SOME FUNDAMENTAL CHARACTERISTICS OF THE U.S. ENERGY SECTOR

This briefing paper presents some basic information on the U.S. energy sector. Initially, some characteristics of the energy commodities are covered. Next the paper discusses electricity. Subsequent sections examine petroleum, natural gas, coal, and renewable energy sources. Concluding sections give some details on domestic energy sources and the Department of Energy (DOE)/Energy Information Administration's (EIA) outlook for energy commodities.

Heat Content

The demand for energy resources is driven by the demand for their heat content. The heat contained within these energy substances is usually converted into other more useable forms of energy. For example, crude oil is refined into gasoline and burned in motor vehicles and coal is burned in boilers to produce electricity.

A standard measure of heat content is the British Thermal Unit (BTU)--the amount of heat required to increase the temperature of one pound of water by one degree Fahrenheit. An comparison of the approximate heat contents of standard amounts of some of the major energy commodities is shown in Table 1.

Table 1 – Typical Heat Contents of Some Standard Energy Commodities

Commodity	Standard Unit	Heat Content (BTU)
Crude Oil	1 barrel (42 gallons)	5.8 million
Natural Gas (Dry)	Thousand cubic feet (Mcf)	1.03 million
Coal	Short ton (2000 pounds)	21.7 million
Electricity (fossil fuel)	Kilowatt-hour (kWh)	10,300
Electricity (nuclear)	Kilowatt-hour (kWh)	10,700
Electricity (geothermal)	Kilowatt-hour (kWh)	21,000

Source: DOE/EIA, Annual Energy Review 1992.

One typical 42-gallon barrel of crude oil contains almost six times more energy than one thousand cubic feet (Mcf) of natural gas. One short ton (2000 pounds) of coal has almost 4 times more contained energy than a barrel of oil.

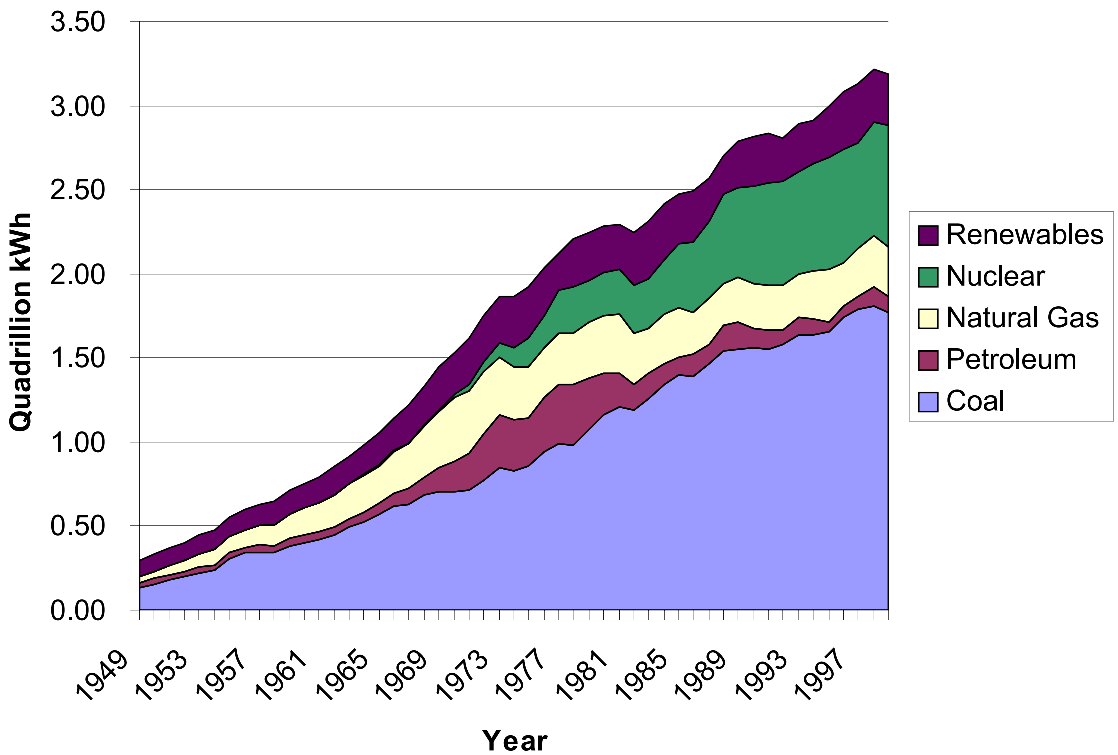
Electricity

Electricity users pay a premium to obtain the energy in this form. The heat content of fuels needed to create electricity is shown in the last three rows of Table 1. These rows depict the average amount of energy that must be extracted from other energy sources to produce one thousand watts of power for one hour (kWh). A typical electrical generator burns coal or natural gas to heat water. The steam created from the boiling water rotates a turbine that generates electricity. On average, about 10,300 BTUs from coal or natural gas is needed to heat the water needed to create one kWh of electricity. A nuclear reactor puts out about 10,700 BTUs to generate one kWh. On average, geothermal generating plants use approximately 21,700 BTUs from heated groundwater to produce a kWh.

