Summary of Important Terms

PETROLEUM PRICES

Refiner acquisition cost of crude oil (RAC): The average monthly cost of crude oil to U.S. refiners, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs. Typically, the imported RAC is about $1.50 per barrel below the monthly average spot price of West Texas Intermediate (WTI) crude oil and is within about $0.20 per barrel of the average monthly spot price of Brent crude oil. Unless otherwise stated, the imported RAC is what is referred to in this report as the "world oil price" or "average crude oil price."

Retail motor gasoline prices: The average pump prices for gasoline reported in the *Short-term Energy Outlook* are derived from the Energy Information Administration (EIA) form EIA-878, "Motor Gasoline Price Survey." The two series are: 1) average retail price of regular motor gasoline, self-service; 2) average retail price for all grades of motor gasoline, self-service. Both price series are for cash transactions. The historical values for these prices are reported on Table 16 of EIA's *Weekly Petroleum Status Report.*

Wholesale motor gasoline price: The monthly average price to refiners of motor gasoline (all types) sold to resellers; it is reported monthly on Table 4 of EIA's *Petroleum Marketing Monthly.*

Retail heating oil price: The cost of Number 2 distillate fuel oil to residences (less taxes). The retail heating oil price referred to in this report is from Table 18 of EIA's *Petroleum Marketing Monthly.*

PETROLEUM DEMAND and SUPPLY

Petroleum Demand (consumption/petroleum products supplied): For each product (gasoline, distillate, etc.), the amount supplied is calculated by summing production, imports, and net withdrawals from primary stocks and subtracting exports. Thus, petroleum demand is represented by the "disappearance" of product from the primary supply system. This demand definition coincides exactly with the term "product supplied" as used in EIA's *Petroleum Supply Monthly.*

Petroleum Stocks, primary: Stocks of crude oil or petroleum products held in storage at (or in) leases, refineries, natural gas processing plants, pipelines, tank farms, and bulk terminals. Crude oil that is in transit from Alaska or that is stored on Federal leases or in the Strategic Petroleum Reserve is included. These are the only stocks included in this report when petroleum inventories or inventory changes are discussed. Excluded are stocks of foreign origin that are stored in bonded warehouses.

Charts in this report displaying inventory levels of crude oil or petroleum products that provide the reader with actual inventory data compared to an "average" or "normal" range are constructed as follows: the actual stock levels are the actual reported end-of-month levels; the ranges are based on the most recent 3-year period running from January through December or from July through June. The ranges also reflect seasonal variation for the past 7 years. The seasonal factors, which determine the shape of the upper and lower curves, are estimated with a seasonal adjustment technique developed at the Bureau of Census (Census X-11). The seasonal factors are assumed to be stable (i.e., the same seasonal factor is used for each January during the 7-year period) and additive (i.e., the series is deseasonalized by subtracting the seasonal factor for the appropriate month from the reported inventory levels). The intent of deseasonalization is to remove only annual variation from the data. Thus, deseasonalized series would contain the same trends, cyclical components, and irregularities as the original data. The seasonal factors are updated annually in October, using the 7 most recent years' final monthly data. The seasonal factors are used to deseasonalize data from the most recent 3-year period (January-December or July-June) in order to determine a deseasonalized average band. The average of the deseasonalized 36-month series is the midpoint of the band, and two standard deviations of the series (adjusting first for extreme points) is its width. When the seasonal factors are added back in (the upper curve is the midpoint plus one standard deviation plus the seasonal factor, and the lower curve is the midpoint minus one standard deviation plus the seasonal factor), the "average range" shown on the graphs reflects the actual data. The ranges are updated every 6 months in April and October.

NATURAL GAS

Wellhead Prices. Composite: The composite (i.e. composed of both contract and spot transactions) wellhead price of natural gas, calculated by dividing the total reported value at the wellhead by the total quantity produced as reported by the appropriate agencies of individual producing States and the U.S. Minerals Management Service, Department of the Interior. The price includes all costs prior to shipment from the lease, including gathering and compression costs, in addition to State production, severance, and similar charges. **Spot**: A transaction price for natural gas concluded "on the spot," that is, on a one-time prompt (immediate) basis, as opposed to a longer-term contract price obligating the seller to deliver the product at an agreed price over an extended period of time.

MACROECONOMIC

Gross Domestic Product (GDP): The total value of goods and services produced by labor and property located in the United States. As long as the labor and property are located in the United States, the supplier may be either U.S. residents or residents of foreign countries. Nominal GDP refers to current dollar value; real GDP refers to GDP corrected for inflation.

GDP Implicit Price Deflator: A byproduct of the price deflation of gross domestic product (GDP). It is derived as the ratio of current- to constant-dollar GDP. It is a weighted average of the detailed price indexes used in the deflation of GDP, but these indexes are combined, using weights that reflect the composition of GDP in each period. Thus, changes in the implicit price deflator reflect not only changes in prices but also changes in the composition of GDP. Corresponding current- and constant-dollar series are published by the U.S. Bureau of Economic Analysis, National Income and Product Accounts. The current base year for the deflator is 1996.

Manufacturing Production Index: A measure of nondurable and durable manufacturing production expressed as a percentage of output in a reference period (currently 1992). Data are published by the Federal Reserve System in the *Federal Reserve Bulletin*.

Employment Employment data refer to persons on establishment payrolls who received pay for any part of the pay period including the 12th of the month (or the last day of the calendar month for government employees). The data exclude proprietors, the self-employed, unpaid volunteer or family workers, farm workers, and domestic workers. Salaried officers of corporations are included. Employment statistics are published by the U.S. Bureau of Labor Statistics in the Employment and Earnings report.

Consumer Price Index: A measure of the average change in prices paid by urban consumers for a fixed market basket of goods and services. The consumer price index is based on the prices of food, clothing, shelter, fuel, drugs, transportation fares, doctor and dentist's fees, and other goods and services that people buy for day-to-day living. All taxes directly associated with the purchase and use of items are included in the index. The consumer price index is published by the U.S. Bureau of Labor Statistics in the *Monthly Labor Review*.

Degree-days, cooling (CDD): For one day, the number of degrees that the average temperature for that day is above 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures for a 24-hour period. As covered in this report, cooling degree-days in a period represent the sum of daily degree-day calculations over the period. Thus, national cooling degree-days for a month represent the weighted average of the daily cooling degree-days for the States, summed across all days in the month. The weights used are population shares unless otherwise noted.

Degree-days, heating (HDD): For one day, the number of degrees that the average temperature is below 65 degrees Fahrenheit. The daily average

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temperature is the mean of the maximum and minimum temperatures for a 24-hour period. As covered in this report, heating degree-days in a period represent the sum of daily degree-day calculations over the period. Thus, national heating degree-days for a month represent the weighted-average of the daily heating degree-days for the States, summed across all days in the month. The weights used are population shares unless otherwise noted.

British thermal unit (Btu): The quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit. In this report, Btu-equivalent energy values are calculated by multiplying estimated thermal content coefficients per physical unit for various products by the respective quantities. These are then aggregated across products to obtain, for example, total energy demand or supply variables.

TOTAL ENERGY

Total energy demand: The sum of fossil fuel consumed by the five sectors (residential, commercial, industrial, transportation, and electric utility), plus hydroelectric power, nuclear electric power, net imports of coal coke, and electricity generated for distribution from wood, waste, geothermal, wind, photovoltaic, and solar thermal energy. Includes estimates for renewable energy sources used in the residential, commercial, and industrial sectors.

GEOGRAPHICAL

Other Asia includes: Afghanistan, American Samoa, Bangladesh, Bhutan, Brunei, Burma, Cambodia, Cook Islands, Fiji, French Polynesia, Hong Kong (prior to July 1, 1997), India, Indonesia, Kiribati, North Korea, South Korea, Laos, Macau, Malaysia, Maldives, Mongolia, Nauru, Nepal, New Caledonia, Niue, Pakistan, Papua New Guinea, Philippines, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, U.S. Pacific Islands, Vanuatu, Vietnam, Wake Island, Western Samoa.

Latin America is defined as including all of the countries of Central and South America, plus Mexico, but excluding Puerto Rico and the U.S. Virgin Islands.

The Appalachian region States are: Alabama, Georgia, Eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The Interior region States are: Arkansas, Illinois, Indiana, Iowa, Kansas, Western Kentucky, Louisiana, Missouri, Oklahoma, and Texas.

The Western region States are: Alaska, Arizona, California, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

Table 1. U.S. Macroeconomic and Weather Assumptions

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Macroeconomic [a]															
Real Gross Domestic Product (billion chained 1996 dollars - SAAR)	**8730**	**8783**	**8906**	**9084**	**9192**	**9309**	*9391*	*9472*	*9563*	*9651*	*9739*	*9833*	**8876**	*9341*	*9696*
Percentage Change from Prior Year	**3.9**	**3.8**	**4.3**	**5.0**	**5.3**	**6.0**	*5.4*	*4.3*	*4.0*	*3.7*	*3.7*	*3.8*	**4.2**	*5.2*	*3.8*
Annualized Percent Change from Prior Quarter	**3.5**	**2.4**	**5.6**	**8.0**	**4.7**	**5.1**	*3.5*	*3.5*	*3.9*	*3.6*	*3.7*	*3.9*			
GDP Implicit Price Deflator (Index, 1996=1.000)	**1.043**	**1.046**	**1.049**	**1.053**	**1.062**	**1.068**	*1.074*	*1.080*	*1.087*	*1.092*	*1.096*	*1.101*	**1.048**	*1.071*	*1.094*
Percentage Change from Prior Year	**1.5**	**1.5**	**1.5**	**1.5**	**1.8**	**2.1**	*2.4*	*2.6*	*2.4*	*2.2*	*2.1*	*2.0*	**1.5**	*2.2*	*2.2*
Real Disposable Personal Income (billion chained 1996 Dollars - SAAR)	**6264**	**6307**	**6342**	**6412**	**6443**	**6497**	*6555*	*6599*	*6709*	*6797*	*6871*	*6943*	**6331**	*6524*	*6830*
Percentage Change from Prior Year	**3.7**	**3.2**	**2.9**	**3.1**	**2.9**	**3.0**	*3.4*	*2.9*	*4.1*	*4.6*	*4.8*	*5.2*	**3.2**	*3.0*	*4.7*
Manufacturing Production (Index, 1996=1.000)	**1.148**	**1.162**	**1.175**	**1.195**	**1.216**	**1.237**	*1.255*	*1.274*	*1.284*	*1.295*	*1.307*	*1.317*	**1.170**	*1.245*	*1.301*
Percentage Change from Prior Year	**3.5**	**4.1**	**4.4**	**4.8**	**6.0**	**6.5**	*6.8*	*6.6*	*5.6*	*4.7*	*4.1*	*3.4*	**4.2**	*6.5*	*4.4*
OECD Economic Growth (percent) [b]													**2.6**	*3.6*	*3.0*
Weather [c]															
Heating Degree-Days															
U.S.	**2153**	**489**	**79**	**1448**	**2023**	**500**	*79*	*1623*	*2236*	*519*	*86*	*1622*	**4169**	*4225*	*4463*
New England	**3040**	**784**	**86**	**2042**	**3007**	**964**	*169*	*2239*	*3177*	*885*	*167*	*2238*	**5952**	*6379*	*6467*
Middle Atlantic	**2816**	**628**	**68**	**1839**	**2713**	**710**	*93*	*2004*	*2895*	*701*	*105*	*2003*	**5351**	*5520*	*5703*
U.S. Gas-Weighted	**2275**	**517**	**85**	**1522**	**2115**	**522**	*83*	*1714*	*2354*	*555*	*90*	*1714*	**4399**	*4435*	*4714*
Cooling Degree-Days (U.S.)	**35**	**353**	**831**	**78**	**45**	**383**	*748*	*75*	*32*	*346*	*781*	*76*	**1297**	*1252*	*1235*

[a] Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.

[b] OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

[c] Population-weighted degree days. A degree day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release G.17(419)*. Projections of OECD growth are based on WEFA Group, "World Economic Outlook," Volume 1. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table 2. U.S. Energy Indicators: Mid World Oil Price Case

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Macroeconomic [a]															
Real Fixed Investment (billion chained 1996 dollars-SAAR)	1574	1607	1638	1667	1731	1794	*1814*	*1850*	*1879*	*1910*	*1933*	*1955*	1621	*1797*	*1919*
Real Exchange Rate (index)	1.090	1.127	1.168	1.167	1.221	1.279	*1.257*	*1.220*	*1.223*	*1.213*	*1.197*	*1.173*	1.138	*1.244*	*1.202*
Business Inventory Change (billion chained 1996 dollars-SAAR)	-1.1	-9.5	3.5	7.6	10.3	7.4	*8.8*	*8.6*	*6.5*	*6.9*	*6.8*	*5.5*	0.1	*8.8*	*6.4*
Producer Price Index (index, 1982=1.000)	1.230	1.245	1.268	1.276	1.302	1.319	*1.352*	*1.364*	*1.364*	*1.356*	*1.349*	*1.350*	1.255	*1.334*	*1.355*
Consumer Price Index (index, 1982-1984=1.000)	1.648	1.662	1.672	1.684	1.701	1.716	*1.730*	*1.741*	*1.748*	*1.753*	*1.759*	*1.766*	1.667	*1.722*	*1.757*
Petroleum Product Price Index (index, 1982=1.000)	0.446	0.591	0.682	0.716	0.833	0.906	*0.929*	*0.911*	*0.894*	*0.815*	*0.776*	*0.766*	0.609	*0.895*	*0.813*
Non-Farm Employment (millions)	127.8	128.4	129.1	129.8	130.6	131.5	*131.6*	*132.0*	*132.4*	*132.8*	*133.1*	*133.4*	128.8	*131.4*	*132.9*
Commercial Employment (millions)	88.6	89.2	89.8	90.5	91.2	91.7	*92.1*	*92.6*	*93.1*	*93.5*	*93.9*	*94.4*	89.5	*91.9*	*93.7*
Total Industrial Production (index, 1996=1.000)	1.127	1.139	1.153	1.168	1.186	1.207	*1.224*	*1.241*	*1.251*	*1.261*	*1.270*	*1.279*	1.147	*1.215*	*1.265*
Housing Stock (millions)	115.4	115.8	116.0	116.1	116.3	116.8	*116.8*	*116.5*	*116.8*	*117.1*	*117.4*	*117.8*	115.8	*116.6*	*117.3*
Miscellaneous															
Gas Weighted Industrial Production (index, 1996=1.000)	1.062	1.060	1.068	1.091	1.096	1.096	*1.099*	*1.103*	*1.112*	*1.121*	*1.131*	*1.141*	1.070	*1.098*	*1.126*
Vehicle Miles Traveled [b] (million miles/day)	6731	7556	7706	7358	6820	7558	*7698*	*7277*	*6921*	*7637*	*7819*	*7376*	7341	*7339*	*7441*
Vehicle Fuel Efficiency (index, 1999=1.000)	0.991	0.992	1.007	1.006	0.997	1.007	*1.001*	*1.003*	*1.002*	*1.004*	*1.009*	*1.001*	0.999	*1.002*	*1.004*
Real Vehicle Fuel Cost (cents per mile)	2.98	3.35	3.51	3.76	4.16	4.29	*4.27*	*4.26*	*4.08*	*3.92*	*3.83*	*3.85*	3.40	*4.24*	*3.92*
Air Travel Capacity (mill. available ton-miles/day)	431.0	453.8	469.4	462.1	452.9	480.8	*498.6*	*487.4*	*484.4*	*507.0*	*524.8*	*514.3*	454.2	*480.0*	*507.7*
Aircraft Utilization (mill. revenue ton-miles/day)	242.2	264.2	277.5	266.0	254.9	283.6	*297.7*	*283.8*	*278.6*	*297.4*	*311.5*	*296.7*	262.6	*280.0*	*296.2*
Airline Ticket Price Index (index, 1982-1984=1.000)	2.130	2.186	2.180	2.254	2.309	2.419	*2.489*	*2.506*	*2.517*	*2.505*	*2.488*	*2.496*	2.188	*2.431*	*2.502*
Raw Steel Production (millions tons)	25.11	25.97	26.26	28.54	29.02	29.33	*29.06*	*29.32*	*29.32*	*29.46*	*28.88*	*29.23*	105.88	*116.73*	*116.88*

[a] Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case

[b] Includes all highway travel.

SAAR: Seasonally-adjusted annualized rate.

Note: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

Table 3. International Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except OECD Commercial Stocks)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Demand [a]															
OECD															
U.S. (50 States)	19.2	19.2	19.8	19.8	19.1	19.3	20.0	20.0	19.7	19.8	20.2	20.4	19.5	19.6	20.8
U.S. Territories	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.4
Canada	1.9	1.9	2.0	2.0	1.9	1.9	2.0	2.0	2.0	1.9	2.1	2.0	1.9	1.9	2.0
Europe	15.2	13.8	14.1	15.0	14.5	13.7	14.5	15.1	14.9	14.0	14.5	15.2	14.5	14.5	14.6
Japan	6.2	5.0	5.2	5.9	6.0	5.1	5.3	5.7	6.2	5.1	5.3	5.7	5.6	5.5	5.6
Australia and New Zealand	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.0	1.0	1.0	1.1	1.0	1.0	1.0
Total OECD	43.8	41.2	42.4	44.0	42.8	41.3	43.1	44.3	44.2	42.1	43.4	44.8	42.8	42.9	43.6
Non-OECD															
Former Soviet Union	3.8	3.5	3.6	3.7	3.8	3.6	3.6	3.6	3.8	3.7	3.7	3.7	3.6	3.7	3.7
Europe	1.6	1.6	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.6	1.6	1.7
China	4.4	4.3	4.3	4.3	4.6	4.5	4.5	4.5	4.8	4.8	4.7	4.8	4.3	4.5	4.8
Other Asia	8.8	8.8	8.7	9.0	9.2	9.2	9.0	9.4	9.7	9.7	9.4	9.9	8.8	9.2	9.7
Other Non-OECD	13.4	13.6	13.7	13.7	13.7	14.0	14.1	14.0	14.2	14.4	14.5	14.5	13.6	14.0	14.4
Total Non-OECD	31.9	31.8	31.7	32.3	32.9	33.0	32.8	33.2	34.2	34.3	34.0	34.5	31.9	33.0	34.2
Total World Demand	75.7	73.1	74.1	76.3	75.7	74.3	76.0	77.5	78.4	76.4	77.4	79.2	74.8	75.9	77.9
Supply [b]															
OECD															
U.S. (50 States)	8.8	8.9	9.0	9.3	9.1	9.1	9.0	9.2	9.2	9.2	9.1	9.2	9.0	9.1	9.2
Canada	2.6	2.6	2.6	2.7	2.7	2.7	2.6	2.7	2.7	2.7	2.8	2.8	2.6	2.7	2.7
North Sea [c]	6.3	6.0	6.2	6.7	6.6	6.2	6.4	6.8	6.5	6.3	6.3	6.5	6.3	6.5	6.4
Other OECD	1.5	1.5	1.5	1.6	1.7	1.7	1.8	1.8	1.8	1.7	1.7	1.8	1.5	1.7	1.8
Total OECD	19.2	19.0	19.3	20.2	20.2	19.7	19.8	20.4	20.2	19.9	19.8	20.3	19.4	20.0	20.1
Non-OECD															
OPEC	30.4	28.9	29.2	28.7	29.3	30.7	31.9	32.4	32.2	32.0	32.0	32.1	29.3	31.1	32.1
Former Soviet Union	7.3	7.3	7.5	7.5	7.6	7.7	7.8	7.9	8.0	8.0	8.1	8.2	7.4	7.8	8.1
China	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.2	3.3	3.3
Mexico	3.6	3.4	3.3	3.3	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.4	3.5	3.6
Other Non-OECD	11.3	11.2	11.2	11.2	11.2	11.2	11.3	11.4	11.4	11.5	11.5	11.6	11.2	11.3	11.5
Total Non-OECD	55.7	54.0	54.5	54.0	54.8	56.4	57.7	58.5	58.4	58.3	58.5	58.8	54.5	56.9	58.5
Total World Supply	74.9	72.9	73.8	74.2	75.0	76.1	77.5	78.9	78.6	78.2	78.3	79.1	73.9	76.9	78.5
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	0.3	-0.2	0.3	1.3	0.1	-0.6	-0.1	0.5	0.2	-0.6	-0.4	0.2	0.4	0.0	-0.1
Other	0.5	0.4	0.0	0.8	0.5	-1.1	-1.5	-1.9	-0.4	-1.2	-0.5	-0.10	.4	-1.0	-0.5
Total Stock Withdrawals	0.8	0.1	0.3	2.1	0.7	-1.7	-1.6	-1.4	-0.2	-1.8	-0.9	0.1	0.8	-1.0	-0.7
OECD Comm. Stocks, End (bill. bbls.)	2.8	2.8	2.8	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.9	2.8	2.6	2.8	2.8
Non-OPEC Supply	44.6	44.0	44.5	45.4	45.7	45.4	45.6	46.5	46.4	46.2	46.3	47.0	44.6	45.8	46.5
Net Exports from Former Soviet Union	3.5	3.8	3.9	3.8	3.9	4.1	4.2	4.3	4.1	4.3	4.4	4.5	3.8	4.1	4.4

[a] Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly*, DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b] Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[c] Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Notes: Minor discrepancies with other published EIA historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report* DOE/EIA-0520. Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

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Table 4. U. S. Energy Prices
(Nominal Dollars)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Imported Crude Oil Prices															
Imported Average[a]	10.91	15.44	19.63	23.01	26.84	26.57	29.65	28.26	26.50	24.34	24.02	23.61	17.21	27.86	24.58
WTI[b] Spot Average	13.07	17.65	21.73	24.56	28.82	28.78	31.61	30.35	28.51	26.33	26.00	25.59	19.25	29.89	26.61
Natural Gas Wellhead															
(dollars per thousand cubic feet)	1.74	2.04	2.27	2.26	2.26	2.97	3.66	4.57	4.39	3.59	3.31	3.72	2.08	3.37	3.75
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	0.99	1.17	1.25	1.30	1.44	1.57	1.56	1.51	1.45	1.45	1.44	1.39	1.18	1.52	1.43
Regular Unleaded	0.95	1.13	1.21	1.26	1.40	1.53	1.52	1.47	1.41	1.42	1.40	1.35	1.14	1.48	1.40
No. 2 Diesel Oil, Retail (dollars per gallon)	0.97	1.08	1.18	1.26	1.42	1.41	1.51	1.57	1.50	1.39	1.35	1.35	1.12	1.48	1.39
No. 2 Heating Oil, Wholesale (dollars per gallon)	0.36	0.44	0.56	0.65	0.85	0.78	0.91	0.91	0.84	0.74	0.71	0.72	0.51	0.87	0.76
No. 2 Heating Oil, Retail (dollars per gallon)	0.80	0.82	0.86	1.01	1.31	1.17	1.25	1.38	1.36	1.18	1.06	1.12	0.88	1.31	1.23
No. 6 Residual Fuel Oil, Retail[d] (dollars per barrel)	11.28	14.03	17.94	21.06	23.64	24.43	27.03	26.93	25.44	22.38	21.82	22.67	15.92	25.60	23.13
Electric Utility Fuels															
Coal (dollars per million Btu)	1.24	1.23	1.21	1.20	1.21	1.20	1.19	1.19	1.20	1.22	1.20	1.19	1.22	1.20	1.20
Heavy Fuel Oil[e] (dollars per million Btu)	1.73	2.26	2.82	3.17	3.74	4.08	4.47	4.33	3.93	3.62	3.65	3.65	2.39	4.22	3.72
Natural Gas (dollars per million Btu)	2.19	2.42	2.74	2.82	2.85	3.71	4.28	5.14	5.09	4.19	3.90	4.34	2.57	4.00	4.25
Other Residential															
Natural Gas (dollars per thousand cubic feet)	6.07	6.86	8.64	6.85	6.48	7.73	9.77	8.61	8.54	8.94	9.93	8.24	6.63	7.57	8.63
Electricity (cents per kilowatthour)	7.76	8.25	8.40	8.10	7.76	8.34	8.64	8.22	7.83	8.41	8.66	8.22	8.14	8.25	8.29

[a] Refiner acquisition cost (RAC) of imported crude oil.
[b] West Texas Intermediate.
[c] Average self-service cash prices.
[d] Average for all sulfur contents.
[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the first quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table 5. U.S. Petroleum Supply and Demand: Mid World Oil Price Case

(Million Barrels per Day, Except Closing Stocks)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Crude Oil Supply															
Domestic Production[a]	5.94	5.84	5.79	5.96	5.86	5.84	5.79	5.87	5.95	5.92	5.85	5.91	5.88	5.84	5.91
Alaska	1.13	1.04	0.98	1.05	1.02	0.97	0.89	0.95	1.02	1.01	0.97	1.00	1.05	0.96	1.00
Lower 48	4.80	4.80	4.82	4.91	4.84	4.87	4.90	4.92	4.92	4.90	4.89	4.91	4.83	4.88	4.91
Net Imports (including SPR)[b]	8.43	8.90	8.85	8.27	8.12	9.14	9.32	8.90	8.78	9.48	9.70	9.31	8.61	8.87	9.32
Other SPR Supply	0.01	0.03	0.01	0.00	0.02	0.17	0.07	0.07	0.00	0.00	0.16	0.16	0.01	0.08	0.08
SPR Stock Withdrawn or Added (-)	-0.01	-0.03	-0.01	0.09	-0.02	0.01	-0.03	0.29	0.00	0.00	-0.16	-0.16	0.01	0.06	-0.08
Other Stock Withdrawn or Added (-)	-0.24	0.15	0.31	0.21	-0.14	0.03	0.11	-0.08	-0.20	-0.05	0.16	0.02	0.11	-0.02	-0.02
Product Supplied and Losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unaccounted-for Crude Oil	0.30	0.15	0.27	0.05	0.32	0.40	0.51	0.21	0.21	0.22	0.22	0.21	0.19	0.36	0.21
Total Crude Oil Supply	14.42	15.01	15.22	14.57	14.16	15.42	15.70	15.19	14.74	15.57	15.77	15.29	14.80	15.12	15.34
Other Supply															
NGL Production	1.72	1.82	1.90	1.95	1.97	1.94	1.92	1.96	1.98	1.97	1.96	2.01	1.85	1.95	1.98
Other Hydrocarbon and Alcohol Inputs	0.37	0.37	0.38	0.38	0.37	0.40	0.38	0.40	0.38	0.37	0.36	0.39	0.38	0.39	0.37
Crude Oil Product Supplied	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Processing Gain	0.82	0.86	0.90	0.97	0.94	0.95	0.92	0.92	0.87	0.92	0.93	0.90	0.89	0.93	0.91
Net Product Imports[c]	1.34	1.52	1.41	0.92	1.35	1.18	1.19	1.27	1.32	1.47	1.51	1.42	1.30	1.25	1.43
Product Stock Withdrawn or Added (-)	0.54	-0.36	0.00	1.03	0.31	-0.62	-0.17	0.25	0.42	-0.54	-0.38	0.37	0.30	-0.06	-0.03
Total Supply	19.21	19.23	19.80	19.83	19.09	19.27	19.94	20.00	19.70	19.75	20.15	20.38	19.52	19.58	20.00
Demand															
Motor Gasoline	7.95	8.60	8.61	8.55	8.01	8.47	8.65	8.48	8.09	8.59	8.73	8.61	8.43	8.40	8.51
Jet Fuel	1.69	1.63	1.68	1.69	1.64	1.67	1.76	1.79	1.78	1.75	1.80	1.83	1.67	1.71	1.79
Distillate Fuel Oil	3.71	3.38	3.45	3.75	3.75	3.55	3.61	3.78	3.97	3.63	3.57	3.82	3.57	3.67	3.75
Residual Fuel Oil	0.93	0.78	0.84	0.78	0.73	0.74	0.89	0.75	0.87	0.79	0.79	0.76	0.83	0.78	0.80
Other Oils[d]	4.93	4.84	5.23	5.05	4.96	4.84	5.04	5.19	4.99	4.99	5.26	5.36	5.01	5.01	5.15
Total Demand	19.21	19.23	19.80	19.83	19.09	19.27	19.95	19.98	19.70	19.75	20.15	20.38	19.52	19.58	20.00
Total Petroleum Net Imports	9.77	10.43	10.27	9.19	9.47	10.33	10.51	10.17	10.11	10.95	11.21	10.72	9.91	10.12	10.75
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	345	332	304	284	297	294	285	292	310	315	300	298	284	292	298
Total Motor Gasoline	217	217	207	193	205	211	192	199	204	203	198	204	193	199	204
Finished Motor Gasoline	169	173	162	154	158	165	150	158	158	162	157	163	154	158	163
Blending Components	48	44	45	39	47	45	42	42	46	41	41	41	39	42	41
Jet Fuel	42	46	49	41	41	44	44	41	39	42	43	41	41	41	41
Distillate Fuel Oil	125	133	145	125	96	106	118	127	95	108	129	132	125	127	132
Residual Fuel Oil	40	42	41	36	36	37	37	41	36	36	38	39	36	41	39
Other Oils[e]	280	298	294	246	235	271	294	253	250	286	301	258	246	253	258
Total Stocks (excluding SPR)	1048	1068	1039	926	910	964	969	953	934	988	1008	972	926	953	972
Crude Oil in SPR	572	575	575	567	569	569	572	545	545	545	560	575	567	545	575
Heating Oil Reserve	0	0	0	0	0	0	0	2	2	2	2	2	0	2	2
Total Stocks (including SPR)	1620	1642	1615	1493	1479	1533	1541	1499	1480	1533	1569	1547	1493	1499	1547

[a] Includes lease condensate.

[b] Net imports equals gross imports plus SPR imports minus exports.

[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.

[d] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.

[e] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve

NGL: Natural Gas Liquids

Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, Table C1. Historical data are printed in bold, forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

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Table 6. Approximate Energy Demand Sensitivities[a] for the STIFS[b] Model
(Percent Deviation Base Case)

Demand Sector	+1% GDP	+ 10% Prices		+ 10% Weather[e]	
		Crude Oil[c]	N.Gas Wellhead[d]	Fall/Winter[f]	Spring/Summer[f]
Petroleum					
Total	0.6%	-0.3%	0.1%	1.1%	0.1%
Motor Gasoline	0.1%	-0.3%	0.0%	0.0%	0.0%
Distillate Fuel	0.8%	-0.2%	0.0%	2.7%	0.1%
Residual Fuel	1.6%	-3.4%	2.6%	2.0%	2.7%
Natural Gas					
Total	1.1%	0.3%	-0.4%	4.4%	1.0%
Residential	0.1%	0.0%	0.0%	8.2%	0.0%
Commercial	0.9%	0.0%	0.0%	7.3%	0.0%
Industrial	1.7%	0.2%	-0.5%	1.3%	0.0%
Electric Utility	1.8%	1.6%	-1.5%	1.0%	4.0%
Coal					
Total	0.7%	0.0%	0.0%	1.7%	1.7%
Electric Utility	0.6%	0.0%	0.0%	1.9%	1.9%
Electricity					
Total	0.6%	0.0%	0.0%	1.5%	1.7%
Residential	0.1%	0.0%	0.0%	3.2%	3.6%
Commercial	0.9%	0.0%	0.0%	1.0%	1.4%
Industrial	0.8%	0.0%	0.0%	0.3%	0.2%

[a]Percent change in demand quantity resulting from specified percent changes in model inputs.
[b]Short-Term Integrated Forecasting System.
[c]Refiner acquisitions cost of imported crude oil.
[d]Average unit value of marketed natural gas production reported by States.
[e]Refers to percent changes in degree-days.
[f]Response during fall/winter period(first and fourth calendar quarters) refers to change in heating degree-days. Response during the spring/summer period (second and third calendar quarters) refers to change in cooling degree-days.

Table 7. Forecast Components for U.S. Crude Oil Production
(Million Barrels per Day)

	High Price Case	Low Price Case	Difference		
			Total	Uncertainty	Price Impact
United States	6.18	5.55	0.63	0.08	0.55
Lower 48 States	5.17	4.47	0.60	0.07	0.53
Alaska	1.01	0.98	0.04	0.02	0.02

Note: Components provided are for the fourth quarter 2001. Totals may not add to sum of components due to independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, Reserves and Natural Gas Division.

Table 8. U.S. Natural Gas Supply and Demand: Mid world Oil Price Case
(Trillion Cubic Feet)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Total Dry Gas Production	**4.69**	**4.66**	**4.64**	**4.67**	**4.60**	**4.66**	*4.72*	*4.72*	*4.72*	*4.73*	*4.75*	*4.75*	**18.66**	*18.70*	*18.[illegible]4*
Net Imports	**0.83**	**0.79**	**0.87**	**0.88**	**0.87**	**0.80**	*0.87*	*0.92*	*0.95*	*0.93*	*1.00*	*1.00*	**3.38**	*3.46*	*3.88*
Supplemental Gaseous Fuels	**0.03**	**0.02**	**0.02**	**0.03**	**0.03**	**0.02**	*0.03*	*0.03*	*0.04*	*0.03*	*0.03*	*0.03*	**0.10**	*0.11*	*0.12*
Total New Supply	**5.55**	**5.48**	**5.54**	**5.58**	**5.50**	**5.48**	*5.62*	*5.67*	*5.70*	*5.69*	*5.78*	*5.78*	**22.14**	*22.27*	*22.95*
Working Gas in Storage															
Opening	**2.73**	**1.43**	**2.16**	**2.88**	**2.51**	**1.15**	*1.71*	*2.53*	*2.20*	*0.86*	*1.68*	*2.60*	**2.73**	*2.51*	*2.20*
Closing	**1.43**	**2.16**	**2.88**	**2.51**	**1.15**	**1.71**	*2.53*	*2.20*	*0.86*	*1.68*	*2.60*	*2.18*	**2.51**	*2.20*	*2.18*
Net Withdrawals	**1.30**	**-0.73**	**-0.73**	**0.38**	**1.36**	**-0.56**	*-0.82*	*0.33*	*1.34*	*-0.83*	*-0.92*	*0.42*	**0.22**	*0.31*	*0.02*
Total Supply	**6.85**	**4.75**	**4.81**	**5.95**	**6.86**	**4.93**	*4.79*	*6.00*	*7.04*	*4.87*	*4.86*	*6.20*	**22.36**	*22.58*	*22.97*
Balancing Item [a]	**-0.08**	**-0.04**	**-0.32**	**-0.56**	**0.02**	**0.02**	*-0.12*	*-0.27*	*0.18*	*0.09*	*-0.09*	*-0.33*	**-1.00**	*-0.36*	*-0.15*
Total Primary Supply	**6.77**	**4.70**	**4.49**	**5.40**	**6.87**	**4.94**	*4.67*	*5.74*	*7.22*	*4.96*	*4.77*	*5.87*	**21.36**	*22.22*	*22.82*
Demand															
Lease and Plant Fuel	**0.31**	**0.31**	**0.31**	**0.31**	**0.30**	**0.31**	*0.31*	*0.31*	*0.31*	*0.31*	*0.31*	*0.31*	**1.23**	*1.23*	*1.23*
Pipeline Use	**0.20**	**0.14**	**0.13**	**0.16**	**0.21**	**0.15**	*0.14*	*0.17*	*0.21*	*0.14*	*0.13*	*0.17*	**0.64**	*0.66*	*0.65*
Residential	**2.24**	**0.80**	**0.38**	**1.27**	**2.20**	**0.77**	*0.37*	*1.41*	*2.42*	*0.85*	*0.38*	*1.42*	**4.69**	*4.75*	*5.06*
Commercial	**1.25**	**0.58**	**0.42**	**0.80**	**1.24**	**0.61**	*0.43*	*0.89*	*1.39*	*0.62*	*0.43*	*0.90*	**3.06**	*3.17*	*3.35*
Industrial (Incl. Nonutility Use)	**2.24**	**2.03**	**2.10**	**2.27**	**2.36**	**2.28**	*2.36*	*2.43*	*2.45*	*2.27*	*2.45*	*2.52*	**8.63**	*9.44*	*9.69*
Electric Utilities	**0.53**	*0.85*	*1.15*	**0.59**	**0.56**	**0.83**	*1.06*	*0.52*	*0.45*	*0.77*	*1.07*	*0.55*	**3.11**	*2.97*	*2.83*
Total Demand	**6.77**	**4.70**	**4.49**	**5.40**	**6.87**	**4.94**	*4.67*	*5.74*	*7.22*	*4.96*	*4.77*	*5.87*	**21.36**	*22.22*	*22.82*

[a] The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

Table 9. U.S. Coal Supply and Demand: Mid World Oil Price Case
(Million Short Tons)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Production	283.5	264.0	273.9	272.6	274.1	260.2	276.3	284.1	272.7	282.9	277.2	285.0	1094.0	1094.6	1117.8
Appalachia	114.8	103.4	103.0	102.1	109.5	105.2	106.1	104.1	106.9	106.3	99.5	102.2	423.3	424.9	414.6
Interior	40.4	40.8	42.4	38.9	36.1	35.2	41.3	38.7	35.7	40.5	39.5	37.0	162.5	151.2	152.7
Western	128.3	119.8	128.5	131.6	128.5	119.8	128.9	141.3	130.2	136.1	138.2	145.7	508.2	518.5	550.2
Primary Stock Levels[a]															
Opening	36.5	42.4	41.5	35.1	36.4	41.3	41.9	35.5	36.4	41.3	41.9	35.5	36.5	36.4	36.4
Closing	42.4	41.5	35.1	36.4	41.3	41.9	35.5	36.4	41.3	41.9	35.5	34.6	36.4	36.4	34.6
Net Withdrawals	-5.8	0.8	6.5	-1.3	-4.9	-0.6	6.4	-0.9	-4.9	-0.6	6.4	0.9	0.2	(S)	1.7
Imports	2.2	2.1	2.4	2.4	2.8	2.7	2.9	2.6	2.9	2.9	2.9	2.9	9.1	11.0	11.6
Exports	13.0	14.4	16.1	15.0	13.6	14.4	15.0	15.2	14.9	15.1	15.3	15.2	58.5	58.2	60.5
Total Net Domestic Supply	267.0	252.5	266.6	258.7	258.4	248.0	270.5	270.6	255.9	270.1	271.1	273.5	1044.8	1047.5	1070.6
Secondary Stock Levels[b]															
Opening	129.4	143.3	151.9	139.7	143.5	139.8	133.2	121.8	129.1	118.0	130.4	115.8	129.4	143.5	129.1
Closing	143.3	151.9	139.7	143.5	139.8	133.2	121.8	129.1	118.0	130.4	115.8	121.8	143.5	129.1	121.8
Net Withdrawals	-13.9	-8.6	12.2	-3.8	3.7	6.6	11.4	-7.3	11.0	-12.4	14.6	-6.0	-14.1	14.4	7.3
Waste Coal Supplied to IPPs[c]	2.1	2.2	2.6	2.8	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	9.7	12.2	12.2
Total Supply	255.2	246.1	281.4	257.6	265.2	257.6	285.0	266.4	270.0	260.8	288.8	270.6	1040.4	1074.2	1090.1
Demand															
Coke Plants	6.8	7.1	7.0	7.2	7.3	7.2	7.1	7.3	7.3	7.3	7.2	7.3	28.1	29.0	29.1
Electricity Production															
Electric Utilities	216.4	213.8	247.3	216.7	214.1	202.1	234.4	214.1	219.0	212.3	237.1	217.5	894.1	864.6	885.9
Nonutilities (Excl. Cogen.)[d]	8.4	10.3	12.3	15.0	24.6	23.6	26.8	25.5	25.2	24.2	27.5	26.1	45.9	100.5	102.9
Retail and General Industry	18.6	17.1	16.9	17.6	18.1	16.7	17.0	19.5	18.5	17.0	17.0	19.7	70.3	71.3	72.2
Total Demand[e]	250.2	248.3	283.6	256.5	264.1	249.6	285.4	266.4	270.0	260.8	288.8	270.6	1038.5	1065.4	1090.1
Discrepancy[f]	5.0	-2.1	-2.1	1.2	1.1	8.0	-0.4	0.0	0.0	0.0	0.0	0.0	1.9	8.7	0.0

[a] Primary stocks are held at the mines, preparation plants, and distribution points.

[b] Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c] Estimated independent power producers' (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d] Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1998 and 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report).

[e] Total Demand includes estimated IPP consumption.

[f] The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period.

Notes: *Rows and columns may not add due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by* simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 10. U.S. Electricity Supply and Demand: Mid World Oil Price Case

(Billion Kilowatt-hours)

	1999				2000				2001				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1999	2000	2001
Supply															
Net Utility Generation															
Coal	**430.0**	**423.8**	**487.6**	**426.2**	**425.7**	**401.2**	*463.3*	*423.7*	*436.5*	*423.8*	*473.2*	*431.4*	**1767.7**	*1713.9*	*1765.0*
Petroleum	**25.7**	**22.1**	**27.4**	**11.7**	**11.0**	**16.4**	*21.9*	*15.9*	*22.2*	*20.9*	*24.4*	*17.6*	**86.9**	*65.1*	*85.2*
Natural Gas	**51.5**	**80.7**	**107.5**	**56.7**	**54.4**	**79.1**	*100.4*	*49.5*	*42.6*	*73.2*	*101.3*	*51.8*	**296.4**	*283.5*	*269.0*
Nuclear	**181.2**	**166.1**	**195.0**	**182.6**	**185.0**	**177.4**	*197.3*	*179.7*	*186.9*	*170.9*	*195.7*	*175.8*	**725.0**	*739.3*	*729.2*
Hydroelectric	**83.4**	**79.8**	**69.9**	**60.9**	**66.9**	**73.0**	*62.7*	*61.3*	*70.5*	*74.6*	*62.1*	*61.1*	**293.9**	*263.9*	*268.3*
Geothermal and Other [a]	**1.6**	**1.0**	**0.6**	**0.5**	**0.5**	**0.6**	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	**3.7**	*2.3*	*2.2*
Subtotal	**773.4**	**773.6**	**888.0**	**738.7**	**743.4**	**747.6**	*846.2*	*730.7*	*759.3*	*763.9*	*857.4*	*738.2*	**3173.7**	*3067.9*	*3118.8*
Nonutility Generation [b]															
Coal	**19.4**	**22.9**	**32.4**	**39.2**	**55.2**	**58.5**	*60.2*	*57.6*	*56.2*	*53.1*	*61.7*	*59.0*	**113.9**	*231.4*	*230.0*
Petroleum	**7.8**	**8.7**	**8.7**	**6.9**	**11.1**	**8.8**	*8.1*	*9.1*	*7.7*	*7.5*	*8.1*	*9.1*	**32.1**	*37.0*	*32.5*
Natural Gas	**53.2**	**58.6**	**77.7**	**69.9**	**66.9**	**76.0**	*88.6*	*79.7*	*75.4*	*76.0*	*101.0*	*90.8*	**259.5**	*311.3*	*343.3*
Other Gaseous Fuels [c]	**2.0**	**2.2**	**2.9**	**2.6**	**2.5**	**2.8**	*2.0*	*2.3*	*2.0*	*1.9*	*2.1*	*2.3*	**9.5**	*9.6*	*8.2*
Nuclear	**0.0**	**0.0**	**1.1**	**2.1**	**5.2**	**5.0**	*5.2*	*5.2*	*5.2*	*5.1*	*5.1*	*5.2*	**3.2**	*20.5*	*20.5*
Hydroelectric	**3.7**	**3.8**	**2.9**	**3.1**	**3.9**	**5.0**	*2.7*	*3.2*	*2.8*	*2.8*	*2.8*	*3.2*	**13.5**	*14.8*	*11.7*
Geothermal and Other [d]	**19.6**	**21.4**	**23.5**	**21.2**	**21.8**	**22.2**	*22.9*	*25.5*	*21.8*	*21.1*	*23.2*	*24.0*	**85.7**	*92.4*	*90.1*
Subtotal	**105.6**	**117.6**	**149.2**	**145.0**	**166.6**	**178.3**	*189.7*	*182.5*	*171.2*	*167.5*	*204.0*	*193.7*	**517.4**	*717.0*	*736.3*
Total Generation	**879.0**	**891.2**	**1037.2**	**883.6**	**910.0**	**925.9**	*1035.9*	*913.2*	*930.5*	*931.4*	*1061.4*	*931.9*	**3691.1**	*3785.0*	*3855.2*
Net Imports [e]	**2.5**	7.3	**12.4**	**8.4**	**9.1**	**8.1**	*9.0*	*7.2*	*6.5*	*8.0*	*10.8*	*7.3*	**30.6**	*33.4*	*32.6*
Total Supply	**881.5**	**898.6**	**1049.6**	**892.0**	**919.1**	**934.0**	*1044.9*	*920.4*	*936.9*	*939.4*	*1072.2*	*939.2*	**3721.7**	*3818.4*	*3887.7*
Losses and Unaccounted for [f]	**53.8**	76.7	**63.1**	**59.2**	**60.2**	**72.8**	*66.6*	*64.0*	*54.5*	*80.5*	*66.7*	*65.2*	**252.8**	*263.5*	*267.0*
Demand															
Electric Utility Sales															
Residential	**287.7**	**251.0**	**350.9**	**256.1**	**292.5**	**264.2**	*337.8*	*267.8*	*305.9*	*266.4*	*349.5*	*273.3*	**1145.7**	*1162.3*	*1195.0*
Commercial	**227.8**	**238.6**	**279.6**	**236.8**	**236.2**	**254.3**	*282.5*	*245.9*	*245.4*	*250.1*	*289.8*	*250.3*	**982.9**	*1018.8*	*1035.6*
Industrial	**252.1**	**267.7**	**277.6**	**265.7**	**260.0**	**268.5**	*278.5*	*267.9*	*260.0*	*271.9*	*283.1*	*272.9*	**1063.3**	*1074.9*	*1087.9*
Other	**24.7**	**25.3**	**28.4**	**25.7**	**26.4**	**27.4**	*29.6*	*26.8*	*26.6*	*27.0*	*30.2*	*27.3*	**104.2**	*110.3*	*111.1*
Subtotal	**792.4**	**782.6**	**936.6**	**784.4**	**815.1**	**814.3**	*928.4*	*808.4*	*838.0*	*815.4*	*952.5*	*823.7*	**3296.0**	*3366.2*	*3429.6*
Nonutility Use/Sales [g]	**35.3**	**39.3**	**49.8**	**48.4**	**43.8**	**46.9**	*49.9*	*48.0*	*44.4*	*43.5*	*53.0*	*50.3*	**172.8**	*188.7*	*191.2*
Total Demand	**827.7**	**821.9**	**986.5**	**832.8**	**858.9**	**861.2**	*978.3*	*856.4*	*882.4*	*858.9*	*1005.4*	*874.0*	**3468.9**	*3554.9*	*3620.7*
Memo:															
Nonutility Sales to Electric Utilities [g]	**70.4**	**78.3**	**99.4**	**96.5**	**122.8**	**131.4**	*139.8*	*134.5*	*126.7*	*124.0*	*151.0*	*143.4*	**344.5**	*528.4*	*545.2*

[a] "Other" includes generation from wind, wood, waste, and solar sources.
[b] Electricity(net Generation) from nonutility sources, including cogenerators and small power producers.
[c] Includes refinery still gas and other process or waste gases and liquefied petroleum gases.
[d] Includes geothermal, solar, wind, wood, waste, hydrogen, sulfur, batteries, chemicals and spent sulfite liquor.
[e] Data for 1999 are estimates.
[f] Balancing item, mainly transmission and distribution losses.
[g] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226. Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 11. U.S. Renewable Energy Use by Sector: Mid World Oil Price Case
(Quadrillion Btu)

	Year				Annual Percentage Change		
	1998	1999	2000	2001	1998-1999	1999-2000	2000-2001
Electric Utilities							
Hydroelectric Power [a]	**3.189**	**3.079**	*2.765*	*2.811*	**-3.4**	*-10.2*	*1.7*
Geothermal, Solar and Wind Energy [b]	**0.109**	**0.036**	*0.004*	*0.004*	**-67.0**	*-88.9*	*0.0*
Biofuels [c]	**0.021**	**0.021**	*0.021*	*0.021*	**0.0**	*0.0*	*0.0*
Total	**3.319**	**3.136**	*2.790*	*2.835*	**-5.5**	*-11.0*	*1.6*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.149**	**0.140**	*0.154*	*0.121*	**-6.0**	*10.0*	*-21.4*
Geothermal, Solar and Wind Energy [b]	**0.240**	**0.313**	*0.401*	*0.438*	**30.4**	*28.1*	*9.2*
Biofuels [c]	**0.523**	**0.705**	*0.726*	*0.703*	**34.8**	*3.0*	*-3.2*
Total	**0.912**	**1.157**	*1.280*	*1.261*	**26.9**	*10.6*	*-1.5*
Total Power Generation	**4.231**	**4.293**	*4.070*	*4.096*	**1.5**	*-5.2*	*0.6*
Other Sectors [d]							
Residential and Commercial [e]	**0.568**	**0.574**	*0.583*	*0.583*	**1.1**	*1.6*	*0.0*
Industrial [f]	**1.515**	**1.542**	*1.569*	*1.569*	**1.8**	*1.8*	*0.0*
Transportation [g]	**0.095**	**0.100**	*0.105*	*0.106*	**5.3**	*5.0*	*1.0*
Total	**2.178**	**2.216**	*2.258*	*2.258*	**1.7**	*1.9*	*0.0*
Net Imported Electricity [h]	**0.214**	**0.249**	*0.272*	*0.265*	**16.4**	*9.2*	*-2.6*
Total Renewable Energy Demand	**6.623**	**6.757**	*6.600*	*6.619*	**2.0**	*-2.3*	*0.3*

[a] Conventional hydroelectric power only. Hydroelectricity generated by pumped storage is not included in renewable energy.

[b] Also includes photovoltaic and solar thermal energy. Sharp declines since 1998 in the electric utility sector and corresponding increases in the nonutility sector for this category mostly reflect sale of geothermal facilities to the nonutility sector.

[c] Biofuels are fuelwood, wood byproducts, waste wood, municipal solid waste, manufacturing process waste, and alcohol fuels.

[d] Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly as inputs tu marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

[e] Includes biofuels and solar energy consumed in the residential and commercial sectors.

[f] onsists primarily of biofuels for use other than in electricity cogeneration.

[g] Ethanol blended into gasoline.

[h] Represents 78.6 percent of total electricity net imports, which is the proportion of total 1994 net imported electricity (0.459 quadrillion Btu) attributable to renewable sources (0.361 quadrillion Btu).

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Table A1. Annual U.S. Energy Supply and Demand

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	**6113**	**6368**	**6592**	**6708**	**6676**	**6880**	**7063**	**7348**	**7544**	**7813**	**8159**	**8516**	**8876**	*9341*	*9696*
Imported Crude Oil Price [a] (nominal dollars per barrel)	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.50**	**12.08**	**17.21**	*27.86*	*24.58*
Petroleum Supply															
Crude Oil Production [b] (million barrels per day)	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.25**	**5.88**	*5.84*	*5.91*
Total Petroleum Net Imports (including SPR) (million barrels per day)	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.76**	**9.91**	*10.12*	*10.75*
Energy Demand															
World Petroleum (million barrels per day)	**63.1**	**64.9**	**65.9**	**66.0**	**66.6**	**66.8**	**67.0**	**68.3**	**69.9**	**71.4**	**73.1**	**73.6**	**74.8**	*75.9*	*77.9*
U.S. Petroleum (million barrels per day)	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.92**	**19.52**	*19.58*	*20.00*
Natural Gas (trillion cubic feet)	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.95**	**21.26**	**21.36**	*22.22*	*22.82*
Coal (million short tons)	**830**	**877**	**891**	**897**	**898**	**907**	**943**	**950**	**962**	**1006**	**1029**	**1039**	**1039**	*1065*	*1090*
Electricity (billion kilowatthours)															
Utility Sales [c]	**2457**	**2578**	**2647**	**2713**	**2762**	**2763**	**2861**	**2935**	**3013**	**3098**	**3140**	**3240**	**3296**	*3366*	*3430*
Nonutility Own Use [d]	**NA**	**NA**	**91**	**113**	**119**	**122**	**127**	**138**	**145**	**145**	**148**	**156**	**173**	*189*	*191*
Total	**NA**	**NA**	**2738**	**2826**	**2881**	**2885**	**2988**	**3073**	**3159**	**3243**	**3288**	**3396**	**3469**	*3555*	*3621*
Total Energy Demand [e] (quadrillion Btu)	**NA**	**NA**	**84.2**	**84.2**	**84.5**	**85.6**	**87.4**	**89.2**	**90.9**	**93.9**	**94.2**	**94.4**	**96.3**	*97.8*	*99.6*
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	**NA**	**NA**	**12.77**	**12.55**	**12.66**	**12.44**	**12.37**	**12.14**	**12.07**	**12.02**	**11.54**	**11.09**	**10.85**	*10.47*	*10.27*

[a] Refers to the imported cost of crude oil to U.S. refiners.

[b] Includes lease condensate.

[c] Total annual electric utility sales for historical periods are derived from the sum of monthly sales figures based on submissions by electric utilities of Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." These historical values differ from annual sales totals based on *Form EIA-861*, reported in several EIA publications, but match alternate annual totals reported in EIA's *Electric Power Monthly*, DOE/EIA-0226.

[d] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates.

[e] "Total Energy Demand" refers to the aggregate energy concept presented in Energy Information Administration, *Annual Energy Review*, 1997, DOE/EIA-0384(97) (AER), Table 1.1. Prior to 1990, some components of renewable energy consumption, particularly relating to consumption at nonutility electric generating facilities, were not available. For those years, a less comprehensive measure of total energy demand can be found in EIA's *AER*. The conversion from physical units to Btu is calculated using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review (MER)*. Consequently, the historical data may not precisely match those published in the *MER* or the *AER*.

Notes: SPR: Strategic Petroleum Reserve. Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis; Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual* DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; *Quarterly Coal Report* DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-520, and Weekly Petroleum *Status Report* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

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Table A2. Annual U.S. Macroeconomic and Weather Indicators

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Macroeconomic															
Real Gross Domestic Product (billion chained 1996 dollars)	6113	6368	6592	6708	6676	6880	7063	7348	7544	7813	8159	8516	8876	*9341*	*9696*
GDP Implicit Price Deflator (Index, 1996=1.000)	0.776	0.802	0.833	0.865	0.897	0.919	0.941	0.960	0.981	1.000	1.020	1.032	1.048	*1.071*	*1.094*
Real Disposable Personal Income (billion chained 1996 Dollars)	4582	4784	4907	5014	5033	5189	5261	5397	5539	5678	5854	6134	6331	*6524*	*6830*
Manufacturing Production (Index, 1996=1.000)	0.765	0.801	0.816	0.812	0.793	0.825	0.855	0.907	0.955	1.000	1.070	1.123	1.170	*1.245*	*1.301*
Real Fixed Investment (billion chained 1996 dollars)	856	887	911	895	833	886	958	1046	1109	1213	1329	1485	1621	*1797*	*1919*
Real Exchange Rate (Index, 1996=1.000)	NA	NA	NA	0.963	0.966	0.960	1.001	0.981	0.927	1.000	1.102	1.137	1.138	*1.244*	*1.202*
Business Inventory Change (billion chained 1996 dollars)	8.5	17.0	14.2	8.9	-6.8	-4.7	3.6	12.1	14.1	10.1	15.2	25.6	0.1	*8.8*	*6.4*
Producer Price Index (index, 1982=1.000)	1.028	1.069	1.122	1.163	1.165	1.172	1.189	1.205	1.247	1.277	1.275	1.244	1.256	*1.334*	*1.355*
Consumer Price Index (index, 1982-1984=1.000)	1.137	1.184	1.240	1.308	1.363	1.404	1.446	1.483	1.525	1.570	1.606	1.631	1.667	*1.722*	*1.757*
Petroleum Product Price Index (Index, 1982=1.000)	0.568	0.539	0.612	0.748	0.671	0.647	0.620	0.591	0.608	0.701	0.680	0.513	0.609	*0.895*	*0.813*
Non-Farm Employment (millions)	102.0	105.2	107.9	109.4	108.3	108.6	110.7	114.1	117.2	119.6	122.7	125.8	128.8	*131.4*	*132.9*
Commercial Employment (millions)	65.2	67.8	70.0	71.3	70.8	71.2	73.2	76.1	78.8	81.1	83.9	86.6	89.5	*91.9*	*93.7*
Total Industrial Production (index, 1996=1.000)	0.780	0.815	0.830	0.828	0.812	0.837	0.866	0.914	0,958	1.000	1.063	1.108	1.147	*1.215*	*1.265*
Housing Stock (millions)	99.8	101.6	102.9	103.5	104.5	105.5	106.8	108.2	109.6	111.0	112.5	114.3	115.8	*116.6*	*117.3*
Weather [a]															
Heating Degree-Days															
U.S.	4334	4653	4726	4016	4200	4441	4700	4483	4531	4713	4542	3951	4169	*4225*	*4463*
New England	6546	6715	6887	5848	5960	6844	6728	6672	6559	6679	6662	5680	5952	*6379*	*6467*
Middle Atlantic	5699	6088	6134	4998	5177	5964	5948	5934	5831	5986	5809	4812	5351	*5520*	*5703*
U.S. Gas-Weighted	4391	4804	4856	4139	4337	4458	4754	4659	4707	4980	4802	4183	4399	*4435*	*4714*
Cooling Degree-Days (U.S.)	1269	1283	1156	1260	1331	1040	1218	1220	1293	1180	1156	1410	1297	*1252*	*1235*

[a] Population-weighted degree-days. A degree-day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population.

Notes: Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G 17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0900.

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Table A3. Annual International Petroleum Supply and Demand Balance
(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Demand [a]															
OECD															
U.S. (50 States)	16.7	17.3	17.4	17.0	16.8	17.1	17.2	17.7	17.7	18.3	18.6	18.9	19.5	*19.6*	*20.0*
Europe [b]	12.3	12.4	12.5	12.6	13.4	13.6	13.5	13.8	14.1	14.3	14.4	14.7	14.5	*14.5*	*14.6*
Japan	4.5	4.8	5.0	5.1	5.3	5.4	5.4	5.7	5.7	5.9	5.7	5.5	5.6	*5.5*	*5.6*
Other OECD	2.5	2.6	2.7	2.7	2.7	2.7	2.8	2.9	3.0	3.0	3.1	3.1	3.2	*3.3*	*3.4*
Total OECD	36.0	37.1	37.6	37.5	38.1	38.8	39.0	39.9	40.6	41.4	41.8	42.3	42.8	*42.9*	*43.6*
Non-OECD															
Former Soviet Union	9.0	8.9	8.7	8.4	8.3	6.8	5.6	4.8	4.6	4.0	3.9	3.6	3.6	*3.7*	*3.7*
Europe	2.2	2.2	2.1	1.9	1.4	1.3	1.3	1.3	1.3	1.4	1.5	1.5	1.6	*1.6*	*1.7*
China	2.1	2.3	2.4	2.3	2.5	2.7	3.0	3.2	3.4	3.6	3.9	4.1	4.3	*4.5*	*4.8*
Other Asia	4.1	4.4	4.9	5.3	5.7	6.2	6.8	7.3	7.9	8.5	9.0	8.7	8.8	*9.2*	*9.7*
Other Non-OECD	9.7	10.0	10.3	10.5	10.6	11.0	11.4	11.8	12.1	12.4	13.0	13.3	13.6	*14.0*	*14.4*
Total Non-OECD	27.1	27.7	28.3	28.5	28.5	28.0	28.0	28.4	29.3	30.0	31.3	31.3	31.9	*33.0*	*34.2*
Total World Demand	63.1	64.9	66.0	66.0	66.6	66.8	67.0	68.3	69.9	71.4	73.1	73.6	74.8	*75.9*	*77.9*
Supply [c]															
OECD															
U.S. (50 States)	10.7	10.5	9.9	9.7	9.9	9.6	9.6	9.4	9.4	9.4	9.5	9.3	9.0	*9.1*	*9.2*
Canada	2.0	2.0	2.0	2.0	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.6	*2.7*	*2.7*
North Sea [d]	3.8	3.8	3.7	3.9	4.1	4.5	4.8	5.5	5.9	6.3	6.2	6.2	6.3	*6.5*	*6.4*
Other OECD	1.4	1.5	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.5	*1.7*	*1.8*
Total OECD	17.9	17.8	17.1	17.1	17.5	17.9	18.0	18.7	19.2	19.7	19.9	19.7	19.4	*20.0*	*20.1*
Non-OECD															
OPEC	19.6	21.5	23.3	24.5	24.6	25.8	26.6	27.0	27.6	28.3	29.9	30.4	29.3	*31.1*	*32.1*
Former Soviet Union	12.5	12.5	12.1	11.4	10.4	8.9	8.0	7.3	7.1	7.1	7.1	7.2	7.4	*7.8*	*8.1*
China	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	3.0	3.1	3.2	3.2	3.2	*3.3*	*3.3*
Mexico	2.9	2.9	2.9	3.0	3.2	3.2	3.2	3.2	3.1	3.3	3.4	3.5	3.4	*3.5*	*3.6*
Other Non-OECD	6.8	11.7	7.7	8.0	8.1	8.4	8.7	9.2	9.9	10.2	10.5	10.8	11.2	*11.3*	*11.5*
Total Non-OECD	44.6	47.0	48.9	49.7	49.1	49.1	49.4	49.6	50.7	52.0	54.2	55.2	54.5	*56.9*	*58.5*
Total World Supply	62.5	64.8	65.9	66.8	66.7	67.0	67.4	68.3	69.9	71.8	74.1	74.9	73.9	*76.9*	*78.5*
Total Stock Withdrawals	0.6	0.1	0.0	-0.8	-0.1	-0.2	-0.4	0.0	0.0	-0.4	-1.0	-1.3	0.8	*-1.0*	*-0.7*
OECD Comm. Stocks, End (bill. bbls.)	2.7	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.7	2.7	2.7	2.8	2.6	*2.6*	*2.8*
Net Exports from Former Soviet Union	3.5	3.8	3.4	3.0	2.1	2.1	2.3	2.4	2.6	3.0	3.3	3.5	3.8	*4.1*	*4.4*

[a] Demand for petroleum by the OECD countries is synonymous with "petroleum product supplied," which is defined in the glossary of the EIA *Petroleum Supply Monthly*, DOE/EIA-0109. Demand for petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

[b] OECD Europe includes the former East Germany.

[c] Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources.

[d] *Includes offshore supply from Denmark, Germany, the Netherlands, Norway, and the United Kingdom.*

OECD: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

SPR: Strategic Petroleum Reserve

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Notes: Minor discrepancies with other published EIA historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated *Forecasting System*.

Sources: Energy Information Administration: latest data available from EIA databases supporting the following reports: *International Petroleum Statistics Report*, DOE/EIA-0520, and Organization for Economic Cooperation and Development, Annual and Monthly Oil Statistics Database.

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Table A4. Annual Average U. S. Energy Prices
(Nominal Dollars)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Imported Crude Oil Prices															
Imported Average[a]	18.13	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.08	17.21	*27.86*	*24.58*
WTI[b] Spot Average	19.20	15.98	19.78	24.48	21.60	20.54	18.49	17.16	18.41	22.11	20.61	14.45	19.25	*29.89*	*26.61*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	1.66	1.69	1.69	1.71	1.64	1.74	2.04	1.85	1.55	2.17	2.32	1.95	2.08	*3.37*	*3.75*
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	0.91	0.92	1.02	1.17	1.15	1.14	1.13	1.13	1.16	1.25	1.24	1.07	1.18	*1.52*	*1.43*
Regular Unleaded	0.91	0.91	0.99	1.13	1.10	1.09	1.07	1.08	1.11	1.20	1.20	1.03	1.14	*1.48*	*1.40*
No. 2 Diesel Oil, Retail (dollars per gallon)	0.93	0.91	0.99	1.16	1.12	1.10	1.11	1.11	1.10	1.22	1.19	1.04	1.12	*1.48*	*1.39*
No. 2 Heating Oil, Wholesale (dollars per gallon)	0.53	0.47	0.56	0.70	0.62	0.58	0.54	0.51	0.51	0.64	0.59	0.42	0.51	*0.87*	*0.76*
No. 2 Heating Oil, Retail (dollars per gallon)	0.80	0.81	0.90	1.06	1.02	0.93	0.91	0.88	0.87	0.99	0.99	0.85	0.88	*1.31*	*1.23*
No. 6 Residual Fuel Oil, Retail[e] (dollars per barrel)	17.76	14.04	16.20	18.66	14.32	14.21	14.00	14.79	16.49	19.01	17.82	12.83	15.92	*25.60*	*23.13*
Electric Utility Fuels															
Coal (dollars per million Btu)	1.51	1.47	1.44	1.45	1.45	1.41	1.38	1.36	1.32	1.29	1.27	1.25	1.22	*1.20*	*1.20*
Heavy Fuel Oil[d] (dollars per million Btu)	2.98	2.41	2.85	3.22	2.49	2.46	2.36	2.40	2.60	3.01	2.79	2.07	2.39	*4.22*	*3.72*
Natural Gas (dollars per million Btu)	2.24	2.26	2.36	2.32	2.15	2.33	2.56	2.23	1.98	2.64	2.76	2.38	2.57	*4.00*	*4.25*
Other Residential															
Natural Gas (dollars per thousand cubic feet)	5.55	5.47	5.64	5.80	5.82	5.89	6.17	6.41	6.06	6.35	6.95	6.83	6.63	*7.57*	*8.63*
Electricity (cents per kilowatthour)	7.4	7.5	7.6	7.8	8.1	8.2	8.3	8.4	8.4	8.4	8.4	8.3	8.1	*8.3*	*8.3*

[a]Refiner acquisition cost (RAC) of imported crude oil.
[b]West Texas Intermediate.
[c]Average self-service cash prices.
[d]Average for all sulfur contents.
[e]Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035, *Electric Power Monthly*, DOE/EIA-0226.

Table A5. Annual U.S. Petroleum Supply and Demand
(Million Barrels per Day, Except Closing Stocks)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Crude Oil Supply															
Domestic Production [a]	8.35	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.45	6.25	5.88	5.84	5.91
Alaska	1.96	2.02	1.87	1.77	1.80	1.71	1.58	1.56	1.48	1.39	1.30	1.17	1.05	0.96	1.00
Lower 48	6.39	6.12	5.74	5.58	5.62	5.46	5.26	5.10	5.08	5.07	5.16	5.08	4.83	4.88	4.91
Net Imports (including SPR) [b]	4.52	4.95	5.70	5.79	5.67	5.99	6.69	6.96	7.14	7.40	8.12	8.60	8.61	8.87	9.32
Other SPR Supply	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.00	0.02	0.01	0.08	0.08
Stock Draw (Including SPR)	-0.13	0.00	-0.09	0.02	-0.01	0.00	-0.08	-0.02	0.09	0.05	-0.06	-0.07	0.09	-0.03	-0.02
Product Supplied and Losses	-0.03	-0.04	-0.03	-0.02	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00
Unaccounted-for Crude Oil	0.14	0.20	0.20	0.26	0.20	0.26	0.17	0.27	0.19	0.22	0.14	0.11	0.19	0.36	0.21
Total Crude Oil Supply	12.85	13.25	13.40	13.41	13.30	13.41	13.61	13.87	13.97	14.19	14.66	14.89	14.80	15.12	15.34
Other Supply															
NGL Production	1.59	1.62	1.55	1.56	1.66	1.70	1.74	1.73	1.76	1.83	1.82	1.76	1.85	1.95	1.98
Other Hydrocarbon and Alcohol Inputs	0.12	0.11	0.11	0.13	0.15	0.20	0.25	0.26	0.30	0.31	0.34	0.38	0.38	0.39	0.37
Crude Oil Product Supplied	0.03	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Processing Gain	0.64	0.66	0.66	0.68	0.71	0.77	0.77	0.77	0.77	0.84	0.85	0.89	0.89	0.93	0.91
Net Product Imports [c]	1.39	1.63	1.50	1.38	0.96	0.94	0.93	1.09	0.75	1.10	1.04	1.17	1.30	1.25	1.43
Product Stock Withdrawn	0.09	0.03	0.13	-0.14	-0.04	0.06	-0.05	0.00	0.15	0.03	-0.09	-0.17	0.30	-0.06	-0.03
Total Supply	16.72	17.33	17.37	17.04	16.76	17.10	17.26	17.72	17.72	18.31	18.62	18.92	19.52	19.58	20.00
Demand															
Motor Gasoline [d]	7.19	7.36	7.40	7.31	7.23	7.38	7.48	7.60	7.79	7.89	8.02	8.25	8.43	8.40	8.51
Jet Fuel	1.38	1.45	1.49	1.52	1.47	1.45	1.47	1.53	1.51	1.58	1.60	1.62	1.67	1.71	1.79
Distillate Fuel Oil	2.98	3.12	3.16	3.02	2.92	2.98	3.04	3.16	3.21	3.37	3.44	3.46	3.57	3.67	3.75
Residual Fuel Oil	1.26	1.38	1.37	1.23	1.16	1.09	1.08	1.02	0.85	0.85	0.80	0.89	0.83	0.78	0.80
Other Oils [e]	3.90	4.03	3.95	3.95	3.99	4.20	4.17	4.41	4.36	4.63	4.77	4.69	5.01	5.01	5.15
Total Demand	16.72	17.34	17.37	17.04	16.77	17.10	17.24	17.72	17.72	18.31	18.62	18.92	19.52	19.58	20.00
Total Petroleum Net Imports	5.91	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	9.16	9.76	9.91	10.12	10.75
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	349	330	341	323	325	318	335	337	303	284	305	324	284	292	298
Total Motor Gasoline	226	228	213	220	219	216	226	215	202	195	210	216	193	199	204
Jet Fuel	50	44	41	52	49	43	40	47	40	40	44	45	41	41	41
Distillate Fuel Oil	134	124	106	132	144	141	141	145	130	127	138	156	125	127	132
Residual Fuel Oil	47	45	44	49	50	43	44	42	37	46	40	45	36	41	39
Other Oils [f]	260	267	257	261	267	263	273	275	258	250	259	291	246	253	258

[a] Includes lease condensate.
[b] Net imports equals gross imports plus SPR imports minus exports.
[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.
[d] For years prior to 1993, motor gasoline includes an estimate of fuel ethanol blended into gasoline and certain product reclassifications, not reported elsewhere in EIA. See Appendix B in Energy Information Administration, *Short-Term Energy Outlook*, EIA/DOE-0202(93/3Q), for details on this adjustment.
[e] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.
[f] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.
SPR: Strategic Petroleum Reserve. NGL: Natural Gas Liquids.
Notes: Minor discrepancies with other EIA published historical data are due to rounding, with the following exception: recent petroleum demand and supply data displayed here reflect the incorporation of resubmissions of the data as reported in EIA's *Petroleum Supply Monthly*, Table C1. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.
Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109, and *Weekly Petroleum Status Report*, DOE/EIA-0208.

Table A6. Annual U.S. Natural Gas Supply and Demand
(Trillion Cubic Feet)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Total Dry Gas Production	16.62	17.10	17.31	17.81	17.70	17.84	18.10	18.82	18.60	18.85	18.90	18.71	18.66	*18.70*	*18.94*
Net Imports	0.94	1.22	1.27	1.45	1.64	1.92	2.21	2.46	2.69	2.78	2.84	2.99	3.38	*3.46*	*3.88*
Supplemental Gaseous Fuels	0.10	0.10	0.11	0.12	0.11	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10	*0.11*	*0.12*
Total New Supply	17.66	18.42	18.69	19.38	19.45	19.88	20.42	21.39	21.40	21.75	21.84	21.80	22.14	*22.27*	*22.95*
Working Gas in Storage															
Opening	2.75	2.76	2.85	2.51	3.07	2.82	2.60	2.32	2.61	2.15	2.17	2.17	2.73	*2.51*	*2.20*
Closing	2.76	2.85	2.51	3.07	2.82	2.60	2.32	2.61	2.15	2.17	2.17	2.73	2.51	*2.20*	*2.18*
Net Withdrawals	-0.01	-0.09	0.34	-0.56	0.24	0.23	0.28	-0.28	0.45	-0.02	0.00	-0.56	0.22	*0.31*	*0.02*
Total Supply	17.65	18.33	19.03	18.82	19.70	20.11	20.70	21.11	21.85	21.73	21.84	21.25	22.36	*22.58*	*22.97*
Balancing Item [a]	-0.44	-0.30	-0.23	-0.11	-0.66	-0.56	-0.42	-0.40	-0.27	0.24	0.11	0.01	-1.00	*-0.36*	*-0.15*
Total Primary Supply	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.95	21.26	21.36	*22.22*	*22.82*
Demand															
Lease and Plant Fuel	1.15	1.10	1.07	1.24	1.13	1.17	1.17	1.12	1.22	1.25	1.20	1.16	1.23	*1.23*	*1.23*
Pipeline Use	0.52	0.61	0.63	0.66	0.60	0.59	0.62	0.69	0.70	0.71	0.75	0.64	0.64	*0.66*	*0.65*
Residential	4.31	4.63	4.78	4.39	4.56	4.69	4.96	4.85	4.85	5.24	4.98	4.52	4.69	*4.75*	*5.06*
Commercial	2.43	2.67	2.72	2.62	2.73	2.80	2.86	2.90	3.03	3.16	3.21	3.00	3.06	*3.17*	*3.35*
Industrial (Incl. Nonutilities)	5.95	6.38	6.82	7.02	7.23	7.53	7.98	8.17	8.58	8.87	8.83	8.69	8.63	*9.44*	*9.69*
Electric Utilities	2.84	2.64	2.79	2.79	2.79	2.77	2.68	2.99	3.20	2.73	2.97	3.26	3.11	*2.97*	*2.83*
Total Demand	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.95	21.26	21.36	*22.22*	*22.82*

[a] *The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.*

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Oil and Gas, Reserves and Natural Gas Division.

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Table A7. Annual U.S. Coal Supply and Demand
(Million Short Tons)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Production	**918.8**	**950.3**	**980.7**	**1029.**	**996.0**	**997.5**	**945.4**	**1033.5**	**1033.0**	**1063.9**	**1089.9**	**1117.5**	**1094.0**	*1094.6*	*1117.8*
Appalachia	**NA**	**NA**	**464.8**	**489.0**	**457.8**	**456.6**	*409.7*	**445.4**	**434.9**	**451.9**	**467.8**	**460.4**	**423.3**	*424.9*	*414.8*
Interior	**NA**	**NA**	**198.1**	**205.8**	**195.4**	**195.7**	**167.2**	**179.9**	**168.5**	**172.8**	**170.9**	**168.4**	**162.5**	*151.2*	*152.7*
Western	**NA**	**NA**	**317.9**	**334.3**	**342.8**	**345.3**	**368.5**	**408.3**	**429.6**	**439.1**	**451.3**	**488.8**	**508.2**	*518.5*	*550.2*
Primary Stock Levels [a]															
Opening	**32.1**	**28.3**	**30.4**	**29.0**	**33.4**	**33.0**	**34.0**	**25.3**	**33.2**	**34.4**	**28.6**	**34.0**	**36.5**	*36.4*	*36.4*
Closing	**28.3**	**30.4**	**29.0**	**33.4**	**33.0**	**34.0**	**25.3**	**33.2**	**34.4**	**28.6**	**34.0**	**36.5**	**36.4**	*36.4*	*34.6*
Net Withdrawals	**3.8**	**-2.1**	**1.4**	**-4.4**	**0.4**	**-1.0**	**8.7**	**-7.9**	**-1.2**	**5.8**	**-5.3**	**-2.6**	**0.2**	*S*	*1.7*
Imports	**1.7**	**2.1**	**2.9**	**2.7**	**3.4**	**3.8**	**7.3**	**7.6**	**7.2**	**7.1**	**7.5**	**8.7**	**9.1**	*11.0*	*11.6*
Exports	**79.6**	**95.0**	**100.8**	**105.8**	**109.0**	*102.5*	*74.5*	*71.4*	**88.5**	**90.5**	**83.5**	**78.0**	**58.5**	*58.2*	*60.5*
Total Net Domestic Supply	**844.7**	**855.3**	**884.2**	**921.6**	**890.9**	**897.8**	**886.9**	**961.8**	**950.4**	**986.3**	**1008.5**	**1045.7**	**1044.8**	*1047.5*	*1070.6*
Secondary Stock Levels [b]															
Opening	**175.2**	**185.5**	**158.4**	**146.1**	**168.2**	**167.7**	**163.7**	**120.5**	**136.1**	**134.6**	**123.0**	**106.4**	**129.4**	*143.5*	*129.1*
Closing	**185.5**	**158.4**	**146.1**	**168.2**	**167.7**	**163.7**	**120.5**	**136.1**	**134.6**	**123.0**	**106.4**	**129.4**	**143.5**	*129.1*	*121.8*
Net Withdrawals	**-10.2**	**27.0**	**12.3**	**-22.1**	**0.5**	**4.0**	**43.2**	**-15.7**	**1.5**	**11.7**	**16.6**	**-23.0**	**-14.1**	*14.4*	*7.3*
Waste Coal Supplied to IPPs [c]	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**6.0**	**6.4**	**7.9**	**8.5**	**8.8**	**8.1**	**8.6**	**9.7**	*12.2*	*12.2*
Total Supply	**834.4**	**882.3**	**896.5**	**899.4**	**891.4**	**907.8**	**936.5**	**954.0**	**960.4**	**1006.7**	**1033.2**	**1031.3**	**1040.4**	*1074.2*	*1090.1*
Demand															
Coke Plants	**37.0**	**41.9**	**40.5**	**38.9**	**33.9**	**32.4**	**31.3**	**31.7**	**33.0**	**31.7**	**30.2**	**28.2**	**28.1**	*29.0*	*29.1*
Electricity Production															
Electric Utilities	**717.9**	**758.4**	**766.9**	**773.5**	**772.3**	**779.9**	**813.5**	**817.3**	**829.0**	**874.7**	**900.4**	**910.9**	**894.1**	*864.6*	*885.9*
Nonutilities (Excl. Cogen.) [d]	**NA**	**NA**	**0.9**	**1.6**	**10.2**	**14.6**	**17.1**	**19.5**	**20.8**	**22.2**	**21.6**	**26.9**	**45.9**	*100.5*	*102.9*
Retail and General Industry	**75.2**	**76.3**	**82.3**	**83.1**	**81.5**	**80.2**	**81.1**	**81.2**	**78.9**	**76.9**	**77.1**	**73.0**	**70.3**	*71.3*	*72.2*
Total Demand [e]	**830.0**	**876.5**	**890.6**	**897.1**	**897.8**	**907.0**	**943.1**	**949.7**	**961.7**	**1005.6**	**1029.2**	**1039.0**	**1038.5**	*1065.4*	*1090.1*
Discrepancy [f]	**4.4**	**5.8**	**5.9**	**2.4**	**-6.4**	**0.8**	**-6.6**	**4.3**	**-1.3**	**1.2**	**4.0**	**-7.7**	*1.9*	*8.7*	*0.0*

[a] Primary stocks are held at the mines, preparation plants, and distribution points.

[b] Secondary stocks are held by users. It includes an estimate of stocks held at utility plants sold to nonutility generators.

[c] Estimated independent power producers (IPPs) consumption of waste coal. This item includes waste coal and coal slurry reprocessed into briquettes.

[d] Estimates of coal consumption by IPPs, supplied by the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration (EIA). Quarterly coal consumption estimates for 1999 and projections for 2000 and 2001 are based on (1) estimated consumption by utility power plants sold to nonutility generators during 1999, and (2) annual coal-fired generation at nonutilities from Form EIA-867 (Annual Nonutility Power Producer Report)

[e] Total Demand includes estimated IPP consumption.

[f] The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period. Prior to 1994, discrepancy may include some waste coal supplied to IPPs that has not been specifically identified.

Notes: Rows and columns may not add due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Quarterly Coal Report*, DOE/EIA-0121, and *Electric Power Monthly*, DOE/EIA-0226. *Projections*: Energy Information Administration, *Short-Term Integrated Forecasting System database*, and Office of Coal, Nuclear, Electric and Alternate Fuels.

Table A8. Annual U.S. Electricity Supply and Demand
(Billion Kilowatt-hours)

	Year														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply															
Net Utility Generation															
Coal	**1463.8**	**1540.7**	**1553.7**	**1559.6**	**1551.2**	**1575.9**	**1639.2**	**1635.5**	**1652.9**	**1737.5**	**1787.8**	**1807.5**	**1767.7**	*1713.9*	*1765.0*
Petroleum	**118.5**	**148.9**	**158.3**	**117.0**	**111.5**	**88.9**	**99.5**	**91.0**	**60.8**	**67.3**	**77.8**	**110.2**	**86.9**	*65.1*	*85.2*
Natural Gas	**272.6**	**252.8**	**266.6**	**264.1**	**264.2**	**263.9**	**258.9**	**291.1**	**307.3**	**262.7**	**283.6**	**309.2**	**296.4**	*283.5*	*269.0*
Nuclear	**455.3**	**527.0**	**529.4**	**576.9**	**612.6**	**618.8**	**610.3**	**640.4**	**673.4**	**674.7**	**628.6**	**673.7**	**725.0**	*739.3*	*729.2*
Hydroelectric	**249.7**	**222.9**	**265.1**	**279.9**	**275.5**	**239.6**	**265.1**	**243.7**	**293.7**	**328.0**	**337.2**	**304.4**	**293.9**	*263.9*	*268.3*
Geothermal and Other [a]	**12.3**	**12.0**	**11.3**	**10.7**	**10.1**	**10.2**	**9.6**	**8.9**	**6.4**	**7.2**	**7.5**	**7.2**	**3.7**	*2.3*	*2.2*
Subtotal	**2572.1**	**2704.3**	**2784.3**	**2808.2**	**2825.0**	**2797.2**	**2882.5**	**2910.7**	**2994.5**	**3077.4**	**3122.5**	**3212.2**	**3173.7**	*3067.9*	*3118.8*
Nonutility Generation [b]	**0.0**	**0.0**	**187.6**	**216.7**	**246.3**	**286.1**	**314.4**	**343.1**	**363.3**	**369.6**	**371.7**	**405.7**	**517.4**	*717.0*	*736.3*
Total Generation	**2572.1**	**2704.3**	**2971.9**	**3024.9**	**3071.3**	**3083.4**	**3196.9**	**3253.8**	**3357.8**	**3447.0**	**3494.2**	**3617.9**	**3691.1**	*3785.0*	*3855.2*
Net Imports [c]	**46.3**	**31.8**	**11.0**	**2.3**	**19.6**	**25.4**	**27.8**	**44.8**	**39.2**	**38.0**	**36.6**	**27.6**	**30.6**	*33.4*	*32.6*
Total Supply	**2618.5**	**2736.0**	**2982.8**	**3027.2**	**3091.0**	**3108.8**	**3224.7**	**3298.6**	**3397.1**	**3485.0**	**3530.8**	**3645.5**	**3721.7**	*3818.4*	*3887.7*
Losses and Unaccounted for [d]	**NA**	**NA**	**243.1**	**207.3**	**215.0**	**223.6**	**236.3**	**225.7**	**238.4**	**242.3**	**242.9**	**249.4**	**252.8**	*263.5*	*267.0*
Demand															
Electric Utility Sales															
Residential	**850.4**	**892.9**	**905.5**	**924.0**	**955.4**	**935.9**	**994.8**	**1008.5**	**1042.5**	**1082.5**	**1075.8**	**1127.7**	**1145.7**	*1162.3*	*1195.0*
Commercial	**660.4**	**699.1**	**725.9**	**751.0**	**765.7**	**761.3**	**794.6**	**820.3**	**862.7**	**887.4**	**928.4**	**968.5**	**982.9**	*1018.8*	*1035.6*
Industrial	**858.2**	**896.5**	**925.7**	**945.5**	**946.6**	**972.7**	**977.2**	**1008.0**	**1012.7**	**1030.4**	**1032.7**	**1040.0**	**1063.3**	*1074.9*	*1087.9*
Other	**88.2**	**89.6**	**89.8**	**92.0**	**94.3**	**93.4**	**94.9**	**97.8**	**95.4**	**97.5**	**102.9**	**103.5**	**104.2**	*110.3*	*111.1*
Subtotal	**2457.3**	**2578.1**	**2646.8**	**2712.6**	**2762.0**	**2763.4**	**2861.5**	**2934.6**	**3013.3**	**3097.8**	**3139.8**	**3239.8**	**3296.0**	*3366.2*	*3429.6*
Nonutility Own Use [e]	**NA**	**NA**	**94.7**	**101.5**	**108.0**	**121.8**	**126.9**	**138.4**	**145.4**	**144.9**	**148.2**	**156.2**	**172.8**	*188.7*	*191.2*
Total Demand	**NA**	**NA**	**2739.7**	**2819.9**	**2875.9**	**2885.1**	**2988.4**	**3073.0**	**3158.7**	**3242.7**	**3287.9**	**3396.0**	**3468.9**	*3554.9*	*3620.7*
Memo:															
Nonutility Sales to Electric Utilities	**NA**	**NA**	**92.9**	**115.2**	**138.3**	**164.4**	**187.5**	**204.7**	**217.9**	**224.6**	**223.5**	**249.5**	**344.5**	*528.4*	*545.2*

[a] Other includes generation from wind, wood, waste, and solar sources.
[b] Net generation.
[c] Data for 1999 are estimates.
[d] Balancing item, mainly transmission and distribution losses.
[e] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1999 are estimates

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold; forecasts are in italics.

