4.6	4.2
Nuclear Fuel	$/kWh	0.006	0.006

Note: All prices in real terms of 1998 dollars.

Sources: Fuel price estimates based on “International Energy Annual 1999” and researcher estimates.

This analysis also assumed some reforms in the baseline scenario that go beyond those assumed by KEPCO. Korea's economy will slowly rely less on energy-intensive heavy industries to power growth and increasingly depend on the service and light industrial sectors for growth. The authors also assume that energy security and diversification will be less problematic in the next 10-20 years due to advances in petroleum and gas exploration technologies, and gas conversion methods such as "gas-to-liquids" technology.[37] These technologies can help diversify supply markets, bring down costs, and secure energy needs. As a result, the modeling allows for slightly increased use of imported coal and LNG.

D. Scenario Analysis

This section reports the results from a series of policy experiments run using the modeling and analytical approach developed for this research. Each scenario presents a plausible policy framework that the Korean government could adopt to accomplish a major social objective. The baseline case represents the status quo, which itself incorporates a strong measure of liberalization of the power sector over the coming decade. Against that base case, the analysis tests a scenario of rapid reform and restructuring in the power sector, a move that would culminate quickly in a competitive supply market. That scenario would have private suppliers make the power supply choices that are now made by the Korean government and its state-owned monopoly. The authors also tested a scenario in which Korea's high energy intensity gradually falls to the level of Japan's by 2015. This case assumes that economic activity will shift from heavy to light industry and services, and that energy efficiency will play an even stronger role in Korea than it does now. The fourth scenario tests a case in which natural gas supplies increase and prices decline due to greater availability of imported pipeline gas. In the fifth scenario, environmental externalities are monetized and incorporated into the price of electricity supplies. The sixth scenario analyzes the ability of nuclear power to compete with other options based on a sensitivity test of capital costs. The final case analyses carbon dioxide control measures. The authors also estimated the cost reductions necessary for advanced power generation technologies such as fuel cells and wind energy to be competitive with fossil fuels.

1. Baseline Scenario

The baseline does not attempt to exactly recreate KEPCO's plan, but will serve as a point of reference for comparison with other scenarios. This scenario incorporates as many of the power sector's existing characteristics and fixed plans as possible. The research team assumes that the Korean government will enact several basic reforms as part of the baseline. The model has been carefully calibrated to actual conditions in 1995 (capacity mix, emissions, capacity factors, and fuel use) and captures all plants currently under construction.

The authors also account for energy diversity and security and environmental concerns by assuming maximum allowable shares by generation type. (See Table 11.) This constraint prevents the LP model from choosing the cheapest generation option for all new power needs and reflects policy decisions rather than market mechanisms. This approach more appropriately reflects the reality of the Korean power "market," which, like most nations' power sectors, is not a free market in the classic sense.

Table 11

Modeling Capacity Share by Plant Type (%)

	1995 (Actual)	2015 (Maximum Allowable Share)
Coal-fired Units with Wet FGD	24	40
Combined-cycle Gas Turbine (LNG)	20	35
Combined-cycle Gas Turbine (Petrol)	19	35
Nuclear Power	27	40
Large Hydropower	10	100

The authors' baseline least-cost power mix is different from the official KEPCO plan, primarily in the number of new nuclear and coal plants added. A decision was made not to replicate the KEPCO plan for these technologies because it uses less plausible cost assumptions. Coal has the lowest levelized cost in the year 2000, but both LNG and petrol-fired units become cheaper in the following years as their efficiencies improve and fuel prices decline due to planned reforms and the continued oversupply of petroleum in international markets. The least-cost mixture of power capacity in 2015 finds coal at 35 percent, LNG at 25 percent, nuclear at 19 percent, oil at 10 percent, and hydro at 6 percent.

(See Figure 7.) In terms of electricity output, coal and nuclear account for 41 and 27 percent, respectively, with LNG and oil supplying 17 and 11 percent. (See Figure 8.) The capacity of coal and LNG will triple compared to their 1995 levels. Consumption of LNG would triple, while coal use would grow even more. (See Table 12.)

Results from the baseline are presented in Table 12. The total, discounted, cumulative cost of generating power in the baseline case from plants built between 1995 and 2015 is $130 billion. This cost, which does not include environmental damage, is one standard against which the alternative scenarios are evaluated. Two other key indices for evaluating alternatives are emissions of carbon and sulfur dioxide. From 1995 to 2015, baseline carbon dioxide emissions more than double to 51 million tons.[38] Baseline emissions of sulfur dioxide decline somewhat from 1995 to 2015 due to a policy of installing scrubbers on new and existing plants, as well as expand-