Despite its relatively high cost, electricity use in this country has grown at the expense of other energy commodities. Electricity's advantages include instant availability, wide range of applications, safety, controllability, and ease of use. In 1999, consumers were willing to pay an average of $23.94 per million BTU for delivered electricity compared with $6.39 per million BTU for delivered natural gas, and $9.83 per million BTU for gasoline.

Figure 1 shows the changing mix of fuels that have been used to generate this nation's ever-increasing amounts of electricity. From 1949 to 1999 net generation of electricity at electrical utilities grew by almost 1000 percent. Renewable electricity-generating sources include hydroelectric power, solar, geothermal (heated groundwater), wood, wind, waste (from waste burning and methane gas generated at landfills), and a few other smaller sources.

Figure 1 – Fuels Used in Electrical Generation at Electric Utilities



Source: U.S. DOE/EIA, 2000, Annual Energy Review.

Hydropower has been a prominent source of U.S. electricity because it is one of the cheapest generating sources. It was used for over 30 percent of electrical generation in 1949 but declined to less than 10 percent in 1999. The diminution of hydropower's role is not so much that it was replaced by cheaper or more efficient energy sources, but that nature itself has limited the number of good hydropower sites in this country.

Coal was and continues to be the largest source of energy for electrical generation--more than one-half of all electricity generated in 1999 was produced by coal-fired generators. Most of the coal-fired boilers used to produce electricity are base-load plants. These types of plants are generally kept running continually throughout the changing daily, weekly, and seasonal electricity demand fluctuations. Initial capital costs of coal-fired boilers are high, but if operated continually, operating costs and total costs per kWh are relatively low.

Electricity from nuclear power was first commercially generated in this country in 1957. By 1999, nuclear power was responsible for about 23 percent of utilities' power generation. Nuclear power's share of generation has been relatively constant in recent years, but most analysts expect its importance to decline significantly in the future as currently operating nuclear plants reach the end of their design life. U.S. nuclear power plants generally are used as base-load plants.

No new nuclear power plants have been ordered since 1978. While the nuclear "event" at Three Mile Island in 1979 crystallized public opposition to nuclear power, the high cost of building nuclear plants has been the primary obstacle to new plants. Expected economies of scale never materialized. Also, significant concerns remain about how and where to dispose of radioactive waste generated at nuclear power plants.

Oil-fired electrical generators' importance increased during the 1970s. But, the rapidly rising price of oil since the 1970s has put them at a cost-disadvantage since then. Electrical generation from petroleum fuels is now largely found in old power plants located in the northeastern U.S.

A majority of new electrical power plants coming on line today and planned for the immediate future are fired by natural gas. The most common design of today's gas plants is based on the same principle as a jet engine. Expanding gases produced by the burning of natural gas drive a turbine that generates electricity. There are significant capital cost advantages to combustion turbines—they are relatively inexpensive to buy and they may be started and stopped relatively quickly as demand for electricity fluctuates. The downside of combustion turbines is that they are noisy (jet engines) and that they are relatively expensive to run. They are usually run during peak electrical usage times.

Usage of electricity varies on a daily, weekly, and seasonal basis and in response to weather extremes. During peak demand times the utility may be running all of its own generating facilities and also need to buy additional electricity from other nearby or more distant suppliers that are linked to the power grid.

Because of energy losses in the generation process, much more power needs to be generated than is consumed by end users. In 1999 about 35 quadrillion BTU of energy was used in the generation process that produced 11 quadrillion BTU worth of electricity used by consumers. A significant amount of energy was lost in the generation process as waste heat, another portion of electricity was used by the generating organization, still more was lost during the voltage conversions and "line loss" that occurred as the electricity traveled from the generating plant to the end user.