Sources: Historical data: Energy Information Administration; latest data available from EIA databases supporting the following report: *Electric Power Monthly*, DOE/EIA-0226 and Electric Power Annual, DOE/EIA-0348.

Projections: Energy Information Administration, Short-Term Integrated Forecasting System database, and Office of Coal, Nuclear, Electric and Alternate Fuels.

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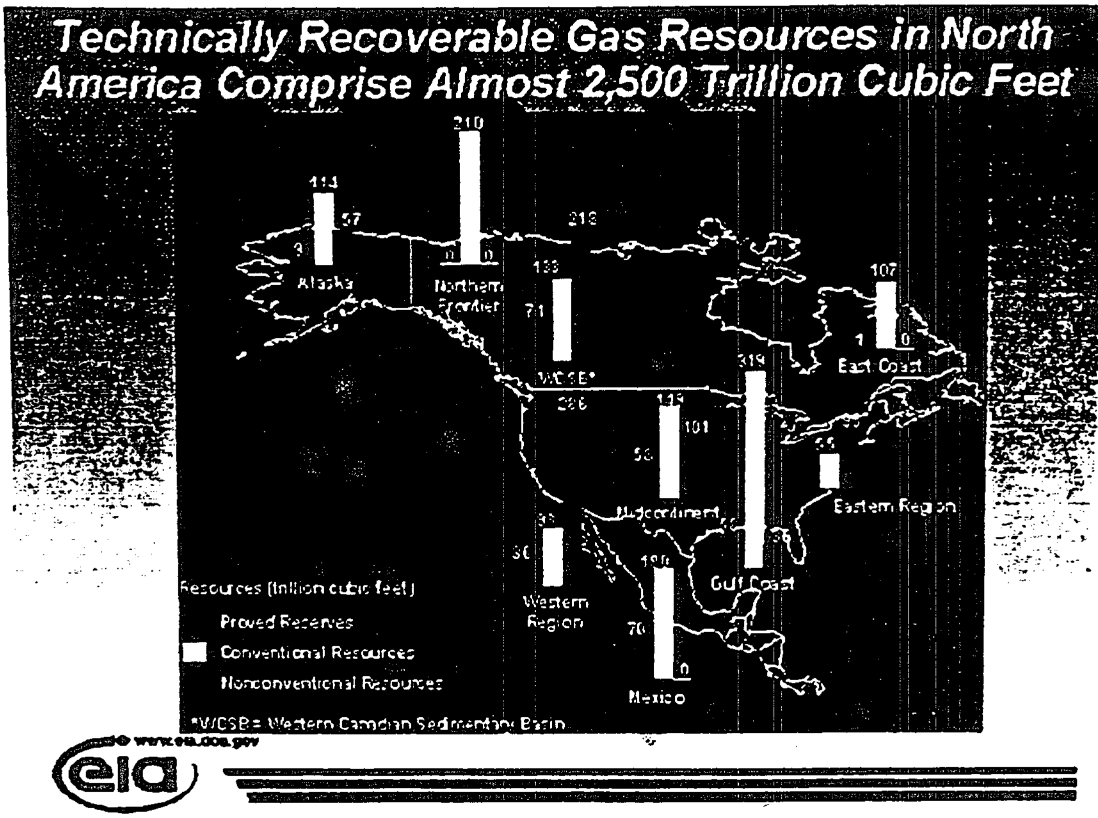

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U.S. Natural Gas Consumption by Secti 1990-2020 (trillion cubic feet)

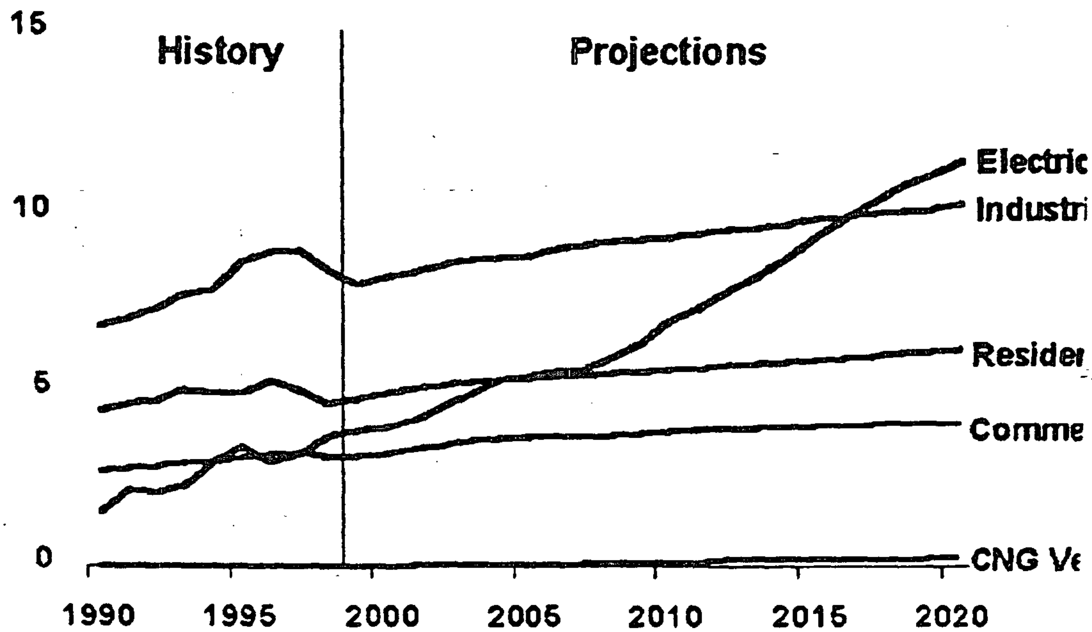

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Table 26. Production of Crude Oil by PAD District and State
(Thousand Barrels)

PAD District and State	September 2000 Total	September 2000 Daily Average	January-September 2000 Total	January-September 2000 Daily Average
PAD District I	E 657	E 22	E 5,901	E 22
Florida	E 372	E 12	E 3,376	E 12
New York	E 20	E 1	E 161	E 1
Pennsylvania	E 145	E 5	E 1,254	E 5
Virginia	E 1	E (s)	E 5	E (s)
West Virginia	E 119	E 4	E 1,070	E 4
Adjustment[a]	0	0	35	(s)
PAD District II	E 13,936	E 465	E 127,719	E 466
Illinois	E 1,055	E 35	E 9,057	E 33
Indiana	136	5	E 1,478	E 5
Kansas	E 2,829	E 94	E 25,879	E 94
Kentucky	366	12	2,610	10
Michigan	E 566	E 19	E 4,634	E 17
Missouri	E 7	E (s)	E 71	E (s)
Nebraska	251	8	2,209	8
North Dakota	2,668	89	24,560	90
Ohio	E 493	E 16	E 4,338	E 16
Oklahoma	5,710	190	E 51,901	E 189
South Dakota	90	3	853	3
Tennessee	29	1	270	1
Adjustment[a]	-283	-9	-150	-1
PAD District III	E 97,430	E 3,248	E 885,809	E 3,233
Alabama	E 881	E 29	E 8,031	E 29
Arkansas	E 675	E 22	E 5,958	E 22
Louisiana[b]	9,005	300	83,610	305
Mississippi	E 1,608	E 54	E 14,956	E 55
New Mexico	E 5,413	E 180	E 48,392	E 177
Texas[b]	E 37,041	E 1,235	E 337,280	E 1,231
Federal Offshore PAD District III	E 42,771	E 1,426	E 381,131	E 1,391
Adjustment[a]	37	1	6,531	24
PAD District IV	E 9,110	E 304	E 83,670	E 305
Colorado	E 1,640	E 55	E 14,990	E 55
Montana	E 1,225	E 41	E 9,687	E 35
Utah	E 1,231	E 41	E 11,615	E 42
Wyoming	E 5,014	E 167	E 42,474	E 155
Adjustment[a]	0	0	4,904	18
PAD District V	E 51,877	E 1,729	E 494,503	E 1,805
Alaska[b]	E 26,767	E 892	E 264,329	E 965
South Alaska	820	27	7,890	29
North Slope	25,946	865	256,492	936
Adjustment for Alaska[a]	0	D	-53	(s)
Arizona	6	(s)	44	(s)
California[b]	22,292	743	202,582	739
Nevada	E 48	E 2	E 470	E 2
Federal Offshore PAD District V	2,752	92	26,335	96
Adjustment excluding Alaska[a]	12	(s)	743	3
U.S. Total[b]	E 173,010	E 5,767	E 1,597,593	E 5,831

[a] These adjustments are used to reconcile the national and PAD District level sums of the State data with the independently estimated U.S. and Alaskan figures shown in the Summary Statistics portion of this issue and with the PAD District level figures published in a previous issue. Revised data at the State, PAD District, and national levels will be published without adjustments in the *Petroleum Supply Annual*.

[b] Includes the following current month offshore production (thousand barrels): Alaska: State - 4,293; California: State - 1,469; Louisiana: State - 1,129; Texas: State - 57; U.S. Total, including Federal offshore - E52,471.

(s) = Less than 500 barrels or less than 500 barrels per day.

E = Estimated.

NA = Not Available

Note: Totals may not equal sum of components due to independent rounding.

Sources: State government agencies, U.S. Department of the Interior, Minerals Management Service and the Conservation Committee of California Oil Producers

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- Recently, FERC accepted the creation of Mountain West as an Independent System Administrator (ISA) and conditionally approved the transfer of transmission facilities belonging to Nevada Power and Sierra Power to the ISA. FERC did not evaluate Mountain West under its ISO or RTO principles. Mountain West is considered an interim step in a broader regional transition plan in the western region.
- In response to FERC's Order 2000, nine transmission-owning utilities are working together to form the Northwest RTO.

Wholesale Electricity Trading Hubs and Power Exchanges

Coinciding with FERC's promotion and approvals of market-based rates for the sale of electricity, the industry has experienced a significant change in the way power is sold. Most noticeable is the emergence of centralized power markets where electricity suppliers submit bids to sell power in regional markets. The market operator evaluates the bids and selects the most economical bid to meet energy demand in the region. Four centralized power markets are now operating—California PX, New York ISO, ISO New England, and PJM-ISO (Figure 28). Of the four operating markets, the California Power Exchange may be the most active because California's three major electric utilities were until recently required by State law to sell all of their power through the exchange. Participation in the other power markets is voluntary and currently most of the power in these regions is sold through bilateral arrangements between buyer and seller. This may change as buyers and sellers gain more experience with centralized power markets.

To support bilateral power trading, numerous electricity trading hubs have emerged over the past few years. A hub is a location on the power grid representing a delivery point where power is sold and ownership changes hands. Potentially, each control area on the power grid could become a trading hub, but a few hubs account for the bulk of power trading (Figure 28). Of the 10 major trading hubs, five of them are located in the western United States, four in the midwest, and one in the east.

Part of the reason that these major trading hubs have emerged is because the New York Mercantile Exchange (NYMEX) and the Chicago Board of Trade (CBOT) have developed and sponsored electricity futures contracts to facilitate trading at these hubs. A futures contract is a common risk management tool used in agricultural, metal, and energy commodities markets. One of the main purposes of a futures contract is to eliminate the risk of price changes. For example, a power marketer entering into a contract to sell power at a predetermined price at the California Oregon Border (COB) runs the risk that the price it must pay for electricity will increase before the power is delivered. However, the power marketer can hedge its risk by buying electricity futures that match the quantity and timing of the original power contract. NYMEX has created electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. CBOT has created electricity futures contracts for the Commonwealth Edison and Tennessee Valley Authority trading hubs.

Market Power in Wholesale Electricity Markets

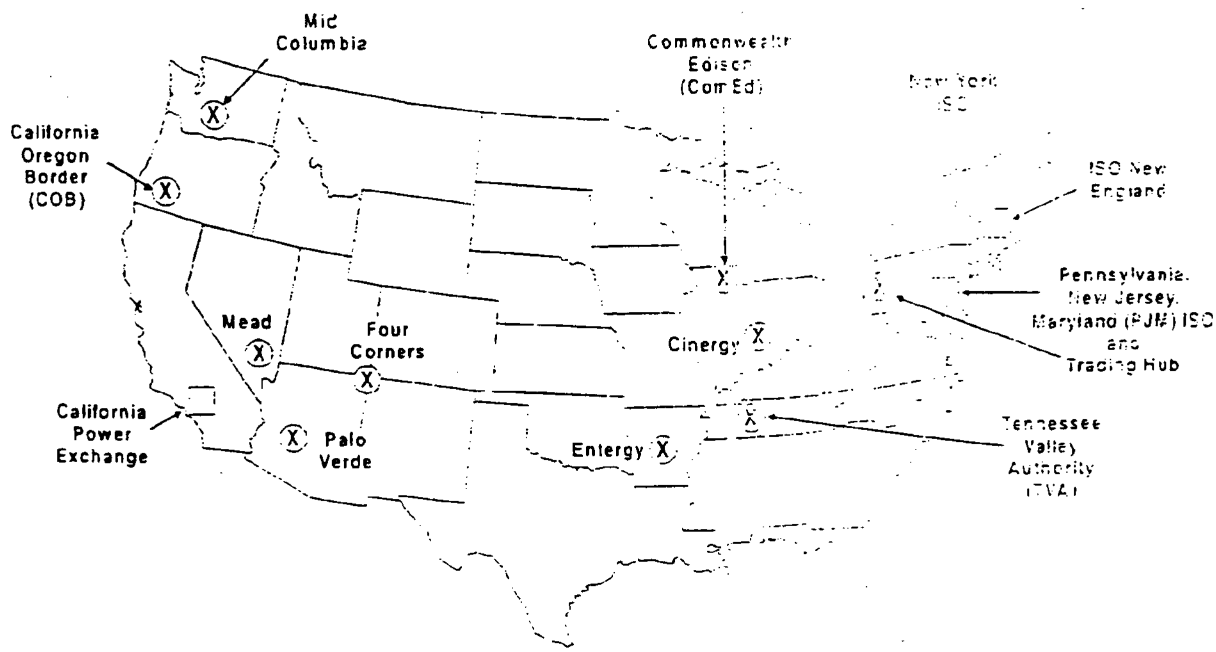
Market power is the ability of an electricity supplier to raise prices profitably above competitive levels and maintain those prices for a significant time. Electricity suppliers exercising market power force consumers to pay higher electricity prices than they would pay in a competitive market.

Market power exists in two forms—horizontal and vertical. Vertical market power may occur when a firm controls two related activities. In the electric power industry, one firm controlling both electricity generation and transmission has the potential to exercise vertical market power. Separating control of electricity generation from control of the transmission system (via ISOs and RTOs) is designed to eliminate the potential for vertical market power. Horizontal market power is more difficult to eliminate. Horizontal market power may occur when a firm controls a significant share of the market. In the electric power generation business, one firm controlling a significant share of electric generation capacity in a particular region has the potential to exercise horizontal market power.[94]

FERC and State regulators are interested in seeing that market power abuses do not undermine the potential benefits of competitive markets. To meet this objective, FERC requires ISOs and RTOs to monitor bulk power markets for abuses and design flaws, and to report

[94] A detailed discussion of horizontal market power and its effects on competition can be found in a report prepared by the U.S. Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis, "Horizontal Market Power in Restructured Electricity Markets," DOE/PO-0060 (Washington, DC, March 2000).

Figure 28. Major Wholesale Electricity Trading Hubs and Centralized Power Markets



X Major wholesale electricity trading hubs.

— Centralized power market. Unlike trading hubs, centralized power markets cover an entire region, and are not restricted to one location.

Notes: Power trading also occurs at locations not indicated on the map. The New York Mercantile Exchange (NYMEX) has established electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. The Chicago Board of Trade has established electricity futures contracts for the ComEd and TVA trading hubs.
Source: Electric industry trade journals and Internet websites.

market anomalies to FERC and other effected regulatory authorities. This market monitoring function is critical, particularly now as new competitive bulk power markets develop across the country.

A report prepared recently by the California ISO's Department of Market Analysis demonstrates the crucial role of market monitoring.[95] The report documents that recent spikes in California's electricity prices over this summer were attributable, in part, to some electricity suppliers exercising market power. The report noted that "the presence of market power can be verified by bid prices significantly over the variable costs of many suppliers in the ISO's market."

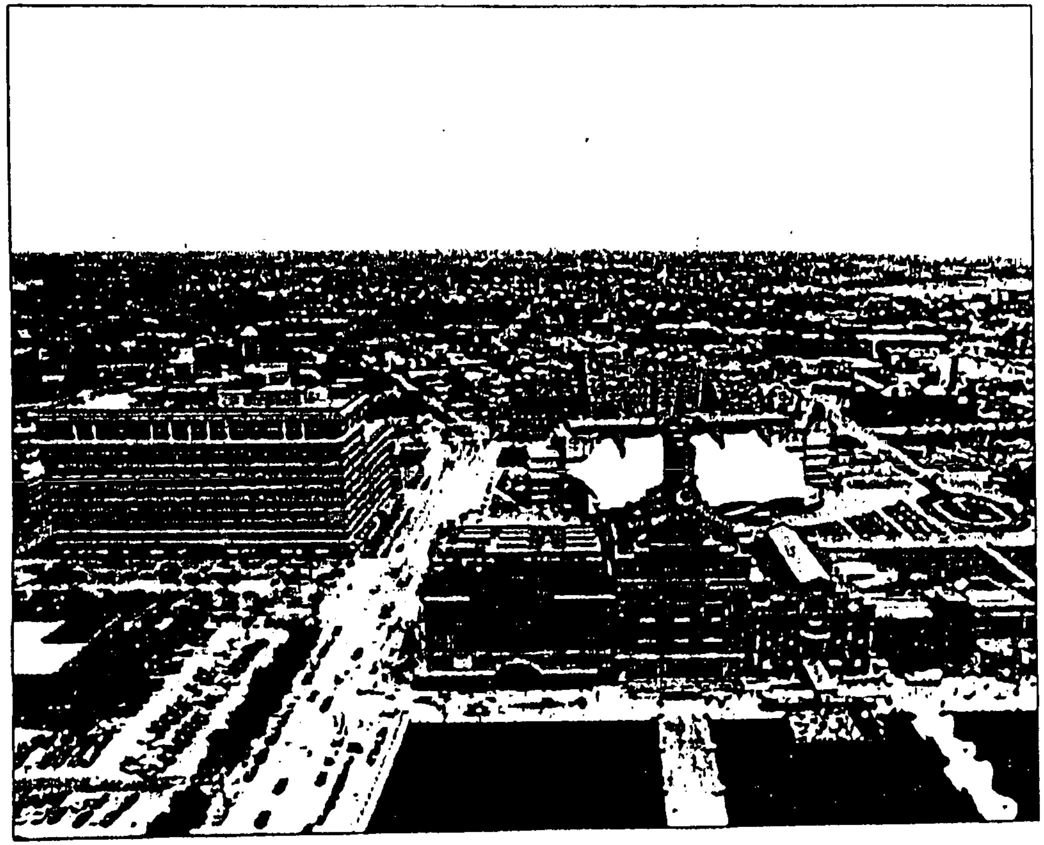
Price spikes in wholesale power markets in California and New York have prompted FERC to conduct an investigation of all electric bulk power markets to determine whether they are working efficiently and, if not, the causes of the problems. Their report is scheduled to be completed November 1, 2000.

Conclusion

By providing the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Nondiscriminatory access to the transmission system for all electricity suppliers is critical to creating competitive power markets. For more than a decade, FERC has been pushing for the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has

[95] California ISO, Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June 2000" (August 2000).

2 End-Use Energy Consumption



Office buildings, industries, residences, and transport systems, Baltimore, Maryland; east view from the Inner Harbor.
Source: U.S. Department of Energy.

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Table 2.1 Energy Consumption by End-Use Sector, 1949-1999
(Quadrillion Btu)

Year	Residential and Commercial: Coal	Residential and Commercial: Natural Gas [1]	Residential and Commercial: Petroleum	Residential and Commercial: Electricity	Residential and Commercial: Losses [2]	Residential and Commercial: Total [3]	Industrial: Coal	Industrial: Natural Gas [1]	Industrial: Petroleum	Industrial: Electricity	Industrial: Losses [2]	Industrial: Total [3,4]	Transportation: Petroleum	Transportation: Total [3]	Total
1949	2.83	1.39	1.85	0.43	1.72	9.28	5.43	3.19	3.47	0.42	1.68	14.73	6.15	7.99	32.00
1950	2.60	1.64	2.20	0.47	1.78	9.90	5.78	3.55	3.95	0.50	1.86	16.24	6.69	8.49	34.63
1951	2.47	2.01	2.40	0.54	1.89	10.27	6.20	4.05	4.27	0.57	2.00	17.68	7.36	9.04	37.00
1952	2.25	2.21	2.48	0.59	2.02	10.45	5.52	4.18	4.36	0.60	2.05	17.31	7.71	9.00	36.77
1953	1.93	2.29	2.60	0.65	2.12	10.35	5.93	4.30	4.48	0.68	2.20	18.21	8.06	9.12	37.68
1954	1.68	2.57	2.67	0.72	2.15	10.60	4.73	4.32	4.63	0.71	2.14	17.16	8.12	8.90	36.66
1955	1.67	2.85	2.87	0.79	2.23	11.20	5.62	4.70	5.11	0.89	2.51	19.49	8.80	9.55	40.24
1956	1.55	3.15	3.00	0.87	2.39	11.72	5.67	4.87	5.34	0.98	2.68	20.22	9.15	9.86	41.79
1957	1.19	3.39	2.91	0.95	2.55	11.70	5.54	5.11	5.24	1.00	2.70	20.22	9.29	9.90	41.82
1958	1.16	3.71	3.12	1.01	2.64	12.35	4.53	5.21	5.41	0.98	2.54	19.32	9.51	10.00	41.67
1959	0.99	4.02	3.18	1.12	2.84	12.81	4.41	5.65	5.74	1.08	2.73	20.33	9.85	10.35	43.49
1960	0.99	4.27	3.49	1.23	3.06	13.68	4.64	5.97	5.75	1.11	2.76	20.84	10.13	10.60	45.12
1961	0.90	4.48	3.58	1.30	3.18	14.04	4.35	6.17	5.75	1.15	2.80	20.94	10.32	10.77	45.78
1962	0.88	4.85	3.72	R1.42	3.40	14.84	4.38	6.45	6.00	1.23	2.95	21.77	10.77	R11.22	47.83
1963	0.76	5.01	3.72	1.54	R3.69	15.28	4.59	6.76	6.23	1.29	3.08	22.73	11.17	R11.65	49.65
1964	0.65	5.33	3.62	1.67	3.96	15.74	4.91	7.11	6.55	1.38	3.29	24.09	11.50	12.00	51.83
1965	0.62	5.52	3.87	1.78	4.25	16.51	5.13	7.34	6.79	1.46	3.49	25.07	11.87	12.43	54.02
1966	0.61	5.85	3.91	1.94	4.65	17.52	5.21	7.80	7.11	1.58	3.79	26.40	12.50	13.10	57.02
1967	0.52	6.47	4.04	2.09	R4.97	18.54	4.93	8.04	7.12	1.65	3.95	26.61	13.11	13.75	58.91
1968	0.47	6.73	4.20	2.32	5.52	R19.68	4.86	8.63	7.39	1.78	4.24	27.88	14.21	14.86	62.41
1969	0.44	7.20	4.26	R2.58	6.12	21.01	4.71	9.23	7.70	1.91	4.56	29.12	14.81	R15.51	65.63
1970	0.37	7.48	4.31	2.79	R6.77	R22.11	4.66	9.54	7.79	1.95	4.72	29.65	15.31	R16.10	67.86
1971	0.35	7.71	4.29	2.99	R7.24	R22.97	3.94	9.89	7.86	2.01	4.87	29.61	15.92	R16.73	69.31
1972	0.27	7.94	4.43	3.25	7.80	24.07	3.99	9.88	8.53	2.19	5.25	30.97	16.89	R17.72	72.76
1973	0.25	7.63	4.39	R3.49	R8.37	24.50	4.06	10.39	9.10	2.34	5.61	32.69	17.83	R18.61	75.81
1974	0.26	7.52	4.00	3.47	8.48	24.10	3.87	10.00	8.69	2.34	5.70	31.86	17.40	18.12	74.08
1975	0.21	7.58	3.80	3.60	8.70	24.33	3.67	8.53	8.15	2.35	5.66	29.46	17.62	18.25	72.04
1976	0.20	7.87	4.18	3.75	9.02	25.51	3.66	8.76	9.01	2.57	6.20	31.46	18.51	19.10	76.07
1977	0.21	7.46	4.21	3.98	9.56	25.94	3.45	8.64	9.78	2.68	6.48	32.38	19.24	19.82	78.12
1978	0.21	7.62	4.07	R4.11	R10.06	26.72	3.31	8.54	9.87	2.76	6.75	32.79	20.04	20.61	80.12
1979	0.19	7.89	3.45	4.18	10.10	26.55	3.59	8.55	10.57	2.87	6.94	34.02	19.82	20.47	81.04
1980	0.15	7.54	3.04	4.35	10.58	26.53	3.16	8.39	9.53	2.78	6.76	32.21	19.01	19.69	R78.43
1981	0.17	7.24	2.63	4.50	10.70	26.13	3.16	8.26	8.29	2.82	6.70	30.93	18.81	R19.50	76.57
1982	0.19	7.43	2.45	4.57	11.00	26.59	2.55	7.12	7.80	2.54	6.12	27.78	18.42	19.07	73.44
1983	0.19	7.02	2.50	4.68	R11.23	R26.57	2.49	6.83	7.42	2.65	6.38	27.60	18.59	R19.14	73.32
1984	0.21	7.29	2.54	4.93	11.51	27.42	2.84	7.45	8.01	2.86	6.68	29.75	19.22	R19.81	76.97
1985	0.18	7.08	2.62	5.06	R11.86	R27.62	2.76	7.08	7.81	2.86	6.69	29.09	19.50	20.07	R76.78
1986	0.18	6.82	2.66	R5.23	12.06	R27.75	2.64	6.69	7.92	2.83	6.53	28.50	20.27	R20.82	R77.06
1987	0.16	6.95	2.59	5.44	R12.47	R28.49	2.67	7.32	8.15	2.93	6.71	29.68	20.87	R21.46	R79.63
1988	0.17	7.51	2.60	5.72	R12.91	R29.83	2.83	7.70	8.43	3.06	6.90	30.92	21.63	22.31	R83.07
1989	0.15	7.73	2.53	5.88	R13.16	R,6 30.43	2.79	8.13	8.13	3.16	7.10	R,6 31.58	21.87	R22.57	R,6 84.69
1990	0.16	7.22	2.17	R6.01	13.24	R29.48	2.78	8.50	8.32	3.23	7.10	R32.15	21.81	R22.54	R84.19
1991	0.14	7.51	2.15	6.18	R13.44	R30.14	2.60	8.62	8.06	3.23	R7.02	R31.80	21.46	R22.13	R84.08
1992	0.14	7.73	2.13	R6.09	R13.18	R30.03	2.51	8.97	~~8.64~~	3.32	R7.18	33.01	~~21.81~~	R22.47	R85.51
1993	0.14	8.04	2.14	R6.41	R13.72	R31.12	2.50	9.41	8.45	3.33	R7.13	R33.30	22.20	R22.69	87.31
1994	0.14	7.97	2.09	6.56	R13.96	R31.37	2.51	9.56	8.85	3.44	7.32	R34.35	R22.76	R23.62	R89.23
1995	0.13	8.09	2.08	6.81	14.43	32.26	2.49	10.06	8.62	3.46	7.32	R34.70	R23.20	R23.97	R90.94
1996	0.14	8.63	2.20	7.04	R14.95	R33.67	2.42	10.39	9.10	3.52	R7.47	R35.71	R23.73	R24.52	R93.91
1997	0.15	8.42	2.14	R7.17	R15.21	R33.64	2.37	R10.31	9.31	3.52	R7.47	R35.85	R23.99	R24.82	R94.32
1998	R0.11	R7.77	R1.97	R7.49	R15.83	R33.68	R2.26	R10.17	R9.15	R3.55	R7.50	R35.54	R24.64	R25.36	R94.57
1999P	0.11	8.02	2.07	7.54	15.89	34.17	2.25	10.23	9.46	3.58	7.55	36.50	25.21	25.92	96.60

[1] Includes supplemental natural gas.
[2] Electrical system energy losses. See Glossary and Diagram 5. Total losses are calculated as the sum of energy consumed at electric utilities to generate electricity, utility purchases of electricity from nonutility power producers, and imported electricity, minus exported electricity and electricity consumed by end users. Total losses are allocated to the end-use sectors in proportion to each sector's share of total electricity use.
[3] "Total" also includes renewable energy, which is not shown separately on this table. See Table 10.2 for quantities since 1989.
[4] Also includes hydroelectric power and net imports of coal coke.
[5] Also includes coal, natural gas, electricity, and electrical system energy losses.
[6] There is a discontinuity in this time series between 1988 and 1989 due to expanded coverage of renewable energy beginning in 1989. See Table 10.2 for quantities since 1989.
R=Revised. P=Preliminary.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Tables 5.12a, 5.12b, 6.5, 7.3, 7.7, 8.1, 8.3, 8.9, A3-A6, and Energy Information Administration estimates for industrial hydroelectric power. "Other" from Table 8.9 is allocated to the Residential and Commercial Sector, except for approximately 5 percent used by railroads and railways and attributed to the Transportation Sector.

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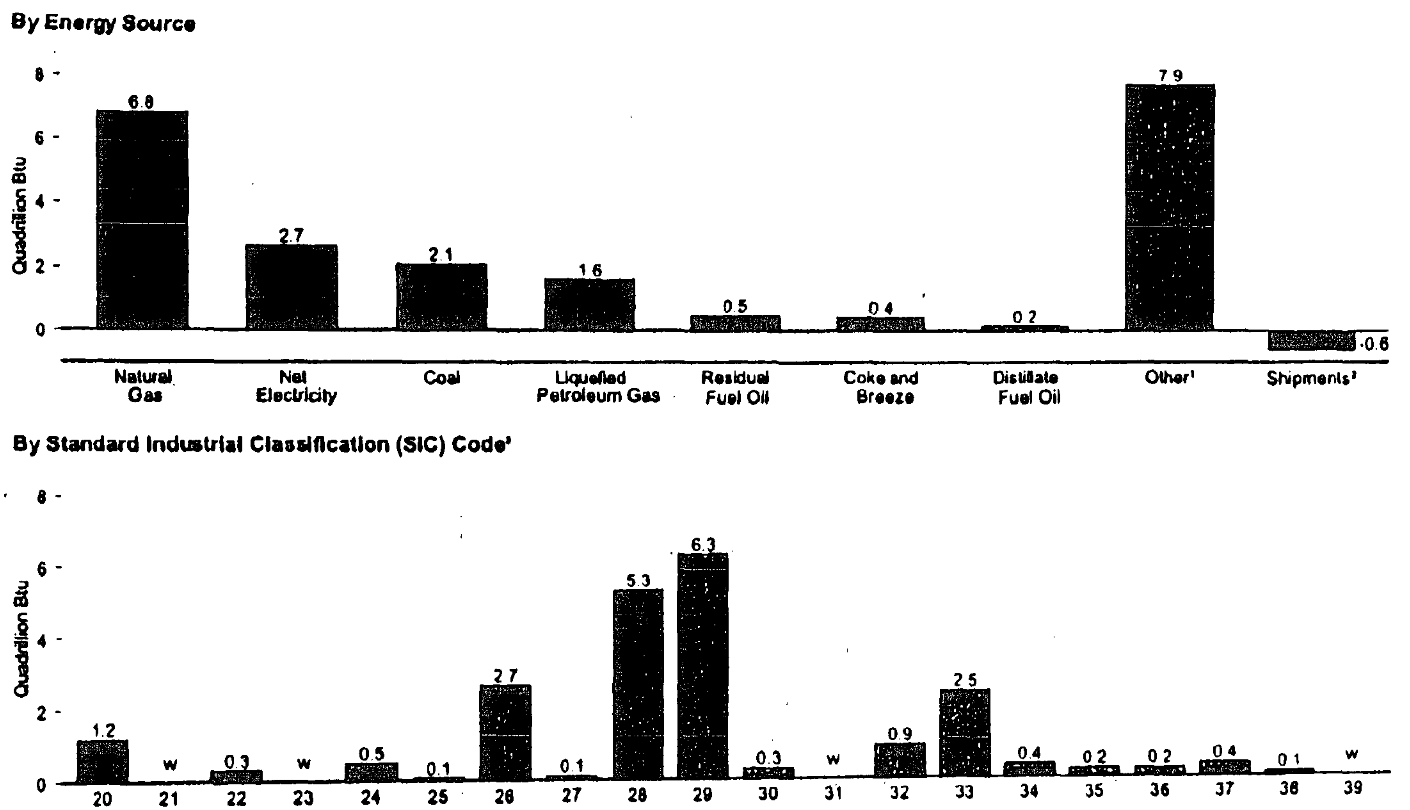
Figure 2.2 Manufacturing Total First Use of Energy for All Purposes, 1994



[1] Includes all other types of energy that respondents indicated were consumed.
[2] Energy sources produced onsite from the use of other energy sources but sold to another entity.
[3] See Table 2.2 for Major Group titles of industries that correspond to the 2-digit SIC codes.
W=Withheld to avoid disclosure of data for individual establishments.
Source: Table 2.2.

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Table 2.2 Manufacturing Total First Use of Energy for All Purposes, 1994

(Trillion Btu)

SIC[1] Code	Major Group	Coal	Coke and Breeze	Natural Gas	Distillate Fuel Oil	Liquefied Petroleum Gas	Residual Fuel Oil	Net Electricity[2]	Other[3]	Shipments of Energy Sources[4]	Total[5]
20	Food and Kindred Products	165	W	631	19	W	30	198	141	0	1,193
21	Tobacco Products	W	0	W	W	W	1	3	W	0	W
22	Textile Mill Products	40	0	117	7	4	17	111	14	0	310
23	Apparel and Other Textile Products	W	0	25	1	W	W	26	W	0	W
24	Lumber and Wood Products	W	0	48	25	W	2	68	341	0	491
25	Furniture and Fixtures	3	0	24	1	1	(s)	22	18	0	69
26	Paper and Allied Products	307	0	575	9	5	173	223	1,373	0	2,665
27	Printing and Publishing	0	0	48	2	W	W	59	2	0	112
28	Chemicals and Allied Products	293	11	2,569	14	1,535	110	520	442	166	5,328
29	Petroleum and Coal Products	W	W	811	22	47	71	121	5,344	87	6,339
30	Rubber and Miscellaneous Plastics Products	5	0	110	4	3	10	149	6	0	287
31	Leather and Leather Products	0	0	W	W	W	2	3	(s)	0	W
32	Stone, Clay, and Glass Products	274	8	432	23	4	7	123	73	0	944
33	Primary Metal Industries	922	424	811	13	5	43	493	85	334	2,462
34	Fabricated Metal Products	W	W	220	4	5	W	115	Q	0	367
35	Industrial Machinery and Equipment	11	W	111	4	3	W	109	5	0	246
36	Electronic and Other Electric Equipment	W	W	88	2	2	3	113	Q	0	243
37	Transportation Equipment	28	2	157	7	3	11	132	23	0	363
38	Instruments and Related Products	W	0	29	1	W	4	48	3	0	107
39	Miscellaneous Manufacturing Industries	1	0	19	1	1	1	19	W	0	W
—	Total Manufacturing	2,105	449	6,835	168	1,631	490	2,656	7,926	587	21,663

[1] Based on 1987 Standard Industrial Classification system.

[2] "Net Electricity" is obtained by summing purchases, transfers in, and generation from noncombustible renewable resources, minus quantities sold and transferred out. It excludes electricity generated from combustible fuels.

[3] Includes all other types of energy that respondents indicated were consumed.

[4] Energy sources produced onsite from the use of other energy sources but sold to another entity.

[5] The sum of net electricity, residual and distillate fuel oil, natural gas, liquefied petroleum gas, coal, coke and breeze and other, minus shipments of energy sources. Previous surveys did not subtract shipments.

(s)=Less than 0.5 trillion Btu. W=Withheld to avoid disclosure of data for individual establishments.

Q=Data withheld because the relative standard error was greater than 50 percent.

Notes: • "First Use" was "Primary Consumption" in previous releases of this table. The estimates are for the first use of energy for heat and power and as feedstocks or raw material inputs. First use is defined as the consumption of the energy that was originally produced offsite or was produced onsite from input materials not classified as energy. • See Table 12.4 for carbon dioxide emissions from energy consumption for manufacturing industries. • Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/emeu/consumption.

Source: Energy Information Administration, *Manufacturing Consumption of Energy 1994* (December 1997), Table A1, Part 3.

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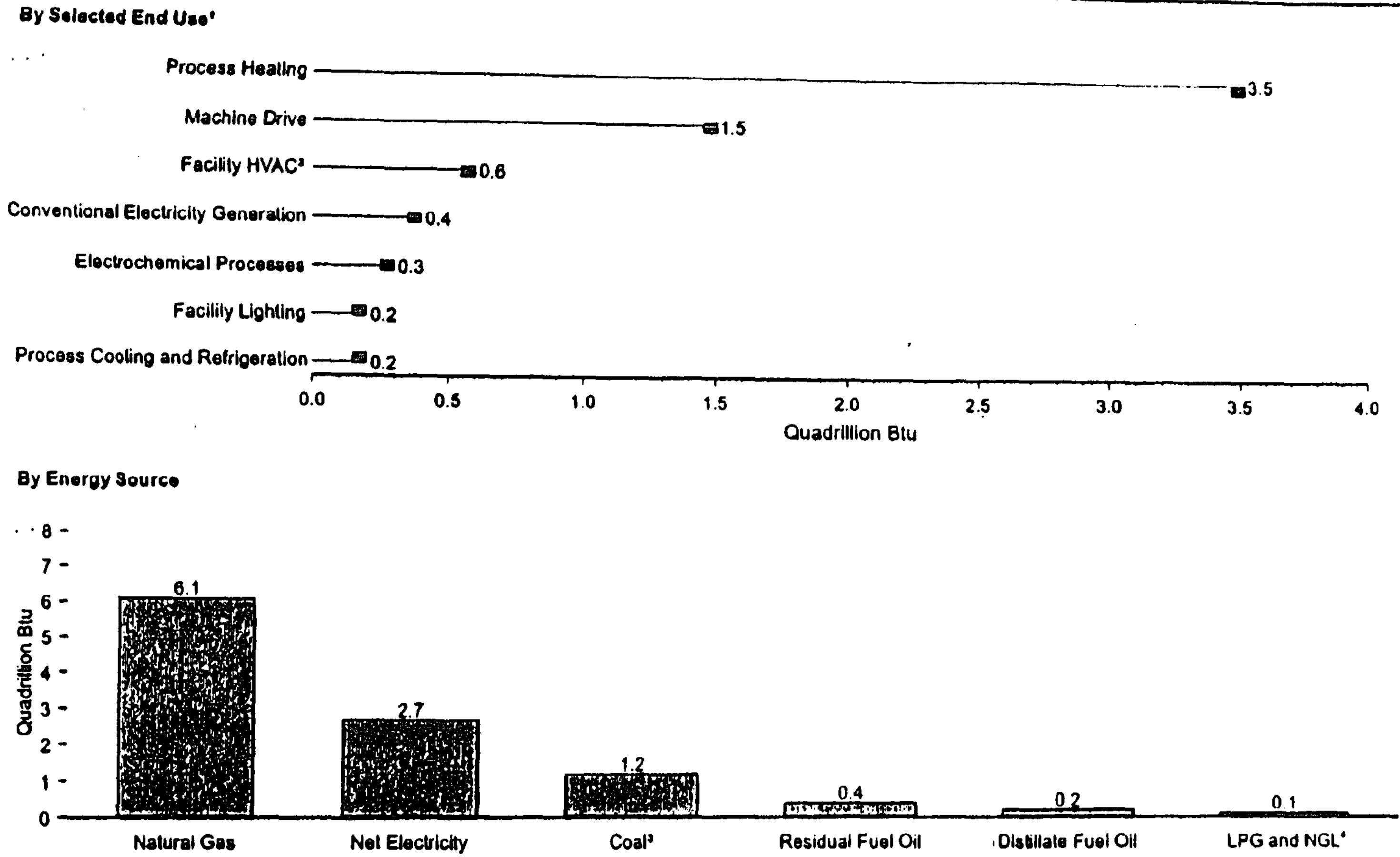
Figure 2.3. Manufacturing Sector Inputs for Heat, Power, and Electricity Generation, 1994



[1] Excludes inputs of unallocated energy sources (5,828 trillion Btu).
[2] Heating, ventilation, and air conditioning.
[3] Excluding coal coke and breeze.
[4] Liquefied petroleum gases and natural gas liquids.
Source: Table 2.3.

Table 2.3 Manufacturing Sector Inputs for Heat, Power, and Electricity Generation by End Use, 1994

End-Use Category	Net Electricity [1]	Residual Fuel Oil	Distillate Fuel Oil	Liquefied Petroleum Gases and Natural Gas Liquids	Natural Gas	Coal (Excluding Coal Coke and Breeze)	Total [2]
	Million Kilowatthours	Thousand Barrels			Billion Cubic Feet	Thousand Short Tons	
Indirect End Use (Boiler Fuel)	8,250	49,731	7,296	3,829	2,326	39,496	
Direct End Use							
All Process Uses	608,190	16,825	8,795	14,051	2,788	13,697	
Process Heating	83,151	16,326	4,919	12,515	2,623	13,545	
Process Cooling and Refrigeration	40,583	19	44	413	20	3	
Machine Drive	400,545	406	3,161	869	93	149	
Electrochemical Processes	79,549	—	—	—	—	—	
Other Process Uses	4,363	74	671	254	52	Q	
All Non-Process Uses	134,020	2,197	8,394	6,860	705	378	
Facility Heating, Ventilation, and Air Conditioning [3]	63,662	777	1,274	1,373	341	118	
Facility Lighting	54,332	—	—	—	—	—	
Other Facility Support	13,545	455	203	156	29	1	
Onsite Transportation	1,192	—	5,997	5,168	1	—	
Conventional Electricity Generation	—	797	604	119	325	259	
Other Non-Process Use	1,290	167	316	44	9	0	
End Use Not Reported	27,874	1,359	1,622	1,209	143	571	
Total	778,335	70,111	26,107	25,949	5,982	54,143	
	Trillion Btu						
Indirect End Use (Boiler Fuel)	28	313	42	18	2,396	875	3,869
Direct End Use							
All Process Uses	2,078	106	61	54	2,872	302	5,460
Process Heating	284	103	29	49	2,702	299	3,466
Process Cooling and Refrigeration	138	(s)	(s)	2	21	(s)	161
Machine Drive	1,367	3	18	3	95	3	1,489
Electrochemical Processes	271	—	—	—	—	—	271
Other Process Uses	15	(s)	4	1	53	(s)	73
All Non-Process Uses	457	14	49	25	726	8	1,279
Facility Heating, Ventilation, and Air Conditioning [3]	217	5	7	5	361	3	588
Facility Lighting	185	—	—	—	—	—	165
Other Facility Support	48	3	1	1	30	(s)	81
Onsite Transportation	4	—	35	19	1	—	59
Conventional Electricity Generation	—	5	4	1	335	6	351
Other Non-Process Use	4	1	2	(s)	9	0	16
End Use Not Reported	96	9	9	4	148	13	279
Total	2,656	441	182	89	6,141	1,196	10,887

[1] "Net Electricity" is obtained by summing purchases, transfers in, and generation from noncombustible renewable resources, minus quantities sold and transferred out.

[2] Total of listed energy sources. Excludes inputs of unallocated energy sources (5,828 trillion Btu). The top half of the "Total" column is blank because different physical units cannot be added.

[3] Excludes steam and hot water.

— = Not applicable. (s)=Less than 0.5 trillion Btu. Q=Withheld because relative standard error is greater than 50 percent.

Notes: • Totals may not equal sum of components due to independent rounding. • The estimates presented in this table are for the total consumption of energy for the production of heat and power, regardless of where the energy was produced. Specifically, the estimates include the quantities of energy that were originally produced offsite and purchased by or transferred to the establishment, plus those that were produced onsite from other energy or input materials not classified as energy, or were extracted from captive (onsite) mines or wells. • Allocations to end uses are made on the basis of reasonable approximations by respondents.

Web Page: http://www.eia.doe.gov/emeu/consumption.

Source: Energy Information Administration, *Manufacturing Consumption of Energy 1994* (December 1997), Table A6, Parts 1 and 2.

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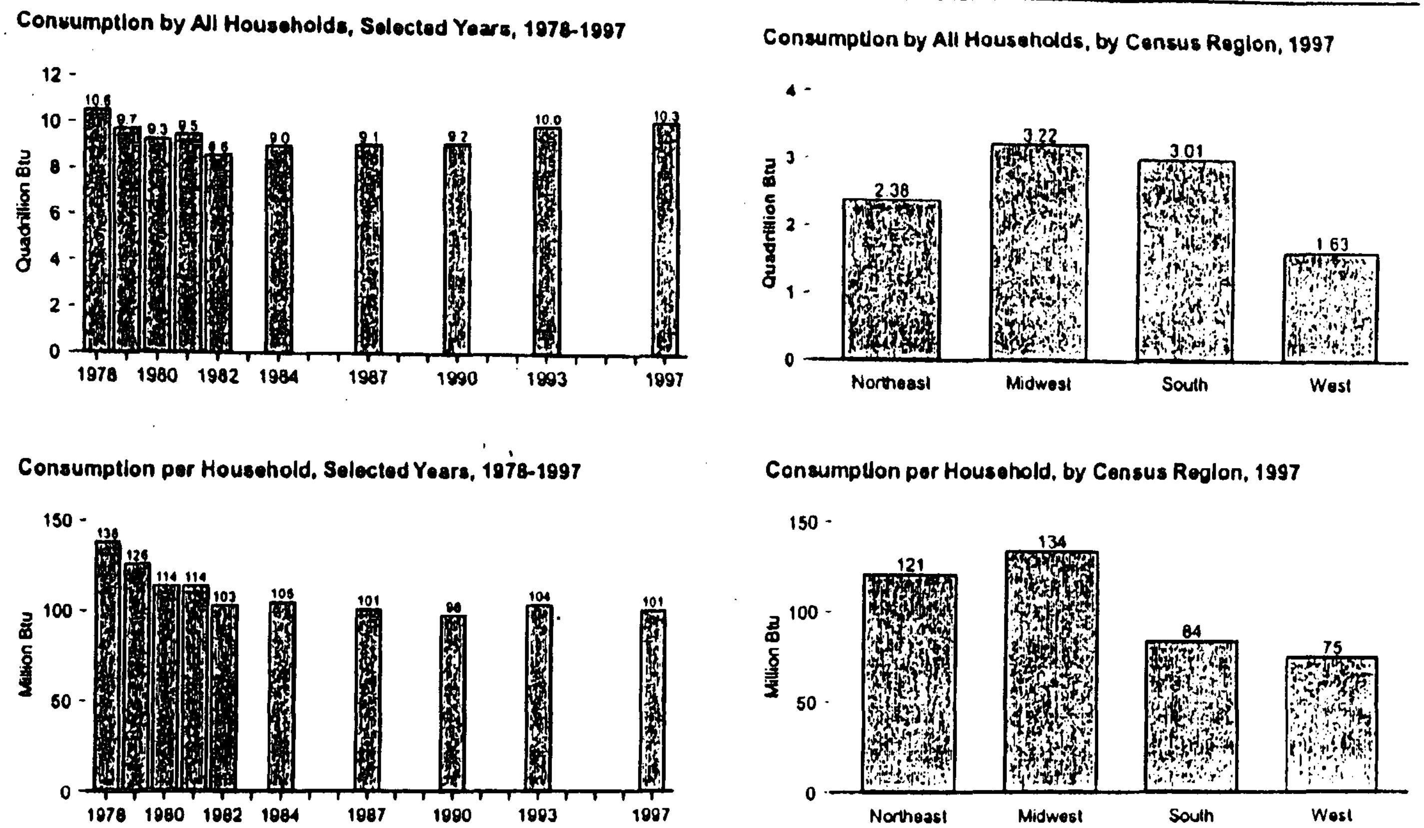
Figure 2.4 Household Energy Consumption



Notes: • No data are available for years not shown. Data for 1978 through 1984 are for April of the year shown through March of the following year; data for 1987, 1990, 1993, and 1997 are for the calendar year. • Because vertical scales differ, graphs should not be compared.

Source: Table 2.4. See Appendix D for Census regions.

DOE024-2140

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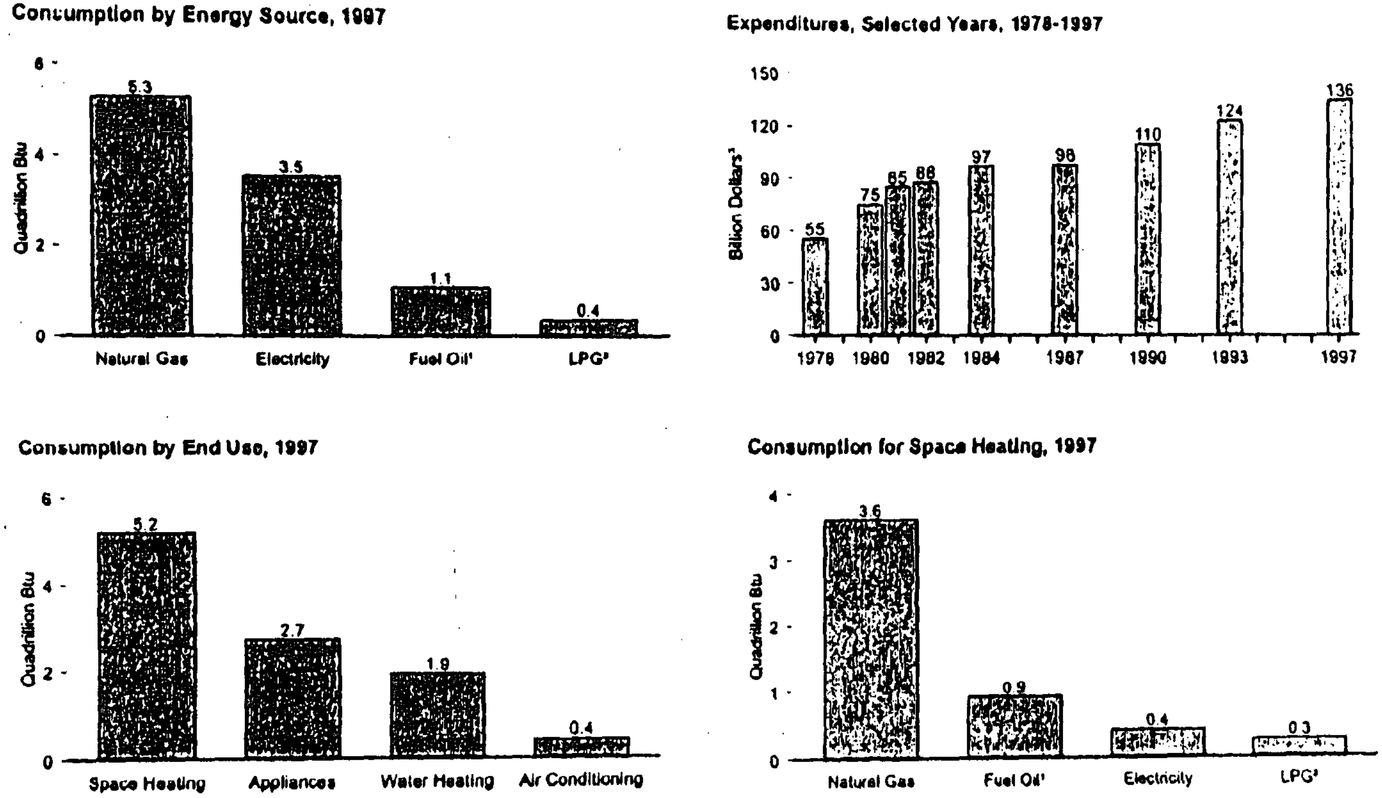
Table 2.4 Household Energy Consumption by Census Region, Selected Years, 1978-1997
(Quadrillion Btu, Except as Noted)

Census Region [1]	1978	1979	1980	1981	1982	1984	1987	1990	1993	1997
Northeast	2.89	2.50	2.43	2.47	2.18	2.29	2.37	2.30	2.38	2.38
Natural Gas	1.14	1.05	0.92	1.06	0.99	0.93	1.03	1.03	1.11	1.03
Electricity [2]	0.39	0.39	0.39	0.42	0.38	0.41	0.44	0.47	0.47	0.49
Distillate Fuel Oil and Kerosene	1.32	1.03	1.09	0.96	0.79	0.93	0.87	0.78	0.78	0.84
Liquefied Petroleum Gases	0.03	0.03	0.03	0.03	0.02	0.03	0.02	0.02	0.03	0.03
Consumption per Household (million Btu)	166	145	138	136	122	125	124	120	122	121
Midwest	3.70	3.48	2.92	3.12	2.60	2.80	2.73	2.81	3.13	3.22
Natural Gas	2.53	2.48	2.02	2.24	1.78	1.99	1.83	1.88	2.07	2.20
Electricity [2]	0.60	0.59	0.60	0.57	0.57	0.56	0.61	0.66	0.74	0.75
Distillate Fuel Oil and Kerosene	0.46	0.31	0.16	0.17	0.15	0.13	0.16	0.13	0.13	0.11
Liquefied Petroleum Gases	0.12	0.10	0.15	0.13	0.11	0.13	0.13	0.13	0.19	0.17
Consumption per Household (million Btu)	180	168	139	147	122	129	123	122	134	134
South	2.43	2.30	2.59	2.46	2.46	2.50	2.61	2.60	2.95	3.01
Natural Gas	0.96	0.91	1.11	1.16	1.13	1.15	1.09	1.03	1.18	1.13
Electricity [2]	1.00	0.97	1.06	1.03	1.05	1.06	1.22	1.38	1.51	1.67
Distillate Fuel Oil and Kerosene	0.32	0.28	0.27	0.16	0.17	0.16	0.17	0.11	0.13	0.10
Liquefied Petroleum Gases	0.16	0.14	0.15	0.12	0.12	0.12	0.12	0.10	0.13	0.12
Consumption per Household (million Btu)	99	92	96	89	86	85	84	81	88	84
West	1.54	1.47	1.38	1.47	1.38	1.45	1.42	1.51	1.55	1.63
Natural Gas	0.95	0.88	0.89	0.93	0.89	0.91	0.88	0.92	0.91	0.93
Electricity [2]	0.48	0.47	0.41	0.46	0.42	0.47	0.48	0.54	0.56	0.64
Distillate Fuel Oil and Kerosene	0.09	0.09	0.04	0.03	0.03	0.04	0.02	0.02	0.03	0.03
Liquefied Petroleum Gases	0.03	0.04	0.04	0.04	0.04	0.03	0.05	0.03	0.04	0.04
Consumption per Household (million Btu)	110	100	88	90	84	85	78	78	76	75
United States	10.56	9.74	9.32	9.51	8.62	9.04	9.13	9.22	10.01	10.25
Natural Gas	5.58	5.31	4.94	5.39	4.77	4.98	4.83	4.86	5.27	5.28
Electricity [2]	2.47	2.42	2.46	2.48	2.42	2.48	2.76	3.03	3.28	3.54
Distillate Fuel Oil and Kerosene	2.19	1.71	1.55	1.33	1.14	1.26	1.22	1.04	1.07	1.07
Liquefied Petroleum Gases	0.33	0.31	0.36	0.31	0.29	0.31	0.32	0.28	0.38	0.38
Consumption per Household (million Btu)	138	126	114	114	103	105	101	98	104	101

[1] See Appendix D for Census regions.
[2] Site electricity. One kilowatthour = 3,412 Btu.
Notes: • This table shows major energy items only. • No data are available for years not shown. • Data for 1978-1984 are for April of year shown through March of following year; data for 1987, 1990, 1993, and 1997 are for the calendar year. • Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/emeu/consumption.
Sources: • 1978 and 1979—Energy Information Administration (EIA), Form EIA-84, "Residential Energy Consumption Survey." • 1980 forward—EIA, Form EIA-457, "Residential Energy Consumption Survey."

Figure 2.5 Household Energy Consumption and Expenditures



[1] Distillate fuel oil and kerosene.
[2] Liquefied petroleum gases.
[3] Nominal dollars.

Notes: • No data are available for years not shown. • Because vertical scales differ, graphs should not be compared.
Source: Table 2.5.

Table 2.5 Household Energy Consumption and Expenditures by End Use and Energy Source, Selected Years, 1978-1997

	Space Heating				Air Conditioning [1]	Water Heating				Appliances [2]			Total [1,2]			
Year	Natural Gas	Electricity [3]	Fuel Oil [4]	LPG [5]	Electricity [3]	Natural Gas	Electricity [3]	Fuel Oil [4]	LPG [5]	Natural Gas	Electricity [3]	LPG [5]	Natural Gas	Electricity [3]	Fuel Oil [4]	LPG [5]
								Consumption (quadrillion Btu)								
1978	4.26	0.40	2.05	0.23	0.31	1.04	0.29	0.14	0.06	0.28	1.46	0.03	5.58	2.47	2.19	0.33
1980	3.32	0.28	1.32	0.25	0.32	1.24	0.31	0.24	0.07	0.38	1.55	0.04	4.94	2.46	1.55	0.36
1981	3.80	0.30	1.12	0.22	0.33	1.10	0.33	0.20	0.08	0.49	1.53	0.03	5.39	2.48	1.33	0.31
1982	3.31	0.27	1.05	0.19	0.30	1.08	0.33	0.09	0.06	0.39	1.52	0.04	4.77	2.42	1.14	0.29
1984	3.51	0.30	1.11	0.21	0.33	1.10	0.32	0.15	0.06	0.35	1.53	0.04	4.98	2.48	1.26	0.31
1987	3.38	0.28	1.06	0.22	0.44	1.10	0.31	0.17	0.06	0.34	1.72	0.04	4.83	2.76	1.22	0.32
1990	3.37	0.30	0.93	0.19	0.48	1.16	0.34	0.11	0.08	0.33	1.91	0.03	4.86	3.03	1.04	0.28
1993	3.67	0.41	0.95	0.30	0.46	1.31	0.34	0.12	0.05	0.29	2.08	0.03	5.27	3.28	1.07	0.38
1997	3.61	0.40	0.91	0.28	0.42	1.29	0.39	0.18	0.08	0.37	2.33	0.02	5.28	3.54	1.07	0.36
								Expenditures (billion dollars [6])								
1978	11.49	3.53	8.08	1.06	3.97	2.88	3.15	0.56	0.38	0.93	19.24	0.25	15.30	29.89	8.62	1.66
1980	12.80	3.71	10.59	1.90	5.07	4.79	4.64	1.89	0.59	1.71	28.82	0.40	19.30	40.14	12.48	2.89
1981	17.07	4.60	9.99	1.84	5.96	4.93	5.32	1.83	0.53	2.50	30.02	0.37	24.50	45.90	11.82	2.74
1982	18.55	4.45	8.64	1.66	6.05	6.06	5.90	0.75	0.57	2.42	32.02	0.47	27.08	48.42	9.59	2.72
1984	20.66	5.71	8.51	2.00	7.37	6.63	8.44	1.09	0.68	2.31	34.96	0.54	29.78	54.48	9.60	3.12
1987	18.05	5.53	6.25	1.85	9.77	6.02	6.45	0.94	0.50	2.02	39.83	0.48	26.15	61.58	7.21	2.81
1990	18.59	6.16	7.42	2.01	R11.23	6.59	7.21	0.83	0.65	2.03	46.95	0.48	27.28	71.54	8.25	3.14
1993	21.95	6.66	6.24	2.81	R11.31	8.08	7.58	0.74	0.58	1.98	53.52	0.42	32.04	81.08	6.98	3.61
1997	24.11	8.56	6.57	2.79	10.20	8.84	8.99	1.04	0.89	2.86	60.57	0.36	35.81	88.33	7.61	4.04

[1] A small amount of natural gas used for air conditioning is included in "Natural Gas" under "Total."
[2] Includes refrigerators. A small amount of fuel oil or kerosene used for appliances is included in "Fuel Oil" under "Total."
[3] Site electricity. One kilowatthour = 3,412 Btu.
[4] Fuel oil is distillate fuel oil and kerosene.
[5] Liquefied petroleum gases.
[6] Nominal dollars.

R=Revised.
Notes: • No data are available for years not shown. Consumption data by energy source for 1979 are available on Table 2.4. • Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/emeu/consumption.
Sources: • 1978—Energy Information Administration (EIA), Form EIA-84, "Residential Energy Consumption Survey." • 1980 forward—EIA, Form EIA-457, "Residential Energy Consumption Survey."

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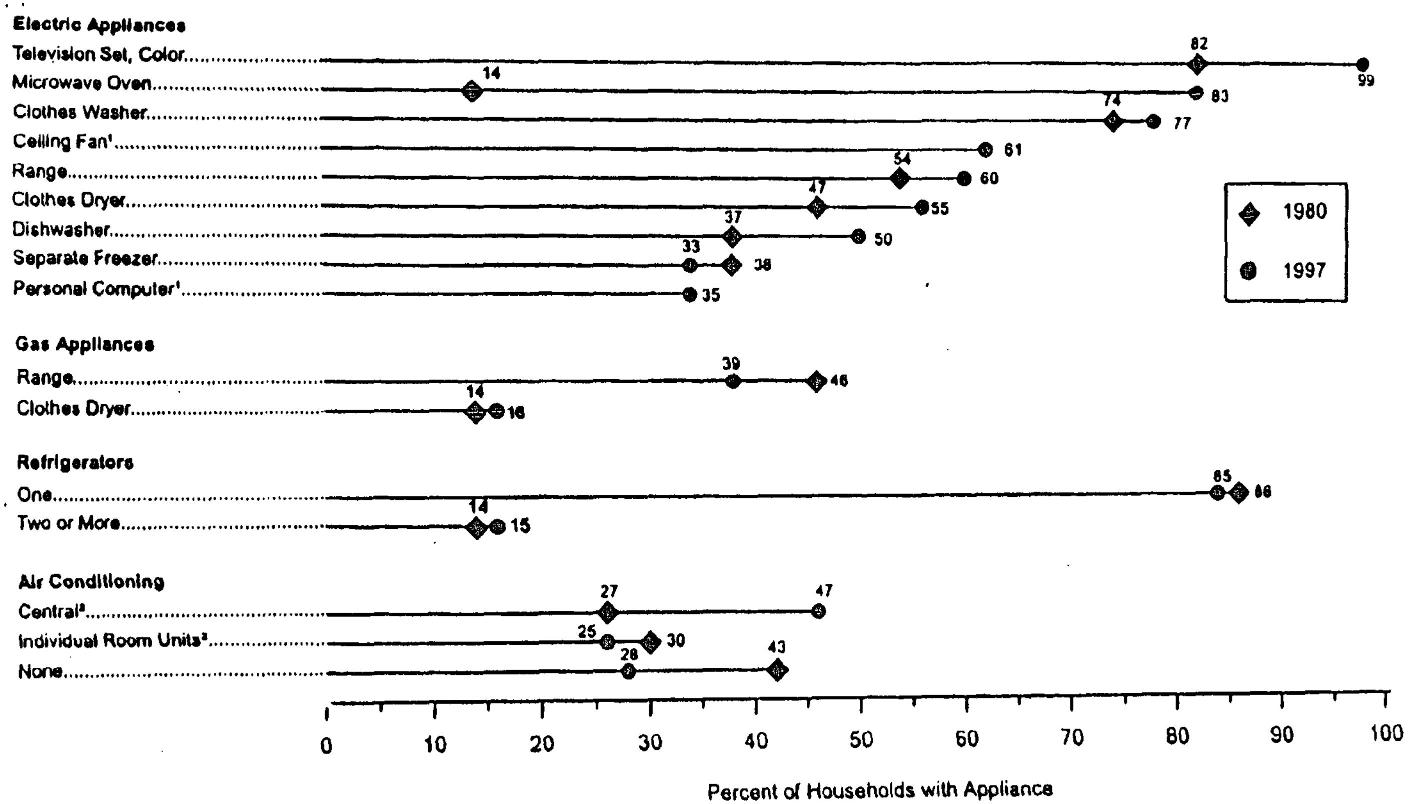
Figure 2.6 Households With Selected Appliances, 1980 and 1997



[1] Not collected in 1980.
[2] Households with both central and individual room units are counted only under "central."

Source: Table 2.6.

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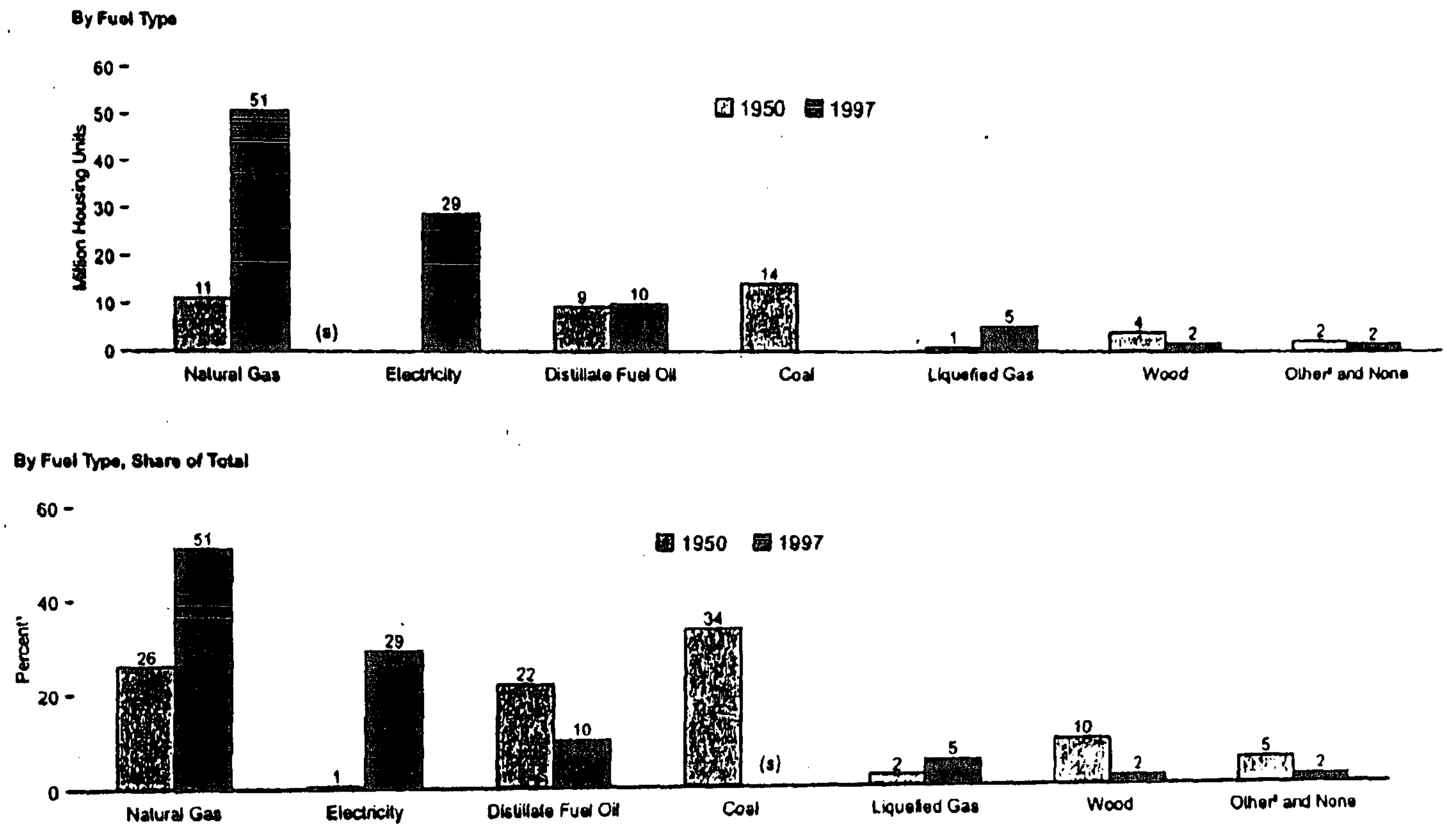
Table 2.6 Household Main Heating Fuel and Presence of Selected Appliances, Selected Years, 1978-1997

Appliance	Year 1978	1979	1980	1981	1982	1984	1987	1990	1993	1997	Change 1980 to 1997
Total Households (millions)	R77	78	82	83	84	86	R91	94	97	101	+20
	Percent of Households										
Type of Main Heating Fuel											
Natural Gas	55	55	55	56	57	55	55	55	53	53	-2
Electricity	18	17	18	17	16	17	20	23	26	29	+12
Liquefied Petroleum Gas	4	6	6	4	5	5	5	5	5	5	0
Fuel Oil	20	17	15	14	13	12	12	11	11	9	6
Wood	2	4	6	6	7	7	6	4	3	2	-4
Type of Appliances											
Electric Appliances											
Television Set (Color)	NA	NA	82	R83	85	88	93	96	98	99	+17
Television Set (B/W)	NA	NA	51	48	R46	43	36	31	20	NA	NA
Television Set (Any)	NA	NA	98	98	98	98	98	99	99	NA	NA
Clothes Washer	R74	NA	74	R73	R71	R73	R75	76	77	77	+3
Range (Stove-Top Burner)	53	NA	54	54	53	54	57	58	61	60	+7
Oven, Microwave	8	NA	14	17	21	34	61	79	84	83	+69
Clothes Dryer	45	NA	47	45	45	46	51	53	57	55	+8
Separate Freezer	38	NA	38	38	37	37	34	R34	35	33	-5
Dishwasher	35	NA	37	37	38	38	43	45	45	50	+13
Dehumidifier	NA	NA	9	9	9	9	10	12	9	NA	NA
Waterbed Heaters	NA	NA	NA	NA	NA	10	14	15	12	8	NA
Window or Ceiling Fan	NA	NA	NA	NA	26	35	48	51	60	NA	NA
Ceiling Fan	NA	NA	NA	NA	NA	NA	NA	NA	54	61	NA
Whole House Fan	NA	NA	NA	NA	8	8	9	10	4	NA	NA
Evaporative Cooler	NA	NA	4	4	4	4	3	4	3	NA	NA
Personal Computer	NA	NA	NA	NA	NA	NA	NA	16	23	35	NA
Pump for Well Water	NA	NA	NA	NA	NA	NA	NA	15	13	14	NA
Swimming-Pool Pump [1]	NA	NA	3	4	3	NA	NA	5	5	5	+2
Gas Appliances [2]											
Range (Stove-Top or Burner)	48	NA	46	46	47	45	43	42	38	39	-7
Clothes Dryer	14	NA	14	16	15	16	15	16	15	16	+2
Outdoor Gas Grill	R 6	NA	9	9	11	13	20	26	29	NA	NA
Outdoor Gas Light	2	NA	2	2	2	1	1	1	1	1	-1
Swimming Pool Heater [3]	NA	NA	(s)	(s)	(s)	1	1	R 1	1	1	0
Refrigerators [4]											
One	86	NA	86	87	86	86	86	84	85	85	-1
Two or More	14	NA	14	13	13	12	14	15	15	15	+1
Air Conditioning (A/C)											
Central [5]	23	24	27	27	28	30	R34	39	44	47	20
Individual Room Units [5]	33	31	30	31	30	30	30	29	25	25	-5
None	44	45	43	42	42	40	36	32	32	28	-15
Portable Kerosene Heaters	(s)	NA	(s)	1	3	6	6	5	R 3	2	+2

[1] All reported swimming pools were assumed to have an electric pump for filtering and circulating the water, except for 1993 and 1997, when a filtering system was made explicit.
[2] Includes natural gas or liquefied petroleum gases.
[3] In 1984 and 1987, also includes heaters for jacuzzis and hot tubs.
[4] Fewer than 0.5 percent of the households do not have a refrigerator.
[5] Households with both central and individual room units are counted only under "Central."

R=Revised data. NA=Not available. (s)=Less than 0.5 percent.
Note: No data are available for years not shown.
Web Page: http://www.eia.doe.gov/emeu/consumption.
Sources: • 1978 and 1979—Energy Information Administration (EIA), Form EIA-84, "Residential Energy Consumption Survey." • 1980 forward—EIA, Form EIA-457, "Residential Energy Consumption Survey."

Figure 2.7 Type of Heating in Occupied Housing Units, 1950 and 1997



¹ Sum of components may not equal 100 percent due to independent rounding.
² Kerosene, solar, and other.
(s)=Less than 0.5.

Source: Table 2.7.

Table 2.7 Type of Heating in Occupied Housing Units, Selected Years, 1950-1997

Year	Coal[1]	Natural Gas	Liquefied Gas	Distillate Fuel Oil	Kerosene	Electricity	Wood	Solar	Other	None[2]	Total
						Million					
1950	14.48	11.12	0.98	9.48	([3])	0.28	4.17	NA	0.77	1.57	42.83
1960	6.46	22.85	2.69	17.16	([3])	0.93	2.24	NA	0.22	0.48	53.02
1970	1.82	35.01	3.81	16.47	([3])	4.88	0.79	NA	0.27	0.40	63.45
1973	0.80	38.48	4.42	17.24	([3])	7.21	0.60	NA	0.15	0.45	69.34
1974	0.74	39.47	4.14	16.84	([3])	8.41	0.66	NA	0.09	0.48	70.83
1975	0.67	40.93	4.15	16.30	([3])	9.17	0.85	NA	0.06	0.47	72.52
1976	0.48	41.22	4.24	16.45	([3])	10.15	0.91	NA	0.09	0.46	74.01
1977	0.45	41.54	4.18	15.82	0.44	11.15	1.24	NA	0.15	0.61	75.28
1978	0.40	42.52	4.13	15.65	0.42	12.26	1.07	NA	0.12	0.60	77.17
1979	0.36	43.32	4.13	16.30	0.41	13.24	1.14	NA	0.10	0.57	78.57
1980	0.33	44.40	4.17	14.50	0.37	14.21	1.38	NA	0.11	0.61	80.07
1981	0.36	46.08	4.17	14.13	0.37	15.49	1.89	NA	0.10	0.59	83.18
1983[4]	0.43	46.70	3.87	12.59	0.45	15.68	4.09	NA	0.16	0.68	84.64
1985	0.45	45.33	3.58	12.44	1.06	18.36	6.25	0.05	0.37	0.53	88.43
1987	0.41	45.96	3.66	12.74	1.08	20.81	5.45	0.05	0.28	0.66	90.89
1989	0.34	47.40	3.66	12.47	1.07	23.06	4.59	0.04	0.40	0.66	93.68
1991	0.32	47.02	3.88	11.47	0.99	23.71	4.84	0.03	0.41	0.86	93.15
1993	0.30	47.67	3.92	11.17	1.02	25.11	4.10	0.03	0.50	0.91	94.73
1995	0.21	49.20	4.25	10.98	1.08	26.77	3.53	0.02	0.64	1.04	97.69
1997	0.18	51.05	5.40	10.10	0.75	29.20	1.79	0.03	0.36	0.62	99.49
						Percent					
1950	33.8	26.0	2.3	22.1	([3])	0.6	9.7	NA	1.8	3.7	100.0
1960	12.2	43.1	5.1	32.4	([3])	1.8	4.2	NA	0.4	0.9	100.0
1970	2.9	55.2	6.0	26.0	([3])	7.7	1.3	NA	0.4	0.6	100.0
1973	1.2	55.5	6.4	24.9	([3])	10.4	0.9	NA	0.2	0.7	100.0
1974	1.0	55.7	5.8	23.8	([3])	11.9	0.9	NA	0.1	0.7	100.0
1975	0.8	56.4	5.7	22.5	([3])	12.6	1.2	NA	0.1	0.6	100.0
1976	0.7	55.7	5.7	22.2	([3])	13.7	1.2	NA	0.1	0.6	100.0
1977	0.6	55.2	5.6	20.7	0.6	14.8	1.6	NA	0.2	0.7	100.0
1978	0.5	55.1	5.4	20.3	0.5	15.9	1.4	NA	0.2	0.8	100.0
1979	0.5	55.1	5.3	19.5	0.5	16.9	1.4	NA	0.1	0.7	100.0
1980	0.4	55.4	5.2	18.1	0.5	17.7	1.7	NA	0.1	0.8	100.0
1981	0.4	55.4	5.0	17.0	0.4	18.6	2.3	NA	0.1	0.7	100.0
1983[4]	0.5	55.2	4.6	14.9	0.5	18.5	4.8	NA	0.2	0.8	100.0
1985	0.5	51.3	4.1	14.1	1.2	20.8	7.1	0.1	0.4	0.6	100.0
1987	0.4	50.6	4.0	14.0	1.2	22.7	6.0	0.1	0.3	0.7	100.0
1989	0.4	50.6	3.9	13.3	1.1	24.6	4.9	(s)	0.4	0.7	100.0
1991	0.3	50.5	4.2	12.3	1.1	25.5	4.8	(s)	0.4	0.9	100.0
1993	0.3	50.3	4.1	11.8	1.1	26.5	4.3	(s)	0.5	1.0	100.0
1995	0.2	50.4	4.4	11.2	1.1	27.4	3.6	(s)	0.7	1.1	100.0
1997	0.2	51.3	5.4	10.2	0.8	29.4	1.8	(s)	0.4	0.6	100.0

[1] Includes coal coke.
[2] Includes nonreporting units in 1950 and 1960, which totaled 997 and 2,000 units, respectively.
[3] Included in distillate fuel oil.
[4] Since 1983, the *American Housing Survey for the United States* has been a biennial survey.
NA=Not available. (s)=Less than 0.05 percent.

Notes: • Includes mobile homes and individual housing units in apartment buildings. Housing units with more than one type of heating system are classified according to the principal type of heating system. • Totals may not equal sum of components due to independent rounding.

Sources: • 1950, 1960, and 1970—Bureau of the Census, *Census of Population and Housing*. • 1973 forward—Bureau of the Census, *American Housing Survey for the United States in 1997*, Table 2-5.

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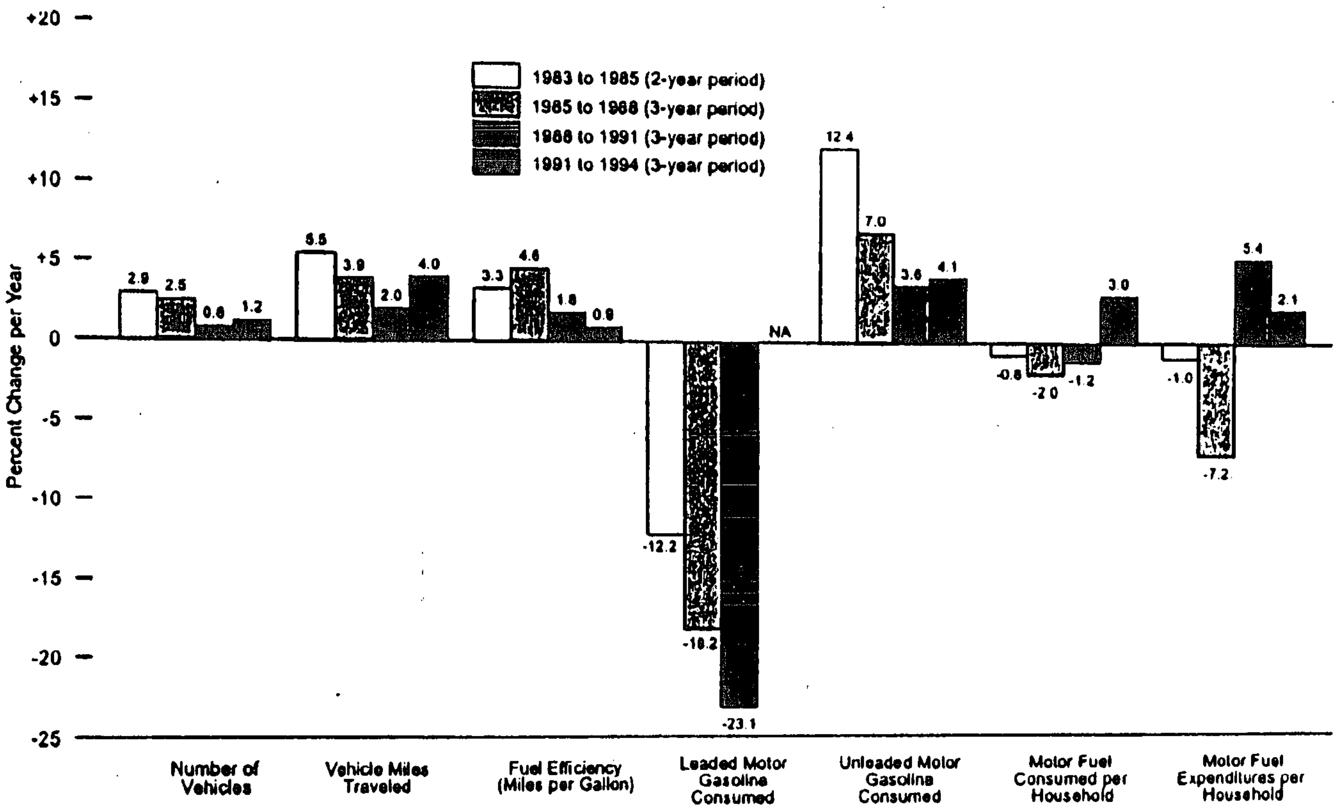
Figure 2.8 Household Motor Vehicle Data



Note: The percent changes are of all income categories; they are simple average annual percent changes (computed as the percent change over the period divided by the number of years in the period) and will differ slightly from compound average annual percent changes.

NA=Not Available.
Source: Table 2.8.