Figure 7

Power Capacity in the Base Case

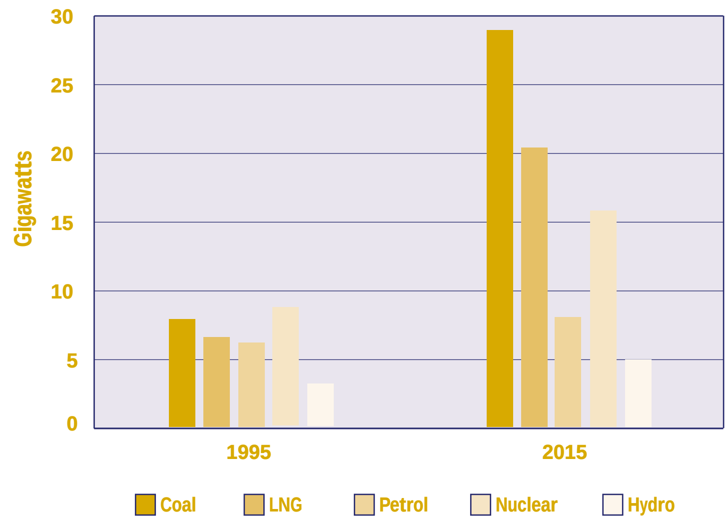


Figure 8

Power Generation in the Base Case

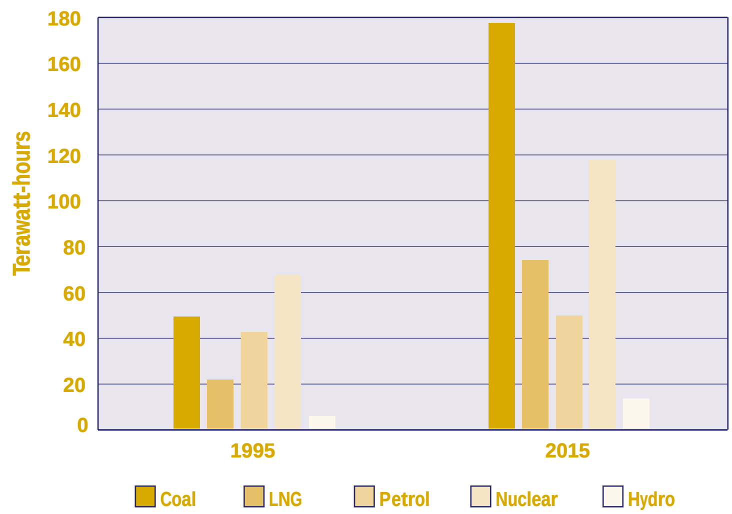


Table 12

Baseline Results

	Units	1995	2000	2005	2010	2015
Capacity and Cost						
Generation	TWh	185	247	329	388	430
Capacity	GW	32	50	61	71	78
Cumulative Discounted Cost	Billion $	—	10	38	79	130
Fuel Consumption						
Coal	Million tons	21	36	52	66	66
Petrol	Million tons	9	5	4	7	7
LNG	Million tons	4	5	5	5	12
Emissions						
SO_2	Thousand tons	357	303	323	323	259
CO_2 (carbon equivalent)	Million tons C	21	28	37	48	51

ing use of gas-fired power plants. (See Figures 10 and 11 for carbon dioxide and sulfur dioxide emissions in each scenario.) Construction of new coal-fired plants in the next ten years somewhat offsets those gains, however, and emissions of sulfur dioxide decline more rapidly to 259,000 tons in 2015.

2. Restructuring Scenario

Korea recently embarked on a policy of power sector reform and restructuring. By introducing competition into electricity generation, the Korean government could reduce power costs, shift the burden of financing to private companies, and possibly improve customer service and choice. To evaluate a reform scenario, the authors changed price and cost assumptions to reflect the impact of privatization on subsidies and tariffs, and on economic efficiency. In this scenario, it is assumed that gas and petroleum prices would decline by 5 percent because import fees and taxes would be reduced and brought more in line with surcharges on imported coal. (See Table 13.) Additionally, operation and maintenance costs would decline by 5 percent due to a greater incentive to lower generation costs. Power sales would rise by an additional 1 percent due to lower costs. Subsidies to some power-related businesses would decline.[39]

A qualitative difference removed from the modeling is private sector risk avoidance. Private power developers minimize risk by building plants with short construction times and adding power incrementally when needed. An increasing number of American analysts agree that the real reasons that no new nuclear power plants have been ordered for two decades in the United States and many other countries are the high costs, scale, lead-time, and risk of nuclear power, rather than public opposition.[40] Buyers might prefer the flexibility of the 50-400 megawatt scale of combined-cycle plants, their much shorter construction times, and the much lower risk of losing a large investment in a single accident.

Table 13

Energy Taxes and Surcharges on Fuel for Power Generators in 1997

	Fuel Cost	Import Duties and Taxes	Duties as a Percent of Final Price
Petroleum (Bunker) ($/barrel)	12	7	37
Bituminous Coal ($/ton)	36	1	3
LNG ($/ton)	167	77[a]	32

[a]about 35 percent of this adder goes for LNG terminal construction.

Note: Numbers rounded to the nearest whole digit.

Source: "National Communication of the Republic of Korea," 1998.

Results from this scenario suggest that reform will shift the mix of power plant capacity in Korea from coal to gas-fired plants. (See Figure 9.) Total costs, however, would increase by less than 0.5 percent due to the greater demand for low-cost power. Carbon dioxide emissions would decline by 9 percent, and sulfur dioxide emissions would drop more than 60,000 tons, or 24 percent, compared to the baseline case. (See Table 14.)

3. Efficiency Scenario

Korea's economy relies on energy-intensive heavy industry for growth. Government policy directs investment, often subsidized, to such industries, instead of allowing the market to determine where capital should flow. In this scenario, the study simulates the effect of Korea gradually abandoning preferential policies for heavy industry, and further promoting efficiency measures, such as cogeneration, district heating, demand-side management, energy standards, and markets for energy service companies (ESCOs).

The authors assume that Korea's income elasticity of electricity demand (the ratio of growth in power demand to economic growth) will gradually converge by 2015 to the level currently prevailing in Japan. The average elasticity from 1985 to 1997 was 1.42 in Korea and 1.21 in Japan.[41] For elasticity to fall to 1.21, demand for power relative to economic growth in 2015 would have to decline by 14 percent compared to the baseline scenario. Great uncertainty about the economic impact of this reform measure exists because no one knows how much subsidy is directed toward investment in heavy industry or the cost of saving energy through other efficiency measures noted above. The authors conservatively estimate the cost of lowering elasticity at $400/kW of avoided new capacity.[42] These costs are included in the scenario results.