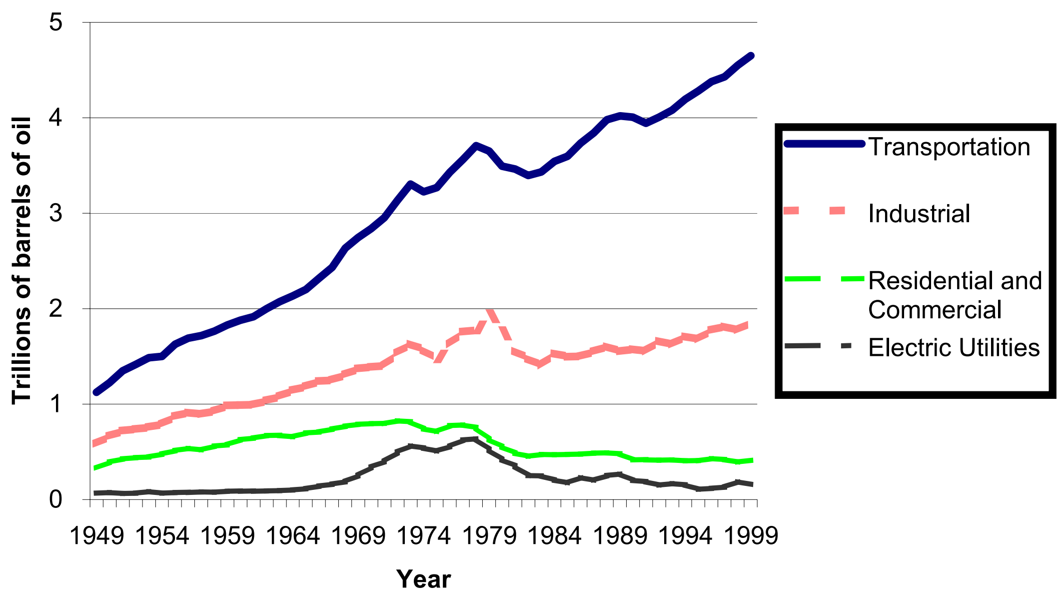
Oil

Unrefined or crude oil is a mixture of heavy and light hydrocarbons that varies by region and oil field. The oil refining process uses "cracking"—applying heat and pressure with catalysts to break down the heavier and more complex hydrocarbons into lighter and simpler molecules. Cracking allows a refinery to be able to produce from crude oil a series of different products; ranging from relatively light commodities such as kerosene and gasoline up to the heavier and more viscous products such as asphalt and residual oil.

End users in the U.S. energy sector can be broken down into (1) the residential and commercial sector, (2) the industrial sector, and (3) the transportation sector., Figure 3 depicts total petroleum consumption by sector. In 1999, the transportation sector used more than two-thirds of all U.S. oil consumed. And, more than 97 percent of all energy used in the transportation sector was supplied by oil. Most of the other significant end-users of oil in the U.S. are in the industrial sector.

With the notable exception of the transportation sector, oil consumption in all sectors has either been declining or slowly increasing since 1979. Gasoline and diesel use in the transportation sector has been growing by between 2.1 and 2.5 percent per year since 1992. This growth in transportation sector oil consumption is largely due to an increase in vehicular traffic and the stagnation in the energy efficiency of vehicles. As measured by fleet mileage, the energy efficiency of vehicles has leveled off, or even decreased, during the 1990s. After increasing 42 percent from 11.9 miles per gallon to 16.9 miles per gallon in 1992, the total fleet fuel efficiency average has not risen since.

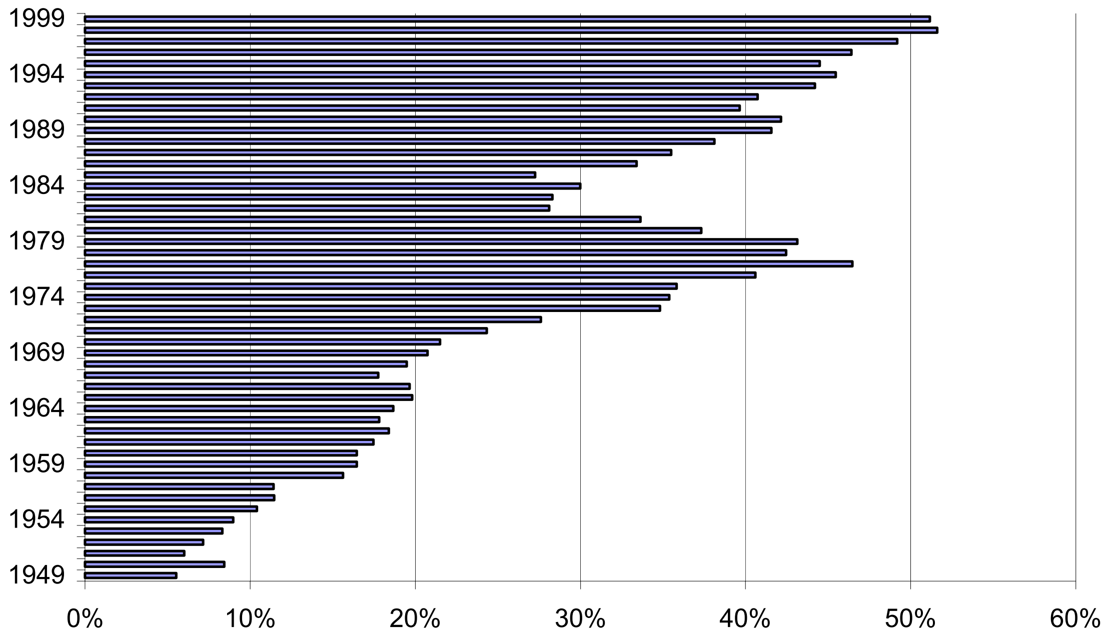
Figure 3 – Total Petroleum Consumption by Sector



Source: DOE/EIA, 2000, Annual Energy Review

Domestic petroleum production has not been able to keep up with the ever-increasing demand for the energy commodity. Figure 4 shows U.S the percent of total U.S. oil consumption claimed by imports.

