DOE/EIA-0578(2000)
Distribution Category UC-950

Energy Information Sheets

March 2002

Energy Information Administration
National Energy Information Center
U.S. Department of Energy
Washington, DC 20585

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Preface

The National Energy Information Center (NEIC), as part of its mission, provides energy information and referral assistance to Federal, State, and local governments, the academic community, business and industrial organizations, and the public. The *Energy Information Sheets* were developed to provide general information on various aspects of fuel production, prices, consumption, and capability. Additional information on related subject matter can be found in other Energy Information Administration (EIA) publications as referenced at the end of each sheet.

Questions concerning the contents of this publication should be directed to NEIC, (202) 586-8800. Questions concerning the publication itself should be directed to Marion King at (202) 586-1183. This issue of *Energy information Sheets* supersedes the previous issues.

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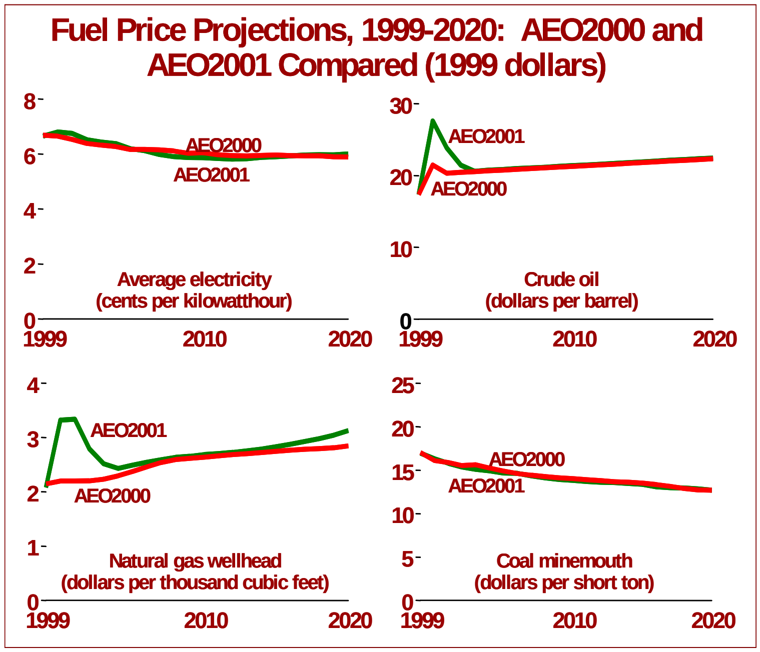
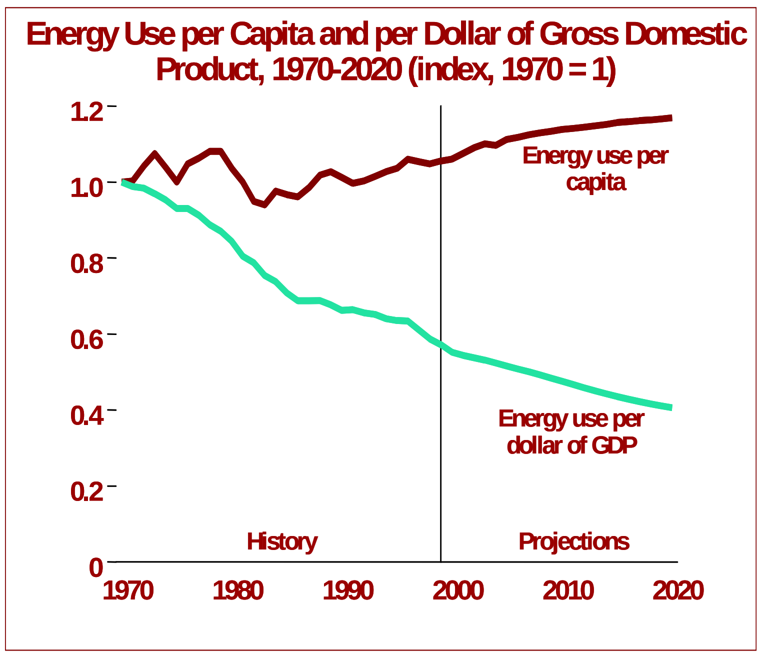
Annual Energy Outlook

In the *Annual Energy Outlook 2001*, projected world oil prices increase from $17.35 per barrel (1999 dollars) in 1999 to about $27.60 per barrel in 2000 and begin falling in 2001. By 2020, the projected price is $22.41 per barrel, as technological improvements help expand production worldwide, restraining price increases as the world demand for oil grows.



Natural gas prices are also projected to remain high through 2001, due to relatively strong demand and tight supplies stemming from low drilling due to low prices in 1998. In the long term, supply technology improvements help offset price increases from growing demand.

Projected electricity prices generally decline through 2020 at an average rate of 0.5 percent per year, due to cost reductions in the increasingly competitive market and falling projected coal prices, but increase slightly at the end of the forecast due to rising natural gas prices. Coal minemouth prices are projected to decline at an average annual rate of 1.4 percent, due to growing production from lower-cost Western mines, productivity gains, and competitive pressures on labor costs.

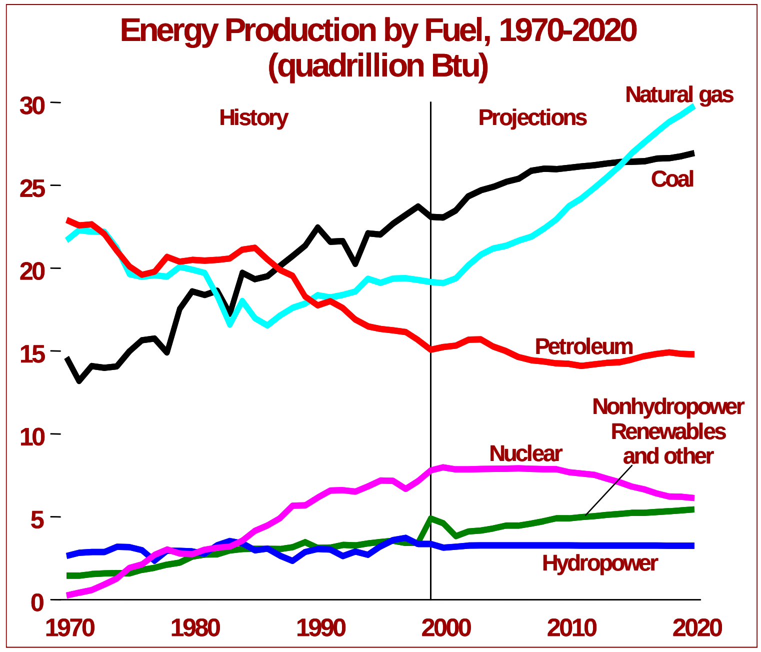


Projected energy use per dollar of gross domestic product declines 1.6 percent per year through 2020, and growth in per capita energy use slows. Efficiency gains and shifts to less-energy-intensive industries partly offset growth in the demand for energy services, which results from population growth and projected economic growth of approximately 3 percent per year.

Highlights	1997	1998	2005	2010	2015	2020	Annual change 1998-2020
Primary Production (quadrillion Btu)							
Petroleum	16.23	15.73	13.92	13.86	14.22	14.49	-0.4%
Natural Gas	19.43	19.40	20.25	23.09	25.73	27.13	1.5%
Coal	23.28	23.89	25.79	26.18	26.63	27.36	0.6%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy	7.00	6.67	7.07	7.39	7.70	7.98	0.8%
Other	0.66	0.57	0.62	0.59	0.63	0.66	0.7%
Total Primary Production	73.30	73.46	74.85	77.81	80.35	82.18	0.5%
Net Imports (quadrillion But)							
Petroleum	19.65	20.95	26.92	29.73	32.00	34.15	2.2%
Natural Gas	2.90	3.20	4.28	4.62	4.96	5.25	2.3%
Coal/Other (-indicates export)	-1.66	-1.48	-0.60	-0.74	-0.55	-0.50	-4.8%
Total Net Imports	20.89	22.69	30.62	33.61	36.41	38.91	2.5%
Consumption (quadrillion Btu)							
Petroleum Products	36.43	37.21	41.21	43.98	46.65	49.05	1.3%
Natural Gas	22.60	21.99	24.57	27.69	30.68	32.38	1.8%
Coal	21.34	21.50	24.72	25.12	25.84	26.60	1.0%
Nuclear Power	6.71	7.19	7.20	6.70	5.45	4.56	-2.1%
Renewable Energy	7.00	6.67	7.08	7.41	7.71	7.99	0.8%
Other	0.33	0.32	0.50	0.36	0.33	0.36	0.6%
Total Consumption	94.41	94.88	105.28	111.26	116.66	120.95	1.1%
Petroleum (million barrels per day)							
Crude Oil	6.45	6.25	5.36	5.18	5.20	5.26	-0.8%
Other Domestic Production	2.96	2.90	3.13	3.45	3.68	3.81	1.2%
Net Imports	9.16	9.77	12.55	13.85	14.96	16.04	2.3%
Consumption	18.59	18.94	21.08	22.51	23.87	25.10	1.3%
Natural Gas (trillion cubic feet)							
Production	18.90	18.88	19.70	22.46	25.03	26.40	1.5%
Net Imports	2.84	3.13	4.19	4.52	4.85	5.14	2.3%
Consumption	21.99	21.39	23.91	26.95	29.88	31.53	1.8%
Coal (million short tons)							
Production	1098	1128	1221	1242	1269	1316	0.7%
Net Imports	-76	-69	-47	-47	-38	-38	-2.7%
Consumption	1029	1043	1175	1195	1232	1279	0.9%
Pries (1998 dollars)							
World Oil Price (dollars per thousand)	18.71	12.10	20.49	21.00	21.53	22.04	2.8%
Natural Gas Wellhead Price	2.39	1.96	2.34	2.60	2.71	2.81	1.7%
Coal Minemouth Price (dollars per Short Tons)	18.32	17.51	14.71	13.84	13.34	12.54	-1.5%
Average Electricity Price (cents per kilowatthour)	6.9	6.7	6.1	6.0	5.8	5.8	-0.6%
Economic Indicators							
Real Gross Domestic Product (billion 1992 dollars)	7,270	7,552	9,056	10,054	11,147	12,179	2.2
GDP Implicit Price Deflator (index, 1992=1.00)	1.12	1.13	1.28	1.42	1.59	1.86	2.3
Real Disposal Personal Income (billion	5,183	5,348	6,406	7,204	8,063	9,008	2.4
Index of Manufacturing Gross Output (index, 1987=1.00)	1.365	1.411	1.645	1.812	1.999	2.160	2.0
Energy Intensity (thousand Btu)	12.99	12.57	11.63	11.07	10.47	9.94	-1.1%
Carbon Emissions (million metric tons)	1479	1485	1683	1787	1893	1979	1.3%

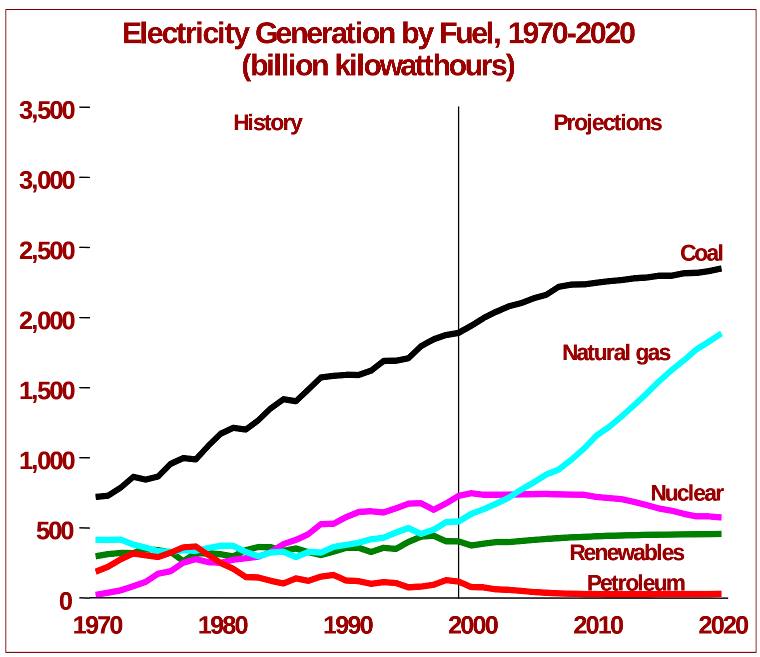
Notes: World Oil Price represents the average refiner acquisition cost for imported crude oil. 1997 and 1998 represent partial historical data, which may be revised in later publications. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Projected U.S. energy demand grows at an average rate of 1.3 percent per year, from 96 to 127 quadrillion Btu between 1999 and 2020. Improved efficiency of equipment and buildings moderates growing demand for energy services. The transportation sector is expected to grow most rapidly, due to growing personal and freight travel. Projected petroleum demand grows at an annual rate of 1.4 percent (measured in Btu) with about 70 percent used for transportation.



Projected natural gas demand grows at an annual rate of 2.3 percent, with the most rapid growth for electricity generation. Projected coal demand grows 1.0 percent annually (measured in Btu) with about 90 percent used for electricity generation.

Domestic crude oil production is projected to decline from 5.9 to 5.1 million barrels per day between 1999 and 2020; however, the decline is offset by other domestic supplies, natural gas liquids and processing gain, so total petroleum production remains essentially flat. By 2020, net petroleum imports are expected to increase from 51 to 64 percent of consumption as demand grows.

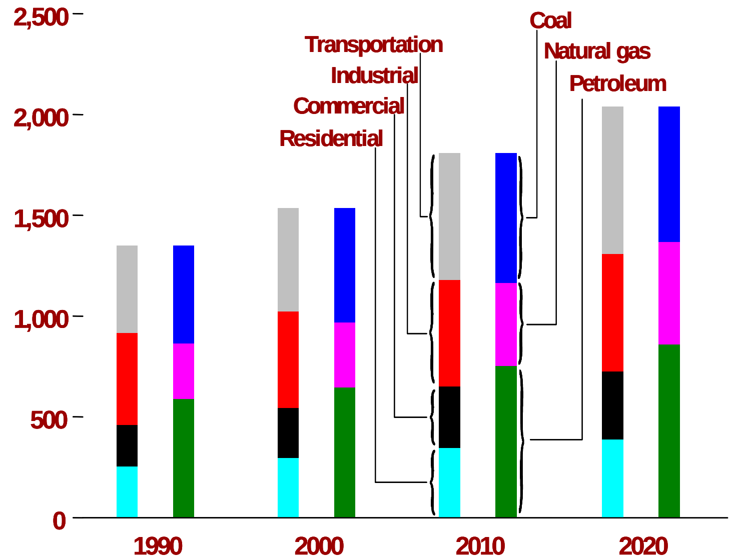


Projected natural gas and coal production increases at average rates of 2.1 and 0.7 percent, respectively, (measured in Btu) to meet growing demand. Net imports of natural gas, primarily from Canada, are expected to meet 17 percent of domestic demand by 2020. Net coal exports are expected to decline through 2020 due to relatively flat demand for U. S. coal and competition from other producers.

Projected natural gas and coal generation increases due to growing electricity demand and declining nuclear generation. The share of coal-fired generation declines but is still the primary generation fuel by 2020. Natural gas grows to a 36-percent share of generation by 2020.

Nuclear generation is projected to decline 21 percent by 2020, as older and higher-cost plants are retired. No new plants are built in the forecast period, but 27 units are expected to be life-extended due to economics.

Projected U.S. Carbon Dioxide Emissions by Sector and Fuel, 1990-2020 (million metric tons carbon equivalent)



Projected renewable generation grows slowly, at an annual rate of 0.7 percent, due to low fossil fuel prices and industry restructuring which favors less-capital-intensive natural gas technologies. Growth in renewables is encouraged by State renewable portfolio standards and other programs.

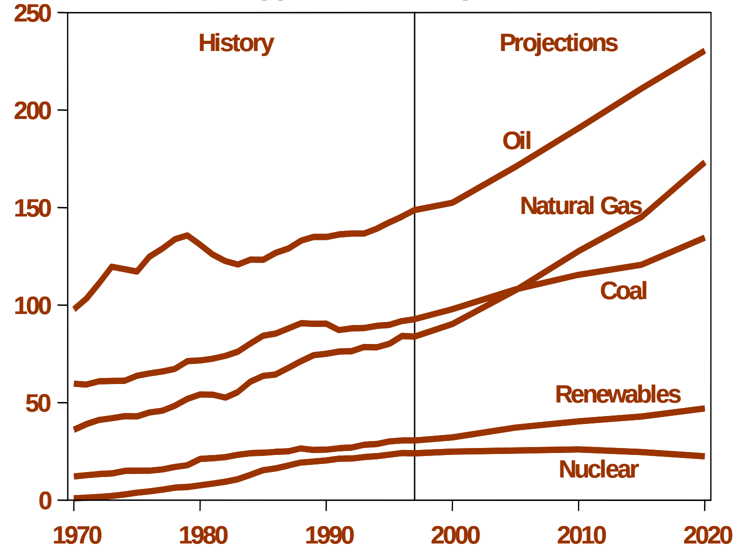
Carbon dioxide emissions from energy use are expected to increase at an average annual rate of 1.4 percent due to rising demand, relatively slow penetration of renewables, and the decline in nuclear generation. The projections include current voluntary programs and policies to reduce emissions.

In 2020, it is projected that petroleum will account for 42 percent of emissions, mostly for transportation, coal for 33 percent, and natural gas for 25 percent. Electricity generation is expected to account for 38 percent of carbon dioxide emissions in 2020, due to continued reliance on fossil fuels.

International Energy Outlook

In the *International Energy Outlook 2000* reference case, world energy consumption is projected to increase by 60 percent between 1997 and 2020, rising to 608 quadrillion British thermal units (Btu).

World Energy Consumption by Fuel Type, 1970-2020 (quadrillion Btu)



Every energy source except nuclear power grows over the projection period. Oil's key role in the transportation sector keeps it the dominant energy source.

