Energy Information Administration
Official Energy Statistics from the U.S. Government

Glossary

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Electric Power Annual

Electric Power Annual with data for 2007
Report Released: January 21, 2009
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Electric Power Industry 2007: Year in Review

(entire report also available in printer-friendly format)

Overview

In 2007, average retail electricity prices increased 2.6 percent from 8.9 to 9.1 cents per kilowatthour (kWh) This followed a 3-year period during which average fossil fuel prices for electricity generation increased a cumulative 30.2 percent. As fuel prices increased 30.2 percent, the National average retail price of electricity increased 17.0 percent from 7.6 cents per kWh in 2004 to 8.9 per kWh in 2006. Fossil fuel prices increased an additional 7.0 percent in 2007, contributing to the 2.6 percent average retail electricity rate.

Both the number of residential and commercial customers increased 1.2 percent over 2006 levels. Residential and commercial customer growth, along with a modest increase in average consumption per residential and commercial customer, resulted in a 3.0 percent increase in residential electricity sales and a 2.8 percent increase in commercial electricity sales in 2007. Residential and commercial sales accounted for 69.5 percent of total retail sales. When all sales to ultimate consumers are considered (e.g., residential, commercial, industrial, transportation, other and direct use), electricity sales increased by 2.8 percent in 2007. In 2006, total sales increased only 0.2 percent from the prior year.

In response to the 2.8 percent increase in sales to ultimate customers, electric power generation increased 2.3 percent, from 4,065 million megawatthours (MWh) in 2006 to 4,157 million MWh in 2007. The remaining energy requirements were met by imports from Canada and Mexico. Although electric power generation increased by 2.3 percent in 2007, net summer capacity increased by 8,673 megawatts (MW) or 0.9 percent. Since more than half of the new capacity was non-dispatchable wind capacity, the 2.3 percent increase in net generation was achieved primarily through the increased performance of existing coal-fired, natural gas-fired and nuclear capacity. All three of these types of capacity set net production levels, and increased average capacity factors, in 2007.

In 2007, for the first time, renewable energy sources, other than conventional hydroelectric capacity, accounted for the largest portion of capacity additions. Total net summer capacity increased 8,673 MW in 2007.

Wind capacity accounted for 5,186 MW of this new capacity. Natural gas-fired generation accounted for 4,582 MW. Two new coal-fired plants with summer capacity totaling 1,354 MW were placed in service in 2007. However, retirements and downward adjustments to existing capacity resulted in a 217 MW net reduction in coal-fired capacity.

Summer peak demand (noncoincident) fell from 789,475 MW in 2006 to 782,227 MW in 2007. Winter peak demand (noncoincident), which is always smaller than summer peak demand, decreased in 2007, falling a modest 0.5 percent from 640,981 MW in 2006 to 637,905 in 2007.

While the National average retail price for electricity for all customer classes increased by 2.6 percent to an average of 9.1 cents per kilowatthour, regional variations were significant. For example, the average retail price in the West South Central Census Division declined in 2007, whereas the average price increased in all other Census Divisions. The East North Central Census Division experienced the largest average price increase at 6.9 percent. This increase was primarily the result of the lifting of rate caps in Illinois that were put in place with retail restructuring in 1997. Average prices increased by 4.0 percent in the New England Census Division, 3.4 percent in the East South Central Census Division and 3.3 percent in the Middle Atlantic Census Division.

Unlike 2006, when carbon dioxide, sulfur dioxide and nitrogen oxides emission declined, carbon dioxide emissions from conventional electric generation and combined heat and power plants increased 2.3 percent in 2007. Sulfur dioxide and nitrogen oxides decreased 5.1 percent and 3.9 percent, respectively. Since 1997, sulfur dioxide and nitrogen oxides emission have been reduced by 32.9 percent and 43.8 percent, respectively.

Generation

Net generation of electric power increased 2.3 percent in 2007, to 4,157 million megawatthours (MWh) from 4,065 million MWh in 2006 (Figure ES1). According to the Bureau of Economic Analysis, the U.S. real gross domestic product increased 2.0 percent in 2007.[1] The Federal Reserve Board reported a 1.7 percent increase in total industrial production.[2] Thus, the increase in electricity demand corresponded with economic growth in 2007. Weather also appears to have been a contributing factor to electricity demand. According to the National Oceanic and Atmospheric Administration (NOAA), heating degree days in 2007 were 6.5 percent higher and cooling degree days were 2.2 percent higher than they were in 2006. Thus, the combination of moderate economic growth and weather-related electricity demand appears to have contributed to the 2.3 percent increase in net generation, as compared to the relatively flat 0.2 percent growth observed in 2006.

Figure ES 1. US Electric Power Industry Net Generation, 2007

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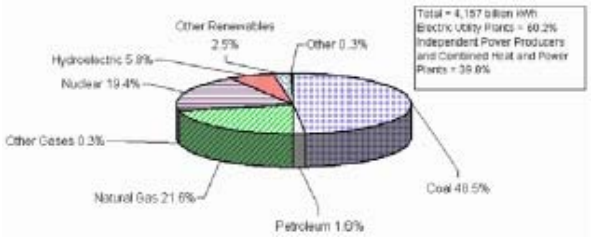

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report."