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Table 2.8 Household Motor Vehicle Data, 1983, 1985, 1988, 1991, and 1994

Unit of Measure	Family Income: Less than $25,000 1983	1985	1988	1991	1994	$25,000 or More 1983	1985	1988	1991	1994	All Income Categories 1983	1985	1988	1991	1994
Households with Vehicles (millions)	42.9	43.3	38.9	38.5	34.5	30.5	34.6	42.2	48.2	50.3	73.4	77.7	81.3	84.6	84.9
Vehicles (millions)	66.7	65.4	58.7	52.7	52.0	63.0	71.9	88.8	98.5	104.6	129.7	137.3	147.5	151.2	156.6
Vehicle Miles Traveled (billions)	589	587	550	488	550.4	630	766	960	1,114	1,242.8	1,219	1,353	1,511	1,602	1,793
Motor Fuel Consumed (billion gallons)	40.6	38.2	31.4	26.9	28.3	39.8	45.7	51.0	55.9	62.3	80.5	83.9	82.4	82.8	90.6
Motor Gasoline Consumed (billion gallons)															
Leaded	19.2	13.5	5.4	1.6	Q	13.2	11.0	5.8	1.6	Q	32.4	24.5	11.1	3.4	Q
Unleaded	20.9	24.2	25.7	24.7	26.7	25.3	33.7	44.3	52.9	60.3	46.3	57.8	69.9	77.5	87.0
Motor Fuel Expenditures (billion dollars[1])	48.1	44.8	30.7	31.7	32.6	47.3	54.3	50.3	66.6	72.1	95.4	99.1	81.1	98.2	104.7
Averages per Household with Vehicles															
Vehicles	1.6	1.5	1.5	1.4	1.5	2.1	2.1	2.1	2.0	2.1	1.8	1.8	1.8	1.8	1.8
Vehicle Miles Traveled (thousands)	13.7	13.6	14.1	13.4	15.9	20.7	22.2	22.7	23.1	24.7	16.6	17.4	18.6	18.9	21.1
Motor Fuel Consumed (gallons)	950	883	807	737	818	1,305	1,328	1,205	1,160	1,238	1,097	1,079	1,014	979	1,067
Motor Fuel Expenditures (dollars[1])	1,121	1,036	789	869	943	1,552	1,575	1,191	1,382	1,433	1,300	1,274	998	1,161	1,234
Averages per Vehicle															
Vehicle Miles Traveled (thousands)	8.8	9.0	9.4	9.3	10.6	10.0	10.7	10.8	11.3	11.9	9.4	9.9	10.3	10.6	11.4
Motor Fuel Consumed (gallons)	612	585	536	510	545	631	636	574	568	594	621	611	559	548	578
Motor Fuel Expenditures (dollars[1])	722	685	524	602	628	751	755	567	676	688	736	722	550	650	668
Fuel Efficiency (miles per gallon)	14.4	15.3	17.5	18.1	19.5	15.8	16.8	18.8	19.9	20.0	15.1	16.1	18.3	19.3	19.8
Price of Motor Gasoline (dollars[1] per gallon)															
Leaded	1.14	1.11	0.90	1.10	Q	1.14	1.11	0.90	1.10	Q	1.14	1.11	0.90	1.10	Q
Unleaded	1.22	1.20	0.99	1.18	1.15	1.22	1.21	1.00	1.19	1.16	1.22	1.21	1.00	1.19	1.16

[1] Nominal dollars.

Q=Data withheld because either the relative standard error was greater than 50 percent or fewer than 10 households were sampled.

Notes: • Included are passenger cars, minivans, passenger vans, cargo vans, motor homes, pickup trucks, and sport-utility vehicles (i.e., jeeplike vehicles, usually four-wheel drive). Excluded are motorcycles, mopeds, large trucks, and buses. • Motor fuel includes motor gasoline and a small amount of other fuels, such as diesel, gasohol, and propane. These data for 1983 differ from previously published 1983 data in that the basis for estimating the number of vehicle-owning households was changed to conform with that being used for 1985. Purchase diaries, which were fuel purchase logs retained by drivers in 1983 and 1985, were used as the basis for estimating data for those years. • Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/emeu/consumption.

Sources: Fuel Efficiency: • 1983 and 1985—Energy Information Administration (EIA), "Residential Transportation Energy Consumption Survey," purchase diaries. • 1988 through 1994—Environmental Protection Agency Certification Files, adjusted for on-road driving. Price of Motor Gasoline: • 1983 and 1985—EIA, "Residential Transportation Energy Consumption Survey," purchase diaries. • 1988 through 1994—Bureau of Labor Statistics Gasoline Pump Price Series and Lundberg Inc. price series. All Other Data: EIA, Form EIA-876A/C, "Residential Transportation Energy Consumption Survey."

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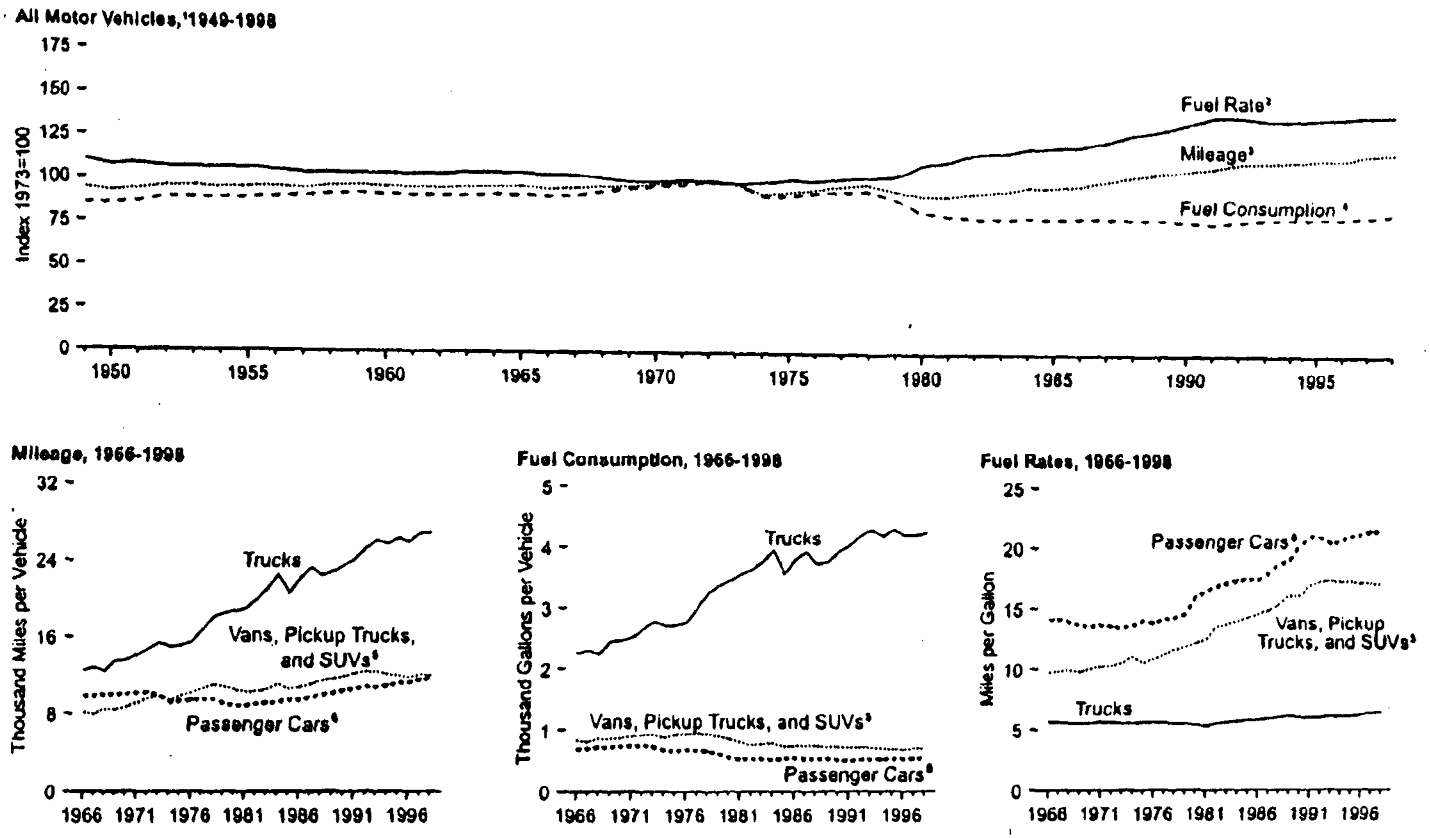
Figure 2.9 Motor Vehicle Mileage, Fuel Consumption, and Fuel Rates



[1] Passenger cars, motorcycles, vans, pickup trucks, sport utility vehicles, trucks, and buses.
[2] Miles per gallon.
[3] Miles per vehicle.
[4] Gallons per vehicle.
[5] Sport utility vehicles.
[6] Motorcycles are included with passenger cars through 1989.
Source: Table 2.9.

Table 2.9 Motor Vehicle Mileage, Fuel Consumption, and Fuel Rates, 1949-1998

Year	Passenger Cars			Vans, Pickup Trucks, and Sport Utility Vehicles [1]			Trucks [2]			All Motor Vehicles [3]		
	Mileage (miles per vehicle)	Fuel Consumption (gallons per vehicle)	Fuel Rate (miles per gallon)	Mileage (miles per vehicle)	Fuel Consumption (gallons per vehicle)	Fuel Rate (miles per gallon)	Mileage (miles per vehicle)	Fuel Consumption (gallons per vehicle)	Fuel Rate (miles per gallon)	Mileage (miles per vehicle)	Fuel Consumption (gallons per vehicle)	Fuel Rate (miles per gallon)
1949	[4]9,388	[4]627	[4]15.0	(5)	(5)	(5)	[6]9,712	[6]1,080	[6]9.0	9,498	726	13.1
1950	[4]9,060	[4]603	[4]15.0	(5)	(5)	(5)	[6]10,316	[6]1,228	[6]8.4	9,321	725	12.8
1951	[4]9,188	[4]614	[4]15.0	(5)	(5)	(5)	[6]10,546	[6]1,242	[6]8.5	9,460	735	12.9
1952	[4]9,360	[4]639	[4]14.7	(5)	(5)	(5)	[6]10,769	[6]1,288	[6]8.4	9,642	762	12.7
1953	[4]9,377	[4]640	[4]14.6	(5)	(5)	(5)	[6]10,963	[6]1,283	[6]8.5	9,684	760	12.7
1954	[4]9,349	[4]641	[4]14.6	(5)	(5)	(5)	[6]10,682	[6]1,281	[6]8.3	9,605	758	12.7
1955	[4]9,447	[4]646	[4]14.6	(5)	(5)	(5)	[6]10,576	[6]1,293	[6]8.2	9,661	761	12.7
1956	[4]9,496	[4]654	[4]14.5	(5)	(5)	(5)	[6]10,511	[6]1,309	[6]8.0	9,688	771	12.6
1957	[4]9,348	[4]656	[4]14.2	(5)	(5)	(5)	[6]10,774	[6]1,304	[6]8.3	9,609	773	12.4
1958	[4]9,500	[4]670	[4]14.2	(5)	(5)	(5)	[6]10,768	[6]1,303	[6]8.3	9,732	782	12.4
1959	[4]9,615	[4]674	[4]14.3	(5)	(5)	(5)	[6]10,702	[6]1,328	[6]8.1	9,817	789	12.4
1960	[4]9,518	[4]668	[4]14.3	(5)	(5)	(5)	[6]10,693	[6]1,333	[6]8.0	9,732	784	12.4
1961	[4]9,521	[4]663	[4]14.4	(5)	(5)	(5)	[6]10,537	[6]1,341	[6]7.9	9,708	781	12.4
1962	[4]9,494	[4]662	[4]14.3	(5)	(5)	(5)	[6]10,554	[6]1,337	[6]7.9	9,687	779	12.4
1963	[4]9,587	[4]655	[4]14.6	(5)	(5)	(5)	[6]10,395	[6]1,380	[6]7.5	9,737	780	12.5
1964	[4]9,665	[4]661	[4]14.6	(5)	(5)	(5)	[6]10,408	[6]1,389	[6]7.5	9,805	787	12.5
1965	[4]9,603	[4]661	[4]14.5	(5)	(5)	(5)	[6]10,851	[6]1,387	[6]7.8	9,828	787	12.5
1966	[4]9,733	[4]688	[4]14.1	6,077	833	9.7	12,537	2,250	5.6	9,675	780	12.4
1967	[4]9,849	[4]699	[4]14.1	7,877	801	9.8	12,789	2,294	5.6	9,751	786	12.4
1968	[4]9,922	[4]714	[4]13.9	8,378	849	9.9	12,402	2,240	5.5	9,864	805	12.2
1969	[4]9,921	[4]727	[4]13.6	8,355	851	9.8	13,484	2,459	5.5	9,885	821	12.0
1970	[4]9,989	[4]737	[4]13.5	8,676	866	10.0	13,565	2,467	5.5	9,976	830	12.0
1971	[4]10,097	[4]743	[4]13.6	9,082	888	10.2	14,117	2,519	5.6	10,133	839	12.1
1972	[4]10,171	[4]754	[4]13.5	9,534	922	10.3	14,780	2,657	5.6	10,279	857	12.0
1973	[4]9,884	[4]737	[4]13.4	9,779	931	10.5	15,370	2,775	5.5	10,099	850	11.9
1974	[4]9,221	[4]677	[4]13.6	9,452	862	11.0	14,995	2,708	5.5	9,493	788	12.0
1975	[4]9,309	[4]665	[4]14.0	9,829	934	10.5	15,167	2,722	5.6	9,627	790	12.2
1976	[4]9,418	[4]681	[4]13.8	10,127	934	10.8	15,438	2,764	5.6	9,774	806	12.1
1977	[4]9,517	[4]676	[4]14.1	10,607	947	11.2	16,700	3,002	5.6	9,978	814	12.3
1978	[4]9,500	[4]665	[4]14.3	10,968	948	11.6	18,045	3,263	5.5	10,077	816	12.4
1979	[4]9,062	[4]620	[4]14.6	10,802	905	11.9	18,502	3,380	5.5	9,722	776	12.5
1980	[4]8,813	[4]551	[4]16.0	10,437	864	12.2	18,736	3,447	5.4	9,458	712	13.3
1981	[4]8,873	[4]538	[4]16.5	10,244	819	12.5	19,016	3,565	5.3	9,477	697	13.6
1982	[4]9,050	[4]535	[4]16.9	10,276	762	13.5	19,931	3,647	5.5	9,644	686	14.1
1983	[4]9,118	[4]534	[4]17.1	10,497	767	13.7	21,083	3,769	5.6	9,760	686	14.2
1984	[4]9,248	[4]530	[4]17.4	11,151	797	14.0	22,550	3,967	5.7	10,017	691	14.5
1985	[4]9,419	[4]538	[4]17.5	10,506	735	14.3	20,597	3,570	5.8	10,020	685	14.6
1986	[4]9,464	[4]543	[4]17.4	10,764	738	14.6	22,143	3,821	5.8	10,143	692	14.7
1987	[4]9,720	[4]539	[4]18.0	11,114	744	14.9	23,349	3,937	5.9	10,453	694	15.1
1988	[4]9,972	[4]531	[4]18.8	11,465	745	15.4	22,485	3,736	6.0	10,721	688	15.6
1989	[4]10,157	[4]533	[4]19.0	11,676	724	16.1	22,926	3,776	6.1	10,932	688	15.9
1990	[R]10,504	[R]520	[R]20.2	11,902	738	16.1	23,603	3,953	6.0	11,107	677	16.4
1991	[R]10,571	[R]501	[R]21.1	12,245	721	17.0	24,229	4,047	6.0	11,294	669	16.9
1992	[R]10,857	[R]517	21.0	12,381	717	17.3	25,373	4,210	6.0	11,558	683	16.9
1993	[R]10,804	[R]527	[R]20.5	12,430	714	17.4	26,262	4,309	6.1	11,595	693	16.7
1994	[R]10,992	[R]531	[R]20.7	12,156	701	17.3	25,838	4,202	6.1	11,683	698	16.7
1995	11,203	530	21.1	12,018	694	17.3	26,514	4,318	6.1	11,793	700	16.8
1996	[R]11,330	534	21.2	11,811	685	17.2	26,092	4,221	6.2	11,813	700	16.9
1997	[R]11,581	[R]539	21.5	12,115	703	17.2	27,032	4,218	6.4	[R]12,107	711	17.0
1998[P]	11,725	548	21.4	12,061	704	17.1	27,064	4,257	6.4	12,183	719	17.0

[1] Includes a small number of trucks with 2 axles and 4 tires, such as step vans.
[2] Single-unit trucks with 2 axles and 6 or more tires, and combination trucks.
[3] Includes buses and motorcycles, which are not shown separately.
[4] Includes motorcycles.
[5] Included in "Trucks."
[6] Includes vans, pickup trucks, and sport utility vehicles.
R=Revised. P=Preliminary.

Note: For vehicle registrations data see the "Sources" or the "Web Page."
Web Page: http://www.fhwa.dot.gov/ohim.
Sources: Passenger Cars: • 1990-1994—U.S. Department of Transportation, Bureau of Transportation Statistics, *National Transportation Statistics 1998*, Table 4-13. All Other Data: • 1949-1994—Federal Highway Administration (FHWA), *Highway Statistics Summary to 1995*, Table VM-201A. • 1995 forward—FHWA, *Highway Statistics*, annual reports, Table VM-1.

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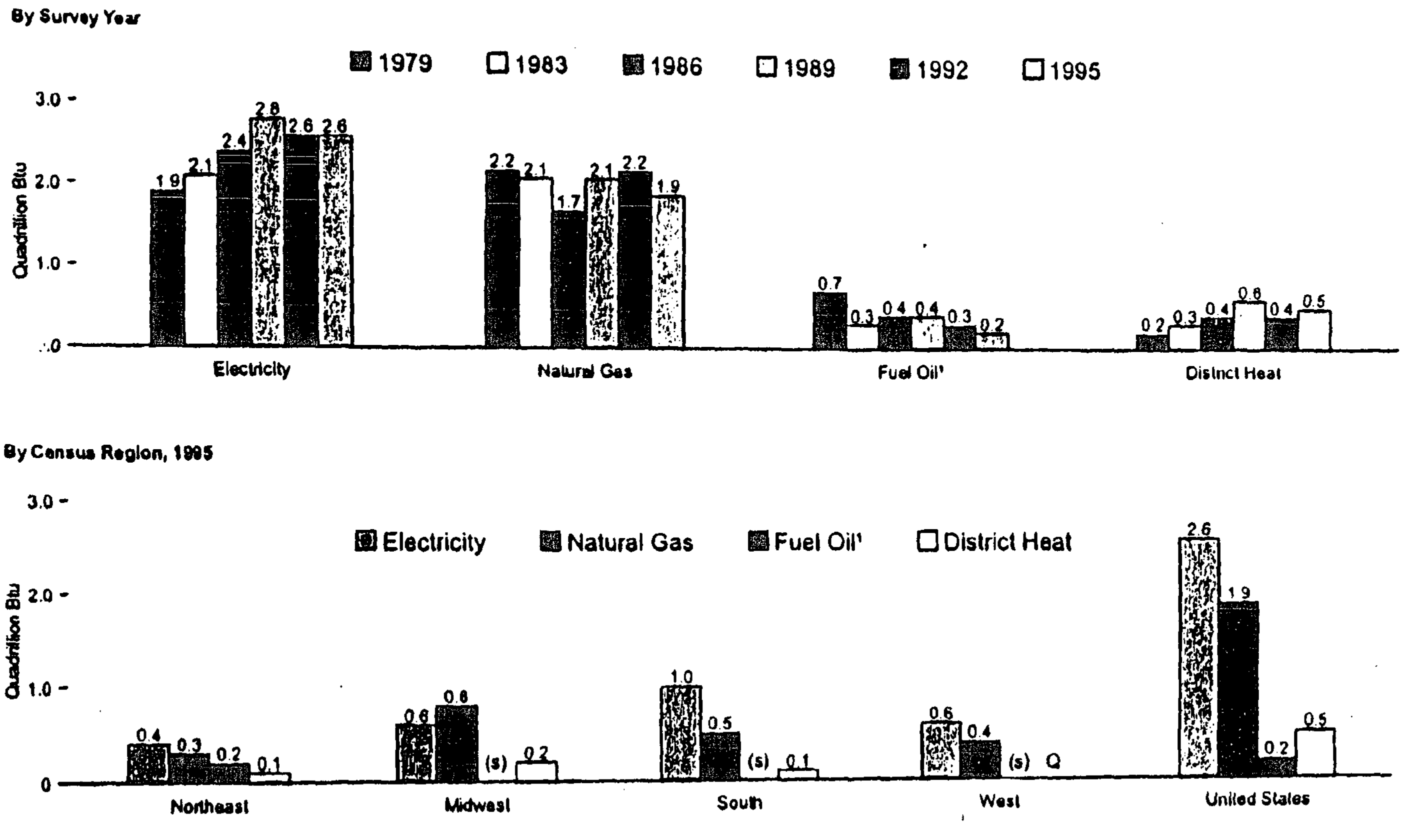
Figure 2.10 Commercial Buildings Consumption by Energy Source



¹ Distillate fuel oil, residual fuel oil, and kerosene.
Q=Data withheld because either the relative standard error was greater than 50 percent or fewer than 20 buildings were sampled.

(s)=Less than 0.05 quadrillion Btu.
Source: Table 2.10. See Appendix D for Census regions.

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Table 2.10 Commercial Buildings Consumption by Energy Source, Selected Years, 1979-1995
(Trillion Btu)

Energy Source and Year	Square Footage Category: 1,001 to 10,000	Square Footage Category: 10,001 to 100,000	Square Footage Category: Over 100,000	Principal Building Activity: Mercantile and Service	Principal Building Activity: Office	Principal Building Activity: Education	Principal Building Activity: All Other	Census Region[1]: Northeast	Census Region[1]: Midwest	Census Region[1]: South	Census Region[1]: West	All Buildings
Major Sources[2]												
1979	1,255	2,202	1,508	694	861	511	2,699	1,217	1,826	1,395	526	4,965
1983	1,242	1,935	1,646	812	1,018	480	2,513	858	1,821	1,462	682	4,823
1986	1,273	2,008	1,698	985	1,008	633	2,351	1,037	1,585	1,459	896	4,977
1989	1,259	2,402	2,127	1,048	1,230	704	2,806	1,354	1,659	1,646	1,126	5,788
1992	1,258	2,301	1,932	892	1,247	637	2,714	1,090	1,578	1,825	998	5,490
1995[3]	1,332	2,152	1,838	973	1,019	614	2,716	1,035	1,497	1,684	1,106	6,321
Electricity												
1979	429	872	608	361	424	163	961	425	593	662	227	1,908
1983	469	903	758	426	509	152	1,041	324	673	801	331	2,129
1986	654	927	809	536	641	179	1,035	430	584	867	510	2,390
1989	572	1,145	1,056	550	781	217	1,225	586	609	975	604	2,773
1992	586	991	1,033	444	704	235	1,226	419	622	1,002	566	2,609
1995[3]	618	1,064	926	508	676	221	1,204	436	558	1,027	587	2,608
Natural Gas												
1979	646	996	532	422	272	214	1,266	443	1,007	470	255	2,174
1983	684	809	597	327	365	246	1,152	278	978	523	311	2,091
1986	485	715	523	332	258	254	878	244	742	426	311	1,723
1989	568	836	670	417	238	323	1,095	363	831	498	391	2,073
1992	572	1,017	588	361	388	291	1,115	354	747	697	376	2,174
1995[3]	535	830	580	395	239	245	1,066	297	750	528	371	1,946
Fuel Oil[4]												
1979	177	272	231	103	107	107	364	285	133	237	26	681
1983	85	140	90	43	75	61	135	172	28	104	Q	314
1986	114	206	121	105	39	103	194	270	63	86	23	442
1989	101	170	86	78	43	71	187	237	61	50	Q	357
1992	86	111	75	55	47	62	109	194	26	48	Q	272
1995[3]	71	104	60	49	28	57	101	168	16	45	7	235
District Heat[5]												
1979	Q	61	136	Q	58	27	108	64	93	Q	Q	201
1983	Q	83	202	Q	68	21	184	84	141	34	30	289
1986	Q	159	243	12	71	97	243	94	196	81	51	422
1989	19	252	315	Q	187	Q	319	179	159	126	121	585
1992	Q	182	238	Q	109	49	264	123	183	78	51	435
1995[3]	Q	154	271	Q	76	91	346	136	173	83	Q	533
Propane												
1979	23	15	5	10	Q	2	29	Q	16	15	10	43
1983	20	12	2	8	Q	2	24	Q	7	21	Q	34
1986	44	18	1	17	Q	3	42	9	19	26	Q	63

[1] See Appendix D for Census regions.
[2] For 1979, 1983, and 1986 includes electricity, natural gas, fuel oil, district heat, and propane. For 1989, 1992, and 1995 includes electricity, natural gas, fuel oil, and district heat. Propane consumption statistics were not collected after 1986.
[3] Commercial buildings on multibuilding manufacturing facilities and parking garages were excluded in the 1995 survey.
[4] Distillate fuel oil, residual fuel oil, and kerosene.
[5] For 1979 and 1983, includes only purchased steam. For 1986, 1989, 1992, and 1995 includes purchased and nonpurchased steam and purchased and nonpurchased hot water.

Q=Data withheld because either the relative standard error was greater than 50 percent or fewer than 20 buildings were sampled.
Note: Statistics for individual fuels are for all buildings using each fuel. Statistics for major sources are for the sum of electricity, natural gas, fuel oil, and district heat, across all buildings using any of those fuels.
Web Page: http://www.eia.doe.gov/emeu/consumption.
Sources: • 1979—Energy Information Administration (EIA), Form EIA-143, "Nonresidential Buildings Energy Consumption Survey." • 1983—EIA, Form EIA-788, "Nonresidential Buildings Energy Consumption Survey." • 1986—EIA, Form EIA-871, "Nonresidential Buildings Energy Consumption Survey." • 1989, 1992, and 1995—EIA, Form EIA-871A-F, "Commercial Buildings Energy Consumption Survey."

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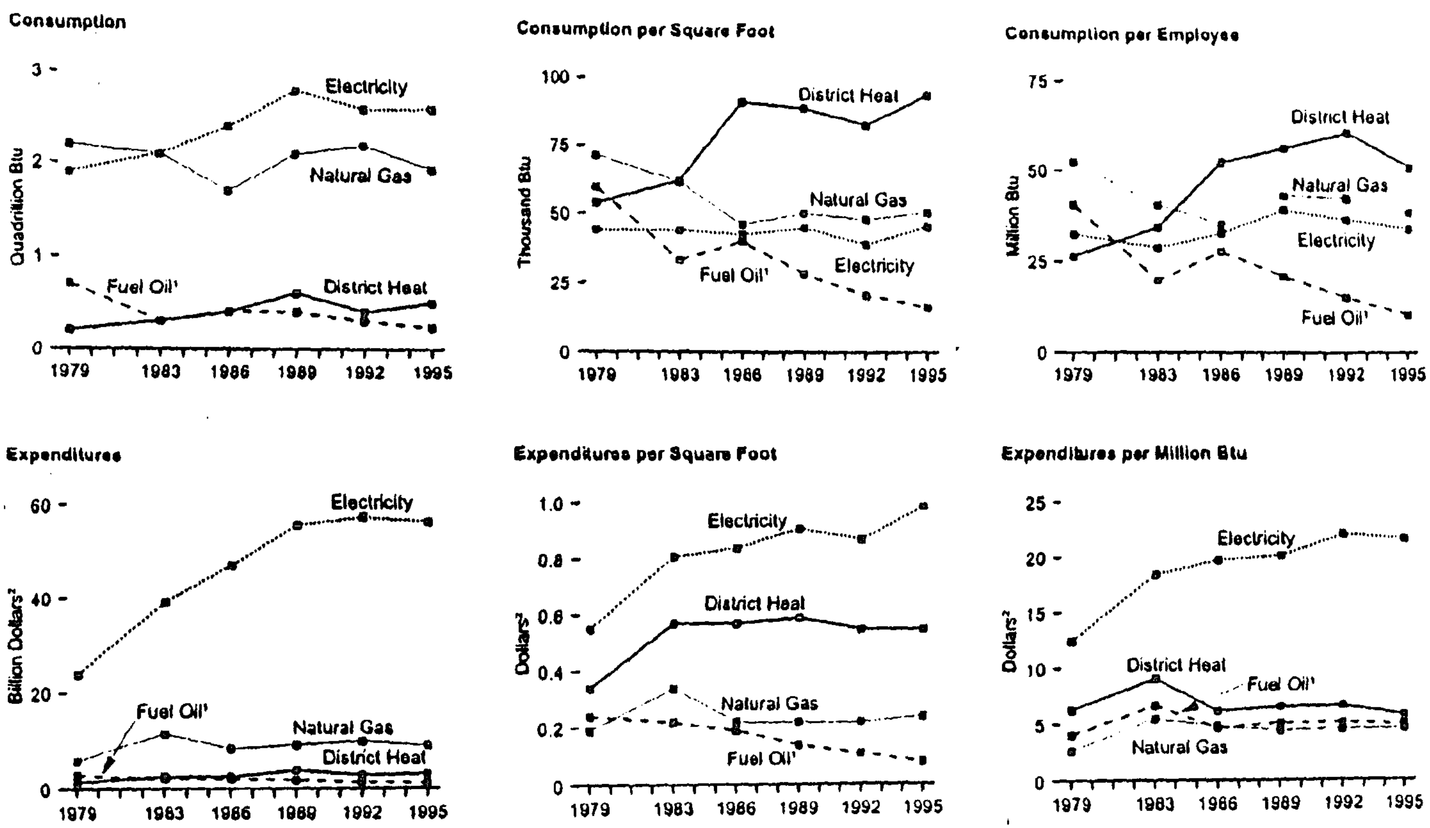
Figure 2.11 Commercial Buildings Energy Consumption and Expenditure Indicators, Selected Years, 1979-1995



¹ Distillate fuel oil, residual fuel oil, and kerosene.
² Nominal dollars.

Notes: • No data are available for 1980-1982, 1984, 1985, 1987, 1988, 1990, 1991, 1993, and 1994. • Because vertical scales differ, graphs should not be compared.
Source: Table 2.11.

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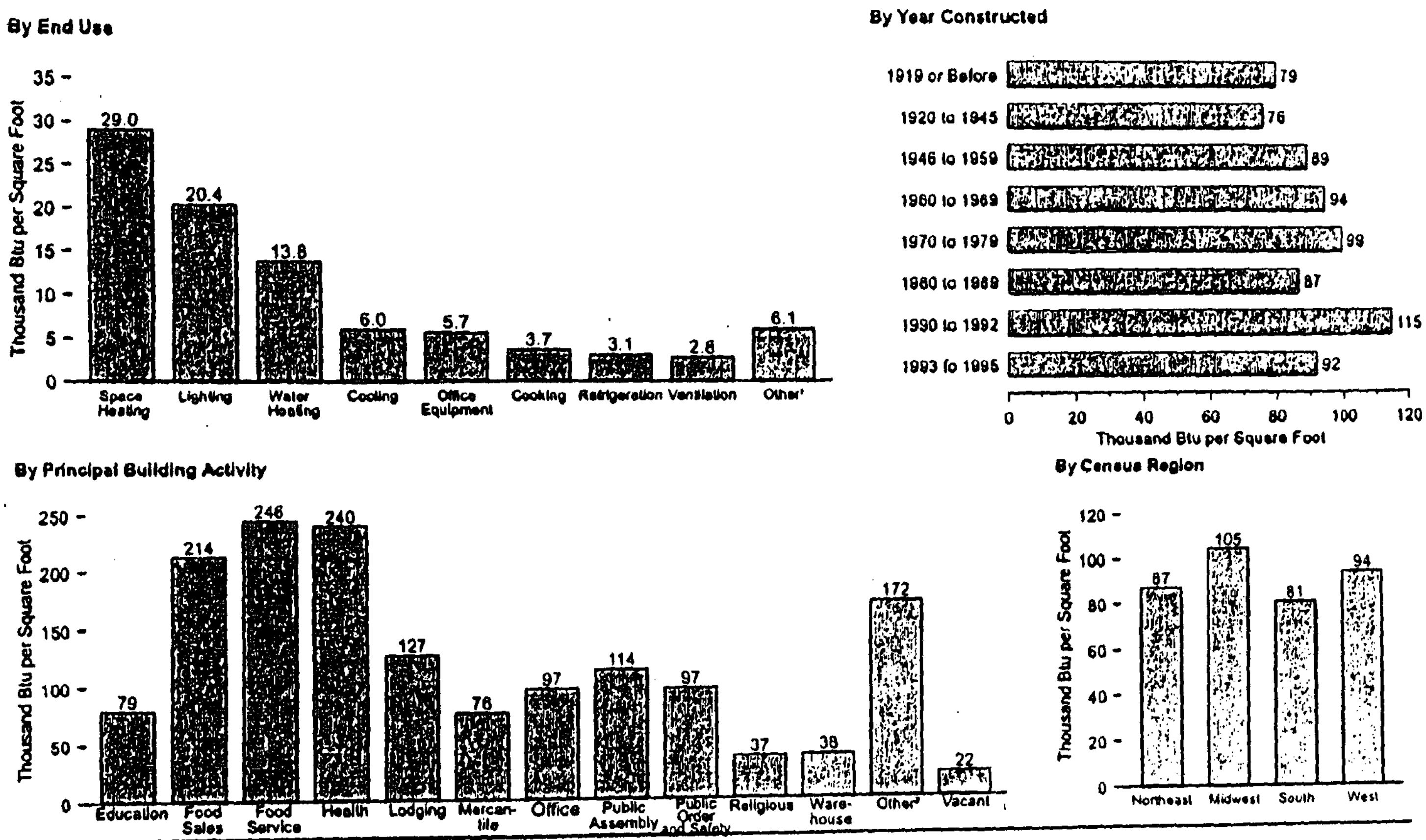
Table 2.11 Commercial Buildings Energy Consumption and Expenditure Indicators, Selected Years, 1979-1995

Energy Source and Year	Building Characteristics			Energy Consumption				Energy Expenditures			
	Number of Buildings (thousand)	Total Square Feet (million)	Square Feet per Building (thousand)	Total (trillion Btu)	Per Building (million Btu)	Per Square Foot (thousand Btu)	Per Employee (million Btu)	Total (million dollars[1])	Per Building (thousand dollars[1])	Per Square Foot (dollars[1])	Per Million Btu (dollars[1])
Major Sources[2]											
1979	3,073	43,546	14.2	5,008	1,630	115.0	85.0	33,821	11.0	0.78	6.75
1983	3,186	49,471	15.5	4,856	1,525	98.2	65.7	55,764	17.5	1.13	11.48
1986	4,154	58,199	14.0	5,040	1,213	86.6	68.6	60,762	14.6	1.04	12.06
1989	4,528	63,184	14.0	5,788	1,278	91.6	81.9	70,826	15.6	1.12	12.24
1992	4,806	67,876	14.1	5,490	1,142	80.9	77.1	71,821	14.9	1.06	13.08
1995[3]	4,579	58,772	12.8	5,321	1,162	90.5	69.3	69,918	15.3	1.19	13.14
Electricity											
1979	3,001	43,153	14.4	1,908	636	44.2	32.4	23,751	7.9	0.55	12.45
1983	3,052	46,327	15.8	2,129	697	44.1	28.9	39,279	12.9	0.81	18.45
1986	3,965	56,508	14.3	2,390	603	42.3	32.7	47,186	11.9	0.84	19.74
1989	4,294	61,563	14.3	2,773	646	45.0	39.3	55,943	13.0	0.91	20.17
1992	4,611	66,526	14.4	2,609	566	39.2	36.6	57,619	12.5	0.87	22.09
1995[3]	4,343	57,078	13.1	2,608	600	45.7	34.1	56,621	13.0	0.99	21.71
Natural Gas											
1979	1,864	30,477	16.4	2,174	1,167	71.3	52.5	5,814	3.1	0.19	2.67
1983	1,904	33,935	17.8	2,091	1,098	61.6	40.6	11,443	6.0	0.34	5.47
1986	2,214	37,263	16.8	1,723	778	46.2	35.2	8,355	3.8	0.22	4.85
1989	2,420	41,143	17.0	2,073	857	50.4	43.2	9,204	3.8	0.22	4.44
1992	2,657	44,894	16.9	2,174	818	48.3	42.5	9,901	3.7	0.22	4.55
1995[3]	2,478	38,145	15.4	1,946	785	51.0	38.7	9,018	3.6	0.24	4.63
Fuel Oil[4]											
1979	641	11,397	17.8	681	1,063	59.7	40.5	2,765	4.3	0.24	4.06
1983	441	9,409	21.3	314	714	33.4	19.8	2,102	4.8	0.22	6.68
1986	534	11,005	20.6	442	827	40.1	27.7	2,059	3.9	0.19	4.66
1989	581	12,600	21.7	357	614	28.3	21.0	1,822	3.1	0.14	5.11
1992	560	13,215	23.6	272	487	20.6	16.1	1,400	2.5	0.11	5.14
1995[3]	607	14,421	23.7	235	387	16.3	10.2	1,175	1.9	0.08	5.00
District Heat[5]											
1979	47	3,722	79.0	201	4,267	54.0	26.5	1,267	26.9	0.34	6.30
1983	64	4,643	72.9	289	4,530	62.1	34.4	2,627	41.2	0.57	9.10
1986	77	4,626	59.7	422	5,446	91.2	52.4	2,620	33.8	0.57	6.21
1989	98	6,578	67.0	585	5,964	89.0	56.5	3,857	39.3	0.59	6.59
1992	95	5,245	55.4	435	4,596	82.9	60.8	2,901	30.7	0.55	6.67
1995[3]	110	5,658	51.5	533	4,849	94.1	51.2	3,103	28.3	0.55	5.83
Propane											
1979	214	2,797	13.1	43	202	15.5	12.9	225	1.1	0.08	5.19
1983	191	2,562	13.4	34	176	13.1	8.5	313	1.6	0.12	9.29
1986	344	3,213	9.3	63	184	19.7	17.6	543	1.6	0.17	8.59
1989	348	4,695	13.5	NA	NA	NA	NA	NA	NA	NA	NA
1992	337	3,393	10.1	NA	NA	NA	NA	NA	NA	NA	NA
1995	589	5,344	9.1	NA	NA	NA	NA	NA	NA	NA	NA

[1] Nominal dollars.
[2] For 1979, 1983, and 1986 includes electricity, natural gas, fuel oil, district heat, and propane. For 1989, 1992, and 1995 includes electricity, natural gas, fuel oil, and district heat. Propane consumption statistics were not collected after 1986.
[3] Commercial buildings on multibuilding manufacturing facilities and parking garages were excluded in the 1995 survey.
[4] Distillate fuel oil, residual fuel oil, and kerosene.
[5] For 1979 and 1983, includes only purchased steam. For 1986, 1989, 1992, and 1995 includes purchased and nonpurchased steam and purchased and nonpurchased hot water.

NA=Not available.
Note: Statistics for individual fuels are for all buildings using each fuel. Statistics for major sources are for all buildings, even buildings using no major fuel.
Web Page: http://www.eia.doe.gov/emeu/consumption.
Sources: • 1979—Energy Information Administration (EIA), Form EIA-143, "Nonresidential Buildings Energy Consumption Survey." • 1983—EIA, Form EIA-788, "Nonresidential Buildings Energy Consumption Survey." • 1986—EIA, Form EIA-871, "Nonresidential Buildings Energy Consumption Survey." • 1989, 1992, and 1995—EIA, Form EIA-871A-F, "Commercial Buildings Energy Consumption Survey."

Figure 2.12 Commercial Buildings Energy Intensities by Building Characteristic, 1995



¹ See Table 2.12, footnote 1, for description of "Other."
² Includes buildings that do not fit into any of the other categories.
Notes: • See Appendix D for Census Regions. • Because vertical scales differ, graphs should not be compared.
Source: Table 2.12.

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Table 2.12 Commercial Buildings Energy Intensities by Building Characteristic, 1995
(Thousand Btu per Square Foot)

Building Characteristic	Space Heating	Cooling	Ventilation	Water Heating	Lighting	Cooking	Refrigeration	Office Equipment	Other [1]	All End Uses
All Buildings	28.0	6.0	2.8	13.8	20.4	3.7	3.1	5.7	6.1	90.5
Building Floorspace (square feet)										
1,001 to 5,000	39.5	7.0	2.9	9.7	22.7	8.9	10.4	6.4	5.1	111.7
5,001 to 10,000	38.6	4.4	1.7	11.1	13.6	4.3	2.5	3.6	2.9	82.8
10,001 to 25,000	27.4	4.8	1.7	9.1	14.7	2.6	2.5	4.3	3.7	70.9
25,001 to 50,000	28.2	6.7	2.1	11.6	18.5	2.1	2.5	5.0	5.2	82.0
50,001 to 100,000	27.0	7.0	3.2	12.8	21.3	2.0	2.1	6.1	6.0	87.6
100,001 to 200,000	26.6	6.2	3.3	19.6	25.0	3.1	1.4	7.2	8.9	101.4
200,001 to 500,000	24.0	6.7	4.5	25.2	27.4	4.6	1.6	8.5	11.9	114.6
Over 500,000	18.5	6.0	3.9	18.0	28.6	3.5	2.2	7.0	9.1	96.8
Principal Building Activity										
Education	32.8	4.8	1.6	17.4	15.8	1.4	1.0	1.5	2.9	79.3
Food Sales	27.5	13.4	4.4	9.1	33.9	5.6	110.9	1.3	7.4	213.5
Food Service	30.9	18.5	5.3	27.5	37.0	77.5	31.6	2.6	13.7	245.5
Health Care	55.2	9.9	7.2	63.0	39.3	11.2	4.7	15.5	34.4	240.4
Lodging	22.7	8.1	1.7	51.4	23.2	6.6	2.3	3.8	7.6	127.3
Mercantile and Service	30.6	5.8	2.5	6.1	23.4	1.5	0.9	2.9	3.7	76.4
Office	24.3	9.1	5.2	8.7	28.1	1.1	0.4	15.1	5.2	97.2
Public Assembly	53.8	6.3	3.5	17.5	21.9	2.8	1.8	2.4	3.6	113.7
Public Order and Safety	27.8	6.1	2.3	23.4	16.4	Q	0.2	5.8	12.7	97.2
Religious Worship	23.7	1.9	0.9	3.2	5.0	0.5	0.6	0.4	1.1	37.4
Warehouse and Storage	15.7	0.9	0.3	2.0	9.8	0.0	1.7	4.4	3.4	38.3
Other [2]	59.8	9.3	8.3	16.3	26.7	Q	0.7	15.2	35.9	172.2
Vacant	11.9	0.6	0.3	2.4	3.6	Q	0.2	0.5	1.9	21.5
Year Constructed										
1919 or Before	34.2	2.6	1.8	10.0	14.9	4.0	1.3	3.2	7.5	79.4
1920 to 1945	37.0	3.4	1.6	10.7	12.3	1.8	1.8	3.3	4.1	75.7
1946 to 1959	37.2	4.4	2.1	14.1	15.5	3.0	2.7	4.6	5.2	88.9
1960 to 1969	30.2	5.7	2.7	16.6	20.4	4.0	3.0	5.3	6.1	94.3
1970 to 1979	26.0	7.2	3.6	15.8	25.6	3.2	3.7	6.7	7.5	99.3
1980 to 1989	19.8	7.8	3.2	11.5	23.5	4.2	3.0	7.6	5.9	86.5
1990 to 1992	26.6	8.4	3.5	17.2	28.7	9.3	5.6	7.9	7.4	114.6
1993 to 1995	24.3	7.9	3.2	11.7	22.7	3.3	7.4	4.9	6.8	92.2
Census Region [3]										
Northeast	32.4	4.0	2.0	14.2	17.7	2.7	3.0	4.5	6.4	87.1
Midwest	46.7	4.3	2.5	15.6	18.8	3.5	2.4	5.1	5.6	104.5
South	18.0	8.4	3.2	10.5	21.3	4.0	3.4	5.9	6.0	80.8
West	23.4	5.5	3.1	17.0	23.6	4.3	3.4	7.2	6.5	94.2

[1] Examples of "other" include medical, electronic, and testing equipment; conveyors, wrappers, hoists, and compactors; washers, disposals, dryers and cleaning equipment; escalators, elevators, dumb waiters, and window washers; shop tools and electronic testing equipment; sign motors, time clocks, vending machines, phone equipment, and sprinkler controls; scoreboards, fire alarms, intercoms, television sets, radios, projectors, and door operators.

[2] Includes buildings that do not fit into any of the other named categories.

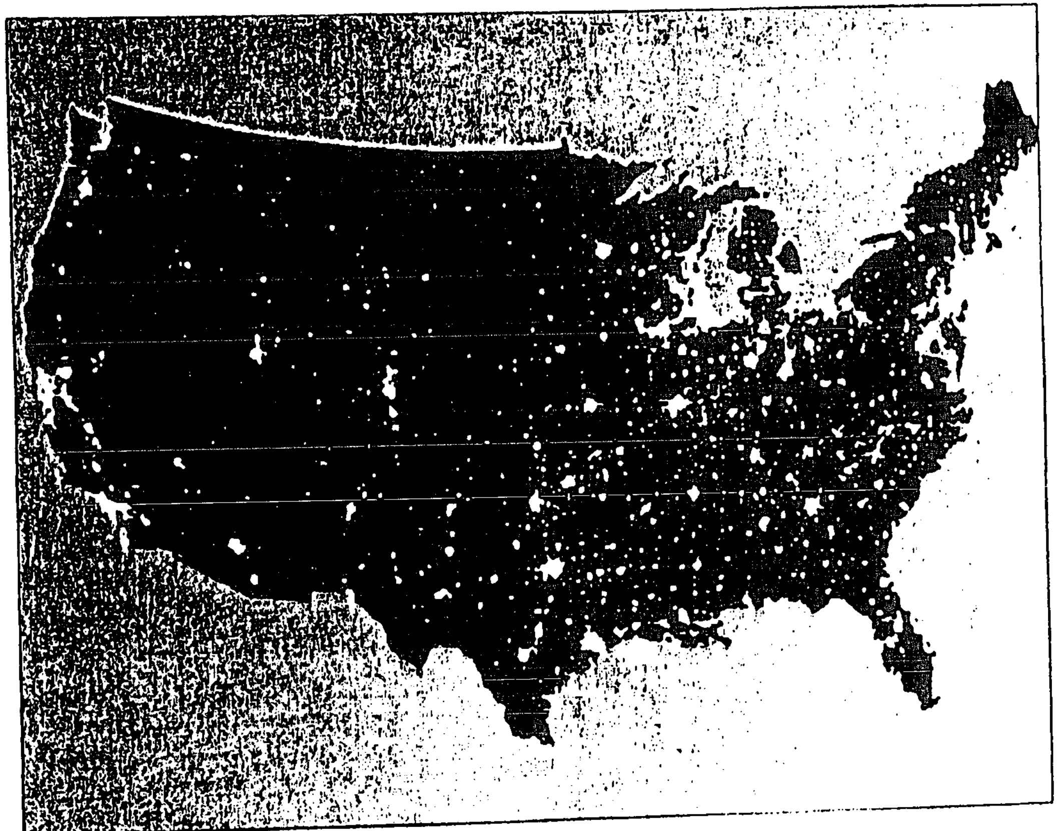
[3] See Appendix D for Census regions.

Q=Data withheld because either the relative standard error was greater than 50 percent or fewer than 20 buildings were sampled.

Web Page: http://www.eia.doe.gov/emeu/consumption.

Source: Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures* (October 1998), Table EU-2

1 Energy Overview



The United States at night from orbit. Source: National Oceanographic and Atmospheric Administration satellite imagery; mosaic provided by U.S. Geological Survey.

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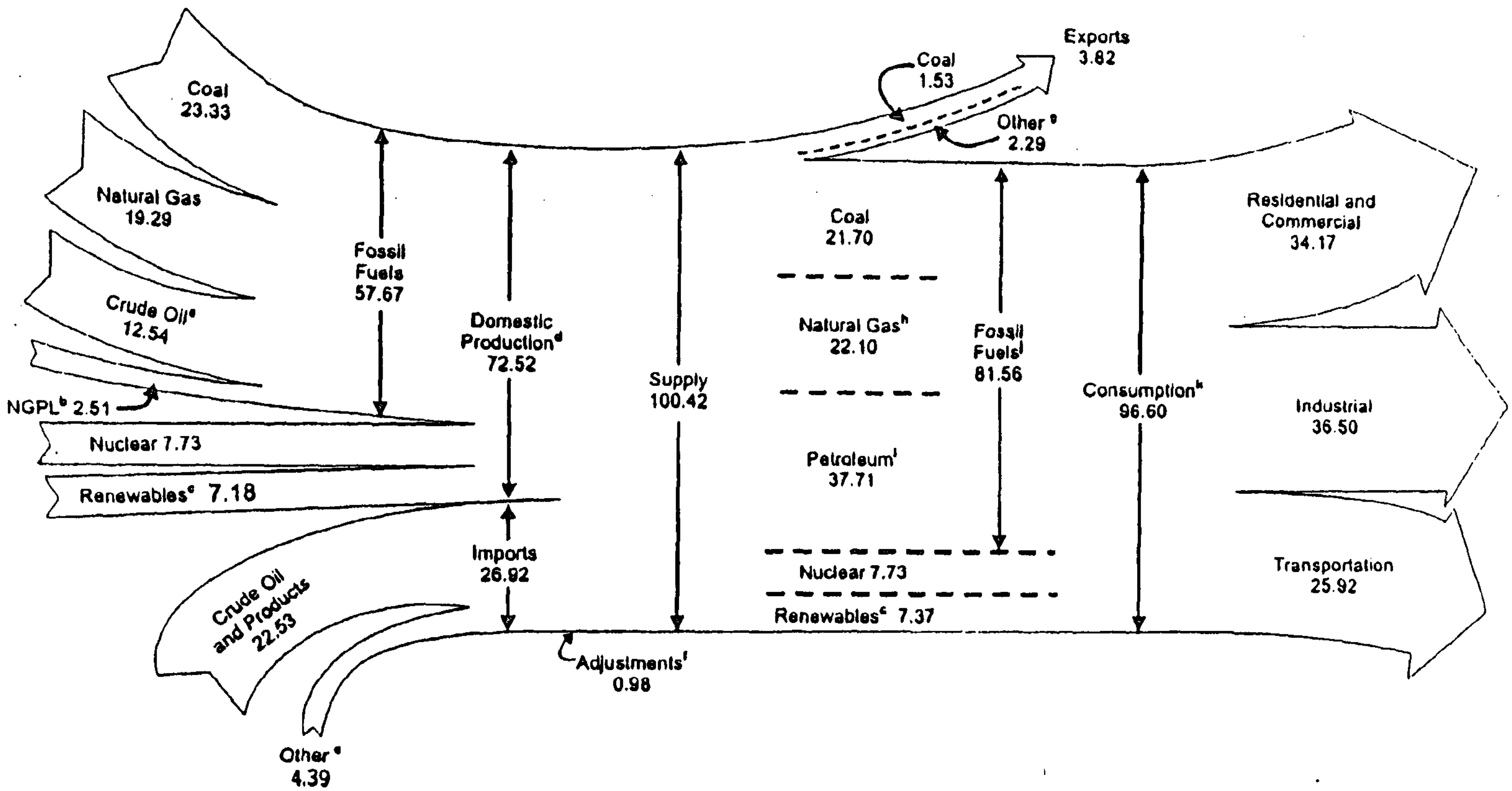
Diagram 1. Energy Flow, 1999
(Quadrillion Btu)



[a] Includes lease condensate.
[b] Natural gas plant liquids.
[c] Conventional hydroelectric power, wood, waste, ethanol blended into motor gasoline, geothermal, solar, and wind.
[d] Includes -0.08 quadrillion Btu hydroelectric pumped storage.
[e] Natural gas, coal, coal coke, and electricity.
[f] Stock changes, losses, gains, miscellaneous blending components, and unaccounted-for supply.
[g] Crude oil, petroleum products, natural gas, electricity, and coal coke.
[h] Includes supplemental gaseous fuels.
[i] Petroleum products, including natural gas plant liquids.
[j] Includes 0.06 quadrillion Btu coal coke net imports.
[k] Includes, in quadrillion Btu, 0.11 net imported electricity from nonrenewable sources; -0.06 hydroelectric pumped storage; and -0.11 ethanol blended into motor gasoline, which is accounted for in both fossil fuels and renewables and removed once from this total to avoid doublecounting.

Notes: • Data are preliminary. • Totals may not equal sum of components due to independent rounding.
Sources: Tables 1.1, 1.2, 1.3, 1.4, 2.1, and 10.2.

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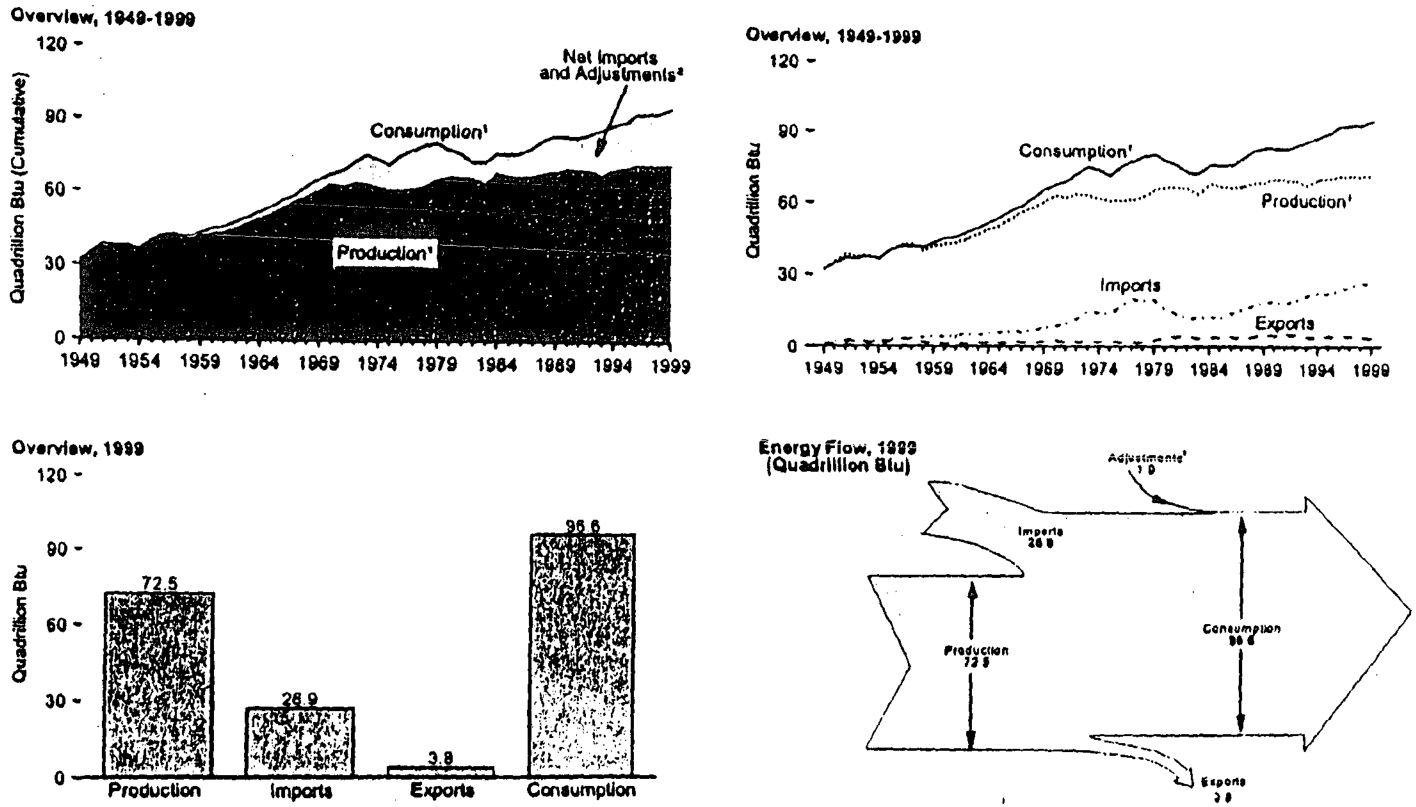
Figure 1.1 Energy Overview



[1] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989.

[2] Stock changes, losses, gains, miscellaneous blending components, and unaccounted-for supply.

Note: Data for 1999 are preliminary.

Source: Table 1.1.

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Table 1.1 Energy Overview, 1949-1999
(Quadrillion Btu)

Year	Production: Fossil Fuels [1]	Production: Nuclear Electric Power [2]	Production: Renewable Energy [3]	Production: Total [4]	Imports: Petroleum [5]	Imports: Total [6]	Exports: Coal	Exports: Total [7]	Adjustments [8]	Consumption: Fossil Fuels [9]	Consumption: Nuclear Electric Power [2]	Consumption: Renewable Energy [3]	Consumption: Total [10]
1949	28.75	0	2.97	31.72	1.43	1.47	0.88	1.59	0.40	29.00	0	3.00	32.00
1950	32.56	0	2.98	35.54	1.89	1.93	0.79	1.47	-1.37	31.63	0	3.00	34.63
1951	35.79	0	2.96	38.75	1.87	1.92	1.68	2.62	-1.05	34.01	0	2.99	37.00
1952	34.98	0	2.94	37.92	2.11	2.17	1.40	2.37	-0.95	33.80	0	2.97	36.77
1953	35.35	0	2.83	38.18	2.28	2.34	0.98	1.87	-0.96	34.83	0	2.86	37.68
1954	33.76	0	2.75	36.52	2.32	2.37	0.91	1.70	-0.53	33.88	0	2.78	36.66
1955	37.36	0	2.78	40.15	2.75	2.83	1.46	2.29	-0.44	37.41	0	2.83	40.24
1956	39.77	0	2.85	42.62	3.17	3.25	1.98	2.95	-1.13	38.89	0	2.90	41.79
1957	40.13	(s)	2.85	42.98	3.46	3.57	2.17	3.45	-1.29	38.93	(s)	2.89	41.82
1958	37.22	(s)	2.82	40.13	3.72	3.92	1.42	2.06	-0.32	38.72	(s)	2.95	41.67
1959	39.05	(s)	2.90	41.95	3.91	4.11	1.05	1.64	-1.03	40.55	(s)	2.94	43.49
1960	39.87	0.01	2.93	42.80	4.00	4.23	1.02	1.48	-0.43	42.14	0.01	2.98	45.12
1961	40.31	0.02	2.95	43.28	4.19	4.46	0.98	1.38	-0.60	42.76	0.02	2.98	45.76
1962	41.73	0.03	3.12	44.88	4.56	5.01	1.08	1.48	-0.57	44.68	0.03	3.12	47.83
1963	44.04	0.04	3.10	47.17	4.65	5.10	1.36	1.85	-0.78	46.51	0.04	3.10	49.65
1964	45.79	0.04	3.23	49.06	4.96	5.49	1.34	1.84	-0.87	48.54	0.04	3.25	51.83
1965	47.23	0.04	3.40	50.68	5.40	5.92	1.38	1.85	-0.72	50.58	0.04	3.40	54.02
1966	50.04	0.06	3.43	53.53	5.63	6.18	1.36	1.85	-0.83	53.51	0.06	3.45	57.02
1967	52.60	0.09	3.69	56.38	5.56	6.19	1.35	2.15	-1.52	55.13	0.09	3.69	58.91
1968	54.31	0.14	3.78	58.23	6.21	6.93	1.38	2.03	-0.71	58.50	0.14	3.77	62.41
1969	56.29	0.15	4.10	60.54	6.90	7.71	1.53	2.15	-0.47	61.36	0.15	4.11	65.63
1970	59.19	0.24	R4.07	63.50	7.47	8.39	1.94	2.66	-1.37	63.52	0.24	R4.09	67.86
1971	58.04	0.41	4.27	62.72	8.54	9.58	1.55	2.18	-0.82	64.60	0.41	R4.30	69.31
1972	58.94	0.58	4.40	63.92	10.30	11.48	1.53	2.14	-0.48	67.70	0.58	4.48	72.78
1973	58.24	0.91	4.43	63.58	13.47	14.73	1.43	2.05	-0.46	70.32	0.91	4.58	75.81
1974	56.33	1.27	4.77	62.37	13.13	14.41	1.62	2.22	-0.48	67.91	1.27	4.90	74.08
1975	54.73	1.90	4.72	R61.35	12.96	14.11	1.76	2.36	-1.07	65.35	1.90	4.79	72.04
1976	54.72	2.11	4.77	61.60	15.67	16.84	1.60	2.19	-0.18	69.10	2.11	4.86	76.07
1977	55.10	2.70	4.25	62.05	18.76	20.09	1.44	2.07	-1.95	70.99	2.70	4.43	78.12
1978	55.07	3.02	5.04	63.14	17.82	19.25	1.08	1.93	-0.34	71.86	3.02	5.24	80.12
1979	58.01	2.78	R5.16	65.95	17.93	19.62	1.75	2.87	-1.65	72.89	2.78	R5.37	81.04
1980	59.01	2.74	5.49	67.24	14.66	15.97	2.42	3.72	-1.05	69.98	2.74	5.71	R78.43
1981	58.53	3.01	5.47	67.01	12.64	13.97	2.94	4.33	-0.08	67.75	3.01	5.82	76.57
1982	57.46	3.13	5.99	R66.57	10.78	12.09	2.79	4.63	-0.59	64.04	3.13	6.29	73.44
1983	54.42	3.20	6.49	64.11	10.66	12.03	2.04	3.72	0.90	63.29	3.20	6.86	73.32
1984	58.85	3.55	6.43	68.83	11.43	12.77	2.15	3.80	-0.82	66.62	3.55	6.84	76.97
1985	57.54	4.15	R6.03	R67.72	10.61	12.10	2.44	4.23	1.19	66.22	4.15	R6.46	R76.78
1986	56.58	4.47	R6.13	R67.18	13.20	14.44	2.25	4.06	-0.50	66.15	4.47	R6.51	R77.06
1987	57.17	4.91	R5.69	R67.76	14.16	15.76	2.09	3.85	-0.04	68.63	4.91	R6.17	R79.63
1988	57.87	5.66	R5.49	R69.03	15.75	17.56	2.50	4.42	0.89	71.66	5.66	R5.82	R83.07
1989	57.47	5.68	R,11 6.32	R,11 69.46	17.16	18.96	2.64	4.77	0.94	72.55	5.68	R,11 6.47	R,11 84.59
1990	58.56	6.16	R6.16	R70.85	17.12	R18.96	2.77	R4.87	-0.75	71.96	6.16	R6.26	R84.19
1991	57.83	6.58	R6.15	R70.51	16.35	R18.60	2.85	R5.16	0.21	71.23	6.58	R6.37	R84.06
1992	57.59	6.61	R5.90	R70.06	16.97	R19.68	2.68	R4.96	0.83	R72.85	6.61	R6.17	R85.51
1993	55.74	6.52	6.15	68.37	18.51	R21.50	1.96	R4.28	R1.73	R74.47	6.52	R6.42	87.31
1994	57.95	6.84	6.08	R70.83	R19.24	R22.73	1.88	R4.08	R-0.25	R75.98	6.84	6.39	R89.23
1995	57.46	7.18	6.66	71.29	18.86	R22.54	2.32	R4.54	R1.65	R76.80	7.18	R6.96	R90.94
1996	R58.30	7.17	7.15	R72.58	20.27	R23.99	2.37	R4.66	R1.99	R79.28	7.17	7.48	R93.91
1997	58.76	6.68	R7.14	R72.53	R21.74	R25.52	2.19	R4.57	R0.84	R80.29	6.68	R7.36	R94.32
1998	R58.68	7.16	R6.78	R72.55	R22.91	R26.86	R2.05	R4.34	R-0.49	R80.51	7.16	R6.98	R94.57
1999P	57.87	7.73	7.16	72.52	22.53	26.92	1.53	3.82	0.98	81.56	7.73	7.37	96.60

[1] Coal, natural gas (dry), crude oil, and natural gas plant liquids.
[2] See Note 1 at end of section.
[3] Conventional hydroelectric power, geothermal, wood, waste, ethanol blended into motor gasoline, solar, and wind.
[4] Also includes hydroelectric pumped storage.
[5] Crude oil and petroleum products.
[6] Also includes natural gas, coal, coal coke, and electricity.
[7] Also includes natural gas, petroleum, electricity, and coal coke.
[8] A balancing item. Includes stock changes, losses, gains, miscellaneous blending components, and unaccounted-for supply.
[9] Coal, coal coke net imports, natural gas, and petroleum.
[10] From 1989, includes net imported electricity from nonrenewable sources and hydroelectric pumped storage, and removes ethanol blended into motor gasoline, which would otherwise be double counted in both fossil fuels and renewable energy.
[11] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989. See Tables 10.1 and 10.2.
R=Revised. P=Preliminary. (s)=Less than 0.005 quadrillion Btu.
Note: Totals may not equal sum of components due to independent rounding.
Sources: See end of section.

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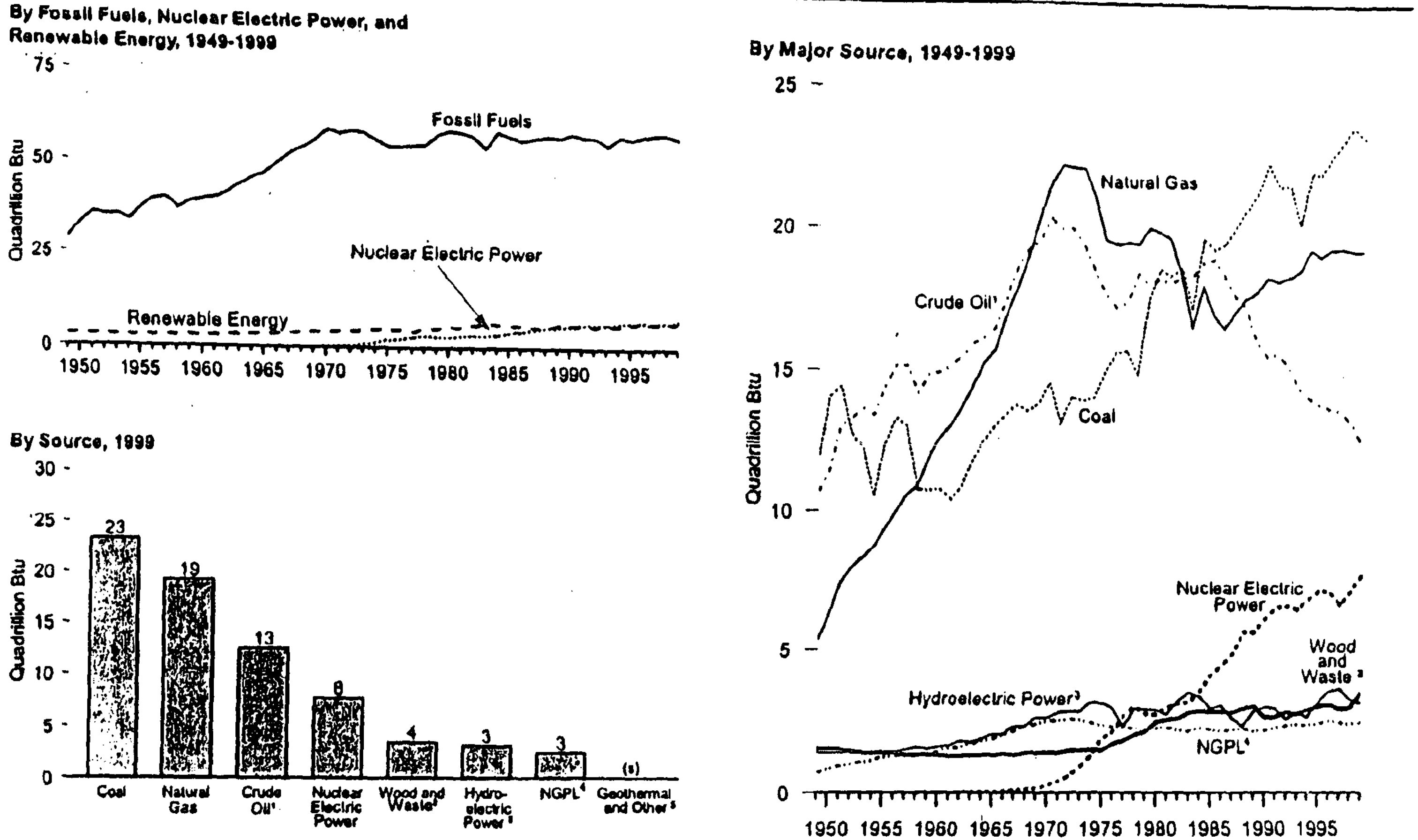
Figure 1.2 Energy Production by Source



[1] Includes lease condensate.
[2] Includes ethanol blended into motor gasoline.
[3] Conventional and pumped-storage hydroelectric power.
[4] Natural gas plant liquids.
[5] Solar and wind.
(s)=Less than 0.5 quadrillion Btu.
Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.2.

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Table 1.2 Energy Production by Source, 1949-1999

(Quadrillion Btu)

Year	Fossil Fuels: Coal	Fossil Fuels: Natural Gas (Dry)	Fossil Fuels: Crude Oil [1]	Fossil Fuels: Natural Gas Plant Liquids	Fossil Fuels: Total Fossil Fuels	Nuclear Electric Power [2]	Hydroelectric Pumped Storage [3]	Renewable Energy: Conventional Hydroelectric Power	Renewable Energy: Geothermal	Renewable Energy: Wood and Waste [4]	Renewable Energy: Solar	Renewable Energy: Wind	Renewable Energy: Total Renewable Energy	Total
1949	11.974	5.377	10.683	0.714	28.748	0	(5)	1.425	0	1.549	0	0	2.974	31.722
1950	14.060	6.233	11.447	0.823	32.563	0	(5)	1.415	0	1.562	0	0	2.978	35.540
1951	14.419	7.416	13.037	0.920	35.792	0	(5)	1.424	0	1.535	0	0	2.958	38.751
1952	12.734	7.964	13.281	0.998	34.977	0	(5)	1.466	0	1.474	0	0	2.940	37.917
1953	12.278	8.339	13.671	1.062	35.349	0	(5)	1.413	0	1.419	0	0	2.831	38.181
1954	10.542	8.682	13.427	1.113	33.764	0	(5)	1.360	0	1.394	0	0	2.754	36.518
1955	12.370	9.345	14.410	1.240	37.364	0	(5)	1.360	0	1.424	0	0	2.784	40.148
1956	13.306	10.002	15.180	1.283	39.771	0	(5)	1.435	0	1.416	0	0	2.851	42.622
1957	13.061	10.605	15.178	1.289	40.133	(s)	(5)	1.516	0	1.334	0	0	2.849	42.983
1958	10.783	10.942	14.204	1.287	37.216	0.002	(5)	1.592	0	1.323	0	0	2.915	40.133
1959	10.778	11.952	14.933	1.383	39.045	0.002	(5)	1.548	0	1.353	0	0	2.901	41.949
1960	10.817	12.656	14.935	1.461	39.869	0.006	(5)	1.608	0.001	1.320	0	NA	2.929	42.804
1961	10.447	13.105	15.206	1.549	40.307	0.020	(5)	1.656	0.002	1.295	0	NA	2.953	43.280
1962	10.901	13.717	15.522	1.593	41.732	0.026	(5)	1.816	0.002	1.300	0	NA	3.119	44.877
1963	11.849	14.513	15.966	1.709	44.037	0.038	(5)	1.771	0.004	1.323	0	NA	3.098	47.174
1964	12.524	15.298	16.164	1.803	45.789	0.040	(5)	1.886	0.005	1.337	0	NA	3.228	49.056
1965	13.055	15.775	16.521	1.883	47.235	0.043	(5)	2.059	0.004	1.335	0	NA	3.398	50.676
1966	13.468	17.011	17.561	1.996	50.035	0.064	(5)	2.062	0.004	1.369	0	NA	3.435	53.534
1967	13.825	17.943	18.651	2.177	52.597	0.088	(5)	2.347	0.007	1.340	0	NA	3.694	56.379
1968	13.609	19.068	19.308	2.321	54.308	0.142	(5)	2.349	0.009	1.419	0	NA	3.776	58.225
1969	13.863	20.446	19.556	2.420	56.286	0.154	(5)	2.648	0.013	1.440	0	NA	4.102	60.541
1970	14.607	21.666	20.401	2.512	59.186	0.239	(5)	2.634	0.011	R1.429	0	NA	R4.074	R63.499
1971	13.186	22.280	20.033	2.644	58.042	0.413	(5)	2.824	0.012	R1.430	0	NA	R4.266	R62.721
1972	14.092	22.208	20.041	2.598	58.938	0.584	(5)	2.864	0.031	R1.501	0	NA	R4.396	R63.918
1973	13.992	22.187	19.493	2.569	58.241	0.910	(5)	2.861	0.043	R1.527	0	NA	R4.431	R63.583
1974	14.074	21.210	18.575	2.471	56.331	1.272	(5)	3.177	0.053	R1.538	0	NA	R4.767	R62.370
1975	14.989	19.640	17.729	2.374	54.733	1.900	(5)	3.155	0.070	R1.497	0	NA	R4.722	R61.355
1976	15.654	19.480	17.262	2.327	54.723	2.111	(5)	2.976	0.078	R1.711	0	NA	R4.766	R61.600
1977	15.755	19.565	17.454	2.327	55.101	2.702	(5)	2.333	0.077	R1.837	0	NA	R4.247	R62.050
1978	14.910	19.485	18.434	2.245	55.074	3.024	(5)	2.937	0.064	R2.036	0	NA	R5.037	R63.136
1979	17.540	20.076	18.104	2.286	58.006	2.776	(5)	2.931	0.084	R2.150	0	NA	R5.164	R65.946
1980	18.598	19.908	18.249	2.254	59.008	2.739	(5)	2.900	0.110	R2.483	0	NA	R5.493	R67.240
1981	18.377	19.699	18.146	2.307	58.529	3.008	(5)	2.758	0.123	2.590	0	NA	5.471	67.007
1982	18.639	18.319	18.309	2.191	57.458	3.131	(5)	3.266	0.105	R2.615	0	NA	R5.985	R66.574
1983	17.247	16.593	18.392	2.184	54.416	3.203	(5)	3.527	0.129	2.831	0	(s)	6.488	64.106
1984	19.719	18.008	18.848	2.274	58.849	3.553	(5)	3.386	0.165	2.880	0	(s)	6.431	68.832
1985	19.325	16.980	18.992	2.241	57.539	4.149	(5)	2.970	0.198	R,6 2.862	0	(s)	R,6 6.030	R,6 67.718
1986	19.509	16.541	18.376	2.149	56.575	4.471	(5)	3.071	0.219	R,6 2.840	0	(s)	R,6 6.131	R,6 67.177
1987	20.141	17.136	17.675	2.215	57.167	4.906	(5)	2.635	0.229	R2.822	0	(s)	R5.686	R67.759
1988	20.738	17.599	17.279	2.260	57.875	5.661	(5)	2.334	0.217	R,6 2.940	0	(s)	R,6 5.491	R,6 69.028
1989	21.346	17.847	16.117	2.158	57.468	5.677	(5)	R,7 2.856	R,7 0.327	R,7 3.050	R,7 0.059	R,7 0.024	R,7 6.316	R,7 69.461
1990	22.456	18.362	15.571	2.175	58.564	R6.162	-0.036	R,8 3.049	R0.346	R2.665	0.063	R0.032	R6.157	R70.847
1991	21.594	18.229	15.701	2.306	57.829	R6.580	-0.047	R3.022	R0.353	R2.679	0.066	R0.032	R6.152	R70.513
1992	21.629	18.375	15.223	2.363	57.590	R6.608	-0.043	2.618	0.361	R2.826	0.068	0.030	R5.903	R70.058
1993	20.249	18.584	14.494	2.408	55.736	R6.520	-0.042	2.893	0.375	R2.782	0.071	0.031	R6.152	R68.366
1994	22.111	19.348	14.103	2.391	57.952	R6.838	-0.035	2.685	0.370	R2.914	0.072	0.036	R6.077	R70.833
1995	22.029	19.101	13.887	2.442	57.458	7.177	-0.028	3.209	0.321	R3.044	0.073	0.033	R6.679	R71.287
1996	22.684	R19.363	13.723	2.530	R58.299	7.168	-0.032	R3.594	0.339	R3.104	0.075	0.035	R7.147	R72.582
1997	23.211	19.394	13.658	2.495	58.758	6.678	-0.042	R3.720	R0.327	R2.982	0.074	R0.034	R7.138	R72.532
1998	R23.719	R19.286	R13.235	R2.420	R58.662	7.157	-0.046	R3.347	R0.334	R2.991	0.074	R0.031	R6.778	R72.550
1999P	23.328	19.295	12.544	2.506	57.673	7.733	-0.063	3.226	0.327	3.514	0.076	0.036	7.161	72.523

[1] Includes lease condensate.
[2] See Note 1 at end of section.
[3] Represents total pumped storage facility production minus energy used for pumping.
[4] Values are estimated. For all years, includes wood consumption in all sectors (see Table 10.4). Beginning in 1970, includes electric utility waste consumption (see Table 8.3). Beginning in 1981, includes industrial sector waste consumption, and transportation sector use of ethanol blended into motor gasoline (see Table 10.3). Beginning in 1989, includes expanded coverage of nonutility wood and waste consumption (see Table 8.4).
[5] Through 1989, pumped storage is included in conventional hydroelectric power.
[6] Not all data were available; therefore, values were interpolated.
[7] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989. See Tables 10.1 and 10.2.
[8] There is a discontinuity in this time series between 1989 and 1990; beginning in 1990, pumped storage is removed.

R=Revised. P=Preliminary. (s)=Less than 0.0005 quadrillion Btu. NA=Not available.
Note: Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/fueloverview.html.
Sources: See end of section.

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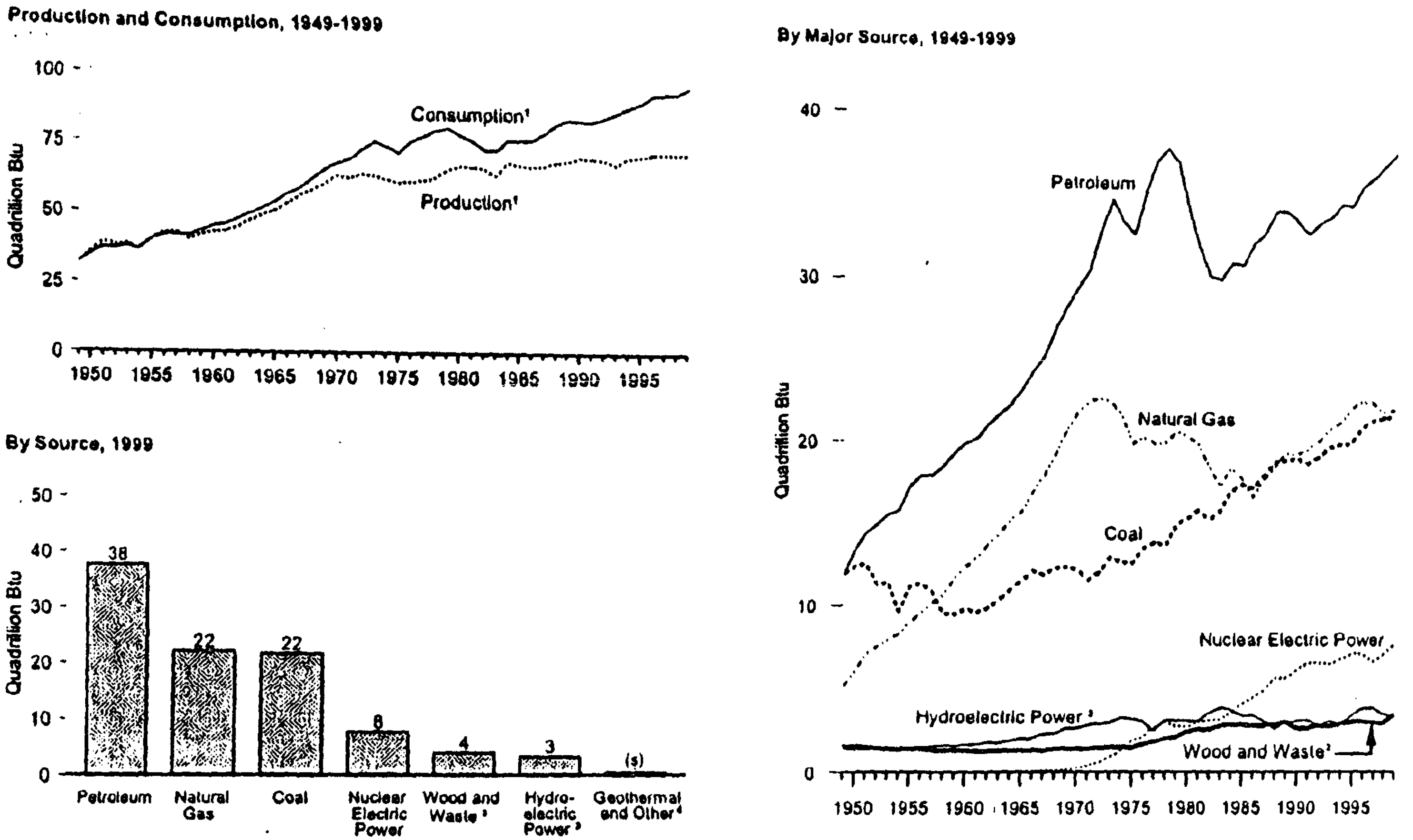
Figure 1.3 Energy Consumption by Source



[1] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989.
[2] Includes ethanol blended into motor gasoline.
[3] Conventional and pumped-storage hydroelectric power.
[4] Solar and wind.
(s)=Less than 0.5 quadrillion Btu.
Note: Because vertical scales differ, graphs should not be compared.
Sources: Tables 1.2 and 1.3.