Natural gas is expected to be the fastest-growing primary energy source. Combined-cycle gas turbine power plants offer some of the highest commercially available plant efficiencies, and natural gas is environmentally attractive because it emits less sulfur dioxide, carbon dioxide, and particulate matter than does oil or coal.

In the IEO2000, much of the growth in worldwide energy use is projected for the developing world. Energy use in developing Asia and Central and South America more than doubles between 1997 and 2020 and these regions account for 54 percent of the world increment in energy use.

Russia experienced stronger than expected recovery from its August 1998 monetary crisis, which also affected most of the other FSU economies. The IEO2000 is more optimistic about the region's recovery prospects; projected FSU energy use is 12 percent higher in 2020 than in last year's IEO.

World Energy Consumption and Carbon Emissions, 1997-2020

	Energy Consumption						Carbon Emissions			
Fuel & Region	Quadrillion Btu			Million Tons of Oil Equivalent			Million Metric Tons			
	1997	2010	2020	1997	2010	2020	1990	1997	2010	2020
By Fuel										
Oil	148.7	190.7	230.4	3,747	4,806	5,807	2,476	2,643	3,391	4,114
Natural Gas	83.9	127.7	173.3	2,113	3,217	4,366	1,077	1,202	1,836	2,492
Coal	92.8	115.4	134.5	2,338	2,909	3,390	2,283	2,330	2,918	3,401
Nuclear	24.0	26.0	22.5	604	655	567	N/A	N/A	N/A	N/A
Renewables	30.6	40.0	47.0	770	1,017	1,184	N/A	N/A	N/A	N/A
Total	379.9	500.2	607.7	9,572	12,604	15,314	5,836	6,175	8,146	10,009
By Region										
North America	112.5	135.0	148.5	2,835	3,403	3,741	1,553	1,716	2,090	2,344
Western Europe	64.0	72.6	78.4	1,614	1,829	1,975	934	918	1,016	1,094
Industrial Asia	27.1	31.1	33.1	684	783	834	264	405	457	490
EE/FSU	53.3	63.0	75.7	1,343	1,587	1,907	1,337	878	992	1,151
Developing Asia	75.3	126.4	172.6	1,897	3,185	4,350	1,067	1,522	2,479	3,380
Middle East	17.9	26.2	34.3	451	661	864	229	297	422	552
Africa	11.4	15.8	20.6	288	398	518	180	214	292	380
Central & South	18.3	30.1	44.7	461	759	1,125	174	225	399	617

Carbon Emissions in the Annex I Countries, 1990 and 2010, and the Effects of the Kyoto Protocol in 2010

Country/Region	Million Metric Tons			Percent Change	
	1990 Estimates	2010 Baseline Projection	2010 Kyoto Target	From 1990	From 2010 Baseline
Annex I Industrialized	2,769	3,420	2,584	-7	-24
United States	1,345	1,787	1,251	-7	-30
Western Europe	934	1,016	860	-8	-15
Annex I EE/FSU	1,135	835	1,153	2	38
FSU	854	591	853	0	44
EE	281	244	300	7	23
Total	**3,904**	**4,255**	**3,737**	**-4**	**-12**

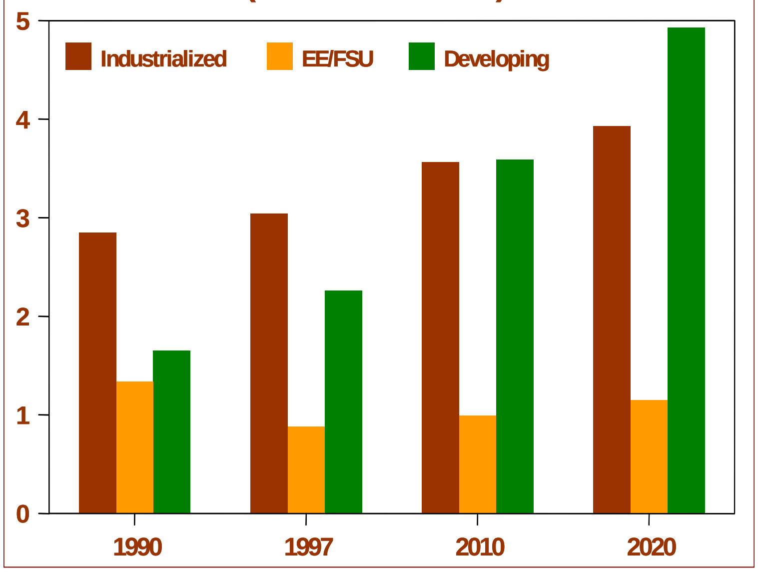
In the IEO2000, carbon emissions exceed their 1990 levels by 40 percent in 2010 and by 72 percent in 2020. Total emissions are projected to reach 8.1 billion metric tons in 2010 and 10.0 billion metric tons in 2020.

Emissions grow most quickly in the developing countries, where long-term, fast-paced economic and energy growth and continued heavy reliance on fossil fuels are projected. By 2010, emissions in the developing world are expected to exceed those of the industrialized countries.

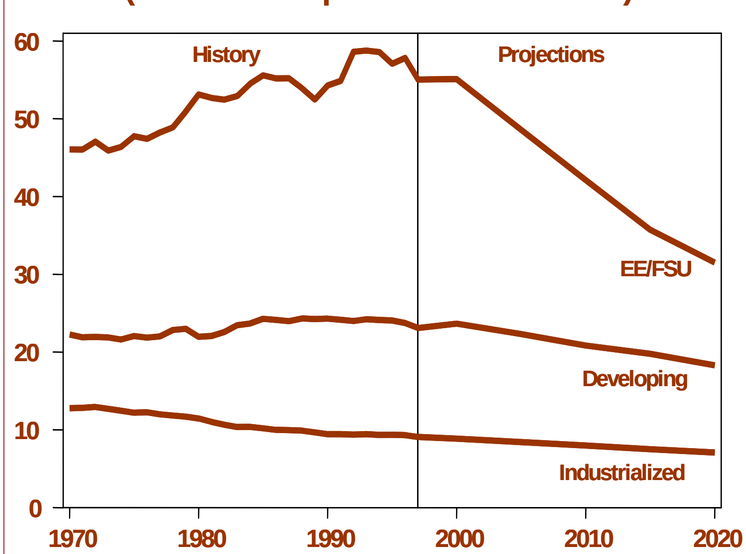
Energy intensity is expected to improve in the industrialized world over the forecast, by 1.1 percent per year. In the developing countries intensity is also projected to improve by 1.0 percent per year.

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

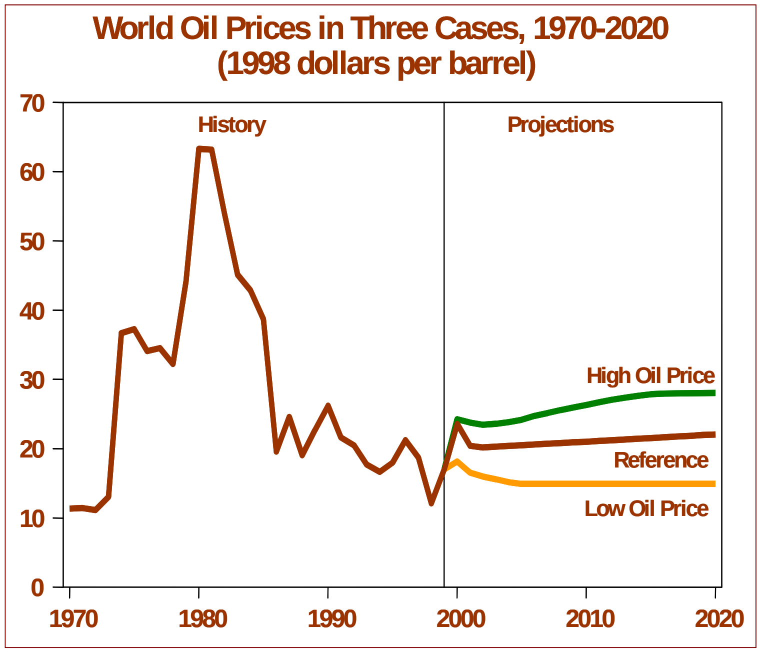
World Carbon Emissions by Region, 1990-2020 (billion metric tons)



World Energy Intensity by Region, 1970-2020 (thousand Btu per 1997 dollar of GDP)

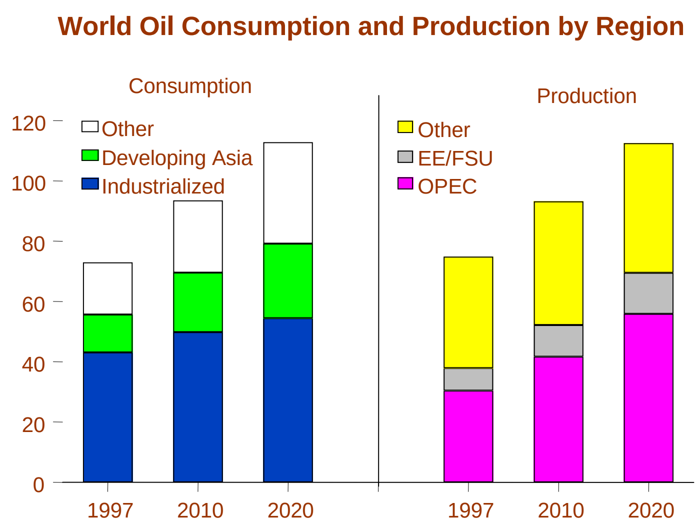


World oil prices recovered substantially in 1999 from their record lows of 1998, mostly because OPEC (and non-OPEC Mexico and Norway) were able to sustain oil production cuts set by the cartel in March 1999, and because oil demand began to recover among the Southeast Asian nations that had been stuck in economic recession since 1997.



Short-term price movements do not affect the long-term price projections, 5 to 10 years out. Oil prices are expected to reach $22 (constant 1998 U.S. dollars) in 2020.

Oil use is projected to rise to 113 million barrels per day by 2020. Most of this increase occurs in the transportation sector. In the developing countries, nontransportation oil uses also experience robust growth, in part because oil products are substituted for noncommercial fuels (such as wood burning for home heating and cooking) as incomes rise and the energy infrastructure matures.



OPEC's share of world oil supply is projected to increase significantly over the forecast horizon. More than two-thirds of the increase in world oil demand over the next two decades is expected to be supplied by OPEC.

Coal Demand

During 2000, 1.07 billion short tons of coal were consumed in the United States. The greatest demand for coal was by electricity generating plants that burn coal to produce electricity. Some 982.6 million short tons, 91.0 percent of the total, were used by the electric power sector to produce more than half (51.4) percent) of all electricity generated. Each ton of coal consumed at an electric power plant produces about 2,000 kilowatthours of electricity. A pound of coal supplies enough electricity to light ten 100-watt bulbs for about an hour.

The second largest sector of coal demand was for industrial use, which amounted to 65.2 million short tons in 2000. Some industries that used coal included cement, chemicals, paper, and primary metals. Cement plants use about a ton of coal for each 3.5 tons of cement produced. Small amounts of coal are also used to manufacture a number of everyday products, such as photographic film base, carbon and graphite electrodes, varnishes, perfumes, dyes, plastics, paints, and inks.

United States coal imports totaled 12.5 million short tons in 2000, a 37.7-percent increase from 1999 imports. Imports represented less than 1 percent of U.S. consumption and were equivalent to about 26 percent of U.S. exports. The increase in imports in 2000 was attributable to increased demand for low-sulfur coal. The average price of all coal imported into the United States fell by 2.2 percent, to $30.10 per short ton in 2000 from the 1999 price of $30.77.

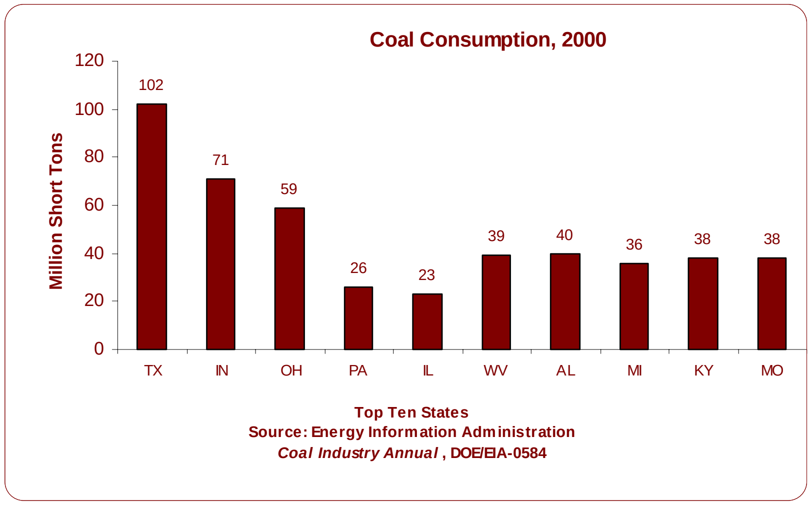
Colombia remained the largest supplier of U.S. imports, with 7.6 million short tons; Venezuela followed with 2.0 million short tons, and Canada with 1.9 million short tons. Although, imports consisted primarily of steam coal bought by a few East Coast power plants, coal from Canada was largely metallurgical coal used by coke plants in Illinois, Indiana, and Michigan.

Coal exports account for a small segment of the U.S. coal industry, and remained unchanged from 1999. Metallurgical coal exports increased in 2000 by 2.2 percent, regaining some of the loss experienced in 1999. The market for U.S. steam coal exports dropped somewhat in 2000. Total steam coal exports were down (by 2.6 percent) to a level of 25.7 million short tons, down from 26.3 million short tons in 1999. Canada represented the largest steam coal export market for the United States, accounting for 58.1 percent of all steam coal exports in 2000, despite the 4.1 percent drop from the 1999 level.

In 2000, 28.9 million short tons of coal were consumed by coke plants (an increase of 3 percent over 1999), and residential/ commercial consumption declined to 4.1 million short tons, down from 4.9 million short tons in 1999., other industrial use of coal (largely in the food, paper, chemical, nonmetallic mineral products, and primary metal manufacturing industries) fell slightly to 65.2 million short tons in 2000, continuing its downward trend in recent years. Competition from natural gas has gradually been diminishing coal use in the manufacturing industry. Coal is converted into coke through a process known as “carbonization.” Coke is then used in smelting iron ore to produce steel. Both the number of coke plants and the amount of coal carbonized have declined since 1973. There are presently about half as many coke plants as there were a decade ago.

Coal stocks at the end of 2000 totaled 140.1 million short tons, a drop of 43.4 million short tons. Stocks held by coal producers and distributors fell by 7.6 million short tons, a decrease of 19.2 percent. Industrial users, including coke plants, held a total of 6.1 million short tons, a decrease of 1.4 million short tons. Coal stocks in the electric power sector declined by 34.4 million short tons in 2000, helping to keep production levels down. The colder than normal weather in many parts of the country combined with the tight coal market at the end of the year, kept inventories at levels well below historical levels.

Texas led all States in coal consumption in 2000, using 102 million short tons. Indiana and Ohio were second and third, respectively. These three States accounted for over 21 percent of the total U.S. coal consumption for the year. North Dakota, which ranked tenth in coal use, is the site of one coal gasification plant that uses 6.3 million tons of lignite per year to produce about 54 billion cubic feet per year of synthetic natural gas.



More information on this subject can be found in the following EIA publications: *Coal Industry Annual 2000 Executive Summary*, *U.S. Coal Supply and Demand: 2000 Review, Quarterly Coal Report,* and *Monthly Energy Review.*

Coal Prices

In the early 1900s, coal was the Nation's major fuel source, supplying almost 90 percent of its energy needs. Later, coal's importance declined, mainly because petroleum and natural gas were cleaner, more cost effective, and more efficient. However, at the present time, coal is the primary source used for electricity generation because it is now far cheaper than other fossil fuels, and because it is also more abundant in the United States than any other fossil fuel. In 2000, coal receipts by the electric power industry totaled a record 983 million short tons. Of the total coal consumed in the United States (1,080 million short tons in 2000), 91 percent was used for generating electricity -- accounting for over half of the total electricity produced.

During the early 1970s, natural gas was the least expensive fuel used to generate electricity. In 1970, electric utilities paid on the average, about 28 cents per million Btu of natural gas, 31 cents per million Btu of coal, and 42 cents per million Btu of petroleum. Since 1976, however, coal has been the least expensive fossil fuel used to generate electricity. In 1999, on a dollars-per-million-Btu basis, natural gas was the most expensive fossil fuel ($2.59), petroleum was second ($2.56), and coal was least expensive ($1.22). Although, these figures show that the cost of generating electricity from coal has increased significantly, it is still lower than the cost of generating electricity from either natural gas or petroleum. The average price for coal delivered to electric utilities was $24.28 per short ton in 2000, with the spot-market price being only slightly higher at $24.85.

The average coal export price for 2000 was $34.90 per short ton. Coal exports in 2000 totaled 58 million short tons, far below the 1996 high of over 90 million short tons. The total coal imports for 2000 rose to an annual level of 12.5 million short tons, an increase from the 1999 level of 9 million short tons. The average coal import price for 2000 was $30.10 per short ton, down from the high of $34.32 per short ton in 1997.

Average Mine Price of U.S. Coal 1990-2000

Year	Dollars per Short Ton
1990	21.76
1991	21.49
1992	21.03
1993	19.85
1994	19.41
1995	18.83
1996	18.50
1997	18.14
1998	17.67
1999	16.63
2000	16.78

Source: Energy Information Administration,
Coal Industry Annual 2000

Another important use of coal is to produce coke, which is used in smelting iron ore to make steel. The average price paid for the special type of coal used to make coke generally declined in the early 1980s. From 1993 to 2000, it decreased from $47.44 per short ton to $44.45 per short ton.

The average mine price per short ton of coal in 2000 was $16.78 up from $16.63 in 1999. Because coal is so abundant, and as long as it remains relatively low priced, power plants will continue to use it rather than the two other major fossil fuels--petroleum and natural gas--to generate electricity.