The three primary energy sources for generating electric power in the United States are coal, natural gas, and nuclear energy. These three sources consistently provided between 84.6 and 89.5 percent of total net generation during the period 1997 through 2007. Petroleum's relative share of total net generation was unchanged in 2007 from 2006 at 1.6 percent. Conventional hydroelectric power continues to decline as a share of total net generation. In 2007, conventional hydroelectric generating capacity accounted for 6.0 percent of total net generation, as compared to 10.2 percent in 1997. Renewable energy sources, excluding conventional hydroelectric generation, contributed 2.5 percent of total net electric generation in 2007. This marks the fourth consecutive year in which renewables' share of total net generation has increased.

In 2007, electricity generation from coal-fired capacity increased 1.3 percent, reversing the decline from 2005 to 2006. Coal-fired generation increased from 1,991 million MWh in 2006 to 2,016 million MWh in 2007. This is a new record, exceeding the previous all-time high of 2,013 million MWh set in 2005. The record level of coal-fired generation reflects a one percentage point increase in the average capacity factor of coal-fired generation to 73.6 percent. Additionally, two coal-fired power plants located in the Pacific Northwest returned to service during 2007. The Boardman Plant, located in Oregon returned to service in May 2006 following a series of outages that began in October 2005. Net generation from the Transalta Centralia Generating Plant, located in Washington State, increased in 2007 following a reduced level of production in 2006, when the plant conducted a test burn of Powder River Basin coal. Coal-fired electricity production was further enhanced by the commencement of commercial operations at the Walter Scott, Jr. Energy Center Unit No. 4, located in Council Bluffs, Iowa (923 MW nameplate rating) and the Cross Generating Station No. 3 located in South Carolina (591 MW nameplate rating).

In spite of setting a record level for generation in 2007, coal's share of total net generation continued its downward trend in 2007. It accounted for 48.5 percent of total net generation in 2007 as compared to 49.0 percent in 2006 and 52.8 percent in 1997. Nevertheless, it remains the primary source of baseload generation. The decline in coal's share of total net generation in 2007 was attributable to continued increase in the share of total net generation produced by natural gas-fired and nuclear

capacity, as well as renewable sources, other than conventional hydroelectric capacity.

Net generation from natural gas-fired capacity increased 9.8 percent, from 816 million MWh to 897 million MWh in 2007. This was the second largest 1-year increase in natural-gas fired generation since the 10.8 percent increase that occurred in 1998. Natural gas-fired generation accounted for 21.6 percent of total net generation in 2007 as compared to 20.1 percent in 2006. For the second consecutive year, natural-gas fired generation was the second leading contributor to total net generation, surpassing nuclear generation, which historically was the second leading source of total net generation after coal.

Net generation at nuclear plants increased 2.4 percent in 2007 to 806 million MWh. Between 1996 and 2007, nuclear generation ranged from an 18.0-20.6 percent share of total net generation with an annual average growth in net generation of 1.6 percent from 1996 through 2007, despite the fact that no new nuclear units have been constructed. The continued growth in nuclear generation is due to improved capacity utilization, and in 2007, the resumption of commercial operations at the Tennessee Valley Authority's Browns Ferry Unit 1 after a 22-year shutdown. Since 1996, average capacity factors for nuclear plants increased from 76.2 percent to 91.8 percent (Table A6). In 2007, nuclear power plants operated at their highest average capacity factor, once again setting a record for net generation. In past years, growth in nuclear generation was the result of both improved capacity factors and uprates of existing plants. In 2007, the increase in nuclear generation appears to be primarily a function of improved plant performance. In 2007, nuclear plant operators reported a 47 MW increase in net winter capability and a 68 MW decrease in net summer capability. This is the first year since 1999 in which the net summer capability of nuclear plants declined, a significant departure from the annual increases in net summer capacity of existing nuclear plants that occurred between 1999 and 2006. During this period net summer capability of existing nuclear plants increased by 2,293 MW, which equates to an average annual increase of 418 MW of net summer capability.

Net generation from conventional hydroelectric plants declined 14.4 percent from 289 million MWh in 2006 to 248 million MWh in 2007. The decline in conventional hydroelectric generation is consistent with the drought conditions, which according to the National Climatic Data Center (NCDC) prevailed over the West and Southeast for much of the year. According to NCDC, evaporation caused by above normal summer temperatures exacerbated drought conditions in these regions. Moreover, precipitation was below average in the Southeast and the mountain snowpack in the Rocky Mountain and Western States was significantly below normal levels.[3]

Petroleum-fired generation increased 2.5 percent, to 66 million MWh. Its share of total net generation remained unchanged from 2006 at 1.6 percent.