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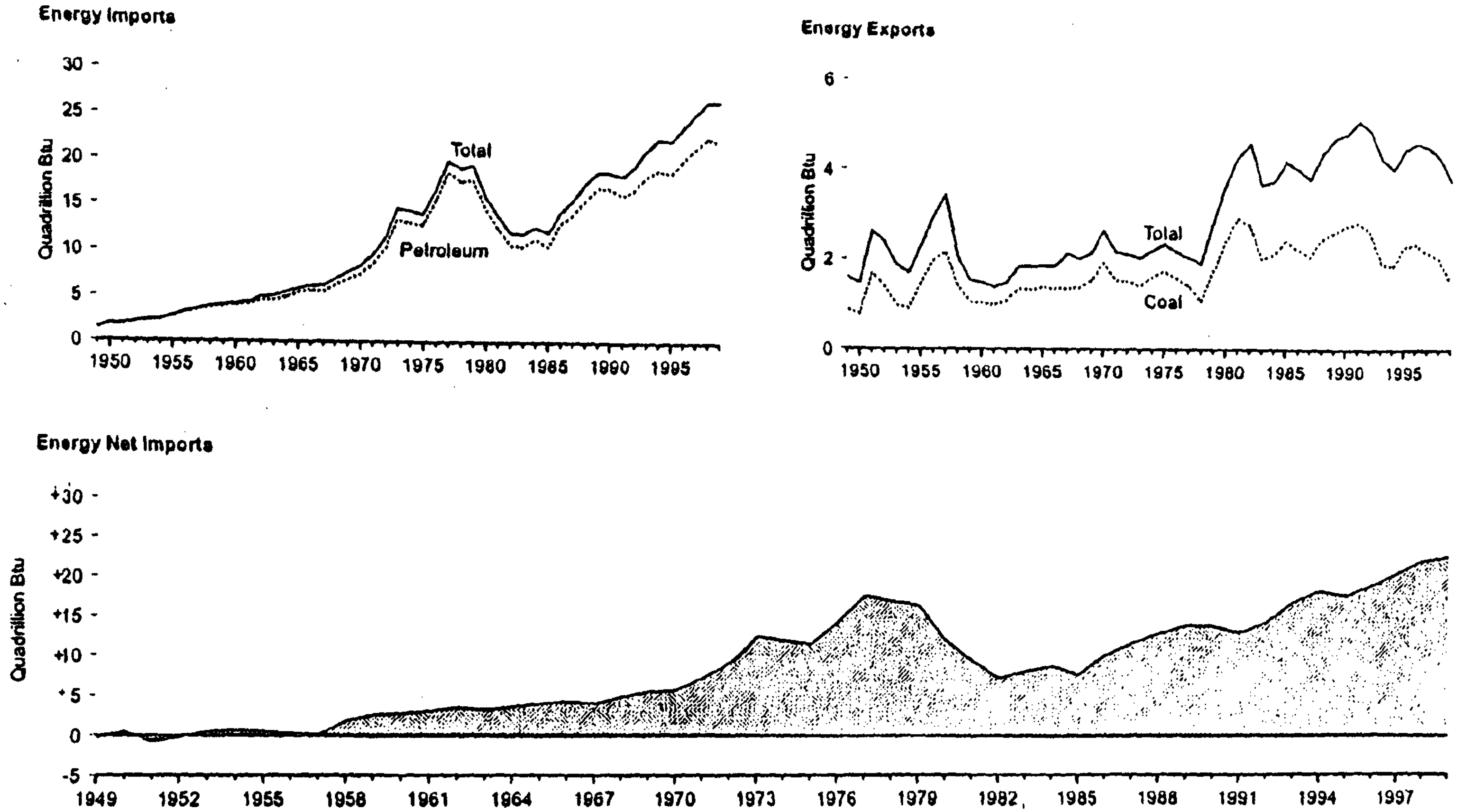
Table 1.3 Energy Consumption by Source, 1949-1999
(Quadrillion Btu)

Year	Fossil Fuels: Coal	Fossil Fuels: Coal Coke Net Imports	Fossil Fuels: Natural Gas [1]	Fossil Fuels: Petroleum [2]	Fossil Fuels: Total Fossil Fuels	Nuclear Electric Power	Hydroelectric Pumped Storage [3]	Renewable Energy: Conventional Hydroelectric Power [4]	Renewable Energy: Geothermal [5]	Renewable Energy: Wood and Waste [6]	Renewable Energy: Solar	Renewable Energy: Wind	Renewable Energy: Total Renewable Energy	Total [7]
1949	11.981	-0.007	5.145	11.883	29.002	0	[8]	1.449	0	1.549	0	0	2.998	32.000
1950	12.347	0.001	5.968	13.316	31.632	0	[8]	1.440	0	1.562	0	0	3.003	34.635
1951	12.553	-0.021	7.049	14.428	34.008	0	[8]	1.454	0	1.535	0	0	2.988	36.996
1952	11.308	-0.012	7.550	14.956	33.800	0	[8]	1.496	0	1.474	0	0	2.970	36.770
1953	11.373	-0.009	7.907	15.556	34.828	0	[8]	1.439	0	1.419	0	0	2.857	37.684
1954	9.716	-0.007	8.330	15.839	33.877	0	[8]	1.388	0	1.394	0	0	2.783	36.660
1955	11.167	-0.010	8.998	17.255	37.410	0	[8]	1.407	0	1.424	0	0	2.832	40.242
1956	11.350	-0.013	9.614	17.937	38.888	0	[8]	1.487	0	1.416	0	0	2.903	41.791
1957	10.821	-0.017	10.191	17.932	38.926	(s)	[8]	1.557	0	1.334	0	0	2.890	41.818
1958	9.533	-0.007	10.663	18.527	38.717	0.002	[8]	1.629	0	1.323	0	0	2.952	41.670
1959	9.518	-0.008	11.717	19.323	40.550	0.002	[8]	1.587	0	1.353	0	0	2.940	43.493
1960	9.838	-0.006	12.385	19.919	42.137	0.006	[8]	1.657	0.001	1.320	0	0	2.977	45.120
1961	9.623	-0.008	12.926	20.216	42.758	0.020	[8]	1.680	0.002	1.295	0	NA	2.977	45.755
1962	9.906	-0.008	13.731	21.049	44.681	0.026	[8]	1.822	0.002	1.300	0	NA	3.124	47.832
1963	10.413	-0.007	14.403	21.701	46.509	0.038	[8]	1.772	0.004	1.323	0	NA	3.099	49.647
1964	10.964	-0.010	15.288	22.301	48.543	0.040	[8]	1.907	0.005	1.337	0	NA	3.248	51.831
1965	11.581	-0.018	15.769	23.246	50.577	0.043	[8]	2.058	0.004	1.335	0	NA	3.397	54.016
1966	12.143	-0.025	16.995	24.401	53.514	0.064	[8]	2.073	0.004	1.369	0	NA	3.446	57.024
1967	11.914	-0.015	17.945	25.284	55.127	0.088	[8]	2.344	0.007	1.340	0	NA	3.691	58.906
1968	12.331	-0.017	19.210	26.979	58.502	0.142	[8]	2.342	0.009	1.419	0	NA	3.771	62.415
1969	12.382	-0.036	20.678	28.338	61.362	0.154	[8]	2.659	0.013	1.440	0	NA	4.113	65.628
1970	12.265	-0.058	21.795	29.521	63.522	0.239	[8]	2.654	0.011	R1.429	0	NA	R4.094	R67.856
1971	11.598	-0.033	22.469	30.561	64.596	0.413	[8]	2.861	0.012	R1.430	0	NA	R4.303	R69.312
1972	12.077	-0.026	22.698	32.947	67.696	0.584	[8]	2.944	0.031	R1.501	0	NA	R4.476	R72.756
1973	12.971	-0.007	22.512	34.840	70.316	0.910	[8]	3.010	0.043	R1.527	0	NA	R4.579	R75.808
1974	12.663	0.058	21.732	33.455	67.906	1.272	[8]	3.309	0.053	R1.538	0	NA	R4.900	R74.078
1975	12.663	0.014	19.948	32.731	65.355	1.900	[8]	3.219	0.070	R1.497	0	NA	R4.786	R72.041
1976	13.584	(s)	20.345	35.175	69.104	2.111	[8]	3.066	0.078	R1.711	0	NA	R4.855	R76.070
1977	13.922	0.015	19.931	37.122	70.989	2.702	[8]	2.515	0.077	R1.837	0	NA	R4.429	R78.120
1978	13.766	0.125	20.000	37.965	71.856	3.024	[8]	3.141	0.064	R2.036	0	NA	R5.242	R80.122
1979	15.040	0.063	20.666	37.123	72.892	2.776	[8]	3.141	0.084	R2.150	0	NA	R5.375	R81.042
1980	15.423	-0.035	20.394	34.202	69.984	2.739	[8]	3.118	0.110	R2.483	0	NA	R5.710	R78.434
1981	15.908	-0.016	19.928	31.931	67.750	3.008	[8]	3.105	0.123	2.590	0	NA	5.818	76.569
1982	15.322	-0.022	18.505	30.232	64.037	3.131	[8]	3.572	0.105	R2.615	0	NA	R6.292	R73.441
1983	15.894	-0.016	17.357	30.054	63.290	3.203	[8]	3.899	0.129	2.831	0	(s)	6.860	73.317
1984	17.071	-0.011	18.507	31.051	66.617	3.553	[8]	3.800	0.165	2.880	0	(s)	6.845	76.972
1985	17.478	-0.013	17.834	30.922	66.221	4.149	[8]	3.398	0.198	R,[9]2.862	0	(s)	R,[9]6.458	R,[9]76.777
1986	17.260	-0.017	16.708	32.196	66.148	4.471	[8]	3.446	0.219	R,[9]2.840	0	(s)	R,[9]6.506	R,[9]77.065
1987	18.008	0.009	17.744	32.865	68.626	4.906	[8]	3.117	0.229	R2.822	0	(s)	R6.169	R79.633
1988	18.846	0.040	18.552	34.222	71.660	5.661	[8]	2.662	0.217	R,[9]2.940	0	(s)	R,[9]5.819	R,[9]83.071
1989	18.926	0.030	19.384	34.211	72.551	5.677	[8]	R,[10]2.999	R,[10]0.338	R,[10]3.050	R,[10]0.059	R,[10]0.024	R,[10]6.470	R,[10]84.593
1990	19.101	0.005	19.296	33.553	71.955	R6.162	-0.036	R,[11]3.140	R0.359	R2.665	0.063	R0.032	R6.260	R84.186
1991	18.770	R0.010	19.606	32.845	R71.231	R6.580	-0.047	R3.222	R0.368	R2.679	0.068	R0.032	R6.367	R84.063
1992	[12]19.158	R0.035	20.131	33.527	R,[12]72.850	R6.608	-0.043	2.863	0.379	R2.826	0.068	0.030	R6.167	R,[11]85.512
1993	19.776	R0.027	20.827	33.841	R74.471	R6.520	-0.042	3.147	0.393	R2.782	0.071	0.031	R6.424	87.309
1994	19.960	R0.058	21.288	R34.670	R75.976	R6.838	-0.035	2.971	0.395	R2.914	0.072	0.036	R6.387	R89.234
1995	20.024	R0.061	22.163	R34.553	R76.802	7.177	-0.028	3.474	0.339	R3.044	0.073	0.033	R6.963	R90.940
1996	20.940	R0.023	R22.559	R35.757	R79.279	7.168	-0.032	R3.915	0.352	R3.104	0.075	0.035	R7.482	R93.911
1997	21.444	R0.046	R22.530	R36.266	R80.286	6.678	-0.042	R3.940	R0.328	R2.982	0.074	R0.034	R7.358	R94.316
1998	R21.593	R0.067	R21.921	R36.934	R80.515	7.157	-0.048	R3.552	R0.335	R2.991	0.074	R0.031	R6.984	R94.570
1999P	21.698	0.058	22.096	37.708	81.557	7.733	-0.063	3.417	0.327	3.514	0.076	0.038	7.373	96.596

[1] Includes supplemental gaseous fuels.
[2] Petroleum products supplied, including natural gas plant liquids and crude oil burned as fuel.
[3] Represents total pumped storage facility production minus energy used for pumping.
[4] Through 1988, includes all net imports of electricity. From 1989, includes only the portion of net imports of electricity that is derived from hydroelectric power.
[5] Includes electricity imports from Mexico that are derived from geothermal energy.
[6] Values are estimated. For all years, includes wood consumption in all sectors (see Table 10.4). Beginning in 1970, includes electric utility waste consumption (see Table 8.3). Beginning in 1981, includes industrial sector waste consumption, and transportation sector use of ethanol blended into motor gasoline (see Table 10.3). Beginning in 1989, includes expanded coverage of nonutility wood and waste consumption (see Table 8.4).
[7] From 1989, includes net imported electricity from nonrenewable sources and removes ethanol blended into motor gasoline, which would otherwise be double counted in both petroleum and renewable energy.
[8] Through 1989, pumped storage is included in conventional hydroelectric power
[9] Not all data were available; therefore, values were interpolated.
[10] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989. See Tables 10.1 and 10.2.
[11] There is a discontinuity in this time series between 1989 and 1990; beginning in 1990, pumped storage is removed and expanded coverage of use of hydroelectric power is included.
[12] Independent power producers' use of coal is included beginning in 1992. See Table 7.3.
R=Revised. P=Preliminary. (s)=Less than 0.0005 and greater than -0.0005 quadrillion Btu. NA=Not available.
Note: Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/fueloverview.html.
Sources: See end of section.

Figure 1.4 Energy Imports, Exports, and Net Imports, 1949-1999



Notes: • Negative net imports are net exports. • Because vertical scales differ, graphs should not be compared.

Source: Table 1.4.

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Table 1.4 Energy Imports, Exports, and Net Imports, 1949-1999
(Quadrillion Btu)

Year	Imports					Exports					Net Imports				
	Coal	Natural Gas (Dry)	Petroleum [1]	Other [2]	Total	Coal	Natural Gas (Dry)	Petroleum	Other [2]	Total	Coal	Natural Gas (Dry)	Petroleum [1]	Other [2]	Total
1949	0.01	0.00	1.43	0.03	1.47	0.88	0.02	0.68	0.02	1.59	-0.87	-0.02	0.75	0.02	-0.13
1950	0.01	0.00	1.89	0.04	1.93	0.79	0.03	0.84	0.01	1.47	-0.78	-0.03	1.24	0.03	0.47
1951	0.01	0.00	1.87	0.04	1.92	1.68	0.03	0.89	0.03	2.62	-1.67	-0.03	0.98	0.01	-0.71
1952	0.01	0.01	2.11	0.04	2.17	1.40	0.03	0.91	0.02	2.37	-1.40	-0.02	1.20	0.02	-0.20
1953	0.01	0.01	2.28	0.04	2.34	0.98	0.03	0.84	0.02	1.87	-0.97	-0.02	1.44	0.02	0.47
1954	0.01	0.01	2.32	0.04	2.37	0.91	0.03	0.75	0.01	1.70	-0.91	-0.02	1.58	0.02	0.67
1955	0.01	0.01	2.75	0.06	2.83	1.46	0.03	0.77	0.02	2.29	-1.46	-0.02	1.98	0.04	0.54
1956	0.01	0.01	3.17	0.08	3.25	1.98	0.04	0.91	0.02	2.95	-1.98	-0.03	2.28	0.04	0.30
1957	0.01	0.04	3.46	0.06	3.57	2.17	0.04	1.20	0.03	3.45	-2.16	(s)	2.28	0.02	0.12
1958	0.01	0.14	3.72	0.05	3.92	1.42	0.04	0.58	0.02	2.06	-1.41	0.10	3.14	0.03	1.86
1959	0.01	0.14	3.91	0.05	4.11	1.05	0.02	0.46	0.02	1.54	-1.04	0.12	3.46	0.03	2.57
1960	0.01	0.16	4.00	0.06	4.23	1.02	0.01	0.43	0.02	1.48	-1.02	0.15	3.57	0.04	2.74
1961	(s)	0.23	4.19	0.04	4.46	0.98	0.01	0.37	0.02	1.38	-0.98	0.22	3.82	0.02	3.08
1962	0.01	0.42	4.56	0.03	5.01	1.08	0.02	0.36	0.03	1.48	-1.08	0.40	4.20	(s)	3.53
1963	0.01	0.42	4.65	0.03	5.10	1.36	0.02	0.44	0.03	1.85	-1.35	0.40	4.21	-0.01	3.25
1964	0.01	0.46	4.96	0.07	5.49	1.34	0.02	0.43	0.06	1.84	-1.33	0.44	4.53	0.01	3.65
1965	(s)	0.47	5.40	0.04	5.92	1.38	0.03	0.39	0.06	1.85	-1.37	0.44	5.01	-0.02	4.06
1966	(s)	0.50	5.63	0.05	6.18	1.35	0.03	0.41	0.06	1.85	-1.35	0.47	5.21	-0.01	4.32
1967	0.01	0.58	5.56	0.04	6.19	1.35	0.08	0.85	0.06	2.15	-1.35	0.50	4.91	-0.02	4.04
1968	0.01	0.67	6.21	0.04	6.93	1.38	0.10	0.49	0.06	2.03	-1.37	0.58	5.73	-0.02	4.90
1969	(s)	0.75	6.90	0.06	7.71	1.53	0.05	0.49	0.08	2.15	-1.53	0.70	6.42	-0.02	5.56
1970	(s)	0.85	7.47	0.07	8.39	1.94	0.07	0.55	0.11	2.68	-1.93	0.77	6.92	-0.04	5.72
1971	(s)	0.96	8.54	0.08	9.58	1.55	0.06	0.47	0.07	2.18	-1.54	0.88	8.07	(s)	7.41
1972	(s)	1.05	10.30	0.11	11.46	1.53	0.08	0.47	0.06	2.14	-1.53	0.97	9.83	0.05	9.32
1973	(s)	1.06	13.47	0.20	14.73	1.43	0.08	0.49	0.06	2.05	-1.42	0.98	12.98	0.14	12.68
1974	0.05	0.99	13.13	0.25	14.41	1.62	0.08	0.48	0.06	2.22	-1.57	0.91	12.66	0.19	12.19
1975	0.02	0.98	12.95	0.16	14.11	1.76	0.07	0.44	0.08	2.36	-1.74	0.90	12.51	0.08	11.75
1976	0.03	0.99	15.67	0.15	16.84	1.60	0.07	0.47	0.06	2.19	-1.57	0.92	15.20	0.09	14.65
1977	0.04	1.04	18.76	0.26	20.09	1.44	0.06	0.51	0.06	2.07	-1.40	0.98	18.24	0.20	18.02
1978	0.07	0.99	17.82	0.36	19.25	1.08	0.05	0.77	0.03	1.93	-1.00	0.94	17.06	0.33	17.32
1979	0.05	1.30	17.93	0.33	19.62	1.75	0.06	1.00	0.06	2.87	-1.70	1.24	16.93	0.27	16.75
1980	0.03	1.01	14.66	0.28	15.97	2.42	0.05	1.16	0.09	3.72	-2.39	0.96	13.50	0.18	12.25
1981	0.03	0.92	12.64	0.39	13.97	2.94	0.06	1.26	0.06	4.33	-2.92	0.86	11.38	0.33	9.65
1982	0.02	0.95	10.78	0.35	12.09	2.79	0.05	1.73	0.06	4.63	-2.77	0.90	9.05	0.28	7.46
1983	0.03	0.94	10.65	0.41	12.03	2.04	0.06	1.57	0.05	3.72	-2.01	0.89	9.08	0.36	8.31
1984	0.03	0.85	11.43	0.46	12.77	2.15	0.06	1.54	0.05	3.80	-2.12	0.79	9.89	0.40	8.96
1985	0.05	0.95	10.61	0.49	12.10	2.44	0.06	1.66	0.08	4.23	-2.39	0.90	8.95	0.41	7.87
1986	0.06	0.75	13.20	0.43	14.44	2.25	0.06	1.67	0.08	4.06	-2.19	0.69	11.53	0.36	10.38
1987	0.04	0.99	14.16	0.57	15.76	2.09	0.05	1.63	0.08	3.85	-2.05	0.94	12.53	0.49	11.91
1988	0.05	1.30	15.75	0.47	17.56	2.50	0.07	1.74	0.10	4.42	-2.45	1.22	14.01	0.37	13.15
1989	0.07	1.39	17.16	0.34	18.96	2.64	0.11	1.84	0.18	4.77	-2.57	1.28	15.33	0.15	14.19
1990	0.07	1.55	17.12	R0.22	R18.95	2.77	0.09	1.82	R0.18	R4.87	-2.70	1.46	15.29	0.03	R14.09
1991	0.08	1.80	16.35	R0.27	R18.50	2.85	0.13	2.13	R0.04	R5.18	-2.77	1.67	14.22	R0.22	R13.34
1992	0.10	2.16	16.97	R0.35	R19.58	2.68	0.22	2.01	R0.05	R4.96	-2.59	1.94	14.96	R0.31	R14.62
1993	R0.20	2.40	18.51	R0.39	R21.50	1.96	0.14	2.12	R0.06	R4.28	R-1.76	2.25	16.40	0.32	R17.22
1994	R0.22	2.68	R19.24	R0.58	R22.73	1.88	0.16	1.99	R0.05	R4.08	R-1.66	2.52	17.26	R0.53	R18.65
1995	R0.24	2.90	18.88	R0.55	R22.54	2.32	0.16	1.99	R0.07	R4.54	R-2.08	2.74	16.87	R0.47	R18.00
1996	R0.20	3.00	20.27	0.52	R23.99	2.37	0.16	2.06	R0.07	R4.66	R-2.17	2.85	18.21	R0.45	R19.33
1997	0.19	3.06	R21.74	R0.52	R25.52	2.19	0.16	2.10	R0.12	R4.57	-2.01	2.90	R19.64	R0.40	R20.94
1998	0.22	R3.22	R22.91	R0.50	R26.86	R2.05	0.16	R1.97	R0.16	R4.34	R-1.83	R3.06	R20.94	R0.34	R22.51
1999P	0.23	3.64	22.53	0.52	26.92	1.53	0.16	1.96	0.17	3.82	-1.31	3.48	20.57	0.36	23.10

[1] Includes imports into the Strategic Petroleum Reserve, which began in 1977.
[2] Coal coke and small amounts of electricity transmitted across U.S. borders with Canada and Mexico.
R=Revised. P=Preliminary. (s)=Less than 0.005 quadrillion Btu and greater than -0.005 quadrillion Btu.
Notes: • Includes trade between the United States (50 States and the District of Columbia) and its territories and possessions. • Totals or net import items may not equal sum of components due to independent rounding.
Sources: Tables 5.1, 5.5, 6.1, 7.1, 7.7, and 8.1, and conversion factors in Appendix A.

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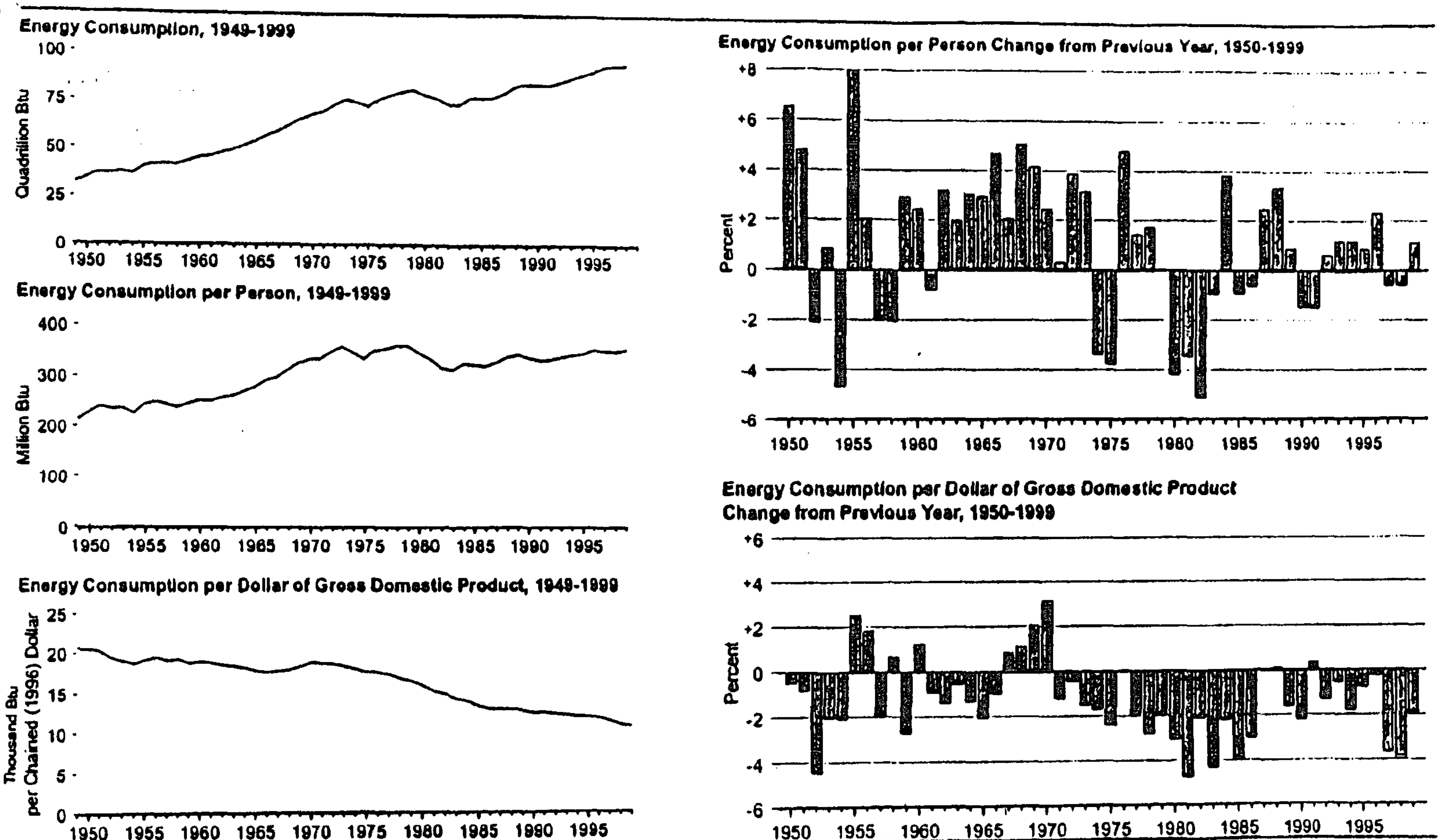
Figure 1.5 Energy Consumption per Person and per Dollar of Gross Domestic Product



Note: There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989.

Source: Table 1.5.

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Table 1.5 Energy Consumption per Person and per Dollar of Gross Domestic Product, 1949-1999

Year	Total Energy Consumption (quadrillion Btu)	Per Person Indicator: Population [1] (million people)	Per Person Indicator: Energy Consumption per Person (million Btu)	Per Person Indicator: Change from Previous Year (percent) [2]	Gross Domestic Product (GDP) Indicator: GDP (billion chained (1996) dollars)	Gross Domestic Product (GDP) Indicator: Energy Consumption per Dollar of GDP (thousand Btu per chained (1996) dollar)	Gross Domestic Product (GDP) Indicator: Changed from Previous year (percent) [2]
1949	32.00	148.7	215	—	R1,560.9	R20.63	—
1950	34.63	151.3	229	6.5	R1,686.6	R20.54	R-0.4
1951	37.00	154.0	240	4.8	R1,815.1	R20.38	R-0.8
1952	36.77	156.4	235	-2.1	R1,887.3	R19.48	R-4.4
1953	37.68	159.0	237	0.9	R1,973.9	R19.09	-2.0
1954	36.68	161.9	226	-4.6	R1,960.5	R18.70	-2.0
1955	40.24	165.1	244	8.0	R2,099.5	R19.17	2.5
1956	41.79	168.1	249	2.0	R2,141.1	R19.52	1.8
1957	41.82	171.2	244	-2.0	R2,183.9	R19.15	R-1.9
1958	41.67	174.1	239	-2.0	R2,162.8	R19.27	0.6
1959	43.49	177.1	246	2.9	R2,319.0	R18.75	R-2.7
1960	45.12	179.3	252	2.4	R2,376.7	R18.98	R1.2
1961	45.76	183.0	250	-0.8	R2,432.0	R18.81	-0.9
1962	47.83	185.7	258	3.2	R2,578.9	R18.55	R-1.4
1963	49.65	188.4	263	1.9	R2,690.4	R18.45	R-0.5
1964	51.83	191.1	271	3.0	R2,846.5	R18.21	-1.3
1965	54.02	193.5	279	3.0	R3,028.5	R17.84	-2.0
1966	57.02	195.5	292	4.7	R3,227.5	R17.67	R-1.0
1967	58.91	197.4	298	2.1	R3,308.3	R17.81	0.8
1968	62.41	199.3	313	5.0	R3,466.1	R18.01	R1.1
1969	65.63	201.3	326	4.2	R3,571.4	R18.38	2.1
1970	67.86	203.3	334	2.5	R3,578.0	R18.96	R3.2
1971	69.31	206.8	336	0.3	R3,697.7	R18.74	R-1.2
1972	72.76	209.3	348	3.9	R3,898.4	R18.66	R-0.4
1973	75.81	211.4	359	3.2	R4,123.4	R18.38	-1.5
1974	74.08	213.3	347	-3.3	R4,099.0	R18.07	-1.7
1975	72.04	215.5	334	-3.7	R4,084.4	R17.64	R-2.4
1976	76.07	217.6	350	4.8	R4,311.7	R17.64	0.0
1977	78.12	219.8	355	1.4	R4,511.8	R17.31	-1.9
1978	80.12	222.1	361	1.7	R4,760.6	R16.83	R-2.8
1979	81.04	224.6	361	0.0	R4,912.1	R16.50	R-2.0
1980	R78.43	226.5	346	-4.2	R4,900.9	R16.00	R-3.0
1981	76.57	229.5	334	-3.5	R5,021.0	R15.25	R-4.7
1982	73.44	231.7	317	-5.1	R4,919.3	R14.93	R-2.1
1983	73.32	233.8	314	-0.9	R5,132.3	R14.29	R-4.3
1984	76.97	235.8	326	3.8	R5,505.2	R13.98	R-2.2
1985	R76.78	237.9	323	-0.9	R5,717.1	R13.43	R-3.9
1986	R77.06	240.1	321	-0.6	R5,912.4	R13.03	R-3.0
1987	R79.63	242.3	329	2.5	R6,113.3	R13.03	0.0
1988	R83.07	244.5	340	3.3	R6,368.4	R13.04	R0.1
1989	R,3 84.59	246.8	R,3 343	[3]0.9	R6,591.8	R,3 12.83	R,3 -1.6
1990	R84.19	248.8	338	R-1.5	R6,707.9	R12.55	R-2.2
1991	R84.06	R252.2	333	-1.5	R6,676.4	R12.59	R0.3
1992	R85.51	255.0	335	0.6	R6,880.0	R12.43	R-1.3
1993	87.31	R257.8	339	1.2	R7,062.6	R12.36	R-0.6
1994	R89.23	260.3	343	1.2	R7,347.7	R12.14	R-1.8
1995	R90.94	262.8	346	0.9	R7,543.8	R12.05	R-0.7
1996	R93.91	265.2	354	2.3	R7,813.2	R12.02	-0.2
1997	R94.32	R267.8	352	-0.6	R8,144.8	R11.58	R-3.7
1998	R94.57	R270.2	R350	R-0.6	R8,495.7	R11.13	-3.9
1999P	96.60	272.7	354	1.1	8,848.2	10.92	-1.9

[1] Resident population of the 50 States and the *District of Columbia* estimated for July 1 of each year, except for the April 1 census count in 1950, 1960, 1970, 1980, and 1990.
[2] Percent change calculated from data prior to rounding.
[3] *There is a discontinuity in this time series between* 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989.

R=Revised. P=Preliminary. — = Not applicable.
Note: See "*Chained Dollars*" in the Glossary.
Sources: Total Energy Consumption: Table 1.3. Population: *Table E1*. *Gross Domestic Product:* Table E1. Energy Consumption per Person and Energy Consumption per Dollar GDP: calculated by Energy Information Administration.

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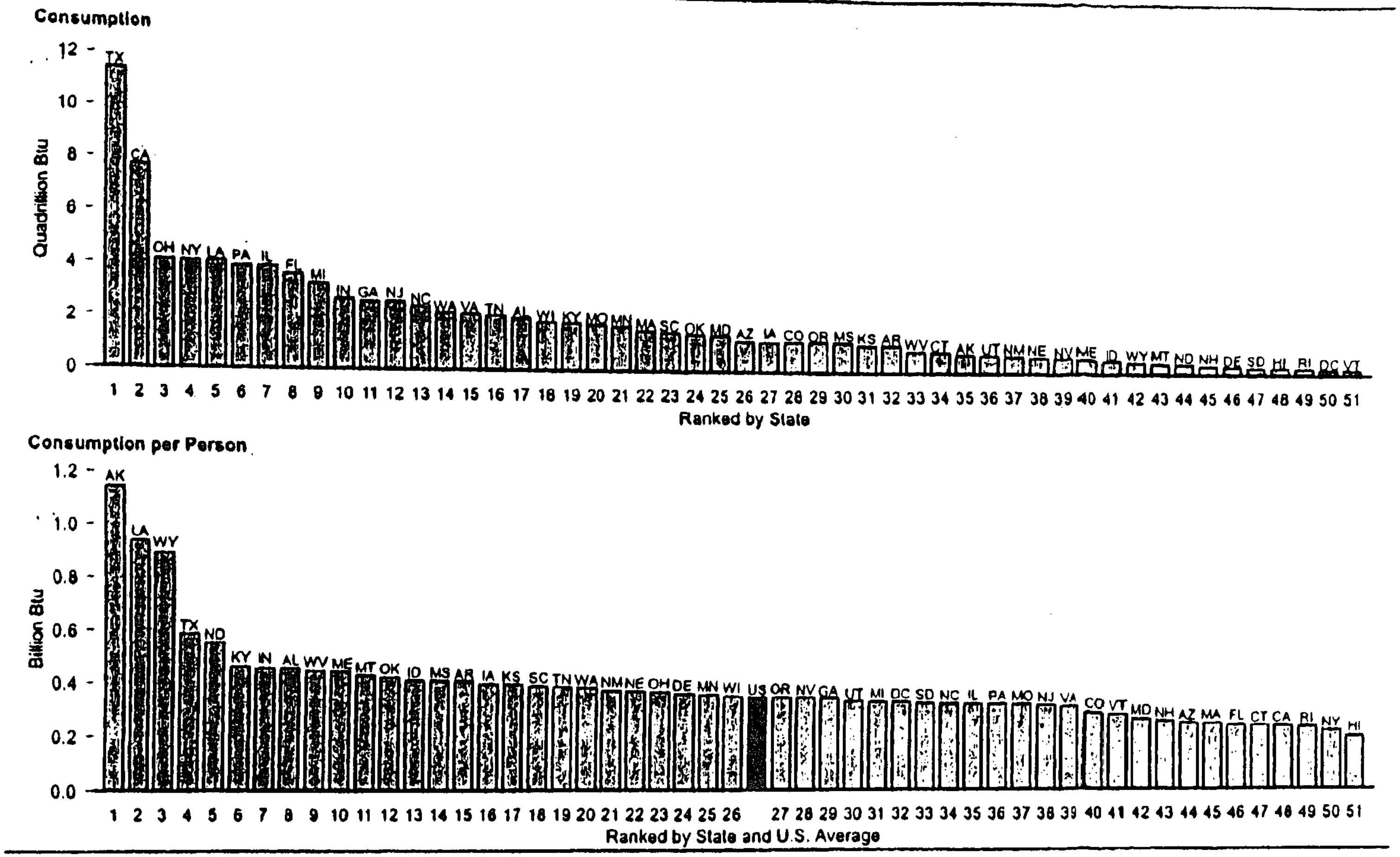
Figure 1.6. State-Level Energy Consumption and Consumption per Person, 1997



Source: Table 1.6.

Table 1.6 State-Level Energy Consumption, Expenditures, and Prices, 1997

Rank	Consumption		Consumption per Person		Expenditures		Expenditures per Person		Prices	
	State	Trillion Btu	State	Million Btu	State	Million Dollars	State	Dollars	State	Dollars per Million Btu
1	Texas	11,398.1	Alaska	1,143.5	California	56,187	Wyoming	3,902	Hawaii	13.34
2	California	7,727.5	Louisiana	940.0	Texas	55,070	Alaska	3,575	District of Columbia	12.84
3	Ohio	4,144.3	Wyoming	892.2	New York	34,089	Louisiana	3,473	Connecticut	12.56
4	New York	4,093.2	Texas	587.8	Pennsylvania	25,810	Texas	2,841	Arizona	11.75
5	Louisiana	4,093.0	North Dakota	554.9	Ohio	25,558	North Dakota	2,651	New Hampshire	11.58
6	Pennsylvania	3,900.7	Kentucky	462.8	Florida	25,117	Maine	2,543	Vermont	11.36
7	Illinois	3,900.2	Indiana	457.5	Illinois	25,089	District of Columbia	2,518	Massachusetts	11.35
8	Florida	3,814.7	Alabama	457.3	Michigan	19,758	Montana	2,471	New York	11.18
9	Michigan	3,269.1	West Virginia	445.6	New Jersey	18,764	Indiana	2,405	Rhode Island	11.04
10	Indiana	2,683.6	Maine	445.3	North Carolina	15,823	Iowa	2,330	Florida	10.99
11	Georgia	2,588.4	Montana	429.4	Georgia	15,642	New Jersey	2,329	Maryland	10.27
12	New Jersey	2,585.4	Oklahoma	422.9	Louisiana	15,120	Vermont	2,324	California	10.27
13	North Carolina	2,425.2	Idaho	411.6	Indiana	14,108	Kentucky	2,313	North Carolina	10.11
14	Washington	2,164.2	Mississippi	411.2	Virginia	13,451	Arkansas	2,304	Delaware	9.98
15	Virginia	2,126.4	Arkansas	408.1	Massachusetts	13,087	Nebraska	2,302	Nevada	9.81
16	Tennessee	2,084.2	Iowa	397.9	Tennessee	11,604	Delaware	2,301	New Jersey	9.48
17	Alabama	1,977.5	Kansas	397.0	Missouri	11,533	Ohio	2,283	New Mexico	9.45
18	Wisconsin	1,835.4	South Carolina	389.0	Washington	10,330	Alabama	2,271	Pennsylvania	9.32
19	Kentucky	1,809.6	Tennessee	387.8	Wisconsin	10,158	Kansas	2,249	Virginia	9.32
20	Missouri	1,748.9	Washington	385.3	Minnesota	9,889	Connecticut	2,219	Missouri	9.15
21	Minnesota	1,685.8	New Mexico	375.2	Alabama	9,816	South Dakota	2,208	Illinois	9.03
22	Massachusetts	1,534.1	Nebraska	372.3	Maryland	9,583	Oklahoma	2,208	Ohio	9.01
23	South Carolina	1,474.2	Ohio	370.1	Kentucky	9,045	West Virginia	2,204	South Dakota	8.98
24	Oklahoma	1,405.2	Delaware	363.2	Arizona	8,574	Mississippi	2,183	Georgia	8.86
25	Maryland	1,360.0	Minnesota	359.5	South Carolina	8,177	Nevada	2,166	Maine	8.82
26	Arizona	1,152.4	Wisconsin	352.8	Oklahoma	7,333	Tennessee	2,160	South Carolina	8.77
27	Iowa	1,138.4	Oregon	349.1	Connecticut	7,248	South Carolina	2,159	Kansas	8.77
28	Colorado	1,133.4	Nevada	348.0	Colorado	6,881	New Hampshire	2,154	Colorado	8.68
29	Oregon	1,132.9	Georgia	345.4	Iowa	6,849	Pennsylvania	2,149	Arkansas	8.65
30	Mississippi	1,123.7	Utah	334.6	Oregon	6,068	Massachusetts	2,140	Tennessee	8.60
31	Kansas	1,033.1	Michigan	333.1	Mississippi	5,963	Missouri	2,132	Mississippi	8.59
32	Arkansas	1,030.2	District of Columbia	333.1	Kansas	5,850	North Carolina	2,129	Nebraska	8.47
33	West Virginia	809.2	South Dakota	327.7	Arkansas	5,812	Idaho	2,109	Minnesota	8.46
34	Connecticut	795.8	North Carolina	326.2	West Virginia	4,002	Minnesota	2,105	Montana	8.41
35	Alaska	697.3	Illinois	325.2	Nebraska	3,814	Illinois	2,093	Oregon	8.40
36	Utah	691.2	Pennsylvania	324.6	Utah	3,708	Georgia	2,088	Wisconsin	8.25
37	New Mexico	647.1	Missouri	323.2	Nevada	3,637	Rhode Island	2,070	Michigan	8.18
38	Nebraska	617.1	New Jersey	320.7	New Mexico	3,428	Michigan	2,020	Iowa	6.10
39	Nevada	584.4	Virginia	315.4	Maine	3,158	Virginia	1,996	Oklahoma	8.07
40	Maine	553.4	Colorado	291.1	Idaho	2,550	New Mexico	1,988	Idaho	8.01
41	Idaho	497.7	Vermont	283.5	New Hampshire	2,525	Wisconsin	1,953	Alabama	7.81
42	Wyoming	428.3	Maryland	266.8	Hawaii	2,288	Hawaii	1,920	Kentucky	7.72
43	Montana	377.5	New Hampshire	259.0	Alaska	2,180	Arizona	1,883	Washington	7.64
44	North Dakota	355.8	Arizona	252.9	Montana	2,171	Maryland	1,881	Utah	7.58
45	New Hampshire	303.9	Massachusetts	250.6	Rhode Island	2,044	New York	1,879	West Virginia	7.33
46	Delaware	267.2	Florida	248.2	Wyoming	1,873	Oregon	1,868	Indiana	7.31
47	South Dakota	241.9	Connecticut	243.3	North Dakota	1,699	Washington	1,840	Texas	6.94
48	Hawaii	239.5	California	240.0	Delaware	1,692	Utah	1,795	Alaska	6.69
49	Rhode Island	235.1	Rhode Island	237.9	South Dakota	1,629	Colorado	1,768	Wyoming	6.51
50	District of Columbia	176.6	New York	225.3	Vermont	1,368	California	1,715	North Dakota	6.25
51	Vermont	167.1	Hawaii	201.0	District of Columbia	1,334	Florida	1,711	Louisiana	5.81
52	United States	[1]94,063.6	United States	351.2	United States	[2]567,318	United States	2,119	United States	8.82

[1] Includes 18.2 trillion Btu of coal coke net imports, which are not allocated to the States.
[2] Includes $72 million for coal coke net imports, which are not allocated to the States.
Note: Rankings based on unrounded data.
Web Page: http://www.eia.doe.gov/emeu/states/_states.html.
Sources: • Consumption: Energy Information Administration (EIA), *State Energy Data Report 1997, Consumption Estimates* (September 1999), Tables 9 and 10. • Expenditures and Prices: EIA, *State Energy Price and Expenditure Report 1997* (June 2000), Table 1. • Both publications include State-level data by end-use sector and type of energy. Consumption estimates are annual 1960 through 1997, and price and expenditures estimates are annual 1970 through 1997.

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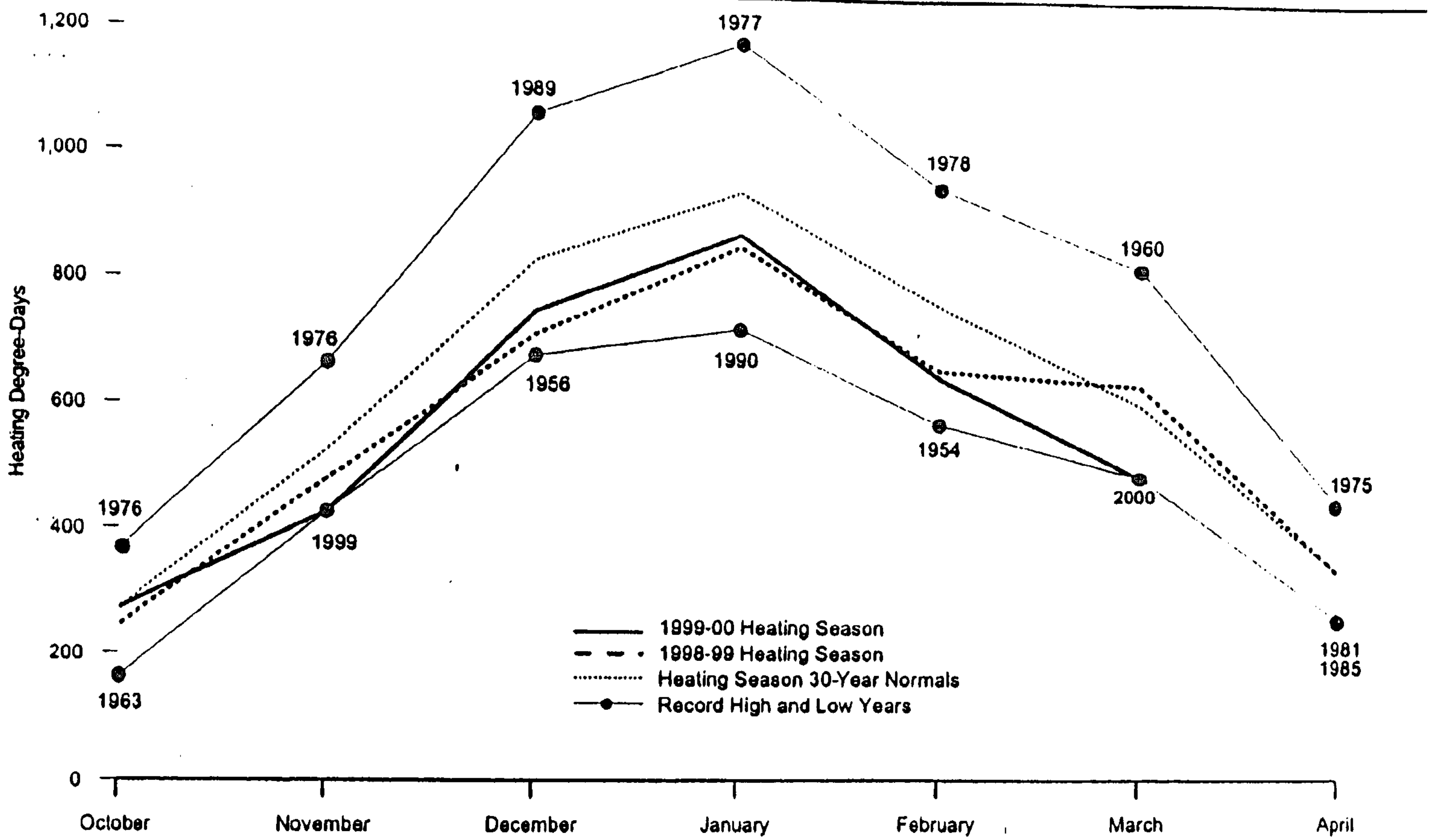
Figure 1.7 Heating Degree-Days by Month, 1949-2000



Source: Table 1.7.

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Table 1.7 Heating Degree-Days by Month, 1949-2000

Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
1949	856	701	611	330	128	21	7	9	94	209	503	763	4,234
1950	761	721	693	412	162	40	11	18	85	196	565	872	4,536
1951	863	724	632	359	135	45	8	17	74	231	645	814	4,547
1952	807	677	670	315	154	32	5	11	54	324	540	785	4,374
1953	754	667	557	378	142	33	5	11	51	208	492	765	4,063
1954	886	577	646	261	192	32	8	18	56	224	523	809	4,232
1955	927	759	600	272	121	48	9	6	56	237	600	886	4,521
1956	900	723	648	387	157	27	10	14	82	215	541	683	4,387
1957	977	628	610	308	148	23	6	16	61	315	536	711	4,339
1958	909	866	690	324	143	54	7	8	60	250	484	917	4,712
1959	944	762	610	305	112	26	4	6	48	249	594	734	4,403
1960	884	780	631	276	160	33	7	11	46	254	502	936	4,724
1961	982	670	565	413	199	29	6	7	46	238	532	852	4,540
1962	978	747	689	337	118	35	14	13	91	234	554	888	4,694
1963	1,061	841	562	325	163	35	8	18	76	162	471	1,012	4,734
1964	871	803	636	339	124	39	5	22	72	301	489	814	4,515
1965	907	780	738	355	114	48	11	14	78	271	494	739	4,549
1966	1,010	790	580	377	188	30	6	14	81	298	496	830	4,700
1967	816	820	600	352	229	34	8	17	82	270	588	793	4,609
1968	979	832	567	309	192	35	6	14	59	240	548	894	4,675
1969	939	778	735	307	134	47	7	9	60	298	564	860	4,738
1970	1,063	758	685	344	120	31	4	9	55	253	541	801	4,664
1971	976	760	681	376	194	29	10	12	47	187	553	723	4,547
1972	890	785	608	377	137	49	7	12	65	330	613	832	4,705
1973	893	772	504	358	182	22	6	9	61	212	497	799	4,313
1974	838	754	556	310	171	42	6	13	94	303	524	795	4,408
1975	821	742	686	449	117	37	5	13	100	235	462	805	4,472
1976	974	609	644	309	176	26	6	19	81	367	668	941	4,728
1977	1,188	751	529	270	119	38	6	13	59	295	493	844	4,606
1978	1,061	958	677	350	157	31	7	11	59	283	517	847	4,958
1979	1,079	950	575	344	148	37	6	15	58	271	528	750	4,781
1980	887	831	680	338	142	49	5	10	54	316	564	831	4,707
1981	984	689	620	260	165	25	6	11	76	327	504	845	4,512
1982	1,067	776	620	408	114	62	7	19	75	264	515	692	4,619
1983	874	708	588	421	189	35	6	5	63	251	509	990	4,627
1984	1,000	646	704	371	172	28	7	7	86	223	565	704	4,514
1985	1,057	807	557	260	123	47	5	17	69	243	508	951	4,642
1986	859	734	542	296	123	30	9	18	76	258	558	793	4,295
1987	920	714	573	309	107	20	8	13	61	345	491	773	4,334
1988	1,004	778	594	344	134	30	3	5	72	352	508	831	4,653
1989	789	832	603	344	163	32	5	14	73	259	542	1,070	4,726
1990	728	655	535	321	184	29	6	10	56	246	457	789	4,016
1991	921	639	564	287	98	30	6	7	69	242	586	751	4,200
1992	852	644	603	345	152	46	14	24	74	301	664	822	4,441
1993	860	827	664	368	128	38	11	9	89	302	580	824	4,700
1994	1,031	813	594	293	174	21	6	16	65	268	479	723	4,483
1995	847	750	558	375	174	31	4	7	77	233	605	872	4,531
1996	945	748	713	360	165	27	8	9	72	276	630	760	4,713
1997	932	672	552	406	198	31	7	16	63	273	592	800	4,542
1998	R765	R623	R598	R331	R109	R41	R4	R5	R33	R245	R482	R717	R3,951
1999P	R881	R664	R642	338	151	52	5	9	67	272	429	755	4,244
2000P	880	652	493	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Normals[1]	948	768	611	339	150	36	7	13	69	271	528	836	4,578

[1] Based on calculations of data from 1961 through 1990.

R=Revised. P=Preliminary. NA=Not available.

Notes: • This table excludes Alaska and Hawaii. • Degree-days are relative measurements of outdoor air temperature. Heating degree-days are deviations of the mean daily temperature below 65° F. For example, a weather station recording a mean daily temperature of 40° F would report 25 heating degree-days. • Temperature information recorded by weather stations is used to calculate State-wide degree-day averages based on resident State population estimated for 1990. The population-weighted State figures are aggregated into Census divisions and the national average.

Sources: • 1949-1998 and Normals—U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), National Climatic Data Center, Asheville, North Carolina. *Historical Climatology Series 5-1*. • 1999 and 2000—Energy Information Administration, *Monthly Energy Review*, June 1999-April 2000 issues, Table 1.11, which reports data from NOAA, National Weather Service Climate Analysis Center, Camp Springs, Maryland.

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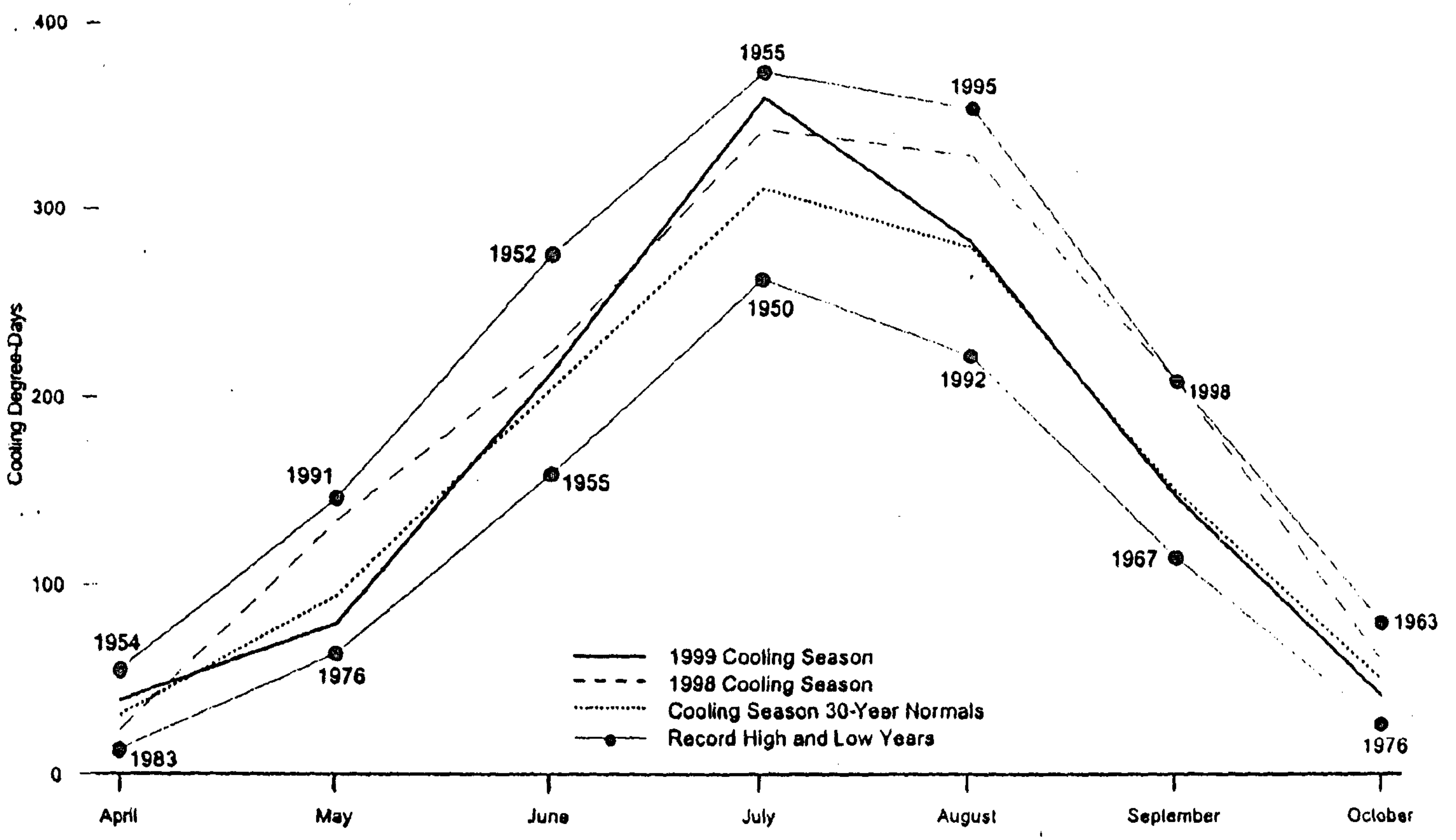
Figure 1.8. Cooling Degree-Days by Month, 1949-1999



Source: Table 1.8.

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Table 1.8 Cooling Degree-Days by Month, 1949-2000

Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
1949	18	14	14	27	110	253	367	294	131	70	12	10	1,318
1950	27	12	13	21	105	201	268	244	128	78	9	4	1,110
1951	8	5	15	22	95	198	316	293	158	65	7	11	1,195
1952	17	8	16	20	98	280	368	303	159	38	10	4	1,318
1953	12	8	28	25	118	263	338	292	168	58	11	7	1,328
1954	11	12	11	55	85	241	356	298	195	60	9	4	1,315
1955	8	7	20	45	121	161	381	355	182	50	10	6	1,344
1956	4	12	14	23	112	232	297	290	151	66	9	11	1,221
1957	12	17	13	33	98	243	337	275	155	30	13	8	1,230
1958	3	1	8	27	101	187	315	304	168	53	18	6	1,189
1959	6	12	13	31	129	228	326	344	179	64	12	5	1,348
1960	7	4	6	37	78	215	301	302	181	59	15	3	1,206
1961	5	9	23	20	71	195	306	287	186	47	12	7	1,168
1962	6	15	9	28	144	204	276	289	136	64	7	3	1,179
1963	5	6	22	42	94	213	308	268	153	83	11	2	1,204
1964	8	3	14	37	114	214	327	256	146	42	17	9	1,185
1965	9	7	10	42	125	179	280	273	155	48	19	6	1,153
1966	4	5	12	28	81	201	353	273	132	43	12	4	1,148
1967	9	5	24	48	70	206	278	253	118	45	12	9	1,077
1968	6	3	9	32	75	204	307	282	145	53	7	4	1,137
1969	7	4	4	33	94	200	331	304	153	46	8	4	1,190
1970	3	4	10	38	104	201	323	313	185	48	6	9	1,242
1971	8	7	10	22	88	244	288	269	182	77	12	17	1,204
1972	15	6	22	38	88	174	299	278	189	44	9	8	1,146
1973	7	3	24	18	75	238	318	303	166	68	21	4	1,241
1974	21	8	28	29	101	173	317	287	120	40	10	5	1,117
1975	14	11	14	24	117	203	301	298	120	55	12	5	1,172
1976	5	11	23	27	64	208	282	243	127	27	8	4	1,029
1977	2	5	21	35	121	212	351	293	180	44	15	8	1,285
1978	3	1	10	31	93	218	310	300	180	52	19	9	1,228
1979	4	4	13	32	82	187	296	268	160	63	11	6	1,113
1980	9	4	13	23	95	199	374	347	192	42	10	6	1,313
1981	3	6	10	52	75	257	333	275	138	43	12	5	1,209
1982	6	10	21	28	116	165	318	262	140	47	15	11	1,136
1983	6	5	9	13	72	193	353	362	172	58	12	5	1,260
1984	5	6	14	24	92	233	291	312	143	70	9	15	1,214
1985	3	5	22	39	108	193	313	269	145	68	25	4	1,194
1986	8	10	17	33	106	231	340	259	161	52	23	9	1,249
1987	5	7	13	23	127	244	334	298	156	40	14	8	1,269
1988	5	6	13	28	89	218	359	348	149	45	18	6	1,283
1989	16	7	19	36	88	206	312	268	138	49	16	2	1,156
1990	15	14	21	29	86	234	318	291	172	57	16	9	1,260
1991	10	9	19	42	147	235	336	305	149	62	8	9	1,331
1992	6	10	15	29	77	170	286	228	150	49	13	7	1,040
1993	13	5	11	19	91	207	347	317	146	47	11	4	1,218
1994	7	8	18	37	76	262	328	263	141	50	20	9	1,220
1995	7	7	18	29	91	202	348	363	160	61	12	5	1,293
1996	7	6	8	28	116	226	299	287	139	45	14	7	1,180
1997	8	11	31	19	81	169	315	268	171	48	10	5	1,156
1998	R12	R7	R10	R23	R135	R228	R350	R337	R215	R62	R20	R11	R1,410
1999P	R6	R9	R9	39	60	217	367	290	151	43	10	5	1,228
2000P	7	9	20	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Normals[1]	7	7	16	31	95	208	317	287	154	52	13	7	1,193

[1] Based on calculations of data from 1961 through 1990.

R=Revised. P=Preliminary. NA=Not available.

Notes: • This table excludes Alaska and Hawaii. • Degree-days are relative measurements of outdoor air temperature. Cooling degree-days are deviations of the mean daily temperature above 65° F. For example, a weather station recording a mean daily temperature of 78° F would report 13 cooling degree-days. • Temperature information recorded by weather stations is used to calculate State-wide degree-day averages based on resident State population estimated for 1990. The population-weighted State figures are aggregated into Census divisions and the national average.

Sources: • 1949-1998 and Normals—U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), National Climatic Data Center, Asheville, North Carolina. *Historical Climatology Series 6-2*. • 1999 and 2000—Energy Information Administration, *Monthly Energy Review*, June 1999-April 2000 issues, Table 1.12, which reports data from NOAA, National Weather Service Climate Analysis Center, Camp Springs, Maryland.

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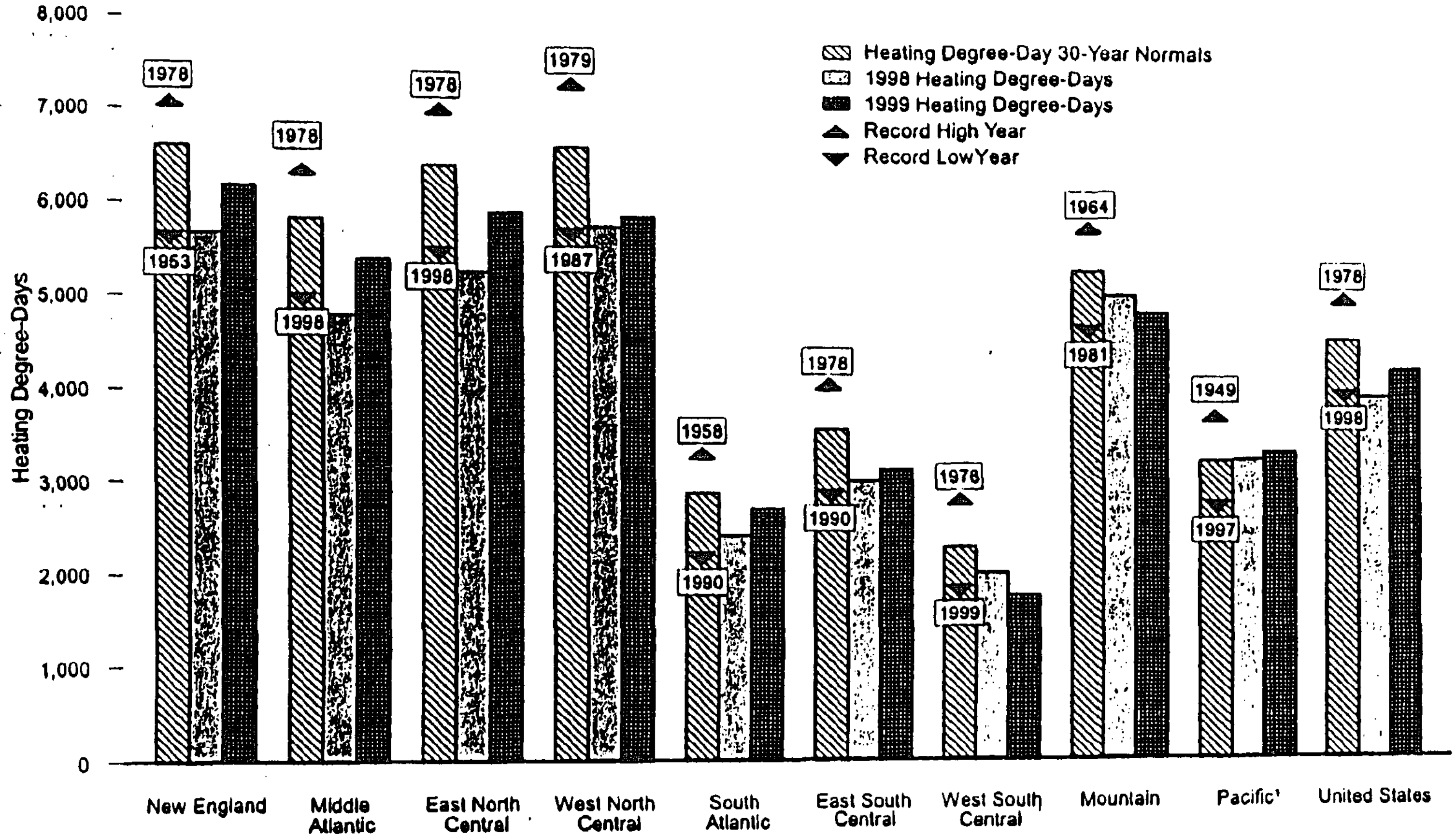
Figure 1.9. Heating Degree-Days by Census Division, 1949-1999



¹ Excludes Alaska and Hawaii.
Note: See Appendix D for Census divisions.

Source: Table 1.9.

DOE024-2196

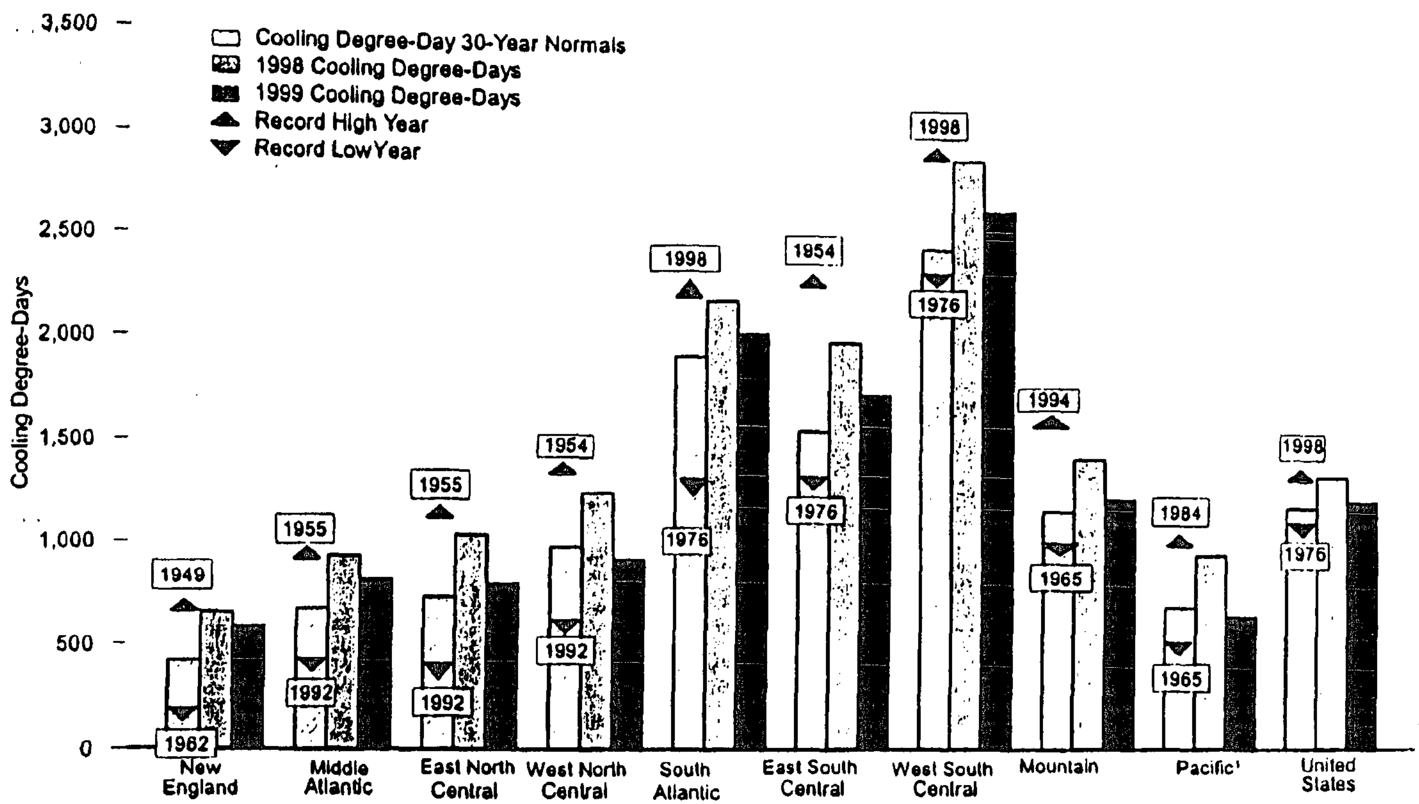
Table 1.9 Heating Degree-Days by Census Division, 1949-1999

Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific [1]	United States [1]
1949	5,829	5,091	5,801	6,479	2,367	2,942	2,133	5,483	3,729	4,234
1950	6,470	5,765	6,619	7,136	2,713	3,315	1,974	4,930	3,355	4,536
1951	6,137	5,497	6,549	7,246	2,726	3,340	2,154	5,513	3,469	4,547
1952	6,180	5,443	5,977	6,386	2,684	3,276	2,074	5,404	3,586	4,374
1953	5,650	5,027	5,626	5,994	2,486	3,132	2,024	4,925	3,224	4,063
1954	6,291	5,473	5,841	6,063	2,713	3,211	1,876	4,679	3,296	4,232
1955	6,577	5,708	6,101	6,630	2,766	3,314	2,083	5,517	3,723	4,521
1956	6,702	5,731	6,019	6,408	2,642	3,113	2,032	5,146	3,382	4,387
1957	6,168	5,469	6,166	6,525	2,594	3,112	2,066	5,203	3,322	4,339
1958	6,907	6,237	6,585	6,585	3,271	4,004	2,690	4,929	2,819	4,712
1959	6,363	5,535	6,303	6,665	2,698	3,415	2,398	5,138	2,925	4,403
1960	6,561	5,901	6,544	6,884	3,147	3,958	2,551	5,328	3,309	4,724
1961	6,632	5,895	6,275	6,591	2,869	3,497	2,296	5,299	3,221	4,540
1962	6,981	6,089	6,545	6,691	3,022	3,627	2,264	5,165	3,400	4,694
1963	6,816	6,103	6,691	6,485	3,138	3,890	2,438	5,060	3,326	4,734
1964	6,594	5,694	6,030	6,303	2,828	3,462	2,272	5,769	3,583	4,515
1965	6,825	5,933	6,284	6,646	2,830	3,374	2,078	5,318	3,378	4,549
1966	6,682	6,012	6,606	6,872	3,118	3,758	2,418	5,275	3,170	4,700
1967	6,987	6,127	6,477	6,569	2,864	3,403	2,082	5,232	3,316	4,609
1968	6,800	5,981	6,331	6,558	3,160	3,927	2,522	5,415	3,198	4,675
1969	6,593	5,933	6,603	6,903	3,205	3,910	2,325	5,324	3,377	4,736
1970	6,839	5,943	6,466	6,835	2,997	3,665	2,396	5,436	3,257	4,664
1971	6,695	5,761	6,236	6,594	2,763	3,395	1,985	5,585	3,698	4,547
1972	7,001	6,064	6,772	7,094	2,759	3,438	2,259	5,352	3,376	4,705
1973	6,120	5,327	5,780	6,226	2,718	3,309	2,256	5,562	3,383	4,313
1974	6,621	5,670	6,259	6,478	2,551	3,171	2,080	5,261	3,294	4,406
1975	6,362	5,477	6,169	6,678	2,640	3,336	2,187	5,693	3,623	4,472
1976	6,839	6,097	6,768	6,870	3,040	3,881	2,446	5,303	3,115	4,726
1977	6,579	5,889	6,538	6,506	3,047	3,612	2,330	5,060	3,135	4,605
1978	7,061	6,330	7,095	7,324	3,187	4,062	2,764	5,370	3,168	4,958
1979	6,348	5,861	6,921	7,369	2,977	3,900	2,694	5,564	3,202	4,781
1980	6,900	6,143	6,792	6,852	3,099	3,855	2,378	5,052	2,986	4,707
1981	6,612	5,989	6,448	6,115	3,177	3,757	2,162	4,671	2,841	4,512
1982	6,697	5,866	6,642	7,000	2,721	3,357	2,227	5,544	3,449	4,619
1983	6,305	5,733	6,423	6,901	3,057	3,892	2,672	5,359	3,073	4,627
1984	6,442	5,777	6,418	6,582	2,791	3,451	2,194	5,592	3,149	4,514
1985	6,571	5,660	6,548	7,119	2,736	3,602	2,466	5,676	3,441	4,642
1986	6,517	5,665	6,150	6,231	2,686	3,294	2,058	4,870	2,807	4,295
1987	6,546	5,699	5,610	5,712	2,937	3,466	2,282	5,153	3,013	4,334
1988	6,715	6,088	6,690	6,634	3,122	3,800	2,348	5,148	2,975	4,653
1989	6,887	6,134	6,834	6,996	2,944	3,713	2,439	5,173	3,061	4,728
1990	5,848	4,998	5,681	6,011	2,230	2,929	1,944	5,146	3,148	4,016
1991	5,960	5,177	5,908	6,319	2,503	3,211	2,178	5,259	3,109	4,200
1992	6,844	5,964	6,297	6,262	2,852	3,498	2,145	5,054	2,763	4,441
1993	6,728	5,948	6,648	7,168	2,981	3,768	2,489	5,514	3,052	4,700
1994	6,672	5,934	6,378	6,509	2,724	3,394	2,108	5,002	3,155	4,483
1995	6,559	5,831	6,664	6,804	2,967	3,626	2,145	4,953	2,784	4,531
1996	6,879	5,986	6,947	7,345	3,106	3,782	2,285	6,011	2,860	4,713
1997	6,662	5,809	6,617	6,762	2,845	3,664	2,418	5,189	2,754	4,542
1998	R5,680	R4,812	R5,278	R5,774	R2,429	R3,025	R2,021	R5,059	R3,255	R3,951
1999P	6,176	5,408	5,913	5,883	2,722	3,162	1,777	4,865	3,339	4,244
Normals[2]	6,621	5,839	6,421	6,635	2,895	3,689	2,306	5,321	3,245	4,576

[1] Excludes Alaska and Hawaii.
[2] Normals are based on calculations of data from 1961 through 1990.
R=Revised. P=Preliminary.
Notes: • Degree-days are relative measurements of outdoor air temperature. Heating degree-days are deviations of the mean daily temperature below 65° F. For example, a weather station recording a mean daily temperature of 40° F would report 25 heating degree-days. • Temperature information recorded by weather stations is used to calculate State-wide degree-day averages based on resident State population estimated for 1990. The population-weighted State figures are aggregated into Census divisions and the national average. • See Appendix D for Census divisions.
Sources: • 1949-1998 and Normals—U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), National Climatic Data Center, Asheville, North Carolina, Historical Climatology Series 5-1. • 1999—Energy Information Administration, *Monthly Energy Review (MER)*, February 1999-January 2000 issues, Table 1.11, which reports data from NOAA, National Weather Service Climate Analysis Center, Camp Springs, Maryland. Census Division data for 1999 are the sums of the current year monthly statistics shown in the cited issues of the *MER*. The U.S. total comes from Table 1.7.

24792

Figure 1.10. Cooling Degree-Days by Census Division, 1949-1999



¹ Excludes Alaska and Hawaii.
Note: See Appendix D for Census divisions.

Source: Table 1.10.

DOE024-2198

Table 1.10 Cooling Degree-Days by Census Division, 1949-1999

Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific [1]	United States [1]
1949	654	901	949	1,038	2,128	1,778	2,510	1,198	593	1,318
1950	353	542	802	729	1,919	1,568	2,473	1,120	597	1,110
1951	400	653	644	777	2,028	1,781	2,684	1,137	593	1,195
1952	581	825	897	1,109	2,097	1,864	2,543	1,278	657	1,318
1953	441	768	946	1,183	2,137	1,893	2,727	1,193	571	1,326
1954	303	648	858	1,250	2,082	1,998	2,907	1,292	590	1,315
1955	602	934	1,043	1,238	2,045	1,791	2,643	1,124	560	1,344
1956	336	566	760	1,155	1,913	1,885	2,833	1,247	596	1,221
1957	428	738	754	1,004	2,050	1,892	2,465	1,155	660	1,230
1958	344	692	838	878	1,922	1,582	2,517	1,328	836	1,189
1959	532	903	997	1,083	2,128	1,745	2,456	1,268	776	1,348
1960	368	640	722	961	1,926	1,813	2,492	1,308	770	1,206
1961	482	787	745	867	1,888	1,370	2,230	1,223	709	1,168
1962	284	561	742	974	1,908	1,738	2,700	1,147	559	1,179
1963	373	571	712	1,196	1,812	1,580	2,899	1,235	605	1,204
1964	312	834	787	1,030	1,905	1,591	2,608	1,095	574	1,185
1965	352	838	888	914	1,931	1,634	2,579	961	542	1,153
1966	421	731	724	919	1,788	1,440	2,309	1,239	680	1,148
1967	420	602	548	713	1,697	1,257	2,385	1,120	817	1,077
1968	410	725	740	902	1,842	1,517	2,247	1,015	832	1,137
1969	447	708	701	940	1,887	1,572	2,505	1,228	680	1,190
1970	479	779	827	1,068	2,007	1,662	2,376	1,163	689	1,242
1971	465	730	783	960	1,932	1,577	2,448	1,074	685	1,204
1972	384	814	643	908	1,843	1,525	2,513	1,141	698	1,146
1973	651	830	884	1,009	2,000	1,665	2,359	1,123	824	1,241
1974	393	814	626	878	1,842	1,382	2,342	1,188	690	1,117
1975	487	708	788	1,003	2,011	1,520	2,261	1,031	547	1,172
1976	402	597	619	939	1,675	1,232	2,035	1,058	620	1,029
1977	407	889	823	1,122	2,020	1,808	2,720	1,256	715	1,285
1978	378	815	741	1,027	1,972	1,685	2,638	1,174	738	1,226
1979	434	588	618	871	1,833	1,412	2,242	1,164	770	1,113
1980	487	793	816	1,217	2,075	1,834	2,734	1,202	658	1,313
1981	436	657	658	924	1,889	1,576	2,490	1,331	876	1,209
1982	321	541	643	859	1,958	1,537	2,502	1,121	819	1,136
1983	538	799	934	1,178	1,925	1,579	2,288	1,174	776	1,260
1984	468	649	724	955	1,866	1,508	2,469	1,190	956	1,214
1985	372	627	643	830	2,004	1,698	2,599	1,210	737	1,194
1986	301	626	738	1,021	2,149	1,792	2,618	1,188	664	1,249
1987	406	729	918	1,116	2,067	1,718	2,368	1,196	706	1,269
1988	545	782	975	1,230	1,923	1,582	2,422	1,320	729	1,283
1989	428	658	662	864	1,977	1,417	2,296	1,330	685	1,156
1990	477	656	647	983	2,143	1,622	2,579	1,294	827	1,260
1991	511	854	959	1,125	2,197	1,758	2,499	1,182	672	1,331
1992	278	460	449	637	1,777	1,293	2,201	1,206	905	1,040
1993	466	764	735	817	2,092	1,622	2,369	1,113	708	1,218
1994	548	722	664	887	2,005	1,448	2,422	1,436	801	1,220
1995	507	803	921	985	2,081	1,671	2,448	1,234	754	1,293
1996	400	623	629	821	1,867	1,474	2,515	1,381	856	1,180
1997	395	586	574	873	1,886	1,393	2,381	1,335	921	1,156
1998	R505	R788	R889	R1,138	R2,277	R1,928	R3,026	R1,271	R732	R1,410
1999P	589	823	803	925	2,038	1,746	2,653	1,235	654	1,228
Normals[2]	421	675	736	981	1,926	1,565	2,460	1,174	694	1,193

[1] Excludes Alaska and Hawaii.
[2] Normals are based on calculations of data from 1961 through 1990.
R=Revised. P=Preliminary.

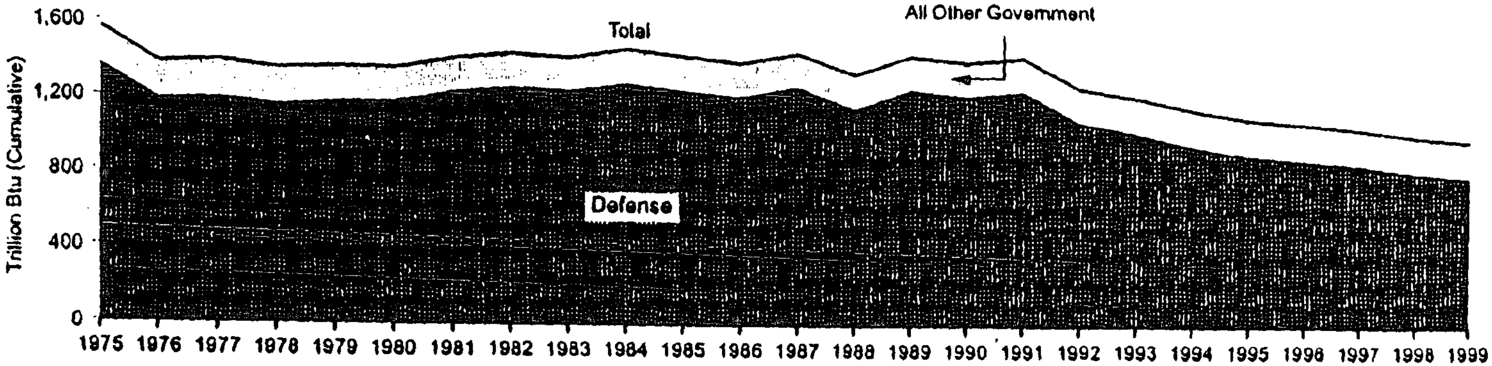
Notes: • Degree-days are relative measurements of outdoor air temperature. Cooling degree-days are deviations of the mean daily temperature above 65° F. For example, a weather station recording a mean daily temperature of 78° F would report 13 cooling degree-days. • Temperature information recorded by weather stations is used to calculate State-wide degree-day averages based on resident State population estimated for 1990. The population-weighted State figures are aggregated into Census divisions and the national average. • See Appendix D for Census divisions.

Sources: • 1949-1998 and Normals—U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), National Climatic Data Center, Asheville, North Carolina. Historical Climatology Series 5-2. • 1999—Energy Information Administration, *Monthly Energy Review*, January 2000 issue, Table 1.12, which reports Census Division data from NOAA, National Weather Service Climate Analysis Center, Camp Springs, Maryland. The U.S. total comes from Table 1.8.

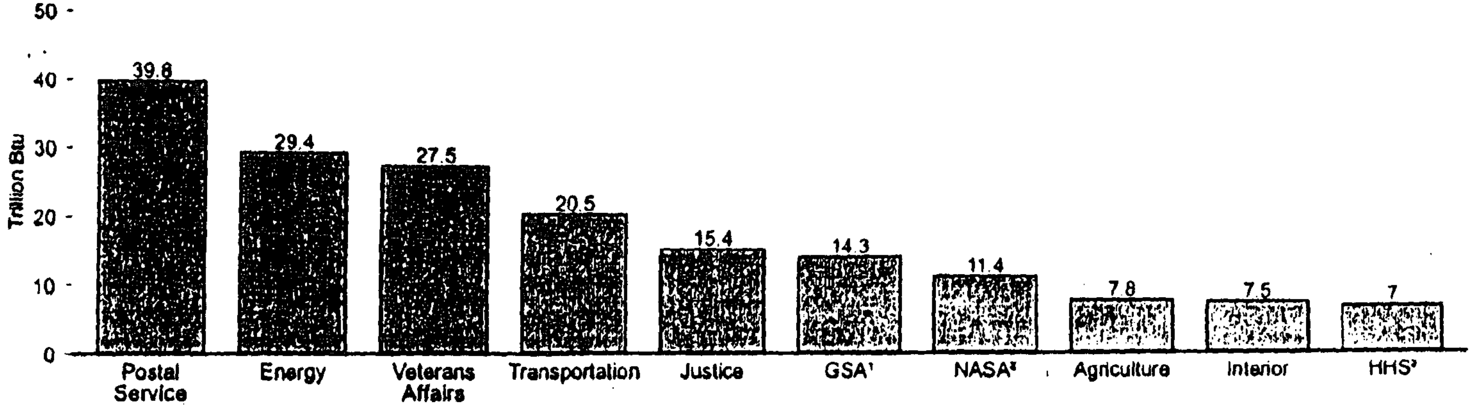
24794

Figure 1.11. U.S. Government Energy Consumption by Agency

Total and U.S. Department of Defense, Fiscal Years 1975-1999



Selected Non-Defense Agencies, Fiscal Year 1999



[1] General Services Administration.
[2] National Aeronautics and Space Administration.
[3] Health and Human Services.

Notes: • The U.S. Government's fiscal year was October 1 through September 30, except in 1975 and 1976 when it was July 1 through June 30. • Because vertical scales differ, graphs should not be compared.
Source: Table 1.11.