Figure 4 – Import Share of Total U.S. Oil Consumption



Source: DOE/EIA, 2000, Annual Energy Review

U.S. petroleum production has exhibited a much-anticipated decline during the study period, with imports of oil rising to satisfy additional domestic demand. Recent history has also shown an period of decreasing imports--from 1977 to 1984. This era saw relatively high oil prices and a determined effort by the U.S. to improve the fuel efficiency of its vehicles. During that time the import share of oil consumption declined from about 47 to 28 percent. Since 1984 the role of imported oil has steadily increased as oil prices have generally declined.

Since 1982, 54 percent or less of U.S. imported petroleum has been shipped from Persian Gulf nations. In 1999, imported oil from Persian Gulf nations represented about 22 percent of all 1999 imports. Canada supplied the largest amount of imported oil in 1999. Other important non-OPEC suppliers to the U.S. include Mexico and the United Kingdom. Venezuela, a Western Hemisphere OPEC member, supplied about 13 percent of total U.S. imports in 1999.

Table 2 presents the average refiner's acquisition price for imported crude oil price from 1970 to 1999 (in inflation-adjusted 1996 dollars). There has been a great deal of volatility in crude oil prices since OPEC's initial muscle-flexing in 1973. Prices peaked in 1981 at almost $60 per barrel (in inflation-adjusted 1996 dollars). The average annual crude price in 2000 was lower than prices seen from any year from 1973 to 1985. During the 1990s oil prices averaged less than $19 per barrel—less than one-third of the 1981 oil price peak.

Table 2 – Average Refiner's Acquisition Price for Imported Crude Oil

Year	Price	Year	Price	Year	Price
1970	$10.19	**1980**	$59.41	**1990**	$25.15
1971	$10.39	**1981**	$59.40	**1991**	$20.86
1972	$10.12	**1982**	$50.64	**1992**	$19.82
1973	$12.14	**1983**	$42.54	**1993**	$17.16
1974	$34.19	**1984**	$40.43	**1994**	$16.15
1975	$34.80	**1985**	$36.63	**1995**	$17.47
1976	$31.87	**1986**	$18.59	**1996**	$20.64
1977	$32.27	**1987**	$23.37	**1997**	$18.18
1978	$30.21	**1988**	$18.15	**1998**	$11.68
1979	$41.47	**1989**	$21.71	**1999**	$16.47
				2000	$24.72

Source: DOE/EIA, 2000, Annual Energy Review

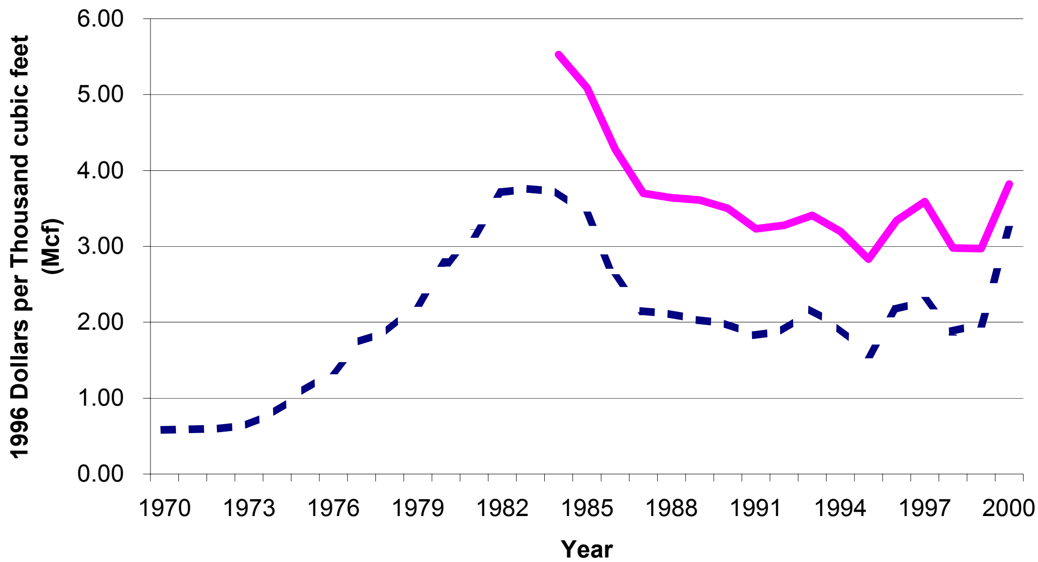
Natural Gas

Natural gas is an imprecise label that describes a variable mixture of gaseous hydrocarbons. Methane is the predominant constituent of natural gas—usually making up from 73 to 95 percent of natural gas. Until the late 1980s U.S. consumption of natural gas was virtually all satisfied by domestic production. Imports of Canadian and Mexican natural gas have become increasingly important, partially because of their proximity to major U.S. consuming cities. A relatively small amount of Liquified Natural Gas (LNG) has also imported by tanker, primarily from Algeria and Australia.