EIA Electric Industry Data Collection *(Appendix A)*	html	pdf

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Net generation produced by renewable energy sources, excluding hydroelectric generation, grew by 9.0 percent as compared to 10.5 percent growth in 2006. Renewable energy accounted for 2.5 percent or 105 million MWh of total net generation in 2007. Wood and wood derived fuels accounted for 39 million MWh or 0.9 percent of total net generation. Wind generation was the second largest renewable energy source, contributing 34 million MWh or 0.8 percent of total net generation in 2007. Geothermal power plants supplied 15 million MWh of net generation and other biomass 17 million MWh. Each of these renewable sources accounted for approximately 0.4 percent of total net generation in 2007. In 2007, wood and wood derived fuels continued to be the largest sources of renewable generation, accounting for 37.1 percent of total net renewable generation, excluding conventional hydroelectric generation. Wind generation is rapidly gaining a larger share of total renewable generation. In 2007, wind accounted for 32.7 percent of total net generation from non-hydroelectric renewable sources, as compared to 4.3 percent in 1997. The annual growth in solar thermal and photovoltaic generation has been sufficient for this renewable source to account, on average, for 0.5 percent of all non-hydroelectric renewable energy. Wood and wood derived fuels and geothermal have maintained fairly stable output levels averaging 38 million MWh and 15 MWh per year, respectively. Other biomass generation has declined from a 23 million MWh peak in 2000 to 17 million MWh in 2007.

Generation from other gases (refinery gases, blast furnace gas, etc.) and other miscellaneous sources accounted for the remaining net generation. Net generation from these sources declined from 27 million MWh in 2006 to 26 million MWh. Finally, net energy requirements for pumped-storage hydroelectric generation increased 0.3 million MWh in 2007.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks for 2007 increased 7.3 percent from 141 million tons to 151 million tons. The build in coal stocks in 2007 was considerably less than the 39.4 percent increase that occurred in 2006. This appears to be the result of the increase in coal-fired generation relative to 2006, and a reduction in coal purchases in response to rising coal prices. While coal consumption at electric power plants increased 16 billion tons receipts declined by 25 billion tons in 2007. The increase in end-of-year stocks is consistent with the finding in the North American Electric Reliability Corporation's (NERC) 2007/2008 Winter Reliability Assessment that power plant inventories were ahead of historical normal levels, with inventory levels approaching 45 days as compared to 40 days.[4] While NERC concluded that coal stocks are satisfactory, it has identified longer-term market risks that could impact the security of supply in the long-run. These include capacity constraints on rail lines, particularly from the Powder River Basin and rolling stock shortages. NERC also indicated that rising coal prices may cause power plant owners to reduce on-site fuel supply in order to minimize carrying costs.[5]

Inventories of petroleum decreased from 51.6 million barrels at the end of 2006 to 47.2 million barrels by year end 2007. The decline in petroleum inventories is a function of increased consumption caused by the 2.5 percent increase in petroleum-fired generation, and a 12.6 million barrel reduction in petroleum receipts at power plants, which is likely attributable to the 13.1 percent increase in petroleum prices.

Capacity

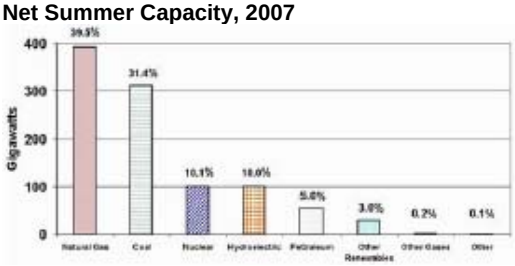
Total U.S. net summer generating capacity as of December 31, 2007 was 994,888 MW, an increase of 1.0 percent from January 1, 2007 (Figure ES2). During the year, net summer generating capacity increased 8,673 MW, after accounting for retirements, deratings (i.e., a reduction in power plant generating capability) and other adjustments. For the first time, non-hydroelectric, renewable energy capacity additions exceeded total fossil fuel capacity additions. Natural gas-fired generating units accounted for 4,582 MW or 52.8 percent of net summer capacity additions.

On December 31, 2007, natural gas-fired generating capacity represented 392,876 MW or 39.5 percent of total net summer generating capacity (Figure ES2). Although new natural gas-fired combined-cycle plants produce electricity more efficiently than older fossil-fueled plants, high natural gas prices can work against full utilization of these plants if such prices adversely affect economic dispatch. Since 1996, net summer natural gas-fired capacity has increased 218,741 MW net of retirements and adjustments. Natural gas capacity additions during this period were virtually equal to the 218,998 MW total increases in net summer capability. During this period coal, petroleum and nuclear capacity decreased by a net 17,612 MW, along with 783 MW of non-hydroelectric renewable capacity. That is, after additions and uprates, net summer capability associated with these types of resources collectively declined over the past 10 years. Since 1997, natural gas-fired additions in effect offset net retirements across all fuel types, with the cumulative net increase in capacity equal to 14,760 MW of non-hydroelectric, renewable capacity and 3,111 MW of other gases, hydroelectric and other capacity.

Petroleum-fired capacity totaled 56,068 MW, down 2,029 MW from 2006. Petroleum-fired capacity accounted for 5.6 percent of all generating capacity.

Coal-fired generating capacity remained essentially unchanged at 312,738 MW, or 31.4 percent of total generating capacity. This share of total capacity represents a slight decline from 2006. Retirements of and other adjustments to existing coal-fired capacity reported by operators in 2007 exceeded the 1,354 MW of net summer capacity of the 2 new plants placed in service by 1,514 MW. Since 1996, net summer coal-fired capacity has declined 644 MW after accounting for new additions, upgrades and other adjustments reported by operators. Nevertheless, net generation from the Nation's coal-fired plants continues to increase due to gains in operating efficiency.