More information on this subject can be found in the following EIA publications: *Electric Power Monthly, Coal Industry Annual*, *Quarterly Coal Report*, and *Annual Energy Review, Cost and Quality of Fuels for Electric Utility Plants*.

Coal Production

Coal, a fossil fuel like petroleum and natural gas, is a sedimentary organic rock that contains more than 50 percent carbonaceous material by weight. It is composed largely of carbon, hydrogen, oxygen, nitrogen, and sulfur, with smaller amounts of other materials ranging from aluminum to zirconium.

Coal had its beginning as plants that grew in swamps hundreds of millions of years ago, before dinosaurs and animals ever existed. Geological processes working over vast spans of time compressed and altered the plant remains, increasing the percentage of carbon present, thereby producing the different ranks of coal: lignite, subbituminous, bituminous, and anthracite.

In the United States, lignite is mined chiefly in Texas, North Dakota, and Louisiana; subbituminous coal is mined principally in Wyoming. Bituminous coal is mined mostly in the Appalachian and Interior Regions, while anthracite, the highest ranking coal, is mined only in northeastern Pennsylvania. Over 50 percent of the coal produced in the nation in 2000 was bituminous coal.

In 2000, Wyoming was the Nation's leading coal-producing State with production of 339.3 million short tons, which was about 31 percent of the national total. West Virginia ranked second, with 159.6 million short tons, and Kentucky was third, with 132.1 million short tons. Together, these three States accounted for 58 percent of total U.S. coal production - the same percentage as in 1998.

U.S. coal production in 2000 reached 1,074 million short tons. This is slightly less than the 1998 record coal production of 1,117 million short tons. However, for the first time in 40 years coal production decreased for two consecutive years, declining 2.4 percent (26.8 million short tons) from the 1999 level. Nevertheless, overall coal consumption increased in 2000. The additional needs of the industry were answered by a substantial drawdown in stocks of 42.9 million short tons--lowering year-end stock levels by 23.4 percent from 1999 levels.

In 2000, each coal region produced less than in 1999. Coal production west of the Mississippi River in 2000 dropped from a 1999 record high of 571 million short tons to 566 million short tons. Miner productivity rose to roughly 20 tons per miner per hour, in part due to the use of new, upgraded equipment at the mines.

In 1998 there were 186 mines in the United States that produced 1 million or more short tons. They produced 75 percent of the total national production, although they represented only 11 percent of active mines. The Nation's largest coal mine, located in Wyoming, produced over 55 million short tons. Of the 186 large mines, 120 mines east of the Mississippi River produced over 304 million short tons, and 66 mines west of the Mississippi River produced 536 million short tons.

Total U.S. productivity in 2000 reached 7.02 short tons per miner per hour. The average number of miners working daily fell to 71,522. The average mine price of coal for 2000 rose to $16.78 per short ton, up from $16.63 per short ton in 1999.

Federal and Indian lands have become increasingly important sources of coal. The 440.1 million short tons produced from these lands in 2000 accounted for about 41 percent of the total U.S. coal output. Federal coal lands produced well over 90 percent of this in 10 States, and Indian coal lands yielded the rest in three States.

An Indian coal lease is granted to a mining company to produce coal from Indian lands in exchange for royalties and other revenues. A Federal coal lease is granted to a mining company from land owned and administered by the Federal Government in exchange for royalties and other revenues.

World coal production and consumption has been in a period of generally slow growth since the late 1980s, a trend that is expected to continue. Although 1999 world consumption, at 4.7 billion short tons, was 15 percent higher than coal use in 1980, it was lower than in any year since 1984. World coal production decreased to 5 billion short tons in 1998 and then to 4.7 billion short tons in 1999. The major producers were China, the United States, India, and Australia. These four leading producers accounted for about 62 percent of the total produced in 1998.

More information on this subject can be found in the following EIA publications: *Annual Energy Review (historical)*; *Coal Data: A Reference; Weekly Coal Production Report*; *Coal Industry Annual*; *Coal Industry Annual Data Tables*; *Monthly Energy Review (historical)*; *International Energy Annual, and International Energy Outlook*.

Coal Reserves

In the United States, there are vast deposits of coal--more extensive than those of natural gas and petroleum, the other major fossil fuels. Identified resources include the demonstrated reserve base (DRB), which comprises coal resources that have been mapped within specified levels of reliability and accuracy and which occur in coal beds meeting minimum criteria for thickness and depth from the surface that generally support economic mining under current technologies.

The actual proportion of coal resources that can be mined and recovered economically from undisturbed deposits varies from less than 40 percent in some underground mines to more than 90 percent at some surface mines. In some underground mines, much of the coal may be left untouched as pillars needed to prevent surface collapse. Adverse geologic features, such as folding, faulting, and interlayered rock strata, limit the amount of coal that can be recovered at some underground and surface mines.

Because of property rights, land use conflicts, and physical and environmental restrictions, some coal in the demonstrated reserve base (DRB) may not be available or accessible for mining. However, over 50 percent of the DRB may be recoverable. As of January 1, 1997, it was estimated that the remaining U.S. recoverable coal reserves totaled 275 billion short tons, from a demonstrated reserve base of 508 billion short tons.

Coal “rank” refers to the degree of alteration or “coalification” that the organic source material in coal has attained. There are four major ranks of coal in the U.S. classification scheme, from highest to lowest: anthracite, bituminous, subbituminous, and lignite. In the United States, coal rank is classified according to its heating value, its fixed carbon and volatile matter content, and, to some extent, its agglomerating characteristics (or caking properties during combustion). Of the four ranks, bituminous coal accounts for over half (52 percent) of the demonstrated reserve base (DRB). Bituminous coal is concentrated primarily east of the Mississippi River, with the greatest amounts in Illinois, Kentucky, and West Virginia. All subbituminous coal (38 percent of the DRB) is west of the Mississippi River, with most of it in Montana and Wyoming. Lignite, the lowest-rank coal, accounts for about 9 percent of the DRB and is found mostly in Montana, Texas, and North Dakota. Anthracite, the highest-rank coal, makes up only 15 percent of the DRB and is concentrated almost entirely in northeastern Pennsylvania.

Worldwide, coal is the most abundant of the fossil fuels, and its reserves are also the most widely distributed. Estimates of the world’’s total recoverable reserves of coal in 1999 are about 1,089 billion tons. The resulting ratio of coal reserves to production exceeds 220 years, meaning that at current rates of production (and no change in reserves), coal reserves could last for another two centuries. The distribution of coal reserves around the world varies notably from that of oil and gas, in that significant reserves are found in the United States and the Former Soviet Union (FSU) but not in the Middle East. The United States and the FSU each have roughly 25 percent of global coal reserves. China (11 percent), Australia (9 percent), Germany (6 percent), South Africa (5 percent), and Poland (4 percent) also have significant amounts of the world's recoverable coal reserves.

EIA obtains new information and data updates largely through its Coal Reserves Data Base program initiated in 1990. That program has encouraged the participation of State agencies in revising coal resource and reserves estimates in their respective States. Since 1990, new demonstrated reserve base (DRB) and recoverable reserve estimates have been developed by State geological and mining agencies and EIA through cooperative agreements in Ohio, Wyoming, New Mexico, eastern Kentucky, and Illinois. These projects include improved analyses of coal quality, accessibility, and recoverability in the study areas. In addition to updating the core resource data, they result in improved estimates of the heat and sulfur content and typical net recovery of the reserves.

More information on this subject can be found in the following EIA publications: *International Energy Outlook, Coal Industry Annual*, *U.S. Coal Reserves: A Review and Update - 1997 (Summary)*, and *Annual Energy Review*.

Electric Power in General

Traditional electric utilities in the United States are responsible for ensuring an adequate and reliable source of electricity to all consumers in their service territories at a reasonable cost. Electric utilities include investor-owned, publicly owned, cooperatives, and Federal utilities. Power marketers are also considered electric utilities--these entities buy and sell electricity, but usually do not own or operate generation, transmission, or distribution facilities. Utilities are regulated by local, State, and Federal authorities.

The electric power industry is evolving from a highly regulated, monopolistic industry with traditionally structured electric utilities to a less regulated, competitive industry. The Public Utility Regulatory Policies Act of 1978 (PURPA) opened up competition in the generation market with the creation of qualifying facilities. The Energy Policy Act of 1992 (EPACT) removed some constraints on ownership of electric generation facilities and encouraged increased competition in the wholesale electric power business.

Nonutility Power Producers

Qualifying Facilities: PURPA facilitated the emergence of a group of nonutility electricity-generating companies called qualifying facilities or QFs. Under PURPA, small power producers and cogenerators receive status as a QF by meeting certain requirements for ownership, operating methods, and efficiency. Those requirements were established by the Federal Energy Regulatory Commission (FERC).

Cogenerators: Facilities which produce electricity and another form of useful thermal energy through the sequential use of energy (usually heat or steam for industrial processes or heating/cooling purposes) are called cogenerators--many of which have status as QFs. Cogenerators are primarily engaged in business activities (such as, agriculture, mining, manufacturing, transportation, education). The electricity that they do generate is mainly for their own use, but any excess is sold to the host utility.

Independent Power Producers: Entities that are also considered nonutility power producers in the United States. These facilities are wholesale electricity producers that operate within the franchised service territories of host utilities and are usually authorized to sell at market-based rates. Unlike traditional electric utilities, Independent Power Producers do not possess transmission facilities or sell electricity in the retail market.

Exempt Wholesale Generators: EPACT modified the Public Utility Holding Company Act (PUHCA) and created another class of nonutility power producers: exempt wholesale generators (EWGs). EPACT exempted EWGs from the corporate and geographic restrictions imposed by PUCHA. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.

Total electric power generating capability as of year-end 2000 totaled 811,625 megawatts of which 74.2 percent was attributed to utilities and 25.8 percent to nonutilities.

Coal accounted for 38.8 percent of generating capability and 51.8 percent of the 3,800 billion kilowatthours of electric industry net generation.

The average price of electricity in the United States increased in 2000, for the second consecutive year since 1992, to 6.81 cents per kilowatthour. The three states with the highest average price of electricity were Hawaii (14.0 cents per kilowatthour), New Hampshire (11.3 cents per kilowatthour), and New York (11.4 cents per kilowatthour). The three lowest were Kentucky (4.2 cents per kilowatthour), Idaho (4.2 cents per kilowatthour), and Wyoming (4.3 cents per kilowatthour).

More Information on this subject can be found in the following EIA publications: *Monthly Energy Review*, *Annual Energy Review*, *Electric Power Monthly*, *Electric Sales and Revenue 2000, Electric Power Annual Volume I*, and *Electric Power Annual , Volume II.*

Electricity Capability

The United States electrical system is the largest in the world, with over twice the generating capability of any other country. (Capability is a measure of the steady hourly output that a generating system is able to supply.) By the end of 2000, the industry, comprised of two segments--utilities (approximately 3,200) and nonutilities (more than 2,100)--had 811 gigawatts (GW) of capability to supply the nation's demand for electricity. Of this total, utilities own 602 GW (74 percent) and nonutilities own 209 GW (26 percent). Nonutility sources include industrial plants, independent power producers, and cogenerators (generating facilities that produce electricity and another form of useful thermal energy used for industrial, commercial, heating, or cooling purposes).

During the year, however, the share of the total industry capability owned by nonutilities rose from 19 to 26 percent, primarily as a consequence of the sale of generating units by utilities to nonutility companies. The total installed capacity of nonutility generating facilities was 209 gigawatts at the end of 2000, 40 percent more than in 1999. The restructuring of the electric power industry has resulted in 48,000 megawatts during 1999 of net summer capability that have been sold (or reclassified) to nonutilities. Although the effect of the shift from utility to nonutility ownership of generating units was relatively small at the national level, it can be observed more strongly at the State level when restructuring legislation required or encouraged divestiture of the utility's generating assets. This shift in ownership shares reflects the sale of plants, as well as unit additions and retirements during the year.

In 2000, the largest share, 38.8 percent, of the nation's generating capability was in coal-fired plants. Gas-fired plants represented 12.2 percent of the total U.S. capability, nuclear plants provided a 12-percent share, and petroleum-fired plants about 6 percent. Petroleum/natural gas (combined) generating capability was about 18 percent, while renewable energy, dominated by hydropower, provided the remainder.

In order to meet the growing demand for electricity and to offset retirements of existing capacity, a projected 393 GW of new capacity will be needed by 2020. Between 1999 and 2020, 26 GW (27%) of the current nuclear capacity and 43 GW (8%) of current fossil-steam capacity are expected to be retired.

Of the 393 GW of new capacity needed, 92 percent is projected to be combined-cycle or combustion turbine technology, including distributed generation capacity, fueled by natural gas. More than 22 GW of new coal-fired capacity is projected to come on line by 2020, accounting for almost 6 percent of all capacity expansion. Renewable energy technologies account for the remaining 2 percent of capacity expansion by 2020 -- primarily wind, biomass gasification units, and municipal solid waste units. Because the best resources for hydropower have already been developed, hydropower capacity is expected to increase only slightly in the future.

More information on this subject can be found in the following EIA publications: *Annual Energy Outlook, Inventory of Electric Utility Power Plants, Electric Power Annual, Volume I,* and *Electric Power Annual, Volume II*.

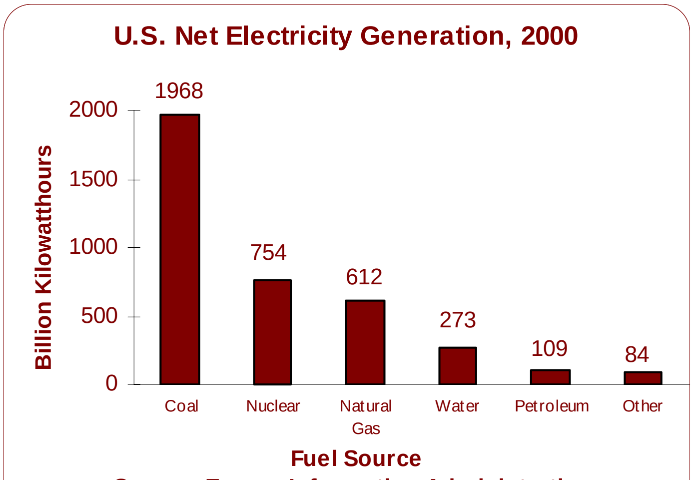
Electricity Generation

Consumers expect electricity to be available whenever they plug in an appliance, turn a switch, or open a refrigerator. Satisfying these instantaneous demands requires an uninterrupted flow of electricity. In order to meet this requirement, utilities and nonutility electricity power producers operate several types of electric generating units, powered by a wide range of fuel sources. These include both fossil fuels (coal, natural gas, and petroleum), and renewable fuels (water, geothermal, wind, and other renewable energy sources).

Coal was the fuel used to generate the largest share (51.8 percent) of electricity in 2000 1,968 billion kilowatthours(kWh). [This is over one and a half times the annual electricity consumption of all U.S. households (1,141 billion kWh).] Natural gas was used to generate 612 billion kWh (16.1 percent), and petroleum accounted for 109 billion kWh (3 percent).

Steam-electric generating units burn fossil fuels, such as coal, natural gas, and petroleum. The steam turns a turbine that produces electricity through an electrical generator. Natural gas and petroleum are also burned in gas turbine generators where the hot gases produced from combustion are used to turn the turbine, which, and in turn, spins the generator to produce electricity. Additionally, petroleum is burned in generating units with internal-combustion engines. The combustion occurs inside cylinders of the engine, which is connected to the shaft of the generator. The mechanical energy provided from the engine drives the generator to produce energy.

In 2000, approximately 40 quads of energy were used to generate electricity. Roughly one-third of this was converted into the 13 quads of electricity that reached end-users (3,800 billion kilowatthours). The other two-thirds wound up mostly as waste heat and dissipated into the environment.



Source: Energy Information Administration, Monthly *Energy Review*, DOE/EIA-0035.

In nuclear-powered generating units, the boiler is replaced by a reactor in which the fission of uranium is used to make steam to drive the turbine. Nuclear generating units accounted for the second largest share (20 percent) of electricity generation in the United States in 2000, 754 billion kWh.

Hydroelectric power units use flowing water to spin a turbine connected to a generator. In a falling water system, water is accumulated in reservoirs created by dams, then released through conduits to apply pressure against the turbine blades to drive the generator. In a run-of-the-river system, the force of the river current applies the pressure to the turbine blades to produce electricity. In 2000, hydroelectric generation had the fourth largest share (7 percent) of electricity production at 273 billion kWh.

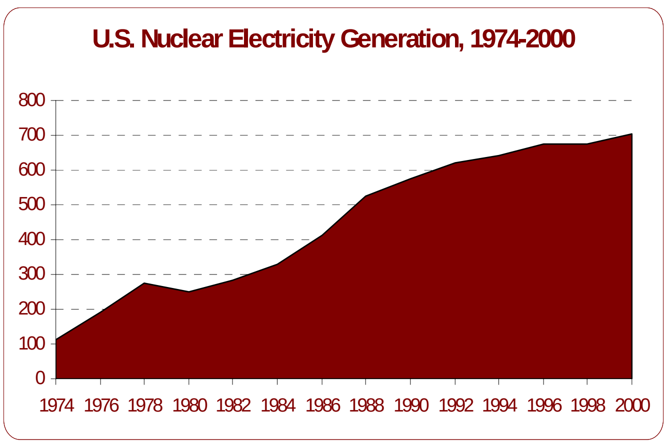
Nonwater renewable sources of electricity generation presently contribute only small amounts (about 2 percent) to total power production. These sources include geothermal, refuse, waste heat, waste steam, solar, wind, and wood. Electricity generation from these sources in 2000 totaled 84 billion kWh. Total electric power industry generation in 2000 was 3,800 billion kWh, 2.5 percent greater than the 1999 total of 3,705 billion kWh. Of this total, utilities net generation for 2000 was 3,015 billion kWh, and net generation by nonutility power producers was 785 billion kWh.