Reducing energy intensity in Korea will require more aggressive promotion of cogeneration, industrial energy efficiency, energy-efficient residential cooling and lighting, and ESCOs far more aggressively. The task will not be easy since Korea already has a relatively modern and efficient industrial base.

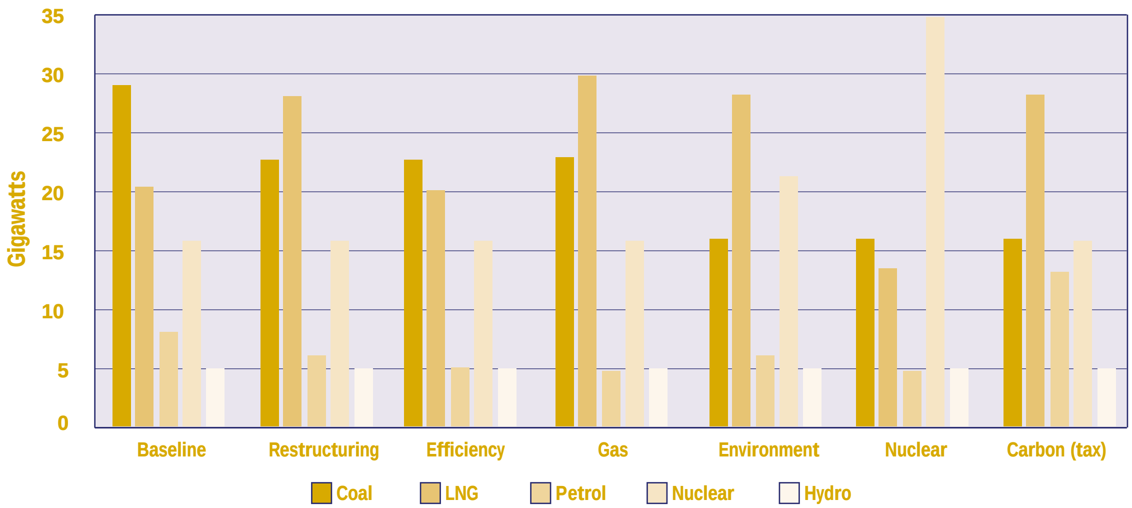
According to model results, Korea will spend about $8 billion less building and operating new power plants if it can lower demand relative to economic growth by 14 percent by 2015. Carbon and sulfur emissions would be reduced by 21 and 25 percent, respectively. (See Table 14.) Perhaps most importantly, Korea would significantly reduce its energy imports, thereby improving its energy security.

4. Natural Gas Policy Scenario

Korea imports most of its natural gas as LNG from Southeast Asia. Consequently, using gas is significantly more expensive in Korea than in countries that have domestic resources. In the natural gas policy scenario, the authors analyze the implication of cheaper imports and expanded supply due to reform of various domestic taxes and add-on fees for LNG. The team also analyzes the impact of constructing a natural gas pipeline from Russia to Korea by 2010. Many barriers might impede the construction of such a pipeline, especially the geopolitics of crossing Chinese or North Korean territory and the security issues such border crossings imply.

Figure 9

Scenario Results for Generation by Energy Source, 2015



LNG costs have declined steadily from over $4 per gigajoule in January 1997 to just over $2.50 per gigajoule in January 1999.[43] Many new LNG supply facilities are coming on stream, while demand has slowed due to the financial crisis and weak economic growth in Japan, which accounts for 60 percent of the world's LNG imports. Researchers in this study believe that downward pressure on LNG prices will probably continue through the first decades of the next century, especially if new gas-to-liquids technology continues to develop rapidly. This technology can make natural gas from remote fields an attractive form of energy since pipelines are not needed to deliver the fuel to markets and expensive liquefaction facilities also are unnecessary.

Results from the natural gas scenario indicate that gas-fired power generation would become the most cost-competitive option, as in the restructuring scenario. This scenario envisions gas meeting 36 percent of power capacity, while lowering costs slightly from the baseline. Installed capacity of gas-fired units would increase to 30 gigawatts by 2015. (See Figure 9.) Sulfur dioxide and carbon dioxide emissions would drop by 64,000 (25 percent) and 5.5 million tons (11 percent), respectively.

5. Environmental Scenario

This scenario incorporates costs for the estimated environmental damage done by sulfur dioxide, nitrogen oxide, and particulates. These emissions harm human health, agriculture, and infrastructure in Korea, as well as degrade the quality of life in other ways. Researchers use detailed field studies and laboratory analysis to estimate the environmental costs of power plant emissions. Quantifying the damage done by these pollutants is difficult and controversial. Many policy-makers choose to ignore environmental externality analysis, even in power sector planning exercises, but assigning a value of zero is clearly incorrect. The Korean Energy Economics Institute estimates these costs to be $211 per ton of sulfur dioxide, $570 per ton of nitrogen oxide, and $2,250 per ton of particulate matter emitted.[44] These estimates compare favorably to other studies for developing countries.[45]

Including these externalities for planning purposes has a significant impact on the power mix in 2015. (See Figure 9.) Coal falls to third place in cost behind gas and nuclear, giving nuclear a greater role in power generation than in any other scenario beside the nuclear one. Sulfur and carbon emissions decline from the baseline by 59 and 28 percent, respectively. Wind power, if available, would become competitive in this scenario by 2010 due to the higher costs of fossil-fuel power plants. However, total cost is about $2.3 billion more than the baseline scenario if the shadow costs are used. Countries can use environmental externality analysis to help plan least-cost power sector growth – the final cost of electricity, however, does not have to include the estimated externality costs. This analysis used shadow environmental externality costs. The cost of electricity presented here does not include the estimated damages.