Figure ES 2. U.S. Electric Power Industry Net Summer Capacity, 2007



Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Wind generating capacity totaled 16,515 MW in 2007, which amounts to a 45.8 percent increase over the 11,329 MW in operation during 2006. Of the 8,673 MW total increase in net summer capability in 2007, wind generating capacity accounted for 5,186 MW. Texas continues to lead the Nation in wind power development with 1,752 MW of new wind capacity placed in service in 2007, increasing its share of Nation's wind capacity currently in operation to 27.2 percent. California has the second highest share of total installed wind generating capacity at 2,312 MW. The remainder of the top five wind producing States includes Iowa at 7.1 percent, Washington at 7.0 percent and Minnesota at 6.9 percent of the Nation's total installed wind generating capacity. Collectively, 10,273 MW or 62.2 percent of total wind generating capacity is located in these 5 States. Wind power development has accelerated in Colorado, Illinois, Oklahoma and Oregon with the addition of 1,794 MW of capacity. Over the last three years 10,059 MW of wind generating capacity has been placed in service. The electric generating capacity from non-hydroelectric renewable energy sources increased 24.7 in 2007. Wind capacity accounted for 87.1 percent of the 5,596 MW of non-hydro renewable energy sources placed in service in 2007.

Nuclear net summer generating capacity totaled 100,266 MW or 10.1 percent of total capacity. Uprates totaling 179 MW of nameplate capacity were made at the Duane Arnold Energy Center and R. E. Ginna plant. However, nuclear plant operators reported that net summer capacity declined by 68 MW and net winter capacity increased by 47 MW. Thus, continued improvement in plant performance was the primary factor supporting the increase in nuclear generation in 2007, with a large share of that increase stemming from the resumption of output from the Browns Ferry 1 unit in Alabama, which returned to service in June 2007 after a two-decade hiatus.

Conventional hydroelectric generating capacity accounted for 7.8 percent of total capacity with a summer net generating capacity of 77,885 MW. Pumped storage hydroelectric generating capacity totaled 21,886 MW. Combined, conventional and pumped storage generating capacity accounted for 10.0 percent of total capacity. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years.

The year 2007 was the fourth year in which EIA has collected data on distributed and dispersed generating facilities. In 2004, 9,579 MW of dispersed and distributed generators were reported. By year-end 2007, the amount of dispersed and distributed generators has increased to 20,999 MW.[6] Of this total, 59.1 percent is internal combustion capacity. While internal combustion capacity is the predominant form of dispersed and distributed generating capacity, wind capacity has grown significantly. In 2004, there were 0.1 MW of dispersed and distributed wind capacity. As of 2007, there is 1,462 MW.

As of December 31, 2007, reported planned additions scheduled to start commercial operation between 2008 and 2012 have total nameplate capacity of 92,996 MW. This compares with 87,109 MW of planned capacity reported on December 31, 2006, for the 5-year period through 2011. The data also show that over the next two years there will be a significant increase in planned additions relative to the past 2 years, if additions are completed as planned. In 2006 and 2007, the industry added 28,381 MW of nameplate capacity. Planned capacity additions projected to be placed in service during calendar years 2008 and 2009 total 44,701 MW. Given the recent turmoil in financial markets, which has affected both the cost and access to capital, and slowdown in economic activity, it is likely that some of this capacity will be deferred. The data also reveal a shift in the fuel mix. New coal-fired and renewable energy sources are projected to play a more significant role over the next 5 years. The industry reports that it is planning to add 23,347 MW of coal-fired capacity over the next 5 years. In terms of net summer capacity, planned coal-fired additions account for 25.7 percent of planned additions over the next 5 years, which is an amount equivalent to 6.9 percent of existing coal-fired capacity. Renewable energy sources, excluding hydroelectric, are 19.5 percent of planned new net summer capacity. Natural gas-fired capacity is projected to be the dominant primary fuel for electricity generation with planned additions totaling 48,100 MW, or 51.7 percent of all planned additions for the 5-year period.

As expected, nuclear and coal-fired generation have the highest average capacity factors at 91.8 percent and 73.6

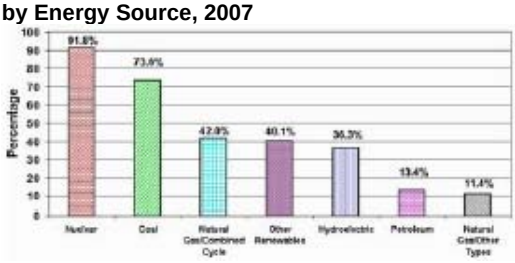
percent, respectively (Figure ES3). This is consistent with the economies of scale that these forms of capital intensive and energy efficient generation provide to serve energy requirements. Accordingly, coal and nuclear capacity serve baseload energy requirements, which are reflected by higher average capacity factors relative to other forms of generation. The average capacity factor for coal-fired generation reflects a one percentage point increase over the 72.6 percent average capacity factor achieved in 2006. The average capacity factor for nuclear generation increased from 89.6 percent to 91.8 percent. This compares to the 89.7 percent average over the past five years and the low of 72.0 percent that occurred in 1997. Because the industry continues to rely on new combined cycle natural gas generation to meet rising demand, average capacity factors for natural gas generation have been calculated for both combined cycle generation and simple cycle natural gas generation.[7] In 2007, the capacity factor for combined cycle generating capacity factor was 42.0 percent. In 2003, the average capacity factor for combined cycle generation was 33.5 percent. The 8.4 percentage point improvement in the average capacity factor reflects both the increased reliance on combined cycle generation to meet energy requirements and further efficiency gains in combined cycle generation technology. In 2007 the average capacity factor for simple cycle natural gas-fired generation was 11.4 percent.