DOE024-2200

Table 1.11 U.S. Government Energy Consumption by Agency, Fiscal Years 1975-1999

(Trillion Btu)

	Agencies												
Year	Agriculture	Defense	Energy	GSA [1]	HHS [2]	Interior	Justice	NASA [3]	Postal Service	Trans-portation	Veterans Affairs	Other [4]	Total
1975	9.5	1,360.2	50.4	22.3	6.5	9.4	5.9	13.4	30.5	19.3	27.1	10.6	1,565.0
1976	9.3	1,183.3	50.3	20.6	6.7	9.4	5.7	12.4	30.0	19.5	25.0	11.2	1,383.4
1977	8.9	1,192.3	51.6	20.4	6.9	9.5	5.9	12.0	32.7	20.4	25.9	11.9	1,398.5
1978	9.1	1,157.8	50.1	20.4	6.5	9.2	5.9	11.2	30.9	20.6	26.8	12.4	1,360.9
1979	9.2	1,175.8	49.6	19.6	6.4	10.4	6.4	11.1	29.3	19.6	25.7	12.3	1,375.4
1980	8.6	1,183.1	47.4	18.1	6.0	8.5	5.7	10.4	27.2	19.2	24.8	12.3	1,371.2
1981	7.9	1,239.5	47.3	18.0	6.7	7.6	5.4	10.0	27.9	18.8	24.0	11.1	1,424.2
1982	7.8	1,264.5	49.0	18.1	6.4	7.4	5.8	10.1	27.5	19.1	24.2	11.6	1,451.4
1983	7.4	1,248.3	49.5	16.1	6.2	7.7	6.5	10.3	26.5	19.4	24.1	10.8	1,431.8
1984	7.9	1,292.1	51.6	16.2	6.4	8.4	6.4	10.6	27.7	19.8	24.6	10.7	1,482.5
1985	8.4	1,250.6	R51.5	17.3	R6.0	7.8	8.2	10.8	27.8	R19.5	25.1	11.0	R1,444.0
1986	6.8	1,222.8	50.4	14.0	6.2	6.9	8.6	11.2	28.0	19.4	25.0	10.6	1,410.1
1987	7.3	1,280.5	48.6	13.1	6.6	8.8	8.1	11.1	28.5	19.0	24.9	11.9	1,468.2
1988	7.8	1,165.9	49.9	12.4	6.4	7.0	9.4	R11.1	29.6	16.7	26.3	15.8	R1,360.2
1989	8.7	1,274.4	44.3	12.7	6.7	7.1	7.7	12.1	30.3	16.5	26.2	15.6	R1,464.5
1990	9.5	1,241.7	43.5	14.2	8.0	7.4	7.0	12.3	30.6	19.0	24.9	15.4	1,433.4
1991	9.6	1,269.3	42.2	14.0	7.1	7.1	6.0	R12.5	30.8	19.0	25.1	13.8	1,458.3
1992	9.1	1,104.0	44.3	13.8	8.0	7.0	7.5	12.5	31.7	17.0	25.3	14.0	1,294.3
1993	9.3	1,048.8	43.7	14.1	8.1	7.5	9.1	12.4	33.7	19.4	25.7	14.7	1,246.6
1994	9.4	977.0	42.3	14.0	8.4	7.9	10.3	12.6	35.0	19.8	25.6	17.0	R1,179.2
1995	9.7	926.0	47.1	13.7	6.1	6.4	10.2	12.4	36.2	R18.7	25.4	R17.0	R1,129.7
1996	9.1	904.2	44.4	14.6	6.6	4.3	12.1	11.5	36.4	R19.8	26.8	18.4	R1,107.9
1997	R7.4	880.0	33.9	14.4	7.9	6.6	12.0	12.0	40.8	R19.1	27.3	19.3	R1,080.5
1998	R7.9	R837.1	R31.5	14.1	7.4	R6.4	R15.8	R11.7	R39.5	R18.5	R27.6	R25.0	R1,042.8
1999P	7.8	810.7	29.4	14.3	7.0	7.5	15.4	11.4	39.8	20.5	27.5	25.1	1,016.3

[1] General Services Administration.
[2] Health and Human Services.
[3] *National Aeronautics and Space Administration.*
[4] Includes National Archives and Records Administration, U.S. Department of Commerce, Panama Canal Commission, Tennessee Valley Authority, U.S. Department of Labor, National Science Foundation, Federal Trade Commission, Federal Communications Commission, Environmental Protection Agency, U.S. Department of Housing and Urban Development, Railroad Retirement Board, Commodity Futures Trading Commission, Equal Employment Opportunity Commission, Nuclear Regulatory Commission, U.S. Department of State, U.S. Department of the Treasury, Small Business Administration, Office of Personnel Management, Federal Emergency Management Agency, and U.S. Information Agency.

R = Revised. P = Preliminary.

Notes: • The U.S. Government's fiscal year was October 1 through September 30, except in 1975 and 1976, when it was July 1 through June 30. • Data include energy consumed at foreign installations and in foreign operations, including aviation and ocean bunkering, primarily by the U.S. Department of Defense. U.S. Government energy use for electricity generation and uranium enrichment is excluded. • Totals may not equal sum of components due to independent rounding.

Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Federal Energy Management Programs.

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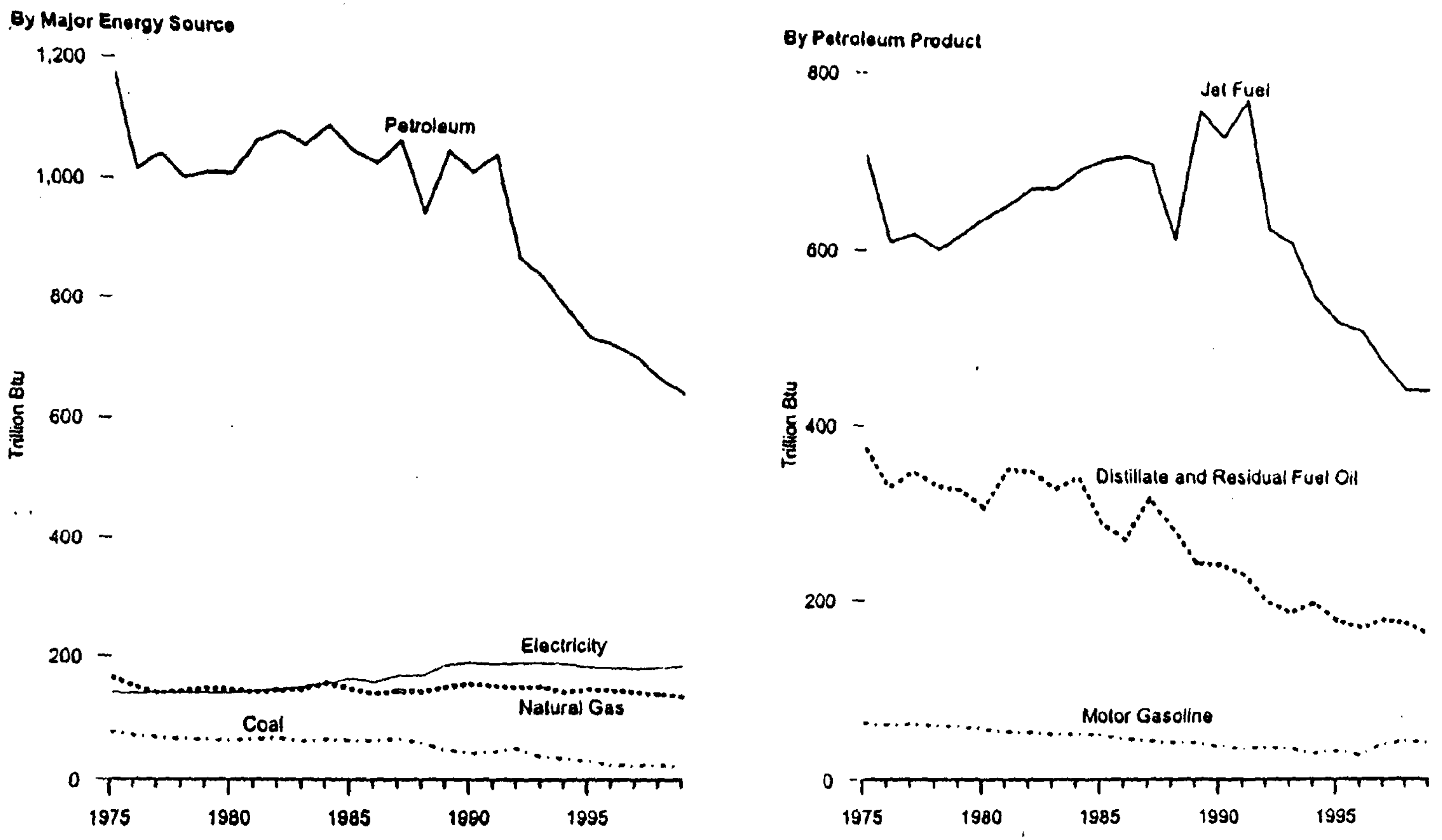
Figure 1.12 U.S. Government Energy Consumption by Source, Fiscal Years 1975-1999



Notes: • The U.S. Government's fiscal year was October 1 through September 30, except in 1975 and 1976 when it was July 1 through June 30. • Because vertical scales differ, graphs should not be compared.

Source: Table 1.12.

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Table 1.12 U.S. Government Energy Consumption by Source, Fiscal Years 1975-1999
(Trillion Btu)

Year	Coal	Natural Gas	Petroleum: Aviation Gasoline	Petroleum: Distillate and Residual Fuel Oil	Petroleum: Jet Fuel	Petroleum: LPG [1] and Other	Petroleum: Motor Gasoline	Petroleum: Total	Electricity	Purchased Steam	Total
1975	77.9	166.2	22.0	376.0	707.4	5.6	63.2	1,174.2	141.5	5.1	1,565.0
1976	71.3	151.8	11.6	329.7	610.0	4.7	60.4	1,016.4	139.3	4.6	1,383.4
1977	68.4	141.2	8.8	348.5	619.2	4.1	61.4	1,042.1	141.1	5.7	1,398.5
1978	66.0	144.7	6.2	332.3	601.1	3.0	60.1	1,002.9	141.0	6.4	1,360.9
1979	65.1	148.9	4.7	327.1	618.6	3.7	59.1	1,013.1	141.2	7.1	1,375.4
1980	63.5	147.3	4.9	307.7	638.7	4.0	56.5	1,011.8	141.9	6.8	1,371.2
1981	65.1	142.2	4.6	351.3	653.3	3.7	53.2	1,066.2	144.5	6.2	1,424.2
1982	68.6	146.2	3.6	349.4	672.7	3.9	53.1	1,082.8	147.5	6.2	1,451.4
1983	62.4	147.8	2.6	329.5	673.4	4.0	51.6	1,061.1	151.5	9.0	1,431.8
1984	65.3	157.4	1.9	342.9	693.7	4.1	51.2	1,093.8	155.9	10.1	1,482.5
1985	64.0	[R]149.2	1.9	[R]290.4	705.7	4.0	50.5	[R]1,052.4	[R]164.5	[R]13.9	[R]1,444.0
1986	63.8	140.9	1.4	271.6	710.2	3.9	45.3	1,032.4	159.2	13.7	1,410.1
1987	67.0	145.6	1.0	319.5	702.3	4.0	43.1	1,069.8	169.9	13.9	1,466.2
1988	60.2	144.6	6.0	284.7	617.2	3.2	41.2	952.3	[R]171.2	32.0	[R]1,360.2
1989	48.7	152.4	0.8	245.1	761.7	5.7	41.1	1,054.4	[R]188.5	20.6	[R]1,464.5
1990	44.2	157.6	0.5	243.7	732.4	6.3	37.2	1,020.1	192.6	18.9	1,433.4
1991	45.9	154.0	0.4	231.9	774.5	9.0	34.1	1,049.9	190.1	18.4	1,458.3
1992	51.7	[R]151.3	1.0	200.5	628.2	11.4	35.6	876.8	191.7	22.8	1,294.3
1993	38.5	153.1	0.7	187.1	612.4	9.3	34.5	843.9	192.4	18.7	1,246.6
1994	35.0	144.0	0.6	198.6	550.7	10.9	29.5	790.3	191.6	18.3	[R]1,179.2
1995	31.7	149.2	0.3	[R]178.6	522.3	11.4	31.9	[R]744.4	[R]185.5	18.9	[R]1,129.7
1996	23.3	147.4	0.2	170.6	513.0	21.7	27.6	733.2	[R]184.3	19.8	[R]1,107.9
1997	22.5	[R]144.6	0.3	179.4	475.7	17.2	39.0	711.5	[R]182.6	[R]19.3	[R]1,080.5
1998	[R]23.9	[R]141.2	0.2	[R]175.9	[R]445.6	[R]9.4	[R]43.1	[R]674.0	[R]184.8	[R]18.8	[R]1,042.8
1999[P]	21.2	137.6	0.1	162.3	444.6	2.9	41.1	651.0	187.2	19.3	1,016.3

[1] Liquefied petroleum gases.

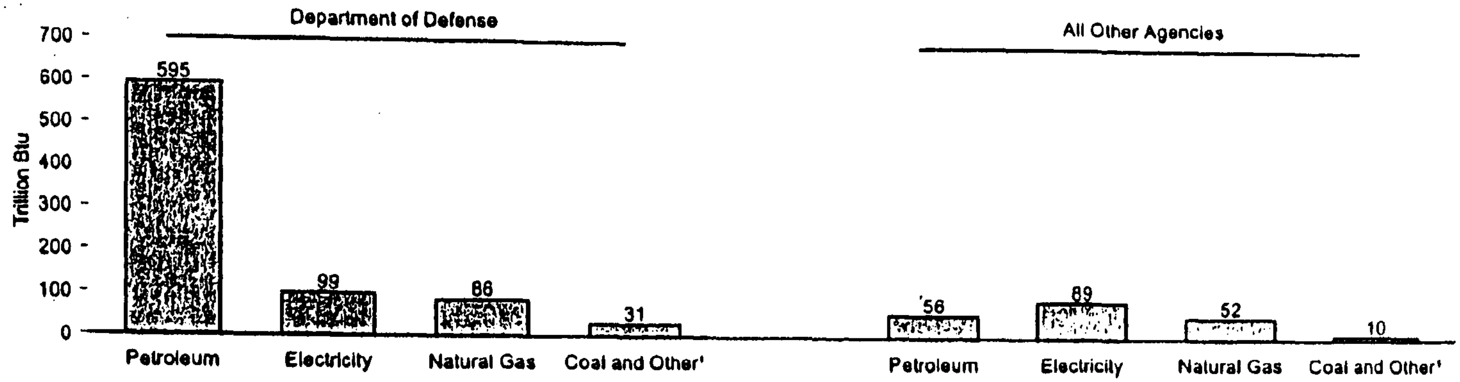
R = Revised. P = Preliminary.

Notes: • The U.S. Government's fiscal year was October 1 through September 30, except in 1975 and 1976, when it was July 1 through June 30. • This table uses a conversion factor for electricity of 3,412 Btu per kilowatthour and a conversion factor for purchased steam of 1,000 Btu per pound. • Data include energy consumed at foreign installations and in foreign operations, including aviation and ocean bunkering, primarily by the U.S. Department of Defense. U.S. Government energy use for electricity generation and uranium enrichment is excluded. • *Totals may not equal sum of components due to independent rounding.*

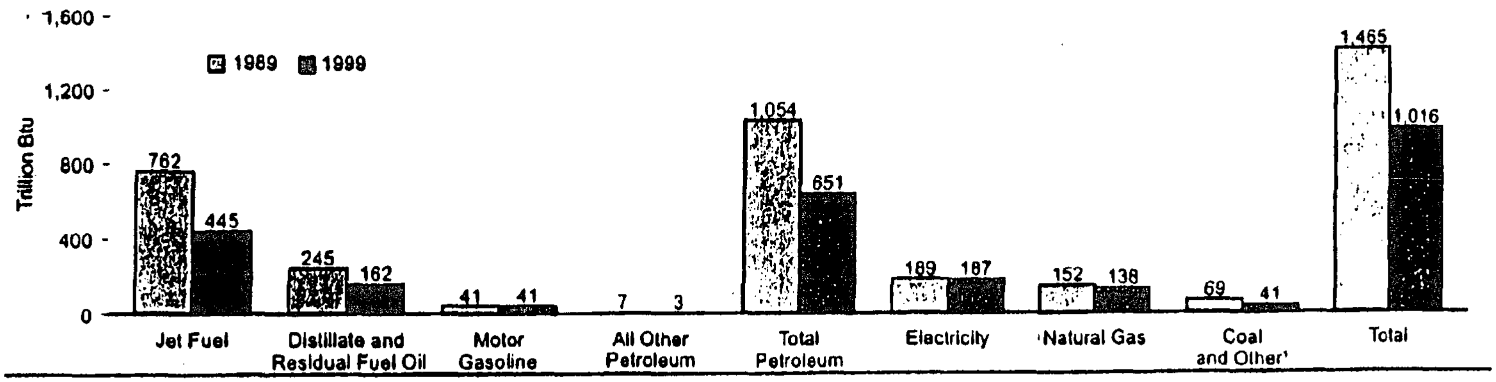
Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Federal Energy Management Programs.

Figure 1.13 U.S. Government Energy Consumption by Agency and Source

By Agency, Fiscal Year 1999



By Source, Fiscal Years 1989 and 1999



¹ Purchased steam and other.

Source: Table 1.13.

Notes: • The U.S. Government's fiscal year runs from October 1 through September 30.
• Because vertical scales differ, graphs should not be compared.

Table 1.13 U.S. Government Energy Consumption by Agency and Source, Fiscal Years 1989 and 1999

(Trillion Btu)

Agency	Coal and Other [2]	Natural Gas	Petroleum: Aviation Gasoline	Petroleum: Distillate and Residual Fuel Oil	Petroleum: Jet Fuel	Petroleum: LPG [1] and Other	Petroleum: Motor Gasoline	Petroleum: Total	Electricity	Total
Total, 1989	69.2	152.4	0.8	245.1	761.7	5.7	41.1	1,054.4	188.5	1,464.5
Defense	52.3	108.1	0.2	220.7	751.8	3.7	17.9	994.3	119.7	1,274.4
Postal Service	0.6	4.7	0.0	4.6	0.0	0.2	8.8	13.6	11.4	30.3
Energy	10.8	9.2	0.0	3.1	0.5	0.2	1.3	5.0	19.2	44.3
Veterans Affairs	1.2	14.3	0.0	2.4	0.0	0.0	0.5	3.0	7.8	26.2
Transportation	0.0	1.1	0.2	5.6	6.7	0.1	0.8	13.4	4.0	18.5
General Services Administration	1.9	2.7	0.0	0.5	0.0	0.0	0.1	0.7	7.4	12.7
Justice	1.1	2.5	0.1	0.3	0.1	0.0	1.9	2.5	1.7	7.7
NASA	0.3	2.8	0.0	1.0	1.4	0.0	0.2	2.6	6.4	12.1
Agriculture	0.1	1.4	0.1	0.7	0.0	0.2	4.5	5.4	1.8	8.7
Health and Human Services	0.1	1.8	0.0	1.9	0.0	0.1	0.2	2.3	2.5	6.7
Interior	0.1	1.0	0.1	1.2	0.1	1.1	1.9	4.5	1.5	7.1
Other [3]	0.6	2.7	0.1	3.1	1.1	0.0	3.0	7.3	5.0	15.6
Total, 1999 P	40.6	137.6	0.1	162.3	444.6	2.0	41.1	651.0	187.2	1,016.3
Defense	30.5	86.0	0.0	143.4	436.8	1.7	13.5	595.4	96.7	810.7
Postal Service	0.6	7.6	0.0	5.0	0.0	0.0	10.4	15.4	16.3	39.8
Energy	4.7	6.7	0.0	1.1	0.0	0.1	1.0	2.3	15.7	29.4
Veterans Affairs	1.5	14.3	0.0	1.1	0.0	0.0	1.2	2.3	9.4	27.5
Transportation	0.0	1.0	0.0	6.5	4.4	0.0	0.8	11.7	7.8	20.5
General Services Administration	1.5	3.2	0.0	0.1	0.0	0.0	0.1	0.2	9.5	14.3
Justice	0.4	4.5	0.1	0.4	1.4	0.0	4.8	6.7	3.8	15.4
NASA	0.2	3.0	0.0	0.4	1.1	0.0	0.2	1.8	6.4	11.4
Agriculture	0.5	2.0	0.0	0.1	0.0	0.1	3.3	3.5	1.9	7.8
Health and Human Services	0.1	3.3	0.0	0.3	0.0	0.1	0.4	0.9	2.8	7.0
Interior	0.1	1.4	0.0	0.8	0.1	0.7	2.8	4.5	1.5	7.5
Other [4]	0.6	4.8	0.0	3.1	0.9	0.0	2.4	6.4	13.3	25.1

[1] Liquefied petroleum gases.
[2] Purchased steam and other.
[3] Includes U.S. Department of Commerce, Panama Canal Commission, Tennessee Valley Authority, U.S. Department of Labor, National Science Foundation, U.S. Department of Housing and Urban Development, Federal Communications Commission, Office of Personnel Management, U.S. Department of State, U.S. Department of the Treasury, Small Business Administration, and Environmental Protection Agency.
[4] Includes National Archives and Records Administration, U.S. Department of Commerce, U.S. Department of Labor, U.S. Department of State, Environmental Protection Agency, Federal Communications Commission, Federal Trade Commission, Panama Canal Commission, Equal Employment Opportunity Commission, Nuclear Regulatory Commission, Office of Personnel Management, U.S. Department of Housing and Urban Development, U.S. Department of the Treasury, Railroad Retirement Board, Tennessee Valley Authority, Federal Emergency Management Agency, and U.S. Information Agency.

P=Preliminary.

Notes: • This table uses a conversion factor for electricity of 3,412 Btu per kilowatthour and a conversion factor for purchased steam of 1,000 Btu per pound. • Data include energy consumed at foreign installations and in foreign operations, including aviation and ocean bunkering, primarily by the U.S. Department of Defense. U.S. Government energy use for electricity generation and uranium enrichment is excluded. • The U.S. Government's fiscal year runs from October 1 through September 30. • Totals may not equal sum of components due to independent rounding.

Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Federal Energy Management Programs.

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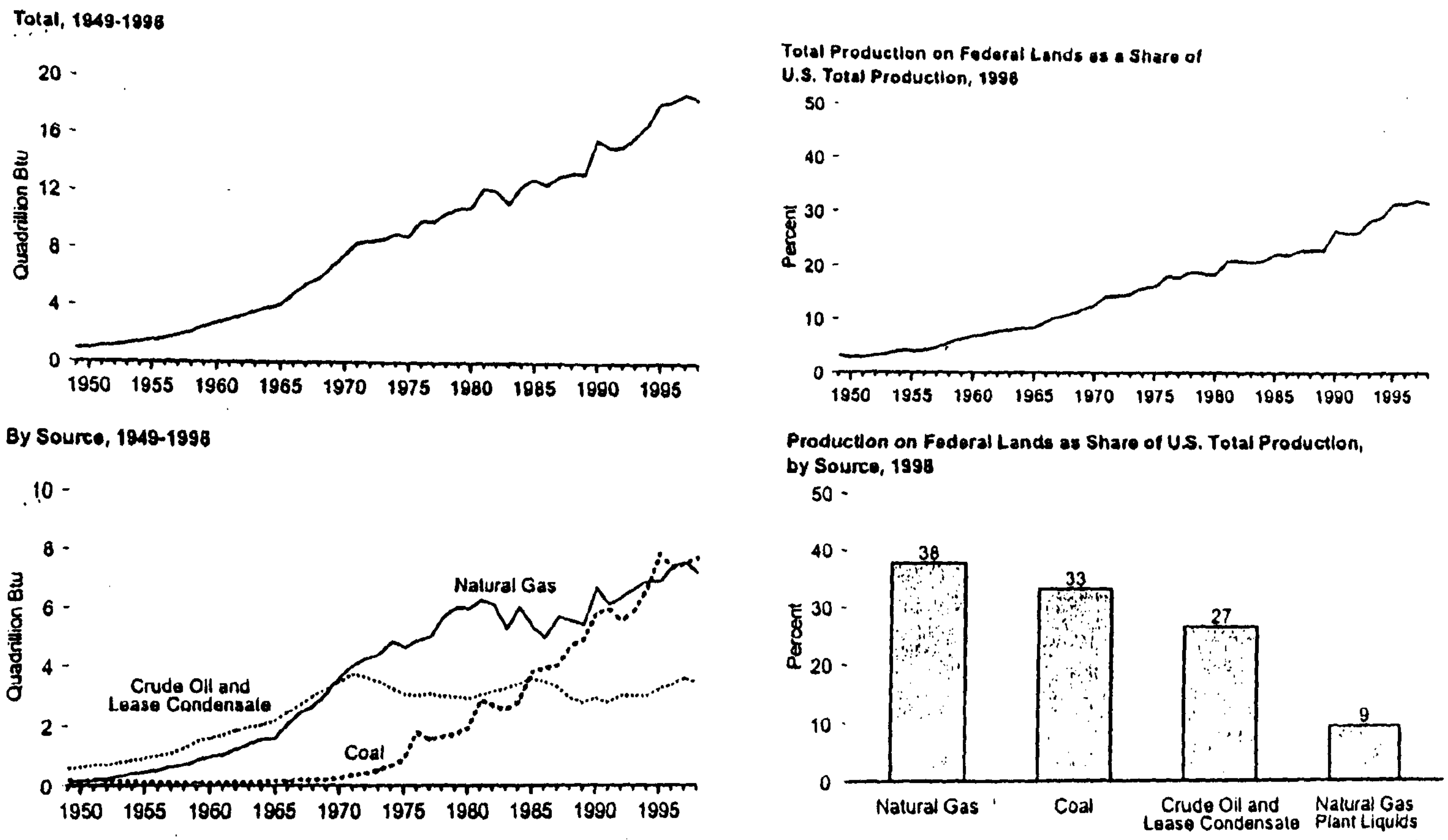
Figure 1.14 Fossil Fuel Production on Federally Administered Lands



Notes: • Federally Administered Lands include all classes of land owned by the Federal Government, including acquired military, Outer Continental Shelf, and public lands.
• Because vertical scales differ, graphs should not be compared.

Source: Table 1.14.

Table 1.14 Fossil Fuel Production on Federally Administered Lands, 1949-1998

Year	Crude Oil and Lease Condensate[1]			Natural Gas Plant Liquids[2]			Natural Gas[3]			Coal[4]			Total	
	Million Barrels	Quadrillion Btu	Percent U.S. Total[5]	Million Barrels	Quadrillion Btu	Percent U.S. Total[5]	Trillion Cubic Feet	Quadrillion Btu	Percent U.S. Total[5]	Million Short Tons	Quadrillion Btu	Percent U.S. Total[5]	Quadrillion Btu	Percent U.S. Total
1949	95.2	0.55	5.2	4.4	0.02	2.8	0.15	0.15	2.8	9.5	0.20	2.0	0.92	3.2
1950	105.9	0.61	5.4	4.4	0.02	2.4	0.14	0.15	2.4	7.7	0.16	1.4	0.94	2.9
1951	117.3	0.68	5.2	5.3	0.02	2.6	0.17	0.18	2.4	9.3	0.20	1.6	1.08	3.0
1952	118.7	0.69	5.2	5.5	0.02	2.5	0.25	0.25	3.2	8.7	0.18	1.7	1.15	3.3
1953	138.9	0.79	5.8	5.7	0.03	2.4	0.29	0.30	3.6	7.5	0.16	1.5	1.28	3.6
1954	146.5	0.85	6.3	6.1	0.03	2.4	0.39	0.40	4.6	7.4	0.16	1.8	1.43	4.2
1955	159.5	0.92	6.4	6.0	0.03	2.1	0.43	0.45	4.8	5.9	0.12	1.2	1.53	4.1
1956	174.1	1.01	6.7	6.4	0.03	2.2	0.49	0.51	5.1	5.8	0.12	1.1	1.67	4.2
1957	189.4	1.10	7.2	6.6	0.03	2.2	0.62	0.64	6.1	5.7	0.12	1.1	1.89	4.7
1958	216.8	1.26	8.9	6.0	0.04	2.7	0.69	0.71	6.5	5.3	0.11	1.2	2.11	5.7
1959	258.2	1.50	10.0	9.5	0.04	3.0	0.83	0.86	7.2	4.9	0.10	1.1	2.50	6.4
1960	277.3	1.61	10.8	11.6	0.05	3.4	0.95	0.98	7.8	5.2	0.11	1.2	2.75	6.9
1961	297.3	1.72	11.3	13.5	0.06	3.7	1.03	1.06	8.1	6.2	0.11	1.2	2.95	7.3
1962	321.7	1.87	12.0	15.3	0.07	4.1	1.18	1.22	8.9	5.8	0.12	1.3	3.27	7.8
1963	342.8	1.99	12.5	16.0	0.07	4.0	1.37	1.41	9.7	5.4	0.11	1.1	3.56	8.1
1964	356.0	2.07	12.8	15.5	0.07	3.7	1.51	1.55	10.2	7.1	0.15	1.4	3.84	8.4
1965	378.6	2.20	13.3	14.3	0.06	3.2	1.56	1.61	10.2	8.2	0.17	1.8	4.04	8.5
1966	426.7	2.47	14.1	15.2	0.06	3.2	2.02	2.09	12.3	8.3	0.17	1.5	4.60	9.6
1967	472.8	2.74	14.7	20.1	0.09	3.9	2.41	2.48	13.8	9.5	0.20	1.7	5.51	10.5
1968	523.7	3.04	15.7	13.7	0.06	2.6	2.61	2.69	14.1	9.1	0.19	1.6	5.97	11.0
1969	563.8	3.27	16.7	19.9	0.08	3.4	3.05	3.14	15.4	10.1	0.21	1.8	6.70	11.9
1970	605.6	3.51	17.2	40.6	0.17	6.7	3.56	3.67	16.9	12.0	0.26	2.0	7.60	12.8
1971	646.9	3.76	18.8	54.0	0.22	8.7	3.95	4.08	18.3	17.3	0.36	3.1	8.42	14.5
1972	630.5	3.66	18.2	56.7	0.23	8.9	4.17	4.28	19.3	19.0	0.40	3.1	8.56	14.5
1973	604.3	3.51	18.0	54.9	0.22	8.7	4.37	4.46	20.1	24.2	0.61	4.1	8.70	14.9
1974	570.2	3.31	17.8	61.9	0.25	10.1	4.75	4.87	22.9	32.1	0.67	5.3	9.10	16.1
1975	531.5	3.08	17.4	59.7	0.24	10.0	4.57	4.67	23.8	43.6	0.92	6.7	8.90	16.3
1976	525.7	3.05	17.7	57.2	0.23	9.7	4.81	4.91	25.2	86.4	1.82	12.6	10.00	18.3
1977	535.0	3.10	17.8	57.4	0.23	8.7	4.94	5.04	25.8	74.8	1.57	10.7	9.94	18.0
1978	523.6	3.04	16.5	25.9	0.10	4.5	5.60	5.71	29.3	79.2	1.66	11.8	10.51	19.1
1979	519.8	3.01	16.7	11.9	0.05	2.1	5.93	6.05	30.1	84.9	1.78	10.9	10.89	18.8
1980	510.4	2.96	16.2	10.5	0.04	1.8	5.85	6.01	30.2	92.9	1.95	11.2	10.96	18.6
1981	529.3	3.07	16.9	12.3	0.05	2.1	6.15	6.31	32.1	138.8	2.91	16.8	12.36	21.1
1982	552.3	3.20	17.5	15.0	0.06	2.7	5.97	6.14	33.5	130.0	2.73	15.5	12.13	21.1
1983	568.8	3.30	17.9	14.0	0.05	2.5	5.17	5.33	32.1	124.3	2.61	15.9	11.30	20.8
1984	595.8	3.46	18.3	25.4	0.10	4.3	5.88	6.07	33.7	136.3	2.86	15.2	12.48	21.2
1985	628.3	3.64	19.2	26.6	0.10	4.5	5.24	5.41	31.8	184.6	3.88	20.9	13.03	22.6
1986	608.4	3.53	19.2	23.3	0.09	4.1	4.87	5.01	30.3	189.7	3.98	21.3	12.61	22.3
1987	577.3	3.35	18.9	23.7	0.09	4.1	5.56	5.73	33.4	195.2	4.10	21.2	13.27	23.2
1988	516.3	2.99	17.3	37.0	0.14	6.2	6.46	5.61	31.9	225.4	4.73	23.7	13.48	23.3
1989	488.9	2.84	17.6	45.1	0.17	8.0	5.32	5.49	30.7	236.3	4.96	24.1	13.46	23.4
1990	515.9	2.99	19.2	50.9	0.19	8.9	6.55	6.75	36.8	280.6	5.89	27.3	15.83	27.0
1991	491.0	2.85	18.1	72.7	0.28	12.0	5.99	6.17	33.8	285.1	5.99	28.6	15.28	26.4
1992	529.1	3.07	20.2	70.7	0.27	11.4	6.25	6.43	35.0	266.7	5.60	28.7	15.37	26.7
1993	529.3	3.07	21.2	64.4	0.24	10.2	6.56	6.74	36.3	285.7	6.00	30.2	16.05	28.8
1994	527.7	3.06	21.7	60.0	0.23	9.5	6.78	6.97	36.0	321.4	6.75	31.1	17.01	29.4
1995	567.4	3.29	23.7	74.0	0.28	11.5	6.78	6.96	36.4	376.9	7.91	36.5	18.45	32.1
1996	596.5	3.46	25.2	71.2	0.27	10.6	7.31	7.51	R38.8	354.5	7.44	33.3	18.68	R32.0
1997	632.8	3.67	26.9	74.7	0.28	11.3	7.43	7.62	39.3	362.6	7.61	33.3	19.18	32.6
1998	[6]606.3	3.52	26.6	[6]60.3	0.23	9.4	[6]7.06	7.27	37.7	371.1	7.79	33.2	18.81	32.1

[1] Production from Naval Petroleum Reserve No. 1 for 1974 and earlier years is for fiscal years (July through June).

[2] Includes only those quantities for which the royalties were paid on the basis of the value of the natural gas plant liquids produced. Additional quantities of natural gas plant liquids were produced; however, the royalties paid were based on the value of natural gas processed. These latter quantities are included with natural gas.

[3] Includes some quantities of natural gas processed into liquids at natural gas processing plants and fractionators.

[4] Converted to British thermal units (Btu) on the basis of an estimated heat content of coal produced on Federally administered lands of 21.0 million Btu per short ton.

[5] Based on physical units.

[6] There is a discontinuity in this time series between 1997 and 1998 due to the sale of "Elk Hills," Naval Petroleum Reserve No. 1.

R=Revised.

Note: Federally Administered Lands include all classes of land owned by the Federal Government, including acquired military, Outer Continental Shelf, and public lands.

Sources: • 1949-1980—U.S. Geological Survey, *Oil and Gas Production, Royalty Income, and Related Statistics*, and *Coal, Phosphate, Potash, Sodium, and Other Production, Royalty Income, and Related Statistics*, and *Mineral Production, Royalty Income, and Related Statistics* (June 1981); Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, unpublished data; and U.S. Geological Survey, National Petroleum Reserve in Alaska, unpublished data. • 1981-1983—U.S. Minerals Management Service, *Mineral Revenues Report on Receipts from Federal and Indian Leases*, (annual); Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, unpublished data; and U.S. Geological Survey, National Petroleum Reserve in Alaska, unpublished data. • 1984 forward—U.S. Minerals Management Service, *Mineral Revenues Report on Receipts from Federal and Indian Leases*, annual reports, and Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, unpublished data.

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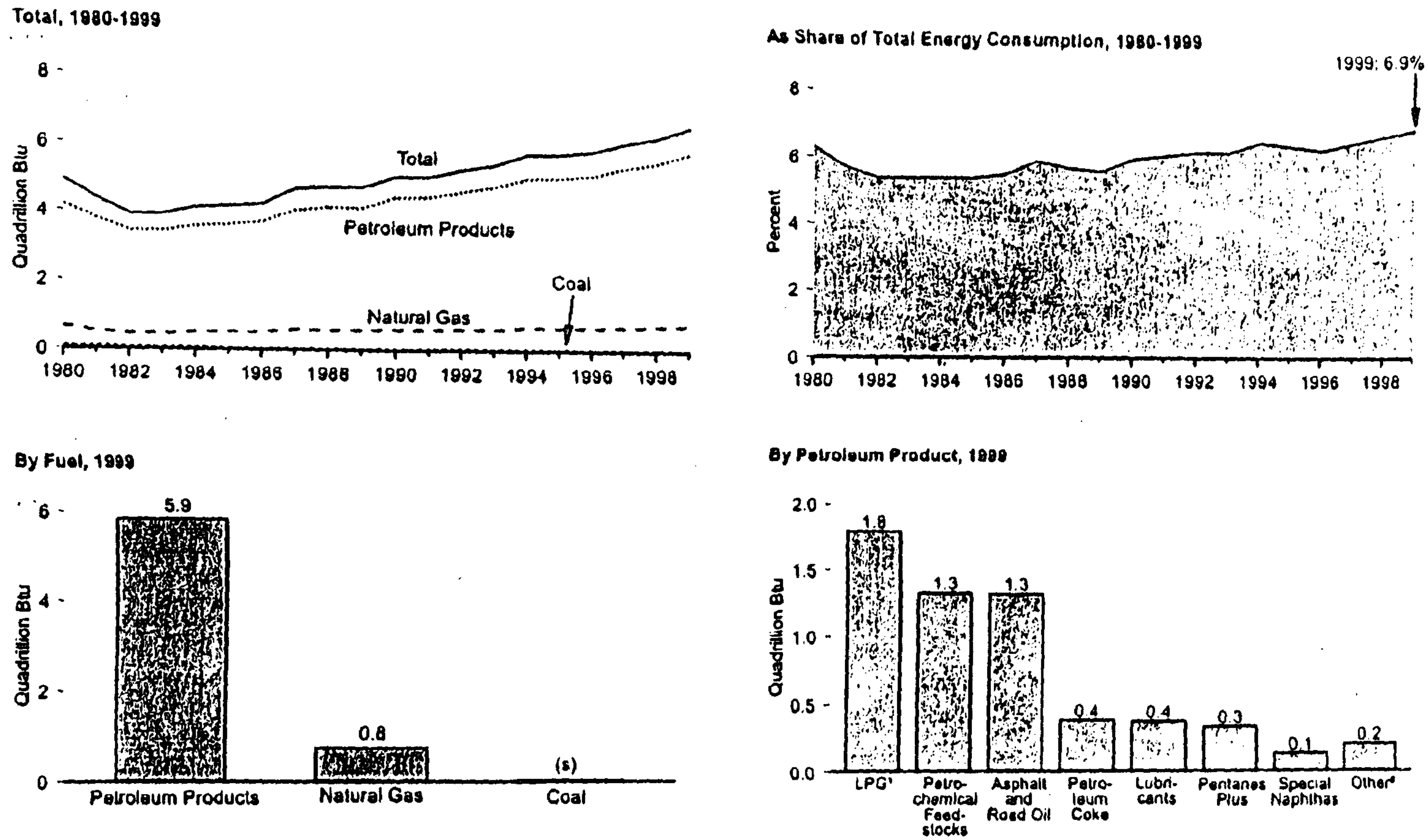
Figure 1.15 Fossil Fuel Consumption for Nonfuel Use



¹ Liquefied petroleum gases.
² Distillate fuel oil, residual fuel oil, waxes, and miscellaneous products.
(s) = less than 0.05 quadrillion Btu.

Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.15.

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Table 1.15 Fossil Fuel Consumption for Nonfuel Use, 1980-1999

Year	Petroleum Products: Asphalt and Road Oil	Petroleum Products: Liquefied Petroleum Gases	Petroleum Products: Pentanes Plus	Petroleum Products: Lubricants	Petroleum Products: Petro-chemical Feedstocks	Petroleum Products: Petroleum Coke	Petroleum Products: Special Naphthas	Petroleum Products: Other [1]	Petroleum Products: Total	Natural Gas	Coal	Total	Percent of Total Energy Consumption
	Physical Units [2]												
1980	145	230	(3)	58	253	R24	37	58	R805	639	2.4	—	—
1981	125	229	(3)	56	216	R29	27	54	R736	507	2.1	—	—
1982	125	256	(3)	51	157	R23	25	48	R686	R438	1.4	—	—
1983	136	264	(3)	53	161	R10	30	45	R689	R441	1.2	—	—
1984	150	247	10	57	145	R18	40	41	R705	R495	1.5	—	—
1985	156	265	13	53	144	R15	30	41	R718	500	1.1	—	—
1986	164	248	17	52	169	R14	25	38	R727	496	0.7	—	—
1987	170	303	12	59	170	R24	28	38	R802	578	0.8	—	—
1988	171	319	21	57	173	R25	22	40	R827	554	0.7	—	—
1989	165	332	17	58	172	R23	20	39	R827	563	0.6	—	—
1990	176	344	18	60	199	R30	20	39	R887	572	0.6	—	—
1991	162	394	10	53	200	R27	17	44	R907	573	0.6	—	—
1992	166	397	13	54	214	R41	20	35	R940	594	1.2	—	—
1993	174	389	60	55	216	R27	20	33	R976	R598	0.9	—	—
1994	176	437	58	58	222	R30	15	35	R1,029	673	0.9	—	—
1995	178	450	66	57	215	32	13	26	1,037	R665	0.9	—	—
1996	177	R470	69	56	R217	34	14	27	R1,063	R667	0.9	—	—
1997	184	R473	R65	56	250	29	14	27	R1,102	R681	0.9	—	—
1998	R190	R454	R58	61	R252	R51	20	R31	R1,117	R710	0.8	—	—
1999P	199	508	71	62	238	61	24	28	1,193	734	0.8	—	—
	Quadrillion Btu												
1980	0.96	0.78	(3)	0.35	1.43	0.14	0.19	0.34	4.19	0.65	0.08	4.92	6.3
1981	0.83	0.77	(3)	0.34	1.21	0.17	0.14	0.31	3.78	0.52	0.07	4.37	5.7
1982	0.83	0.87	(3)	0.31	0.88	0.14	0.13	0.28	R3.44	0.45	0.04	R3.93	R5.4
1983	0.90	0.89	(3)	0.32	0.85	R0.06	0.16	0.26	R3.45	R0.45	0.04	3.94	5.4
1984	0.99	0.84	0.05	0.35	0.82	0.09	0.21	0.24	R3.58	0.61	0.05	R4.14	5.4
1985	1.03	0.80	0.06	0.32	0.82	0.09	0.16	0.24	R3.63	0.52	0.03	R4.18	5.4
1986	1.09	0.85	0.08	0.31	0.95	R0.08	0.13	0.22	R3.72	0.51	0.02	R4.25	5.5
1987	1.13	1.08	0.06	0.36	0.96	R0.14	0.14	0.21	R4.08	0.60	0.03	R4.69	5.9
1988	1.14	1.11	0.10	0.34	0.97	R0.16	0.11	0.23	R4.16	0.57	0.02	R4.75	5.7
1989	1.10	1.18	0.08	0.35	0.96	R0.14	0.11	0.23	R4.14	0.58	0.02	R4.74	5.6
1990	1.17	1.20	0.08	0.36	1.12	R0.18	0.11	0.23	R4.46	0.59	0.02	R5.07	6.0
1991	1.08	1.36	0.04	0.32	1.15	R0.16	0.09	0.26	R4.48	0.59	0.02	R5.09	R6.1
1992	1.10	1.39	0.06	0.33	1.20	R0.25	0.10	0.20	R4.64	0.61	0.04	R5.29	6.2
1993	1.15	1.35	0.28	0.34	1.22	R0.17	0.10	0.20	R4.80	R0.61	0.03	R5.44	6.2
1994	1.17	1.56	0.26	0.35	1.26	R0.16	0.08	0.20	R5.05	0.69	0.03	R5.77	R6.5
1995	1.18	1.59	0.30	0.35	1.21	0.19	0.07	0.20	5.08	R0.67	0.03	R5.78	6.4
1996	1.18	1.65	0.32	0.34	R1.21	0.21	0.07	0.19	R5.17	R0.68	0.03	R5.88	6.3
1997	1.22	R1.67	0.30	0.35	1.40	0.18	0.07	0.20	R5.40	R0.70	0.03	R6.13	6.5
1998	R1.26	R1.60	R0.27	0.37	R1.40	R0.31	R0.11	R0.22	R5.54	R0.73	0.03	R6.30	R6.7
1999P	1.32	1.79	0.33	0.38	1.33	0.37	0.13	0.20	5.85	0.75	0.02	6.62	6.9

[1] Distillate fuel oil, residual fuel oil, waxes, and miscellaneous products.
[2] Petroleum - million barrels; natural gas - billion cubic feet; and coal - million short tons.
[3] Included in liquefied petroleum gases.

R=Revised. P=Preliminary. — = Not applicable.

Notes: • Because of changes in methodology, data series may be revised annually. • See Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1998* (October 1999), Appendix A, for a discussion of the estimates in the table. • 1999 is an early estimate by EIA and may differ from the emissions inventory to be published in late 2000. • Totals may not equal sum of components due to independent rounding.

Sources: **Petroleum Products:** • 1980—EIA, Energy Data Reports, *Petroleum Statement, Annual* and *Sales of Liquefied Petroleum Gases and Ethane in 1980*. • 1981-1998—EIA, *Petroleum Supply Annual*, annual reports, and unpublished data. • 1999—EIA, *Petroleum Supply Monthly* (February 2000), and EIA estimates. **Natural Gas:** • 1980—Bureau of the Census, 1980 Survey of Manufactures, *Hydrocarbon, Coal, and Coke Materials Consumed*. • 1981 forward—U.S. Department of Commerce. **Coal:** • 1980-1995—U.S. International Trade Commission, *Synthetic Organic Chemicals, United States Production and Sales, 1995* (January 1997). • 1996 forward—Estimated because the data series has been discontinued. **Percent of Total Energy Consumption:** Derived by dividing total by total consumption on Table 1.3.

Energy Overview Notes

1. Data on the generation of electricity in the United States represent net generation, which is gross output of electricity (measured at the generator terminals) minus power plant use. Nuclear electricity generation data identified by individual countries in Section 11 are gross outputs of electricity.

Sources

Table 1.1
Tables 5.1, 6.1, 7.1, 7.7, 8.1, 8.3, 10.1, 10.3, and Energy Information Administration (EIA) estimates for industrial hydroelectric power; conversion factors in Appendix A; and for the biomass estimates 1949-1980, EIA, *Estimates of U.S. Wood Energy Consumption from 1949 to 1981* (August 1982), Table A2, and *Estimates of U.S. Wood Energy Consumption 1980-1983* (November 1984), Table ES1.

Table 1.2
Tables 5.1, 6.1, 7.1, 7.7, 8.1, 8.3, 10.1, 10.3, and Energy Information Administration (EIA) estimates for industrial hydroelectric power; conversion factors in Appendix A; and for the wood and waste estimates 1949-1980, EIA, *Estimates of U.S. Wood Energy Consumption from 1949 to 1981* (August 1982), Table A2, and *Estimates of U.S. Wood Energy Consumption 1980-1983* (November 1984), Table ES1.

Table 1.3
Tables 5.1, 6.1, 7.1, 7.7, 8.1, 8.3, 10.1, 10.3, and Energy Information Administration (EIA) estimates for industrial hydroelectric power; conversion factors in Appendix A; and for the biomass estimates 1949-1980, EIA, *Estimates of U.S. Wood Energy Consumption from 1949 to 1981* (August 1982), Table A2, and *Estimates of U.S. Wood Energy Consumption 1980-1983* (November 1984), Table ES1.

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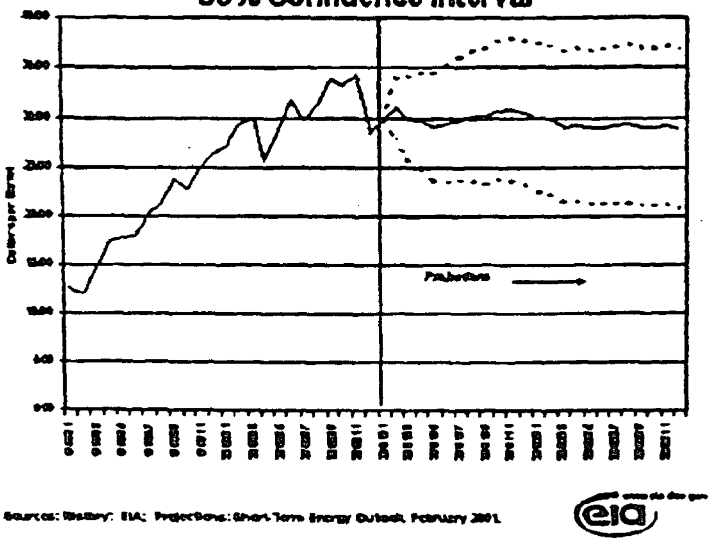
Short-Term Energy Outlook

February 2001

Overview

Figure 1. WTI Crude Oil Price: Base Case and 95% Confidence Interval



Barring a sharp drop in world oil consumption below our current expectations, no compelling case for rapidly declining oil prices emerges from the world oil market outlook (Figure 1). We expect the WTI spot price average to remain near $30 per barrel for the rest of this year. Prices are likely to drift downward some next year, perhaps losing $1 per barrel between 2001 and 2002. The balance of world oil demand and supply suggests a continuation of the tight inventory situation in industrialized countries seen over the last year.

Expanded supply of heating oil in the United States and some comparatively warm weather in the Northeast of late has eased pressure on heating oil prices and improved storage levels relative to previous expectations. Although supplies may still be considered below normal, the market has come a long way toward resolving any potential heating oil shortfalls in the Northeast.

Natural gas storage was improved by end-January relative to what was expected previously. A combination of new supply, demand cutbacks due to fuel substitution and industrial slowdowns, as well as overall conservation saved about 140 billion cubic feet more than we anticipated last month. (Some of this change was due to revisions.) Consequently, very much lower spot gas prices developed in late January. Despite the improvement, gas prices remain quite sensitive to weather shifts and storage remains well below normal.

We have recast the way in which we present the electricity balance beginning with this month's report. A more complete definition of electricity demand that includes sales to end users by power marketers (instead of just electric utility sales plus nonutility own use) has been adopted (see footnote "g" to Table 10). On this basis, electricity demand grew by about 2.3 percent in 1999 and 3.6 percent in 2000. Growth over the next 2 years is expected to average about 2.3 percent.

International

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The most reliable inventory data are from the OECD countries. The data indicates that there was very little stockbuild in 2000 for these countries, which account for a little more than half of total world oil demand. However, EIA's global supply/demand estimates suggest that OECD inventories should have been building by almost 400,000 barrels per day in 2000. EIA's projections for OECD inventories are adjusted to reflect the assumption that the "missing barrels problem" will continue in 2001, but will be diminished by 2002. With this adjustment, OECD inventories are projected to grow relatively slowly in 2001 and 2002. EIA believes that this stock growth will be small enough to provide continued price support because inventories will continue to be low compared to normal levels.

U. S. Energy Prices

Heating Oil. With the heating season (October-March) past the halfway point, we can be fairly confident that retail heating oil prices have seen their seasonal peak provided that no substantial deviations in heating demand above normal occur over the next two months. Warm spells last month and deteriorating crude oil prices in December (falling $5.50 dollars per barrel from November) and January, have helped ease heating oil prices. Over the past 6 weeks, spot heating oil prices have fallen by more than 20 cents per gallon. Because of the relatively balmy weather in the Northeast during the last half of January, heating oil stock levels have not weakened over the past month. Furthermore heating oil production has been unusually robust, running several hundred thousand barrels per day over last year's pace. Now, we project winter prices to average around $1.40 compared to $1.48 in our previous Outlook. Despite this, retail heating oil prices remain quite high in historical terms. The national average price last December was 44 cents per gallon above the December 1999 price (Figure 5). This month, the average price is not expected to be much different from the record high of $1.42 per gallon set last February.

Despite the recent warm weather, a risk, though diminished, still continues this winter for abrupt price jumps similar to what happened last February, especially if the weather turns sharply cold in the Northeast. For the U.S., distillate stocks are currently about 9 million barrels below the low end of the normal range (Figure 6).

Motor Gasoline. Pump prices have backed down from the high prices experienced last fall. The retail price for regular unleaded motor gasoline fell 11 cents per gallon from September to December. However, with crude oil prices rebounding somewhat from their December lows combined with lower than normal stock levels, we project that prices at the pump will rise modestly as the 2001 driving season begins in the spring (Figure 7). For the summer of 2001, we expect only a little difference from the average price of $1.50 per gallon seen during the previous driving season, as motor gasoline stocks going into the driving season are projected to be slightly less than they were last year (Figure 8). The situation of relatively low inventories for gasoline could set the stage for some regional imbalances in supply that could once again bring about significant price volatility in the U.S. gasoline market.

High natural gas prices are contributing to higher prices, reduced domestic production, and higher imports of methyl tertiary butyl ether (MTBE), an oxygenated blending component for reformulated gasoline. The raw materials in MTBE production, methanol and butane, are primarily derived from natural gas. The increase in production cost and price of MTBE will lead to a higher price premium for reformulated gasoline, which represents about 1/3 of total U.S. gasoline demand, over conventional unleaded gasoline.

For example, 10% of each gallon of reformulated gasoline is MTBE. Each 10 cent per gallon increase in the price of MTBE should increase the price premium for reformulated gasoline by about 1 cent per gallon, and increase the average U.S. price of gasoline by about 1/3 cent per gallon. The increase in cost of producing MTBE should also lead to greater demand for fuel ethanol as an alternative oxygenated blendstock for reformulated gasoline.

Natural Gas. Spot wellhead prices last summer averaged well over $4.00 per thousand cubic feet during a normally low-price season. During the fall, these prices stayed above $5.00 per thousand cubic feet, more than double the year-ago average price (Figure 9). In January, the spot wellhead price averaged a record $8.98 per thousand cubic feet. Spot prices at the wellhead have never been this high for such a prolonged period. The chief reason for these sustained high gas prices was, and still is, uneasiness about the supply situation. Concern about the adequacy of winter supplies loomed throughout most of the summer and fall as storage levels remained significantly depressed. Last December, the most severe assumptions about low storage levels became real, when the spot price closed for the day at over $10.00 per cubic feet on several occasions. The low levels of gas storage have put the spot market in an extremely volatile position. However, heating demand was eased by milder than normal weather during the latter part of January in much of the nation's gas consuming regions. This in turn led to spot prices plunging to less than $6.00 per thousand cubic feet. Nevertheless, spot prices and wellhead prices still remain quite high by historical standards.

We are projecting that winter (October 2000-March2001) natural gas prices at the wellhead will average about $6.14 per thousand cubic feet, more than two and one half times the price of the previous winter season. In our base case, residential prices for natural gas this winter would be about 50 percent higher than last year during that period. This spring and summer, monthly average wellhead prices should drop from the winter peak by about $4.00 per thousand cubic feet as the weather-related demand recedes. Still, for the year 2001, assuming normal weather and our projection of continued low underground storage levels, wellhead prices are not expected to dip much below $4.00 per thousand cubic feet. In 2001, the annual average wellhead price is projected to be close to $5.00 per thousand cubic feet. Next year, we expect the storage situation to improve modestly and with that, a decrease in the average annual wellhead price. Increases in production and imports of natural gas needed to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

Electric Utility Fuels. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices, on a cost per Btu basis (Figure 10). As this situation is likely to persist, we anticipate some recovery in the amount of oil used for power generation over the very low levels seen since late 1999. Interestingly, after years of gradual, but steady decline, the cost of coal to electric utilities is projected to increase slightly, on a quarterly year-over-year basis, as coal, like oil, is being used more intensively for electricity generation in lieu of expensive or unavailable natural gas.

U.S. Oil Demand

The most recent estimates for 2000 indicate that petroleum demand shrank by 14,000 barrels per day or 0.1 percent. Despite colder-than-normal fourth-quarter weather, first-quarter warm weather and continuing price increases throughout much of the year contributed to the contraction in demand. Motor gasoline demand declined an estimated 0.7 percent for the year in reaction to the substantial increase in pump prices--which reached records in nominal terms-and a moderation in real disposable income growth. Although prices have retreated somewhat, they are still well above those of a year ago. Total jet fuel growth in 2000 averaged 1.8 percent compared to 3.1 percent in 1999 (Figure 11). Led by growth in international air traffic, commercial jet fuel demand grew by 3.9-percent despite an almost 10-percent increase in ticket prices and a slowing in real income growth late in the year. But, jet fuel used in blending for diesel fuel declined as a result of first-quarter mild weather. Distillate fuel oil demand, however, grew 3.2 percent, led by growth in transportation demand. Space-heating demand, however, declined. Despite the combined effects of rising prices and warm weather that depressed demand in the first half of the year, residual fuel oil demand eked out an estimated 1.1-percent growth in 2000. Cold weather in the fourth quarter, a decline in prices from their mid-year peak, and the spike in natural gas prices contributed to the second-half recovery in industrial demand and the late surge in power-generation demand.

During the next 2 years, energy prices are projected to moderate somewhat (or at least not rise significantly), and real disposable income is expected to grow at relatively robust rates (*despite a slowing overall economy) due in part to expected reductions in taxes and interest rates. Weather patterns are assumed to be normal. Petroleum demand is therefore projected to exhibit strong growth throughout the forecast interval, averaging about 350,000 barrels per day, or 1.8 percent, per year. In 2002, petroleum demand is projected to exceed 20 million barrels per day for the first time. Reversing last year's decline, motor gasoline demand is projected to increase once again, although with growth averaging only 1.5 percent per year. Commercial jet fuel demand is projected to continue to increase steadily at a 2.3-percent average rate. That demand is bolstered by continued increases in disposable income and a taming of ticket-price inflation to 3 percent from the 8 percent of the previous 2 years. Total distillate fuel oil demand is projected to increase at a 2.4-percent rate. Transportation diesel fuel demand is projected to continue to expand, but space-heating fuel demand is not projected to exhibit any growth. Residual fuel oil demand, on the other hand, is expected to contract during the forecast interval. Despite the assumptions of normal weather, continued declines in natural gas prices from their recent records are expected to result in a displacement of fuel oil in the price-sensitive power-generation and industrial sectors.

U.S. Oil Supply

Average domestic oil production is expected to increase by 10 thousand barrels per day or 0.2 percent in 2001, to a level of 5.85 million barrels of oil per day (Figure 12). For 2002, a 0.5 percent decrease is expected and results in a production rate of 5.82 million barrels of oil per day average for the year.

Lower-48 States oil production is expected to decrease by 40 thousand barrels per day to a rate of 4.8 million barrels per day in 2001, and followed by an decrease of 55 thousand barrels per day in 2002. Shell started production in 1999 in their Ursa field and will peak in production in the year 2001. Shell's Brutus platform is expected to start production in the third quarter of 2001 with peak oil production at 100,000 barrels per day in 2002. Oil production from the Mars, Troika, Ursa, and Brutus Federal Offshore fields is expected to account for about 8.3 percent of the lower-48 oil production by the 4th quarter of 2002.

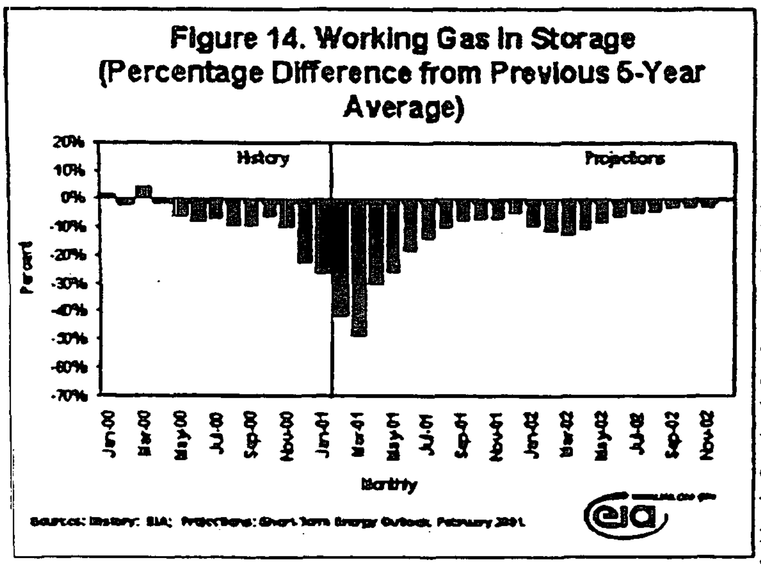
Alaska is expected to account for 18.0 percent of the total U.S. oil production in 2002. Its oil production is expected to increase by 5.6 percent in 2001 and again increase by 2.4 percent in 2002. The increase in 2001 is the result of adding two new satellite fields, Colville River (Alpine) and Prudhoe Bay (Aurora), which contribute to the Alaska North Slope production. The initial rate from Alpine averaged 18,000 barrels per day during November and it is expected to peak at 80,000 barrels per day in mid 2001. Aurora peak production should occur late this year. Another satellite field, North Star, is expected to come on in early to mid 2002 and will peak at a rate of 65,000 barrels per day later that year. Production from the Kuparuk River field plus like production from West Sak, Tabasco and Tarn fields is expected to stay at an average of 236,000 barrels per day in 2001-2002 forecast period.

Natural Gas Demand and Supply

January natural gas demand is estimated to have increased by about 5-6 percent over year-ago, as heating degree-days (HDD) averaged 3-4 percent above year-ago levels. This was down considerably from the growth rates estimated for November and December 2000, when severe winter weather pushed natural gas demand in these months to levels averaging 13 percent higher than a year ago, led by the residential and commercial sectors. The jump in natural gas prices has served to dampen higher demand levels in the industrial and utility sectors as generating units able to switch to other fuels presumably did so. Assuming normal weather for the remainder of the forecast period, natural gas demand is projected to grow by 2.3 percent in 2001 and by 4.1 percent in 2002, compared with estimated demand growth of 4.3 percent in 2000 (Figure 13).

In 2001 and 2002, natural gas demand in the industrial sector is expected to increase by 3.1 percent and 7.5 percent, respectively. Natural gas demand for nonutility electricity generation in 2001 is expected to be up by about 7.0 percent. Electric utility gas demand is expected to remain about level with consumption rates seen in 2000. This distinction is due in part to sales of electric generating plants by electric utilities to unregulated generating companies, fuel consumption by which is currently recorded by EIA in the industrial sector. We assume, for the purposes of the forecast, that no additional sales of generating units to unregulated entities occur, but that assumption merely affects the label attached to the fuel demand source, not the overall demand trend.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 1.1 percent in 2000 and it is forecast to increase by significantly higher rates of 5.4 percent rate in 2001 and 2.5 percent in 2002.



According to the American Gas Association (AGA), during the week ending January 26, a total of 128 billion cubic feet was withdrawn from storage, bringing the total of working gas to 38 percent full, or 1,241 bcf. EIA estimates that gas stocks at the end of January were about one third below the previous 5-year average (Figure 14). Although this points to an improvement for end-January stocks over previous expectations, with almost two months of winter still to go, continuing fears about the domestic supply situation are helping to maintain relatively high spot and futures prices. Still, given recent spot price movements, a drop of about $3 per mcf is possible in February compared to the January average $8.98.

Net imports of natural gas are projected to rise by about 16 percent in 2001 and by another 4 percent in 2002. For this winter, we expect net imports to be 7.6 percent higher than last winter's imports. The Alliance Pipeline began carrying gas from western Canada to the Midwest on December 1, having been delayed from its original October 2 opening. A new report by Canada's National Energy Board predicts that gas deliverability from Western Canada will rise by 1.1 bcf/d by 2002, due to the ongoing drilling boom. Western Canada supplies 15 percent of the gas consumed in the United States.

The critical power situation in California highlights the inter-related tightness in both electricity and gas markets. As environmental regulations on coal and oil fired generation units have become more strict over the past few years, gas fired generators began to take on more of the baseload burden. And as power generation demand has increased, demand for gas has increased with it. California lacks the pipeline capacity to provide enough natural gas to all the new power plants in development, let alone its current supply demands. Also, the region is short on the electricity generating capacity and transmission wires to deliver enough power into a market that is growing at 4% annually. California had the highest gas prices in the nation during the month of December. The lack of adequate power reserves this winter has been a repeat of last summer's situation. The economic impact of high natural gas and electricity prices is that many manufacturers of various commodities have chosen to interrupt operations and resell contracted energy back into the regional market.

Electricity Demand and Supply

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.3 percent in both 2001 and in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This winter's overall heating degree-days (HDD) are assumed to be almost 18 percent above last winter's HDD, which were well below normal. This is based on the very cold temperatures seen in November and December, as well as on the assumption that the remainder of the winter will be normal. This winter, total electricity demand is expected to be up by 4.5 percent over last winter's level, driven by increased demand in the residential and commercial sectors, which are expected to be up by 6.8 and 3.7 percent, respectively (Figure 15 and Table 10).

In the fourth quarter of 2000, previously falling demand for oil-fired generation began to turn around as the price differential between natural gas and oil in the electricity generating sector shifted to favor oil, prompting those plants which can switch to oil to do so. The favorable price differential for oil relative to gas is expected to continue through the forecast period. Growth in coal-fired generation also turned positive in the fourth quarter of 2000. Nevertheless, by the second half of 2001, expected increases in gas-fired capacity are expected to keep gas demand for power generation growing.

Supply problems in California for gas-fired electricity generation have helped to boost gas prices and have frequently caused interruptible customers to be cut off in that state. The situation in California is characterized by low gas storage, gas pipeline bottlenecks, high demand and low hydro and nuclear electric power availability. These supply problems are following on last summer's supply problems with no obvious end visible over the next two years. Average California gas prices dramatically outstripped prices elsewhere in the country through December but have since been coming down as weather-related demand has eased up somewhat (Figure 16).

Table HL1. U. S. Energy Supply and Demand

(Energy Information Administration/Short-Term Energy Outlook – February 2001)

	Year				Annual Percentage Change		
	1999	2000	2001	2002	1999-2000	2000-2001	2001-2002
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	8876	9326	9569	9986	5.1	2.6	4.4
Imported Crude Oil Price [a] (nominal dollars per barrel)	17.22	27.66	26.75	26.17	60.6	-3.3	-2.2
Petroleum Supply (million barrels per day) Crude Oil Production [b]	5.88	5.84	5.85	5.82	-0.7	0.2	-0.5

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Total Petroleum Net Imports (including SPR)	**9.91**	*10.08*	*10.67*	*10.97*	*1.7*	*5.9*	*2.8*
Energy Demand							
World Petroleum (million barrels per day)	**74.9**	*75.8*	*77.4*	*79.1*	*1.2*	*2.1*	*2.2*
Petroleum (million barrels per day)	**19.52**	*19.51*	*19.85*	*20.22*	*-0.1*	*1.7*	*1.9*
Natural Gas (trillion cubic feet)	**21.70**	*22.63*	*23.14*	*24.08*	*4.3*	*2.3*	*4.1*
Coal [c] (million short tons)	**1044**	*1077*	*1089*	*1097*	*3.2*	*1.1*	*0.7*
Electricity (billion kilowatthours)							
Retail Sales [d]	**3236**	*3335*	*3393*	*3466*	*3.1*	*1.7*	*2.2*
Nonutility/Sales [e]	**185**	*210*	*236*	*247*	*13.5*	*12.4*	*4.7*
Total	**3421**	*3545*	*3629*	*3713*	*3.6*	*2.4*	*2.3*
Total Energy Demand [f] (quadrillion Btu)	**97.1**	*98.4*	*99.4*	*101.3*	*1.4*	*1.0*	*1.9*
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	**10.94**	*10.56*	*10.39*	*10.14*	*-3.5*	*-1.6*	*-2.4*
Renewable Energy as Percent of Total [g]	**7.2**	*7.1*	*7.0*	*7.0*			

[a]Refers to the refiner acquisition cost (RAC) of imported crude oil.

[b]Includes lease condensate.

[c]Total Demand includes estimated Independent Power Producer (IPP) coal consumption.

[d]Total of retail electricity sales by electric utilities and power marketers. Utility sales for historical periods are reported in EIA's *Electric Power Monthly* and *Electric Power Annual*. Power marketers' sales for historical periods are reported in EIA's Electric Sales and Revenue, Appendix C. Data for 2000 are estimates.

[e]Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 2000 are estimates.

[f]The conversion from physical units to Btu is calculated by using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review* (*MER*). Consequently, the historical data may not precisely match those published in the *MER* or the *Annual Energy Review (AER)*.

[g]Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

SPR: Strategic Petroleum Reserve.

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis and Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-0520; *Weekly Petroleum Status Report*, DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0101.

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Table 7

Table 7. Marketed Production of Natural Gas, by State, 1994-2000

(Million Cubic Feet)

Year and Month	Alabama[b]	Alaska	Arizona	California	Colorado	Florida	Kansas
1994 Total	515,272	555,402	752	309,427	453,287	7,486	712,730
1995 Total	519,661	469,550	558	279,555	523,084	6,463	721,436
1996 Total	530,841	480,828	463	286,494	572,071	6,006	712,796
1997 Total	583,272	468,311	452	285,690	637,375	6,114	687,215
1998							
January	46,466	43,382	43	24,752	57,511	503	53,032
February	41,653	39,244	42	22,151	52,954	491	48,698
March	46,476	42,479	53	22,708	58,795	592	52,948
April	46,281	38,540	43	21,952	57,586	531	51,415
May	48,978	35,281	38	23,894	57,916	513	54,334
June	49,638	36,217	34	24,871	55,989	426	52,862
July	50,131	36,171	42	27,157	57,737	486	51,324
August	49,215	36,118	36	29,727	58,584	472	54,059
September	42,308	36,884	32	29,114	57,005	498	43,419
October	47,503	39,958	31	30,467	60,868	423	47,058
November	46,682	39,483	33	29,508	59,592	401	47,359
December	48,447	42,890	33	28,974	61,783	459	47,078
Total	563,779	466,648	457	315,277	696,321	5,796	603,506
1999							
January	47,546	43,013	31	31,961	62,170	511	52,200
February	43,684	38,930	27	27,952	63,344	503	43,801
March	45,306	42,128	35	30,224	61,664	604	47,290
April	42,455	38,249	37	28,811	57,978	548	45,904
May	47,604	35,039	39	31,170	63,312	537	46,147
June	46,613	35,938	44	30,778	62,489	442	46,452
July	46,886	35,896	60	33,356	61,282	499	46,254
August	45,972	35,853	51	34,047	61,337	480	45,902
September	44,743	36,627	43	33,273	58,761	501	44,294
October	45,420	39,617	43	34,685	62,548	427	45,342
November	45,157	39,158	35	33,373	61,819	408	44,094
December	46,085	42,517	28	33,085	62,383	473	45,740
Total	547,271	462,967	474	382,715	739,085	5,933	553,419
2000							
January	[R]32,259	43,584	37	31,011	[RE]63,486	499	44,772
February	[R]30,264	38,884	33	28,855	[RE]60,681	480	42,199
March	[R]31,540	39,274	26	31,351	[RE]64,312	567	40,737
April	[R]30,422	39,084	28	30,645	[RE]62,013	[RE]500	[R]49,749
May	31,134	35,171	31	31,886	[RE]64,061	[RE]482	43,445
June	29,595	35,120	32	29,799	[RE]62,366	[RE]392	43,565
July	[R]30,209	36,894	32	31,124	[RE]63,526	[RE]432	42,591
August	[R]30,436	[E]36,962	33	32,702	[E]64,198	[E]398	[R]43,918
September	28,739	[E]37,375	33	47,344	[E]62,063	[E]447	40,524
2000 YTD	274,598	[E]342,348	285	294,719	[E]566,706	[E]4,197	391,500
1999 YTD	410,810	341,674	368	281,572	552,336	4,625	418,244
1998 YTD	421,146	344,317	361	226,329	514,078	4,513	462,091

See footnotes at end of table.

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Table 7

Table 7. Marketed Production of Natural Gas, by State, 1994-2000

(Million Cubic Feet) — Continued

Year and Month	Louisiana[b]	Michigan	Mississippi	Montana	New Mexico	North Dakota	Oklahoma
1994 Total	5,169,705	222,657	63,448	60,416	1,557,689	57,805	1,934,864
1995 Total	5,108,366	238,203	95,533	50,264	1,625,837	49,468	1,811,734
1996 Total	5,289,742	245,740	103,263	50,996	1,554,087	49,674	1,734,887
1997 Total	5,229,821	305,950	107,300	52,437	1,558,633	52,401	1,703,888
1998							
January	453,867	28,460	9,639	4,831	130,265	4,623	158,897
February	409,480	8,278	8,574	4,569	118,164	4,039	126,200
March	459,384	30,780	9,781	4,892	132,729	4,344	136,334
April	452,863	17,823	8,957	4,683	127,544	4,311	134,115
May	471,279	29,198	9,121	4,978	131,488	4,529	140,400
June	451,104	26,958	8,586	4,448	120,632	4,304	136,013
July	454,637	26,171	9,258	4,636	126,924	4,460	134,510
August	457,279	18,896	8,834	4,594	129,164	4,546	139,914
September	363,707	28,491	8,664	4,750	124,152	4,435	134,805
October	433,764	21,816	8,868	5,040	129,640	4,610	138,167
November	431,629	12,013	8,602	5,044	116,404	4,465	134,583
December	448,896	29,193	9,184	5,182	113,991	4,520	130,592
Total	5,287,870	278,076	108,068	57,645	1,501,098	53,185	1,644,531
1999							
January	459,044	20,743	9,152	5,235	129,321	4,408	135,369
February	417,264	8,426	8,678	4,768	116,787	3,931	121,063
March	462,267	40,112	9,933	5,240	128,657	4,227	133,865
April	451,763	22,574	9,426	4,889	126,045	4,299	125,362
May	457,608	25,240	9,708	5,057	125,612	4,345	128,071
June	437,730	25,084	9,480	4,666	125,381	4,333	128,410
July	455,946	23,988	9,542	5,178	127,971	4,578	134,140
August	451,409	19,154	9,406	5,123	130,728	4,542	139,529
September	429,403	24,652	9,198	5,026	124,664	4,432	126,716
October	439,129	13,540	9,050	5,305	130,728	4,613	139,787
November	422,311	21,676	8,608	5,048	127,749	4,534	130,810
December	429,918	32,175	8,840	5,629	118,027	4,622	127,725
Total	5,313,794	277,364	111,021	61,163	1,511,671	52,862	1,578,847
2000							
January	460,309	22,664	8,241	[R]5,938	119,673	4,596	[E]133,257
February	432,654	16,043	[R]5,386	[R]5,544	120,198	4,114	[E]124,665
March	467,392	33,779	7,350	[R]5,881	129,748	4,288	[E]132,000
April	452,175	12,800	6,785	[R]5,610	[RE]125,466	4,270	[E]128,321
May	462,558	26,717	[E]7,527	[R]4,958	[RE]127,931	4,530	[E]134,196
June	458,181	17,497	[E]6,938	[R]5,470	[RE]120,686	4,316	[E]128,340
July	470,775	30,350	[E]7,347	[R]5,876	[RE]125,694	4,503	[E]137,592
August	465,305	32,904	[E]7,571	[R]5,836	[E]128,081	4,329	[E]138,201
September	440,578	24,785	[E]7,341	5,724	[E]122,774	4,324	[E]129,454
2000 YTD	4,109,927	217,540	[E]64,486	50,837	[E]1,120,251	39,271	[E]1,186,026
1999 YTD	4,022,436	209,973	84,522	45,181	1,135,166	39,994	1,172,526
1998 YTD	3,973,581	215,054	81,415	42,379	1,141,062	39,590	1,241,188

See footnotes at end of table.

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Table 7. Marketed Production of Natural Gas, by State, 1994-2000

(Million Cubic Feet) — Continued

Year and Month	Oregon	Texas[c]	Utah	Wyoming	Other[a] States	U.S. Total
1994 Total	3,221	6,353,844	270,858	696,018	774,724	19,709,525
1995 Total	1,923	6,330,048	241,290	673,775	759,728	19,506,474
1996 Total	1,439	6,470,620	250,767	666,036	805,491	19,812,241
1997 Total	1,173	6,453,873	257,139	738,368	736,679	19,866,093
1998						
January	90	550,623	21,826	66,238	64,219	1,719,267
February	79	497,583	21,758	59,825	56,464	1,520,246
March	96	548,845	23,656	64,659	60,395	1,699,925
April	92	531,219	23,513	61,338	57,355	1,640,161
May	92	545,368	24,967	65,642	57,484	1,705,500
June	90	522,691	23,968	59,655	55,586	1,634,073
July	95	536,998	23,036	63,534	58,630	1,665,937
August	94	542,707	23,681	63,228	56,789	1,677,936
September	90	507,526	21,554	63,059	56,609	1,527,103
October	83	529,662	23,830	65,994	61,915	1,649,698
November	85	509,919	23,045	64,618	57,038	1,590,505
December	80	495,612	22,507	63,523	62,259	1,615,203
Total	1,067	6,318,754	277,340	761,313	704,742	19,645,554
1999						
January	83	526,872	23,467	68,995	73,022	1,693,142
February	84	482,797	21,141	63,372	64,209	1,530,761
March	120	528,147	23,878	69,149	67,861	1,700,709
April	111	509,507	22,076	65,885	64,148	1,620,068
May	113	526,194	22,771	63,061	65,032	1,656,660
June	111	504,194	21,828	68,120	63,027	1,615,119
July	110	524,016	21,707	66,954	64,718	1,662,881
August	74	513,844	21,493	68,293	63,445	1,650,681
September	90	499,047	19,725	68,694	64,276	1,594,165
October	124	517,242	21,610	72,965	70,415	1,652,589
November	134	495,575	21,364	70,952	68,512	1,601,317
December	138	490,218	21,554	76,691	71,915	1,617,763
Total	1,291	6,117,853	262,014	823,132	800,579	19,595,854
2000						
January	120	534,692	21,995	[E]86,404	[RE]75,054	[RE]1,688,591
February	101	497,914	20,513	[E]80,313	[RE]66,471	[RE]1,575,311
March	102	540,947	21,897	[E]85,644	[RE]71,039	[RE]1,707,874
April	95	518,945	21,241	[E]83,875	[RE]67,479	[RE]1,639,504
May	98	537,490	22,513	[E]83,469	[RE]68,351	[RE]1,686,551
June	90	529,585	21,508	[E]82,406	[RE]65,614	[RE]1,641,500
July	86	535,212	22,747	[E]85,393	[RE]67,413	[RE]1,697,797
August	92	546,326	22,739	[RE]86,757	[E]66,494	[RE]1,713,281
September	93	519,017	22,545	[E]85,039	[E]65,743	[E]1,643,942
2000 YTD	877	4,760,128	197,698	[E]759,299	[E]613,658	[E]14,994,352
1999 YTD	895	4,814,818	198,086	602,523	589,737	14,724,185
1998 YTD	818	4,783,560	207,959	587,177	523,530	14,790,148

[a] Includes Arkansas, Illinois, Indiana, Kentucky, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Pennsylvania, South Dakota, Tennessee, Virginia and West Virginia. The 2000 monthly values for these States are estimated.

[b] For Alabama and Louisiana, all data for 1994 through 1999 include Federal Offshore production. For 2000, Alabama data do not include Federal Offshore production, while data for Louisiana include both the Louisiana and Alabama portions of Federal Offshore Production.

[c] Federal offshore production volumes are included.

[R] Revised Data.

[E] Estimated Data.

[RE] Revised Estimated Data.

Notes: Data for 1994 through 1999 are final. All other data are preliminary unless otherwise indicated. Totals may not equal sum of components because of independent rounding. See Appendix A, Explanatory Notes 1 and 3 for discussion of computation procedures and revision policy.

Sources: 1994-1999: Energy Information Administration (EIA), *Natural Gas Annual 1999*. January 2000 through current month: Form EIA-895, "Monthly Quantity and Value of Natural Gas Report," Minerals Management Service reports, and EIA computations

Table 7

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About ENERGY STAR®

Money Isn't All You're Saving

ENERGY STAR is a dynamic government/industry partnership that makes it easy for busi consumers to save money and protect the environment.

For your home, ENERGY STAR:

- Labels energy-efficient products. Check out our Store Locator now or just look for STAR label on products like clothes washers, TVs/VCRs, heating and cooling equi more to save money on energy bills and help the environment at the same time!
- Labels energy-efficient new homes, that provide increased comfort and quality wh costs. Find out how to start saving 30% per year on your energy bills.
- Offers home improvement tools, so you can increase the comfort and energy effic home now

For your business, ENERGY STAR:

- Provides a benchmarking tool for buildings that allows you to compare your energ those of similar organizations. Measure your building's energy consumption and, v toolbox created by ENERGY STAR, improve your bottom line through increased ene environmental performance!
- Helps you purchase products for your business with the ENERGY STAR label
- Earn the ENERGY STAR label for your building and increase your bottom line

ENERGY STAR partner opportunities:

- Improve the energy and financial performance of your business/organization
- Label products that you manufacture to meet the ENERGY STAR specifications, and your product in the marketplace while demonstrating environmental stewardship
- Sell ENERGY STAR labeled products in your store and meet consumer demand for r environmentally friendly choices on store shelves
- Promote ENERGY STAR qualified products or homes as a utility or state funds admi Check out our list of partners
- Build ENERGY STAR qualified homes – homes with features that not only save hom 30% on their energy bills every year, but also offer better comfort and health, incr and a return on their investment.

Background on ENERGY STAR:

ENERGY STAR was introduced by the US Environmental Protection Agency in 1992 voluntary labeling program designed to identify and promote energy-efficient prod in order to reduce carbon dioxide emissions. EPA partnered with the US Departm Energy in 1996 to promote the ENERGY STAR label, with each agency taking responsibility for particular product categories. ENERGY STAR has expanded to cov homes, most of the buildings sector, residential heating and cooling equipment, appliances, office equipment, lighting, consumer electronics, and more product ar

Click here for the time line of ENERGY STAR milestones, past and present.

You Can Make A Difference:

If all consumers, businesses, and organizations in the United States made their pr choices and building improvement decisions with ENERGY STAR over the next deca the national annual energy bill would be reduced by about $200 billion. With that w come a sizable contribution to reducing air pollution and protecting the earth's clim for future generations. With ENERGY STAR, money isn't all you're saving.