More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Annual Energy Review, Electric Power Monthly,* and *Electric Power Annual.*

Nuclear Power Generation

Electricity has been generated by burning fossil fuels (coal, oil, and gas) since before the turn of the twentieth century. For over three decades, however, a nonfossil fuel, uranium, also has been used to produce electricity. The first U.S. nuclear power plant went into commercial operation in 1957 at Shippingport, Pennsylvania. Since then, the use of nuclear-generated electricity has grown substantially in the United States.

The U.S. nuclear power industry achieved its third straight year of record power generation levels during 2000 Total power generated was 754 billion kilowatthours, 3.5 percent above the previous record of 728.1 billion kilowatthours set in 1999. This represents continued growth in power production for the nuclear power industry that had produced only 577.0 billion kilowatthours as recently as 1990. The record year 2000 output was achieved despite the fact that the industry had only 104 operating reactors compared to 111 operating reactors as recently as 1990. Record output was attained through an annual net capacity factor of 88.1 percent during 2000 compared to 85.3 percent in 1999 and 66 percent in 1990.

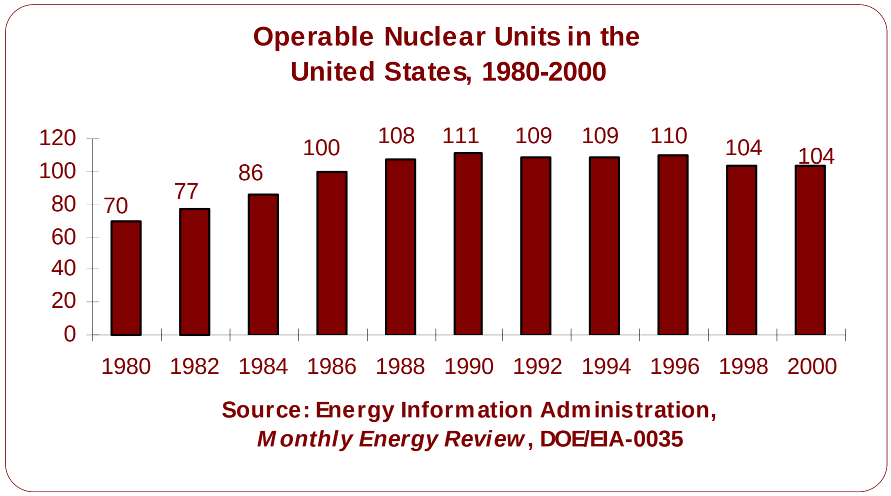


Nuclear generation surpassed 700 billion kilowatthours for the second consecutive year. For eight of the first nine months of 2000, nuclear generation was higher than in the same months during 1999. The nuclear industry generated 69.2 billion kilowatthours in July 2000, the highest level for the U.S. nuclear power industry ever.

The increase in nuclear generation over the past 2 years would have been enough to meet the power needs of all residential consumers in California in 2000.

Uranium occurs in nature in combination with small amounts of other elements. Economically recoverable uranium deposits have been discovered principally in the western United States, Australia, Canada, Africa, and South America. A ton of uranium ore mined in the United States yields about 7 pounds of uranium oxide (U3O8). Uranium ore must be chemically processed, enriched, and formed into pellets before it can be used as a fuel.

Uranium fuel pellets are loaded into hollow tubes called fuel rods. Hundreds of fuel rods form fuel assemblies that, along with control rods, are placed into a nuclear reactor core and then submerged in water. Like fossil fuels, the resulting uranium fuel produces heat that turns water into steam. The steam turns blades in a turbine connected to an electrical generator. However, heat is produced differently in a nuclear reactor than in a fossil fuel power plant.



The nucleus of an atom consists of combinations of protons and neutrons--each of about equal weight. Energy in a nuclear reactor is derived from a process called nuclear fission, in which a neutron strikes the nucleus of a uranium atom and is absorbed. The absorption of the neutron makes the nucleus unstable, causing it to split into two atoms of lighter elements and release heat and new neutrons. The heat is used to produce electricity, while the neutrons can potentially be absorbed by other atoms of uranium, resulting in more nuclear fissions. This continuing process of fissioning is called a chain reaction. It is sustained because, for every atom of uranium fissioned by a neutron, new neutrons are released to continue the process.

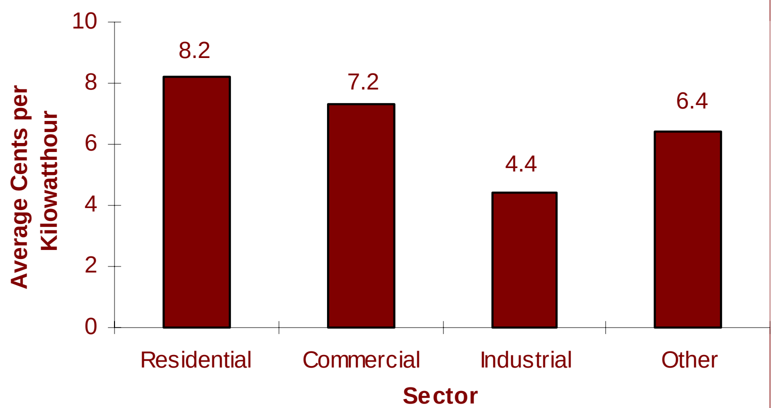
The United States has more nuclear generating capacity, 97 million kilowatts, than any other nation in the world; next is France, third is Japan, and fourth is Germany. Worldwide, growth in nuclear power has slowed and this trend is expected to continue. While no nuclear reactors have been ordered in the United States since 1978, several countries, notably France, Japan, and South Korea, continue to have ambitious nuclear construction programs. Concerns about issues such as high-level waste disposal, decommissioning expenses when reactors are retired, and the use of nuclear reactors to relieve possible global warming associated with fossil fuel-based generation will influence the future level of growth of nuclear power worldwide.

More information on this subject may be found in the EIA publications: *Monthly Energy Review, Annual Energy Review* and *Nuclear Power Generation and Fuel Cycle Report.*

Electricity Prices

Electricity prices, or rates, are the fees an electric utility company charges its customers for service. Electric utility companies charge their customers different rates, depending on the type of customer, the kind of contract, and on the customer's electricity needs. An electric bill is computed on the basis of the individual customer's rate, the level of consumption, and other charges, such as taxes and fuel adjustments.

Average Retail Prices of Electricity, 2000



Source: Energy Information Administration, *Electric Power Annual 2000*, Vol. 1 DOE/EIA-0348(2000/1)

That collection of rates is called a tariff. The tariff is designed to provide the privately owned electric utility with enough income to allow investors to earn a cash return and cover operation and maintenance costs. Most of the larger utilities operate as regulated franchises, meaning that the prices they charge are subject to public review, often by a State public utility commission.

Publicly owned electric utilities are nonprofit, local government agencies established to provide service to their communities and nearby consumers at cost, returning excess funds to the consumer in the form of community contributions, more economic and efficient facilities, and lower rates.

Publicly owned electric utilities (which number approximately 2,000) include municipals, public power districts, State authorities, irrigation districts, and other State organizations.

There are approximately 900 cooperative electric utilities in the United States currently doing business in 47 States. These utilities are owned by their members and are established to provide electricity to those members.

Average retail prices of electricity are calculated by dividing utility revenue by retail sales. The resulting measurement is the cost, or average revenue per kilowatthour, of electricity sold. (A kilowatthour is equal to one watt of power supplied to an electric circuit steadily for 1,000 hours.) Electric utilities usually offer three primary classes of service: residential, commercial, and industrial. The average price per kilowatthour for residential consumers is generally higher than for any other sector due in part to higher costs associated with serving many consumers who use relatively small amounts of electricity. The industrial sector has the lowest rates due to the economies of serving a few consumers who use relatively large amounts of electricity.

Federal electric utilities have the lowest average revenue per kilowatthour among ownership classes because these electric utilities have access to relatively low-cost financing and generally utilize inexpensive hydroelectric facilities. Because publicly owned electric utilities also have access to relatively low-cost financing and are nonprofit entities, they have lower average revenue per kilowatthour than investor-owned electric utilities. Although cooperative electric utilities have economic advantages similar to those of publicly owned electric utilities, cooperatives generally serve sparsely populated areas and provide service to a higher percentage of rural residential consumers than other classes of utilities, cooperatives generally serve sparsely populated areas and provide service to a higher percentage of rural residential consumers than other classes of utilities. Additionally, many cooperatives do not generate electricity, but as full requirement customers of electric utilities with generation facilities, must pay requirement demand charges. As a result, cooperative electric utilities usually have higher average revenue per kilowatthour than publicly owned electric utilities.

During the first half of the century, the national average price of electricity decreased as more efficient generating units were brought into service. This general trend has continued. The average real price of electricity to all sectors in 1999 (that is, the price adjusted to reflect the purchasing power of the dollar) was 22 percent below the price in 1960. However, the apparent stability in electricity prices masked fluctuations that occurred throughout the period. For example, following the oil embargo in 1973 and 1974, electricity prices increased rapidly because of escalation in the costs of fuel, labor, materials, capital, and services to electric utilities.

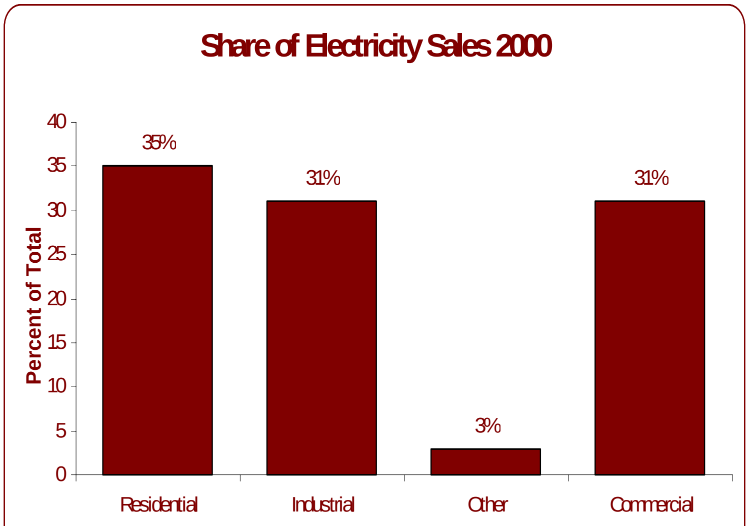
More information on this subject can be found in the following EIA publications: *Annual Energy Review, Electric Sales and Revenue, and Electric Power Annual.*

Electricity Sales

The electric utility industry began in 1882 with the establishment of Thomas Edison power station in New York City. The use of electricity has been growing ever since. It is vital to virtually every aspect of our economy.

Electricity sales can be defined as the number of kilowatthours (kWh=1,000 watthours) sold during a given period of time. Sales are normally classified according to the type of customer or service using the electricity, such as residential, commercial, industrial, transportation, and "other," which includes public street and highway lighting.

In 2000, U.S. electric power companies generated 3,799,944 million kilowatthours of electricity and sold an estimated 3,421,414 million kilowatthours to their consumers. This amount represents about a 26 percent increase over 1990, when total sales were about 2,712,555 million kilowatthours. In 1973, by contrast, total sales were 1,712,909 million kilowatthours.



Source: Energy Information Administration,
Annual Energy Review 2000, DOE/EIA-0384
Electric Sales and Revenue, 2000, DOE/EIA-0540

Since 1980, sales to residential consumers have increased almost 60 percent. Residential consumers, in 2000, purchased 1,192,446 million kilowatthours, an increase of about 4 percent over the amount purchased the previous year. The 2000 residential sales accounted for 35 percent of total sales.

Since 1980, sales to commercial consumers have more than doubled to 1,055,232 million kilowatthours in 2000. Industrial consumers in 2000 purchased 31 percent of sales to consumers, or 1,070,827 million kilowatthours, about 1 percent higher than in 1999, reflecting the impact of restructured markets on traditional full-service utilities. Other sales (public street and highway lighting, sales to public authorities, and sales to railroads and railways) were 109,496 million kilowatthours, about 3 percent of total sales to all consumers and slightly more than the amount sold for similar purposes in 1999.

More information on this subject can be found in the following EIA publications: *Electric Power Annual, Electric Power Monthly, Electric Sales and Revenue 2000, and Annual Energy Review (historical)*.

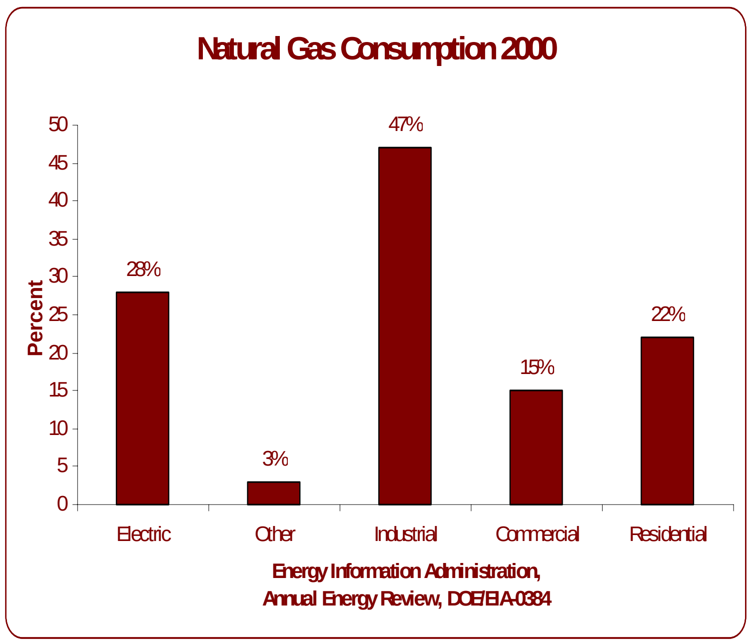
Natural Gas Consumption

Natural gas is best known as the fuel that produces the blue flame that heats our food, our water, and our homes and buildings. This gas is mostly methane. It is also used to generate electricity, provide heat for industrial processes, and as a raw material to produce petrochemicals, plastics, paints, and a wide variety of other products.

For centuries, natural gas has been used in various parts of the world. The Chinese, 2,000 years ago, piped natural gas through bamboo poles from shallow wells. They then burned the gas to heat large pans to evaporate sea water for salt. It is believed that the first commercial use of natural gas in the western world was for street lighting in Genoa, Italy, in 1802.

In 2000, U.S. natural gas consumption reached 22.6 trillion cubic feet (Tcf), 4 percent more than in 1999. The decade began with 18.7 trillion cubic feet of natural gas consumption in 1990 and increased steadily to 22.0 trillion cubic feet in both 1996 and 1997. Warmer-than-normal winter weather contributed to the decline in consumption to 21.3 trillion cubic feet in 1998. The historical peak in U.S. natural gas consumption occurred in 2000 when 22.6 trillion cubic feet were consumed.

Consumption of natural gas in the industrial and electric utility sectors moved in opposite directions in 2000. Residential natural gas consumption in 2000 was 5.0 trillion cubic feet. Commercial natural gas consumption in 2000 was 3.2 trillion cubic feet. Industrial consumption in 2000 was 9.5 trillion cubic feet, 5.6 percent higher than in 1999. Electric utilities consumed 3.0 trillion cubic feet of natural gas in 2000, which was 2 percent less than in 1999. By the year 2020, U.S. natural gas consumption is projected to range between 28 Tcf and 32 Tcf, with most of the increase being used for electricity generation.



In 1999, world natural gas consumption was 84.2 Tcf. Russia, which consumed 14.0 Tcf, and the United States, which consumed 21.7 Tcf, accounted for 47 percent of the total. By the year 2020, total world consumption is expected to range between 110 Tcf and 174 Tcf.

More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Natural Gas Monthly*, *Natural Gas Annual*, *International Energy Annual, Annual Energy Outlook, and International Energy Outlook.*

Natural Gas Reserves

The most widely accepted theory about how natural gas was created is that it was formed by the underground decomposition of organic matter (dead plants and animals). If the organic matter is buried deeply enough, much of the carbon and hydrogen is converted to methane, the major component of natural gas. (The chemical formula for methane is CH4--that is, a molecule of methane has one carbon atom and four hydrogen atoms.) Large volumes of methane can be trapped in the subsurface of the Earth at places where the right geological conditions occurred at the right times. Such a place is called a reservoir.

Proved reserves of natural gas are estimated quantities that analyses of geological and engineering data have demonstrated to be economically recoverable in future years from known reservoirs. Produced natural gas placed in temporary underground storage is not included in proved reserves.

The capacity to produce gas is related to the level of proved natural gas reserves, which in turn is closely tied to the level of gas well drilling. Because production rates from new gas wells typically decline rapidly, maintenance of the levels of proved gas reserves and production capacity requires continual drilling of new gas wells in sufficient numbers.

"*Wet after lease separation" is the term used to describe the volume of natural gas remaining after removal of lease condensate, a mixture consisting primarily of pentanes and heavier hydrocarbon.*

As of December 31, 2000, the estimated U.S. total proved reserves, wet after lease separation, were 186,510 billion cubic feet (Bcf). Of that quantity, non-associated gas (natural gas not in contact with significant quantities of crude oil) accounted for 156,677 Bcf. The remaining natural gas occurred with crude oil, either as free gas (associated) or in solution (dissolved), and accounted for 29,833 Bcf. Estimated proved reserves of dry natural gas in the United States were 177,427 Bcf. (Dry natural gas is the volume of natural gas that remains after the economically liquefiable hydrocarbon portion has been removed from the produced gas stream at a natural gas processing plant.) Dry natural gas reserves increased 6 percent in 2000, a gain of 10,021 Bcf. Coalbed methane accounted for 9 percent of reserves and 7 percent of production in 2000

In addition to proved natural gas reserves, there are large volumes of natural gas classified as undiscovered recoverable resources. Those resources are expected to exist because the geologic settings are favorable. Over half of all onshore undiscovered gas resources are located in the Alaska and Gulf Coast regions. Over one-third of all undiscovered gas resources are estimated to be in Federal offshore areas, primarily near Alaska, in the Gulf of Mexico, and along the Atlantic Coast.