The more recent emphasis placed on wind capacity, which is not a dispatchable resource, is reflected in the reduced performance of renewable resources in aggregate as measured by a composite capacity factor. Renewable generation other than hydroelectric had a 40.1 percent capacity factor in 2007. In 1999, the average capacity factor for other renewable generation was 56.9 percent. The continuous decline in the average capacity factor for all non-hydroelectric renewable resources is consistent with the significant growth of wind capacity relative to other forms of renewable electricity generation. Wind is a non-dispatchable resource that is available for generation subject to prevailing wind conditions. It is expected to have a lower capacity factor relative to solid and liquid biomass generating capacity (e.g., landfill gas, municipal solid waste, black liquor and wood waste solids), which have greater continuity in the receipt of primary fuel supply for electricity generation. The primary factor limiting the capacity factor of biomass generating capacity is its position in the economic dispatch order relative to load.

Wind generating capacity exceeds all forms of non-hydroelectric renewable energy sources. In 2007, wind capacity accounted for 16,515 MW of net summer capacity. Wood and wood derived fuels contributed the second largest share of renewable capacity at 6,704 MW. The growth of this source of renewable energy has fluctuated between net increases and decreases in capacity over time. Since 1996, the amount of wood and wood derived fuels capacity has fallen by 104 MW. Wind generating capacity is the fastest growing renewable energy source. In 2007, 5,186 MW of new capacity was placed in service increasing total wind capacity to 16,515 MW. New wind capacity accounted for 87.1 percent of the 5,956 MW of total renewable capacity (other than conventional hydroelectric capacity) placed in service in 2007. As a result the average capacity factor for renewable energy declined as expected.

Conventional hydroelectric generation had an average capacity factor of 36.3 percent in 2007 as compared to 42.4 percent in 2006. The decline in conventional hydroelectric generation is a result of drought conditions in the Southeast, Rocky Mountains and West.

Figure ES 3. Average Capacity Factor by Energy Source, 2007



Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report;” Form EIA-923, "Power Plant Operations Report.”

Fuel Switching Capacity

The total amount of net summer capacity reporting natural gas as the primary fuel in 2007 was 392,876 MW, of which 123,862 MW (31.5 percent) reported a current operational capability to switch to fuel oil as an alternative fuel. This means that the capacity had in working order all necessary equipment, including fuel storage, to switch from gas to petroleum-fired operation. However, most of this capacity is subject to environmental regulatory limits on the use of oil, such as restrictions on how many hours per year a unit is allowed to burn oil. Of the 123.862 MW of gas-fired capacity that reported the ability to switch to oil, only 39,817 MW (32.1 percent) reported no environmental regulatory constraints or other factors that would limit oil-fired operations.

“Switchable” capacity is spread across the major generating technologies. Combustion turbine peaking units account for 43.7 percent (54,135 MW) of this capacity. Steam-electric generators (33,553 MW) and combined cycle units (35,270 MW) account for 27.1 percent and 28.4 percent, respectively. Internal combustion engines make up the remaining 0.7 percent. When running on fuel oil the net summer capability of the 33,553 MW of steam-electric generating capacity is 18,245 MW. The 54,135 MW of gas turbine capacity has an achievable net summer capacity of 15,358 MW when running on oil.

Over time, the achievable net summer capacity for natural-gas fired capacity when run on fuel oil has declined. Through 1974, the net achievable summer capacity for gas-fired capacity running on oil was 51.6 percent of all switchable natural gas-fired capacity. This ratio has gradually declined to 32.1 percent by the end of 2007.

Interconnection Costs

During 2007, 269 generators representing a total nameplate capacity of 14,061 MW were connected for the first time to the electric grid. The interconnection costs are presented by producer type (Table 2.12) and by distribution, subtransmission and transmission voltage class (Table 2.13). Total cost for individual generator interconnection varies based on its components. The components of the total cost may vary based on whether or not an interconnection infrastructure was already in place, and the type of equipment for which costs were incurred, along with other factors associated with the generator technology. Though the amount of capacity connected to the grid was about the same for both independent power producers (IPP) and electric utilities, the total cost for the IPP sector was significantly greater due in part to the interconnection of several large wind plants. Typically sited in relatively remote locations, wind plants usually require the construction of longer transmission line extensions to the plant sites than might be required for conventional power plants.