For decades, the industrial sector has been the largest user of natural gas. Non-utility generators (NUGs) of electricity are currently one of the primary consumers. A NUG is a firm that typically uses a combustion turbine to produce electricity that is sold to electrical utilities or directly into the industrial or commercial sectors. Other large industrial consumers of natural gas use it for internal power generation, space heating, or as a feedstock or fuel for producing other products. In the residential and commercial sectors natural gas has become an increasingly popular fuel for space heating. A much-touted environmental benefit of natural gas is its "clean-burning" produces a relatively lesser amount of carbon dioxide (greenhouse gas) per BTU than do its energy competitors.

The price paid for natural gas by residential user is made up of three components (1) the commodity (wellhead) price (price at the point at which the natural gas is produced from the ground), (2) transmission costs (the costs to move gas by pipeline from the field to the local gas companies), and (3) distribution costs (costs incurred moving gas from local gas companies' facilities to individual consumers). Figure 4 shows the inflation-adjusted price for natural gas at the wellhead and at the city gate (the entry point of gas regional pipelines into main population centers). The difference between the wellhead and city gate prices is an approximation of the transmission cost

Figure 4 – Average Annual Real Price of Natural Gas at the Wellhead and City Gate



Source: DOE/EIA, 2000, Annual Energy Review

The dashed line shows the average annual real price paid for natural gas at the wellhead. The solid line shows the average real price paid at the city gate. (City gate data are not currently available prior to 1984). Natural gas prices were largely regulated prior to the early 1980s. After an initial decline following deregulation, inflation-adjusted prices for wellhead and city gate gas showed relative stability from the mid-1980s until 1999. The gap between the wellhead and city gate prices (transmission cost) has declined over time. In 1984 the average transmission cost was $1.81. By 2000 this cost had shrunk to $0.61. This declining spread between wellhead and city gate prices has had the effect of insulating the end users of natural gas from the full effect of wellhead gas price increases.

Relatively low gas prices in 1999 encouraged consumption and discouraged drilling. The increased consumption from the booming U.S. economy depleted existing supplies and led to higher gas prices. Another important factor in the recent gas price increase was the unexpectedly cold winter weather in 2000/2001. These events combined to raise natural gas prices. Although drilling for additional gas resources increased rapidly in response to higher prices, there is a lag of from 6-to-18 months from initial drilling to additional production. EIA expects that new gas supplies resulting from the recent gas price spike will have the effect of decreasing gas prices in the near future (EIA, 2001, Residential Natural Gas Prices: What Consumers Should Know).

Coal

The range of coal uses has changed remarkably with the times. In the late-1800s through the mid-1950s coal was used as the fuel of choice in steam locomotives, ship and factory boilers, and in residential and commercial furnaces. Natural gas began displacing coal from the home heating sector just as diesel locomotives began replacing steam. At the same time ships were being converted from coal power to oil power.

The decreases in coal demand discussed above were offset by the growth in the demand for electricity. Coal-fired boilers in 1999 used more than 90 percent of the coal consumed in this country and produced more than one-half of all U.S. electrical generation. Coal exports were sent around the world to Canada, Japan, Brazil, Italy and the Netherlands and represent 40 percent of this country's energy exports. U.S. coal production in 1998 reach a record of 1.12 billion tons and ranked second worldwide to China.

Emissions from coal-fired boilers have had major environmental impacts. Coal-fired plants produce significant amounts of sulfur dioxide and nitrogen oxides (a constituent of acid rain), and collectively contribute about 32 percent of all carbon dioxide (a primary greenhouse gas) emitted from all U.S. fuel sources (DOE/EIA, 2001, Energy in the United States: A Brief History and Current Trends). The Clean Air Act and various state agencies have produced a shift away from high-sulfur coal. Regulatory agencies are now poised to limit nitrogen oxides in the Midwest and Northeast and to further decrease sulfur emissions.

Emission controls, as well as changing regional economics, have combined to shift the focus of U.S. coal production from the relatively high-sulfur underground mines of the Appalachians and Illinois Basin towards production from Western surface mines in the Powder River Basin of Wyoming and other Western sources.

No longer do electric utilities consume coal just from the nearest possible source. Instead they often combine several types of coals from many different geographic regions to create an optimal fuel source that meets all emissions regulations and satisfies the BTU requirements of their boilers. The more-distant fuel sources mean that transportation costs make up a larger share of the delivered coal price than before.