6. Nuclear Power Scenario

Nuclear power can meet the demand for electricity without creating emissions of sulfur, nitrogen, particulates, or carbon. In this scenario, a sensitivity analysis was conducted to see if nuclear power can be economical as well. To simulate the expanded use of nuclear power, the number of coal, oil, and gas power plants that can be brought on line is constrained, forcing the model to choose nuclear plants.

Results indicate that expanded use of nuclear power can dramatically improve air quality, but power costs are about 4 percent higher. (See Table 14.) Sulfur dioxide, nitrogen oxide, and carbon dioxide emissions decline by 40 to 60 percent. The marginal cost of building and operating these plants would be $4.8 billion, or $205 per ton of mitigated carbon.

Nuclear capital costs may actually be higher or lower than the value used in this study. The team therefore tested a case in which capital costs decline to $1,400 per kilowatt, as suggested

Table 14

Total Cumulative Discounted **Costs and Emissions** in 2015

Scenario	Cost* (billions of dollars)	Capacity (gigawatts)	SO_2 (thousands of tons)	CO_2 (millions of tons of carbon)	NO_x (millions of tons)
Baseline	130.1	77.9	259	51.1	431
Restructuring	130.8	78.6	198	46.4	414
Efficiency	122.5	68.1	193	40.2	345
Gas	129.8	77.8	195	45.6	411
Environment	132.4	76.8	106	36.9	340
Nuclear	134.9	73.8	102	27.7	232
Carbon Control					
Tax	135.8	77.9	123	42.5	387
Cap	130.3	77.8	199	46.0	410

* These values are for plants built between 1995 and 2015 and include capital, operation and maintenance, and fuel.

by some Korean specialists, or increased to $1,993 per kilowatt, the average for OECD countries.[46] In the former case, nuclear power becomes the cheapest alternative for each time period except for 2010-2015. Total costs decline to $125 billion (4 percent below baseline). Carbon dioxide and sulfur dioxide emissions drop to 31 million tons and 102,000 tons, respectively. Total installed nuclear capacity in this case is 29 gigawatts in 2015. LNG-fired combined-cycle plants are still cheaper in 2015 and account for about 20 gigawatts total. Given the higher capital cost estimate, nuclear power would not compete with any of the other technologies, and the total cost would rise to $137 billion.

LNG-fired combined-cycle plants are still cheaper in 2015 and account for about 20 gigawatts total. This explains why carbon emissions are higher in this special case than in the primary nuclear scenario. Given the higher capital cost estimate, nuclear power would not compete with any of the other technologies and the total cost would rise to $137 billion.

7. Carbon Control Scenario

Two cases were used to estimate the effect of carbon control on the power sector. The first assumes that Korea decides to lower carbon emissions by 10 percent from the baseline in 2015. In the second, the size of a carbon tax to achieve a similar effect was estimated.

It was found that the least-cost way to reduce carbon emissions by 10 percent from the 2015 baseline would be to switch from coal and petroleum to gas-fired plants. The model also indicates that a

Table 15

Fuel Required in Alternative Scenarios in 2015 (millions of tons)

Scenario	Coal	Petrol	LNG
Baseline	66	7	12
Restructuring	52	6	20
Efficiency	52	4	12
Gas	52	4	21
Environment	36	6	20
Nuclear	37	4	5
Carbon Control			
Tax	36	12	20
Cap	52	6	19

$20 tax per ton of carbon emissions on all new generation would be enough to change the least-cost power mixture significantly. Different results would have been achieved if the tax were applied to existing plants as well. The tax is low because initial costs of switching between coal and oil- and gas-fired plants were not large. If Korea were interested in selling carbon permits internationally, fuel switching from coal to natural gas would be a simple and cost-effective way (although energy security might be another issue to consider).

The carbon tax—which makes the levelized cost of coal and petrol plants higher than gas plants—would result in much lower coal use and much more use of LNG and clean petrol. (See Table 15.) In the model, this is fundamentally different from the carbon cap—which is a physical constraint on the amount of carbon that can be released. The cap is less costly since no external tax is applied, but results in less mitigation of carbon and sulfur dioxide emissions. (See Table 14.) Neither case assumes that Korea will use carbon trading to lower emissions.

8. Advanced Technology Options

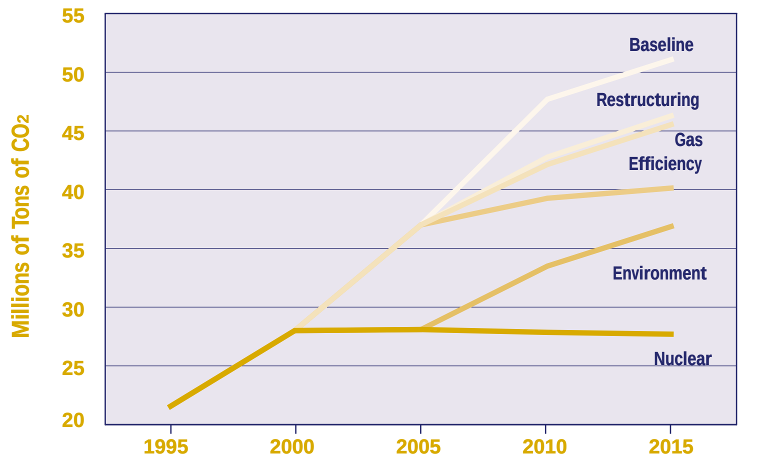
The team also provides a sensitivity analysis demonstrating how far costs will need to decline before other advanced and renewable energy technologies are able to compete with fossil fuel plants. Wind turbines currently cost about $1,100 per kilowatt installed. Capital costs would need to decline by another 30 percent to $775 per kilowatt before the levelized cost of wind could match that of combined-cycle turbines. Korea does not appear to have significant wind resources located in prime locations, but extensive resource assessments have not yet been completed. Wind costs will likely continue to decline due to advances in technology. This resource may be able to contribute to the country's energy needs and security by 2015 if quality wind sites are found.