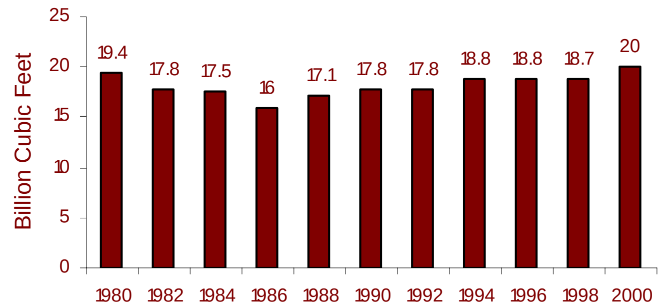
More information on this subject can be found in the following EIA *publications: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* and *Annual Energy Review.*

Natural Gas Supply

Natural gas, a combustible gaseous mixture of hydrocarbons, mostly methane, is produced from wells drilled into underground reservoirs of porous rock. When the gas is first withdrawn from the well, it may contain liquid hydrocarbons and nonhydrocarbon gases. The natural gas is separated from these components near the site of the well or at a natural gas processing plant. The gas is then considered “dry” and is sent through pipelines to a local distribution company, and ultimately, to the consumer.

The United States had 20.0 trillion cubic feet of marketed natural gas production in 2000, which was 1 percent less than in 1999. Four States continue to account for the majority of the natural gas produced in the United States, comprising 73 percent of the total in 1999: Texas (31 percent), Louisiana (25 percent), Oklahoma (8 percent), and New Mexico (8 percent).

U.S. Dry Natural Gas Production, 1980-2000 (Billion Cubic Feet)



Source Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035

After reaching a peak of 22.6 Tcf in 1973, U.S. natural gas production declined as low as 16.1 Tcf in 1986. Since then, production has steadily increased. By the year 2020, production is expected to range between 25.7 Tcf and 28.0 Tcf.

In addition to natural gas production, the U.S. gas supply is augmented by imports, by withdrawals from storage, and by supplemental gaseous fuels. Imports of natural gas in 2000 totaled 3.5 Tcf, or 16 percent of total U.S. gas consumed. The vast majority of these imports arrive from Canada via pipeline. During 2000, pipeline imports grew by 5.2 percent compared with a 10 percent rise in 1999. Trinidad became the major supplier of LNG imports, with 99 billion cubic feet, or 44 percent, of total LNG imports. LNG is first cooled to -260 degrees Fahrenheit, at which point the gas becomes a liquid. (As a liquid, over 600 cubic feet of natural gas can occupy the same amount of space that one cubic foot of natural gas would at standard conditions.) The liquefied natural gas is then transported to the United States on specially designed ships.

There were 413 active storage fields in the United States during 1999. Natural gas is injected into these fields generally during April thorough October and withdrawn during November through March. The volume of gas available for withdrawal ranges from near 3 Tcf at the end of September to under 1 Tcf at the end of March.

Supplemental gas supplies, which in 2000 totaled 86 Bcf, include blast furnace gas, refinery gas, propane-air mixtures, and synthetic natural gas, which is manufactured from petroleum hydrocarbons or from coal. The single largest source of synthetic gas is the Great Plains Synfuels Plant in Beulah, North Dakota, which, in 2000, produced 49 Bcf of gas from coal.

World production of natural gas is dominated by the United States (24 Tcf) and Russia (21 Tcf), whose combined gross production accounts for 45 percent of the 102 Tcf produced in 1998.

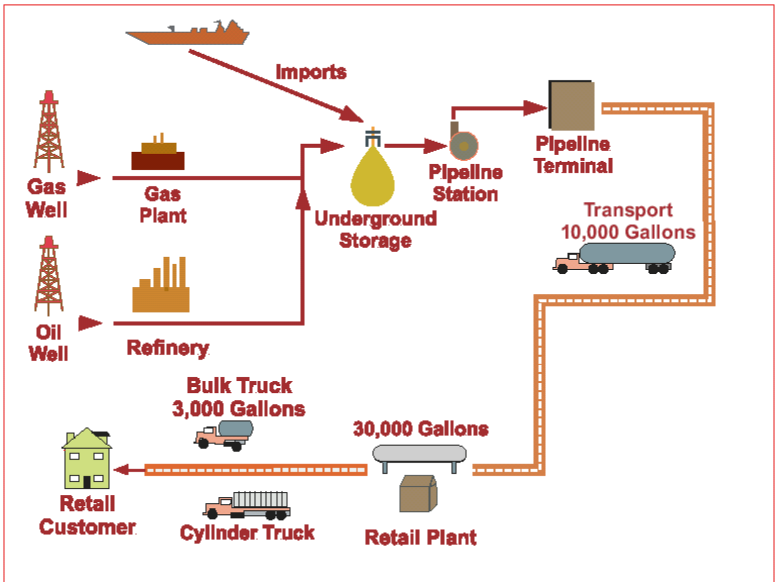
More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Natural Gas Monthly, Natural Gas Annual, International Energy Annual,* (historical)*, Annual Energy Outlook.*

Propane

Most people know propane as the fuel in a white container attached to a barbecue grill. But propane has long proven its versatility for heating homes, heating water, cooking, drying clothes, fueling gas fireplaces, and as an alternative fuel for vehicles. However, more propane is used to make petrochemicals which are the building blocks for plastics, alcohols, fibers, and cosmetics, to name just a few.

Propane naturally occurs as a gas at atmospheric pressure but can be liquefied if subjected to moderately increased pressure. It is stored and transported in its compressed liquid form, but by opening a valve to release propane from a pressurized storage container, it is vaporized into a gas for use. Simply stated, propane is always a liquid until it is used. Although propane is non-toxic and odorless, an identifying odor is added so the gas can be readily detected.

Propane Production and Distribution System



Source: Energy Information Administration

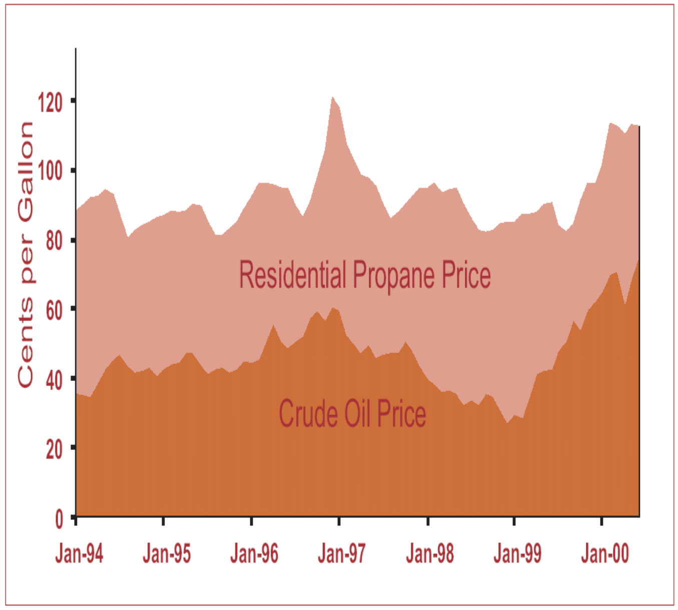
A unique feature of propane is that it is not produced for its own sake, but is a by-product of two other processes, natural gas processing and petroleum refining. Figure 1 shows a diagram of where propane comes from and how it gets to the consumer.

Natural gas plant production of propane primarily involves extracting materials, such as propane and butane, from natural gas to prevent these liquids from condensing and causing operational problems in natural gas pipelines. Similarly, when oil refineries make major products, such as motor gasoline and heating oil, some propane is produced as a by-product of those processes. It is important to understand that the by-product nature of propane production means that the volume made available from natural gas processing and oil refining cannot be adjusted when prices and/or demand for propane fluctuate.

In addition to these two processes, demand is met by using imports of propane and by using stored inventories. Although imports provide the smallest (about 10 percent) component of U.S. propane supply, they are vital when consumption exceeds available domestic supplies of propane. Propane is imported by land (via pipeline and rail car from Canada) and by sea (in tankers from such countries as Algeria, Saudi Arabia, Venezuela, Norway, and the United Kingdom).

Propane prices are subject to a number of influences; some are common to all petroleum products, and others are unique to propane. Because propane is portable, it can serve many different markets, from fueling barbecue grills to producing petrochemicals. The price of propane in these markets is influenced by many factors, including the prices of competing fuels in each market; the distance propane has to travel to reach a customer; and the volumes used by a customer. More specifically, propane prices are affected by:

Propane Prices Follow Crude Oil Price Trends



Note: Data are not adjusted for inflation.
Source: Crude Oil: West Texas Intermediate Crude Oil Spot Prices as reported by *Reuters News Services*, Propane Prices: Energy Information Administration, *Petroleum Marketing Monthly*.

Crude Oil and Natural Gas Prices. Although propane is produced from both crude oil refining and natural gas processing, its price is influenced mainly by the cost of crude oil. This is because propane competes mostly with crude oil-based fuels.

Supply/Demand Balance. Propane supply and demand is subject to changes in domestic production, weather, and inventory levels, among other factors. While propane production is not seasonal, residential demand is highly seasonal. This imbalance causes inventories to be built up during the summer months, when consumption is low, and for inventories to be drawn down during the winter months, when consumption is much higher. When inventories of propane at the start of the winter heating season are low, chances increase that higher propane prices may occur during the winter season.

Colder-than-normal weather can put extra pressure on propane prices during the high demand winter season because there are no readily available sources of increased supply except for imports. And imports may take several weeks to arrive, during which time larger-than-normal withdrawals from inventories may occur, sending prices upward. Cold weather early in the heating season can cause higher prices sooner rather than later, since early inventory withdrawals affect supply availability for the rest of the winter.

Proximity of Supply. Due to transportation costs, customers farthest from the major supply sources (the Gulf Coast and the Midwest) will generally pay higher prices for propane.

Markets Served. Propane demand comes from several different markets that exhibit distinct patterns in response to the seasons and other influences. Residential demand, for instance, depends on the weather, so prices tend to rise in the winter. The petrochemical sector is more flexible in its need for propane and tends to buy it during the spring and summer, when prices decline. If producers of petrochemicals should have to depart from this pattern for some reason, the coinciding demand could raise prices. And when prices rise unexpectedly, as they do sometimes in the winter, petrochemical producers pull back, helping to ease prices. Prices could also be driven up if agricultural sector demand for propane to dry crops remains high late into the fall, when residential demand begins to rise.

Where are Crucial Winter Inventories Stored & How Are They Delivered to Consumers?

There are three types of storage for propane inventories (stocks): primary, secondary, and tertiary. Primary storage consists of refinery, gas plant, pipeline, and bulk terminal stocks. Primary inventory withdrawals provide the second largest source of propane during the winter heating season, the largest source being production from natural gas plants and refineries. Propane storage facilities at the primary level are generally located near the major production and transportation hubs and consist of pressurized depleted mines and underground salt dome storage caverns clustered mostly in Conway, Kansas, and Mont Belvieu, Texas. The reservoirs are linked directly to the major natural gas liquids pipelines and are capable of maintaining high deliverability rates during peak demand periods.

Secondary storage consists primarily of large, pressurized above-ground tanks located at approximately 25,000 retail dealers scattered throughout the United States. Tertiary storage consists of small above-ground tanks located mostly at residences and commercial establishments.

The primary mode of transporting propane within the United States is by approximately 70,000 miles of interstate pipelines. The pipeline system is most developed along the corridors between production areas and petrochemical consumers along the Gulf Coast and the agricultural-industrial consumers in the Midwest. The Northeast and South Atlantic States each are served by a single pipeline. The upper Midwest also is served by two lines from Canada. Other modes of transport include about 22,000 rail tank cars, 6,000 highway bulk transports, 18,000 local delivery trucks, about 60 inland waterway barges, and several ocean-going tankers.

The Use of Propane Varies According to Customer, Season, and Region

Petrochemical Industry Use - Seasonal & Regional.

About 47 percent of the propane consumed in the United States is used in the petrochemical industry. Propane is only one of many possible raw materials used by this industry to make plastics, etc. Therefore, because the petrochemical industry can switch to other commodities when the price of propane becomes too high, propane usage here tends to exhibit seasonal patterns, rising during the summer when its price is low and falling during the winter heating months (October-March), when its price is high. Petrochemical demand is also regional due to the high concentration of petrochemical plants in the Gulf Coast region.

Residential/Commercial Use - Highly Seasonal & Regional.

Excluding use by propane gas grills, residential and commercial use accounts for 39 percent of all propane used in the United States. Of the 101.5 million households in the U. S., 8.1 million depend on propane for one use or another. Because 57 percent of these households rely on propane for their primary heating fuel, this is highly seasonal usage . Propane is most commonly used to provide energy to areas not serviced by the natural gas distribution system. Thus, it competes mainly with heating oil for space heating purposes. Homeowners in the Midwest use it predominantly for heating, while Northeast residences rely on it more for cooking.

Farm Use - Seasonal & Regional.

Farm use is the third largest retail propane market, accounting for about 8 percent of total demand. Farm or agricultural uses of propane include crop drying, weed control, and fuel for farm equipment and irrigation pumps. The amount of propane used for crop drying, the largest component of farm use, is not only seasonal (fall months), but can vary greatly from year to year depending on crop size and moisture content. Agricultural use of propane is primarily concentrated in the Midwest.

Industrial Use - Not Seasonal But Regional.

Industrial use of propane, the fourth largest propane-consuming sector accounts for about 4 percent of U. S. consumption. Uses include space heating, soldering, cutting, heat treating, and fork-lift fuel. Sixty percent of industrial applications for propane occur in the Midwest and are typically not seasonal.

Transportation.

While transportation represents the smallest sector to use propane, the largest alternative fuel in use today for transportation is propane.

Why Do Propane Prices Spike?

Propane prices occasionally spike, increasing disproportionately beyond that expected from normal supply/demand fluctuations. The main cause appears to lie in the logistical difficulty of obtaining resupply during the peak heating season. Because propane is produced at a relatively steady rate year-round by refineries and gas processing plants, there is no ready source of incremental production when supplies run low. Propane wholesalers and retailers are forced to pay higher prices as propane markets are bid higher due to dwindling supply. Consequently, higher propane prices are simply passed on to consumers. Imports do not offer much cushion for unexpected demand increases or supply shortages due to the long travel time. On the other hand, when propane prices do spike, the petrochemical sector may cut back on its use, thus freeing up supplies for other uses.

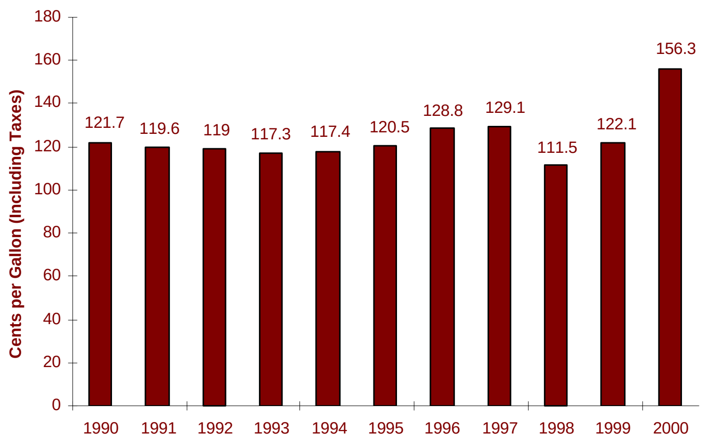
More information on this subject can be found in the following EIA publications: Winter Fuels Report, Petroleum Supply Monthly, Petroleum Supply Annual, Petroleum Marketing Monthly, Petroleum Marketing Annual.

Crude Oil and Petroleum Product Prices

Crude oil is processed at a refinery where it is transformed into useable petroleum products. The average cost of crude oil to U.S. refineries (referred to as the "composite refiner acquisition cost") greatly affects the final cost of petroleum products. The composite refiner acquisition cost peaked in 1981 at $35.24 per barrel. Two dramatic energy-related events of 1990 and 1991 caused a slight fluctuation in crude oil prices: the war in the Persian Gulf, which entailed the loss of Iraqi and Kuwaiti oil, and the dissolution of the Soviet Union, the world's leading oil producer. In 1990, as a result of the Persian Gulf crisis, the average cost of crude oil rose to $22.22 per barrel. Prices declined steadily until 2000. The yearly average cost of crude oil in 2000 was $28.23 per barrel.

Motor gasoline constitutes about half of the total volume of products produced from crude oil. Retail motor gasoline prices generally follow the same pattern as crude oil prices; however, prices fluctuate widely and are based on supply and demand conditions. Data from EIA indicate that taxes and factors other than the cost of crude oil account for more than half of the price paid by the consumer for a gallon of motor gasoline.

Motor Gasoline Prices US City Average, All Types, 1990-2000



Source: Energy Information Administration, *Monthly Energy Review, DOE/EIA-0035*

Environmental concerns have played a key role in changing the formulation of motor gasoline. The phaseout of lead in motor gasoline was brought about by a series of 1970s initiatives aimed at reducing emissions. By 1990, leaded motor gasoline represented only 5 percent of total motor gasoline sales and had been replaced almost entirely by unleaded motor gasoline. Refining processes have been changing in order to produce high octane unleaded motor gasoline, and in response to tighter restrictions on motor gasoline volatility (RVP), which became effective in 1989. Oxygenates, such as methyl tertiary butyl ether (MTBE), and gasoline set forth in the Clean Air Act Amendments of 1990 (CAAA) will make these additives increasingly important in the future.

The CAAA also imposed new requirements on producers, transporters, and suppliers of distillate fuel oil. Those requirements included standards for fuels designated for on-highway use of a maximum sulfur content of 0.05 percent by weight and a minimum octane level of 40. Further, these fuels must also be colorless to clearly designate them for on-highway use. Other diesel or distillate fuels will be dyed blue. The restrictions were designed to combat emissions of sulfur dioxides and to assure the ignition performance of the diesel fuel meets the American Society for Testing and Materials standards for combustion. The CAAA standard took effect October 1, 1993, and affects about 46 percent of the total domestic demand for distillate fuel, or about 9 percent of total U.S. petroleum demand.