Inflation-adjusted mine-mouth and delivered prices for most types of coal have been generally declining for many years due to increasing efficiencies in coal production. In 1999, on average, one million contained BTUs of coal sold for $0.84, compared with $1.86 for natural gas and $2.68 for crude oil (DOE/EIA, 2001, Energy in the United States: A Brief History and Current Trends).

Renewable Resources

Water and wind power are among the oldest sources of renewable energy. Modern man has improved on and augmented these sources with power generated from wood and waste burning, as well as solar-, wind-, and geothermal- (heated groundwater) derived power. Improved hydroelectric and wind generation technologies have greatly increased the efficiency of the age-old water- and wind-power sources.

With the renewed emphasis on renewable energy sources in recent decades, renewables now contribute about 10 percent of all energy consumed in this country. This sector is dominated by contributions from (1) hydroelectric power and (2) wood and waste products. About 45 percent of all renewable energy is produced from water. Important water-generation regions include the Northwest's Columbia River basin, the large and extensive dams of the Intermountain West, the Tennessee River valley, as well as countless other smaller sites.

Another 45 percent of renewable energy is produced by the burning of wood and wood products, or wastes. Combining waste disposal with electrical generation allows for the disposal of items as disparate as wood sludge, straw, railroad ties, pitch, municipal solid waste, agricultural waste, tires, landfill gas, fish oil, and others, while generating power in the process. Not surprisingly, the paper manufacturing and lumber sectors are among the largest users of wood and wood products for energy generation.

Geothermal energy currently contributes about 5 of all renewable energy consumption in the U.S. Solar energy and wind power contribute about one and one-half percent of all renewable energy consumption, respectively.

Adequacy of U.S. Energy Sources

Oil and Gas

The U.S. is a storehouse of energy resources. The U.S. Geological Survey (USGS) separates domestic energy commodities into (1) energy resources, and (2) energy reserves. U.S. energy resources include all occurrences of energy commodities within the nation's boundaries (including up to 200 miles out to sea). Energy reserves are the subset of energy resources whose extent and richness is known and whose production costs are less than their price.

Table 3 presents USGS estimates of the technically recoverable fraction of known and yet-to-be-discovered U.S. oil and gas resources. The top two rows in Figure 3 depict the best-known oil and gas resources. The bottom three rows represent resources whose exact location, size, and richness are less well known.

Table 3 –Technically Recoverable U.S. Oil and Gas Resources

Supply Category	Oil and NGL (Billion barrels)	Natural Gas (Trillion cubic feet)
Current Discovered Reserves	26.8	135.1
Current Discovered Reserve Growth	73.4	322.0
Undiscovered Conventional	38.0	258.9
Undiscovered Unconventional Continuous-Type Accumulations	4.2	308.1
Undiscovered Unconventional Coalbed Gas	NA	49.9
Total	142.4	1,074.0

Note: Undiscovered resources shown in Table 3 include only the technically recoverable fraction of total oil, gas, and natural gas liquid resources.

Source: U.S. Geological Survey, 1996, *1995 National Assessment of United States Oil and Gas Resources—Results, Methodology, and Supporting Data.*

Conventional resources are those that can be produced using standard "off-the-shelf" energy technology. Unconventional resources require production technologies that are still being developed and refined. Natural gas liquids (NGL) are hydrocarbons that occur naturally as gases but are converted for use in liquid form—this resource is grouped with oil in Table 3.

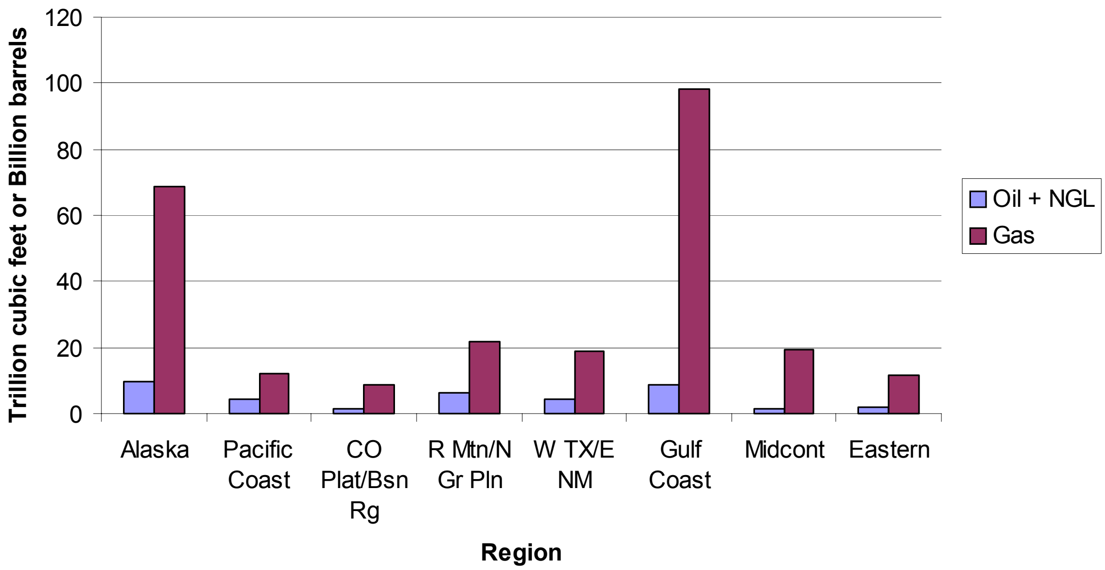
One method of judging the adequacy of resources is to compare annual consumption with total resource estimates. This ratio, known as the consumption to resource ratio, gives a rough estimate of how many years of the commodity are know to exist at current consumption rates.