The capital cost of integrated gasification combined-cycle systems (coal gasification coupled with gas turbine power generation) would likewise need to be reduced from their current level of an estimated $1,700 per kilowatt to $1,000 per kilowatt. This result is based on an assumption that sufficient coal is available at $30 per ton. For comparison, capital costs in the other model scenarios are assumed to decline to $1,400 per kilowatt, and power plant efficiency rises from the current value of 43 percent to 46 percent by 2015 without any significant action.

Fuel cells would need to be substantially less expensive to compete in the power sector. If the capital costs of fuel cells can be reduced to $800 per kilowatt (from approximately $3,000 per kilowatt now), and if their efficiency can reach 75 percent, fuel cells would be competitive. However, fuel cells are highly reliable—a factor that should be considered in any direct comparison.

Figure 10

Carbon Dioxide Emissions in the Various Scenarios

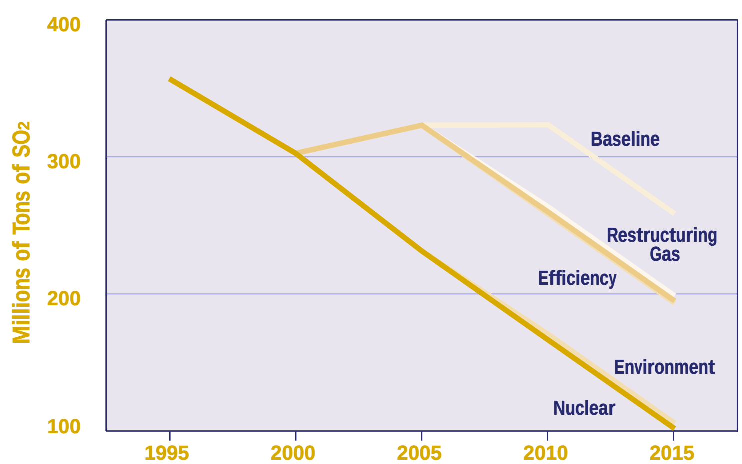


Note: Values for the Carbon Control scenario are not shown in this chart, but can be found in Table 14.

Nuclear | Environment | Efficiency | Gas | Restructuring | Baseline

Figure 11

Sulfur Dioxide Emissions in the Various Scenarios



Note: Values for the Carbon Control scenario are not shown in this chart, but can be found in Table 14.

IV. Conclusions and Recommendations

Electricity consumption in Korea is expected to continue to grow, and the power sector will remain a major source of sulfur dioxide, nitrogen oxide, and carbon dioxide emissions. Incorporating local and global environmental concerns as well as economic considerations into the development of the power sector, however, will become increasingly important.

Seven feasible scenarios were evaluated to determine the impacts of various policies on technology choices in the power sector. From these, the following recommendations can be made.

Coal-fired power generation costs are currently lower than the costs of other technologies when environmental damage is not included. If planners ignore the environmental impacts of electricity generation, least-cost analysis would call for more coal plant construction in the first decade of the new century. But if environmental costs are included, coal is not the least-cost source of electricity. Natural gas and, to a lesser extent, light petroleum-fired combined-cycle plants produce power for less total cost when full cost accounting methods are used.

Reform and restructuring of Korea's power sector can lead to a cleaner energy future. Taxes and duties on LNG reduce its competitiveness with coal and heavy oil plants. Now that the won exchange rate is stabilizing, imported LNG will be cheaper in local terms. New supply facilities will put downward pressure on LNG prices. Efforts to construct a pipeline to bring natural gas from Russia would yield substantial benefits, although securing the supply could be difficult.

Nuclear power would play an important role in reducing carbon and sulfur dioxide emissions, but these benefits come at a cost. The analysis reveals that nuclear power is not the cheapest option, and may not fare well in a competitive environment. Securing necessary sites and financial resources, gaining public acceptance, and improving technological safety are among the difficult obstacles to overcome in expanding the nuclear supply.

Some observers would argue that failure to reform will lead to excess productive capacity, leaving Korea vulnerable to repeated rounds of economic and financial instability. If the current structure survives, Korea's economic competitiveness and security may be threatened by dependence on foreign sources for almost all primary energy.[47] Korea produces little energy other than anthracite coal, which has high production costs and raises concern for particulate, sulfur dioxide, and carbon dioxide emissions.

Demand-side management and other energy efficiency measures may be the best tools to improve energy security. Korean energy demand is growing fastest for end-uses such as commercial lighting and air conditioning. Providing lighting and cooling with less energy per unit of service has proven cost-effective in the United States, China, and Europe. Korea appears not to have implemented cost-effective energy efficiency measures, which partially explains the exceptionally high rates of electricity demand growth in that country.

Korean researchers and policy-makers would be wise to focus on demand-side technologies, accelerated economic reform, and market transformation. Greenhouse gas emissions mitigation efforts will probably succeed or fail in direct proportion to the attention paid to these issues.