For more information, call the **ENERGY STAR** Hotline at **1-888-STAR-YES** (1-888-7

(Quadrillion Btu)

	Fossil Fuels					Nuclear Electric Power	Hydroelectric Pumped Storage[c]	Renewable Energy[a]					Total
	Coal	Natural Gas (Dry)	Crude Oil[b]	Natural Gas Plant Liquids	Total			Conventional Hydroelectric Power	Wood, Waste, Alcohol[d]	Geothermal	Solar and Wind	Total	
1973 Total	13.992	22.187	19.493	2.569	58.241	0.910	(e)	2.861	1.529	0.043	NA	4.433	63.585
1974 Total	14.074	21.210	18.575	2.471	56.331	1.272	(e)	3.177	1.540	.053	NA	4.769	62.372
1975 Total	14.989	19.640	17.729	2.374	54.733	1.900	(e)	3.155	1.499	.070	NA	4.723	61.357
1976 Total	15.654	19.480	17.262	2.327	54.723	2.111	(e)	2.976	1.713	.078	NA	4.768	61.602
1977 Total	15.755	19.565	17.454	2.327	55.101	2.702	(e)	2.333	1.838	.077	NA	4.249	62.052
1978 Total	14.910	19.485	18.434	2.245	55.074	3.024	(e)	2.937	2.038	.064	NA	5.039	63.137
1979 Total	17.540	20.076	18.104	2.286	58.006	2.776	(e)	2.931	2.152	.084	NA	5.166	65.948
1980 Total	18.598	19.908	18.249	2.254	59.008	2.739	(e)	E 2.900	2.485	.110	NA	5.494	67.241
1981 Total	18.377	19.699	18.146	2.307	58.529	3.008	(e)	E 2.758	2.590	.123	NA	5.471	67.007
1982 Total	18.639	18.319	18.309	2.191	57.458	3.131	(e)	E 3.266	2.615	.105	NA	5.985	66.574
1983 Total	17.247	16.593	18.392	2.184	54.416	3.203	(e)	E 3.527	2.831	.129	(s)	6.488	64.106
1984 Total	19.719	18.008	18.848	2.274	58.849	3.553	(e)	E 3.386	2.880	.165	(s)	6.431	68.832
1985 Total	19.325	16.980	18.992	2.241	57.539	4.149	(e)	E 2.970	E 2.864	.198	(s)	6.032	67.720
1986 Total	19.509	16.541	18.376	2.149	56.575	4.471	(e)	E 3.071	E 2.841	.219	(s)	6.132	67.178
1987 Total	20.141	17.136	17.675	2.215	57.167	4.906	(e)	E 2.635	E 2.823	.229	(s)	5.687	67.760
1988 Total	20.738	17.599	17.279	2.260	57.875	5.661	(e)	E 2.334	E 2.937	.217	(s)	5.488	69.025
1989 Total	21.348	17.847	16.117	2.158	57.468	f 5.677	(e)	2.855	E 3.050	.323	.083	6.311	69.457
1990 Total	22.456	18.362	15.571	2.175	58.564	6.162	-.036	3.046	E 2.846	.343	.094	6.132	70.822
1991 Total	21.594	18.229	15.701	2.306	57.829	6.580	-.047	3.021	E 2.687	.348	.097	6.153	70.515
1992 Total	21.629	18.376	15.223	2.363	57.590	6.608	-.043	2.617	E 2.831	.355	.097	5.901	70.056
1993 Total	20.249	18.584	14.494	2.408	55.736	6.520	-.042	2.892	2.791	.369	.102	6.153	68.367
1994 Total	22.111	19.348	14.103	2.391	57.952	6.838	-.035	2.684	2.825	.364	.107	5.980	70.836
1995 Total	22.029	19.101	13.887	2.442	57.458	7.177	-.028	3.207	3.056	.314	.106	6.683	71.291
1996 Total	22.684	19.363	13.723	2.530	58.299	7.168	-.032	3.593	3.114	.332	.110	7.148	72.583
1997 Total	23.211	19.394	13.658	2.495	58.758	6.678	-.042	3.719	2.991	.322	.107	7.120	72.532
1998 January	2.081	1.680	1.176	.211	5.155	.615	(s)	E .298	E .256	E .029	E .008	.591	6.362
February	1.850	1.493	1.052	.196	4.591	.542	.001	E .308	E .230	E .025	E .008	.571	5.705
March	2.042	1.689	1.152	.217	5.079	.571	(s)	E .326	E .255	E .029	E .009	.619	6.268
April	1.955	1.610	1.128	.211	4.904	.506	-.005	E .295	E .246	E .025	E .009	.574	5.979
May	1.926	1.674	1.141	.214	4.956	.547	-.008	E .341	E .253	E .025	E .009	.627	6.123
June	1.962	1.604	1.091	.198	4.854	.592	-.007	E .332	E .245	E .025	E .009	.611	6.051
July	1.831	1.636	1.114	.185	4.865	.653	-.007	E .298	E .254	E .028	E .009	.587	6.099
August	1.944	1.647	1.115	.201	4.908	.641	-.007	E .261	E .256	E .029	E .009	.553	6.095
September	2.034	1.489	1.007	.184	4.735	.600	-.003	E .210	E .247	E .028	E .008	.502	5.841
October	2.083	1.629	1.104	.204	4.991	.610	-.005	E .199	E .256	E .030	E .009	.494	6.090
November	1.920	1.562	1.068	.200	4.750	.609	-.005	E .210	E .247	E .028	E .009	.494	5.847
December	2.011	1.606	1.087	.189	4.872	.664	(s)	E .262	E .258	E .028	E .009	.557	6.093
Total	23.719	19.284	13.236	2.420	58.663	7.157	-.046	3.345	3.003	.327	.104	6.700	72.662
1999 January	1.942	1.653	1.072	.192	4.858	.695	-.006	R .300	RE .302	E .027	RE .008	R .636	R 6.185
February	1.866	1.494	.969	.181	4.509	.608	-.004	R .295	RE .270	E .024	E .007	.598	R 5.810
March	2.090	1.690	1.058	.207	5.024	.622	-.004	R .329	RE .298	RE .026	E .008	R .660	R 6.302
April	1.908	1.581	1.024	.203	4.714	.513	-.005	R .284	RE .288	E .025	E .009	.607	R 5.830
May	1.818	1.817	1.056	.208	4.899	.593	-.007	R .299	RE .298	E .028	RE .011	R .635	R 5.920
June	R 1.931	1.576	1.002	.210	4.720	.659	-.006	R .310	RE .288	RE .033	E .011	.642	R 6.015
July	R 1.879	1.623	1.042	.221	R 4.766	.710	-.008	R .301	RE .299	E .036	RE .011	.647	R 6.116
August	R 1.963	1.611	1.039	.217	R 4.851	.725	-.008	R .282	RE .299	RE .037	RE .010	R .600	R 6.177
September	R 1.876	1.556	1.010	.215	R 4.757	.648	-.004	R .218	RE .296	E .035	E .009	R .556	R 5.957
October	1.924	1.613	1.069	.227	4.833	.501	-.005	R .208	RE .297	E .036	E .008	R .550	R 5.968
November	1.961	1.563	1.037	.219	4.780	.645	-.005	R .219	RE .290	RE .034	RE .008	R .550	R 5.971
December	1.971	1.579	1.071	.227	4.848	R .720	-.004	R .281	RE .301	E .033	E .008	R .624	R 6.194
Total	R 23.356	19.126	12.451	2.528	R 57.460	7.738	R -.063	R 3.305	R 3.622	.374	.110	R 7.311	R 72.444
2000 January	1.867	E 1.654	E 1.049	.225	R 4.795	.723	-.005	R .281	RE .302	E .027	RE .010	R .600	R 6.102
February	1.849	E 1.543	E .991	.215	4.598	.665	-.005	R .231	RE .283	RE .024	RE .009	R .547	R 5.795
March	2.110	E 1.673	E 1.066	.290	R 5.089	.643	-.008	R .273	RE .302	E .023	RE .010	R .608	R 6.314
April	R 1.780	E 1.808	E 1.018	R .220	R 4.804	.586	-.004	R .291	RE .291	RE .025	E .011	R .619	R 5.816
May	R 1.909	E 1.862	E 1.049	.225	R 4.838	.653	-.005	R .281	RE .299	E .026	RE .010	R .616	R 6.100
June	R 1.950	E 1.608	E 1.013	R .215	R 4.787	.686	-.008	R .259	RE .288	E .028	RE .009	R .581	R 6.048
July	R 1.813	E 1.663	E 1.041	R .222	R 4.740	.736	-.003	R .251	RE .305	RE .027	RE .009	R .592	R 6.064
August	R 2.068	E 1.879	E 1.045	R .225	R 5.018	.722	-.004	R .229	RE .302	E .028	E .009	R .568	R 6.304
September	R 1.910	E 1.611	E 1.003	.216	R 4.740	.654	-.006	R .188	RE .292	E .027	E .009	.516	R 5.904
October	R 1.999	RE 1.670	E 1.048	R .222	R 4.837	.687	-.004	R .180	RE .304	E .029	E .010	R .522	R 6.041
November	R 1.945	RE 1.628	E 1.021	R .210	R 4.803	.633	-.004	R .199	RE .295	E .028	RE .010	.532	R 5.963
December	1.804	E 1.764	E 1.090	.183	4.791	.721	-.008	.205	E .303	E .029	E .009	.546	6.052
Total	22.075	E 19.741	E 12.363	2.601	57.707	8.009	-.058	E 2.848	E 3.568	E .317	E .115	6.846	72.504

= 9.4%

[a] End-use consumption, and electric utility and nonutility electricity net generation.
[b] Includes lease condensate.
[c] Pumped storage facility production minus energy used for pumping.
[d] Alcohol is ethanol blended into motor gasoline.
[e] Included in conventional hydroelectric power.
[f] Beginning in 1989 includes electricity generated by nonutility nuclear units.
R=Revised. NA=Not available. E=Estimate. (s)=Less than +0.5 trillion Btu and greater than -0.5 trillion Btu.

Notes: • See Note 1 at end of section. • Totals may not equal sum of components due to independent rounding. • Geographic coverage is the 50 States and the District of Columbia.

Sources: • Coal: Tables 6.1 and A3. • Natural Gas (Dry): Tables 4.1 and A4. • Crude Oil and Natural Gas Plant Liquids: Tables 3.1a and A2. • Nuclear Electric Power: Tables 8.1 and A6. • Hydroelectric Pumped Storage: Tables 7.2 and A6. • Renewable Energy: Tables E2, E3a, and E3b.

4

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According to the National Petroleum Council Report on natural gas (December 1999):

Much of the nation's natural gas resource base resides on federal lands or in federal waters, yet a large portion of this resource base is not open to either assessment or development. Two of the most promising regions for future gas production, the Rocky Mountains and the Gulf of Mexico, currently have significant access restrictions. For example, an estimated 40%—or 137 trillion cubic feet (TCF)—of potential gas resource in the Rockies is on federal land that is either closed to exploration or is open under restrictive provisions. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. The eastern Gulf of Mexico is largely closed to exploration and the limited areas that are now open are the subject of political debate. The proposed MMS Lease Sale 181 scheduled for December 2001 in the eastern Gulf of Mexico is the first such sale in this area since the late 1980s, yet only covers a small portion of the entire area. The East Coast of the United States is completely closed to development while Canada is pursuing its East Coast gas resources, as demonstrated by the Sable Island development off the coast of Nova Scotia. In addition, drilling on the West Coast of the United States also faces strong restrictions, while offshore British Columbia is opening up to greater exploration and production.

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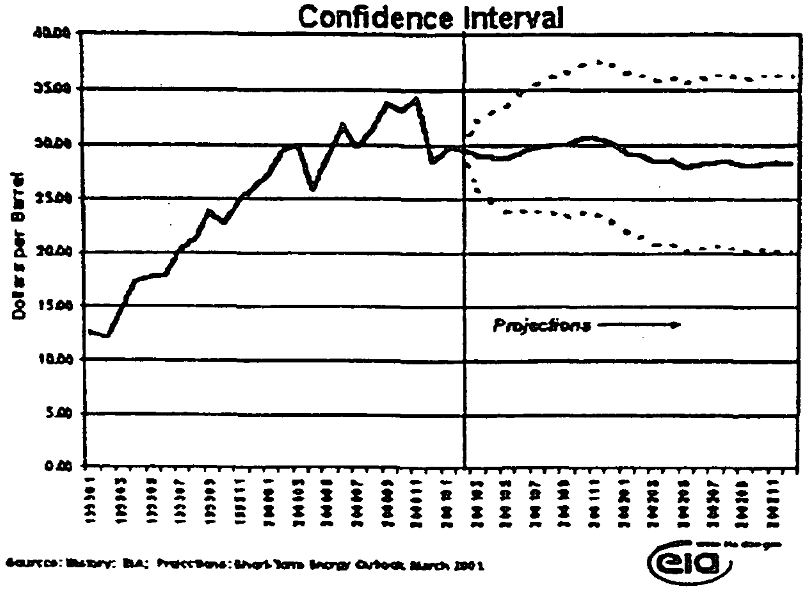
Short-Term Energy Outlook

April 2001

Figure 1. WTI Crude Oil Price: Base Case and 95% Confidence Interval



Overview

U.S. economic growth assumptions have been lowered for this edition of the Outlook from last month's report, resulting in somewhat weaker expected growth in U.S. energy consumption. We now expect U.S. real GDP to advance at about 2.2 percent in 2001 instead of the 2.6 percent projected in February. A result of the downward revision in projected growth this year is a slightly more rapid rebound in 2002 but overall levels of economic activity are lower throughout the projection period. Oil demand in the United States and other consuming regions is now seen as to increase less rapidly in 2001 than projected previously. We have adjusted global oil demand growth for this year downward to 1.5 million barrels per day from the 1.6 million barrels per day indicated last month. This results in projected world demand levels of 77.2 million barrels per day in 2001 and 78.9 million barrels per day in 2002. Cumulatively, we have lowered the world demand total expected for 2001 by 700,000 barrels per day from the level projected three months ago.

Despite the lower demand outlook, industrialized country oil stocks continue to fall below expectations, effectively offsetting most if not all of any resulting downward pressure on prices relative to the levels indicated in our previous Outlook. Thus, we see the U.S. refiner cost of crude oil likely to average around $26.60 per barrel this year compared to $27.70 per barrel in 2000. Our view of the world oil balance suggests that significant improvement in the inventory situation (on a seasonally adjusted basis) over the next 21 months is rather unlikely, so prices are likely to remain relatively high through 2002 (Figure 1). A more severe slowdown in economic growth in consuming countries than we are allowing for in our base case could alter the price outlook significantly. We have evaluated in some detail the sort of overall demand impacts in the United States that could be expected under a very low short-term growth scenario. In such a case, U.S. oil demand growth could be reduced by as much as 150,000 - 200,000 barrels per day relative to the base case. Reverberations worldwide from such a development would be expected to generate additional reductions in demand elsewhere in 2001 or 2002.

The U.S. natural gas supply picture seemed to brighten a little last month as average storage withdrawals during the month were below normal and below previous expectations. However, even if only modest withdrawals are required this month, we are still likely to end the heating season with the total level of gas in storage below the previous low recorded by EIA. In our view, only a spectacular performance from the U.S. and Canadian gas industry in terms of increased production or an extremely mild summer this year would generate much in the way of additional reductions in natural gas prices beyond what has already happened since mid winter. As we currently expect working gas to reach 689 billion cubic feet at end-March, seasonal injections of 2,310 billion cubic feet would be required from April through October to reach 3 trillion cubic feet (the approximate average end-October level between 1995 and 1999) before the next heating season. That kind of build would be about 500 billion cubic feet (25 percent) above average (1995-1999). Consequently we expect the industry to fall well short. Average monthly gas spot prices below $4 per thousand cubic feet between now and next winter are possible but do not seem very likely under these circumstances.

More good news for Northeast heating oil customers arrived since last month. Average residential heating oil prices fell to an estimated $1.32 per gallon in February from the $1.37 per gallon seen in January. This was 9 cents below the December average. The winter average is now expected to be $1.36 per gallon, 8 percent below the $1.48 price we projected as recently as January. Household heating oil expenditures for the winter will still be about 27 percent above last year's estimated level, but this is certainly less dramatic than the 40 percent projected in January (Figure 2). Because of strong production and imports and a respite from the kind of abnormally cold weather seen at the beginning of winter, inventories of heating oil are now within the normal range. For natural gas consumers, the expected level of winter expenditures has not changed much. We still expect that the increase in household gas bills over last winter will amount to 70-75 percent (Figure 3).

International

Crude Oil Prices. The monthly average U.S. imported crude oil price in February was about $26 per barrel (almost $30 per barrel for West Texas Intermediate crude oil), about $1 per barrel higher than January's average U.S. imported crude oil price (Figure 1).

Price declines during the past few weeks had indicated weakness in the near-term market. However, EIA believes that the OPEC 10's (OPEC excluding Iraq) decision to cut oil production quotas effective February 1 will provide enough support to maintain world oil prices near current levels. EIA does not believe that further quota cuts are necessary to maintain the OPEC basket oil price (roughly equivalent to the average U.S. imported crude oil price) within OPEC's target range of $22 - $28 per barrel in 2001 and 2002.

International Oil Supply. Although OPEC cut production quotas by 1.5 million barrels per day effective February 1, OPEC has suggested that further cuts could be needed to maintain the OPEC basket price within its desired range. In addition, some OPEC delegates have suggested that further quota cuts may be adopted even if the OPEC basket prices remain within this range, in part because of concerns that a seasonal second quarter decline in demand and a world economic slowdown could weaken the demand for OPEC oil. OPEC Secretary-General Ali Rodriguez was earlier quoted as saying that there was "almost a conviction" among producers for a production cut ahead of a forecasted drop in demand in the second quarter, with the cuts totaling up to 1 million barrels per day.

EIA's assessment does not factor in any further cuts in 2001 because EIA's analysis indicates that the February 1 quotas are sufficient to support OPEC's desired price range. The seasonal decline in demand during the second quarter is seen as a necessary accompaniment to the seasonal stock build normally associated with this time of year. EIA expects that oil stocks in the OECD countries will continue to be tight compared to normal levels and will provide enough support to prevent prices from falling significantly.

Iraqi efforts to end U.N. sanctions have continued to result in lowered exports and production since December. The U.N. reported that reduced Iraqi exports have resulted in a revenue loss of over $2.2 billion or $2.4 billion (euros) to the program since December 2000. Despite these revenue losses, EIA's projections assume that Iraqi efforts to end sanctions will continue in 2001 with negative consequences on Iraqi exports and production (Figure 4). Iraqi production in 2001 is not assumed to exceed the 3 million barrels per day level reached as recently as October 2000.

Non-OPEC production is expected to increase by another 0.7 million barrels per day in 2001, and another 0.9 million barrels per day in 2002. This represents an increase of 100,00 barrels per day from the previous Outlook, with the gain expected primarily from the former Soviet Union.

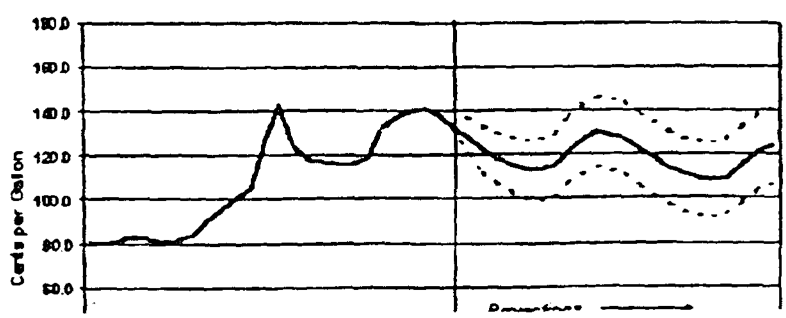
International Oil Demand. World oil demand is expected to continue to grow despite concerns over a gradual economic slowdown in the industrialized countries (Figure 5). However, EIA has lowered its projected world oil demand in 2001 by 100,000 barrels per day from the previous Outlook, reducing world oil demand growth to 1.5 million barrels per day in 2001. Non-OECD Asia is still expected to be the leading region for oil demand growth over the next two years.

World Oil Inventories. EIA does not attempt to estimate oil inventory levels on a global basis, however, the direction global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. These estimates provide only a rough guide because of what has come to be known as the "missing barrels problem". The available limited data for tracking inventories suggest that inventories have not been building as fast as any of the global supply/demand estimates (including EIA's) would indicate, and that the inventory estimates are being overstated.

The most reliable inventory data are from the OECD countries. The data indicates that there was very little stockbuild in 2000 for these countries, which account for a little more than half of total world oil demand (Figure 6). However, EIA's global supply/demand estimates suggest that OECD inventories should have been building by almost 400,000 barrels per day in 2000. EIA's projections for OECD inventories are adjusted to reflect the assumption that the "missing barrels problem" will continue in 2001, but will be diminished by 2002. With this adjustment, OECD inventories are projected to grow relatively slowly in 2001 and 2002. EIA believes that this stock growth will be small enough to provide continued price support because inventories will continue to be low compared to levels required to provide normal coverage for forward demand.

EIA's evaluation of normal OECD stock levels accounts for both historical averages and increasing inventory requirements, reflecting world demand increases. For this reason, EIA's assessments of OECD stocks are more bullish for prices than those using just historical averages.

Figure 7. Residential Heating Oil Prices: Base Case and 95% Confidence Interval



U. S. Energy Prices

Heating Oil. Retail heating oil prices have been sliding down from their winter peak of $1.41 per gallon last December. Our winter heating oil prices are expected to average around $1.36 compared to $1.39 in our previous Outlook.

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Nevertheless, retail heating oil prices have been quite high in historical terms. The national average price for the 4th quarter (October-December) of last year was almost 40 cents per gallon above the 1999 4th quarter price (Figure 7). Now that the heating season (October-March) is nearly over, we can be confident that retail heating oil prices have peaked for the winter, provided that no sustained crude oil price shocks occur over the next month. Warmer than normal weather for the first two months of the year accompanied by falling crude oil prices in December (dropping about $5.00 dollars per barrel from November) and January, have helped ease heating oil prices. Because of the relatively mild weather in the Northeast during the last half of January and portions of February, heating oil stock levels have stayed fairly steady over the past two months. For the first time since November 1999, U.S. distillate stocks are currently within bounds of the normal range (Figure 8). Also, heating oil production had been quite vigorous, running several hundred thousand barrels per day over last year's pace.

Motor Gasoline. Pump prices have dropped about 10 cents per gallon since last September, but will soon be heading back up as we enter the driving season in April. With crude oil prices gaining about $1.00 per barrel from their December lows, combined with lower than normal stock levels, we project that prices at the pump will rise to about $1.49 per gallon (for regular unleaded self-service) during the peak months of the driving season (Figure 9). For the summer of 2001, we are projecting an average price of $1.47 per gallon, compared to $1.53 seen during the previous driving season. Even though motor gasoline stocks during the driving season are projected to be slightly lower than they were a year ago (Figure 10), crude oil prices are also projected to be lower. Moreover, last year the high national average prices were skewed by exceedingly high pump prices in the Midwest (over $2.00 per gallon at times), which, in turn, were the result of critical regional supply problems. Although in our base we do not project a repeat of last year, the current situation of relatively low inventories for gasoline could once again set the stage for some regional imbalances in supply that could bring about significant price volatility in the U.S. gasoline market.

Natural Gas. Natural gas prices (Figure 11) began an ascent that originated last summer primarily in response to low levels of underground gas storage. Spot prices have increased well over $4.00 per thousand cubic feet since late June, even topping $10.00 per thousand cubic feet on several occasions this winter. The wellhead price this heating season is likely to end up more than double the price of last heating season. The length of time that gas prices have remained so high is unprecedented. Moreover, the current dynamics of the natural gas market leads us to believe that prices at the wellhead will not soon be returning to the low $2.00 per thousand cubic feet experienced just one year ago. The chief basis for our view is our outlook for robust levels of gas demand growth over the next two years, particularly in the electric power sector. By the year 2002, more than half of the increases in electricity generation are expected to come from natural gas. Furthermore, gas demand in the industrial sector (the single largest gas consuming sector) is also expected to make strong gains over the same time period. Although gas production and imports are expected to increase in the forecast period, we believe that the gains in supply will not be enough to bring the wellhead price down to the $2.00-3.00 range in the short-term.

We expect that winter (October 2000-March 2001) natural gas prices at the wellhead will end up averaging about $5.64 per thousand cubic feet. In our base case, residential prices for natural gas this winter would be about 46 percent higher than last year during that period. When the heating season ends next month, average wellhead prices are projected to decline, averaging about $4.05 per thousand cubic feet for the spring and summer. However, if the summer weather is exceedingly hot in regions that consume large quantities of gas-fired electricity, (California and Texas for example), then injections into underground storage for the next winter would be strained and prices could start rising more sharply and sooner than expected. In 2001, the annual average wellhead price is projected to be about $4.73 per thousand cubic feet. Next year, we expect the storage situation to improve modestly and with that, a decrease in the average annual wellhead price. Increases in production and imports of natural gas needed

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to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

Electric Utility Fuels. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices on a cost per Btu basis (Figure 12). As this situation is likely to persist, we anticipate some recovery in the amount of oil used for power generation over the very low levels seen since late 1999. In 2001, the cost of coal to electric utilities is projected to increase slightly, after years of slow but continual decline, as coal, like oil, is being used more intensively for electricity generation lieu of expensive or unavailable natural gas. On an inflation-adjusted basis, however, coal prices should still show a deadline this year.

U.S. Oil Demand

The recent release of December 2000 monthly data confirms the overall shrinkage in last year's petroleum demand that had become increasingly apparent for the past several months. The data for last year show that shipments of petroleum products declined by 30,000 barrels per day despite substantial growth in major economic indicators for much of the year (Figure 13). Despite robust economic growth and the presence of colder-than-normal weather of the fourth quarter, petroleum markets were unable to overcome the effects of a record mild first quarter--the peak heating season--and the substantial increase in energy prices that eroded demand during the second half of the year.

Motor gasoline demand in 2000 fell by almost 50,000 barrels per day, reflecting a fractional decline in highway travel activity brought about by a 30-percent year-to-year increase in retail motor gasoline prices. Although highway travel declined during the third quarter---the peak driving season--from that of the previous year, the lagged effects of the earlier price increases and the moderation in economic growth resulted in an even larger year-over-year contraction in the fourth quarter. Despite a 10-percent hike in ticket prices in 2000, commercial jet fuel demand, buoyed by 6.5- and 4.5-percent increases in utilization and capacity, respectively, rose 3.5 percent. (The resultant 2-percent increase in load factor boosted consumption by constraining fuel-efficiency increases to only one percent, half the long-term average). Total jet fuel deliveries, which include corporate, military, and weather-related components, rose just 2.0 percent, down from 3.1 percent in the previous year. The record mild warm weather of the first quarter depressed shipments of jet fuel used as a blending component during the winter months. Distillate fuel oil demand grew by 3.2 percent in 2000 led mostly by strength in transportation diesel demand. Residual fuel shipments, highly sensitive to changes in relative prices, fluctuated wildly but managed to increase by 1.8 percent for the year as a whole. Following a year of double-digit increases, the combination of slowdowns in petrochemical activity, and mild weather resulted in a slight decline in the total demand for liquefied petroleum gas and oil-based petrochemical products.

During the forecast interval, total petroleum demand is projected to increase once again. Despite the current economic slowdown, growth in real disposable income is projected to be 3.1 percent in 2001, and a robust 4.6 percent in 2002. Petroleum prices, which are expected to decline slowly throughout the forecast interval, will not have the same kind of negative impact on demand this year that was brought about last year by large average price increases. Weather patterns are assumed to exhibit normal seasonality. In this environment, total petroleum demand is projected to increase by 260,000 barrels per day in 2001, accelerating to 443,000 barrels per day next year, a 1.8-percent average increase. Reversing last year's declines, motor gasoline demand and highway travel activity are both expected to increase, but at an average of only 2.2 percent despite the steady downward trend in retail gasoline prices and robust growth in disposable income. Total jet fuel demand is expected to increase by an average 1.6-percent rate, with commercial demand rising by 3 percent. Distillate fuel demand is projected to rise by an average of 2.1 percent, down from the 3-percent average of the previous 2 years, due to a moderation in transportation demand. Demand for residual fuel oil is projected to continue to decline throughout the forecast interval, as declines in non-power generation demand offset a modest recovery in shipments to power generators.

U.S. Oil Supply

Average domestic oil production is expected to be flat in 2001, at a level of 5.83 million barrels of oil per day (Figure 14). For 2002, a 0.20 percent rise is expected to result in a production rate of 5.84 million barrels of oil per day average for the year.

In the Lower-48 States, oil production is expected to decline by 53,000 barrels per day to a rate of 4.80 million barrels per day in 2001,and followed by an decrease of 13,000 barrels per day in 2002. Oil production from the Mars, Troika, Ursa, and Brutus Federal Offshore fields is expected to account for about 8.2 percent of the lower-48 oil production by the 4th quarter of 2002.

Alaska is expected to account for about 18 percent of the total U.S. oil production in 2002. Its oil production is expected to increase by 5.6 percent in 2001 and by 2.4 percent in 2002. The gain in 2001 is the result of adding two new satellite fields, Colville River (Alpine) and Prudhoe Bay (Aurora) which contributed to the Alaska North Slope production. Initial rates from Alpine averaged 67,000 barrels per day during January and it is expected to peak at 80,000 barrels per day in mid-2001, while Aurora peak production should occur later in the year. Another satellite field, North Star, is expected to come on in early to mid-2002 and will peak at a rate of 65,000 barrels per day by year's end. A substantial portion of the oil production from Alaska comes from the giant Prudhoe Bay Field. As a result of maintenance, better well work, more development drilling, and better coordination of occasional down time, this field's decline rate last year has changed from the usual 10 percent to only 3 percent per year. However, the field is expected to follow a steeper decline during this forecast period. Oil production from recent discoveries is expected to substantially offset the decline in oil production from the Prudhoe Bay field in the North Slope in 2001. Production from the Kuparuk River field plus like production from West Sak, Tabasco and Tarn fields is expected to stay at an average of 236,000 barrels per day in the 2001-2002 forecast period.

Natural Gas Demand and Supply

U.S. natural gas demand is expected to grow at about a 2.3-percent rate this year, following the strong 4.4-percent performance in 2000 (Figure 15). A slowing economy and less rapid demand growth in the industrial and commercial sectors is the reason. Growth in 2002 is expected to heat up again to about 4.1 percent as the economy picks up again and as new gas-fired power generation requirements continue to mount.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 3.1 percent in 2000 and it is forecast to continue to increase by 3.3 percent rate in 2001 and 2.5 percent in 2002.

According to the American Gas Association (AGA), during the week ending February 23, a total of 101 billion cubic feet (bcf) was withdrawn from storage, bringing the total of working gas to 26 percent full (Figure 16). Based on this information, we estimate that, on an EIA survey basis, working gas in storage at end-February will reach 901 billion cubic feet. From this we project that end-season (March 31) working gas will fall to 689 bcf. This level is more than 100 bcf above last month's projections. While this represents an improvement over previous estimates (and expectations for March spot prices have softened some over the last 2 months) such an end-season level would still represent the lowest recorded

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by EIA and is 38 percent below the previous 5-year average. We estimate that net injection, between April 1 and October 31, would have to be about 500 bcf (25 percent) above average to bring working gas to average pre-season levels for next winter. We think that only about 60 percent of the extra 500 bcf is likely during the injection season, so that a 200 bcf deficit relative to the 5-year average is likely at end-October.

Net imports of natural gas are projected to rise by about 15 percent in 2001 and by another 4 percent in 2002. For this winter, we expect net imports to be 6.6 percent higher than last winter's imports. The Alliance Pipeline began carrying gas from western Canada to the Midwest on December 1, having been delayed from its original October 2 opening. A new report by Canada's National Energy Board predicts that gas deliverability from Western Canada will rise by 1.1 bcf/d by 2002, due to the ongoing drilling boom. Western Canada supplies 15 percent of the gas consumed in the United States.

Electricity Demand and Supply

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.2 percent in 2001 and 2.3 percent in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This winter's overall heating degree-days (HDD) are assumed to be about 17 percent above last winter's HDD, which were well below normal. This is based on the very cold temperatures seen in November and December, the somewhat more moderate rise in HDD in January and February, as well as on the assumption that the less than one month remaining of winter will be normal. This winter, total electricity demand is expected to be up by 4.6 percent over last winter's level, driven by increased demand in the residential and commercial sectors, which are expected to be up by 8 and 4 percent, respectively (Figure 17 and Table 10).

In the fourth quarter of 2000, previously falling demand for oil-fired generation began to turn around as the price differential between natural gas and oil in the electricity generating sector shifted to favor oil, prompting those plants which can switch to oil to do so. This trend is projected to continue through first quarter 2001. Although the favorable price differential for oil relative to gas is expected to continue through the forecast period, by the second half of 2001, expected increases in gas-fired capacity are expected to keep gas demand for power generation growing.

Natural gas supply and deliverability problems in California for gas-fired electricity generation have helped to boost gas price to electric producers and other consumers. The situation in California is characterized by low gas storage, gas pipeline bottlenecks, high demand and low hydropower availability. These supply problems are following on last summer's supply problems with no obvious end visible over the next two years. Average California gas prices dramatically outstripped prices elsewhere in the country through December but have since been coming down as weather-related demand has eased up somewhat (Figure 18).

Table HL1. U. S. Energy Supply and Demand

(Energy Information Administration/Short-Term Energy Outlook – March 2001)

	Year				Annual Percentage Change		
	1999	2000	2001	2002	1999-2000	2000-2001	2001-2002
Real Gross Domestic Product (GDP) (billion chained 1996 dollars)	8876	9321	9526	9928	5.0	2.2	4.2

Imported Crude Oil Price [a] (nominal dollars per barrel)	17.22	27.72	26.57	25.43	61.0	-4.1	-4.3
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	5.88	5.84	5.84	5.84	-0.7	0.0	0.0
Total Petroleum Net Imports (including SPR)	9.91	10.11	10.71	11.00	2.0	5.9	2.7
Energy Demand							
World Petroleum (million barrels per day)	74.9	75.7	77.2	78.9	1.1	2.0	2.2
Petroleum (million barrels per day)	19.52	19.49	19.76	20.21	-0.2	1.4	2.3
Natural Gas (trillion cubic feet)	21.70	22.65	23.18	24.14	4.4	2.3	4.1
Coal [c] (million short tons)	1044	1078	1085	1095	3.3	0.6	0.9
Electricity (billion kilowatthours)							
Retail Sales [d]	3312	3414	3468	3543	3.1	1.6	2.2
Nonutility Use/Sales [e]	185	210	236	247	13.5	12.4	4.7
Total	3497	3624	3704	3790	3.6	2.2	2.3
Total Energy Demand [f] (quadrillion Btu)	97.1	98.4	99.2	101.3	1.3	0.8	2.1
Total Energy Demand per Dollar of GDP (thousand Btu per 1996 Dollar)	10.94	10.56	10.42	10.20	-3.5	-1.3	-2.1
Renewable Energy as Percent of Total [g]	7.2	7.0	7.0	7.0			

[a]Refers to the refiner acquisition cost (RAC) of imported crude oil.

[b]Includes lease condensate.

[c]Total Demand includes estimated Independent Power Producer (IPP) coal consumption.

[d]Total of retail electricity sales by electric utilities and power marketers. Utility sales for historical periods are reported in EIA's *Electric Power Monthly* and *Electric Power Annual*. Power marketers' sales for historical periods are reported in EIA's Electric Sales and Revenue, Appendix C. Data for 2000 are estimates.

[e]Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 2000 are estimates.

[f]The conversion from physical units to Btu is calculated by using a subset of conversion factors used in the calculations performed for gross energy consumption in Energy Information Administration, *Monthly Energy Review (MER)*. Consequently, the historical data may not precisely match those published in the *MER* or the *Annual Energy Review (AER)*.

[g]Renewable energy includes minor components of non-marketed renewable energy, which is renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy. The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

SPR: Strategic Petroleum Reserve.

Notes: Minor discrepancies with other published EIA historical data are due to independent rounding. Historical data are printed in bold; forecasts are in italics. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Latest data available from Bureau of Economic Analysis and Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-0520; *Weekly Petroleum Status Report*, DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0101.

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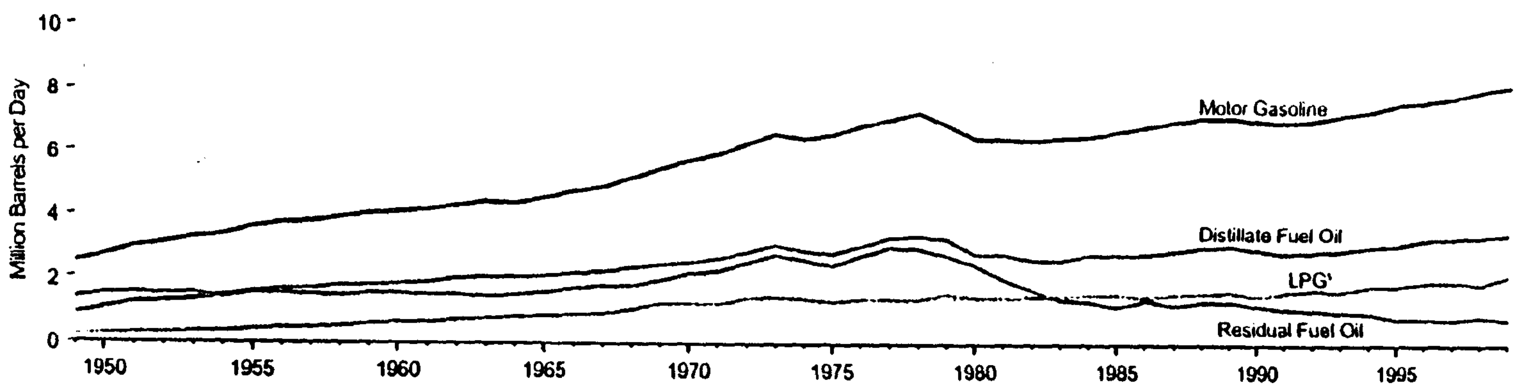
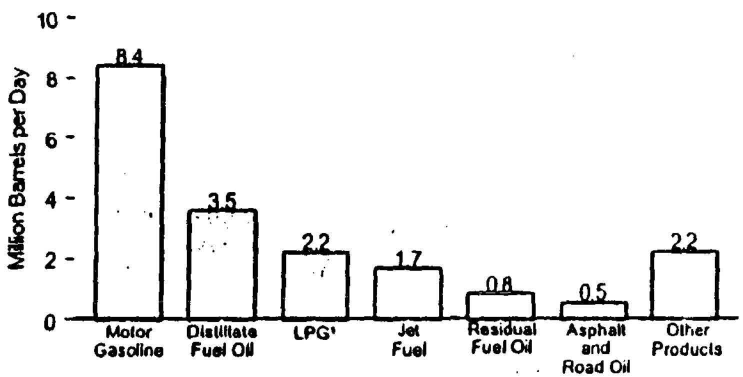
Figure 5.11 Petroleum Products Supplied by Type

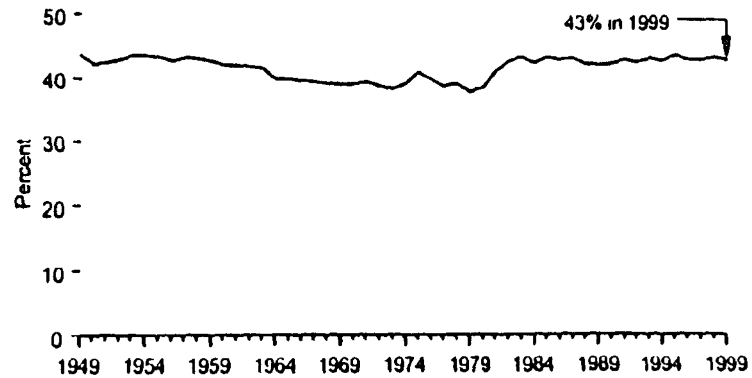
By Selected Product, 1949-1999



By Product, 1999



Motor Gasoline's Share of Total Petroleum Products Supplied, 1949-1999



[1] Liquefied petroleum gases.

Source: Table 5.11.

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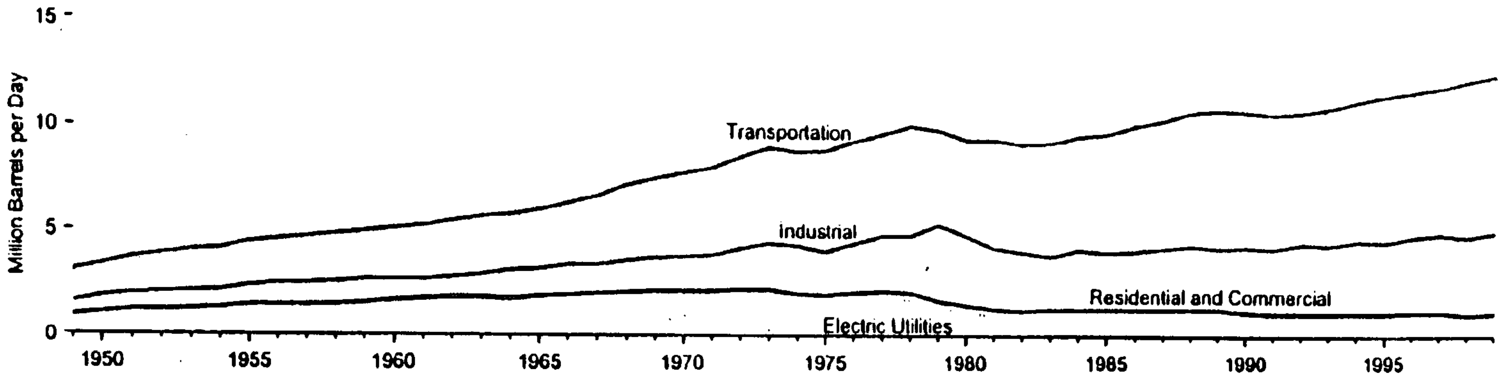
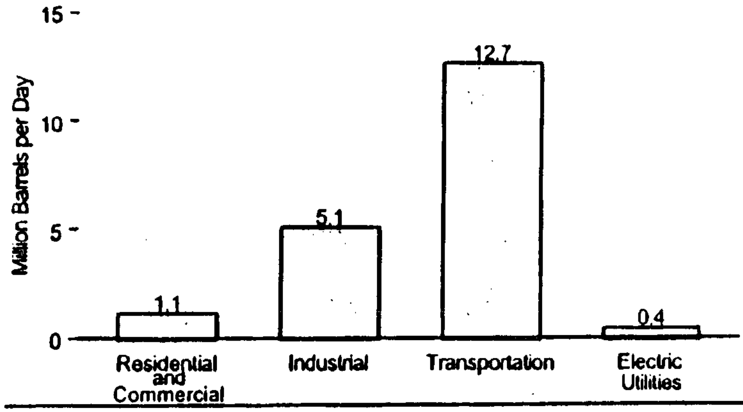
Figure 5.12a Petroleum Products Supplied by Sector

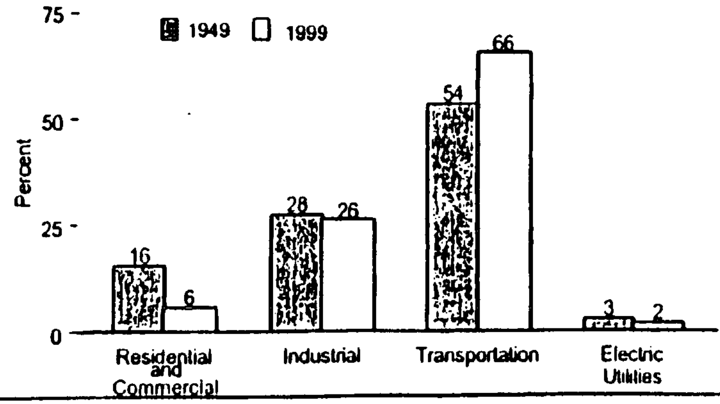
By Sector, 1949-1999



By Sector, 1999



Shares[1] by Sector, 1949 and 1999



[1] Sum of shares may not equal 100 percent due to independent rounding.

Note: See related Figure 5.12b.

Sources: Tables 5.12a and 5.12b.

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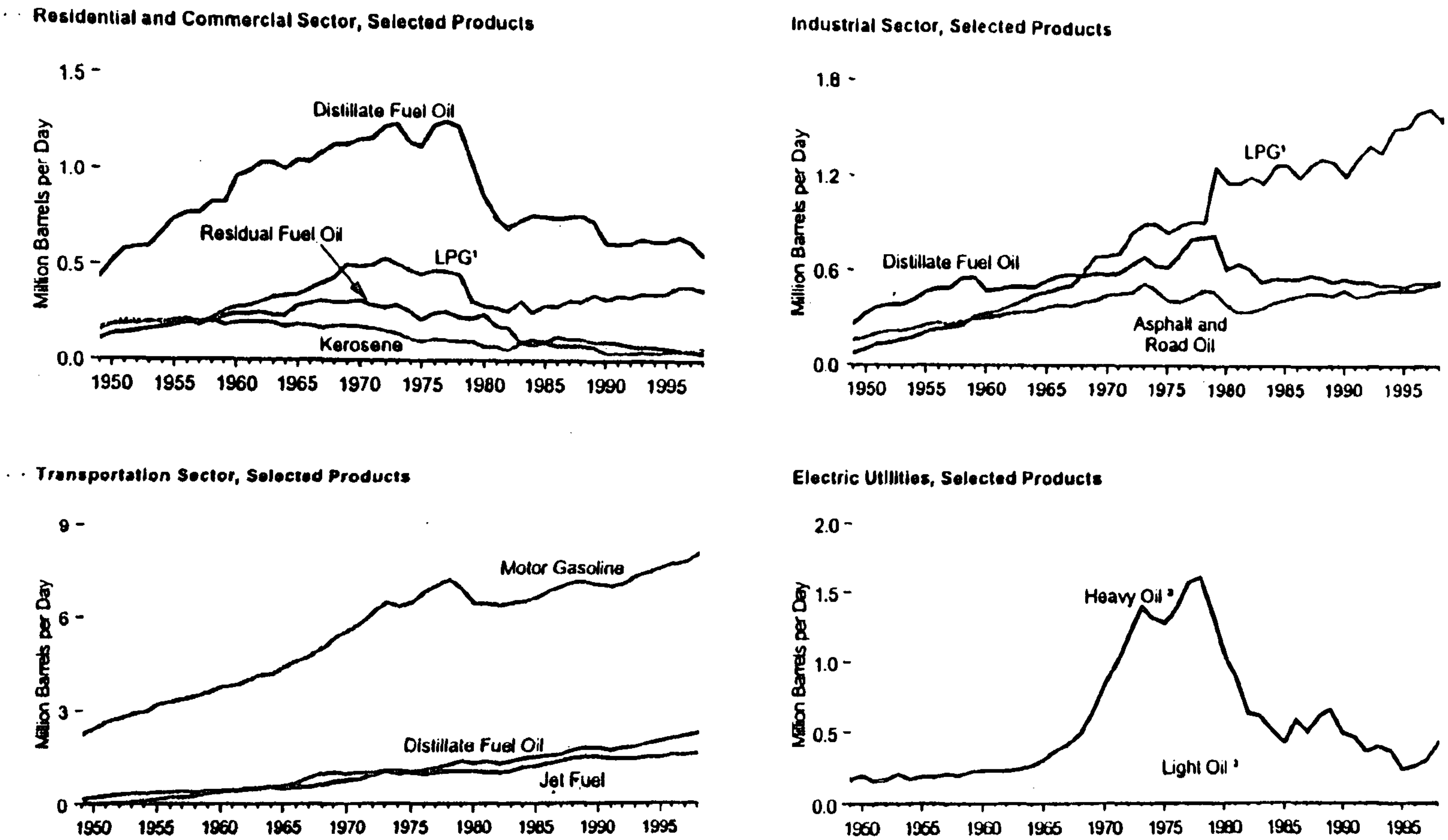
Figure 5.12b Petroleum Products Supplied by Product by Sector, 1949-1998



¹ Liquefied petroleum gases.

² Prior to 1980, based on oil used in steam plants. Since 1980, heavy oil includes fuel oil nos. 4, 5, and 6, and residual fuel oil.

³ Prior to 1980, based on oil used in internal combustion and gas turbine engine plants. Since 1980, light oil includes fuel oil nos. 1 and 2, kerosene, and jet fuel.

Notes: • See related Figure 5.12a. • Because vertical scales differ, graphs should not be compared.

Sources: Tables 5.12a and 5.12b.

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Table 1.3 Energy Consumption by Source, 1949-1999
(Quadrillion Btu)

Year	Fossil Fuels: Coal	Fossil Fuels: Coal Coke Net Imports	Fossil Fuels: Natural Gas [1]	Fossil Fuels: Petroleum [2]	Fossil Fuels: Total Fossil Fuels	Nuclear Electric Power	Hydroelectric Pumped Storage [3]	Renewable Energy: Conventional Hydroelectric Power [4]	Renewable Energy: Geothermal [5]	Renewable Energy: Wood and Waste [6]	Renewable Energy: Solar	Renewable Energy: Wind	Renewable Energy: Total Renewable Energy	Total [7]
1949	11.981	-0.007	5.145	11.883	29.002	0	(8)	1.449	0	1.549	0	0	2.998	32.000
1950	12.347	0.001	5.968	13.315	31.632	0	(8)	1.440	0	1.562	0	0	3.003	34.635
1951	12.553	-0.021	7.049	14.428	34.008	0	(8)	1.454	0	1.535	0	0	2.988	36.996
1952	11.306	-0.012	7.550	14.954	33.800	0	(8)	1.496	0	1.474	0	0	2.970	36.770
1953	11.373	-0.009	7.907	15.556	34.826	0	(8)	1.439	0	1.419	0	0	2.857	37.684
1954	9.715	-0.007	8.330	15.839	33.877	0	(8)	1.388	0	1.394	0	0	2.783	36.660
1955	11.167	-0.010	8.998	17.255	37.410	0	(8)	1.407	0	1.424	0	0	2.832	40.242
1956	11.350	-0.013	9.614	17.937	38.888	0	(8)	1.487	0	1.416	0	0	2.903	41.791
1957	10.821	-0.017	10.191	17.932	38.926	(s)	(8)	1.557	0	1.334	0	0	2.890	41.816
1958	9.533	-0.007	10.663	18.527	38.717	0.002	(8)	1.629	0	1.323	0	0	2.952	41.670
1959	9.518	-0.008	11.717	19.323	40.550	0.002	(8)	1.587	0	1.353	0	0	2.940	43.493
1960	9.838	-0.006	12.385	19.919	42.137	0.006	(8)	1.657	0.001	1.320	0	NA	2.977	45.120
1961	9.623	-0.008	12.926	20.216	42.758	0.020	(8)	1.680	0.002	1.295	0	NA	2.977	45.755
1962	9.906	-0.006	13.731	21.049	44.681	0.026	(8)	1.822	0.002	1.300	0	NA	3.124	47.832
1963	10.413	-0.007	14.403	21.701	46.509	0.038	(8)	1.772	0.004	1.323	0	NA	3.099	49.647
1964	10.964	-0.010	15.288	22.301	48.543	0.040	(8)	1.907	0.005	1.337	0	NA	3.248	51.831
1965	11.581	-0.018	15.769	23.246	50.577	0.043	(8)	2.058	0.004	1.335	0	NA	3.397	54.016
1966	12.143	-0.025	16.995	24.401	53.514	0.064	(8)	2.073	0.004	1.369	0	NA	3.446	57.024
1967	11.914	-0.015	17.945	25.284	55.127	0.088	(8)	2.344	0.007	1.340	0	NA	3.691	58.906
1968	12.331	-0.017	19.210	26.979	58.502	0.142	(8)	2.342	0.009	1.419	0	NA	3.771	62.415
1969	12.382	-0.038	20.678	28.338	61.362	0.154	(8)	2.659	0.013	1.440	0	NA	4.113	65.628
1970	12.265	-0.058	21.795	29.521	63.522	0.239	(8)	2.654	0.011	[R]1.429	0	NA	[R]4.094	[R]67.856
1971	11.598	-0.033	22.469	30.561	64.596	0.413	(8)	2.861	0.012	[R]1.430	0	NA	[R]4.303	[R]69.312
1972	12.077	-0.026	22.698	32.947	67.696	0.584	(8)	2.944	0.031	[R]1.601	0	NA	[R]4.476	[R]72.756
1973	12.971	-0.007	22.512	34.840	70.316	0.910	(8)	3.010	0.043	[R]1.527	0	NA	[R]4.579	[R]75.806
1974	12.663	0.056	21.732	33.455	67.906	1.272	(8)	3.309	0.053	[R]1.538	0	NA	[R]4.900	[R]74.078
1975	12.663	0.014	19.948	32.731	65.355	1.900	(8)	3.219	0.070	[R]1.497	0	NA	[R]4.786	[R]72.041
1976	13.584	(s)	20.345	35.175	69.104	2.111	(8)	3.066	0.078	[R]1.711	0	NA	[R]4.855	[R]76.070
1977	13.922	0.015	19.931	37.122	70.989	2.702	(8)	2.515	0.077	[R]1.837	0	NA	[R]4.429	[R]78.120
1978	13.766	0.125	20.000	37.965	71.856	3.024	(8)	3.141	0.064	[R]2.036	0	NA	[R]5.242	[R]80.122
1979	15.040	0.063	20.666	37.123	72.892	2.776	(8)	3.141	0.084	[R]2.150	0	NA	[R]5.375	[R]81.042
1980	15.423	-0.035	20.394	34.202	69.984	2.739	(8)	3.118	0.110	[R]2.483	0	NA	[R]5.710	[R]78.434
1981	15.908	-0.016	19.928	31.931	67.750	3.008	(8)	3.105	0.123	2.590	0	NA	5.818	76.569
1982	15.322	-0.022	18.505	30.232	64.037	3.131	(8)	3.572	0.105	[R]2.615	0	NA	[R]6.292	[R]73.441
1983	15.894	-0.016	17.357	30.054	63.290	3.203	(8)	3.899	0.129	2.831	0	(s)	6.860	73.317
1984	17.071	-0.011	18.507	31.051	66.617	3.553	(8)	3.800	0.165	2.880	0	(s)	6.845	76.972
1985	17.478	-0.013	17.834	30.922	66.221	4.149	(8)	3.398	0.198	[R,9]2.862	0	(s)	[R,9]6.458	[R,9]76.777
1986	17.260	-0.017	16.708	32.196	66.148	4.471	(8)	3.446	0.219	[R,9]2.840	0	(s)	[R,9]6.506	[R,9]77.065
1987	18.008	0.009	17.744	32.865	68.626	4.906	(8)	3.117	0.229	[R]2.822	0	(s)	[R]6.169	[R]79.633
1988	18.846	0.040	18.552	34.222	71.660	5.661	(8)	2.662	0.217	[R,9]2.940	0	(s)	[R,9]5.819	[R,9]83.071
1989	18.926	0.030	19.384	34.211	72.551	5.677	(8)	[R,10]2.999	[R,10]0.338	[R,10]3.050	[R,10]0.059	[R,10]0.024	[R,10]6.470	[R,10]84.593
1990	19.101	0.005	19.296	33.553	71.955	[R]6.162	-0.036	[R,11]3.140	[R]0.350	[R]2.665	0.063	[R]0.032	[R]6.260	[R]84.186
1991	18.770	[R]0.010	19.606	32.845	[R]71.231	[R]6.580	-0.047	[R]3.222	[R]0.368	[R]2.679	0.066	[R]0.032	[R]6.367	[R]84.063
1992	[12]19.158	[R]0.035	20.131	33.527	[R,12]72.850	[R]6.606	-0.043	2.863	0.379	[R]2.828	0.068	0.030	[R]6.167	[R,12]85.512
1993	19.776	[R]0.027	20.827	33.841	[R]74.471	[R]6.520	-0.042	3.147	0.393	[R]2.782	0.071	0.031	[R]6.424	87.309
1994	19.960	[R]0.058	21.288	[R]34.670	[R]75.976	[R]6.838	-0.035	2.971	0.395	[R]2.914	0.072	0.036	[R]6.387	[R]89.234
1995	20.024	[R]0.061	22.163	[R]34.553	[R]76.802	7.177	-0.028	3.474	0.339	[R]3.044	0.073	0.033	[R]6.963	[R]90.940
1996	20.940	[R]0.023	[R]22.559	[R]35.757	[R]79.279	7.168	-0.032	[R]3.915	0.352	[R]3.104	0.075	0.035	[R]7.482	[R]93.911
1997	21.444	[R]0.046	[R]22.530	[R]36.268	[R]80.288	6.678	-0.042	[R]3.940	[R]0.328	[R]2.982	0.074	[R]0.034	[R]7.358	[R]94.316
1998	[R]21.593	[R]0.067	[R]21.921	[R]36.934	[R]80.515	7.157	-0.046	[R]3.552	[R]0.335	[R]2.991	0.074	[R]0.031	[R]6.984	[R]94.570
1999[P]	21.698	0.058	22.096	37.706	81.557	7.733	-0.063	3.417	0.327	3.514	0.076	0.038	7.373	96.596

[1] Includes supplemental gaseous fuels.
[2] Petroleum products supplied, including natural gas plant liquids and crude oil burned as fuel
[3] Represents total pumped storage facility production minus energy used for pumping.
[4] Through 1988, includes all net imports of electricity. From 1989, includes only the portion of net imports of electricity that is derived from hydroelectric power.
[5] Includes electricity imports from Mexico that are derived from geothermal energy.
[6] Values are estimated. For all years, includes wood consumption in all sectors (see Table 10.4). Beginning in 1970, includes electric utility waste consumption (see Table 8.3). Beginning in 1981, includes industrial sector waste consumption, and transportation sector use of ethanol blended into motor gasoline (see Table 10.3). Beginning in 1989, includes expanded coverage of nonutility wood and waste consumption (see Table 8.4).
[7] From 1989, includes net imported electricity from nonrenewable sources and removes ethanol blended into motor gasoline, which would otherwise be double counted in both petroleum and renewable energy
[8] Through 1989, pumped storage is included in conventional hydroelectric power
[9] Not all data were available, therefore, values were interpolated
[10] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989. See Tables 10.1 and 10.2
[11] There is a discontinuity in this time series between 1989 and 1990, beginning in 1990, pumped storage is removed and expanded coverage of use of hydroelectric power is included
[12] Independent power producers' use of coal is included beginning in 1992. See Table 7.3

R=Revised P=Preliminary. (s)=Less than 0.0005 and greater than -0.0005 quadrillion Btu NA=Not available

Note: Totals may not equal sum of components due to independent rounding
Web Page: http://www.eia.doe.gov/fueloverview.html
Sources: See end of section.

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FERC'S AUTHORITY TO AMEND ANNGTC'S CERTIFICATES UNDER THE NGA

An issue which has arisen recently is the extent of the authority for the Federal Energy Regulatory Commission ("FERC") or other federal agencies to amend or modify aspects of certificates, permits or other authorizations issued to Alaska Northwest Natural Gas Transportation Company ("ANNGTC") for the construction of the Alaska Highway Project. Based upon the provisions of the governing statute, the Alaska Natural Gas Transportation Act of 1976 and the Presidential Decision issued September 22, 1977 highlighted below, it is clear that the agencies may amend, modify or abrogate such authorizations so long as such actions would not "compel a change in the basic nature and general route of the approved transportation system or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system."

- Congress envisioned that the federal agencies, including the FERC, would need the authority to amend from time to time previously issued certificates, permits and authorizations. The operative sections of ANGTA which specify the scope of the amending authority are sections 9(d) and (e).

- Section 9(d) provides that any federal officer or agency "may...add to, amend or abrogate any term or condition" included in an authorization, permit or certificate provided however that any term or condition to be added, or as amended, may not "compel a change in the **basic nature** and **general route** of the approved transportation system or would otherwise prevent or impair in any significant respect the expeditious **construction and initial operation** of such transportation system."

- Section 9(e) addresses the circumstances of amending or modifying specific terms and conditions recommended by the President in his Decision to be included in various federal permits, authorizations or certificates. Even with respect to those specific terms and conditions, section 9(e) states that the authority to amend or modify contained in section 9(d) shall also be available to the federal officers or agencies to amend or modify terms and conditions included in federal authorizations at the recommendation of the President in his Decision.

In order to understand the scope of the authority to amend or modify, it is necessary to understand the derivation and meaning of the terms "**basic nature**" and "**general route**".

- Section 7(a)(4)(A) required that the President "describe the **nature and route** of the system designated for approval." In section 2 of his Decision, President Carter specified the nature and route for the system, as required by section 7(a)(4)(A). In describing the nature of the system, the Decision does no more than specify that it be and "overland pipeline system to transport natural gas from the Prudhoe Bay area of Northern Alaska through Alaska and Canada into ... the contiguous United States." The decision then specifies the capacity, initially, at 2.0 to 2.5 Bcfd, capable of being expanded. There are no other details on the **nature** of the system. The **route** is then specified as the Alaska Highway Project route. No other details such as facilities, diameter, pressure, tariff are included in the President's Decision fulfilling the statutory requirement to "**describe the nature and route.**"

- In Section 3 of his Decision, President Carter separately identified the facilities which would be "encompassed" for purposes of section 9, as provided in section 7(a)(4)(C). The facilities identified by the President pursuant to section 7(a)(4)(C) are entitled to be "encompassed" in "construction and initial operation" for purposes of "defining the scope of the directions" contained in section 9.

- Under ANGTA section 7, the requirements that the President "describe" the "nature and route," as provided in section 7(a)(4)(A), and that he "identify" facilities for purposes of section 9 under section 7(a)(4)(C), have different consequences. The President's choice as to the "nature and route" can be changed only by waiver under section 8. Under section 9(d), however, FERC is expressly authorized to amend certificates covering the facilities "identified" by the President, so long as its amendment does not change "the basic nature and general route" of the system chosen by the President.

- Section 7(a)(6) allowed, but did not require, the President also to "identify" in his decision "such terms and conditions permissible under existing law as he determines appropriate for inclusion," with respect to any federal authorization issued under section 9, including certificates issued under the Natural Gas Act. Under section 9(e), the agency issuing such authorizations was required to include the terms and conditions identified by the President in their authorizations.

- Section 5 of the President's Decision specified, pursuant to section 7(a)(6), general terms and conditions which were to be incorporated into certificates, rights of way, leases , permits or authorizations to be made by Federal officers and agencies. These terms and conditions addressed "general standards of environmental and construction and performance, and the procedures for the submission and approval of construction plans and environmental safeguards . . . ." They did not include terms and conditions precluding amendments allowing modifications of facility design specifications or configuration.

- Section 2 of President Carter's decision can be changed only by waiver under section 8 of ANGTA , or by an Act of Congress. Facilities "identified" in Section 3 as qualified for being "encompassed" in the scope of the directions under section 9, and the conditions "identified" in Section 5, can be changed by amendment.

- The "scope of directions" under section 9 includes the FERC's powers, expressly conferred by section 9(c), to **condition** certificates, and by section 9(d), to **amend** certificates. These powers are subject to the limitation in both subsections prohibiting changes in the "<u>basic</u> nature and <u>general</u> route," and actions which will "otherwise" prevent or impair in any significant respect the expeditious construction and initial operation of "the system."

- The Commission's authority to amend is confirmed by comparing section 9(d) with section 9(e). The latter provision required the Commission to include in its certificates the terms and conditions identified by the President in Section 5 of his decision. However, Section 9(e) contains an express exception that plainly preserves the Commission's authority to amend even terms and conditions identified by the President in Section 5. Although § 9(e) commands that authorizing agencies "shall include" them, it further provides, "except that the requirement to include such terms and conditions <u>shall not limit the Federal officer or agency's authority under subsection (d) of this section</u>."

- If certificates and permits for facilities specifically "identified" by President Carter could not be amended to permit changes in those facilities, section 9(d) would be meaningless. Moreover, those changes may include anything except changes in the basic nature and general route. Otherwise, the terms "basic" modifying "nature" and "general" modifying "route" in the limitation expressed in sections 9(c) and 9(d) would likewise become meaningless. Congress intentionally included those terms, and they must be given effect under the familiar rule of construction that every word in a statute must be given meaning

- The distinction between changes in the "basic nature and general route"as specified pursuant to section 7(a)(4)(A), which cannot be effectuated by amendment, and changes in "identified facilities", which can, is reflected in President Reagan's Decision in 1981 waiving Congress's approval of § 2, ¶ 3, First Sentence, of President Carter's Decision. The waived sentence specified that the ANGTS began at the "discharge side of the gas plant facilities in the Prudhoe Bay field." That waiver was necessary because inclusion of the conditioning plant in the ANGTS changed the system's basic nature and general route as previously specified by President Carter and approved by Congress. President Reagan did not, however, separately add the conditioning plant to the facilities identified for section 9 treatment under section 7(a)(4)(C). He left that process for FERC to address by amendment under section 9(d). He also waived Condition IV-3 of the Carter Decision, which barred FERC from allowing the billing of pre-completion fees, payments or surcharges, so that the costs of the Canadian portion could be recovered. He also added a new condition limiting FERC's authority to change tariffs to impair recovery of expenses, taxes and debt service, and foreclosed any over-ride of this condition through the amendment process by also waiving provisions in the NGA under which such modifications might be made. In sum, "identified facilities" can be changed by amendment, but the basic nature and general route cannot.

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Comparison of Murkowski and Bingaman Energy Bills
March 30, 2001

Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
General Provisions–Evaluations, Reports, and Studies	**Title I**	**Titles III and XI**	
Federal actions affecting energy supply	Requires each Federal agency to notify DOE before taking action that could have a significant adverse effect on availability of domestic energy resources. (101)	No similar provision	
Goal for reduced dependence on foreign oil Report progress on achieving goal, recommendations for achieving goal, and refinery and storage capacity Notification of decline in petroleum stocks	- Requires DOE to report annually to the President and Congress on progress the US has made in achieving not more than 50% dependence on foreign oil by 2010 and make recommendations for meeting the goal. Certain years the report is to assess domestic refinery and storage capacity. - Requires DOE to notify Congress immediately if stocks of petroleum products decline or may decline to levels jeopardizing national security or threatening supply shortages, or price increases. (102)	No similar provision.	
Strategic Petroleum Reserve uses	Requires President to establish an interagency panel to study oil markets and SPR's appropriate capacity and uses and to report to President and Congress. (103)	Requires DOE to report to President and congressional energy committees on whether DOE should have greater flexibility to drawdown SPR to mitigate price volatility or regional supply shortages. (308)	
Energy rights-of-way	Requires Federal agencies issuing rights-of-way across Federal lands for transmission lines or energy pipelines to report to FERC or DOE on ability of existing rights-of-way to support new or additional capacity. (104)	Requires DOE to study the possibility of using existing rights-of-way owned by a PMA for siting other transmission facilities. (304)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Federal hydro facilities	Requires DOI and Secretary of the Army to inventory their hydroelectric facilities and report to Congress on increasing their output. (105)	No similar provision	
Nuclear generation	Requires NRC to report to Congress on the state of US nuclear power generation and potential for increasing it, including recommendations for improving the process for relicensing and issuing new licenses. (106)	No similar provision.	
Spent nuclear fuel	Requires Congress to determine whether spent fuel should be treated as waste for burying forever or an energy resource for the future. Also establishes Office of Spent Nuclear Fuel Research within DOE for investigating technologies for treating, recycling, and disposing of high-level nuclear waste and spent nuclear fuel. (107)	No similar provision.	
Domestic refining industry and petroleum product distribution system	Requires DOE to report annually to Congress on the condition of the domestic petroleum refining industry and petroleum product distribution industry. (108)	No similar provision.	
Natural gas pipeline certification	Requires FERC to review procedures for the certification of natural gas pipelines to determine how to reduce the cost and time of obtaining a certificate. (109)	Same provision. (305)	
US electricity grid maintenance	Requires DOE to submit an annual report to the President and Congress on the sufficiency of domestic energy generation sources to maintain the US electricity grid. (110)	No similar provision.	

Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Financing new electricity generation technologies	Requires DOE to assess innovative financing techniques to encourage construction of new electricity generation technologies with high initial capital costs. (111)	Almost identical provision. (307)	
Eliminate barriers to new energy-efficient technologies	Requires Federal agencies to review regulations to find barriers to market entry for emerging energy-efficient technologies and report to Congress on actions to remove barriers. (112)	Almost identical provision. (301)	
Natural gas pipelines-expedited environmental review	Requires DOE to establish an interagency task force to expedite environmental review and permitting of natural gas pipeline projects. (113)	Similar provision, requires the task force to be established by and under the Council for Environmental Quality and requires FERC to review its policies on pipeline certification. (305)	
Energy and hazardous liquids pipeline research and development (Very similar provisions passed the Senate on 2/8/01 as sections 11, 12, and 13 of S. 235)	Requires Dept. of Transportation, in coordination with DOE, to establish a R&D program to ensure the safety and reliability of energy and hazardous liquids pipelines. (114)	Almost identical provision. Provides for use of DOT users fees and amounts in Oil Spill Liability Trust Fund to fund the DOT part of the program. (1101-1103)	
R&D for natural gas transportation and distributed energy	Requires DOE to conduct R&D and demonstration activities to improve both natural gas transportation infrastructure and distributed energy resources (small power generation systems) (115)	No similar provision.	
FERC policies on electric energy transmission and wholesale power rates	No similar provision.	Requires FERC to reevaluate its regulatory policies on transmission of electric energy and wholesale power rates. (302)	
Volatility in domestic oil and gas development	No similar provision.	Requires DOE to evaluate the effect of Federal and State tax and royalty policies on the development of domestic oil and gas resources. (303)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Vehicle fuel specifications	No similar provision.	Requires DOE and EPA to report to Congress on the feasibility of developing fuel specifications for vehicles used in the US. (306)	
Coal-Based Technologies	**Title II**	**Title VIII**	
Coal-based technologies R&D	Requires DOE to identify goals and technologies that would permit the continued use of coal for electricity generation, chemical feedstocks, and transportation fuel in the future. To achieve these goals, requires DOE to conduct an R&D, demonstration, and commercial application program for coal-based technologies. (202-205)	Almost identical provisions. (801-814)	
Power plant improvement	Requires DOE to demonstrate commercial application of advanced coal-based technologies for new and existing power plants to improve efficiency, environmental performance, and cost competitiveness. (206-208)	Same provisions. (801, 821-823)	
Coal mining technologies	Requires DOE to establish a program to develop coal mining research priorities, establish a process for joint industry-government research, and expand mining research capabilities at universities. (209)	No similar provision.	
Railroad efficiency	Requires DOE to establish a research partnership with railroads and locomotive manufacturers to develop and demonstrate locomotive technologies to increase fuel economy, reduce emissions, improve safety, and reduce costs. (210)	No similar provision.	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Study on use of coal for electricity generation through 2020	No similar provision.	Requires DOE to identify technologies and a research program that would permit the cost-competitive use of coal for electricity generation through 2020 while furthering national environmental goals. (1404(b))	
Oil and Gas	**Title III**	**Title X**	
Outer Continental Shelf deep water royalty relief	Re-establishes the Outer Continental Shelf Deep Water Royalty Relief Act, which expired in 2000. Allows the Department of the Interior to modify royalty or net profit share terms in leases to promote development and production in certain areas of the Gulf of Mexico. Applies cash bonus bidding system in certain areas. (301-306)	Requires the Secretary of the Interior to proceed, not later than 12/31/01, with the proposed Eastern Gulf of Mexico Outer Continental Shelf Oil and Gas Lease Sale 181, modified. (1001)	
Oil or gas royalties in kind	Requires, if DOE chooses, all royalties paid the US under any Federal onshore or offshore oil or gas lease to be paid in oil or gas, with certain conditions. Allows DOI to sell the oil or gas and use a portion of the revenues to pay cost of transporting or disposing of the oil or gas. DOI may delegate royalty-in-kind program to States. (310)	No similar provision.	
Use of royalty-in-kind-oil for SPR	Requires DOI and DOE to agree to transfer the Federal share of crude oil production from Federal lands to DOE for use in filing SPR or for other disposal within the Federal Government. (320)	No similar provision.	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Federal oil and gas lease management	Provides for State regulation of oil and gas leases on Federal lands, except for issuance of leases, approval of plans for surface operations, and environmental analyses. Sets time limits for Federal actions on leases. (330-339)	No similar provision.	
Credit against Federal oil and gas royalties	Requires DOI to allow a credit against payment of royalties under Federal oil and gas leases for capital expenditures on exploration and development. (351)	No similar provision.	
National Environmental Policy Act compliance onshore	No similar provision.	Authorizes appropriations to DOI and the Department of Agriculture for additional personnel to ensure expeditious compliance with NEPA regarding oil and gas production on their Federal lands. (1002)	
Oil and gas production on private and State lands	No similar provision.	Requires DOE to evaluate how to increase oil and natural gas production from State and private lands and report to Congress and Governors. (1003)	
Fossil energy R&D	No similar provision.	Sets goals for a core fossil energy R&D program, developing technologies for offshore oil and natural gas resources development, and developing low-cost transportation fuels from natural gas and liquefaction of coal and biomass. Authorizes appropriations for developing fossil energy resources technologies. (1404(a) and (c))	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Nuclear	**Title IV**	**Title IX**	
Price-Anderson Act amendments	- Extends to 2012 indemnity authority for NRC licensees, DOE contractors, and nonprofit educational institutions. - Increases maximum standard deferred premium to $20,000,000 in any year. - Provides $10 billion ceiling on aggregate DOE liability and raises liability on incidents outside the US to $500,000,000. - Requires DOE and NRC to submit a report on need for P-A by 8/1/08. - Provides for adjusting the amount of indemnification for inflation. - Provides civil penalties on non-profits to amount of fee (like H.R. 723). (401-409)	Identical provisions. (901-909)	
Nuclear energy research	Authorizes appropriations for DOE grants for nuclear energy research. (410)	Sets goals for nuclear energy research, development, and deployment program. Authorizes appropriations for a DOE nuclear energy research, development, demonstration, and deployment program. (1405)	
Nuclear energy plant optimization	Authorizes appropriations for a joint program with industry for nuclear energy plant optimization. (411)	Sets goals for nuclear energy research, development, and deployment program, including extending lifetimes of existing nuclear power plants. Authorizes appropriations for a DOE nuclear energy research, development, demonstration, and deployment program. (1405)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Nuclear energy technology development	Authorizes appropriations to develop "a roadmap" to design and develop a new nuclear energy facility in the US. (412)	Sets goals for nuclear energy research, development, and deployment program, including development of components of an advanced power reactor. Authorizes appropriations for a DOE nuclear energy research, development, demonstration, and deployment program. (1405)	
Nuclear energy production incentives	Requires DOE to make to an operator of an existing nuclear power reactor incentive payments over a 15 year period for increasing amount of electric energy generated. (420)	No similar provision.	
Nuclear energy efficiency improvements	Requires DOE to make to an operator of an existing nuclear power reactor incentive payments for capital improvements directly related to improving the electrical output efficiency of the facility. (421)	No similar provision.	
Arctic National Wildlife Refuge	**Title V**	**No similar title**	
Development of the Coastal Plain of the Arctic National Wildlife Refuge	Requires DOI to establish an environmentally sound oil and gas leasing program for ANWR that uses the best commercially available technology and ensures receipt of fair market value for oil and gas leased. Revenues go to Alaska, Treasury miscellaneous receipts account, and a fund for DOE R&D on renewable energy resources. (501-514)	No similar provision.	
Energy Efficiency, Energy Conservation, and Assistance for Low-Income Families	**Title VI**	**Title XIII also sections of the Senate-passed bankruptcy bill, S. 420**	

Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Low Income Home Energy Assistance Program	Extends and generally increases the authorization of appropriations for HHS's Low Income Home Energy Assistance Program. (601)	No similar provision in S. 597, but a Bingaman amendment to the Senate-passed bankruptcy bill (S. 420) would extend LIHEAP authorization of appropriations for slightly different time and level and increase the income level for those who may receive grants.	
Energy efficient schools	Establishes in DOE a program to make grants to school districts to implement plans for energy efficiency in new and existing school buildings. (602)	Almost identical provision. (1302)	
Weatherization Assistance Program	Increases the income level for grant recipients and extends the authorization of appropriations for WAP (but mistakenly amends a section that already had been replaced). (603)	No similar provision in S. 579, but the Bingaman amendment to the Senate-passed bankruptcy bill (S. 420) extends and sets specific amounts on authorization of appropriations for WAP.	
State Energy Program	Allows a Governor to revise his state energy conservation plan every three years, amends the goal for improvement in the efficient use of energy in the State under the plan, and extends the authorization of appropriations for the program (but mistakenly amends a section that already had been replaced). (604)	No similar provision in S. 579, but the Bingaman amendment to the Senate-passed bankruptcy bill (S. 420) extends and sets specific amounts on authorization of appropriations for the State Energy Program.	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Federal energy savings performance contracts	Expands the types of energy savings that may be the subject of a contract under the program to include savings from the replacement of old Federal buildings with new, more energy-efficient buildings; extends the authority to enter into new contracts; and provides that a Federal agency may enter into a long-term contract with a utility under the utility incentive program and include in the contract savings from replacement buildings. (605)	No similar provision in S. 579, but the Bingaman amendment to the Senate-passed bankruptcy bill (S. 420) expands the types of energy savings that may be subject of a contract under the program to include savings from replacement buildings and savings in the cost of water or wastewater treatment (as well as savings in the cost of energy), and extends indefinitely the authority to enter into new contracts.	
Federal energy efficiency requirement	Requires a Federal agency to reduce energy consumption per gross square foot of its facilities by 30 percent by 2010 and 50 percent by 2020 relative to 1990. (606)	No similar provision.	
Energy efficiency science initiative	Authorizes appropriations for DOE grants for research relating to energy efficiency. (607)	Sets goals for energy efficiency in housing, industry, and transportation. Authorizes appropriations for a DOE energy efficiency R&D program. Requires DOE to make awards for advanced technology for an electricity transmission line using superconducting materials and for increased efficiency in electricity transmission in rural and remote areas. (1402)	
Federal Energy Bank	No similar provision.	Establishes in the Treasury an account into which each Federal agency deposits, in FY 2002, 2003, and 2004, 5% of its utility payments the preceding year and from which DOE makes loans to agencies for energy efficiency projects. (1301)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Industrial energy use	No similar provision.	Requires DOE to enter into agreements with industrial energy users to reduce voluntarily the "energy intensity" of their production activities. (1303)	
Alternative Fuels and Renewable Energy	**Title VII**	**Title XII**	
HOV exception for alternative fuel vehicle	Allows a State highway department to exempt alternative fueled vehicles from the two-occupant requirement for travel in high-occupancy vehicle lanes under the program for Federal aid to highways. (701)	Same provision. (1203)	
Alternative fueled vehicle infrastructure	Requires DOE to give credit, under the fleet requirement program, for the cost of installation of fueling or other infra-structure facilities for alternative fueled vehicles. (702)	No similar provision.	
State and local government use of Federal refueling facilities	Allows Federal agencies to include States or local government alternative fueled vehicles in a commercial arrangement for fueling Federal alternative fueled vehicles. (703)	No similar provision.	
Federal fleet fuel use.	Requires a Federal agency to increase the average fuel economy rating of its passenger cars and light trucks and use alternative fuels for at least 50% of the total fuel used by the agency. (704)	No similar provision.	
Federal fleet vehicle use	No similar provision.	Limits the circumstances under which DOE can waive the requirement that Federal dual fueled vehicles be operated only on alternative fuel and allows a 3-wheel enclosed electric vehicle to qualify for the Federal fleet program. (1202)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Local government grants	Requires DOE to establish a program to make grants to local governments for the incremental cost of alternative fueled vehicles. (705)	No similar provision.	
Grants for residential renewable energy efficiency	Requires DOE to implement a grant program to offset part of the cost of certain residential renewable energy systems. (710)	No similar provision.	
Assessment of renewable energy sources	Requires DOE to submit annually to Congress an assessment of all renewable energy resources available in the US. (711)	Similar provision. (601)	
Renewable energy R&D	No similar provision.	Sets goal for RD&D of renewable energy technologies (wind, photovoltaic, solar thermal electric systems, biomass-based power systems, geothermal, beefaloes, hydrogen, hydro power, and new electricity lines, generators, and systems). Authorizes appropriations for a solar and renewable resources development program. Requires DOE to make awards for use of advanced wind technologies in delivering electricity to rural and remote areas. (1403)	
General vehicle fuel efficiency	No similar provision.	Requires the Department of Transportation, with aid of DOE, to develop and implement mechanisms to increase fuel efficiency of light duty vehicles (cars, trucks, and SUBS.) and negotiate with the manufacturers of cars sold in the US enforceable mechanisms to increase vehicle efficiency. (1201)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Hydroelectric licensing reform	- Requires that conditions, proposed by DOI, Commerce, or other agency, on a license for a hydroelectric facility or on the construction and operation of lights, signals, and fishways in connection with such a facility to meet additional requirements. (724) - Requires FERC to conduct a single consolidated environmental review for each hydro project or appropriate multiple projects and prohibits any other agency from doing such a review. (725)	Requires agencies to adopt an alternative condition proposed by an applicant for a hydroelectric relicensing project if it is equally or more protective of the environment, is based on sound science, and is more cost effective or results in less loss of generating capacity. (701)	
Study of small hydroelectric projects	Requires FERC to study the feasibility of establishing a separate licensing procedure for small hydro projects (generating capacity of 5 megawatts or less). (726)	No similar provision.	
Use by FERC of hydroelectric fees	No similar provision.	Allows an agency administering public lands to keep its hydroelectric fees and use them for protection of its water resources and to make grants to increase local employment and job training opportunities. (702)	
Relicensing study	No similar provision.	Requires FERC to study all new licenses issued since January 1, 1994, for existing projects under the relicensing section of the FPA and examine the data to determine where problems actually exist concerning FERC issuance of new licenses. (703)	
Electricity	**Title VIII**	**Titles IV, V, and VI**	

Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Electric energy transmission reliability	Creates an industry-run, FERC-overseen, Electric Reliability Organization that sets enforceable rules for the reliable operation of the interstate transmission grid. The ERO shall report annually to DOE on the condition of the interconnected bulk power system. (802)	Almost identical provision. (401)	
PURPA mandatory purchase and sale requirements.	Repeals PURPA requirement that utilities purchase power from certain providers at full avoided cost rates. Does not affect or remedy any existing power purchase arrangements. (803)	No similar provision.	
Public Utility Holding Company Act of 2001	Repeals PUHCA 1935 to allow electric utilities to diversify without dealing with the restrictions of PUHCA. (813)	No similar provision.	
Federal access to books and records	Requires holding companies to make available to FERC books and records relevant to costs incurred by a public utility company or natural gas company associated with the holding company. (814)	No similar provision.	
State access to books and records	Requires a holding company upon written request from a State Commission to produce books and records for inspection. (815)	No similar provision.	
Emission free control measures under a state implementation plan	Requires that action to continue or expand operation of emission-free electricity sources should be recognized under the Clean Air Act's State Implementation Plan (SIP) as control measures and provide access to existing and future economic incentive programs that prevent and control air emissions. (830)	No similar provision.	

Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Improved Electricity Capacity and Access	**No similar Title**	**Title V**	
Public benefits fund	No similar provision.	Establishes a public benefit fund, collected as a wires charge by a fiscal agent appointed by DOE, for distribution to States and Indian tribes to be used for various energy efficiency, renewable energy, and cost-shared greenhouse-gas mitigation projects, and low- income households energy programs. (502)	
Rural construction grants	No similar provision.	Establishes a Department of Agriculture grant program for the purpose of increasing energy efficiency and building or upgrading transmission and distribution facilities in rural areas and on tribal lands. (503)	
Comprehensive Indian energy program	No similar provision.	Establishes an Office of Indian Energy Policy and Programs in DOE to coordinate Federal energy policy and research and to implement energy programs concerning Indian tribes and related entities. Also, establishes an Indian energy grant program. (504)	
Environmental disclosure to consumers	No similar provision.	Requires the FTC to issue rules making sure that retail and wholesale electricity customers are notified of the energy sources used to generate the power used by the customer. Requires DOE to establish a program to certify electricity products with at least 50 percent renewable content. (505)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Consumer protections	No similar provision.	Requires the FTC to issue regulations governing complete disclosure by retail electricity seller of the terms of service. Also prohibits certain unfair trade practices in retail sale of electricity. (506)	
Wholesale electricity market data	No similar provision.	Requires FERC to establish a public information system for providing current and transparent information on the availability of generating and transmission capacity and constraints. (507)	
Wholesale electricity energy rates in the western energy market	No similar provision.	Requires FERC to impose just and reasonable load-differentiated demand rates or cost-of-service based rates on sales by electric utilities of electric energy at wholesale in the western energy market, if a State allows such rates to be passed along to consumers and meets other conditions (similar to the Smith amendment to S. 287). Also requires BPA to seek to prevent or mitigate electricity price spikes in poor communities. (508)	
Natural gas rate ceiling in California	No similar provision.	Reimposes a ceiling on the rate that can be charged for unused capacity in natural gas pipelines into California. (509)	
Sale price in bundled natural gas transactions	No similar provisions.	Requires FERC to issue an order that sellers of natural gas in bundled transactions disclose the portions of the sale price related to the cost of the gas and cost of the transportation paid by the seller. (510)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Renewables and Distribution Generation	**No Similar Title**	**Title VI**	
Federal purchase requirement	No similar provision.	Requires the Federal government to purchase a certain amount of its electricity needs from renewable energy sources. The percentage increases from 3 percent in 2002 to 7.5 percent by 2010 and each fiscal year thereafter. (602)	
Interconnection standards	No similar provision	Requires FERC to adopt rules to ensure the interconnection of distributed generation to local distribution facilities. (603)	
Net metering	No similar provision.	Requires electric suppliers to provide net metering services for on-site generators that use renewable energy resources. (604)	
Access to transmission by intermittent generators Access to transmission by intermittent generators	No similar provision.	Requires transmitting utilities to provide service for intermittent generators at rates and terms that do not penalize the generator for scheduling deviations. An exemption may be granted to avoid a substantial adverse impact on the utility's system. (605)	
Global Climate Change	**No similar title.**	**Title I**	
National Commission on Energy and Climate Change	No similar provision.	Establishes the National Commission on Energy and Climate Change to study measures that achieve stabilization of greenhouse gas emissions in the US at and below the 1990 level and are consistent with US energy and environmental goals and to recommend to Congress a US greenhouse gas management strategy. (101-107)	

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
International clean energy technology transfer	No similar provision.	Establishes an interagency working group to focus on transferring, to developing countries and countries in transition, clean energy technology (a technology that emits less pollutants or greenhouse gases and generates smaller or less toxic volumes of solid or liquid waste than technologies now in use). (111)	
Regional coordination of energy policy in the US	**No similar title.**	**Title II**	
Interstate coordination of energy policy	No similar provision.	Authorizes DOE to provide technical assistance to States and regional organizations in coordinating energy policies on a regional basis and requires DOE to convene annual conferences to promote regional coordination. (201-202)	
Management of DOE Science and Technology Programs	**No similar title**	**Title XV and part of XIV**	
Independent review of award of funds.	No similar provision.	Requires award of funds under title XIV to be made only after DOE has completed an independent review of proposals. (1501)	
Cost sharing.	Most individual R&D provisions have a cost sharing component.	Requires R&D projects under title XIV to be 20% cost-shared and demonstration and deployment projects to be 50% cost-shared. (1502)	

DOE024-2279

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Issue	Murkowski Bill (S. 389) (non-tax parts)	Bingaman Bill (S. 597)	Administration Position
Management of DOE science and technology	No similar provision.	Creates an advisory board to oversee DOE R&D and an Under Secretary for Science and Technology in DOE. (1503)	
Fundamental energy science	No similar provision.	Sets goals for a DOE program of fundamental energy research in the basic physical sciences and authorizes appropriations for fundamental energy R&D. (1406)	
Training	**No similar title.**	**Title XVI**	
Monitoring energy technology workers and making training grants.	No similar provision.	Requires the Secretary and EIA to monitor availability of skilled workers in the energy technology industries and DOE to make grants to enhance training for those workers for which there will be a shortage. (1601)	
Training guidelines for electric energy industry personnel.	No similar provision.	Requires DOE to develop model employee training guidelines to support electric supply system reliability and safety. (1602)	

Congress of the United States

January 3, 2000

The Honorable Hirofumi Nakasone
Minister of State for Science and Technology
2-2-1, Kasumigaseki
Chiyoda-ku, Tokyo
100-8966, Japan

Dear Minister Nakasone:

We are writing to request your assistance in obtaining Japanese Government support and funding for a project which promises to have substantial benefits in both nuclear non-proliferation and in nuclear power production.