The EIA estimates that the U.S. consumed about 7.1 billion barrels of oil and approximately 21.4 trillion cubic feet of gas in 1999. Summing all categories of oil and gas in Table 3 above, the U.S. contains about 20.0 years worth of oil and 50.2 years worth of gas at 1999 consumption rates. Using only this ratio oversimplifies resource adequacy discussions, but it does give a general estimate of the nation's oil and gas resources. This exercise also shows that this country's remaining natural gas resources are relatively greater than its oil resources.

Figure 5 shows the regional distribution of undiscovered conventional technically recoverable oil, natural gas liquids, and gas resources. The leftmost series of bars on Figure 5 represent the oil and natural gas liquids (NGL) resources and the rightmost bars show natural gas resources.

The Alaska and the Gulf Coast regions contain the greatest quantities of known and undiscovered oil and gas resources. States with the largest oil production and reserves include Alaska, Texas, and Louisiana. Other notable oil production is obtained from California and Oklahoma. States with the largest gas production and reserves are Texas, Louisiana, Oklahoma and New Mexico. With the exception of gas production from New Mexico and the offshore regions of the Gulf Coast, most oil and gas output is not produced from Federal lands.

Figure 5 – Conventional Undiscovered Technically Recoverable Oil and Gas Resources in the U.S. by Region



Source: U.S. Geological Survey, 1996, *1995 National Assessment of United States Oil and Gas Resources—Results, Methodology, and Supporting Data.*

Coal

By almost any measure, U.S. coal resources are numerous. In fact, U.S. coal resources are so bountiful that the EIA does not readily provide estimates of coal resources, only coal reserves. Led by Montana's 120 billion tons, aggregate coal reserves for the top ten states tops 450 billion tons. At 1999 consumption rates the U.S. has enough coal to last more than 400 years.

But, this ample resource estimate does not tell the whole story. In general, for each BTU of energy burned, coal produces the greatest volume of harmful emissions of all the major fossil fuels. Sulfur dioxide, nitrogen oxides, and carbon dioxide are all disproportionately produced by coal combustion. Controls on these emissions have pushed U.S. coal consumption towards deposits with lower sulfur and nitrogen contents.

The nation's largest low-sulfur coal resources are located in Wyoming and Montana. These states are far from the primary consuming regions and their low-sulfur coal has a very low-BTU content. Not all coal-fired boilers can currently use the low-BTU coal found in these states. As emissions controls have become more stringent, owners of coal-fired boilers have found it more economical to use lower-sulfur coal. In some regions electric utilities have found that they must forego the use of coal entirely—with many switching to natural gas-fired combustion turbines or other generating sources.

EIA Reference Case Energy Outlook, 1999-2020

EIA projections presented below assume that will occur: (1) full electricity deregulation in CA, NY, New England, Mid-Atlantic states, IL, TX, OK, MI, OH, AZ, NM, and WV; (2) increased competition in the electricity market through restructuring and efficiency and operating improvements; and (3) a robust average annual growth rate in the U.S. Gross Domestic Product (GDP) of 3.0 percent. All prices are expressed as inflation-adjusted 1999 prices.

Consumption

According to EIA projections for the Reference Case, aggregate national energy consumption will increase at an annual rate of 1.3 percent from 1999 to 2020. Growth in annual natural gas consumption is expected to exceed the growth of any other energy commodity (2.3 percent). Consumption of petroleum products, renewable energy, and coal are projected to grow at annual rates of 1.4, 1.1, and 1.0 percent, respectively.

Fuel consumption in the transportation sector is expected to grow by an average annual rate of 1.8 percent, faster than in any other sector. New vehicle efficiency in 2020 is projected to increase by 0.9 miles per gallon for new cars and 1.9 miles per gallon for light trucks over 1999 measures. Total petroleum use is projected to increase by an average of 1.3 percent per annum, mostly for use in the transportation sector.