Distillate fuel oil is a general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on- and off-highway diesel engine fuel, and electric power generation.

No. 2 distillate includes No. 2 fuel oil and No. 2 diesel fuel. Currently these products are physically similar; however, No. 2 diesel fuel intended for use in passenger cars is blended with kerosene to increase its liquidity during cold weather. The cost of this process, in addition to Federal, State, and local motor fuel taxes, partially explains why No. 2 diesel fuel prices are higher than those for No. 2 fuel oil.

The average U.S. sales price of No. 2 fuel oil sold to residential consumers for heating was 119.4 cents per gallon in 1981; it then declined to 80.3 cents per gallon in 1987 and rebounded to 106.3 cents per gallon in 1990, further declined to 87.6 cents per gallon in 1999, and rose to 131.0 cents per gallon in 2000. The price data for No. 2 diesel fuel are for sales through company-operated retail outlets, include low sulfur diesel fuel only, and do not include taxes. In 2000, the price of No. 2 diesel fuel averaged 103.6 cents per gallon. The sales price of No. 2 diesel through company-operated outlets has been consistently lower than No. 2 fuel oil prices but, when taxes are added, diesel is more expensive for the consumer.

Residual fuel oil is the heavy, viscous oil that remains after the other fractions have been distilled off in the refining process. It is used for generating electricity, for space heating, for industrial purposes, and as fuel for ships. The average refiner's price of residual fuel oil to end users peaked at 75.6 cents per gallon in 1981. The average price was 62.2 cents per gallon in 2000.

In the late 1970s, prices of most petroleum products were subjected to Federal Government price control regulations. On January 28, 1981, all remaining product and crude oil prices were decontrolled, establishing a free market for petroleum pricing. Refiner, distributor, and retailer pricing decisions for petroleum products are now based on the operation of a free market economy and may, therefore, differ not only from region to region, but from State to State, and even from one area to another in the same State.

More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Annual Energy Review, Petroleum Marketing Monthly, Petroleum Marketing Annual,* and *Weekly Petroleum Status Report.*

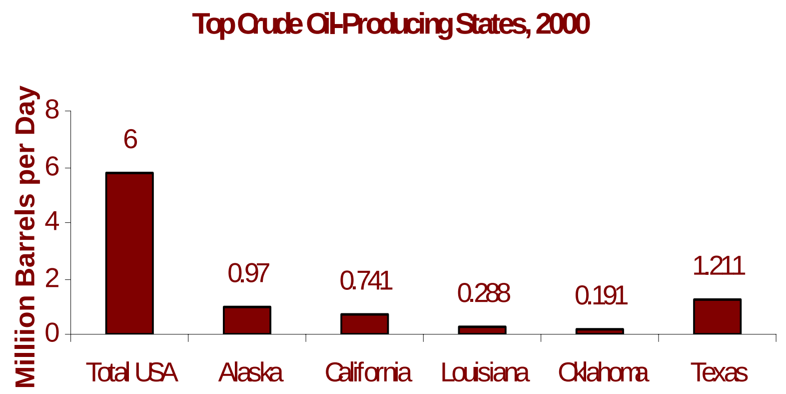
Crude Oil Production

Crude oil, a malodorous yellow-to-black liquid, is a product of the decayed remains of prehistoric marine animals and terrestrial plants. Over many centuries, organic matter in mud was buried under additional thick sedimentary layers. Additional sedimentary layers, the increasing heat and pressure caused crude oil-saturated shales to form, from which the oil was expelled. It then moved through adjacent rock layers until it became trapped underground in porous rocks called reservoirs.

While getting the oil out of the ground may seem complicated, moving it from the point of production to the final consumer is just as complex. Today, there are more than 200,000 miles of oil pipeline in the United States.

Drilling a well to extract crude oil is a complicated process, but it is the only way to confirm the existence of the oil. After initial exploration activities, site preparation begins. The type of rig system to be used, whether rotary or cable, is determined. When completed, the drilled well has been turned into a production facility capable of bringing a steady flow of oil to the surface, usually for many years.

In 2000, total domestic crude oil field production averaged 5,822,000 barrels per day, a decrease of 59,000 barrels per day from the 1999 average. The top crude oil-producing States are Texas, Alaska, California, Louisiana, and Oklahoma.



Source: Energy Information Administration. *Petroleum Supply Annual 2000*, DOE/EIA-0340.

The United States and Russia, along with the Organization of Petroleum Exporting Countries (OPEC),* accounted for 61 percent of the total crude oil produced in the world in 2000. The United States accounted for 8.5 percent of the world's total 2000 crude oil production, and Russia 9.5 percent. Because uses for crude oil in its natural state are limited, almost all crude oil is processed into finished petroleum products at a refinery. The refining process usually involves (1) *distillation,* or separation of the hydrocarbons that make up crude oil so that the heavier products, such as asphalt, are separated from some of the lighter products, like kerosene; (2) *conversion*, or cracking of the molecules to allow the refiner to squeeze a higher percentage of light products, such as gasoline, from each barrel of oil; and (3) *treatment*, or enhancement of the quality of the product which could entail removing sulfur from such fuels as kerosene, gasoline, and heating oils. The addition of blending components to gasolines is also a part of this process.

Crude oil is measured in barrels. A barrel of 42-U.S. gallons of crude oil yields slightly more than 44 gallons of petroleum products. This "process gain" of volume is due to a reduction in the density during the refining process. In 2000, one barrel of crude oil, when refined, yielded 19.4 gallons of finished motor gasoline, as well as smaller quantities of many other petroleum products.

Petroleum Products Yielded from One Barrel of Crude, 2000

Product	Gallons
Finished Motor Gasoline	19.40
Distillate Fuel Oil	9.70
Kero-Type Jet Fuel	4.33
Residual Fuel Oil	1.89
Still Gas	1.76
Petroleum Coke	1.97
Liquefied Refinery Gas	1.89
Asphalt and Road Oil	1.43
Naptha for Feedstocks	0.55
Other Oils for Feedstocks	0.55
Lubricants	0.50
Special Naphthas	0.17
Kerosene	0.17
Miscellaneous Products	0.17
Finished Aviation Gasoline	0.04
Waxes	0.04
Total	44.56

More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Annual Energy Review, Petroleum Supply Monthly,* and *Petroleum Supply Annual.*

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*OPEC comprises oil-producing and exporting countries that have organized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela are OPEC member countries. Prior to January 1, 1993, Ecuador was a member of OPEC.

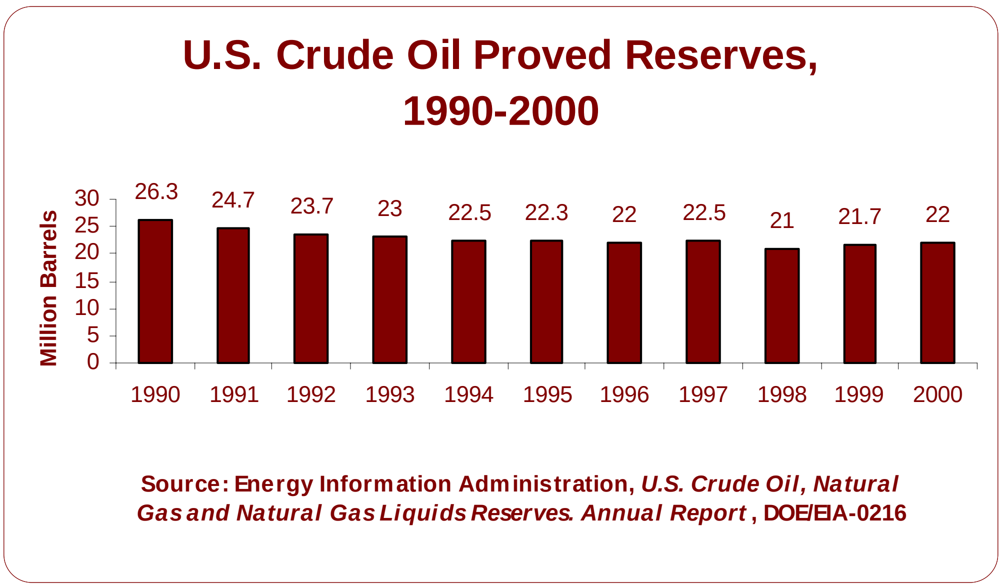
Petroleum Reserves

Proved reserves of crude oil are the estimated quantities which geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs, assuming existing economic and operating conditions.

Offshore refers to that geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line making the seaward limit of inland water.

Proved reserves make up the domestic production base and are the primary source of oil and gas used in the United States. Total proved reserves of crude oil in the United States, as of year-end 2000, are 22.05 billion barrels, a 1.3 percent increase from those of 1999 and the second consecutive year that crude oil reserves have increased Thirty-one States have crude oil reserves. The top five are Texas, with 5.3 billion barrels; Alaska, with 4.9 billion barrels; California, with 3.8 billion barrels; New Mexico, with 719 million barrels; and Oklahoma, with 610 million barrels. Also, there are substantial crude oil reserves located in Federal Offshore fields: 3.1 billion barrels in the Gulf of Mexico and 596 million barrels in the Pacific.

Estimates of proved crude oil reserves do not include the following: (1) “indicated additional reserves,” a category of oil that is reported separately and may become available from known reservoirs through the application of improved recovery techniques using current technology; (2) natural gas liquids (including lease condensate); (3) oil of doubtful recovery because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in undrilled prospects: (5) oil that may be produced from oil shales, coal, Gilsonite (asphalt), and other such sources.



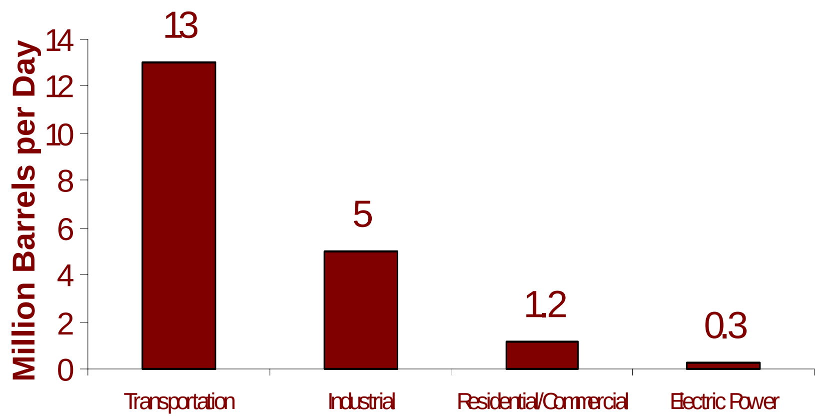
Volumes of crude oil placed in underground storage, such as those in the Strategic Petroleum Reserve, are not considered proved reserves. The Strategic Petroleum Reserve was created to diminish the impact of disruptions in petroleum supplies and to carry out obligations of the United States under the International Energy Program. In 1975, Public Law 94-163 (the Energy Policy and Conservation Act) established the Strategic Petroleum Reserve of up to one billion barrels of petroleum supplies. These petroleum stocks are to be maintained by the Federal Government for use during periods of major supply interruptions.

More information on this subject can be found in the following EIA publications: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report* and Annual Energy Review.

Petroleum Products

We find petroleum products in every area of our lives. They are easily recognized in the gasoline we use to fuel our cars and the heating oil we use to warm our homes. Less obvious are the uses of petroleum-based components of plastics, medicines, food items, and a host of other products. Petroleum products fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel); finished nonfuel products such as solvents and lubricating oils; and feedstocks for the petrochemical industry such as naphtha and various refinery gases. Demand is greatest for products in the fuels category, especially motor gasoline.

Estimated Petroleum Demand by End-Use Sector, 2000

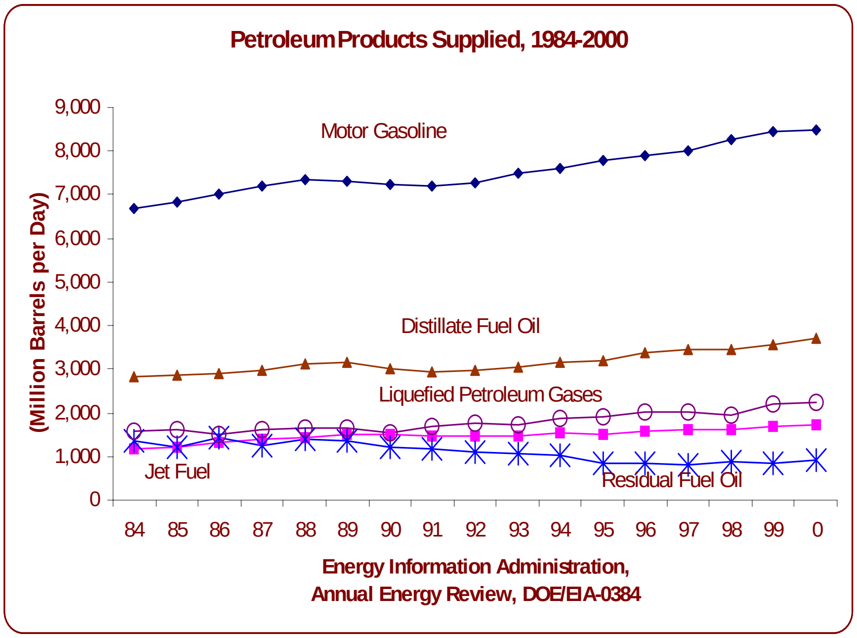


Source: Energy Information Administration, *Annual Energy Review*, DOE/EIA-0384, Tables 5.12a and 5.12b.

Petroleum products contribute about 40 percent of the energy used in the United States. This is a larger share than any other energy source including natural gas with a 25 percent share, coal with about a 23 percent share, and the combination of nuclear, hydroelectric, geothermal and other sources comprising the remaining 12 percent share. 1 It is projected that petroleum consumption in the United States will increase by 1.2 percent annually, reaching 24.7 million barrels per day by the year 2020. Although petroleum consumption will continue to increase overall, its share of total energy use has shrunk over the past several decades as a result of conservation efforts, fuel efficiency improvements, and growing use of alternative sources of energy. While petroleum will undoubtedly remain the Nation's leading energy source for some time, the need to balance environmental, economic, and energy security objectives has led policy-makers and planners to seek means of diversifying the sources and reducing the role of this resource in our overall energy supply.

Petroleum products, especially motor gasoline, distillate (diesel) fuel, and jet fuel, provide virtually all of the energy consumed in the transportation sector. Transportation is the greatest single use of petroleum, accounting for an estimated 67 percent of all U.S. petroleum consumed in 2000. The industrial sector is the second largest petroleum consuming sector and accounts for about 25 percent of all petroleum consumption in the U.S. Residential/Commercial and the electric utility sectors account for the remaining 8 percent of petroleum consumption.

Demand for petroleum products in the United States averaged 19.7 million barrels per day in 2000. This represents about 3 gallons of petroleum each day for every person in the country. By comparison, petroleum demand averaged about 2 gallons per person per day in the early 1950's and nearly 3.6 gallons per person per day in 1978.



Price levels, economic growth trends, and weather conditions influence the demand for petroleum products. For example, oil prices affect a consumer's willingness to use petroleum instead of other fuels such as natural gas. High prices relative to other fuels tend to encourage fuel-switching, especially at electric utilities, in industrial plants having dual-fuel boilers, and in households that have wood- burning stoves and electric heaters available. High prices also provide incentive for individuals to adopt short-term conservation measures, such as adjusting thermostats and reducing discretionary driving. High prices stimulate long-term measures as well, such as design changes that increase fuel efficiency in automobiles, improved insulation in newly constructed and existing buildings, and design changes in appliances to improve energy efficiency. Once in place, these long-term conservation measures continue to affect fuel use regardless of subsequent price fluctuations.

Low oil prices tend to stimulate demand. Demand also increases during periods of economic expansion, particularly in the industrial and transportation sectors, as increases in the production of goods bring corresponding increases in transportation of raw materials and deliveries of finished products. Lower prices coupled with economic expansion consumption during periods in the mid-1980's mid-1990's.

Weather extremes (winters that are colder than normal or summers that are warmer than normal) also increase petroleum demand for heating or electricity generation for air- conditioning purposes. Milder weather than normal tends to reduce heating and air conditioning-related demand for petroleum fuels. Weather can also contribute to the seasonal variations in demand for transportation fuels such as gasoline.

Petroleum demand illustrated the effects of these factors several times during the 1990's. For instance, the Iraqi invasion of Kuwait on August 2, 1990, caused petroleum demand to sink to under 17 million barrels per day, its lowest level since 1987. The slowing economy and mild weather had weakened demand early in the year. Then, following the invasion, prices climbed rapidly in response to uncertainty over future supplies, with motor gasoline and jet fuel prices registering dramatic increases. Shortly after the United Nations Security Council approved an embargo against oil exports from Iraq and Kuwait, the Organization of Petroleum Exporting Countries (OPEC) adopted a resolution allowing member countries to exceed their production quotas to make up the difference. As production increases from OPEC and other countries began to offset the loss of Iraqi and Kuwaiti oil, petroleum prices subsided.

Petroleum Fuels

Fuel products account for nearly 9 out of every 10 barrels of petroleum used in the United States. The leading fuel, motor gasoline, consistently accounts for the largest share of petroleum demand. Demand for motor gasoline alone accounts for more than 40 percent of the total demand for petroleum products. Other petroleum fuels include distillate fuel oil (diesel fuel and heating oil), liquefied petroleum gases (LPG's) (including propane and butane), jet fuel, residual fuel oil, kerosene, aviation gasoline, and petroleum coke.

Motor gasoline is chiefly used to fuel automobiles and light trucks for highway use. Smaller quantities are used for off- highway driving, boats, recreational vehicles, and various farm and other equipment.