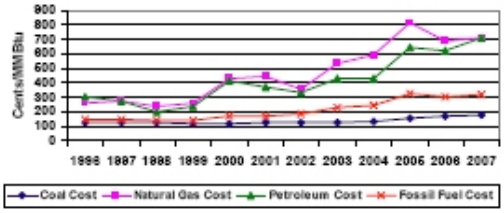
Fuel Costs

The 2007 average delivered cost for all fossil fuels used at electric power plants (coal, petroleum, and natural gas combined) for electricity generation was $3.23 per million British thermal units (MMBtu) (Figure ES4) as compared to $3.02 per MMBtu in 2006, an increase of 6.9 percent. Between 2003 and 2007, the average cost of all fossil fuels has increased 41.7 percent. The price of all fossil fuels increased in 2007. The cost of natural gas at electric power plants in 2007 increased 2.4 percent to $7.11 per MMBtu. Since 2002, natural gas prices have increased 99.7 percent, with more than half of the total increase occurring between 2002 and 2003.

The cost of petroleum increased 15.1 percent, from $6.23 per MMBtu in 2006 to $7.17 MMBtu in 2007. This increase was caused by increased global demand for petroleum and tight supply. Petroleum-fired generation increased in spite of the significant increase in petroleum prices. This appears to be the result of petroleum capacity being used partially to offset the decline in conventional hydroelectric generation.

The 2007 delivered cost of coal increased 4.7 percent, from $1.69 per MMBtu in 2006 to $1.77 MMBtu in 2007. This marked the seventh straight year that coal prices have increased. Since 2000 the delivered cost of coal has increased 47.5 percent (Figure ES4).

Figure ES 4. Fuel Costs for Electricity Generation, 1996- 2007



Source: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," “Annual Electric Generator Report;” Form EIA-923, "Power Plant Operations Report.”

Emissions

The estimated carbon dioxide, sulfur dioxide and nitrogen oxide emissions for electricity are based on the fossil fuels consumed by electric power plants for electric power generation, and fossil fuels consumed by combined heat and power plants for the generation of electric power and useful thermal output. The emissions factors used in the estimation methodology are described in the discussion of Air Emissions in the Technical Notes, and are

summarized in Tables A1, A2, and A3.

Estimated carbon dioxide emissions by U.S. electric generators and combined heat and power facilities increased by 2.3 percent from 2006 to 2007 (from 2,460 million metric tons to 2,517 million metric tons). This reverses the decline in carbon dioxide emissions reported for 2006. Total net generation of electricity from fossil fuels increased to meet the increase in demand in 2007. Coal-fired generation increased 1.3 percent and coal consumed for electric generation and by combined heat and power facilities increased by 1.5 percent. Petroleum-fired generation increased 2.5 percent and the petroleum consumed for electric generation and useful thermal output increased 1.1 percent from 131 million barrels in 2006 to 132 million barrels in 2007. Consumption of natural gas for electricity generation and useful thermal output, which contributes the least amount of carbon dioxide per Btu consumed, rose by 7.5 percent in 2007 as natural gas generation increased by 10.1 percent.

Estimated emissions of nitrogen oxides and sulfur dioxide declined for the second year in a row. Nitrogen oxides emissions dropped by 3.9 percent (from 3.799 to 3.650 million metric tons). Sulfur dioxide emissions decreased by 5.1 percent (from 9.524 to 9.042 million metric tons). Emissions of both of these gases are capped by the Clean Air Act and other legislation.

Trade

Total wholesale purchases of electric power in the United States declined in 2007 for the fourth straight year to 5,411 million MWh, a 1.7 percent reduction. Almost half the volume of wholesale sales is provided by energy-only providers, or power marketing companies, a class of electric entities, authorized by FERC to transact at market based rates, that came into being during the late 1990s with the deregulation of the wholesale power markets. In 2007, wholesale sales by wholesale power marketers and retail energy service providers increased from 2,446 million MWh in 2006 to 2,477 MWh, which represented 45.2 percent of the wholesale market. This is the first increase in market share for these entities since 2002 when they accounted for 67.2 percent of all wholesale sales. Independent power producers and combined heat and power (CHP) plants accounted for 25.5 percent of wholesale sales in 2007 compared to 24.6 percent in 2006.

The Nation’s only international trade in electric power is with Canada and Mexico, and nearly all the trade is conducted with Canada. Most Mexican electric power trade is done with the State of California, while transactions with Canada are conducted through several large transmission corridors located in the Pacific Northwest, the Northern Plains, and New England. Much of the electricity provided from Canada is hydroelectric generation available for sale because of heavy seasonal river flows.

Total international net imports of electric power in 2007 increased 69.7 percent, from 18.4 million MWh in 2006 to 31.3 million MWh. Overall, total U.S. imports increased 8.7 million MWh in 2007 from 42.7 million MWh in 2006 to 51.4 million MWh, while exports declined by 4.1 million MWh. Imports from Canada increased from 41.5 million MWh in 2006 to 50.1 million MWh in 2007, and U.S. exports decreased from 23.4 million MWh to 19.6 million MWh. Electricity trade with Mexico followed a similar pattern of net imports, increasing relative to 2006 as a result of a decline in exports and an increase in imports. Net imports more than doubled, from 0.3 million MWh in 2006 to 0.7 million MWh in 2007.