As you are aware, the U.S. and Russia are currently engaged in the development of the Gas Turbine Modular Helium Reactor (GT-MHR) for the purpose of destroying surplus Russian weapons plutonium. The GT-MHR promises to be an extremely effective means of destroying plutonium and has the additional characteristics of superior safety and efficiency which appear to make it a very desirable reactor for electric power production. For these reasons, it is our hope that Japan and France will join with the U.S. and Russia in funding this project and participate in its development with technical support.

In our 1999 fiscal year, the U.S. government contributed $5 million. Part of this money will go to Russia and will be matched by the Russians. In the current fiscal year, there will be an identical level of U.S. expenditure; again, part of the money will go to Russia. The estimated cost and schedule of a completed detailed and licensed design is a total of $320 million over approximately six years. Our hope, and that of the Russians, is that this cost can be shared among Japan, France, Russia and the U.S.

If this effort is joined by Japan and France, we can assure you that, as Chairmen of the U.S. Senate and U.S. House Subcommittees on Energy and Water Development Appropriations, that we will seek appropriate levels of U.S. funding to advance this project. Japanese support for completion of this project is very important; we hope that you can help make this a reality.

Please do not hesitate to contact either of us if we can provide any more information or if you think we should make additional contacts in Japan to help secure funding for this important project. This letter was also sent to Ambassador Norio Hattori.

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DOE024-2281

Thank you very much for your consideration.

Sincerely,

Senator Pete V. Domenici
Chairman
Senate Subcommittee on Energy and Water Development Appropriations

Congressman Ron Packard
Chairman
House Subcommittee on Energy and Water Development Appropriations

24876
DOE024-2282

Congress of the United States

January 19, 2000

The Honorable Loyola de Palacio
Vice Presidente, Commissaire Transport et Energie
Commission de l'Union Europeenne
200 Rue de la Loi
Bruxelles B1049 Belgique

Dear Vice Presidente Palacio:

We are writing to request your assistance in obtaining additional European Union support and funding for a project that promises to have substantial benefits in nuclear non-proliferation.

As you are aware, the U.S. and Russia are currently engaged in the development of the Gas Turbine Modular Helium Reactor (GT-MHR) for the purpose of destroying surplus Russian weapons plutonium. The GT-MHR promises to be an extremely effective means of destroying plutonium and has the additional characteristics of superior safety and efficiency. For these reasons, it is our hope that Europe and Japan will join with the U.S. and Russia in funding this project and participate in its development with technical support.

In our 1999 fiscal year, the U.S. government contributed $5 million. Part of this money will go to Russia and will be matched by the Russians. In the current fiscal year, there will be an identical level of U.S. expenditure; again, part of the money will go to Russia. The estimated cost and schedule of a completed detailed and licensed design is a total of $320 million over approximately six years. Our hope, and that of the Russians, is that this cost can be shared among Japan, Europe, Russia and the U.S.

If this effort is joined by Europe and Japan, we can assure you that, as Chairmen of the U.S. Senate and U.S. House Subcommittees on Energy and Water Development Appropriations, we will seek appropriate levels of U.S. funding to advance this project in a timely manner. Additional European support for this project is very important for its completion; we hope that you can help make this a reality.

Please do not hesitate to contact either of us if we can provide any more information or if you think we should make additional contacts in Europe to help secure funding for this important project. This letter was also sent to Commissaire Phillipe Busquin and Commissaire Chris Patten.

Thank you very much for your consideration.

Sincerely,

Senator Pete V. Domenici
Chairman
Senate Subcommittee on Energy and Water Development Appropriations

Congressman Ron Packard
Chairman
House Subcommittee on Energy and Water Development Appropriations

cc: Mr. Francois Lamoureux, Directeur General Transport
Mr. Christian Waeterloos, Directeur des Energies Non-Fossiles
Mr. G. Legras, Directeur General Relations Exterieures
Mr. F. Chevallard, Chef d'Unite Aspects de Securite, DG Relations Exterieures
Mr. Didier Gambier, Administrateur Principal, ISTC-STCU, DG Recherche
Mr. Herbert Allgeier, Directeur General du CCR

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JOINT U.S. – RUSSIAN DEVELOPMENT OF GT-MHR

Since 1994, General Atomics and the Russian Federation Ministry for Atomic Energy (MINATOM) have been engaged in the joint development of the Gas Turbine Modular Helium Reactor (GT-MHR) for the destruction of surplus Russian weapons plutonium. Russian interest in the GT-MHR is very strong and revolves around its unique efficiency in destroying plutonium, its inherent safety characteristics and its substantially greater thermal efficiency. This work is now receiving funding under the Department of Energy's Fissile Materials Disposition program.

WHAT IS THE GT-MHR?

The GT-MHR is a substantial leap forward in fission reactor technology: it utilizes inert helium gas (as opposed to water) as the coolant, it incorporates ceramic encapsulated (as opposed to metal-clad) fuel, and it eliminates the need for numerous complex systems by driving the turbines and generators with high-temperature helium flowing directly from the reactor core. These and other innovations yield:

> ***A Better Way to Destroy Plutonium*** – Because pure plutonium oxide can be utilized in the reactor core (as opposed to mixed oxide fuel or MOX which contains only 5% plutonium), vastly less fuel processing and fabrication is required and a much higher percentage of plutonium is consumed by the GT-MHR.
>
> Meltdown Proof Safety – The GT-MHR is truly melt-down proof because the failure temperature of the fuel is hundreds of degrees higher than the highest possible temperature the reactor can reach.
>
> Vastly Improved Efficiency - Higher working temperatures and the elimination of steam generators and intermediate cooling loops makes the GT-MHR nearly 50% more thermally efficient than the present generation of reactors.
>
> Substantially Reduced Nuclear Waste – Because of the improved thermal efficiency, less nuclear fuel is consumed to produce any given amount of electricity. Hence, only about two thirds as much nuclear waste is produced by the GT-MHR. In addition, much less waste heat is exhausted to the environment.
>
> Greater Proliferation Resistance – Because of the high burn up rate of the fuel and because of the extreme difficulty of separating any remaining nuclear material from the ceramic encapsulation, spent GT-MHR fuel is virtually unusable for weapons production.

JOINT DEVELOPMENT PROGRAM WITH THE RUSSIANS

In the Summer of 1994, General Atomics and MINATOM agreed to initiate development of the GT-MHR for the destruction of Russian weapons grade plutonium. Each party agreed to pay equal sums to fund the design work which has been largely carried out by

GENERAL ATOMICS
Linden Blue, Vice Chairman

April 23, 2001

202-456-1606

Mr. Andrew Lundquist, Staff Director
Vice President's National Energy Policy Development Group
The White House
1600 Pennsylvania Avenue, N.W.
Washington, D.C. 20500

Dear Mr. Lundquist:

Attached you will find two one-page white papers addressing two different energy subjects: development of the Gas Turbine Modular Helium Reactor and fusion energy research. Our hope of course, is that these proposals might be included in the Vice President's energy policy recommendations. Both proposals are credible, will send a signal that the Administration's energy policy is forward looking and can make a substantial difference in the future.

By way of very brief background, General Atomics has been in the forefront of fission and fusion research in the world for over 40 years. During much of that time, GA has been partnered with the federal government on the development of a next generation nuclear reactor that is melt-down proof, ~50% more efficient, and creates less high-level waste. That reactor, the GT-MHR, is now being developed in Russia as part of DOE's non-proliferation programs.

Progress in fusion research has been very exciting and significant during the past decade. There is no longer any debate about whether fusion energy can be achieved: it is created in the laboratory with some regularity. However, the question remains whether it can be made practical. In that regard, fusion is ready for its next scientific step: a burning plasma experiment. The Administration's energy package should recommend that a planning process be undertaken for this next step.

Thank you for your consideration of these white papers and their recommendations. If you have any questions, please call me at (858) 455-4300.

Sincerely,

Linden Blue

PO BOX 85608, SAN DIEGO, CALIFORNIA 92186-5608
PHONE: 858-455-4300 FAX: 858-455-2122

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DOE024-2286

THE GAS TURBINE MODULAR HELIUM REACTOR

RECOMMENDATION: *The Administration should more aggressively promote international funding for the development of the Gas Turbine Modular Helium Reactor both as a means of destroying surplus Russian weapons plutonium and as a next generation civilian power reactor.* The use of Russian scientists and engineers coupled with international cost sharing is an exceptionally low cost way of developing this next generation reactor system for use in the U.S. and elsewhere.

BACKGROUND

The Gas Cooled Modular Helium Reactor (GT-MHR) **represents a breakthrough** in nuclear power. It is a next-generation reactor system whose advantages include **~50% greater efficiency, melt-down proof safety, substantially lower capital and operating costs, reduced waste production and improved proliferation resistance.** As implied by its name, the GT-MHR is modular, with each module producing 285 megawatts of electric power.

Over the past many years, the U.S. federal government and private sector have made a substantial investment in the development of the GT-MHR. Although historically, most of the investment in GT-MHR technology has been directed toward developing a next-generation commercial power reactor, development dollars are now primarily directed toward developing the GT-MHR for the purpose of destroying surplus Russian weapons plutonium as part of the Department of Energy's non-proliferation efforts.

Other than the content of the fuel (uranium vs plutonium), there is no significant difference between a plutonium burning GT-MHR and a uranium burning commercial version. The development of this reactor in Russia is a very inexpensive and politically **smart way of developing a next generation power reactor** for near term use in U.S. and overseas markets.

STATE OF THE PRESENT PROGRAM

In brief, the costs of DOE's program to develop the GT-MHR is shared by the Russians and is contributed to by the Japanese and the Europeans. At present, there are over 500 Russians working on the development of this reactor. Since the total cost of a completed and ready to construct design is $320 million over 5 to 6 years in Russia, each partner (U.S., Russia, Europe and Japan) would need to contribute about $15 million per year. The previous Administration did a very poor job of working with Japanese and Europeans on the program and hence, their contributions are inadequate at this point. Stronger Japanese and European contributions are likely if the U.S. is more explicit about the program as being a means to develop a next generation of power reactor. It is **strongly in the interest of the US to have this breakthrough in nuclear power** with or without contributions from the Japanese and Europeans.

WHY AND HOW THE PRESIDENT'S ENERGY PACKAGE SHOULD ADDRESS FUSION RESEARCH

WHAT IS A CREDIBLE RECOMMENDATION FOR THE PRESIDENT'S ENERGY PLAN?

A realistic and credible position for the President to take with regard to fusion would be two-fold:

> ***First, strengthen the base fusion energy sciences program which has suffered nearly a 50% reduction in the past decade.***
>
> ***Second, support a two-year planning process at DOE for a burning plasma experiment with National Academy of Science review at the end of that process***

BACKGROUND

Looking beyond fossil fuels, there are only three known sources of energy: renewables (solar, wind, biomass, etc.), fission(conventional nuclear) and fusion. For a number of reasons, renewables alone hold out little hope of meeting base load power needs. Hence, fission and fusion are essential "post fossil" base load energy alternatives for the future.

WHAT IS THE STATE OF FUSION RESEARCH?

In the past decade, debate has ceased about whether controlled fusion can be achieved on earth - - it is done with relative regularity in the laboratory. The remaining question is whether fusion can make the challenging step from the laboratory into a practical energy resource.

WHEN WILL FUSION ENERGY BE AVAILABLE?

In part, the answer to this question is dependent on funding. Realistically, however, practical fusion is probably three experimental steps away: 1. A "burning plasma" experiment (see below); 2. An engineering test facillity; and (3) a demonstration plant. If well-funded, each of those steps should take approximately 10 to 15 year with the possibility of some overlap between them. In making these steps, it is very important to underlay the fusion effort with a strong program in fusion science and plasma physics, much the same as underpinning the cure for cancer with a strong research program in the underlying genetics.

WHAT IS A BURNING PLASMA EXPERIMENT?

The importance of magnetic fusion taking the next step to a burning plasma experiment has been emphasized in recent reports of the National Academy of Sciences, the Secretary's Energy Advisory Board and the Fusion Energy Sciences Advisory Committee. In present fusion experiments, large amounts of energy must be injected into the fusion plasma to keep the reaction going. In a burning plasma, the heat from the fusion reaction itself (in the form of energetic or hot helium nuclei), is sufficient to maintain the fusion reaction. This is an important step in many regards, but most particularly because the science or physics associated with a burning plasma are expected to be different in important respects from that of a non-burning plasma and because a burning plasma will produce many times more energy than was required to get it going. Using some poetic license, existing fusion experiments are similar to a campfire that is kept going with a blowtorch. A burning plasma experiment will be like a campfire that burns on its own.

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WHAT IS FUSION?

Fusion is the energy source that powers the sun and the stars. At its most basic, it is the combining or fusion of two small atoms into a larger atom. When two atomic nuclei fuse, tremendous amounts of energy are released. The present focus of fusion energy science research is the combination of two forms of hydrogen (deuterium and tritium) to form helium.

WHAT ARE THE ADVANTAGES OF FUSION?

If proven practical, fusion will be close to the ideal energy source: it produces no air pollutants (the byproduct of the reaction is helium, the same gas used in toy balloons); it is safe (cannot blow-up or melt-down); its fuel source is practically unlimited and easily obtained (the starting point is a common form of hydrogen found in water); and no nation can have a cartel on the fuel. It is also a very concentrated form of energy and hence, will not require much land. Finally, the extraction and manufacture of its fuel is environmentally benign.

WHAT ARE THE DISADVANTAGES OF FUSION ENERGY?

The only disadvantage of fusion is that part of the fuel is mildly radioactive and depending on the materials chosen, the fusion chamber may become radioactive. However, several studies have shown that in the worst conceivable case, radioactivity associated with fusion is several orders of magnitude less than that associated with the nuclear fission plants we have today and that the radioactivity is relatively short-lived. Fusion plants are not expected to require any substantial emergency evacuation zone.

EPA Requirements to Produce Ultra Low Sulfur Diesel Fuel Jeopardize the Financial Viability of Small Business Refiners and Run Counter to a Balanced U.S. Energy Policy

Government Mandated Costs Impact Small Business Refiners Disproportionately and Should be Offset with a Tax Incentive

On January 18, 2001, the Environmental Protection Agency ("EPA") published new regulations, which create new standards for levels of sulfur in highway diesel fuel beginning in June, 2006. Under the new regulations, refiners must meet a stringent new standard of 15 parts per million sulfur limit for most on-road diesel volume ("Ultra Low Sulfur Diesel Fuel").

Just one year earlier, the EPA promulgated regulations that will severely restrict the concentration of sulfur in gasoline and that will become effective during the same time frame as the diesel requirements.

Prior to the issuance of these new EPA diesel regulations, small business refiners (refiners with fewer than 1500 employees and less than 155,000 barrels per day ("bpd") total capacity) participated in a process to review EPA proposals pursuant to the Small Business Regulatory Enforcement Fairness Act (SBREFA). Small business refiners presented information and opinions in support of the position that the new regulations, when combined with other recent EPA regulations, will have a disastrous impact on their business.

In the final rule, EPA agreed with the final SBREFA report regarding the diesel sulfur standards "that small business refiners would likely experience a significant and disproportionate financial hardship in reaching the objectives of our diesel fuel sulfur program." However, EPA has made no provision to assist small business refiners in financing the mandated capital expenditures.

Without such provision, some small business refiners will shut down and all will struggle to meet the mandated expenditures. Such a policy ignores the important role of the small business refiner in the U.S. energy market. The result of such a policy will have serious consequences for our country.

The Small Business Refiner is a Critical Part of the U.S. Economy

Some 25 U.S. refineries have shut down over the last decade. Today, approximately 124 refineries which produce highway diesel are still operating in this country. Some 18 small business refiners operate 22 of these diesel producing facilities. Small business refiners produce about 4 percent of the nation's diesel fuel and in some

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regions provide over half of the diesel fuel. Small business refiners are primarily owned by U.S. citizens including privately held businesses and one farmer cooperative.

Small business refiners have long served an essential function of maintaining competition. Individually, each small business refiner represents a relatively small share of the petroleum product marketplace. Cumulatively, however, their impact is substantial and decidedly procompetitive. Such pricing competition pressures the larger integrated companies to lower prices to the consuming public. For example, in early 1991, Amoco shut down its 40,000 bpd refinery in Casper, Wyoming, and gasoline prices jumped almost 10 cents per gallon. In California, the Attorney General concluded that after five small refiners shut down because they could not manufacture California's cleaner burning gasoline, the loss of competition cost consumers hundreds of millions of dollars.

Small business refiners also fill a critical national security function. For example, in 1998 and 1999, small business refiners provided almost 20 percent of the jet fuel used by U.S. military bases. This adds up to almost 500 million gallons of jet fuel supplied each year under defense contracts between the government and small business refiners. In the event small business refiners stop operating because they cannot make Ultra Low Sulfur Diesel Fuel, this resource would not be available to the U.S. military.

The Impact on Small Business Refiners will be Substantial and Disproportionate

The cost to comply with the new regulations will be substantial and impact small business refiners disproportionately. Costs include both up-front capital expenditures and increased on-going operating costs. These costs will vary from facility to facility, and estimates vary as well. But even EPA estimates, which the industry disputes as substantially too low, show high costs of compliance and a disproportionate impact on small business refiners.

EPA estimates that small business refiners will incur average capital costs of $14 million per facility to meet the new diesel regulations; for some facilities the cost will be substantially more. In addition, costs to produce low-sulfur gasoline will add significantly to capital requirements in approximately the same time frame. Such capital investments are significantly beyond the financial capability of facilities operated by small business refiners, whose total investment is dwarfed by these requirements. On top of the initial required capital expenditures, the related increases in operating costs could equal or exceed the refineries' historical annual profits, and thus, imperil the viability of these important US businesses.

Small Business Refiners Must Be Protected

If small business refiners reduce or eliminate production of on highway diesel, and if some go out of business, the competitive fabric of the U.S. oil and gas industry will be irreparably damaged. If small business refiners are unable to operate, it will adversely affect not only the market for diesel fuel but also the market for every other product manufactured by small business refiners.

The new regulations also will make it even less likely that new refineries will ever be built. With the exception of one small topping facility in Alaska, no new refinery has been built in the United States for almost 20 years. Existing facilities are operating at full sustainable capacity. Operational demands imposed by the new regulations will result in a reduction of on-road diesel production. At the same time, U.S. consumer demand for diesel fuel, as forecast by the Energy Information Administration, is expected to grow by 6.5 percent between now and 2007. If small business refiners are eliminated from diesel production, supply shortages will become even more likely. Therefore, it is important to seek methods to reimburse small business refiners for their costs in meeting these new government imposed mandates, which endanger their long-term economic viability.

A Substantial Tax Incentive Is Necessary To Provide Meaningful Relief to Small Business Refiners

As a legislative matter, the tax code has traditionally dealt with similar issues by providing tax incentives such as investment tax credits, accelerated depreciation, or expensing of certain qualified expenditures. Given the magnitude of the mandated expenditures, and the short time frame under which they must be expended, a substantial tax incentive equal to a 35 percent tax credit (not subject to the alternative minimum tax ("AMT") calculation) is necessary to provide meaningful relief to assist small business refiners. Further, small business refiners must be allowed a substantial tax incentive equal to a 35 percent tax credit toward additional operating expenses incurred as a result of the new regulations.

A taxpayer who qualifies for the tax incentive should be defined as a "small business refiner" under the EPA definition, *i.e.* refiners with fewer than 1500 employees and less than 155,000 bpd total capacity.

The tax incentive would be applicable to qualified property purchased in order to comply with the "applicable EPA regulations." Applicable EPA regulations include "Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements." Further, the tax incentive would be applicable to qualified operating expenses incurred in order to comply with the same applicable EPA regulations.

Since many small business refiners are just beginning to pay under the regular income tax regime (due to loss carryforwards and application of the AMT), it is important that the tax incentive not be subject to the AMT. Thus, these tax incentives would not be subject to the AMT calculation. Further, depending on the form of the tax incentive, a taxpayer could carryback and carryforward the tax incentive.

The tax incentive applicable to capital expenditures will become effective immediately and expire on the date a qualified taxpayer must meet the EPA regulations. The tax incentive applicable to operating costs would be effective immediately and would be permanent.

March 2001

Small Business Refiners Producing Diesel

Age Refining Company	San Antonio, TX
American Refining Company	Bradford, PA
Calcasieu Refining Company	Lake Charles, LA
Countrymark Cooperative, Inc.	Mt. Vernon, IN
Foreland Refining	Tonopah, NV
Frontier Oil Corporation	Cheyenne, WY; El Dorado, KS
Gary-Williams Energy Corporation	Denver, CO (Wynnewood,OK)
Golden Bear Oil Specialties	Bakersfield, CA
Inland Refining, Inc.	Woods Cross, UT
Kern Oil & Refining Company	Bakersfield, CA
Paramount Petroleum Corporation	Paramount, CA
Petro Star, Inc.	North Pole and Valdez, AK
Placid Refining Company	Port Allen, LA
San Joaquin Refining Company	Bakersfield, CA
U.S. Oil & Refining Company	Tacoma, WA
Wyoming Refining Company	Newcastle, WY

TALKING POINTS: SCOPE OF ANGTA

- ANGTA, the President's Decision thereunder, and Congress's enactment of that decision into law discarded the usual procedures of the NGA for certifying a system for transporting natural gas from Alaska's North Slope to the Lower 48 States. In the mid-1970s, the FPC was struggling to choose, under § 7 of the NGA, the best among three mutually exclusive projects. The outcome of its complex comparative proceeding was further subject to judicial review under the NGA. While agreeing with the FPC that only one system could be certified, Congress concluded the NGA's procedures were too cumbersome to meet the nation's needs.

- In ANGTA, Congress superseded the NGA and the FPC's proceeding as applied to the transportation of Alaska North Slope gas to markets in the contiguous States. It empowered the President, subject to Congressional approval, to make the choice under ANGTA's unique procedures.

- Section 5 of ANGTA directed the FPC to suspend its pending comparative proceedings until the President's Decision took effect following Congressional approval, or no such decision took effect. Once Congress approved the President's Decision, the Commission was directed to vacate the suspended proceedings and in accordance with the President's Decision, issue a certificate of public convenience and necessity for the system and sponsors he designated.

- Under § 9, no condition in any certificate or permit related to the construction or initial operation of the approved system and no amendment or abrogation of any such term or condition could change the basic nature and general route of the approved system, or otherwise prevent or impair, in any significant respect its expeditious construction and initial operation.

- Under § 5, only if the President made no designation, or his designation never became effective for lack of Congressional approval, could the selection of an Alaska natural gas transportation system thereafter be made under the NGA's usual procedures.

- The ANGTS is controlled by international agreement. The President's Decision choosing the ANGTS was submitted to Congress on September 22, 1977. It reflected an agreement between the United States and Canada, signed two days earlier, specifying the ANGTS. The agreement cannot be terminated before 2012. Congress approved the President's Decision, including the Agreement with Canada incorporated therein, on November 8, 1977.

- ANGTA provided for its sunset and for a resumption of ordinary procedures under § 7 of the NGA with respect to the transportation of North Slope gas to the contiguous States, but <u>only if no designation by the President became effective</u>. Because the President's decision became effective, ANGTA and that Decision can be terminated only by another act of Congress.

- Thus, ANGTA's limitation of the NGA remains in effect until all components of the ANGTS are completed and in initial operation under final certificates. Other provisions of the NGA may apply to the ANGTS, but only to the extent that they are not inconsistent with ANGTA and the President's Decision.

- The President's choice cannot now be revoked by new FERC proceedings under the NGA comparing his chosen system, *i.e.*, the ANGTS, with subsequently filed proposals. Congress has never authorized other officers of the United States to overrule a substantive decision vested in the President as Chief Executive and the nation's organ of foreign policy. Because such an authorization would raise grave constitutional issues under Article II of the Constitution, it would require explicit statutory language. No such provisions are contained in ANGTA or the NGA.

- It would, moreover, be absurd to construe ANGTA as allowing FERC to use NGA procedures to reconsider and nullify the President's Decision. Having directed the vacation of the FPC's pending comparative "Ashbacker" proceedings, Congress could not have intended to allow the same parties or new applicants to begin the whole discarded comparative process again by thereafter filing new alternative proposals under § 7 of the NGA.

- Congress made its intent clear in § 9(b) of ANGTA, which requires that applications and requests with respect to authorizations required by the approved system "shall take precedence" over any similar applications and requests.

- Moreover, if notwithstanding § 9(b), such a proceeding could be launched today under the NGA, the Commission would be entangled in the same issues of mutual exclusivity that were pending before the FPC in the mid-1970s. The proceedings would be even more complex than the FPC's, given contemporary economic and environmental considerations. The specter of delay which Congress had sought to dispel in ANGTA, would be revived, including the full scale judicial review which Congress limited in § 10 of ANGTA.

- Since ANGTA bars inclusion in certificates and permits for the chosen system of any conditions obstructing that system's expeditious completion and startup, it follows *a fortiori* that alternatives to the chosen system cannot be considered or certified. The mere conduct of such proceedings by the FERC would necessarily delay or prevent completion and initial operation of the Presidentially designated system.

- Assuming that a literal construction of § 5(a)(1) of ANGTA permitted FERC to reconsider the President's Decision at any time after it became effective, such a construction would be both inconsistent with Congress's intention and unnecessarily raise constitutional problems concerning revision by FERC of a Presidential decision. In these circumstances, the plain intent of Congress necessarily must overcome any literal reading at odds with that intent.

- ANGTA does not create a perpetual monopoly for the ANGTS. It establishes a priority designed to assure that the chosen system will be completed and begin initial operation in accordance with the decision of the President and Congress. Thereafter, but only thereafter, additional projects that compete with the completed system may be considered under § 7 of the NGA. This result is clearly indicated by the Department of Energy's Order Nos. 350 and 350-A relating to the export of North Slope gas, as contemplated by § 12 of ANGTA, to Pacific Rim countries.

- Nothing in ANGTA or in the certificates issued to the ANGTS thereunder provides for the expiration of the chosen system's priority because completion of the Alaska segment was postponed until the U.S. domestic market could support it. Rather, the **Alaska phase of the ANGTS has been held in reserve**, like the natural gas it will transport from North Slope, until the need arises in the Lower 48 States and that phase can be completed. All phases of ANGTS that could be economically supported were completed in 1982 after waiver by President Reagan of certain provisions of the original President's Decision and of the NGA. The sponsors have actively protected the reserved Alaskan segment by maintaining all necessary certificates and permits and actively overseeing all rights-of-way. Moreover, FERC has repeatedly confirmed its commitments to the ANGTS.

- Congress reconfirmed the status of the ANGTS in § 3012 of the Energy Policy Act of 1992. That section rejected recommendations for repeal of ANGTA by the Federal Inspector of the ANGTS, an officer appointed by the President and confirmed by the Senate to oversee compliance with the requirements of ANGTA and the President's Decision. The Federal Inspector's various characterizations of ANGTA included statements such as: the ANGTA regime conferred a "specific route for the transportation of Alaska gas . . ."; "the designation of the route and the sponsors for the various legs grants them a monopoly in perpetuity over the delivery system . . ."; and the ANGTA regime gave the "ANGTS project sponsors unique legal monopoly status." (Report to the President on the Construction of the Alaska Natural Gas Transportation System, January 14, 1992). The Federal Inspector then recommended that Congress abandon the whole scheme of ANGTA and withdraw the President's Decision on the ground that the ANGTS might never be needed or completed. Senator J. Bennett Johnson urged the President to reject this recommendation because American consumers would eventually need access to Alaska North Slope gas. He emphasized that the ANGTS as approved by the United States and Canadian governments would be the most economic and environmentally sound means of providing that access.

  The Secretary of Energy subsequently urged the elimination of the Office of the Federal Inspector and the transfer of its functions, but did not endorse any other aspect of the Inspector's recommendations. Thus, neither the Executive Branch nor Congress rejected the Federal Inspector's characterization of the ANGTS Sponsors' unique legal monopoly status, nor did they accept his recommendation that ANGTA be revoked. Section 3012 of EPAct 92 simply transferred the Federal Inspector's functions to the Secretary of Energy so that if new activity begins in the future on ANGTS, the inspection function can be carried out.

Because Congress revisited ANGTA in 1992 and reaffirmed it in the face of calls for its repeal, the original intent to limit the NGA must be given effect.

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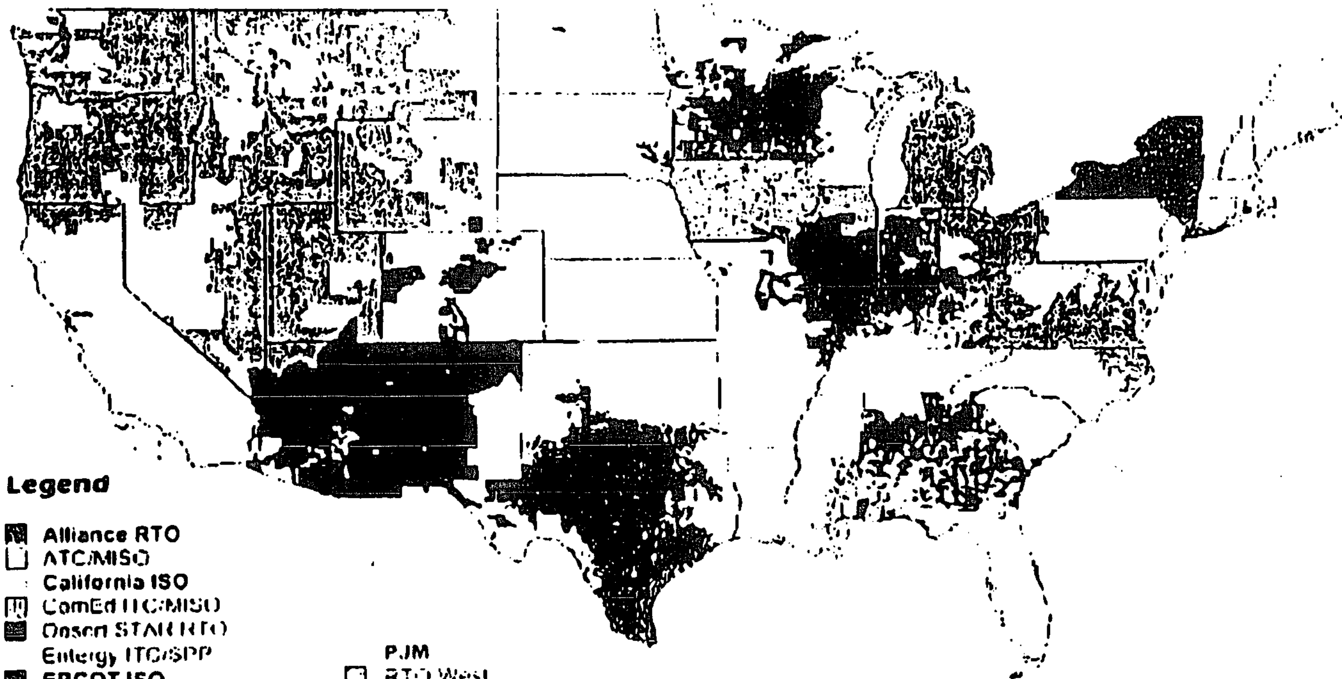
Regional Transmission Organizations

Utility Participation as of September 2000



Legend

- **Alliance RTO**
- ATC/MISO
- **California ISO**
- ComEd ITC/MISO
- Desert STAR RTO
- Entergy ITC/SPP
- **ERCOT ISO**
- GridSouth Transco
- **ISO New England**
- **Midwest ISO**
- **Mountain West ISA** *
- **New York ISO**
- **Northern Maine ISA**
- Peninsular Florida Transco
- PJM
- RTO West
- RTO West/ITC
- Southern RTO
- SPP
- Non-participating IOUs
- Non-participating cooperatives
- Non-participating public power
- Non-utility/no electric service area

DOE024-2298

"SEC. 217. STANDARDS FOR ESTABLISHING RATES, CHARGES, TERMS, AND CONDITIONS FOR TRANSMISSION SERVICE.

"(a) RECOVERY OF COSTS.—In reviewing rates, charges, terms, and conditions for transmission services under this Act, the Commission shall permit a transmitting utility to recover the costs incurred by the utility in connection with the transmission services and necessary associated services, including, but not limited to, the costs of any enlargement of transmission facilities.

"(b) CONSIDERATION OF COST AND BENEFIT.—In reviewing the rates, charges, terms, and conditions of transmission services that are provided by a regional transmission organization and that make use of facilities constructed after the date of enactment of this section, the Commission shall take into account the incremental cost and the benefit to interconnected transmission systems of such facilities.

"(c) CERTAIN REQUIREMENTS.—Rates, charges, terms and conditions established pursuant to subsections (a) and (b) shall—

"(1) be just and reasonable and not unduly discriminatory or preferentia and

"(2) promote the economically efficient transmission of electricity, the expansion of transmission networks, the introduction of new transmission technologies, and the provision of transmission services by regional transmission organizations.

"(d) VOLUNTARY INNOVATIVE PRICING POLICIES.—Notwithstanding subsection (a) of this section, the Commission shall encourage innovative pricing policies voluntarily filed by transmitting utilities. Innovative pricing policies include policies that—

"(1) provide incentives to transmitting utilities to promote the voluntary participation in and formation of regional transmission organizations, without having the effect of forcing transmitting utilities to join regional transmission organizations and extend such incentives to transmitting utilities that already have formed a regional transmission organization;

"(2) limit the charging of multiple rates for transmission service over the transmission facilities operated by the regional transmission organization, provided, however, that a reasonable transition mechanism or period may be used before eliminating such rates;

"(3) minimize the shifting of costs among existing customers of the transmitting utilities within the regional transmission organization;

"(4) encourage the efficient and reliable operation of the transmission grid and supply of transmission services through congestion management, performance-based or incentive ratemaking, and other measures; and

"(5) encourage efficient and adequate investment in and expansion of the transmission facilities owned or controlled by the regional transmission organization.

"(e) NEGOTIATED RATES.—Notwithstanding subsection (a) of this section, the Commission may permit the charging of negotiated rates for transmission services without regard to costs whenever an individual company or companies are willing to pay such negotiated rates, provided, however, that such costs shall not be recovered from other transmission customers.

"(f) EFFECTIVE COMPETITION.—Notwithstanding subsection (a) of this section, in reviewing rates, charges, terms, and conditions for transmission rates under this Act, the Commission may permit the recovery of market-based rates for transmission services where it finds that relevant geographic and product markets for transmission services or for delivered wholesale power are subject to effective competition.

"(g) RULEMAKING.—Within 180 days after enactment of this section, the Commission shall establish by rule definitions and standards to govern its approval of performance-based or incentive pricing policies under subsection (d) and negotiated rates under subsection (c) With respect to performance-based or incentive rates, the definitions and standards shall include, but not be limited to, (1) a method for calculating initial transmission rates (including price caps that would include discounting); (2) an index mechanism for adjusting initial rates; (3) time periods for redetermining initial rates; and (4) costs to be excluded from performance-based rates.

"(h) REPORT.—Within 360 days after enactment of the section, the Commission shall submit to Congress a report on all policies adopted by the Commission to encourage the economic use and expansion of the transmission network through incentive rates or other similar market-oriented approaches.

"(i) ANNUAL REPORTS.—The Commission shall submit annually a report to the Congress comparing the allowed financial returns on transmission related investment by electric utilities to the financial returns earned by a sample of United States companies from other industrial sectors.".

SEC. 106. CONFORMING AMENDMENTS.

(a) ENFORCEMENT.—Subsections (a) and (b) of section 316A of the Federal Power Act (16 U.S.C. 791a) are each amended by striking "section 211, 212, 213, or

214," in each place such phrase appears and inserting "part II".

(b) COMPLAINTS.—Section 306 of the Federal Power Act is amended by inserting "agency or instrumentality of the United States," after "person," in the first sentence and by inserting ", electric utility, transmitting utility" after "licensee" in each place it appears.

(c) REVIEW OF COMMISSION ORDERS.—Section 313 of the Federal Power Act is amended by inserting "agency or instrumentality of the United States," after "person," in the first sentence in subsection (a).

(d) TECHNICAL CORRECTIONS.—(1) Section 211(c) of the Federal Power Act is amended by striking "(2)" and by redesignating subparagraphs (A) and (B) as paragraphs (1) and (2) and by striking "termination of modification" and inserting "termination or modification".

(2) Section 315 of the Federal Power Act is amended by striking "subsection" and inserting "section".

SEC. 107. SAVINGS CLAUSE.

(a) STATE AUTHORITY TO ORDER RETAIL ACCESS.—Neither silence on the part of Congress nor any Act of Congress shall be construed to preclude a State or State commission, acting under authority of State law, from requiring an electric utility subject to its jurisdiction to provide unbundled local distribution service to any electric consumers within such State.

(b) EXISTING STATE PROGRAMS.—Nothing in this Act nor any amendment to the Federal Power Act made by this Act preempts, overrides, or requires any change in the terms of any State retail access plan enacted, adopted, approved, promulgated or ordered prior to or within three years after the date of the enactment of this Act to the extent that such plan addresses matters within the jurisdiction of the State prior to the enactment of this Act.

TITLE II—ELECTRIC RELIABILITY

SEC. 201. ELECTRIC RELIABILITY.

Part II of the Federal Power Act (16 U.S.C. 824 and following) is amended by adding at the end the following section:

"SEC. 218. ELECTRIC RELIABILITY ORGANIZATION AND OVERSIGHT.

"(a) DEFINITIONS.—As used in this section:

"(1) AFFILIATED REGIONAL RELIABILITY ENTITY.—The term 'affiliated regional reliability entity' means an entity delegated authority under the provisions of subsection (h).

"(2) BULK-POWER SYSTEM.—The term 'bulk-power system' means all facilities and control sys-

Testimony of
Curt L. Hébert, Jr., Commissioner
before the
Senate Committee on Energy and Natural Resources

April 27, 2000

Overview

I thank the Committee for the honor of testifying here this morning on the various electricity restructuring bills pending before you. In my opinion, Congress should adopt the principle that legislation should remove obstacles to the natural evolution of the industry. FERC does not need more jurisdiction; indeed, we need less. Right now, the generation and transmission businesses are moving in opposite directions. On the wholesale level, FERC has deregulated prices for generation because of the proliferation of independent power and technology that allows plants to come on line in 18 months or so. Transmission, on the other hand, will have to remain regulated for the foreseeable future. Transmission must become a stand-alone business and respond to the market. It must do so, however, within the framework of regulation, though a new form.

Historically, regulation reigned in economic interest for the sake of the public interest. Most people agree that approach failed. From now on, regulation must align economic interest with the public interest. Together, Congress and FERC must act in a way that gives the new model a chance to succeed. What may have worked in the Depression Era no longer works in the Internet Age. In our respective spheres, Congress and the FERC must clear out the underbrush to allow new growth to take over.

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FERC and the states can, and, under the right leadership, will remove most regulatory impediments toward efficiency in electricity. Recently, FERC issued Order No. 2000, which flatly states that restructuring will succeed only if transmission becomes a stand-alone business. By unanimous vote , we applied what an economist called a form of performance-based regulation." Rather than write rules and mandate outcomes, Order No. 2000 laid out a business plan – 12 goals, four characteristics and eight functions, for regional transmission organizations to meet.

The Commission opened the door to rate reforms for RTO's to propose as necessary to make the transmission business viable on a stand-alone basis. The Order listed eight, from temporary rate moratoria to perfomance-based rates. Rather than look at costs, we will focus on value to the customer, as businesses do in the free market. FERC has jurisdiction under current law to approve each of them and many others that RTO's can justify.

People know that about half the States have passed laws opening their retail markets to increased customer choice, to one degree or another. Less well known to most people, some have gone farther. States, such as Wisconsin, have passed laws that require utilities to separate transmission into a separate business. In the case of Wisconsin, the Legislature chose a for-profit company. With transmission as a separate business, FERC has jurisdiction over the wires under current law.

With the right leadership FERC will move forward toward effective restructuring. Incentives and performance-based rates will unleash entrepreneurial initiative. By aligning the public interest with economic interest, doing the right thing for customers will also result in better earnings for shareholders. Transmission companies will establish a business plan in consultation with customers. Companies that meet or exceed the goals in the business plan will earn profits for shareholders. Those that fail will take the risk, and, ultimately, as in any market, will sell their facilities to more efficient entities. All that can happen under FERC's current jurisdiction, without one word of new legislation.

FERC can go only so far, however. Laws enacted as far back as the Depression and as recently as the Carter Administration, that made sense in their time, now act as a drag on restructuring. These laws have the ironic effect of causing harm to the very consumer they were supposed to protect. In addition, unintended consequences of tax law encrust the *status quo*, at a time that cries out for change. More than the incentives of Order No. 2000, Federal Marketing Agencies, including Bonneville Power Administration and the Tennessee Valley Authority, need legislation to authorize them to become or join Regional Transmission Organizations. Participants in the discussions in the Northwest agree that Congress should act, whether the RTO takes the form of a for-profit transmission company or a not-for-profit system operator.

Worse than doing nothing, Congress can harm the process of restructuring by taking the wrong road and passing unnecessary legislation or laws that point toward more regulation.

The Need for Legislation

Repeal Outdated Laws

1. PUHCA

The Public Utility Holding Company Act, dating from the Depression, and the Public Utility Regulatory Policies Act, dating from the Carter Administration, act as serious brakes on restructuring. The Holding Company Act requires registered companies to submit to onerous regulation by the Securities and Exchange Commission, including seeking permission for moves that companies make in the ordinary course of their business. Pointedly, the Act exempts utilities operating within one state from registration. The Act also subjects holding companies to requirements that they operate an "integrated" and contiguous system.

Tied to a world in which state commissions, to the extent they existed, operated in isolation, Federal securities laws had just been enacted, power could flow over short distances and designed to combat the effects of stock manipulation during the 1920's, it has outlived its usefulness. As information technology has improved and investors have become more sophisticated, utilities must grow larger and operate beyond the boundaries of single states. Enforcement of securities regulation has eliminated the abuses of the 1920's, in all areas of the stock market. For that reason alone, Congress should repeal the law.

More important, the Holding Company Act has perverse effects. Because of the provisions for foreign utilities, the Act causes foreign companies to buy here and U.S.

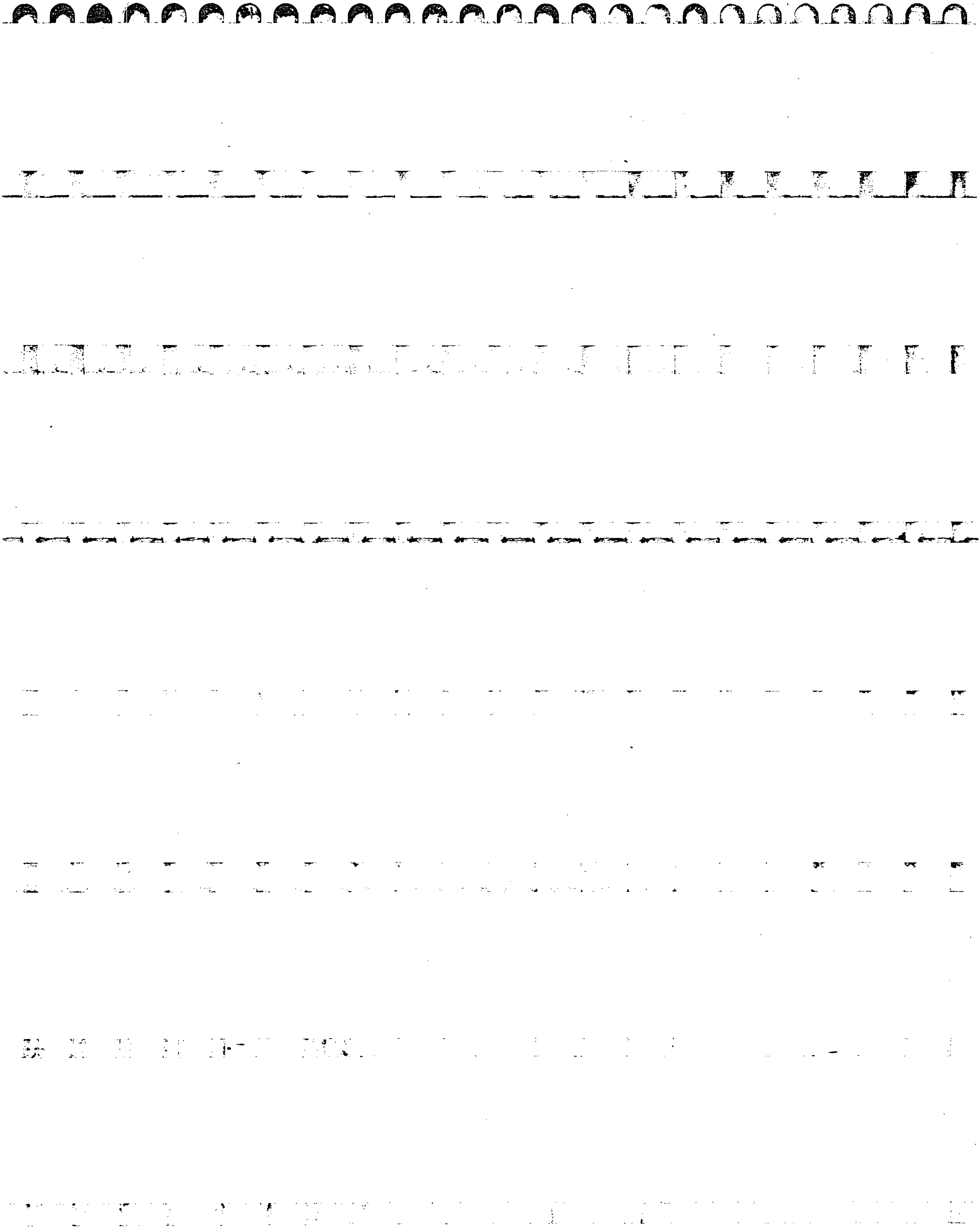
companies to invest overseas. Investment in and from overseas help integrate the world economy. The investment should result from economics, not the vestige of a law that outlived its time.

2. PURPA

While not as old as the Holding Company Act, the Public Utility Regulatory Policies Act needs repeal. PURPA, as we call it, forces utilities to buy from alternate energy sources at high prices. Congress passed it at a time when people thought we needed to lessen our dependence on oil for electric generation and that subsidies would help accomplish that result. Now, 22 years later, when we want to bring prices down and when developers can build gas-fired generators in about 18 months and distributed generation lies on the horizon, subsidizing certain types of generation makes no sense. Moreover, experience at FERC shows that the alternate sources PURPA envisioned -- those exclude gas – have either been fully exploited or (as in the case of municipal waste) have proven infeasible. Several proposals before the Committee this morning would repeal both laws and I support that.

3. Section 203 of the Federal Power Act

The Federal Power Act gives FERC the authority to review electric mergers. FERC has no expertise in the area. FERC enacted a Merger Policy Statement that ignores contemporary economics, such as the Department of Justice and Federal Trade Commission's practices in making mergers difficult. When utilities should consolidate with neighbors to reflect the growth in the economy, FERC considers those moves anti-



debt-laden bureaucracies. To its credit, Bonneville has reformed, but remains burdened with bad debt from nuclear plants. Bonneville has continuing disputes with utilities in the Northwest that claim it uses its transmission (80% of the region) to favor its own generation. The stakeholders in the Northwest, according to my understanding, prefer to separate Bonneville's transmission from generation and to form a for-profit entity, even as a Government corporation. Bonneville has already split its transmission into a separate business line. It needs a separate Board of Directors and a new mandate. This will alleviate preference concerns while not harming the already low rate structure in the Bonneville region.

TVA remains a great problem. Forces in Bonneville want to separate transmission from generation into a stand-alone for-profit business. TVA's transmission has value that, if sold, would help retire its huge debt to the Treasury. While Order No. 2000 created the atmosphere to a separate transmission business, Bonneville and TVA may not legally change. Congress must pass a law. I could support, as a first step, the creation of a for-profit government transmission corporation in the Northwest and another in the Southeast. The program would resemble Conrail, the for-profit stand-alone Federal freight railroad for the Northeast that the Government eventually sold for a good return. States can change their laws regarding locally owned public power.

As a private businesses, Bonneville and TVA would become subject to Order No. 2000. Given the incentives in the Rule, the Federal transmission owners will form into regional transmission organizations. State and local Legislatures have the authority to allow municipal utilities (and in some cases, cooperatives) to join RTO's. To the extent, state constitutions require amendment, the individual State can use its own procedures to accomplish the goal. I emphasize that, given the economic evolution of the industry and the incentives of Order No. 2000, States will see it in their interest to act. As with retail competition, where the States took the lead, Congress should stay its hand.

Congress has a large role in tax policy. While this area lies outside my expertise, I have heard from many trying to form for-profit transmission companies that spinning off or selling assets creates a tax liability. Turning over operation without ownership does not. Therefore, utilities would find it more difficult to create for-profit transmission companies. Since Congress must deal with the thorny issue of tax exemption for public facilities anyway, I have every confidence that legislation will solve this tax issue also.

What Congress Need Or Should Not Do

I have often said that Alfred Kahn described restructuring when he said that competition is a substitute for regulation and regulation is a substitute for competition. To me, we must choose which direction to move in. We must move away from regulation and toward competition. That requires, in some instances, a new way of thinking. As I discuss next, some issues the market will address that previously regulation addressed. In other instances, we must let go altogether and not fear the unknown.

Reliability

We hear great clamor over possible reliability problems in a restructured market. Many fear for this summer. I think this a legitimate issue for discussion. I think, however, that the solution lies in the market, not in creating an organization, under FERC oversight, with FERC having last-resort authority to impose standards on the industry.

I testified on this question before the House Commerce Committee's Subcommittee on Energy and Power. I said then that I oppose FERC having authority to establish reliability standards. I also think that the current system, involving private regional reliability councils establishing the standards needs reform. I favor injecting reliability standards in the performance based rate plans I advocate for utilities. In particular, each plan for each Regional Transmission Organization would contain a target for reliable performance. I envision interested parties negotiating the issue, along with the other factors in the plan for presentation to FERC. Each RTO';s earnings would rise or fall on how well it does.

My suggestion then is to create a climate in which that occurs in transmission. Specifically, tie profits to performance – safe performance and an adequate number of transactions. Give transmission companies business plans to meet. Favorable earnings result from good results, losses from poor management. Clearly, we don't need legislation to do that. FERC has the authority to institute performance based rates. We did it in Mississippi. The Public Service Commission put three criteria into the final plans. Two of them fall directly under the category of reliability, and one indirectly.

Earnings depended on the number and duration of interruptions, customer satisfaction (using actual complaints) and price into which we factored sales transactions. The companies figured out how to set and meet reserve margins, safety standards and capacity goals. We aligned the private economic interest with the public interest. FERC can do that now.

Lastly, I note that, in other industries, such as electric appliances, the market participants established an organization, Underwriter's Laboratory to endorse the safety and reliability of their products. RTO's, especially for-profit companies, have the same incentive to form an organization that will establish proper standards. I will illustrate the problem with a governmental mandate. At the most recent FERC public meeting, we considered in the case *New York Reliability Council*, whether to allow the New York Council to reduce its reserve margin from 22 to 18 percent. We did. It turns out, however, that the study on which the New York Council relied said that 12 percent would ensure smooth operation, but at maximum, 17 percent would do the job. The New York Council threw in 1 percent for good measure! In economic terms, the New York Council either withheld capacity that belongs on the market or wasted money. A private, for-profit transmission company would have relied on hedging or financial means in case 12 or 17 percent proved too low.

On this issue I think reasonable people can discuss various alternatives.

Market Power Authority

Another area in which we hear much advocacy relates to giving FERC more authority over "market power." Mind you, the antitrust laws would still apply. FERC would have regulatory power in addition to the Antitrust Division and the Federal Trade Commission. Legislation here I consider wrong, in the sense that it moves in the direction of regulation and away from competition. Exercising market power, in the true sense of the term, violates the antitrust laws. What more can FERC guard against? Proponents give evasive answers. My experience at FERC, however, gives me a clue.

In a number of cases involving price caps for independent system operators in California and New England, the cry of market power arose every time the price rose to a level that the ISO did not like. Without proof of monopoly or collusion, regulators cried market power, when, in fact, prices rose during peak season, when demand rose. The pleadings say that market power occurs every time a price rises above marginal (operating) cost. I called this "capitalism at its best." I also pointed out that prices in the flowers market rise just before February 14, without anyone calling for controls.

Levity aside, legislation here poses a danger. Price caps mask mistakes in market rules or ISO procedures and make reform difficult. When regulators depend on a crutch, they need not undergo painful rehabilitation that would, in the end, allow them maximum mobility. In addition, high prices bring new supplies or decreased demand during peak times. Holding prices at operating costs all the time does not allow sellers to recover overhead, let alone earn a profit. Markets require giving sellers the opportunity to earn a profit.

Interconnection Policy

Lately, we have heard that Congress must give FERC the mandate of writing rules to allow generators to connect to the grid. Not only that, but a DOE-led task force calls for uniform provisions as well. I find this a waste of time and money. An RTO, especially a for-profit, stand-alone transmission company, would welcome interconnection from generators, as railroads, ships and trucks (and airlines) welcome freight. The problem the DOE addresses results from an alleged bias toward generation. If we separate transmission from generation, we remove the bias.

More important, at a time when FERC and the industry are engaged in collaboration to form stand-alone transmission companies, we must keep our eyes on the forest and off the trees. As with all things, the market knows better and can adapt better than regulators to changes. While Franklin D. Roosevelt advocated trying something else when the original solution fails, how many of us in Government, without pressure of the laws of economics, have the courage to live by his credo? Very few, I am afraid.

I will gladly answer your questions.

ATTACHMENT 2

Electricity Tax Agreement

LPPC/APPA and EEI

The industry agreement on electricity restructuring tax issues is intended to modify the federal tax laws to remove certain impediments to effective competition in the electric power industry. The agreement is intended to preserve the right to use tax-exempt financing to serve public power systems' own electric load and remove the current tax law impediments to opening up these systems to competition. The agreement preserves public systems' use of tax-exempt bonds to finance distribution facilities, with some limitations. The agreement eliminates taxation of customer contributions in aid of construction for shareholder-owned systems' electric transmission and distribution facilities. The agreement also facilitates FERC's open access transmission policies by allowing public systems to provide open access without violating private use rules and by providing tax relief to shareholder-owned utilities that sell or spin-off transmission facilities to businesses that join independent regional transmission organizations. Last, the agreement is intended to assure adequate financing of nuclear decommissioning activities in a competitive, restructured electric industry.

The provisions of the agreement are described more specifically below.

I. PRIVATE USE

A. Election to Terminate Issuing New Tax-Exempt Bonds

1. Termination Election

Under the agreement, public power systems can elect to permanently terminate issuing most new tax-exempt bonds, in return for an exemption from private use rules for all of their existing tax-exempt bonds issued before date of enactment. However, an electing system may continue to issue certain tax-exempt bonds which are described below.

2. Tax-Exempt Bonds that may be Issued after a Termination Election

Qualified bonds and refunding bonds. -- An electing system may continue to issue any qualified bond as defined in Section 141(e) of the tax code. (These are tax-exempt bonds that are currently free of most private use constraints.) An electing system may also issue any eligible refunding bonds. An eligible refunding bond is a state or local bond issued after the system

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the system made the election, provided the weighted average maturity of the refunding bonds does not exceed the remaining average maturity of the refunded bonds.

Qualifying transmission and distribution facilities. -- An electing system may continue to issue bonds to finance a local transmission facility over which the system provides open transmission access (a qualifying transmission facility); and a distribution facility over which the system provides open retail access (a qualifying distribution facility). New transmission and distribution bonds issued under this exception are subject to private use rules, as modified by the agreement.

Repairs. -- An electing system may continue to issue tax-exempt bonds for repair of electric generating facilities that were in service on the date of enactment or construction of which was commenced prior to June 1, 2000. Repair may include replacement of components of the electric generating facilities, but does not include replacement of a major portion of an electric generating facility. The repairs performed with the tax-exempt financing may not increase the capacity of the generating facility by more than 3% of base year capacity.

Environmental. -- An electing system may also continue to issue tax-exempt bonds to meet federal or state environmental requirements applicable to electric generating facilities that were in service on the date of enactment or construction of which was commenced prior to June 1, 2000.[1/]

Renewables. -- An electing system may issue tax-exempt bonds for renewable energy generation facilities during any period in which tax credits for the same type of facility are available to private entities. Tax credits are currently available for solar, wind, geothermal and closed-loop biomass generating facilities.

B. Updated Private Use Rules for Non-electing Systems

Under the agreement, public power systems that do not make the termination election remain subject to private use rules. However, the agreement would modify the private use rules applicable to public power systems that do not make the termination election to permit open access transmission and distribution and to permit public power systems to make certain electric sales not subject to private use rules in order to retain or replace certain load.

[1/] LPPC/APPA and EEI jointly express support for the concept that all electric utilities, public and shareholder-owned, be allowed to issue new tax-exempt bonds for air or water-pollution control facilities placed in service after the date of enactment. However, the parties are not going to propose legislative language to cover this concept.

1. Open Access

The following open access transmission and distribution activities do not constitute a private business use: (1) providing non-discriminatory open access transmission service; (2) participation in an ISO, RTO or RTG agreement approved by FERC; (3) providing nondiscriminatory open access to distribution facilities for retail delivery of electricity sold by other suppliers; and (4) other open access transactions as provided by the Secretary. Open access transmission must be provided under a FERC-approved RTO agreement or pursuant to an open access tariff approved by FERC. If the open access tariff has been filed voluntarily, the public power system must comply with requirements of FERC Order No. 2000 concerning reporting its plans for regional transmission organizations. For certain Texas utilities, approvals are by the Public Utility Commission of Texas, rather than by FERC.

2. Sales

Wholesale sales by open access transmission utilities. – Public power systems that do not make the termination election and that provide open access transmission service are permitted to make certain wholesale sales not subject to private use rules from generation facilities in service on the date of enactment or construction of which commenced prior to June 1, 2000. To qualify under this provision, the sale must be to a "wholesale native load purchaser" or a "wholesale stranded cost mitigation sale".

A wholesale native load purchaser is a wholesale purchaser to whom the public power system had a service obligation in the base year, or an obligation in the base year under a requirements contract or firm sales contract that has been in effect for, or has an initial term of, 10 years or more.

A wholesale stranded cost mitigation sale is a wholesale sale to an existing or new wholesale customer which replaces lost wholesale native load. Lost load is measured by the difference between base year sales to wholesale native load purchasers and the sales to such purchasers during recovery period years. The recovery period is a 7 year period beginning with the start-up year; however, there is a limited one year carry-over to an eighth year. At the election of the public power system, the start-up year is the year the system first offers open transmission access, the first year in which at least 10% of the system's wholesale customers' aggregate retail load is open to retail competition or, the year of enactment, if later. The base year is the year of enactment or, at the election of the public power system, one of the two preceding years.

On-system sales by open access transmission and distribution utilities. – Public power systems that do not make the termination election and that provide open access transmission (if the system owns or operates transmission) and open access distribution service may also make sales not subject to private use rules to an "on-system purchaser" from generation facilities in service on the date of enactment or construction of which commenced prior to June 1, 2000. An on-system purchaser is specifically defined as one whose facilities or equipment are directly connected with the public power system's transmission or distribution facilities and who purchases electricity from such system and is either a retail purchaser within the area in which the system provided distribution services in the base year or is one to whom the system has a service obligation, or who is a wholesale native load purchaser from the system.

C. Limits on New Tax-Exempt Financing for Certain Transmission and Distribution Facilities

1. Transmission

Local transmission facilities limitation. -- Under the agreement, whether or not they make the termination election described above, public power systems may issue new tax-exempt bonds for transmission facilities only if the facilities are "local transmission facilities." Local transmission facilities are transmission facilities located in a public power system's existing distribution area or facilities which are, or will be, necessary to serve its wholesale or retail native load. A system's retail native load is the load of end-users served by its distribution facilities. A system's wholesale native load is its wholesale sales to its wholesale native load purchasers (or purchasers under wholesale requirements or other firm contracts that were in effect in the base year), or the electric load of end-users served by any such wholesale purchaser's distribution facilities. Electric reliability standards of national or regional reliability organizations, or decisions of RTOs or state or federal agencies shall be taken into account in determining whether facilities are or will be necessary to serve wholesale or retail native load. Transmission siting and construction decisions of RTOs and state and federal agencies shall be presumptive evidence as to whether transmission facilities are necessary to serve native load.

Exceptions. -- Tax-exempt bonds may also be issued to finance any repair, replacement or qualifying upgrade of an existing transmission facility that is not a local transmission facility or to comply with an obligation under an existing shared transmission agreement. However, repair or replacement may not increase the voltage level nor may it increase thermal load limit by more than 3%. A qualifying upgrade is defined as an improvement to existing transmission facilities ordered or approved by an RTO or ordered by a state or federal regulatory or siting agency.

2. Distribution

As under current law, a public system can use tax-exempt financing to construct distribution facilities to serve its customers or existing customers of other utilities as governed by state law. However, under the agreement, a public power system which begins operation after the date of enactment would be precluded from issuing tax-exempt bonds for distribution facilities until it has been in operation for 10 years. In addition, except for certain voluntary transactions, public power systems could no longer issue tax-exempt bonds under the state volume cap to purchase distribution facilities owned by non-governmental utilities.

II. SHAREHOLDER-OWNED UTILITY TAX RELIEF

A. Contributions in Aid of Construction

Tax relief for investor owned utilities in the form of contributions in aid of construction (CIAC) would be as proposed in H.R. 2464 (the Watkins bill), but limited to electric distribution and transmission. Contributions in aid of construction (CIACs) for electric transmission and distribution facilities (including contributions for customer connection fees) would be exempt from income tax. However, fees received for starting and stopping service would not be CIACs and would still be subject to income tax. A utility would not obtain basis in property constructed with the proceeds of CIACs (to the extent of the CIAC received).

B. Transco Tax Relief

The transco tax relief provision of the agreement would defer taxes attributable to certain gains on sales (IRC Sec. 1033) and would permit tax-free spin-offs (IRC Sec. 355) by a utility of transmission facilities to an entity which FERC determines is not a market participant and which is either a FERC-approved RTO or is part of a FERC-approved RTO, or which a state commission, in ERCOT only, approves as consistent with state law regarding an independent transmission organization. The agreement would permit the deferral of tax on the entire proceeds of sale of transmission facilities to an independent transco; but with a savings provision that makes it clear that the tax treatment of the acquisition is not intended to affect FERC or state policy with respect to the extent to which any acquisition premium paid in connection with the purchase of the facilities can be recovered in the buyer's rates. FERC's longstanding policy in the context of facilities that remain under cost of service regulation has been to restrict buyer's rate base to the seller's depreciated original cost of the facility unless the buyer shows that the investment decision is prudent and can demonstrate that the acquisition provides measurable net benefits to ratepayers.

C. Nuclear Decommissioning

The nuclear decommissioning provisions of the agreement would be identical to the nuclear decommissioning tax provisions found in H.R. 2038 (which was introduced by Rep. Weller). These provisions would eliminate the requirement that amounts contributed to a qualified nuclear decommissioning fund come solely from amounts specifically collected from ratepayers under cost-of-service regulation. The provision would also define nuclear decommissioning costs and acknowledge that all such costs are currently deductible when paid or incurred, allow contributions to a qualified fund on an accelerated basis if such funding is required in connection with the transfer of a nuclear power plant, allow taxpayers to use a qualified fund to accumulate all monies needed for decommissioning irrespective of the age of a generating plant and discontinue the requirement that taxpayers obtain a ruling from the Internal Revenue Service before making contributions to a qualified fund.

The Washington Post
Tuesday, February 20, 2001

Shortage Of Power Lines Looms

U.S. Consumers Face Higher Prices

By Peter Behr
Washington Post Staff Writer

The nationwide move toward deregulated and restructured electric power service, experts say, is being undermined by a growing weakness in the U.S. electrical grid system: a shortage of high-voltage transmission lines.

Strained power-line capacity has added to California's energy woes, blocking the movement of surplus power from the state's south end to northern cities hit hardest by blackouts last month.

Crowded transmission lines are also heightening the risk of sharply higher electricity prices and power shortages in New York City this summer, energy analysts warn. The Washington region is one of the few in the country that is unlikely to be affected, because it is part of a strong, five-state power-sharing organization.

In other parts of the country—around the Great Lakes, and in the Southeast and Northeast—traffic jams in long-distance power lines threaten to undercut the very competition in electric service that is the purpose of deregulation. That will confront consumers with an increasing risk of electricity price shocks.

"The seeds of what has grown in California have been sown over the United States as a whole by our failure to keep up with our [transmission] infrastructure over the past decade," said Karl Stahlkopf, vice president of the Electric Power Research Institute, an industry-backed think

See ELECTRICITY, A6, Col. 1

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Power-Line Shortage May Drive Prices Up

ELECTRICITY, From A1

tank in Palo Alto, Calif.

"As we look into the next decade, it gets even scarier," warned Stahlkopf. The institute predicts 20 percent to 25 percent growth in electricity demand in the next decade, but only a 4 percent increase in power lines and electric-grid equipment.

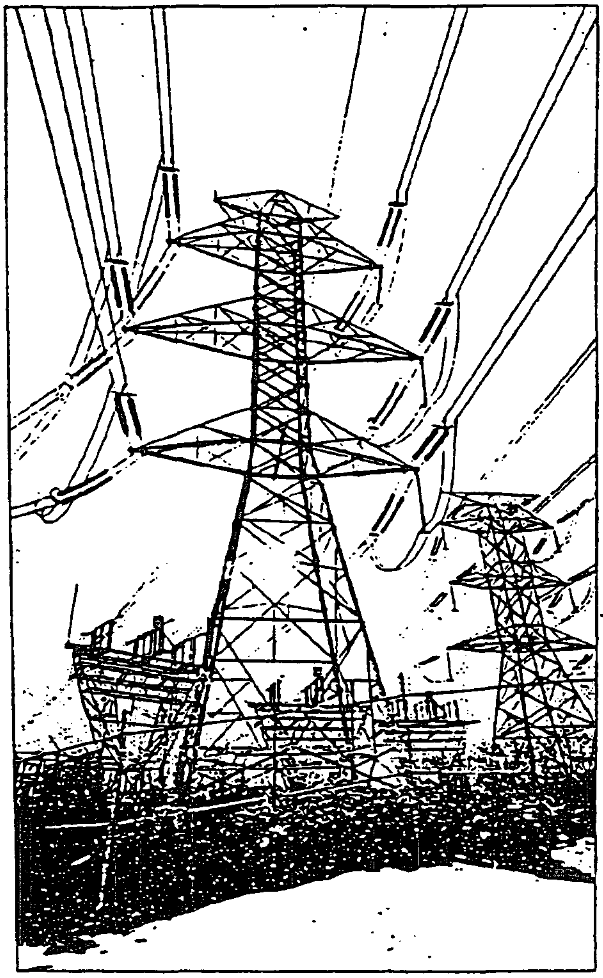
The mobility of power—the idea that market forces would move electricity from areas with excess to areas with shortages—is a fundamental assumption of deregulation. But it turns out that deregulation, as designed by most states, provides little financial or political incentive for generators or utilities to construct long-distance high-voltage transmission lines, according to Stahlkopf and other industry officials.

Transmission capacity is falling further and further behind the demand for power, said consultant Eric Hirst, in a report for the D.C.-based Edison Electric Institute.

That would not be so troubling if electricity service had remained a local business, with communities served primarily by nearby utilities responsible for both generation and transmission.

But long-distance power transmission can be essential in a deregulated system, by increasing competitive offers for customers, said Ken Rose, senior economist with the National Regulatory Research Institute in Columbus, Ohio.

Texas, for example, has ample generating capacity. But weak transmission connections with its neighbors make it impossible to share much of Texas's surplus with states short of power. New York, meanwhile, may have problems even though it is next to the PJM Interconnection, the five-state consortium that supplies power to the Washington area, because there is limited transmission capacity from PJM to the north and east.



The aging transmission lines that bring electricity from points north and west into New York City supply nearly a third of the city's power.

bility.

In the meantime, the FERC has called on utilities to create cooperative Regional Transmission Organizations that would decide on transmission needs and encourage member utilities to build lines where they're needed. The FERC's deadline is Dec. 15, but the process is moving slowly in some areas of the country, particularly the Midwest.

Still another obstacle is the political and regulatory turmoil over deregulation. Utilities "are like deer frozen in the headlights, waiting for state and federal legislators and regulators to define the structure of the industry in which they will operate, invest and be regulated," Hirst said in his report.

A new group of "merchant" generating companies, including Duke Energy Corp., Calpine Corp., Reliant Energy Inc. and the table would run eastward, enabling utilities to export power from Minnesota toward Milwaukee and Chicago, where it might bring twice the price, Hatch said.

"We have cheap electricity in this state. It is a huge economic benefit," he said. But if some of that power can be sold outside the state for a bigger profit, that's where it's going to go, Hatch warned—and such moves could leave his state worse off.

New York City, which must import more than one-quarter of its peak electricity requirements through old, heavily loaded transmission ties, exemplifies the hazards faced by cities with small margins of electric generating capacity and limited transmission links.

Demand for electricity in New York City this summer is expected to peak at about

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When power can move freely within or between regions, generators in distant cities can compete with each other, Rose said. When bottlenecks occur, competition suffers and generators can push prices up in their home markets. "When you don't have enough transmission, it's easier for suppliers to exercise market power," Hirst said.

A major problem is that building transmission lines is fraught with political and financial challenges.

From suburbs to farms, the giant towers and the drooping lines they support are loathed and opposed. "It's easier to site a generation plant than to build a 20-mile transmission line through people's backyards," said Mike Calimano, vice president for operations of the New York Independent System Operator, the state's power grid manager.

"We haven't built any [transmission lines] from Canada or the West since 1978, and that was a war," said Minnesota Attorney General Mike Hatch. "We had highway patrols trying to keep the peace. It was awful then," and will be again as new power-line projects go forward, he warned.

Utilities often complain that the profit they are allowed to make on building transmission lines, as determined by Federal Energy Regulatory Commission rules, is too low to make the investment worthwhile, Stahlkopf said.

Transmission construction has also been frustrated by a split in regulatory responsibility. The Federal Energy Regulatory Commission (FERC), whose members are appointed by the president, oversees rates charged for transmitting power. But states have jurisdiction over where the lines are built.

Sen. Frank H. Murkowski (R-Alaska), chairman of the Senate Energy and Natural Resources Committee, will soon introduce legislation seeking to speed up transmission line siting, and some analysts say that can't happen unless the federal government takes control of final decisions. But such an approach would run into opposition from other members of Congress, such as Rep. Joe Barton (R-Tex.), chair of the House Commerce energy subcommittee, who argues that siting should remain a state responsi

A new group of "merchant" generating companies, including Duke Energy Corp., Calpine Corp., Reliant Energy Inc. and others, have bought utilities' generating plants in many parts of the country and could also fund transmission investments. But they, too, have difficulty predicting how such investments would pay off, analysts say.

"This grand experiment is going on, but the result is that nobody's investing now because it's far too uncertain," said Lawrence Makovich, a senior director at Cambridge Energy Research Associates in Massachusetts.

And utilities often have a powerful self-interest in dragging their feet on new transmission construction, said Illinois Public Service Commissioner Terry Harvill.

Commonwealth Edison, Chicago's major utility, has little incentive to build new long-line transmission connections, for instance, if that would make it easier for its customers to buyer cheaper power from competitors in neighboring states, Harvill said.

In fact, Commonwealth Edison has just built two major power lines from the south of Chicago to the city's western suburbs to serve customers, said Thomas Wiedman, director of transmission planning. He said he expects no electricity problems this summer.

Commonwealth Edison is obliged to build transmission if a competing generating company needs it, provided the generator is willing to pay for it, he said. "We can't build for free."

The fundamental reality, Harvill said, is that transmission in many parts of the country is no longer part of a regulated utility company's responsibility to serve customers. Rather, it is a major issue in the competitive struggle among utilities and generators, where profit considerations are paramount, he said.

Minnesota provides a case in point, said attorney general Hatch. The state urgently needs more transmission links beyond its borders to cope with a shortage of generating capacity in the state, he said.

The best choice, from the state's standpoint, would be new lines bringing inexpensive power in from Canada and North and South Dakota, he said. But no such projects have been proposed.

Instead, the two major transmission projects currently on

Demand for electricity in New York City this summer is expected to peak at about 10,800 megawatts—enough to light 10 million homes—according to the state's electric grid manager, the New York ISO.

Add a requirement for another 2,000 megawatts of standby generating capacity in the city as an emergency cushion in case a plant fails, and the city needs to be able to draw on a total of 12,800 megawatts of power, the ISO says. Power plants in the city can produce about 8,000 megawatts at peak periods. The rest, about 4,000 megawatts, must be imported through New Jersey or from the north—and that's just about how much power the transmission connections can carry, if all are working.

But two of three cables from New Jersey were not in operation last summer. With imports limited, the city ran short of power in June, resulting in a spike in electricity prices that cost consumers an estimated $100 million, according to regulators.

"If they hadn't had a cool summer last year, they'd have really paid the piper," Makovich said. The price escalation has led to the same political outcry and charges of generating company profiteering now heard all over Califoraia.

Across the Hudson River from Manhattan, crews will soon begin installing a new house-size transformer in Jersey City, the missing piece in the repair of one of the eastward power conduits to New York. The job will be finished by June, promised Paul Cafone, manager of systems operations for Public Service Electric & Gas in Jersey City.

"Seeing is believing," said Calimano, the New York grid operator, of his friend Cafone's assurances. Calimano also worries about the main transmission lines entering New York from the north. They haven't been upgraded or expanded since the 1970s, he said.

As long as the current transmission systems and the city's power plants hold up, "we should be able to survive the summer," Calimano said.

But if New York catches the California virus, analysts and regulators agree, there will be a dramatic demonstration of the nation's power transmission weaknesses—and another blow to the public's confidence in electricity deregulation

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BOTTLENECK AT 'RUSH HOUR'

The *other* electricity crisis: transmission lines

By Ron Scherer
Staff writer of The Christian Science Monitor

NEW YORK – Over the next five or six years, if all goes according to plan, there *should* be enough electricity to provide plenty of power for every American.

But with all the generating capacity, will electricity actually reach everyone who needs it?

The answer lies in transmission lines – those long, saggy cables strung between ungainly steel towers. They're part of the electricity superhighway that sends kilowatts flowing from places that welcome power plants to those that don't. And, unsettlingly, these lines are becoming congested, pushed to their limits, close to burning out during peak periods.

"It's probably the most vulnerable part of the system, if not the most important part of the system, and the one that people pay the least amount of attention to," says Thomas Kuhn, president of Edison Electric Institute (EEI), a trade group in Washington.

But building new transmission lines to ease the strain is not an easy task. People who live near proposed corridors for new towers, often joined by local environmental groups, have become effective at delaying or rerouting new lines. Landowners complain about lost property values and question whether the lines cause health problems. To some environmentalists, the steel towers can be an eyesore, ruining a mountain trail.

power transmitted over the new line would not be used locally, but sold for use as far away as eastern Virginia or North Carolina.

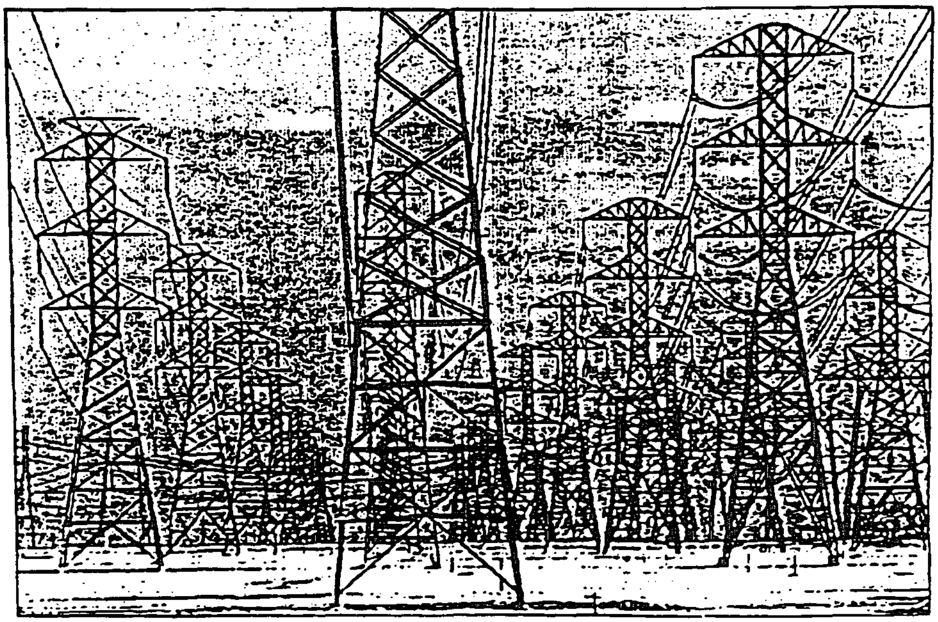
"The transmission line would ruin landscape and property values," says William Dougherty, president of FORCE (Friends of Regional Culture and Environment), the local group that sprang up to fight AEP's proposal.

Eleven years later, the company has shortened the route, eliminating some regulatory hurdles. Even FORCE has grudgingly accepted that something will be built. "Keep-

"When we took control of the system, it was one of our biggest issues," says Lisa Szot, an ISO spokeswoman.

In this case, environmental groups are not protesting. "It's fairly short and an area not likely to create a lot of disturbance except on some agricultural lands," says Rich Ferguson, director of energy programs for the Sierra Club, based in San Francisco. He says the club is not opposed to transmission lines per se, but looks at them on a project-by-project basis.

"We'd like to see better use of wind power



MEGAWATT CENTRAL: High-voltage transmission lines near Buttonwillow, Calif., carry power through the state's Central Valley to homes and businesses in southern California.

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The tensions have not gone unnoticed in Washington. Sen. Frank Murkowski (R) of Alaska, chairman of the Energy Committee, is considering provisions to speed the siting of transmission lines. It's not yet clear if he'll proceed because of the potential controversy over such legislation, Senate sources say.

The siting controversy is heating up even as the lines are increasingly used to transfer power among regions. In just five years, power sales from one region to another jumped from 25,000 transactions to more than 2 million, according to EEI.

"The system was never designed for that," says Mr. Kuhn.

But building new transmission lines just to move power from one part of the country to another is a sensitive issue, particularly among landowners. Indeed, local objections have forced many power companies, including American Electric Power (AEP) Co. in Columbus, Ohio, to alter their plans.

When AEP said in 1990 it wanted to build a major new line from West Virginia to western Virginia, it knew getting approval would be arduous. The new line would cross the Appalachian Trail several times, as well as the New River – a route that would require approval from two state regulatory commissions and three federal agencies.

But more than tangling with the bureaucracy, AEP was also fighting an aroused local populace. One key objection was that ing it short will help," says Mr. Dougherty.

The process, though, has consumed more time and money than AEP expected. The plan had called for the line to be in place by 1998. Now AEP hopes to have the juice flowing by 2005 – at a cost of $283 million, up $83 million from the original price tag.

Meanwhile, to cope with rising demand, AEP has installed load-shedding equipment that will let it institute rotating blackouts to protect its system. "The lesson you learn is you have to keep pace with demand – look at California," says spokesman Todd Burns.

IN FACT, transmission capacity is a serious problem for California. As part of a utility bailout deal, the state may take over 32,000 miles of wire – even though some reports show as much as $1 billion may be needed to upgrade the lines.

In particular, five power bottlenecks need to be corrected, according to the California Independent System Operator (ISO). One example: At transmission lines between Los Banos and Gates (outside of Bakersfield), three 500,000-volt lines are constricted into two lines – the equivalent of making a three-lane highway into two lanes at rush hour. On both days last month when California experienced rotating blackouts, these lines were operating at capacity.

in the Dakotas – and if that means more transmission lines to supply Chicago or Detroit, we might support it," he says.

Some states are net importers, relying on surrounding states for power.

That's the case with Wisconsin, which imports about 15 percent of its power during peak periods. Demand continues to grow at almost 5 percent annually in urban areas, says Larry Borgard, vice president for transmission at Wisconsin Public Service. Until new plants are built, electricity to meet that demand must flow over congested wires.

To prevent blackouts, WPS and Allete (formerly Minnesota Power) hope to upgrade the connection to Minnesota at a cost of $175 million. The company plans to complete the new line in 2004.

Wisconsin may be in the vanguard of electricity transmission. Last year, the local utilities spun off the transmission assets into a new company, American Transmission Co., which now controls 6,000 miles of wire and 500 substations. It's hoping to make money not only providing Wisconsin with power but also shuttling electricity from power generators in South Dakota to energy consumers in New York.

"It's up to us to make it a business," says Jose Delgado, the president. "If we're successful, it will show Congress and other utilities that divestiture should take place."

THE REAL THREAT TO AMERICA'S POWER

Sure, California is suffering from a generator shortage—but overloaded power lines pose a much greater risk of blowing the fuses of the national economy.

by David Stipp Ask a hardhatted power engineer what is most needed to prevent California's electricity crisis from proliferating, undercutting America's vaunted productivity gains, cratering the economy, and erasing trillions more from our already stunningly shrunken net worths. You're likely to get an earful about peak-time congestion on high-kV lines, level-three alerts, and unstable N-minus-five situations. That's the long answer. For the short one, nothing beats novelist E.M. Forster's timeless maxim: "Only connect." We need more wires.

Utility investments in high-voltage power lines, our electrical superhighways, have been falling since the late 1970s. That mattered little when most of our power traveled only short distances from local utilities' generators. But in 1996 the federal government ordered utilities to open their big, high-voltage transmission lines to other suppliers, triggering explosive growth in the long-distance transmission of electricity. Since then, many utilities have left the generation game to become middlemen that distribute power from vendors potentially hundreds of miles away. This trend, not the generator shortage that plagues California, is the main threat to the system nationwide. But the fallout nationwide may be much the same as in California: sky-high electric prices during periods of peak demand and a calamitous drop in the system's reliability.

If the California crisis is a heart attack, the clogging of the transmission grid is the atherosclerosis that precedes it. Consider how the Haywire State got that way. The common wisdom is that bad planning and bungled deregulation caused too few generators to be built as

Bottlenecks in the grid are forcing power bound from Los Angeles to San Francisco to detour through Oregon transformers like this one.