A number of factors influence the demand for motor gasoline. For example, rising gasoline prices in the 1970's encouraged consumers to reduce discretionary driving and stimulated consumer demand for smaller, more fuel efficient automobiles. The Corporate Average Fuel Economy (CAFÉ) Standards established by the Energy Policy and Conservation Act of 1975 set mileage standards for new cars that helped reduce gasoline demand even more as new, more fuel efficient cars replaced older, less efficient cars. The effects of the market shift to smaller cars and the fuel efficiencies resulting from the CAFÉ standards continued to restrain growth in gasoline demand through the 1980's. However, by the mid-1990's, fuel efficiency growth slowed considerably as low gasoline prices and rising disposable income spurred consumers to buy less fuel efficient light trucks, vans, and sport utility vehicles.

Environmental concerns have brought about a number of changes in gasoline composition. To meet emission standards specified in the Clean Air Act of 1970, automobile manufacturers introduced catalytic converters requiring un- leaded fuel beginning in the 1975 model year. The Environ- mental Protection Agency (EPA) issued regulations in 1973 establishing requirements for the availability of unleaded fuels and, as the new cars entered the fleet, unleaded gasoline began to displace leaded fuel. EPA continued the lead phase-down, further restricting the lead content of motor gasoline in 1982, 1985, and 1986. The Clean Air Act Amendments of 1990 banned lead use entirely, effective January 1, 1996.

As lead was eliminated, the use of other components, such as butane, aromatics, alcohols, and ethers, to boost gasoline octane increased. Some of these additives like butane increase the volatility, or evaporative tendency, of gasoline. As gasoline evaporates, contaminants are released into the atmosphere. EPA and several States have issued regulations to restrict gasoline volatility in the summer months when the problem is more severe. Federal regulations restricting gasoline volatility took effect in 1989. Several States and localities have also begun to require the use of other additives termed “oxygenates” in gasoline to reduce carbon monoxide emission levels during the wintertime. These restrictions and proposals to amend the Clean Air Act encouraged the industry to develop and market new “reformulated” gasolines. The Clean Air Act Amendments of 1990 set standards for re-formulated gasoline and mandated its use in several U.S. cities beginning in 1995. A number of “alternative” fuels have been developed for automotive use. Methanol (an alcohol produced from natural gas, coal, or biomass) and ethanol (an alcohol produced from biomass) are two alternative fuels that may be viewed as potential replacements for petroleum products or as additives for use in present or future gasoline formulations.

Compressed natural gas, electricity, propane, liquefied natural gas, hydrogen, and solar energy are other transportation fuel alternatives under consideration and in various stages of development.

Distillate fuel oil includes diesel oil, heating oils, and industrial oils. It is used to power diesel engines in buses, trucks, trains, automobiles, and other machinery. It is also used to heat residential and commercial buildings and to fire industrial and electric utility boilers. Specifications differ for heating oils and diesel fuels based primarily on the sulfur content of each fuel.

Diesel fuel accounts for about three-fourths of refinery first sales of distillate fuel oils. 8 Most diesel fuel is used for transportation purposes: highway diesel fuel represents more than half of distillate fuel sales. Residential heating, the next largest end-use category, represents about 12 percent of annual distillate use, but is concentrated in the winter months.

Environmental concerns also extended to diesel fuel. The Clean Air Act Amendments of 1990 mandated standards, effective October 1, 1993, for diesel fuels designated for on-highway use to a maximum sulfur content of 0.05 percent by weight.

Liquefied petroleum gases (LPG’s) rank third in usage among petroleum products, behind motor gasoline and distillate fuel oil. LPG’s are used as inputs (feedstocks) for petrochemical production processes. This is their major nonfuel use. LPG’s are also used as fuel for domestic heating and cooking, farming operations, and as an alternative to gasoline for use in internal combustion engines.

Individual LPG products have distinct uses. For example, propane is widely used as a fuel in the residential, commercial, and industrial sectors. It is also important as a petrochemical feedstock. Ethane is used primarily as a petrochemical feedstock. Butane is used as a gasoline blending component, although volatility regulations for gasoline have limited its use. Butane also has many domestic and industrial uses.

Most jet fuel is a kerosene-based fuel primarily used in commercial airlines. It requires a higher temperature to ignite and is safer for commercial use than naphtha-based fuel. Naphtha jet fuel meets the specifications required for certain military aircraft. It has a lower freezing point than commercial fuel and a lower flash (ignition) point. However, from October 1, 1993, through 1995, the U.S. military essentially converted most of its jet fleet from naphtha-type jet fuel to kerosene-type jet fuel.

Kerosene-type jet fuel is sometimes blended into heating oil and diesel fuel during periods of extreme cold weather. This is done to help alleviate viscosity (thickness), handling and performance problems associated with cold weather.

Electric utilities use residual fuel to generate electricity. Although this sector uses relatively little petroleum compared with the transportation and industrial sectors, the electric utility sector depends on petroleum for about 5 percent of its total energy requirements. Much of the surplus capacity for electricity generation is oil-fired, so petroleum use by utilities is expected to increase along with electricity demand. Residual fuel oil is also used as bunker fuel (fuel for ships), industrial boiler fuel, and heating fuel in some commercial buildings.

Kerosene is used for residential and commercial space heating. It is also used in water heaters, as a cooking fuel, and in lamps. Kerosene falls within the light distillate range of re- finery output that includes some diesel fuel, jet fuel, and other light fuel oils.

Petroleum coke can be used as a relatively low-ash solid fuel for power plants and industrial use (marketable coke) if its sulfur content is low enough, or used in nonfuel applications (catalyst coke), such as in refinery operations.

Nonfuel Products

Nonfuel use of petroleum is small compared with fuel use, but petroleum products account for about 89 percent of the Nation’s total energy consumption for nonfuel uses. There are many nonfuel uses for petroleum, including various specialized products for use in the textile, metallurgical, electrical, and other industries. A partial list of nonfuel uses for petroleum includes:

- Solvents such as those used in paints, lacquers, and printing inks
- Lubricating oils and greases for automobile engines and other machinery
- Petroleum (or paraffin) wax used in candy making, packaging, candles, matches, and polishes
- Petrolatum (petroleum jelly) sometimes blended with paraffin wax in medical products and toiletries
- Asphalt used to pave roads and airfields, to surface canals and reservoirs, and to make roofing materials and floor coverings
- Petroleum coke used as a raw material for many carbon and graphite products, including furnace electrodes and liners, and the anodes used in the production of aluminum.
- Petroleum Feedstocks used as chemical feedstock derived from petroleum principally for the manufacture of chemicals, synthetic rubber, and a variety of plastics.

Petrochemical Feedstocks

Petroleum feedstocks have been used in the commercial production of petrochemicals since the 1920's. Petrochemical feedstocks are converted to basic chemical building blocks and intermediates used to produce plastics, synthetic rubber, synthetic fibers, drugs, and detergents. Naphtha, one of the basic feedstocks, is a liquid obtained from the refining of crude oil.

Petrochemical feedstocks also include products recovered from natural gas, and refinery gases (ethane, propane, and butane). Still other feedstocks include ethylene, propylene, normal- and iso-butylenes, butadiene, and aromatics such as benzene, toluene, and xylene. These feedstocks are produced by processing products such as ethane (separated from natural gas), distillates, naphthas, and heavier oils.

Industry data show that the chemical industry uses nearly 1.5 million barrels per day of natural gas liquids and liquefied refinery gases as petrochemical feedstocks and plant fuel. 10 Demand for textiles, explosives, elastomers, plastics, drugs, and synthetic rubber during World War II increased the petrochemical use of refinery gases. Gas byproducts from the production of gasoline are an important source of many feedstocks.

More information on this subject can be found in the following EIA publication: *Petroleum : An Energy Profile (Table 2)*.

Petroleum Products Consumption

When crude oil was first discovered in the United States, it was taken from natural pools on the earth's surface and was used mainly for medicinal purposes. These natural pools supplied about 3 gallons of oil a day (per pool). As the population expanded and the need for the oil grew, and as whale oil, an alternative to crude oil, became scarce as a source for lighting, the need to produce more crude oil was addressed.

In Titusville, Pennsylvania, using the same technology as they used to drill for water, producers excavated the first successful oil well in 1859. As crude oil became ample, refineries sprang up to process it into useable petroleum products. The main product was kerosene, which began replacing whale oil as the prime source of illumination. Other main petroleum products refined out of a typical 42-gallon barrel (industry standard) were greases and lubricants. Today, there are many refined products, the major ones being motor gasoline, distillate fuel oil, and kerosene jet fuel. These major petroleum products heat homes and businesses and supply power to automobiles, transportation systems, and other industries.

In 2000, total U.S. demand for petroleum was 19.7 million barrels per day, of which 10.4 million barrels per day, or 52.9 percent, was from net imports (imports minus exports).

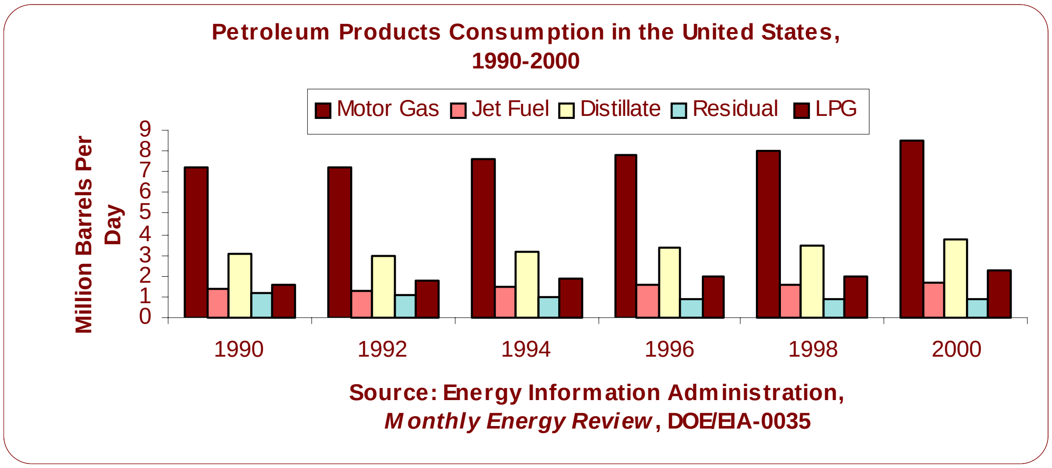
Imports nearly doubled between 1970 and 1973, the year of the Arab oil embargo, rising to nearly 6.3 million barrels per day, with crude oil accounting for more than half. Net imports averaged more than 6 million barrels per day. The growth in imports was due largely to economic growth, rising personal income, and greater numbers of automobiles all of which stimulated demand for oil, just as domestic crude oil production, which had peaked at 9.6 million barrels per day in 1970, began to decline.

Did you know that motor gasoline is the petroleum industry's principal refined product?

A record 8.5 million barrels per day were consumed in 2000.

Distillate fuel oil consists of diesel fuels and fuel oils. Diesel fuels furnish power to diesel engines, such as those used in heavy construction equipment, trucks, buses, tractors, trains, and some automobiles. No. 2 fuel oil is utilized in the central heating of homes and small buildings. Distillate fuel oil consumption for 2000 was 3.72 million barrels per day, the highest ever.

Residual fuel oil is heavier than distillate fuel oil; i.e., it has a higher density, viscosity, and boiling point. It is used mainly by electric utilities, large apartment and commercial buildings, and industries that maintain kilns, open-hearth furnaces, and steam boilers. Residual fuel use declined from 1977 to 1999, before rebounding in 2000 to 909 thousand barrels per day, a 71 percent decrease from the 1977 high of 3.1 million barrels per day. Conservation efforts and fuel-switching are the two main reasons cited for the drop in consumption. In 2000, the three countries that consumed the most petroleum products were the United States (19.7 million barrels per day), Japan (5.5 million barrels per day), and China (4.6 million barrels per day).

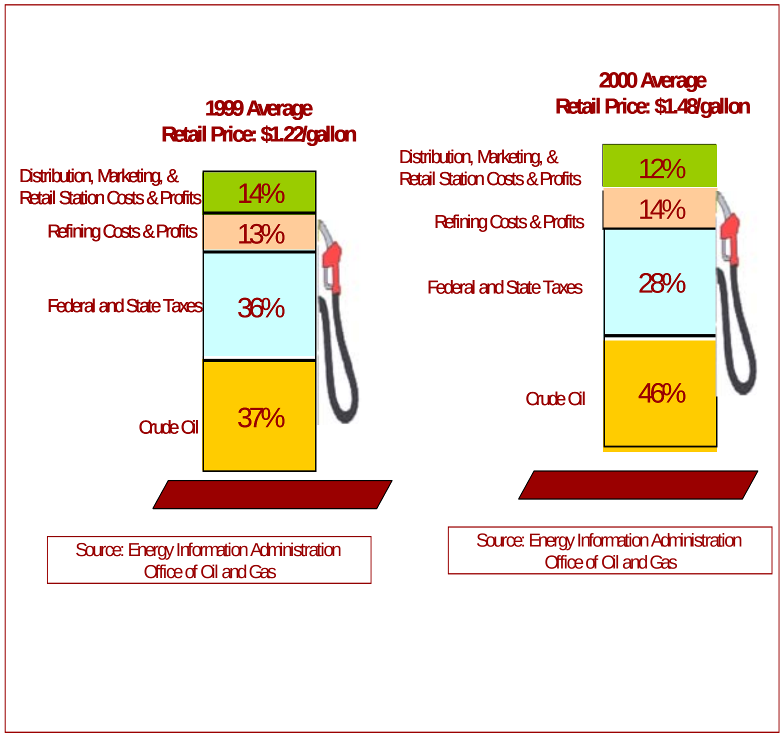


More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Annual Energy Review, Petroleum Marketing Monthly,* and *International Energy Annual, International Petroleum Monthly.*

A Primer on Gasoline Prices

Gasoline, one of the main products refined from crude oil, accounts for just about 20 percent of the energy consumed in the United States. The primary use for gasoline is in automobiles and light trucks. Gasoline also fuels boats, recreational vehicles, and various farm and other equipment. While gasoline is produced year-round, extra volumes are made in time for the summer driving season. Gasoline is delivered from oil refineries mainly through pipelines to a massive distribution chain serving 180,000 retail gasoline stations throughout the United States. There are three main grades of gasoline: regular, midgrade, and premium. Each grade has a different octane level. Price levels vary by grade, but the price differential between grades is generally constant.

What are the components of the retail price of gasoline?



The cost to produce and deliver gasoline to consumers includes the cost of crude oil to refiners, refinery processing costs, marketing and distribution costs, and, finally, the retail station costs and taxes. The prices paid by consumers at the pump reflect these costs, as well as the profits (and sometimes losses) of refiners, marketers, distributors, and retail station owners.

In 2000, when the price of crude oil averaged $28.36 per barrel, crude oil accounted for about 46% of the cost of a gallon of regular grade gasoline. In comparison, the average price for crude oil in 1999 was $17.46 per barrel, and it composed 37% of the cost of a gallon of regular gasoline. The share of the retail price of regular grade gasoline that crude oil costs represent varies somewhat over time and among regions.

Federal, State, and local taxes are a large component of the retail price of gasoline. Taxes (not including county and local taxes) account for approximately 36 percent of the cost of a gallon of gasoline. Within this national average, Federal excise taxes are 18.4 cents per gallon and State excise taxes average 19.96 cents per gallon. Also, seven States levy additional State sales taxes, some of which are applied to the Federal and State excise taxes. Additional local county and city taxes can have a significant impact on the price of gasoline.

Distribution, marketing and retail station costs, and profits combined make up 14% of the cost of a gallon of gasoline. Only 28% of service station outlets today are company stations, i.e., are owned or leased by a major oil company and operated by its employees. Nearly 72% are operated by independent dealers free to set their own prices. The price on the pump reflects both the retailer's purchase cost for the product and the other costs of operating the service station. It also reflects local market conditions and factors, such as the desirability of the location and the marketing strategy of the owner.

Why Do Gasoline Prices Fluctuate?

> *Why are California gasoline prices higher and more variable than others?*
>
> *The State of California implements its own reformulated gasoline program with more stringent requirements than Federally-mandated clean gasolines. In addition to the higher cost of cleaner fuel, there is a combined State and local sales and use tax of 7.25 percent on top of an 18.4 cent-per-gallon Federal excise tax and an 18.0 cent-per-gallon State excise tax.*
>
> *California prices are more variable than others because there are relatively few supply sources of its unique blend of gasoline outside the State. California refineries need to be running near their fullest capabilities in order to meet the State's fuel demands. If more than one of its refineries experiences operating difficulties at the same time, California's gasoline supply becomes very tight and the prices soar. Supplies could be obtained from the Gulf Coast and foreign refineries; however, California's substantial distance from those refineries is such that any unusual increase in demand or reduction in supply results in a large price response in the market before relief supplies can be delivered. The farther away the necessary relief supplies are, the higher and longer the price spike will be.*

Even when crude oil prices are stable, gasoline prices normally fluctuate due to such factors as seasonality and local retail station competition. Additionally, gasoline prices can change rapidly due to crude oil supply disruptions stemming from world events or domestic problems, such as refinery or pipeline outages.

Seasonality in the demand for gasoline. When crude oil prices are stable, retail gasoline prices tend to gradually rise before and during the summer, when people drive more, and fall in the winter. Good weather and vacations cause U.S. summer gasoline demand to average about 5% higher than during the rest of the year. Prices during the summer typically show a 3.5 cent-per-gallon increase, even after correcting for changes in crude oil prices.

Changes in the cost of crude oil. Events in crude oil markets were a major factor in all but one of the five run-ups in gasoline prices between 1992 and 1997, according to the National Petroleum Council's study U.S. Petroleum Supply - Inventory Dynamics.

Crude oil prices are determined by worldwide supply and demand, with significant influence by the Organization of Petroleum Exporting Countries (OPEC). Since it was organized in 1960, OPEC has tried to keep world oil prices at its target level by setting an upper production limit on its members. OPEC has the potential to influence oil prices worldwide because its members possess such a great portion of the world's oil supply, accounting for nearly 40% of the world's production of crude oil and holding about 67% of the world's estimated crude oil reserves. Rapid gasoline price increases have occurred in response to crude oil shortages caused by, for example, the Arab oil embargo in 1973, the Iranian revolution in 1978, the Iran/Iraq war in 1980, and the Persian Gulf conflict in 1990. The most recent gasoline price increases are due in part to OPEC crude oil production cuts in 1999. In addition, higher demand from a recovering Asian economy caused more competitive bidding for crude oil supplies in the international market and was a contributing factor to an increase in gasoline prices in 1999.