Demand for electricity is expected to show an annual growth rate of 1.8 percent during the study period. Consumption of natural gas is projected to increase by 2.3 percent per year, on average—mostly for increased electrical generation. Coal use will likely increase by an average of 1.1 percent per year—largely for use in the electrical generation sector. Renewable fuel use is expected to grow at an average of 1.1 percent per year through 2020, with a large impetus from mandates from various States.

Domestic Production and Imports

EIA projects that the composite annual growth rate for domestic production of all energy commodities will be 0.8 percent from 1999 to 2020. Fastest production growth is expected in natural gas liquids and natural gas, with projected annual rates of 2.2 and 2.1 percent, respectively. Coal output is expected to increase by 0.7 percent annually, and renewable energy by 1.1 percent. Nuclear power output will likely peak about 2005 and show an annual decline of 1.1 percent over the study period.

Domestic crude oil production is expected to decline by about 0.7 percent annually. EIA projects that imports of crude oil and petroleum products will grow by an average of 1.6 and 4.6 percent per annum, respectively. Natural gas imports, primarily from Canada and Mexico are expected to increase by 2.9 percent per year over the study period.

Energy Prices

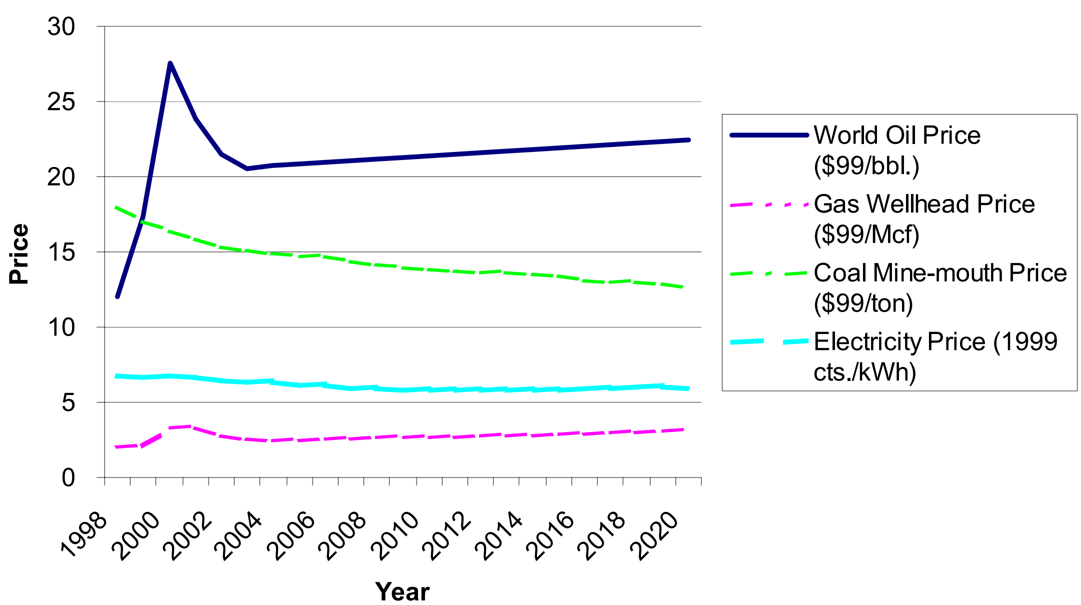
Figure 6 shows EIA projections for energy prices. The solid line in Figure 6 depicts a projected world oil price--the price paid for U.S. crude oil imports. From 1999 to 2020, EIA projects that the world oil price will increase by an average of 1.2 percent per annum. From a price of $27.60 in 2000, EIA expects that the petroleum price will decline to about $20.50 in 2003 and then rise slowly to about $22.40 in 2020. Causes for the projected increase in world oil price include (a) OPEC and some non-OPEC production cutbacks, (b) a lag in world petroleum production after price increases, and (c) renewed oil demand growth in Asia.

The lowest line on Figure 6, representing the gas wellhead price, shows an average annual increase of 2.0 percent over the study period. Natural gas wellhead prices are projected to increase from the 1999 level of $2.08 per thousand cubic feet to about $3.13 in 2020. Price growth for this commodity is expected to be moderated by technological improvements in gas exploration and production.

EIA's projected coal price exhibits an average annual price decline of 1.4 percent. Mine-mouth prices for coal, shown by alternating long and short dashes, are projected to decline from about $17 per ton in 1999 to about $12.70 per ton in 2020. Strong competition in labor markets and increased productivity as coal production continues to shift to Western surface mines from Eastern underground mines are the major causes for the expected real coal price decline.

The second-lowest line shows EIA's expected electricity price trajectory—tracing an average annual decrease of 0.5 percent per year from 1999 to 2020. Average electricity prices are projected to fall from about 6.7 cents per kilowatt-hour in 1999 to about 5.9 cents in 2020.

Figure 6 – EIA-Projected Energy Prices



Source: DOE/EIA, 2001, Annual Energy Outlook, 2001.