Revenue and Expense Statistics

In 2007, major investor-owned electric utility operating revenues (from sales to ultimate customers, sales for resale, and other electric income) were $283 billion, a 2.1 percent increase from 2006. Operating expenses in 2007 stayed in line with revenue growth, also increasing 2.0 percent, to $252 billion. Net income in 2007 was $30.7 billion, a slight increase over the $30.0 billion realized in 2006.

In 2007, major investor-owned electric utility purchased power costs, which accounted for roughly 30 percent of total utility operating expenses, fell 1.7 percent as compared to the 1.5 percent increase realized in 2006. Fuel costs increased 10.5 percent in 2007. Transmission expenses were $6.1 billion in 2007 as compared to $6.2 billion in 2006. This modest decrease stands in contrast to the average 21.2 percent annual increase between 2001 and 2006. Distribution expenses increased 5.8 percent, more than twice the average annual increase incurred between 2001 and 2006.

Electricity Prices and Sales

In 2007, the average retail price for all customers rose 0.2 cents to 9.1 cents per kWh. This amounted to a 2.6 percent increase over the 8.9 cents per kWh average retail price paid in 2006. Year-over-year, the average retail

price for all customers served increased in 40 of the 50 States. The average price of electricity increased by 10 percent or more in 5 States. In another 11 States, the average price for all customers declined within a 0.2 percent to 6.1 percent range. The average price of electricity to all customers increased in all regions of the country, with the exception of the West South Central Census Division. Within the four States of the West South Central Census Division, average electric prices declined by 1.6 percent. In Arkansas the average retail rate for all customers declined by 0.4 percent. In Oklahoma the average price declined by 0.2 percent and in Texas it declined by 2.3 percent. In Louisiana, the average electricity price for all customers increased by 1.0 percent. The East North Central Census Division experienced the largest increase in average retail prices for all customers at 6.9 percent. The New England and East South Central Census Divisions had the next largest average retail price increases over 2006, at 4.0 percent and 3.4 percent, respectively. The lowest regional price increase was in the Pacific Contiguous Census Division, where the average price to all customers increased 0.8 percent over 2006.

Residential prices increased to 10.7 cents per kWh, or 2.4 percent, between 2006 and 2007. The average residential price increased by 10 percent or more in 6 States and the District of Columbia. These jurisdictions implemented retail competition and all of the investor-owned utilities operating within them participate in organized, competitive wholesale markets operated by independent system operators. The average residential price in Maryland increased 22.4 percent, from 9.7 cents per kWh in 2006 to 11.9 cents per kWh in 2007. This was the largest average increase in the Nation. It was caused by the transition to market based rates for the wholesale electricity portion of retail electric service. In order to mitigate the impact of higher retail prices, the Maryland Public Service Commission approved a plan for the largest investor-owned utility in the state that gave customers two payment options. The first option provided for retail prices based on the full market price of wholesale electricity prices, effective June 1, 2007. This option resulted in approximately a 50 percent increase in the average electric bill. The second option provided that the cost of wholesale electricity would be phased in over the 6 month period ending January 1, 2008. Deferred costs would be recovered by December 31, 2009.[8]

After Maryland, Illinois had the next largest increase in residential prices at 20.1 percent, followed by Maine (19.7 percent), Connecticut (13.4 percent), the District of Columbia (12.9 percent), Delaware (11.1 percent) and New Jersey (10.1 percent). On a regional basis, the highest average residential price increase was observed in the East North Central Division. This was primarily driven by Illinois, where the average residential price increase was nearly 4 times the average of the region overall. Like Maryland, the price increase in Illinois was the result of the termination of rate caps that had been put in place in 1997 as part of the transition to retail competition. Average residential prices in the New England and Mid-Atlantic Census Divisions increased 4.5 percent. Average residential prices fell by 2.9 percent in the West South Central Census Division, the only region to see a year-over-year decline in average residential prices. Texas out-paced the region with a 4.0 percent decline from 12.9 cents per kWh in 2006 to 12.3 cents per kWh in 2007.

A number of these States have taken legislative action in response to significant rate increases caused by a combination of rising fuel prices and the termination of rate caps imposed during the transition to retail competition. In Illinois average residential prices increased by 20.1 percent. The large average price increases for all customer groups in Illinois reflects the January 2, 2007 termination of the 10-year rate freeze that was imposed on the State's investor-owned utilities as part of its 1997 electric industry restructuring legislation. The termination of the rate freeze caused large rate increases primarily for residential and certain non-residential customers that did not select alternative energy suppliers and remained customers of the State's largest investor-owned utilities under standard offer service rate schedules. On August 28, 2007, Illinois Senate Bill 1592 was signed into law, which provided approximately $1 billion in refunds, eliminated the auction process under which the Illinois investor-owned utilities purchased wholesale power to supply standard offer service, and created the Illinois Power Agency as the entity responsible for energy procurement. [9]

Average commercial prices increased from 9.5 to 9.7 cents per kWh, a 2.0 percent increase over 2006. The largest regional price increase was in the East North Central Census Division at 4.2 percent. Average commercial prices in Illinois increased 7.8 percent, from 7.9 cents per kWh to 8.6 cents per kWh. Wisconsin had the second highest rate increase in the region at 4.0 percent. The average commercial rate in the West South Central Census Division was unchanged at 9.3 cents per kWh. The average commercial price declined by slightly less than 1 percent in Arkansas and Oklahoma, while increasing by 0.2 percent in Texas and 1.2 percent in Louisiana. In the Pacific Contiguous Census Division the average commercial price declined from 11.2 cents per kWh in 2006 to 11.0 cents per kWh in 2007. It was the only region in which average commercial rates declined. Oregon was the only the State within the region where rates increased, rising from 6.8 cents per kWh to 7.2 cents per kWh.