Product supply/demand imbalances. A continuing economic boom in the United States has led to greater demand for gasoline. If demand rises quickly or supply declines unexpectedly due to refinery production problems or lagging imports, gasoline inventories (stocks) may decline rapidly. When stocks are low and falling, some wholesalers become concerned that supplies may not be adequate over the short term and bid higher for available product. Such was the case in late summer 1997, as a demand surge drained gasoline stocks and prices rose rapidly.

Gasoline may be less expensive in one summer when supplies are plentiful vs. another summer when they are not. These are normal price fluctuations, experienced in all commodity markets. For example, the price of corn is higher than normal just before harvest time because corn inventories are depleted at that time. Prices may remain high after the harvest if a drought occurred during the growing season, thereby limiting the supply of corn. Or prices may decline when a healthy crop is produced.

However, prices of basic energy (gasoline, electricity, natural gas, heating oil) are generally more volatile than prices of other commodities. One reason is that consumers are limited in their ability to substitute between fuels when the price for gasoline, for example, fluctuates. So, while consumers can substitute readily between food products when relative prices shift, most do not have that option in fueling their cars.

Why do gasoline prices differ according to region?

Although price levels vary over time, Energy Information Administration (EIA) data indicate that average retail gasoline prices tend to be typically higher in certain States or regions than in others. Aside from taxes, there are other factors that contribute to regional and even local differences in gasoline prices:

Proximity of supply. Areas farthest from the Gulf Coast (the source of nearly half of the gasoline produced in the U.S. and, thus, a major supplier to the rest of the country) tend to have higher prices. The proximity of refineries to crude oil supplies can even be a factor, as well as shipping costs (pipeline or waterborne) from refinery to market.

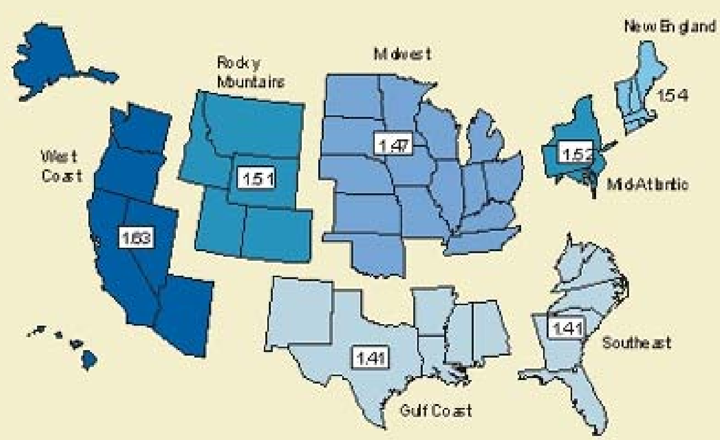
Long-term (Years 2000 to 2020) Outlook for Gasoline Prices

In the future, gasoline prices are expected to be pushed generally higher by an increase in the population and an economic expansion, particularly in the third world countries. In addition, tighter environmental standards on the quality of gasoline will also be a factor in higher prices as will the lack of available U.S. refining capacity. The lack of available refining capacity is already contributing to higher retail prices in California (see box on California) and is expected to spread to other States. Offset by lower tax rates, though, U.S. retail gasoline prices are expected to remain among the lowest in the world.

Supply disruptions. Any event which slows or stops production of gasoline for a short time, such as planned or unplanned refinery maintenance, can prompt bidding for available supplies. If the transportation system cannot support the flow of surplus supplies from one region to another, prices will remain comparatively high.

Competition in the local market. Competitive differences can be substantial between a locality with only one or a few gasoline suppliers versus one with a large number of competitors in close proximity. Consumers in remote locations may face a trade-off between higher local prices and the inconvenience of driving some distance to a lower-priced alternative.

Environmental programs. Some areas of the country are required to use special gasolines. Environmental programs, aimed at reducing carbon monoxide, smog, and air toxics, include the Federal and/or State-required oxygenated, reformulated, and low-volatility (evaporating more slowly) gasolines. Other environmental programs put restrictions on transportation and storage. The reformulated gasolines required in some urban areas and in California add three and five cents, respectively, to the price of conventional gasoline served elsewhere.



Source: Energy Information Administration, Weekly Motor Gasoline Price Survey, 2000

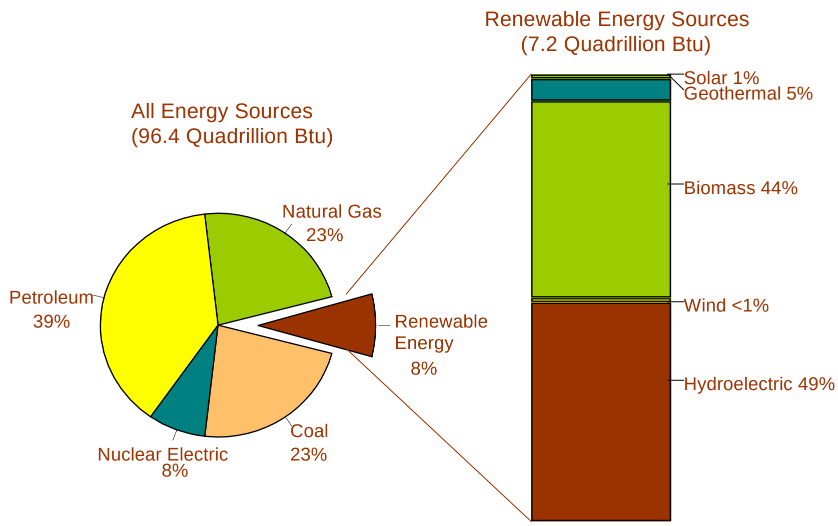
Operating costs. Even stations co-located have different traffic patterns, rents, and sources of supply that influence retail price.

More information on this subject can be found in the following EIA publications: *Petroleum Marketing Monthly.*

Renewable Energy

Fossil fuels are finite, with known domestic supplies projected to last no more than another 10 generations. On the other hand, renewable energy sources - water (hydropower), biomass, wind, heat from the earth (geothermal), and the sun (solar energy) - can be sustained indefinitely. "Green" renewables contribute much less to global warming, and climate change by offsetting fossil fuels used to generate electricity.

The use of renewable energy is not new. Five generations (125 years) ago, wood supplied up to 90 percent of our energy needs. Due to the convenience and low prices of fossil fuels, wood use has fallen. Now, the biomass which would normally present a disposal problem is converted into electricity (e.g., manufacturing wastes, rice hulls, and black liquor from paper production).



Total may not equal some of components due to independent rounding.

Currently, low fossil fuel prices, especially for natural gas, make growth difficult for renewable fuels. The deregulation and restructuring of the electric power industry could have a major impact on renewable energy consumption. Demands for cheaper power in the short term would likely decrease demand for renewable energy, while preferences for renewables included in some versions of proposed electricity restructuring legislation would breathe new life into this industry. Use of renewables in the United States is not currently expected to approach that of the major fuels, and, due to their limitations (e.g., their intermittent nature - cloudy days, no wind blowing, land availability, dams are primarily for flood control; hydroelectricity production varies as dams' water levels change), renewables may never provide "the" answer to all energy problems. Under some conditions however, renewable energy is proving to be of great value, especially overseas.

The sun produces a nearly constant flow of energy that can be converted to other energy forms, such as electricity and heat, or stored in biomass. Clouds, the daily pattern of light and darkness, seasons, and dust in the air greatly affect the fraction of sunlight which is available. The sun's rays have to fall on a relatively large area for enough heat to be collected for conversion to electricity; a "concentrating collector" can be used to focus the rays onto a much smaller area.

Solar energy can also be converted into electricity by means of a photovoltaic cell (based on the element silicon). Photovoltaic systems generate electricity which may be used for lighting and appliances, stored in batteries, or in a one-person automobile. In nations with underdeveloped electricity networks, photovoltaic systems have been chosen because of their flexibility.

The major economic application of solar energy is heating residences and other buildings. Solar collectors, often seen on rooftops, are used for hot water, space heating, and heating swimming pools. However, backup heating systems are generally needed.

Electricity from modern windpower has been demonstrated using technologically advanced wind turbine designs. Steady, fairly high winds (12+ miles per hour), without lulls and high gusts, are needed for commercial electricity generation. Such conditions occur in many places in the United States.

Biomass, formed when the sun shines on plants and trees, can be burned, providing heat for homes and fuel for boilers. Electricity generators burn wood chips, sawdust, garbage, bagasse (a plant refuse), and low-quality methane gases from landfills, but this is limited by distance to the generator from the available supply (roughly 35 miles; distance increases costs and decreases profits) and by the mass that would be removed from the topsoil (a form of erosion). Another widely available fuel source is the biomass from corn; this is fermented into alcohol (ethanol) and the alcohol is used to replace automobile fuel (by blending with gasoline).

Geothermal energy comes from natural processes beneath the earth's surface, and is recovered as steam and hot water. Known geothermal resource areas are rare, with the current domestic potential being around 27,400 megawatts (MW). (Current total national electric generating capability from all fuel sources is about 787,902 MW). Roughly 11 percent of this geothermal resource is being used for electricity generation. Most domestic electricity from geothermal energy is generated in California (the world's largest geothermal facility is at The Geysers), the other far western States, and Hawaii. Direct-use of geothermal energy for aquaculture, health spas and district heating continues to grow, as do installations of geothermal heat pumps.

More information can be found in the following EIA publications: *Renewable Energy Annual; Annual Energy Review; Monthly Energy Review;* and the *Electric Power Annual.*

Apples, Oranges and Btu

The first energy fuel measurements were made by the legendary Sumerian Gilgamesh, who taught tax collectors to record urns of oil on soft clay tablets. Energy, the work that a physical system is capable of doing, includes, in general, contributions of potential energy, kinetic energy, and rest energy. The ways energy in fuels and electricity are measured varies according to the fuel's chemical and physical attributes (e.g., native units are tons for coal, barrels for oil, millions of cubic feet for natural gas, kilowatt hours for electricity).

To make meaningful comparisons of energy commodities, you must convert physical units of measure (such as weight or volume) and the energy content of each fuel to comparable units. One practical way to compare different fuels is to convert them into British thermal units (Btu). The Btu is a precise measure of energy--the amount of energy required to raise the temperature of 1 pound of water 1 degree Fahrenheit.

To make meaningful comparisons of energy fuels, physical measurements (such as weight or volume) are combined with the potential energy content of each fuel to make values that can be compared in a way that we can relate to them. Eight gallons of gasoline contain about 1 million Btu and cost about $10; so on the individual and residential level, 1 million Btu is a meaningful quantity. The average single-family residence in the United States consumed a little over 100 million Btu of energy in 1999; the per capita consumption was 351 million Btu. To put those quantities into a broader perspective, one billion Btu equal all the electricity that 30 average Americans use in 1 year; and one trillion Btu are equal to 474 100-ton railroad cars of coal intended for electric utilities. One quadrillion Btu are equal to 470 thousand barrels of oil consumed every day for 1 year. In 1999, the Nation used 97 quadrillion Btu of energy: 38 quadrillion Btu of petroleum, 22 quadrillion Btu of natural gas, 22 quadrillion Btu of coal, and 15 quadrillion Btu of other energy sources.

Billions, trillions, and quadrillions of Btu are used to measure quantities of energy larger than those consumed by typical households. (Written out, 1 quadrillion is a 1 followed by 15 zeros.)

Assume that you have been assigned the responsibility of purchasing fuel for a large electric utility company. The 1999 average prices of fuel delivered to electric utilities were $24.72 per short ton of coal, $16.03 per 42-gallon barrel of oil, and $2.62 per thousand cubic feet of natural gas. Tons, barrels, cubic feet--how do you compare apples and oranges?

British thermal units are useful for more than just calculating volumes of consumption. Price equivalents are usually expressed in cents per million Btu, and the homeowner often thinks of Btu in terms of dollars and cents. In 1999, a ton of coal used to generate electricity cost more than twice as much as a barrel of oil. The barrel of oil, however, contained about 6.2 million Btu, while the ton of coal contained 21 million Btu, over three times as much energy. On a Btu basis, coal was cheaper. (Of course, cost is not the only consideration in selecting a fuel. Environmental restrictions, equipment costs, and other factors must also be taken into account.)

By use of the Btu, it is possible to compare prices not only for different forms of fuel, but also for different products from the same fuel. For example, motor gasoline contains an average of 5.25 million Btu per barrel, while jet fuel (kerosene-type) contains 5.67 million Btu per barrel. At $51.287 per barrel for motor gasoline and $22.80 per barrel for jet fuel in 1999, motor gasoline costs $9.76 per million Btu and jet fuel costs $4.02 per million Btu. By itself, a single Btu does not mean very much. For the average consumer who uses millions of Btu per year, however, it is a term well worth knowing.

More information on this subject can be found in the following EIA publications: *Monthly Energy Review, Annual Energy Review,* and *Electric Power Annual.*

Degree-Days

Freezing winter weather or a long, sweltering summer--either one can increase your utility bills. But how much of the rise in the cost is a result of the weather? You can find out by using a unit of measure called the“degree-day.”

> Technically, a cooling degree-day is calculated when there is a 1-degree Fahrenheit (F) difference between 65 degrees F and a mean outdoor air temperature of 66 degrees F, on any given day.

A degree-day compares the outdoor temperature to a standard of 65 degrees Fahrenheit (F); the more extreme the temperature, the higher the degree-day number. Thus, degree-day measurements can be used to describe the effect of outdoor temperature on the amount of energy needed for space heating or cooling. Hot days, which may require the use of energy for cooling, are measured in cooling degree-days. On a day with a mean temperature of 80 degrees F, for example, 15 cooling degree-days would be recorded. Cold days are measured in heating degree-days. For a day with a mean temperature of 40 degrees F, 25 heating degree-days would be recorded. Two such cold days would result in a total of 50 heating degree-days for the 2-day period.

By studying degree-day patterns in your area, you can evaluate the increases or decreases in your heating or air-conditioning bills from year to year. In some areas, degree-day information is published in the local newspapers, usually in the weather section. Information may also be available from your local utility. Its public relations department may be able to tell you the number of degree-days in the last billing period and how they compare to the number of degree-days in previous billing periods. You can also obtain U.S. national heating degree-day totals for longer periods, and cooling degree-day totals, too.

EIA provides information about heating degree-days, and cooling degree-days in its publication, *Monthly Energy Review*. The heating degree-day table (below) lists the population-weighted degree-days that occur in each region of the United States. It compares monthly and year-to-date totals to similar totals for previous periods. For example, the degree-day table shows that, in the Middle Atlantic States, January 1999 was cooler than January 1998. In January 1999, 1,219 heating degree-days were recorded, up from 1,054 degree-days (warmer than normal) in January 1998. On the other hand, the Mountain States were warmer in January 1998 (865 heating degree-days) than in January 1999 (856 heating degree-days). The data show that, on average, the United States was warmer in January 1998 than in January 1999, and warmer than normal in 1998, but warmer than in 1998.

Heating Degree-Days by Census Division

Census Division	January[a] 1 through January 31					Cumulative[a] July 1 through January 31				
				Percent Change					Percent Change	
	Normal	1998	1999	Normal to 1999	1998 to 1999	Normal	1998	1999	Normal to 1999	1998 to 1999
New England	1,262	1,054	1,219	-3.4	15.7	3,702	3,693	3,531	-4.6	-4.4
Middle Atlantic	1,170	897	1,099	-6.1	22.5	3,301	3,155	2,983	-9.6	-5.5
East North Central	1,315	1,037	1,273	-3.2	22.8	3,717	3,577	3,323	-10.6	-7.1
West North Central	1,398	1,188	1,347	-3.6	13.4	3,994	3,781	3,559	-10.9	-5.9
South Atlantic	670	503	541	-19.3	7..6	1,754	1,715	1,464	-16.5	-14.6
East South Central	844	636	651	-22.9	2.4	2,223	2,219	1,784	-19.7	-19.6
West South Central	620	428	446	-28.1	4.2	1,497	1,467	1,160	-22.5	-20.9
Mountain	991	865	856	-13.6	-1.0	3,136	3,020	2,864	-8.7	-5.2
Pacific[b]	573	513	554	-3.3	8.0	1,800	1,618	1,860	3.3	15.0
U.S.[b] Average	948	754	860	-9.3	-14.1	2,672	2,566	2,396	-10.3	-6.6

[a] Normal is based on calculations of data from 1961 through 1990.

[b] Excludes Alaska and Hawaii.

Census Divisions

New England
Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont

Middle Atlantic
New Jersey, New York, Pennsylvania

East North Central
Illinois, Indiana, Michigan, Ohio, Wisconsin

West North Central
Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota

South Atlantic
Delaware, Florida, Georgia, Maryland, District of Columbia, North Carolina, South Carolina, Virginia, West Virginia

East South Central
Alabama, Kentucky, Mississippi, Tennessee

West South Central
Arkansas, Louisiana, Oklahoma, Texas

Mountain

Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming

Pacific
California, Oregon, Washington

Sources: There are several degree-day databases maintained by the National Oceanic and Atmospheric Administration. The information published here is developed by the National Weather Service Climate Analysis Center, Camp Springs, MD. The data are available weekly with monthly summaries and are based on mean daily temperatures recorded at about 200 major weather stations around the country. The National Oceanic and Atmospheric Administration (NOAA) has other sources of information about degree-days for the country as a whole. The data provided here are available sooner than the Historical Climatology Series 5-1 (heating degree-days) and 5-2 (cooling degree-days) developed by the National Climatic Center, Federal Building, Asheville, NC, 28801, which compiles data from some 8,000 weather stations.

More information on this subject can be found in the EIA publication *Monthly Energy Review.*