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Appendix B: Selected Economic and Performance Assumptions Used in the Modeling

Technology	2000	2005	2010	2015
Coal w/ FGD				
Capital Cost ($/kW)[1]	1,050	1,025	1,000	975
Capacity Factor (%)	70	70	70	70
Efficiency (%)[2]	41	42	42	42
Combined-Cycle (natural gas)				
Capital Cost ($/kW)[3]	550	540	530	520
Capacity Factor (%)	70	70	70	70
Efficiency (%)[4]	54	56	58	60
Combined-Cycle (light oil)				
Capital Cost ($/kW)[5]	570	560	550	540
Capacity Factor (%)	70	70	70	70
Efficiency (%)[6]	53	55	57	59
Nuclear				
Capital Cost ($/kW)[7]	1,715	1,700	1,690	1,680
Decommissioning ($/kWh)[8]	0.001	0.001	0.001	0.001
Capacity Factor (%)[9]	83	85	85	85
Hydro				
Capital Cost ($/kW)[10]	1,360	1,360	1,360	1,360
Capacity Factor (%)	30	30	30	30
Integrated Gasification Combined-Cycle				
Capital Cost ($/kW)	1,700	1,600	1,550	1,400
Efficiency (%)	43	44	45	46
Wind				
Capital Cost ($/kW)	1,100	975	900	850
Capacity Factor (%)	30	30	30	30

Notes:

1) Capital costs presented in this table include all costs except interest during construction. This value is for a 500 MW supercritical boiler with wet flue gas desulfurization. A less sophisticated subcritical boiler plant in the United States with 36 percent efficiency costs $1,079/kW according to the U.S. Department of Energy ("Annual Energy Outlook 1999").

2) Supercritical plants obtain higher efficiency than subcritical ones through high pressure, high temperature steam cycles.

3) Capital costs for combined-cycle turbines have fallen dramatically in the 1990s. Only a few manufacturers in Japan, Europe, and the United States are capable of producing large, high efficiency gas turbines due to the material and engineering challenges. Capital costs in the United States are $400/kW at 54 percent efficiency ("Annual Energy Outlook 1999"). Estimates for Korea given here are taken from *Projected Costs of Generating Electricity, Update 1998*, p. 54.

4) The most advanced combined-cycle system, the H frame, is approximately 60 percent efficient, and is now commercially available. U.S. Department of Energy, Federal Energy Technology Center, 1999; http://www.fetc.doe.gov/.

5) Capital costs for oil-fired combined-cycle systems are higher than gas-fired units because they can switch between a variety of fuels, including natural gas. See John Hart John and Ronald Weiner, "Condensate—Clean Fuel for Electric Power Generation," Enron International, 1998.

6) There is a small efficiency penalty for using oil in a combined-cycle because it does not combust as easily as gas.

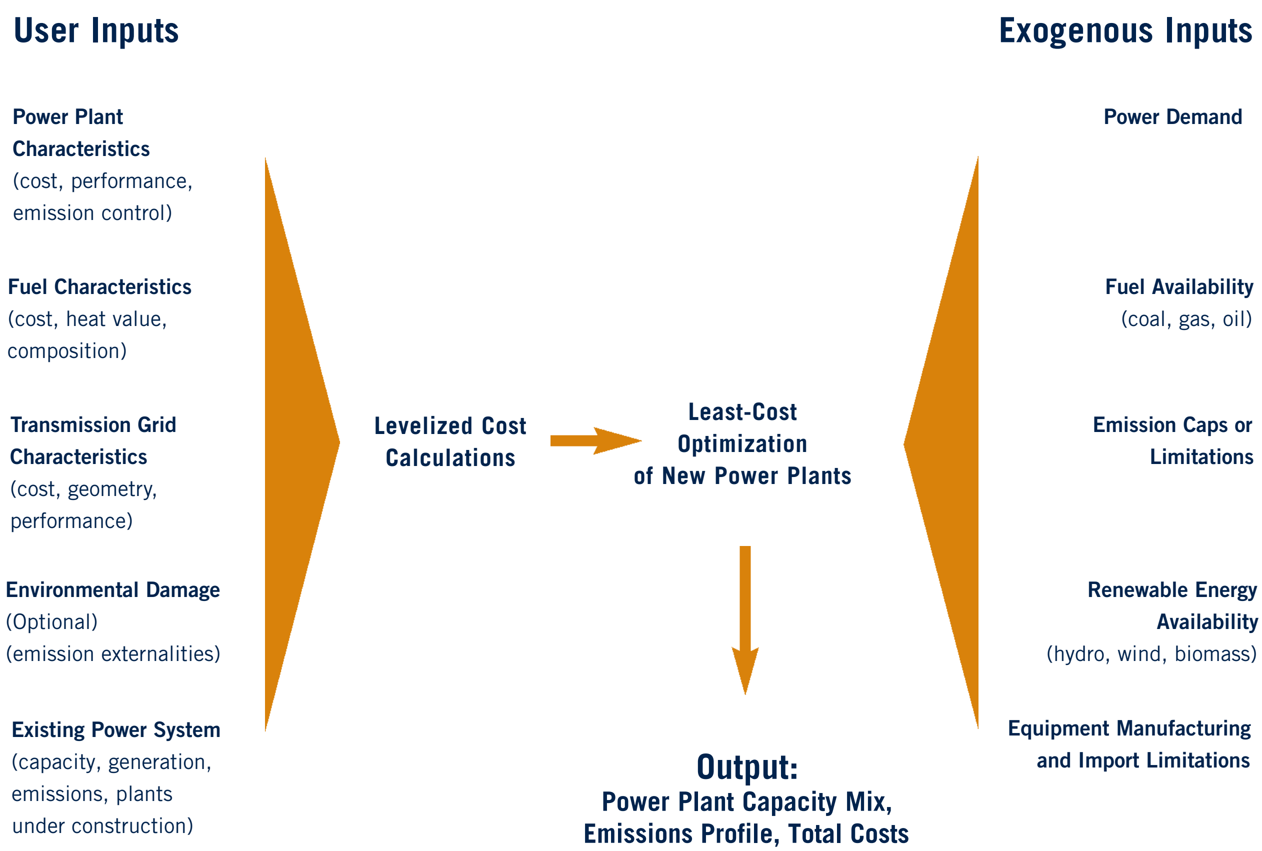
7) Estimating the base capital cost for nuclear plants is difficult. In most industrialized countries, they cost between $1,400 and $2,200 per kilowatt and take between five and nine years to build. In 1996, the French-built 1,400 MW unit reactor cost $1,764/kW. In China, the average overnight cost of nuclear power plants has been about $2,000/kW ("China's Electric Power Options"). U.S. DOE estimates that an advanced reactor will be available in 2005, with an initial cost of $2,356/kW, falling to $1,550/kW as the technology and engineering matures by 2010 ("Annual Energy Outlook 1999"). Park estimates a cost of $2,100/kW in Korea in 1996. KEPCO estimates that the nuclear plant planned for North Korea under a consortium of U.S.-led financiers will cost over $2,500/kW ("North Korea's Nuclear Reactor to Cost $5.5 Billion," Kyodo News Service, 4 November 1997.) The team chose a starting value of $1,715/kW based on values for Korea provided in *Projected Costs of Generating Electricity, Update 1998* (p. 54). Some data provided by KEPCO indicates that Korea can build plants for less cost – even as low as $1,300/kW – but this data may not include all costs associated with building and decommissioning a plant and is based on a weak won/dollar exchange rate. The authors performed a sensitivity analysis in the nuclear power scenario that explores the importance of their estimates.