Average industrial prices increased 4 percent from 6.2 cents per kWh in 2006 to 6.4 cents per kWh in 2007.

Total retail sales of electricity in 2007 were 3,764 million MWh. Annual growth in electricity sales in 2007 was 2.6 percent, exceeding the 1.8 percent year average annual growth rate since 1996. Sales to the residential sector increased by 3.0 percent from 2006 to 2007. Sales to the commercial sector increased by 2.8 percent, and industrial

sales increased 1.6 percent. Since 1997, annual industrial sales declined in three years. Otherwise, with the exception of 2003 when industrial sales increased 2.2 percent, they have increased annually by less than one percent. Thus, while the increase in industrial sales in 2007 showed significant improvement over prior years, the faster growth of residential and commercial sales in 2007 provides for the continuation of the gradual shift of total load away from the industrial sector. The industrial sector accounted for 33.3 percent of total retail sales in 1996. By 2007 it has declined to 27.3 percent. Between 1996 and 2007, the commercial sector share of retail sales increased from 28.6 percent to 35.5 percent. Over the same period, the residential sector has grown from 34.9 percent of total retail sales to 37.0 percent.

In the last few years, some States have encouraged utilities to adopt customer service programs which respond to growing concerns about the environment, electricity reliability, and the rising cost of providing electricity. Green pricing programs allow consumers to purchase electricity generated from wind and other renewable sources and pay for renewable energy development. In 2007, 835,651 retail consumers were reported to be purchasing electricity under green pricing programs. Residential consumers accounted for 773,391 or 92.5 percent of the total number of green pricing consumers. All of the States, with the exception of Louisiana, reported providing electric service under green pricing programs in 2007. Retail consumers in Texas accounted for 17.0 percent of all green pricing consumers nationwide. Oregon was ranked second with 12.0 percent of all green pricing consumers Nationwide. The top 5 States were rounded out by California (7.0 percent) and Colorado (6.9 percent) and Maryland (6.7 percent). Together, retail consumers in these 5 States accounted for 49.6 of consumers purchasing green power and 56.0 percent of green power sales volumes Nationwide.

Net metering programs allow consumers with onsite generators to send excess generation to the grid and to receive credit for that energy on their bill. The number of customers in these programs has been steadily increasing. In 2002 there were 4,472 customers in net metering programs; in 2007 there were nearly 48,820 customers participating in net metering programs. These customers were dispersed across 47 States and the District of Columbia. California leads the Nation in net metering, with 34,910 customers reported as participating. These customers accounted for 71.5 percent of all customers participating in such programs.

Demand-Side Management

In 2007, electricity providers reported total peak-load reductions of 30,276 MW resulting from demand-side management (DSM) programs, an 11.1 percent increase from the amount reported in 2006. Reported DSM costs increased to $2.5 billion, up 23.2 percent from the $2.1 billion reported in 2006. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. Since 2003, nominal DSM expenditures have increased at 18.1 percent average annual growth rate. During the same period, actual peak load reductions have grown at a 7.2 percent average annual rate from, 22,904 MW to 30,276 MW. The divergence between the growth rates of load reduction and expenditures is driven in large measure by 2007 expenditures, which are in response to higher overall energy prices. The full effect of these expenditures may appear in additional load reductions in the coming years. The combined DSM energy savings programs (i.e., load management and energy efficiency) increased to 69.1 million MWh in 2007 from 63.8 MWh.

[1] See http://bea.doc.gov/national/index.htm#gdp.

[2] See http://www.federalreserve.gov/releases/g17/Current/table11.txt, accessed November 24, 2008.

[3] *National Climatic Data Center, Climate of 2007 Annual Review, U.S. Drought, January 15, 2008, http://www.ncdc.noaa.gov/oa/climate/research/2007/ann/us-summary.html*

[4] *North American Electric Reliability Corporation, 2007/2008 Winter Reliability Assessment. November 2007., p.10*

[5] *North American Electric Reliability Corporation, 2007 Long-term Reliability Assessment 2007-2016, October 2007, p. 89*

[6] *Dispersed and distribute generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer's site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. This data is collected at the distribution utility level on the Form EIA-861.*

[7] *The data required to average capacity factors for combined cycle and simple cycle natural gas-fired generation was obtained from plant-specific capacity and energy data from the Form EIA-860, Form EIA-906 and Form EIA-920.*

[8] *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan Pursuant to Section 7-548 of the Public Utility companies Article and the Commission's Inquiry into Factors Impacting Wholesale Electricity Prices, Maryland Public Service Commission, Order No. 81423. Case No. 9099, May 23, 2007.*

[9] *Illinois General Assembly, Public Act 095-0481, effective August 28, 2007.*

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