8) The team uses a decommissioning cost for nuclear power plants in Korea of $320 million for a 1,000 MW unit. The value is based on typical French estimates (personal communication, International Atomic Energy Agency, October 1997). This discounted amount is generated by applying a sinking fund of $0.0011/kWh.

9) Korea has a very high average capacity factor for their fleet of power plants. Industrialized countries often use values between 0.75 and 0.80 in their planning analysis. The authors' value of 0.83-0.85 is based on averages for the 1990s.

10) Source: KEPCO

Appendix C: The Linear Programming Model



Endnotes

1. Jin-Gyu Oh led the Korean team; Jeffrey Logan was lead modeler and author; William Chandler directed the project.

2. In this report, Korea refers to the Republic of Korea, commonly known as South Korea.

3. Power demand fell precipitously during the Asian financial crisis of 1997-1998, but the economy has largely recovered at the time of this writing. Electricity consumption in the first half of 1999 rose 8 percent from the previous year's level. ("South Korea Power Monopoly to Post Brisk First Quarter Profits," Reuters, 24 July 1999.)

4. Korea's per capita GDP exceeded $10,000 in 1995, roughly equal to that of Portugal.

5. Technically speaking, the GDP elasticity of energy demand was 1.3 from 1980 to 1998. The comparable U.S. figure during 1950-70 was roughly 0.9.

6. See Jae Edmonds and John Reilly, *Global Energy: Assessing the Future* (New York: Oxford University Press, 1985); and Jonathan E. Sinton and Mark D. Levine, "Energy Efficiency in China: Accomplishments and Challenges," *Energy Policy*, Vol. 26, No. 11, 1998, pp. 813-829.

7. The primary sources of industrial energy are oil products, which supplied 57 percent, followed by bituminous coal and electricity which supplied 25 percent and 14 percent, respectively, in 1997.

8. *Chaebols* are industrial collectives, or conglomerates, that work in close cooperation with the government. The IMF pressured Seoul to adopt wide-ranging fiscal, financial, and corporate reforms aimed primarily at the *chaebols* in exchange for a record $58.4 billion in loans. ("Bank of Korea sees 5% GDP growth in 1999," *Reuters*, 14 June 1999.)

9. David E. Sanger and Mark Landler "Asian Rebound Derails Reform as Many Suffer," *The New York Times*, 12 July 1999, p. 1.

10. Gasoline consumption tripled between 1990 and 1997. (*Korean Energy Review Monthly*, February 1999.)

11. Production of anthracite coal in Korea has fallen steadily from a peak of 24.3 million tons in 1988 to less than 5 million tons in 1998. Imports of bituminous coal, on the other hand, have nearly tripled over the same period to 50 million tons. (*Korean Energy Review Monthly*, February, 1999.)

12. Note that Chinese coal production declined by more than 80 million tons in the first four months of 1999, an indication of oversupply and the downward pressure on prices. Officials expect output to drop by 250 million tons—about 20 percent—from 1998 to 1999. (*China Daily*, "Closure of Small Coal Mines Progressing," 13 May 1999.)

13. Supercritical units achieve higher efficiency than subcritical units by pressurizing the working fluid (steam) to over 220 atmospheres.

14. From a presentation by Gordon Sandison of Phillips Petroleum entitled "Economics of the LNG Project Chain," Houston, 21 July 1999.

15. See U.S. DOE's "Liquefied Natural Gas Fact Sheet" for more information on worldwide LNG markets.

16. For a description of current issues in Korea's power sector, see KEPCO's web site at http://www.kepco.co.kr/.

17. Hungary has gone furthest among the transition economies to privatize its power market, but has had to make special provisions for nuclear power. See Virginia Marsh, "Hungary Delays Power Sale," *Financial Times*, 1 October 1996, p. 4; and International Energy Agency, *Energy Policies of Hungary*: *1995 Survey* (Paris, Organization for Economic

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18. On a per capita basis, the United States has over three times as much capacity as Korea. In January 1998, installed capacity in the United States reached approximately 750,000 megawatts. “Annual Energy Outlook 1999”.

19. *Yearbook of Energy Statistics*, Korean Energy Economics Institute, 1998.

20. “National Communication of the Republic of Korea: 1998 Submission of the ROK Under the United Nations Framework Convention on Climate Change”.

21. See “China’s Electric Power Options,” 1998.

22. A reserve margin is defined as the available, but unused, capacity needed to meet fluctuations in moment-to-moment power demand, as well as back-up power facilities needed to replace capacity taken out of service for planned or unscheduled maintenance. An industry rule-of-thumb sets this desired margin at 20 percent above peak demand.

23. In 1998, power consumption fell by more than 4 percent compared to the 1997 level.

24. Traditionally, coal and nuclear plants were operated to meet baseload power demand, while gas turbines and combined-cycle plants were used for peak power demand. Falling gas prices and advances in turbine blades have made combined-cycle plants the preferred technology for new baseload applications in many countries.

25. Korea has some of the world’s highest capacity factors for nuclear and coal plants. Capacity factor is defined as the ratio of power produced by a generating unit over a given period of time to the maximum amount of power that could have been produced during the same period. In Korea, LNG plants have been dispatched for peaking power, so capacity factors are low.

26. See Chapter 5 of “National Communication of the Republic of Korea.”

27. Based on a 1,000 megawatt plant using flue gas desulfurization and 0.75 percent sulfur coal.

28. “The Fourth Long-Term Power Development Plan,” KEPCO.

29. For a review of linear programming, see *Linear and Nonlinear Programming* or *Introduction to Linear Optimization*.

30. Other models, such as the systems analysis model used in “Developing Countries and Global Climate Change: Electric Power Options for Growth,” can also be used for thoughtful scenario analysis.

31. Levelized cost analysis, also referred to as lifecycle costing, spreads costs out over the economic lifetime of a plant, allowing direct comparisons of cost per kilowatt-hour of delivered power.

32. Worldwide, capital costs for new nuclear power plants range from an estimated $1,500 per kW to over $2,200 per kW. The authors have applied a 1996 estimate for Korea of $1,715 per kW, adjusted to 1998 dollars. See Nuclear Energy Agency, International Energy Agency, *Projected Costs of Generating Electricity: Update 1998*, Paris, Organisation for Economic Cooperation and Development, 1998.

33. Private communication, Korean Electric Power Company to Jin-Gyu Oh, May 1999.

34. The authors performed multiple linear regression analysis using GDP per capita and electric power price as the independent variables and power demand per capita as the dependent variable. They found a very strong statistical relationship between GDP and electric power growth. Prices have had little impact because they have been declining relatively slowly. GDP growth explains perhaps 95 percent of electric power demand growth at a statistically significant level.

35. Note that these figures are net demand; additional generation would be required to overcome transmission and distribution losses and in-plant power use.

36. The shares of total installed capacity—old and new—in the year 2010 would be nuclear, coal, LNG, hydro,

and oil at 31, 29, 24, 9, and 7 percent, respectively.

37. For a description of how these technologies could alter energy security, see "Emerging Technology in the Energy Industry and its Impact on Supply, Security, Markets, and the Environment," James Baker Institute, Rice University, Houston, April 1999.

38. In 1995, Korea produced approximately 113 grams of carbon for each kilowatt-hour of electricity generated compared to 207 grams per kilowatt-hour in the U.S.

39. For a discussion of the relevance of reform to energy technology, see U.S. President's Council of Advisors on Science and Technology, *Powerful Partnerships: The Federal Role in International Cooperation on Energy Innovation*, Washington, D.C., Executive Office of the President, June 1999.

40. See Chapter 5 of "Report To The President On Federal Energy Research And Development For The Challenges Of The Twenty-First Century," President's Committee Of Advisors On Science And Technology Panel On Energy Research And Development, Office of Science and Technology Policy, Washington, D.C., 1997.

41. *Main Economic Indicators*, OECD, 1999.

42. It is equally likely that these costs could be negative if the government is allocating the investments irrationally to heavy industry. Likewise, saving energy through efficiency measures can be cheaper than installing new capacity. See, for example, the World Bank's 1994 report, "China: Issues and Options in Greenhouse Gas Control."

43. *Korean Energy Monthly Review*, KEEI, Seoul, February 1999.

44. Some states in the United States are required to use shadow environmental externality costs in their planning analysis. These values range from $0-$23,000 per ton of sulfur dioxide, $0-$31,500 per ton of nitrogen oxide, and $0-$4,554 per ton of suspended particulates. For a more complete discussion of how environmental externalities are calculated, see "Electricity Generation and Environmental Externalities: Case Studies," Energy Information Administration, Washington, D.C., U.S. Department of Energy, 1995.

45. In "Developing Countries and Global Climate Change: Electric Power Options for Growth," the corresponding values for sulfur dioxide, nitrogen oxide, and particulates ranged from $130-$240, $430-$2,200, and $170-$1,130 per ton, respectively. In "China's Electric Power Options: An Analysis of Economic and Environmental Costs," sulfur dioxide values used in the study ranged from $180 to $960 per ton.

46. See *Projected Costs of Generating Electricity: Update 1998*, p. 54.

47. This statement includes nuclear power because all nuclear fuel must be imported.

notes

notes