PHOTOGRAPHS BY SERGIO FERNANDEZ

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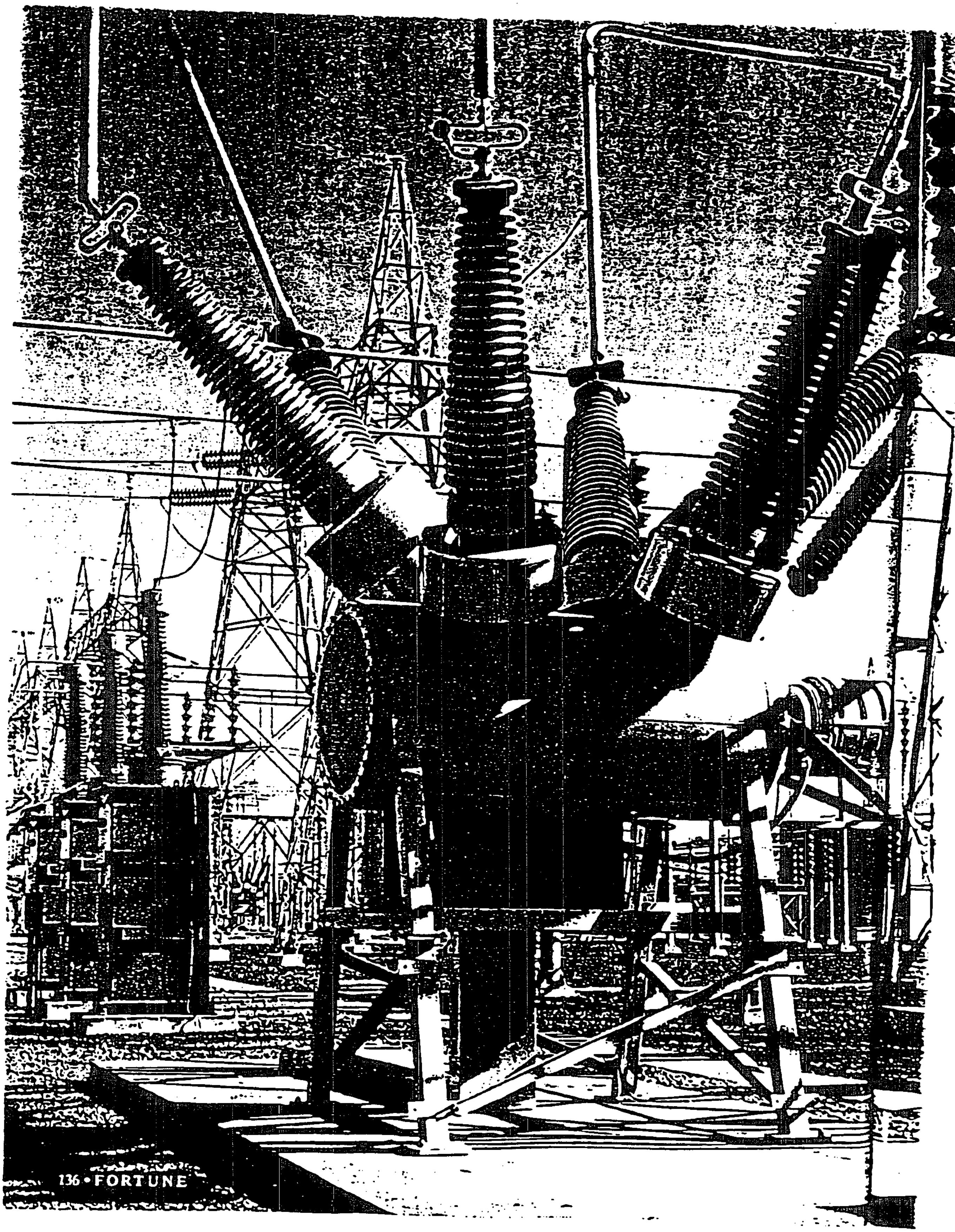

Grid guru John Hauer says utilities have grown increasingly willing to "accept more risks and not spend money on problems until they occur."

demand for electricity soared. That is true. But zoom up high enough to look down on the whole grid west of the Rockies, the "Western Interconnection," and you'll see the deeper problem of grid congestion at work.

California's worst-clogged electric artery is Path 15, a 90-mile bottleneck in the main transmission line between Los Angeles and San Francisco. Recently it has carried spare megawatts from Southern California to power-strapped Northern California. Unfortunately, Path 15 hasn't been able to convey enough electricity to prevent rolling blackouts in the north.

Scrambling to keep San Francisco's lights on, California's beleaguered Independent System Operator, the state's grid controller, has resorted to shipping power on a giant detour around Path 15. The power is sent north from L.A. through the 846-mile-long "Pacific DC intertie" to the Celilo Converter Station, a building perched on a bucolic, orchard-covered hill overlooking the Columbia River in Oregon. At Celilo, which is run by the federal Bonneville Power Administration, the power is converted from DC to AC (direct current to alternating current), then returned south through the "Pacific AC intertie," three lines linking Oregon and Northern California.

The detour worked fine until the afternoon of Jan. 21, when a 12-year-old computer at the Celilo station crashed, knocking out some of its DC-to-AC converters—monster devices reminiscent of Scotty's beloved warp drive on the starship *Enterprise*. That sharply cut the power going through the station. ("Captain, we canna do more than warp three!") Instantly hundreds of megawatts formerly looping from L.A. through Oregon rerouted themselves to Path 15 to reach the lights, computers, and other Northern California "loads" that were sucking them in at the speed of light.

That put Path 15 in danger of overload. To avert it, operators in California quickly instigated a "controlled outage" of 120 megawatts—about 100,000 houses' worth of electricity. Meanwhile, Bonneville operators in Vancouver, Wash., opened massive intake gates at dams on the Columbia River to ramp up their turbines. Seconds later an emergency 500 megawatts from the dams was pouring down the AC intertie to California. Fortunately it was Sunday, a time of relatively low demand. Within 20 minutes the out-of-kilter flow was fixed and the outage ended.

It seemed business as usual at Celilo when I dropped by the station four days after the emergency. But it wasn't. "We're walking on eggs," confided operations manager Bruce Laviet. "When you're maxing out the capacity of the system, minor things can have major impact." That, in a nutshell, is why California's crisis, though largely due to blunders peculiar to the state, may portend nationwide calamities.

Several trends are conspiring to max out the grid. First, deregulation has triggered an electric land rush—more than 190,000 megawatts of new capacity is on power vendors' drawing boards, enough to boost U.S. capacity by 25%. If only half of the planned generators are built, "capacity margins will be adequate" across the land by 2004, projects the North American Electric Reliability Council, or NERC, a Princeton, N.J., nonprofit. Even California should have watts aplenty.

Here's the rub, though: There's no parallel move to upgrade the grid, which increasingly "looks like L.A. freeways on a hot Friday afternoon," says Karl Stahlkopf, vice president at the Electric Power Research Institute in Palo Alto. "And if you can't get a supply to market, you don't have a supply."

Since 1975, annual utility investments in the U.S. power-transmission system have fallen by more than half, to about $2 billion, according to a study by industry consultant Eric Hirst of Oak Ridge, Tenn. Meanwhile, sales of power loaded onto the lines have risen more than 100-fold since mid-decade, thanks largely to the advent of hundreds of Enron wannabes—companies seeking to emulate the giant Houston energy broker. Episodes of congestion requiring grid operators to apply anti-clogging procedures, including curtailment of power transfers, more than doubled last summer compared with 1999's hot season.

Operators of the grid are forced to run it ever closer to its limits. The average number of megawatts loaded onto transmission lines during summer peak demand rose 22% from 1989 to 1999, says Hirst. It's expected to rise another 14% by 2009. The grid is literally heating up—when lines are heavily loaded, they get hot, expand, and sag. Wires drooping onto branches on sweltering days are a major cause of voltage sags and blackouts

The computerization of everything vastly multiplies the cost of such mishaps. A tree shorting out a distant power line might cause a voltage sag too brief to make your lights flicker. But such blips can crash hundreds of computers controlling factory machines. Annual U.S. losses in economic output from such relatively minor glitches already total an estimated $50 billion. If bigger outages become more frequent, our bright Information Age could rapidly become a lot darker. In sum, says Hirst, we must beef up the transmission system within a few years or face a crisis.

That's a tall order. Scary reports about the carcinogenic risks of electric and magnetic fields near power lines have greatly intensified public resistance to them. Never mind that after an exhaustive review, the U.S. National Research Council flatly concluded the "evidence does not show exposure to these fields presents a human-health hazard." Further, power transmission remains a regulated business, overseen by the Federal Energy Regulatory Commission. Utilities' potential returns on investments in unregulated energy businesses have been much higher than their FERC-allowed returns on transmission investments—a major deterrent to capital spending on the grid.

A seminal tract published in 1968 by biologist Garrett Hardin, "The Tragedy of the Commons," best sums up what is going wrong. Hardin described how herdsmen sharing a pasture, or common, inevitably spoil it by quite rationally enlarging their flocks—a herdsman's gain from adding an animal goes entirely to him, while the cost is borne by everyone using the common.

For decades, utilities tended the grid in a collaborative way, knowing they could recoup the costs in their rate bases. Now they're becoming rival electron herders, less willing to invest in the wiry commons—especially given uncertainty about how transmission assets will be divvied up as deregulation unfolds. Says John F. Hauer, a senior scientist at Pacific Northwest National Laboratory in Richland, Wash., who recently served on two federal teams that analyzed major blackouts: Utilities' strategy increasingly has been "to accept more risk and not spend money on problems until they occur."

New watt vendors don't own wires and actually stand to gain from heavily loading the grid—they can reap huge profits when peak-time line congestion pushes wholesale power prices sky-high. "We're always under pressure from power sellers to reduce our reserve margins," says Gordon van Welie, chief operating officer of ISO New England, which operates the region's grid from a control center in Holyoke, Mass. But heavily loading the grid cuts down the spare transmission capacity that serves as a safety margin if something goes wrong.

Industry veterans regard an episode two years ago involving Cinergy, a Cincinnati utility, as an ominous sign of the tragedy of the grid. Headed by former Enron executive James E. Rogers, Cinergy charged into power dealing in the mid-1990s. In August 1999, the company jarred Wall Street by disclosing that it had racked up $73 million in losses during a record heat wave in July—the company had had to buy scarce power for up to $7,000 a megawatt-hour, more than 100 times the average rate, to meet high demand in its service area and fulfill wholesale power contracts with outsiders.

Over the next 73 seconds, HELPLESS OPERATORS watched in dismay as all 13 dynamos at McNary Dam went offline, one after the other. The grid's gyrations went wild.

An even more jarring story was unfolding behind the scenes. On three afternoons in late July, spinning generators all over the Eastern Interconnection, the grid east of the Rockies, had mysteriously slowed, a sign that somewhere a mammoth load had unexpectedly come online. The load alarmingly depressed the Interconnection's AC frequency—when the grid's normal 60-cycles-a-second rhythm dips as little as 2%, operators may be forced to activate emergency "load shedding," or rolling blackouts, to prevent damage to generators. (If generators go even slightly out of sync with the grid, terrific forces build up inside them, potentially cracking turbines or causing fires.)

NERC, the reliability council, launched an investigation that led to Cinergy. On the three days in question, the utility had quietly siphoned 9,616 megawatt-hours from power lines linking its service area to surrounding ones—in effect, it had taken electricity worth tens of millions of dollars from unsuspecting peers. Worse, it had knowingly "jeopardized the reliability of the Eastern Interconnection" in "blatant disregard for NERC policy," raged a Dec. 6 letter to the utility's CEO from NERC's regional office in Ohio. Cinergy, which didn't contest the charges, says it has taken vigorous steps to ensure such episodes don't happen again.

In any case, simple neglect may threaten the commons more than abuse. While trying to transform themselves from poky old utilities into lean, mean energy dealers, many of the grid's keepers have cut their maintenance budgets. The trend was a prime contributor to major outages during the hot summer of 1999, according to a study by the Department of Energy. From 1991 to 1998, for example, Commonwealth Edison's maintenance spending on key substations in the Chicago area fell by two-thirds, setting the stage for blackouts that left up to 100,000 customers with dead fans and air conditioners over several sweltering days in 1999.

A related threat, says Hauer, the national lab expert, is a "collective loss of memory" at power companies about the subtle workings of the grid, as budget cuts thin their ranks of senior engineers. In a fascinating 1999 report written with colleague Jeff E. Dagle, Hauer showed how this experience drain led to the biggest outage of recent decades, which blacked out most of the Western Interconnection on Saturday, Aug. 10, 1996.

As with most big blackouts, its immediate cause was hot weather. Temperatures along the West Coast soared to 100 degrees, prompting a heavy flow of power to California from western Canada's dams. At first, it seemed a fairly routine summer day, one in which operators might have to contend, at worst, with local glitches from a few "sagged out" lines. But the situation looked quite treacherous to Hauer.

To understand why, you have to know a bit about how the grid runs. First, the regional operators who sit in control rooms surrounded by giant grid boards can't work like air-traffic controllers. The speeding electrons they oversee move much too fast to be managed like aircraft, and widespread outages can unfold in seconds. Thus, the operators rely heavily on automatic safeguards—"relays" on generators, for example, instantly switch them offline if they get too far out of sync with the grid.

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As I boned up on the vast system of generators behind all our plugs, I began picturing it as a choir of whales singing in unison a single cosmic note, which we know as AC hum. If one singer notices the collective hum getting a little flat, it momentarily hums a little sharp to get the choir back on key. If the group is going sharp, it corrects by humming flat. The simile is rough—automatic "power system stabilizers" on generators are geared not only to help keep the grid's AC frequency steady but also to help stabilize its voltage and power flow. Still, the whale choir helps explain why Hauer was worried.

Years of analyzing the Western Interconnection with the aid of computer models had taught him that when lots of power is being sent from Canada to California, the grid is like a choir stretched out over a very great distance, making unison difficult to achieve. Weakly linked generators can wind up reinforcing off-key notes rather than damping them out. This uncoordinated humming, in turn, can lead to "ringing"—gridwide power oscillations that aren't damped out. Ringing can quickly lead to wild oscillations that cause the grid to crash.

Relays tripped all over the West, tearing it into gridlets filled with SHUT-DOWN GENERATORS and blacked-out buildings, like a scene in the classic *The Day the Earth Stood Still.*

Hauer and a few others had warned the West's gridmeisters about this risk, noting that computer models used to set safety margins overestimated the amount of automatic damping that would occur during heavy power flows from Canada to California. "I thought everyone knew about the risk and would run the system accordingly," with extra-large safety margins, says Hauer. "But the institutional memory had faded."

The risk on that Saturday in 1996 was especially high because dams on the Columbia River east of Portland, Ore., were largely powered down for the annual "fish flush," in which water is fed through spillways next to dams so that fingerling salmon can migrate downstream. The Army Corps of Engineers' four dams along the lower Columbia, like the whale choir's centrally located members, are critical for maintaining harmony—they supply strategically located "voltage support." During fish flushes this support is much reduced.

Still, the grid was copacetic on Aug. 10 until 2:06 P.M., when a major line between The Dalles, Ore., and Portland sagged into a tree and shorted out. Bonneville operators in Vancouver, Wash., delayed closing the relays that would reactivate the line after getting a report that gunshots had been fired near it—they feared a trigger-happy citizen had been using a glass insulator for target practice, making it unsafe to re-energize the 500,000-volt line.

Forty-six minutes later, another big line south of Portland sagged out. Then, at 3:42, a key line linking Portland and Seattle drooped onto a hazelnut tree a few miles west of Portland, knocking it out. At that point, the Western Interconnection began ringing—the whales were losing it. When yet another line near Portland sagged into a tree six minutes later, there was a gridwide voltage drop and the onset of portentous power gyrations.

Instantly, automatic controls at McNary Dam, a key grid node 160 miles east of Portland, revved its dynamos to the max in an effort to hold up the grid's voltage—at that moment, the dam became the Western grid's main prop. But seconds later, faulty controls at the dam, 18 months overdue for maintenance or replacement, began disconnecting its generators. Over the next 73 seconds, helpless operators watched in dismay as all 13 dynamos tripped off, one after another. As McNary toppled, the grid's gyrations went wild. Seconds later, relays on the Pacific AC intertie in Oregon automatically opened, severing Canada from California.

That was the final blow—in a split second, relays protectively tripped all over the West, tearing its power system into four disconnected gridlets filled with shut-down generators and blacked-out buildings. California resembled a scene from the 1951 sci-fi classic *The Day the Earth Stood Still*. Some 7.5 million people lost power for six or more hours. Economic losses were estimated at more than $2 billion.

By Monday the grid was mostly back to normal, and a far-reaching effort to beef up reliability was under way. A ferocious Bonneville crew completely chainsawed the defunct hazelnut orchard where the key Portland–Seattle line had shorted out. The fish flush was abruptly ended. Helicopters buzzed countless power lines, checking for overgrown trees.

In a longer-term effort, the Bonneville Power Administration has spearheaded development of high-speed grid monitors to alert operators about abnormally low voltage support and other danger signs. Over time, these monitoring devices are expected to combine into a futuristic control system that may be able to orchestrate gridwide activities by the millisecond—a computerized conductor to keep the whales in perfect unison. But Hauer and other experts say such efforts are just a beginning. To fully address the national problem, policymakers must find ways to overcome the tragedy of the grid. In a first stab, the Federal Energy Regulatory Commission in December 1999 called for utilities to form regionwide companies to manage the transmission grid with the broad perspective needed to cope with long-distance power dealing. FERC also has signaled that it may allow higher returns to transmission companies that efficiently increase the amount of power their lines can carry without jeopardizing reliability. NERC, the reliability council, is lobbying for a federal law that would enable it, in collaboration with FERC, to crack down on players that jeopardize the system.

But local resistance to new power lines isn't likely to go away, and the costs of expanding the transmission system might well be prohibitive—it would cost at least $50 billion over the next decade to add new power lines at the same rate that peak demand is expected to grow. Thus grid operators will probably be forced to run the system as hot as possible for years to come. That's a disconcerting prospect. Indeed, data from the new monitoring systems have shown that the computer models used to guide grid operations can be way off.

This doesn't mean we're all about to re-enact California's increasingly *noir* story. But if the tragedy of the grid isn't overcome, we eventually may find E.M. Forster's sunny slogan about connecting less apropos than his dark tale about what happens when a civilization's supporting technology seizes up. Its title: "The Machine Stops." ■

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One Year Later—Nancy Fry at a memorial for the 88 people who died in Alaska Airlines crash. A7

COLUMN ONE

Unexpected 'Heirs' of Flight 261

■ Claims that four men on the doomed jet left behind children in Guatemala are a scam, grieving relatives say.

By RICHARD MAROSI

Alan and Helen Clemetson were still mourning the death of their son David on Alaska Airlines flight 261 when an unexpected aftershock of the crash landed on their doorstep.

It was a lawsuit claiming that David B. Clemetson, a respected Scottsdale-area physician who perished aboard the flight along with his wife and four children, had secretly fathered a Guatemalan girl 10 years earlier. The girl, the suit alleged, was now entitled to a share of his estate as well as any settlement his family might receive.

Around the same time, Dale Rettinger of San Francisco got a similar jolt: A lawsuit claiming his gay partner of 20 years, another Alaska Airlines crash victim named Juan Marquez, 52, had fathered two children with a woman Rettinger had never heard of.

In all, four men aboard the plane that plunged into the Pacific a year ago today—strangers from different cities and completely different walks of life—have been accused of fathering illegitimate children, all of them from Guatemala.

[illegible]

Please see FLIGHT, A7

Senate Panel Splits 10-8 for Ashcroft

■ Cabinet: Final floor vote, and heated debate, over attorney general nominee may come today.

By ERIC LICHTBLAU

WASHINGTON—A bitterly divided Senate Judiciary Committee endorsed John Ashcroft for attorney general Tuesday on a 10-8 vote, sending his nomination to the full Senate for a vote as early as today in the first big political test of the Bush administration.

Although Republicans say they remain confident of securing the 51 votes needed to confirm Ashcroft as the nation's top law enforcement official, Democrats vowed to fight, and the debate is sure to expose the deep rifts between the parties on such hotly contested issues as abortion, civil and gay rights, gun control, racial profiling and affirmative action.

A mini-version of the debate played out Tuesday before the Senate Judiciary Committee, where Republicans portrayed Democrats as overly partisan and unfair to the former Missouri senator, while Democrats sought to raise doubts about Ashcroft's credibility and [illegible] that he would be held accountable for his actions.

The vote, with only one Democrat endorsing the nomination, was the closest in memory for a would-be attorney general, and Ashcroft's opponents said that it should send a strong signal to the Bush White House about the divisive effect Ashcroft's nomination has had on the nation.

Controversy has raged around the nomination since President Bush named Ashcroft on Dec. 22. Opponents have flooded Senate offices with hundreds of thousands of letters, e-mail messages and phone calls, while religious groups have mounted a counteroffensive portraying Ashcroft—the devout son of a Pentecostal minister—as a victim of "religious profiling."

Several Republicans said Tuesday that they were stung by the depth of opposition, though it was not surprising after five weeks of vigorous debate over Ashcroft's conservative views.

"I was obviously disappointed that the Democrats did not see fit to give Sen. Ashcroft the benefit of the doubt," Sen. Orrin G. Hatch [illegible]

Please see ASHCROFT, A5

More Inside

[illegible] The Senate confirmed Gale A. Norton as Interior secretary and former New Jersey Gov. Christine Todd Whitman as EPA chief. A5

Student Held in Bomb Plot

Acting on a tip from a [illegible] clerk, San Jose police arrested a 19-year-old student who detectives say was planning to launch a Columbine-style assault Tuesday at a community college. A3

A view of the center of Bhachau, one of the towns hit hardest by quake that rocked India last week.

Power Line Traffic Jams Add to Energy Woes

■ Electricity: California's transmission system is severely taxed, and the problem is expected to worsen in the next decade.

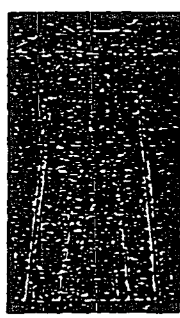
By CHRIS KRAUL

An antiquated and overworked system of electric transmission lines could leave much of California starved for power even if the state can eventually generate and import enough electricity to serve its 34 million residents.

The 35,000-mile-long system—enough wire to circle Earth—has long been neglected, a victim of poor planning, unexpected growth in electricity consumption and regulations that make the lines a poor investment from the standpoint of the big utilities.

The long-distance transmission lines, strung on 150-foot-tall steel towers spaced at quarter-mile intervals, face particularly strong local opposition. Citizen protests have also stalled plans to build power plants, but outrage soars when it comes to the high-voltage wires, which many associate with radiation-related health hazards.

Please see LINES, A10



CAROLYN COLE / Los Angeles Times

Power lines near Coalinga are in the Path 15 segment, a bottleneck for electricity transmission.

More Inside

In the Hot Seat: Pressure to [illegible] the power crisis has pitted party against party and Senate against Assembly. A3

Quake Victim Kept Up Hope, as Did Rescuers

By PAUL WATSON

ANJAR, India—For more than 3½ days, Kunal Doshi was trapped naked in rubble up to his neck. But he refused to give up, so his rescuers knew they had to try everything to pull him free.

They finally saved the 15-year-old boy in the early morning hours Tuesday after Indian army surgeon Lt. Col. Prem Singh Bhandari did what other doctors could not.

He amputated Kunal's leg with a large knife, a hammer, a chisel and a carpenter's saw, working in a space not much bigger than a large drawer in the [illegible] concrete tomb.

Soldiers and civilians had failed in one rescue attempt after another during the 83 hours that Kunal was trapped in the ruins of a collapsed four-story apartment building. His [illegible] will to live, they said, meant they couldn't let him die like an estimated 20,000 others killed by last week's massive earthquake here in western India's Gujarat state.

"I was thinking of god only," he said from his army hospital cot Tuesday night, searching for the words in English through a [illegible] [illegible]

Please see INDIA, A14

INSIDE TODAY'S

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Power Line Traffic Jams Add to Energy Woes

■ **Electricity:** California's transmission system is severely taxed, and the problem is expected to worsen in the next decade.

By CHRIS KRAUL
TIMES STAFF WRITER

An antiquated and overworked system of electric transmission lines could leave much of California starved for power even if the state can eventually generate and import enough electricity to serve its 34 million residents.

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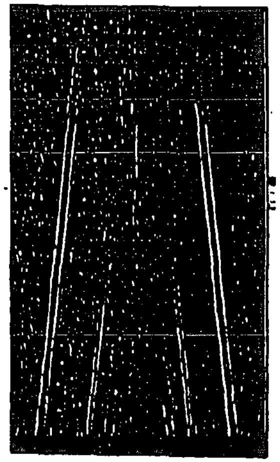
The long-distance transmission lines, strung on 150-foot-tall steel towers spaced at quarter-mile intervals, face particularly strong local opposition. Citizen protests have also stalled plans to build power plants, but outrage soars when it comes to the high-voltage wires, which many associate with radiation-related health hazards.

Please see LINES, A10



CAROLYN COLE / Los Angeles Times

Power lines near Coalinga are in the Path 15 segment, a bottleneck for electricity transmission.

More Inside

In the Hot Seat: Pressure to quickly end the power crisis has pitted party against party and Senate against Assembly, A3

LINES: Shortfall in Transmission Capacity

Continued from A1

"It's difficult to build a power plant, but often more difficult to build a transmission line," said Bob Therkelsen, deputy director for facilities siting at the California Energy Commission.

The problem has deep roots. In the early part of the 20th century, there was no electricity grid: Each utility was self-sufficient. But by the 1920s, utilities and states were connecting their systems to form a sort of mutual-aid society in the event of outages or natural calamities.

As utilities have been deregulated, more and more electricity is bought, sold and delivered as a commodity over ever-increasing distances and from state to state. That has put an unanticipated strain on transmission systems that were initially designed to be self-contained.

As with California's shortage of power generation, its transmission woes are a simple case of energy demand having outpaced the infrastructure to supply it. Electricity use in the last decade has grown twice as fast as new transmission capacity.

The problem could get much worse in the next decade, because the state is planning to boost generation capacity by 25%, but it is expanding transmission capacity only by about 5%.

Two weeks ago, the transmission crunch came to a head in unprecedented rolling blackouts, which brought the energy crisis home to hundreds of thousands of residents and businesses in the northern and central parts of the state.

A principal culprit in the Jan. 17 and 18 blackouts was a relatively short segment of the statewide power grid called Path 15, a 90-mile link between the Central Valley towns of Los Banos and Coalinga where capacity problems imperiled the entire state system.

It is at that point that the Pacific Gas & Electric and Southern California Edison systems connect.

Like a two-lane freeway tunnel suddenly taking on three lanes of bumper-to-bumper traffic at rush hour, Path 15 has proved inadequate to the task of delivering electricity from occasionally electron-rich Southern California to electron-starved Northern California.

There are other weak points in the grid that would require hundreds of millions of dollars in investment and up to five years' lead time to repair. Concerns are focused on San Diego County, the San Francisco Bay Area and California's "interconnects" with Arizona and Oregon.

How is it that a state at the vanguard of the technology revolution, itself the sixth-largest economy in the world, has developed such an Achilles' heel?

The answer lies in a tangle of factors:

- The major utilities, elected officials and other architects of California's now-discredited deregulation plan failed to anticipate sharp growth in electricity demand.
- Expansion has been discouraged in part because regulations deny utilities an adequate return on investment in transmission lines, said Karl Stahlkopf, vice president at the Electric Power Research Institute, a Palo Alto think tank.

Because electricity is an interstate commodity, grid operations are overseen by the Federal Energy Regulatory Commission, which restricts the profit that utilities make on new transmission projects to an annual average of 9% on investment. Such returns pale in comparison with the 15% to 20% utilities can earn on other, unregulated investments.

- A dry fall and winter have caused a precipitous drop in hydroelectric generation in the Pacific Northwest, normally a source of power for California. That has forced Northern California to import electricity from the southern half of the state, exposing the bottleneck at Path 15.

The state's problems are just the most vivid symptoms of an issue that seems to have crept up on an entire nation.

Experts including Stahlkopf cite studies that have pegged the cost of lost U.S. productivity from power outages and related problems at $100 billion a year. Jack Kyser, chief economist of the Los Angeles County Economic Development Corp., estimates that the outages of the last two weeks have cost California $2.3 billion in production cutbacks and lost wages.

Building more transmission capacity would be easier, proponents say, if there were a regional or federal authority that could exercise eminent domain siting powers.

Builders of natural gas pipelines, for example, have such an authority in the Federal Energy Regulatory Commission. But where the commission has rate-setting authority over power transmission, it lacks siting powers for lines.

Timothy Gallagher, manager of technical services at the North American Electric Reliability Council in Princeton, N.J., said new power plants are only part of the solution to California's electricity shortage.

"An influx of new generation capacity isn't enough if transmission isn't built along with it," Gallagher said. "There are only so many locations where you can get all the air-quality [and other] environmental permits for power plants and still be in a viable place for all those transmission lines that you need to serve the system."

Others say technology holds the key, as researchers seek ways to squeeze more electricity out of existing transmission. Stahlkopf of the Electric Power Research Institute said innovations in increasing the stability and thermal limits of transmission lines, undergoing testing in Oregon and Arizona, hold great promise. But up to now utilities have had little incentive to pursue them because of the limited investment returns, he said.

Whatever the causes and possible solutions, most agree that traffic jams along these electricity highways will become more frequent and problematic. Population growth, in the absence of meaningful conservation, will add to demand growth.

On the supply side of the transmission imbalance, the numerous jurisdictions that the wires must cross, and the shrinking availability of suitable open space, will make it that much more difficult to upgrade or expand the existing statewide grid.

Moreover, most of the new power plants that have been approved or are under review are in the southern part of the state, which means the north-south bottleneck could grow tighter, said State Senate President Pro Tem John Burton (D-San Francisco).

"It needs some upgrading, because if we're building new power plants in Kern County, you have to be able to move the power to where it's needed in Northern California," said Burton, who floated the idea of the state buying the transmission system from the debt-ridden utilities before it ran into opposition from Republicans and many Democrats.

Consumer groups such as the Utility Reform Network in San Francisco say expansion could be facilitated if the state were to buy the grid from the utilities. That would free grid upgrades from the investment strictures of federal oversight and take advantage of the state's lower cost of borrowing.

But however they are financed, any new lines are sure to generate heated public debate.

An example of the acrimony that surrounds transmission projects can be found in northern San Diego County, where San Diego Gas & Electric has been pushing since August for a 30-mile high-voltage link to Edison's grid in Riverside County. SDG&E says its customers in San Diego County and southern Orange County could face outages as early as 2004 unless the connection is built.

"You need the generation and the electric transmission, and the two have to go together," said SDG&E Chairman Edwin Guiles. Guiles said the clock is ticking on the three- to four-year lead time needed to put the so-called Valley-Rainbow Interconnect into service.

But the project faces opposition from residents in the increasingly developed Temecula area. The towers and wires—engineers prefer to call them "conductors"—would require condemnation of surrounding property and would almost certainly lower real estate values.

The watchdog group Utility Consumers Action Network deems the interconnect unnecessary and contends that SDG&E should study alternatives.

To the north, PG&E is somewhat reluctantly considering an expansion of the troubled Path 15.

The San Francisco-based utility owns the two 500,000-volt lines in the link but is awaiting a feasibility study before expanding capacity with a third. The study is being conducted by the Independent System Operator, the nonprofit state corporation that maintains reliability along three-quarters of the statewide grid.

The utility is hesitant to commit to the project—which would cost at least $200 million and take up to four years to complete—because it has been only during the last few months that such an expansion seemed necessary, executives say. Armando Perez, the Independent System Operator's director of grid planning, said the Bay Area is another weak point in the state grid, noting that a major new line will be needed there by 2004.

The area's vulnerability came to the fore June 14, when neighborhoods suffered rolling outages in what was the first overt evidence of a statewide power crunch that has deepened in the months since.

"That's where the red flags are going up. There are quite a few new generation plants coming on-line, and when that power becomes available in the next couple of years, we'll be seeing the effect on the grid," Therkelsen of the Energy Commission said. "It's critical for the state to start looking at long-term transmission needs."

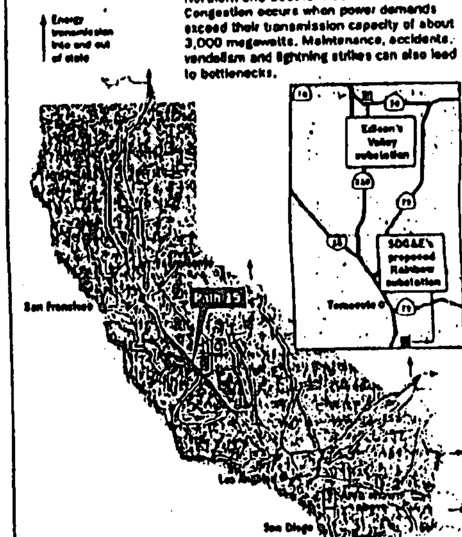
Times staff writer Nancy Vogel contributed to this report.

The California Grid

Electricity is moved throughout the state on a 26,000-mile network of power lines carrying current at up to 500,000 volts. The electricity is "stepped down" in a series of substations and transformers for different levels of use in industry and in homes. New transmission lines often face opposition. One example is a proposal to link a San Diego Gas & Electric substation in northern San Diego County to an Edison substation in Riverside County. Temecula residents don't want the lines cutting through their area.

Transmission lines of 230 and 500 kilovolts in California

PATH 15: Energy bottlenecks sometimes occur on Path 15, a critical group of high-voltage lines that move power between Northern and Southern California. Congestion occurs when power demands exceed their transmission capacity of about 3,000 megawatts. Maintenance, accidents, vandalism and lightning strikes can also lead to bottlenecks.



Sources: California Energy Commission, California Independent System Operator
Researched by NONA YATES/Los Angeles Times

LORENA IñIGUEZ / Los Angeles Times

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THE REQUIREMENTS OF THE "JUST AND REASONABLE" STANDARD: LEGAL BASES FOR REFORM OF ELECTRIC TRANSMISSION RATES

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Sean B. Cunningham

ENERGY
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THE REQUIREMENTS OF THE "JUST AND REASONABLE" STANDARD: LEGAL BASES FOR REFORM OF ELECTRIC TRANSMISSION RATES

*Patrick J. McCormick III**
*Sean B. Cunningham***

> The return [on a public utility company's assets] should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate . . . to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.[1]

According to the North American Electric Reliability Council (NERC), electric transmission capacity in the United States is not keeping pace with demand for electric power. As a result, electric reliability and the development of competitive electricity markets could be impaired.[2]

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* Partner of the Washington, D.C. office of Balch & Bingham, LLP. Former Deputy Assistant General Counsel for Electric Rates and Corporate Regulation, Federal Energy Regulatory Commission (FERC). Mr. McCormick is counsel to the companies forming the Alliance regional transmission organization (RTO), which was conditionally approved by the Commission on December 20, 1999. See *Alliance Companies*, 89 F.E.R.C. ¶ 61,298 (1999). Mr. McCormick and Mr. Cunningham also represent an informal coalition of transmission providers, including CMS/Consumers Energy, Detroit Edison Company, Duke Energy, FirstEnergy Corp., Northeast Utilities, Northern States Power Company, Public Service Electric and Gas Company, and Southern Company.

** Associate of the Washington, D.C. office of Balch & Bingham, LLP. Former counsel, House Government Reform Committee, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs.

1. Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 693 (1923).

2. NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, RELIABILITY ASSESSMENT 1999-2008 7 (May 2000) ("Very few bulk transmission line additions are planned. Only 6,978 miles . . . (230kV and above) are planned throughout North America over the next ten years. This represents *only a 3.5% increase in circuit miles. . . . The majority of the proposed transmission projects are for* local system support."). Furthermore, NERC warns, "transmission systems [are] increasingly challenged to accommodate demands of evolving competitive electricity markets. Market-driven changes in transmission usage patterns, the number and complexity of transactions, and the need to deliver replacement power to capacity-deficient areas are causing new transmission limitations to appear in different and unexpected locations." NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, RELIABILITY ASSESSMENT 1998-2007 6 (September 1998). In its comments on the FERC Notice of Proposed Rulemaking on Regional Transmission Organizations (hereinafter RTO NOPR), NERC emphasized that "the number and complexity of transactions on the grid is growing enormously." Comments of North American Electric Reliability Council on FERC's Notice of Proposed Rulemaking, Regional Transmission Originals, Docket No. RM99-2, 15 (Aug. 23, 1999). As demands on the transmission system continue to increase, NERC warns, "the ability to deliver remote resource to load center will deteriorate." *Id.* In Order No. 2000, the Commission acknowledged the lack of transmission: "It appears that the planning and construction of transmission and transmission-related facilities may not be keeping up with increased requirements." Order No. 2000, *Regional Transmission Organi-*

bility of the bulk transmission system."[5] A primary cause of the lack of capacity appears to be declining investment in improvement and expansion of transmission facilities.[6] Electric industry analysts argue that, due to increased risks in the restructured environment, greater incentives are needed to spur the attraction of scarce capital needed to expand and improve the grid.[7] It is also widely agreed that to provide such incentives, the transmission "pricing"[8] policies of the FERC must be reformed to address the "transmission investment gap."[9] Voices advocating transmission pricing reform have included the NERC,[10] the Department of Energy,[11] and Members of the Commission.[12]

5. NERC, RELIABILITY ASSESSMENT, 1999-2008 34 (May 2000). Furthermore: "As the demand on the transmission system continues to rise, the ability to deliver energy from remote resources to demand centers is deteriorating. New transmission limitations are appearing in different and unexpected locations as the generation patterns shift to accommodate market-driven energy transactions," and the connection of new, market-responsive merchant capacity that was not considered at the time the transmission system was designed. *Id.* at 34. Again: "Delivering energy to deficient areas in any direction and amount that market forces desire [is] difficult and, at times, not possible."

6. Although this shortage of capacity is the product of several factors, including siting issues at the state and local level, the lack of incentives to invest in new transmission seems to be a primary cause. According to NERC, "transmission providers . . . may find it difficult to justify investment in new upgraded transmission facilities without proper incentive. . . . [U]ntil sufficient incentives are put in place, the growth in transmission capacity is not likely to keep pace with the business or reliability needs of the system." NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, RELIABILITY ASSESSMENT 1998-2007 34 (1998). According to Eric Hurst, annual investment in new transmission has declined by approximately $100 million per year in the past two decades. ERIC HURST, ELECTRIC RELIABILITY: POTENTIAL PROBLEMS AND POSSIBLE SOLUTIONS 10 (2000).

7. Along with the growth of wholesale competition and the "unbundling" of transmission assets, the risk "profile" of the transmission industry has changed dramatically. Statement of Paul R. Moul, Southern California Edison Company, Docket No. ER97-2355-000, at 1. Because investors tend to be risk averse, "increased uncertainty will require compensation for the higher risk related thereto." *Id.*

8. The terms "pricing" and "ratesetting" or "ratemaking" are used interchangeably in this article, because a rate is essentially a price fixed by the government. *See, e.g.*, FPC v. Hope Natural Gas Co., 320 U.S. 591, 601 (1944) ("Rate-making is indeed but one species of price-fixing.").

9. *See, e.g.*, NERC, RELIABILITY ASSESSMENT 1999-2008 7 (2000) ("It is yet unclear if appropriate incentives exist to prompt transmission system additions and reinforcements to support the needs of a competitive energy market. [A]dequate pricing incentives . . . must be developed to deal with the need for new transmission lines for an open market.").

10. The NERC has counseled reform in this area as a remedy for transmission constraints. In comments filed with the Commission, the NERC called for incentives to increase transmission capacity and secure the benefits of competition: "transmission rates must provide incentives to get the right amount of transmission infrastructure built. . . . We must make sure that shortages of transmission capacity do not restrict power flows and limit the benefits that otherwise could be achieved from competitive electricity markets." North American Electric Reliability Council, Comments on FERC RTO NOPR, August 23, 1999, at 14.

11. *See, e.g.*, DEPARTMENT OF ENERGY, FINAL REPORT OF THE TASK FORCE ON ELECTRIC SYSTEM RELIABILITY, INCENTIVES FOR TRANSMISSION ENHANCEMENT 111 (Sept. 29, 1998). This report, known as the "Sharp Report" (for its principal author, Dr. Philip Sharp), expressly links the problem of inadequate transmission to a lack of investment: "Restructuring of the electric-power industry and unbundling of transmission from generation create challenges for reliably operating the existing transmission system and raise concerns about the future adequacy of transmission planning and incentives for investment in transmission enhancements." *Id.*

12. According to Commissioner Curt Hebert, incentive regulation can satisfy the interests of

thority to mandate RTOs.[18]

To promote its policy of voluntary RTO formation, Order No. 2000 provides for "favorable" or "innovative" rate treatments to facilitate RTO formation.[19] According to the Commission, "[w]e believe that it is critically important for RTOs to develop ratemaking practices that . . . provide incentives for transmission owning utilities to efficiently operate and invest in their systems. In particular, the Commission encourages RTOs to develop and propose innovative ratemaking practices, particularly with respect to efficiency incentives."[20] Specifically, Order No. 2000 provides for the Commission's consideration of a variety of "innovative" rate treatments, including performance-based rates, return on equity (ROE) reforms, and non-traditional cost-valuation methods.[21] The regulatory text enumerates these rate treatments as follows:

> (i) A transmission rate moratorium, which may include proposals based on formerly bundled retail transmission rates;
> (ii) Rates of return that (a) are formulary; (b) consider risk premiums and account for demonstrated adjustments in risk; or (c) do not vary with capital structure;
> (iii) Non-traditional depreciation schedules for new transmission investment;
> (iv) Transmission rates based on levelized recovery of capital costs;
> (v) Transmission rates that combine elements of incremental cost pricing for new transmission facilities with an embedded-cost access fee for existing transmission facilities; or
> (vi) Performance-based transmission rates.[22]

It must be noted that the incentive pricing language of Order No. 2000 does not bind the Commission to apply any of these rate treatments. Order No. 2000 only requires the Commission to "consider" incentive rate proposals advanced by RTO applicants and participants.[23] Its proposed rate reforms nevertheless represent a willingness to expand upon, or even depart from, its historic methods in order to ensure that transmission rates accurately reflect new risks and responsibilities faced by transmission pro-

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18. Order No. 2000, *supra* note 2, at 31,034. It should be noted that the Commission did not say that it lacks legal authority to mandate RTOs, and it expressly recognized the possibility of requiring RTO participation as a condition for receiving approvals for market-based rates and mergers. *Id.* at 31,034. The question of whether the Commission has legal authority to mandate market structure, by requiring RTO participation or by other structural means beyond its traditional ratemaking function, is beyond the scope of this article. *See generally* Order No. 2000, *supra* note 2, at 31,039-31,046 for discussion of the Commission's legal authority with respect to RTOs.

19. Order No. 2000, *supra* note 2, at 31,034. Although the decision whether to join an RTO is left to the individual tranmitting utility, all transmitting utilities are required to make certain informational filings explaining their plans to participate in an RTO or, if they have no such plans, to explain their reasons for not doing so.

20. Order No. 2000, *supra* note 2, at 31,171.

21. Regional Transmission Organizations, 18 C.F.R. § 35.34(e)(2) (2000).

22. *Id.* *See infra*, Part 4 for a discussion of these rate treatments.

23. 18 C.F.R. § 35.34(e)(1). The burden of development of such rate treatments rests principally on the RTO applicants. The Commission is not required to develop rate proposals *sua sponte* and applicants are required to include detailed justifications for their rate proposals, including a cost-benefit analysis and an explanation of how the rate treatment will further the purposes of RTOs in general *See generally* 18 C.F.R. 35.34(e).

rent law, or would it displace or even violate that standard?

Summary of Conclusions. The Article concludes that the Commission is authorized by the Constitution, the FPA, and its own policy statements to change its methods of regulation as needed to close the transmission investment gap. In doing so, the Commission may modify or even abandon old methods for the sake of protecting consumers' present and future interest in a vigorous and reliable transmission grid. Under current law, the Commission is not required to use a particular formula or method in setting rates. The Commission is, however, required to ensure that returns on transmission investments are adequate to attract the capital that a transmission provider needs to perform its public duties, including, arguably, a duty to maintain reliable, high-capacity transmission networks that are adequate to meet the demands of competitive electricity markets. The Commission's reformed policies to achieve these goals would likely withstand federal court review, provided they are supported by substantial evidence and coherent justification. Likewise, legislation to channel the Commission's discretion could be consistent with the just and reasonable standard.

Summary of Parts. The article proceeds in five parts. Part One, "The Modern Just & Reasonable Standard: Constitutional Requirements," examines the requirements of *Hope* that the "end result," not a particular method, governs the application of the just and reasonable standard.[29] It also examines the requirement that the return on a regulated entity's assets be sufficient to attract the capital needed for the performance of the entity's public duties, both present and future. Part One argues that promoting a reliable, high-capacity transmission grid could fall within the category of a transmission provider's public duties and therefore, rates should enable grid expansion accordingly. Part Two, "The Modern Just & Reasonable Standard: Federal Power Act Text and Legislative History," examines the FPA to determine what guidance, if any, the Act provides the Commission in applying the just and reasonable standard. This Part concludes that, while there is little in the Act that specifically qualifies the standard or limits the Commission's discretion, several provisions (particularly under the Energy Policy Act of 1992 (EPAct)) suggest that the Commission has a statutory responsibility to promote the overall adequacy of transmission networks. Part Three, "The Modern Just & Reasonable Standard: Administrative Law Principles," sets forth the basic requirements of federal administrative law applicable to transmission ratemaking under the FPA. It explains that, as a matter of administrative law, the court's obligation of review under the just and reasonable standard is strictly limited to a determination of whether the Commission has engaged in reasoned decision-making supported by substantial evidence. The Commission is, therefore, free to depart from precedent, provided that it acknowledges and carefully justifies such departure.

29. *Hope*, 320 U.S. at 602 ("[I]t is the result reached not the method employed which is controlling.").

content, if any, of the just and reasonable standard in light of the Constitution's requirements, and to determine the nature and limits of the Commission's obligation under the standard. This Part reaches three broad conclusions: (1) neither the Constitution nor the FPA mandates the use of a particular method, formula, or set of factors in applying the just and reasonable standard, rather, it is the "end result" that matters; (2) the Commission is required to set rates at levels that accomodate both investor and consumer interests, sufficient to allow a public utility to perform its "public duties;" such duties arguably include maintenance and, in some instances, construction of transmission networks vigorous enough to meet the reliability and capacity demands of consumers in competitive markets; and (3) the Commission has discretion to take into account, not only the present, but the future interests of the public, arguably including the public's interest in the long-term reliability and commercial adequacy of transmission infrastructure.

(A) No Particular Formula Or Method Required; End Result Test; Zone of Reasonableness

Under the Fifth Amendment, the government may not take private property for "public use" without paying "just compensation."[35] In the context of ratemaking by regulatory agencies, at least since the Railroad Commission Cases,[36] the Supreme Court has held that in the context of ratemaking, public utilities have a constitutional right to earn a sufficient return.[37] In other words, the government must allow a regulated industry to earn a reasonable rate of return on its investment. This is because an unreasonably low rate would effect an unconstitutional taking of the industry owners' property without just compensation. As the Supreme Court explained in *Bluefield*, "[r]ates which are not sufficient to yield a reasonable rate of return . . . are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in viola-

life, liberty, or property, without due process of law. . . ."). Although the applicable caselaw tends to refer to the Fifth and Fourteenth Amendments as if they both apply to the federal government, it should be noted that, strictly speaking, the Fourteenth Amendment applies only to the States and, therefore, only the Fifth Amendment applies to the ratemaking by federal agencies. The constitutional analysis under both provisions is, however, the same.

35. U.S. CONST. amend. V.

36. Railroad Comm'n Cases v. Farmers Loan & Trust Co., 116 U.S. 307 (1886).

37. *Id. See also* Duquesne Light Co. v. Barasch, 488 U.S. 299, 307-8 (1989) ("The guiding principle has been that the Constitution protects public utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory. . . . If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments."); FPC v. Natural Gas Pipeline Co. of Am., 315 U.S. 575, (1942) ("By long standing usage in the field of rate regulation, the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense"); Covington & Lexington Turnpike Rd. Co. v. Sandford, 164 U.S. 578, 597 (1896) (A rate is too low if it is "so unjust as to destroy the value of [the] property for all the purposes for which it was acquired," and thereby "practically deprive[s] the owner of property without due process of law.").

result" test which requires a balancing of investor and consumer interests.[50]

Hope: End Result Test. It was not until the 1944 case of *FPC v. Hope Natural Gas* that the Supreme Court decided to "withhold its legislative hand" and leave the choice of methods to the regulatory agency.[51] The *Hope* opinion made clear that the NGA does not require the use of a specific method or formula for calculating a reasonable rate: "Congress . . . provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled the details of the general prescription."[52] It follows that Congress has delegated its legislative authority to the ratemaking agency to the extent necessary to "fill" such details.[53] Accordingly, "the Commission [is] not bound to the use of any single formula or combination of formula in determining rates."[54] This is so even if the method used is internally inconsistent, provided the overall result is just and reasonable: "an otherwise reasonable rate is not subject to constitutional attack by questioning the theoretical consistency of the method that produced it."[55] The important thing for constitutional purposes is the result of the rate, not the underlying method: "it is the result reached not the method employed which is controlling."[56] Thus, "[t]he fact that the method employed to

50. *See, e.g.*, Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168, 1181 (D.C. Cir. 1987) (reversing Commission order excluding certain plant investment from rate base).

51. ALFRED E. KAHN, THE ECONOMICS OF REGULATION 40, n. 45 (quoting "the immortal words of Lord Mountararat").

52. FPC v. Hope, 320 U.S. 591, 600-01 (1944).

53. *See, e.g.*, Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) ("[T]he legislative discretion implied in the rate making power necessarily extends to the entire legislative process, embracing the method used in reaching the legislative determination as well as that determination itself.' . . . It follows that rate-making agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'"). The constitutional aspects of delegation of legislative authority to a ratemaking agency are discussed in Part 3, *infra*.

54. *Hope*, 320 U.S. at 602. *See also* Wisconsin v. FPC, 873 U.S. 294, 309 (1963) ("[T]o declare that a particular method of rate regulation is so sanctified as to make it highly unlikely that any other method could be sustained would be wholly out of keeping with this Court's consistent and clearly articulated approach to the question of the Commission's power to regulate rates. It has repeatedly been stated that no single method need be followed by the Commission in considering the justness and reasonableness of rates."); Grand Council of the Crees (of Quebec) v. FERC, 198 F.3d 950 (D.C. Cir. 2000) ("In interpreting the statutory provision, 'just and reasonable,' the Supreme Court has emphasized that 'the Commission [is] not bound to the use of any single formula or combination of formulae in determining rates.'" (quoting *Hope* at 602)).

55. *Duquesne*, 488 U.S. at 314 (addressing whether a rate set by a State public utility commission was reasonable). Moreover,

> The adoption of a single theory of valuation as a constitutional requirement would be inconsistent with the view of the Constitution this Court has taken since [*Hope*] . . . [C]ircumstances may favor the use of one ratemaking procedure over another. The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors

Id. at 316. *Duquesne*, 488 U.S. at 314 (citing Wisconsin v. FPC, 373 U.S. 294 (1963) (gas case holding that the Commission is not limited to a single method in determining the whether a rate is just and reasonable)).

56. *Hope*, 320 U.S. at 602. Moreover, "[i]f the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry . . . is at an end." *Id.*

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tory and a ceiling above which the rate would be exploitative.[67] The extent to which the Commission has discretion to "lean" in one direction or the other within the zone is not entirely clear.[68]

Flexibility to Serve Public Interest. In *Duquesne*, the Supreme Court also emphasized the importance of leaving the State or regulatory commission a free hand to "decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public."[69] For the Court to identify a single method as a constitutional requirement "would unnecessarily foreclose alternatives which could benefit both consumers and investors."[70] Because the reasonable balance of consumers and investor interests may vary widely according to the diversity of circumstances, the regulator is free to use whatever method or methods will yield a reasonable result.[71] The regulator's duty to balance these interests takes precedent over any slavish adherence to precedent or traditional method for its own sake.

Indeed, when the interests of consumers and investors require it, the ratemaker's methodological discretion is not even limited to the field of cost-based methods. Although the "no single formula" doctrine of *Hope* arose from debates over historical cost versus present (reproduction) costs, the principle has been applied in the context of non-cost-based theories as well, such as market-based rate treatments.[72]

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67. *See, e.g.*, Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168, 1177 (D.C. Cir. 1987) (stating that zone of reasonableness is "bounded at one end by the investor interest against confiscation and at the other by the consumer interest against exorbitant rates") (quoting Washington Gas Light Co. v. Baker, 188 F.2d 11, 15 (D.C. Cir. 1950)); Farmers Union Cent. Exchange, Inc. v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (holding that the FERC may approve rates that fall within zone of reasonableness where rates are neither "less than compensatory" nor "excessive"); City of Chicago v. FPC, 458 F.2d 731, 750-51 (D.C. Cir. 1971) (affirming that rates must be high enough to attract investors but low enough to prevent exploitation of consumers), *cert. denied*, 405 U.S. 1074 (1972).

68. The standards for determining a zone of reasonableness and a particular rate within that zone are discussed in subparts (2) and (3) of this Part.

69. Duquesne Light Co. v. Barasch, 488 U.S. 299, 316 (1989).

70. *Id.* As discussed in the remaining subparts of this Part, this point is critical is discussion of pricing reform promote investment in new transmission capacity.

71. *See generally* Permian Basin Area Rate Cases, 390 U.S. 747, 790 (1968): "We must reiterate that the breadth and complexity of the Commission's responsibilities demand that it be given every reasonable opportunity to formulate methods of regulation appropriate for the solution of its intensely practical difficulties." Also,

> we see no objection to its use of a variety of regulatory methods. Provided only that they do not together produce arbitrary or unreasonable consequences, the Commission may employ any 'formula or combination of formulas' it wishes, and is free 'to make the pragmatic adjustments which may be called for by particular circumstances.'

Id. at 800 (quoting FPC v. Natural Gas Pipeline Co. 315 U.S. 575, 586 (1942)).

72. *See, e.g.*, *Permian*, 390 U.S. 747 (1968) (upholding as just and reasonable area rate methodology that did not account for costs of individual gas producers); Mobil Oil Corp. v. FPC, 417 U.S. 283, 308 (1974) (noting that, in *Permian*, the Commission "had not adhered rigidly to a cost-based determination of rates, much less one that based each producer's rates on his own costs"); *Farmers Union*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) ("non-cost factors may legitimate a departure from a rigid cost-based approach . The mere invocation of a non-cost factor, however, does not alleviate a reviewing court of its duty to assure itself that the Commission has given reasoned consideration to each of the pertinent

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form of marginally higher rates.[77] As the court stated in *Hope*, "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[78] Indeed, the regulator should consider the investor's "legitimate concern with the financial integrity of the company whose rates are being regulated."[79] The return must include not only operating costs, but also the capital costs of running a viable business enterprise. Echoing *Bluefield*, *Hope* provides additional guidance on this point: "[The] return . . . should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[80] The Court did not define the term "confidence," nor did it specify how much capital is enough to "maintain" credit or to constitute an "attraction" of capital: "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business."[81] To ensure that sufficient revenue is available to cover capital costs, the rate of return must be comparable to returns in industries with similar risks: "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[82]

The Court neither imposed nor proposed a method for measuring the risks faced by "other enterprises," or for comparing such risks with those faced by the regulated firm. Nor did the Court specify whether the field of "other enterprises" should be limited to firms in the same industry, e.g., electric or gas utilities, or even to regulated industries in general. The Court did not say that the regulated firm should earn the same returns as, for example, the manufacturing or financial services industries, or the average return earned by the Standard & Poors 500 companies. On the other hand, the Court did not say that they should *not* earn the same returns as such industries. The term "corresponding risks" suggests that the Commission should compare the regulated firm to other firms that are in comparable circumstances, e.g., that the Commission should compare regulated gas firms with other regulated gas firms. However, the term should not be read so narrowly. It could be read in terms of "quantity" or level of risk, rather than in term of specific industry characteristics or regu-

77. This is particularly the case in the area of transmission rates, where the transmission portion of the rate constitutes a relatively small portion of the overall price for delivered power, and transmission itself constitutes a critical link in the overall efficiency and proper functioning of the market. As Alfred Kahn explains, the quality and reliability of the service provided by a regulated utility may justify marginal increases in rates: "the nature of our dependence on public utility services is typically such that customers may correctly be *more* interested in . . . the reliability, continuity, and safety of the service than in the price they have to pay." ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS 21 (1998).

78. FPC v. Hope, 320 U.S. 591, 603 (1944).

79. *Id.*

80. *Hope*, 320 U.S. at 603.

81. *Id.* ("These [costs] include service on the debt and dividends on the stock. . . .").

82. *Hope*, 320 U.S. at 603 (emphasis added). *See generally* A. LAWRENCE KOLBE ET AL., THE COST OF CAPITAL: ESTIMATING THE RATE OF RETURN FOR PUBLIC UTILITIES 13 (1984).

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Permian Basin: Assessment of Public Interest. As noted, *Bluefield* required that rates be sufficient to allow a utility to discharge its "public duties." The Commission's duty to consider public duties is not limited to a formulaic analysis of costs or expected levels of investment. As the Supreme Court stated in *Permian Basin*, "[t]he Commission cannot confine its inquiries either to the computation of costs of service or to conjectures about the prospective responses of the capital market; it is instead obliged at each step of its regulatory process to assess the requirements of the broad public interests entrusted to its protection by Congress."[89]

In light of the pragmatic nature of the Commission's mandate, it must be free to use whatever method best ensures the attraction of capital adequate for the discharge of "public duties." The Commission must also be free to change its methods to reflect changes in circumstances over time. As the Court recognized in *Bluefield*, "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."[90]

The importance of this constitutional principle of flexibility in ratemaking cannot be gainsaid, particularly in the context of the transmission capacity. To the extent that interstate transmission service is an integral part of electric service, particularly for the purpose of maintaining system reliability in a cost-effective manner, it is certainly an activity affected with the public interest.[91] This is all the more the case in connection with growing competition in interconnected wholesale markets.[92] The public's interest in reliable electric service at competitive prices is apparent.[93] The reliable provision of an essential service, however, goes to the heart of the

89. *Permian Basin*, 390 U.S. at 791.

90. Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Virginia, 262 U.S. 679, 693 (1923) (emphasis added).

91. *See, e.g.*, Otter Tail Power Co. v. United States, 410 U.S. 366, 378 (1973) (discussing the siginificance of transmission as an essential facility for "isolated electric power systems"); Gainesville Utils. v. Florida Power Corp., 402 U.S. 515, 519-20 (discussing the role of transmission interconnections in maintaining system equilibrium, freeing isolated systems from the "necessity of constructing and maintaining its own equipment").

92. *See, e.g.*, Transmission Access Policy Study Group v. FERC, 2000 WL 762706, *5 (D.C. Cir. 2000) (acknowledging that "[a]s entry into wholesale power generation markets increased . . . the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.") (quoting Order No. 888, F.E.R.C. STATS. & REGS. ¶ 31,036, at 33,062).

93. *See, e.g.*, *Transmission Access Policy Study Group*, 2000 WL 762706 at *5 (acknowledging the FERC's findings regarding the for "access to competitively priced electric generation" and the "substantial benefits" to consumers of lower electricity pricings resulting from wholesale competition) (quoting Open Access NOPR F.E.R.C. STATS. & REGS. ¶ 32,514, 33,052). The primary consumer interest in electric power markets is reliable, high-quality electric service. In the high-tech economy and infrastructure of the United States today, this means not only keeping the lights on, but also eliminating disruptions or fluctuations in the flow of power required to keep personal and business computers, sophisticated health care equipment, air and rail traffic control systems, and the myriad other precision, electricity-dependent systems and technologies upon which our economy and our very lives depend. *See generally* ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS 21 (1998).

ther *Hope* nor *Bluefield* imposed a specific temporal framework on the scope of property value, consumer interests, or the performance of public duties. Indeed, the broad public interest mandate of these cases suggests that a regulatory commission should take a long view, as well as a broad view, of a utility's public duties.

Permian Basin. Subsequent cases suggest that the FERC has a duty to consider the future, as well as the present interests of the public. In *Permian Basin Area Rate Cases*,[98] the Supreme Court summarized the duties of a reviewing Court in applying the *Hope* "end result" test, holding that the court must, among other things, "determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant *public interests, both existing and foreseeable*."[99] The Court further held that the FERC must assess the "consequences" of its rate order on the "character and future development of the industry."[100]

In *Permian Basin*, the Commission employed an "area" method of rate regulation, whereby rates for different geographic areas were set at different levels to advance a policy of promoting increased exploration and production of natural gas within certain areas.[101] The Court made it clear that the rate need not be based exclusively on costs and rate of return, but could be used to advance policy goals not directly related to cost.[102] The Commission could, within the zone of reasonableness, "employ price functionally in order to achieve relevant regulatory purposes; it may, in particular, take fully into account the probable consequences of a given price level for future programs of exploration and production."[103] The Commission furthermore linked the need for methodological flexibility to the Commission's duty to protect consumers, "[t]he Commission's responsibilities necessarily oblige it to give continuing attention to values that may be reflected imperfectly by producers' costs; a regulatory method that excluded as immaterial all but current or projected costs could not properly serve the consumer interests placed under the Commission's protection."[104] If

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679, 693 (1923).

98. Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

99. *Id.* (emphasis added).

100. *Permian Basin*, 390 U.S. at 792.

101. *Id.* at 796-97.

102. *Permian Basin*, 390 U.S. at 796-97, 815. *See also* Mobil Oil Corp. v. FPC, 417 U.S. 283 (1974) (upholding Commission area gas rate order and rejecting the argument that a "rate must be based entirely on some concept of cost plus a reasonable rate of return. We rejected this argument in *Permian Basin* and we reject it again here. The Commission explicitly based its additional 'non-cost' incentives on the evidence of a need for increased supplies.").

103. *Permian Basin*, 390 U.S. at 797.

104. *Id.* at 815. (cited in Mobil Oil Corp. v. FPC, 417 U.S. 283, 309-10 (1974)). Similarly, in *Mobil Oil Corp. v. FPC*, another area rate gas case, the Supreme Court held that the Commission could use area method as an "appropriate mechanism for protecting the public interest," in view of a "serious and growing domestic gas shortage." In view of such shortage, the Court held that it was reasonable for the Commission to conclude that area-differential rates (as opposed to uniform increases) were an

Commission had nevertheless considered "massive evidence on supply, demand, and the relationship between the two."[111] On this basis, the Court found that the "record sufficiently supports the Commission's conclusion" that its area rate method would be "more likely to lead to the immediately increased capital necessary in the face of a crisis."[112]

TAPS v. FERC. The recent case of *Transmission Access Policy Study Group v. FERC*[113] (hereinafter *TAPS*) supports the view that the FERC has an obligation to consider the future public interest in setting rates under sections 205 and 206 of the FPA.[114] In connection with Order No. 888, the Court applied the just and reasonable standard to the Commission's rate determination related to stranded cost recovery. The Commission's rate determinations under the Order provided for retail stranded cost recovery in situations where State laws did not provide for recovery of such costs.[115] The Commission noted in the Order that "[r]ecovery of this type of cost through a transmission rate is obviously not the norm, but is necessitated by the need to deal with the transition costs associated with this Rule."[116] In this context, the Court noted the "wide discretion the FPA affords [the] FERC to determine what constitutes 'just and reasonable rates' and 'undue discrimination. . . .'"[117] The Court also acknowledged the "unusual circumstances created by an industry change as fundamental as Order 888's open access requirement."[118] Thus the Court established the premise that "unusual circumstances" in connection with the establishment of a new policy warrant the use of novel methods of ratemaking.

Order No. 888 was intended to supply a long-term, albeit "structural," remedy to a perceived "systemic" problem of discrimination in transmission access, implicating consumer interests.[119] To the extent that this rate determination was ancillary to the overall purposes of Order No. 888, it

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111. *Id.* at 318.

112. *Mobil Oil*, 417 U.S. at 319-20.

113. Transmission Access Policy Study Group v. FERC, 2000 WL 762706, at *9 (D.C. Cir. June 30, 2000) [hereinafter TAPS].

114. Although the case addresses issues of access to existing facilities rather than expansion of such facilities, the Court's discussion of the Commission's ratemaking authority are apposite independent of questions surrounding the Commission's authority to mandate unbundling and open access on a generic basis. See *infra* Part 3 of the article for discussion of *TAPS* in the context of *Chevron* deference.

115. *TAPS*, 2000 WL 762706 at *49.

116. *Id.* at 49 (quoting Order 888-A, III F.E.R.C. STATS. & REGS. ¶ 31,048, at 30,418)

117. TAPS at *49.

118. *Id.*

119. "The Commission decided . . . that relying upon voluntary arrangements and [case-by-case orders under FPA § 211] would not remedy the fundamentally anti-competitive structure of the transmission industry. Instead, the Commission concluded, such a piecemeal approach would result in an inefficient 'patchwork' of transmission systems nationwide. 'The ultimate loser in such a regime is the consumer.'" Transmission Access Policy Study Group v. FERC, 2000 WL 762706, at *6 (D.C. Cir. June 30, 2000) (quoting Notice of Proposed Rulemaking, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities: Recovery of Stranded Costs By Public Utilities and Transmitting Utilities* [1988-1998 Proposed Regs.] IV F.E.R.C. STATS. & REGS. ¶ 32,514 (1995).

FPA Transmission Adequacy Policy. Other sections of the FPA suggest that the Commission has a duty to promote the maintenance and expansion of vigorous, efficient transmission networks to support reliability and commerce. Section 202(a) of the FPA sets forth the purposes of "assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources. . . ."[127] Ensuring an "abundant supply" of electricity with the "greatest possible economy" arguably presupposes a properly functioning, reliable, high-capacity transmission network.[128] In addition to its duty to "divide the country" into districts for the "voluntary interconnection and coordination" of transmission facilities, the section sets forth a general duty to "promote and encourage such interconnection and coordination within each such district and between such districts."[129] Construction or modification of transmission facilities needed to achieve such interconnection and coordination is a highly capital-intensive enterprise. To the extent that it can, the Commission arguably has an obligation under section 202(a) to set transmission rates at levels that are high enough to encourage such construction and modification.

Transmission Rate Standards Under EPAct and FPA Sections 211 and 212. In 1992, Congress passed the Energy Policy Act of 1992 (EPAct), which, among other things, amended sections 211 and 212 of the FPA to require the Commission to apply certain standards in setting rates in connection with mandatory transmission orders under section 211.[130] Section 212, as amended, requires the Commission to permit a utility, subject to mandated open access, to recover "all the costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any

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(quoting 15 U.S.C. § 717o). Specifically, the Court held that the Commission could use a non-cost-based area method to encourage gas exploration and production. 16 U.S.C. § 825h ("The Commission shall have the power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter.").

127. 16 U.S.C. § 824a (1985).

128. To achieve the purposes in section 202(a),

> the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest.

Id. Thus, it seems to follows that "voluntary interconnection and coordination" for the sake of ensuring an abundant electricity supply are in the public interest.

129. 16 U.S.C. § 824a (1985).

130. Pub. L. No. 102-486, Title VII, §§ 721-722 (1992). Section 211, as amended, authorizes the Commission to order, on a case-by-case basis, transmitting utilities to provide open access transmission service. Under section 211(a), a utility or supplier may may apply to the Commission for an order requiring a transmitting utility "to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant. . . ." 16 U.S.C. § 824j(a) (1985)

requirements of full cost recovery for expanded transmission should apply to all transmission rates set by the Commission, not just to rates set as a result of a section 212 interconnection order.[137] The legislative history also suggests that the pricing requirements of section 212 should apply in any instance in which the FERC orders transmission services under section 203 or section 205 for whatever reason.[138] Subsequently, in Order No. 888, the Commission did precisely that-relying in part on sections 205, 211, and 212, it ordered open access to transmission service by generic rule.[139] Thus, consistent with the legislative history, the pricing standards set forth in section 212(a) arguably should apply to all rates set in connection with transmission services provided pursuant to Order No. 888. In other words, to the extent that these sections apply to rate orders under sections 205 and 206, the Commission is arguably required to take transmission expansion costs into account in determining all rates.[140]

(3) Transmission Expansion Policy. At a minimum, the transmission cost language of section 212 indicates a policy concern for adequacy of transmission facilities to support wholesale competition. In particular, the requirement that rates permit recovery of costs for "enlargement" of transmission facilities supports such a policy. Also, the requirement that rates promote "economically efficient" transmission suggests a policy in favor of transmission networks of optimal capacity to handle the demands of competitive electricity markets.

This Part showed that the FPA prescribes no particular requirements for applying the just and reasonable standard, but it provides additional support for the view that the Commission has legal authority to set rates at levels sufficient to promote investment in transmission infrastructure for the future needs of consumers.

137. *See also* 138 CONG. REC. S17,613 (daily ed. Oct. 8, 1992) (statement of Sen. Johnston). Senator Johnston, Chairman of the Committee on Energy and Natural Resources, engaged Senator Wallop in a colloquy, in which Senator Wallop asked: "Do the pricing provisions of new FPA section 212(a) apply only to FERC-ordered transmission pursuant to section 211, or do they also apply to the pricing of transmission pursuant to other authorities under the FPA?" Johnston replied: "I see no reason why these new pricing principles should not be applied by the FERC to other transmission orders. It would make good policy sense to do so." *Id.* *See also* Joshua Z. Rokach, *Transmission Pricing Under the Federal Power Act: Applying a Market Screen*, 14 ENERGY L.J. 95, 96 (1993).

138. *See also* 138 CONG. REC. S17,566, S17,619 (daily ed. Oct. 8, 1992) (statement of Sen. Wallop). Senator Wallop observed:

> [I]f for some reason not based on this legislation the FERC concludes that it has a legitimate claim of authority to require transmission services under section 203 or section 205 (which I do not believe they do), the FERC should adopt the pricing criteria and standards included in amended FPA sections 211 and section 212 because they provide the clear intent of Congress with regard to any non-voluntary transmission services.

Id.

139. *See also* Order No. 888, F.E.R.C. STATS. & REGS. ¶ 31,036 (1996).

140. *See* discussion *infra* Part 4 of this article where the Commission adopted this interpretation of section 212(a) in its 1994 Transmission Pricing Policy Statement.

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"[j]udges are not experts in the field. . . ."[145] Ratemaking is a specialized task involving analysis of enormous quantities of data using a variety of technical economic and financial concepts. The sheer practical burden of reviewing each "subordinate element" of an ROE formula or rate base accounting scheme seemed to be a major factor in the Court's "retreat" from "method" review.[146]

The second reason for the Court's deference is the constitutional principle of the separation of powers. Under Articles I and III, legislative power belongs to Congress; the judiciary, by contrast, is authorized only to "say what the law is," not to make the law.[147] Ratemaking is essentially a legislative enterprise involving legislative-style factfinding (involving enormous quantities of data) and the characteristically legislative task of balancing multiple, competing policy considerations and political factions. Thus, the methodological elements of ratemaking are not only beyond the Court's technical competence, but also beyond the Court's constitutional authority.[148] Thus, under *Chevron*, when a statutory term is broad or unclear, the courts generally defer to the agency's expertise in exercising its delegated authority.[149]

It could be objected that substantive judicial review is necessary to prevent the politics of a particular President's administration from unduly influencing an agency's regulatory policy. According to *Chevron*, however, "an agency to which Congress has delegated policy-making responsi-

145. Chevron v. Natural Resources Defense Council, 467 U.S. 837, 865 (1984).

146. *See also* Richard J. Pierce, Jr., *Public Utility Regulatory Takings: Should the Judiciary Attempt to Police the Political Institutions?*, 77 GEO. L.J. 2031 (discussing institutional limits of the courts to engage in substantive review of ratemaking decisions of regulatory commissions).

147. Marbury v. Madison, 1 Cranch 137, 177 (1803). *See also* U.S. CONST., art. I (All legislative power herein granted shall be vested in a Congress of the United States. . . ."); U.S. CONST. art. III ("The Judicial Power of the United States shall be vested in a Supreme Court, and in such inferior courts as the Congress may from time to time ordain and establish.").

148. *See also Chevron*, 467 U.S. at 865 (Observing that judges "are not part of either political branch of the Government" and must not substitute their "personal policy preferences" for the determinations of the regulatory agency).

149. In *Chevron*, the Supreme Court addressed a challenge to the Reagan Administration EPA's interpretation of the term "stationary source" in the Clean Air Act Amendments of 1977. *Id.* at 840. The Act required a rigorous permitting process for each new "stationary source" of certain pollutants. *Chevron*, 467 U.S. at 840. The EPA reasoned that all pollution-emitting devices within the same industrial facility could qualify as a single stationary source. *Id.* at 840-42. The petitioners argued that the purposes of the Clean Air Act would be better served by requiring that each single device be subject to the permitting regime. *Chevron*, 467 U.S. at 859-66. In other words, the petitioners effectively asked the Court to hold that the EPA had failed to choose the best policy to advance the purposes of the Act. The Court refused to substitute its judgment for that of the agency on constitutional grounds:

> When a challenge to an agency construction of a statutory provision, fairly conceptualized, really centers on the wisdom of the agency's policy, rather than whether it is a reasonable choice within a gap left open by Congress, the challenge must fail. In such a case, federal judges – who have no constituency – have a duty to respect legitimate policy choices made by those who do. The responsibilities for assessing the wisdom of such policy choices and resolving the struggle between competing views of the public interest are not judicial ones: "Our Constitution vests such responsibilities in the political branches." . . .

Id. at 866.

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court has no authority to "substitute its [policy] judgment for that of the agency."[161] Rather, the court need only ensure that the policy choice is coherently presented and justified by the facts, and that the agency has not failed to consider relevant factors in the rulemaking record.[162] In general, this standard is "highly deferential" to the FERC.[163]

In *TAPS*, the D.C. Circuit applied the arbitrary and capricious standard to the Commission's variable treatment of stranded costs in rate determinations under Order No. 888.[164] Certain petitioners claimed that the FERC acted arbitrarily and capriciously in determining that just and reasonable transmission rates include "retail stranded cost recovery in some circumstances but not others."[165] Specifically, they noted that rates must be just and reasonable and not unduly discriminatory. Therefore, they argued, by approving different transmission rates (some including stranded costs and others not including such costs), the Commission acted arbitrarily and capriciously. In response, the court stated that those petitioners "ignore the wide discretion the FPA affords FERC to determine what constitutes 'just and reasonable rates' and 'undue discrimination,' as well as the unusual circumstances created by an industry change as fundamental as Order 888's open access requirement."[166] The court held that the mere fact that some transmission rates include stranded costs, while others do not, does not by itself make the rate determination arbitrary and capricious. Rather, the court added, "petitioners must show that there is no reason for the difference.... We think [the] FERC has provided a convincing explanation for the difference."[167]

Typically, a rate determination fails the arbitrary and capricious test only if the Commission fails to provide a coherent, or at least somewhat thorough, explanation. In *North Carolina Utilities v. FERC*,[168] for example, the court held that the Commission's use of a novel "hypothetical capital structure" used to calculate ROE, and its decision to allow the company a rate of return at the high end of the zone of reasonableness, were arbitrary and capricious.[169] The Commission provided "no explanation" of why its

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161. *Overton Park*, 401 U.S. at 416.

162. *See, e.g.*, Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168 (D.C. Cir. 1987) ("where ... the Commission has reached its determination by flatly refusing to consider a factor to which it is undeniably required to give some weight, its decision cannot stand.") (citing *Overton Park*, 401 U.S. at 416).

163. *See also* Indiana Municipal Power Agency v. FERC, 56 F.3d 247 (D.C. Cir. 283), upholding the Commission finding that coal supply prices allegedly including a premium passed on to wholesale electricity customers were not unjust or unreasonable under the FPA. In *Indiana*, the court observed that, "'[b]ecause 'issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission,' our review of whether a particular rate design is 'just and reasonable' is highly deferential.'" *Id.* at 252 (citations omitted)

164. TAPS v. FERC, 2000 WL 762706, at *9 (D.C. Cir. June 30, 2000)

165. *Id.* at *48.

166. *TAPS*, 2000 WL 762706 at *49.

167. *Id.*

168. North Carolina Utils. v. FERC, 42 F.3d 659 (D.C. Cir. 1994).

169. *Id.* at 663.

would have been appropriate to have a higher return.[176] The court found, however, that the Commission had failed to consider a change of circumstances, which no longer justified a return at the same level.[177] Presumably this reasoning would apply in the reverse scenario. If circumstances were to change such that a higher (rather than a lower) return were justified, it would be arbitrary for the Commission to adhere to obsolete, counterfactual zones of reasonableness. This principle could be applied in the context of the transmission investment gap, in which new risks facing the transmission industry may justify an upward adjustment of the zone of reasonableness for transmission rates.

Substantial Evidence Review. Although the arbitrary and capricious standard may seem rather undemanding, the courts have made clear that "[o]ur review is not, however, an empty gesture: the Commission must be able to demonstrate that it has 'made a reasoned decision based upon substantial evidence in the record.'"[178] Section 706(2)(E) of the APA, provides that the reviewing court shall set aside an agency action that it finds to be "unsupported by substantial evidence" contained in the "whole record."[179] This evidence, however, need not constitute a preponderance of the evidence, instead, it need only be such evidence as "a reasonable mind might accept as adequate to support a conclusion."[180] Nor must the evidence establish that each element of the Commission's method or calculation was fully persuasive, so long as the end result is just and reasonable.[181] Moreover, the Commission need not use what the court might regard as the "best" method or even the method that produces the most favorable end result, so long as the end result, whatever it may be, appears to be reasonably articulated and supported by substantial evidence.[182] As the court stated in *Alabama Power Co. v. FERC*,[183] "[s]o long as its decision is

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176. *Town of Norwood*, 80 F.3d 526.

177. *Id.*

178. Northern States Power Co. v. FERC, 30 F.3d 177 (D.C. Cir. 1994) (upholding FERC order rejecting rates that would "vary with the direction of the transmission from or across Northern States' control area") (quoting *Town of Norwood*, 80 F.3d at 22).

179. 5 U.S.C. § 706.

180. Consolidated Edison Co. v. NLRB, 305 U.S. 197, 229 (1938).

181. According to the Supreme Court in *Permian Basin*, "We are not obliged to examine each detail of the Commission's decision; if the 'total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.'" Permian Basin Area Rate Cases, 390 U.S. 747 (1968). So long as the rate is within the "zone of reasonableness," the Court lacks authority to overturn it. *Id.* ("Moreover, this Court has often acknowledged that the Commission is not required by the Constitution or the Natural Gas Act to adopt as just and reasonable any particular rate level, rather, courts are without authority to set aside any rate selected by the Commission which is within a 'zone of reasonableness.'").

182. *See, e.g.*, Public Serv. Co. of New Mexico. v. FERC, 832 F.2d 1201 (10th Cir. 1987) ("The Commission's pronouncements in [the area of ROE] are admittedly not uniform.... However, we need not enter this morass for it is not our prerogative to require the Commission to use what we perceive to be the 'best' methodology. We are to ensure only that the methodology employed was reasonable and produced reasonable rates.").

183. Alabama Power Co. v. FERC, 993 F.2d 1557, 1559 (D.C. Cir. 1993) (holding that a single system-wide transmission rate based upon an average system transmission cost is just and reasonable).

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The D.C. Circuit has applied this principle in cases involving the FERC's rate determinations. For example, in *Boston Edison Co. v. FERC*,[191] the court found that "the law simply requires a commission, wishing to depart from a prior rule or prior precedent, to focus on the departure, to decide to change, and to explain why it has done so."[192] Likewise, in *Tennessee Gas Pipeline Co. v. FERC*,[193] the court emphasized that the Commission is "free to adopt a minority position in the financial and economic communities," such as an unconventional variant of the DCF method.[194] "But it must say so, and, if the rejection is inconsistent with prior decisions, explain the change," the court added. In this case, the Commission had rejected the "efficient market theory," an element of a particular DCF method, apparently without providing adequate justification for the departure.[195] The court noted that the Commission "appears quite wedded to DCF analysis and to efficient market theory as its theoretical mainstay. . . ."[196] This case highlights the Commission's obligation, particularly in the ROE context, to provide thorough justification for any departure from conventional DCF practice.

Conclusion to Part 3. This Part showed that the courts' review of rate determinations is highly deferential, particularly regarding matters of method and detail. The Commission must nevertheless support its rate determinations under the just and reasonable standard with carefully reasoned arguments and substantial evidence. The Commission is free to change is policies to reflect new conditions, but must take particular care to justify such departures from precedent. The next Part discusses particular areas in which the Commission has proposed to reform its ratemaking policies.

PART 4. FERC PRICING POLICIES THROUGH ORDER NO. 2000

The preceding parts of this article examined the legal boundaries of transmission ratemaking from the standpoint of constitutional, statutory, and administrative law doctrines. An examination of the Commission's own application of these doctrines in its ratemaking decisions and policy statements further illustrates the breadth of the Commission's discretion

191. Boston Edison Co. v. FERC, 855 F.2d 962 (1st Cir. 1959) (upholding FERC's adjustment of a utility's rate of return to take into account general decline in interest rates).

192. *Id.* at 966 (citing *Atchison*). *See also* Northern California Power Agency v. FERC, 37 F.3d 1517, 1522 (D.C. Cir. 1994) (Holding that the FERC order applying a certain uniform discount rate was consistent with reasoning of prior order, but noting that "[i]t is true that an agency acts arbitrarily when it departs from its precedent without giving any good reason."). *But see* Environmental Action v. FERC, 996 F.2d 401, 411 (D.C. Cir. 1993) (Noting that, when prior decisions are "readily distinguishable," the Commission "may distinguish precedent simply by emphasizing the importance of considerations not previously contemplated, and that in so doing it need not refer to the cases being distinguished by name.").

193. Tennessee Gas Pipeline Co. v. FERC, 926 F.2d 1206 (D.C. Cir. 1991)

194. *Id.* at 1211.

195. *Tennessee Gas Pipeline*, 926 F.2d at 1211.

196. *Id.*

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priately compensates transmission owners and creates adequate incentives for system expansion when such expansion is efficient."[199]

Order No. 2000. More recently, the Commission has addressed the need for incentive regulation to promote transmission expansion in connection with RTO formation. In Order No. 2000, the Commission acknowledged that transmission pricing reform is necessary as a result of industry restructuring, and that adjustments must be made to compensate for the special risks inherent in RTO participation that may discourage the voluntary formation of RTOs. Order No. 2000 states that "transmission pricing reform is needed as a result of the rapid restructuring of the industry that is underway, particularly with respect to changes in the ownership and control of transmission assets, and changes in the transmission services being provided in competitive generating markets."[200] The Commission concluded that, "[a]s a result of these changes ... [it] needs to mitigate various 'disincentives' that may prevent transmission owners from efficiently operating their systems."[201] Moreover, RTO participants "should be accorded transmission pricing that reflects the financial risks of turning facilities over to an RTO and that reflects other changes in the structure of the industry."[202] The Commission also acknowledged the concerns of commenters who believe that investment in transmission is inadequate to support competition.[203]

As noted, the regulatory text of Order No. 2000 specifically enumerates eight types of "innovative" or incentive rate treatments the Commis-

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199. TPPS, *supra* note 193, at 31,149.

200. Order No. 2000, *supra* note 2, at 31,191.

201. *Id.* For example:

> Commenters cite to the potential that transmission owners will earn lower returns for providing unbundled transmission service than they earned for providing bundled service, even though risks associated with transmission ownership have increased.... One source [of increased risk] is the potential for bypass of transmission assets due to distributed generation and the phasing out of older generators from service. Other sources are directly related to RTO formation. For example, some commenters assert that stand-alone transmission companies (e.g., transcos) are riskier because they have a less-diversified portfolio of assets than a vertically integrated utility. Other commenters argue that participation in an ISO is inherently riskier, suggesting that increased risk comes from ownership of transmission assets that are ceded for purposes of operational control to another, non-affiliated entity.

Order No. 2000, *supra* note 2, at 31,191.

202. *Id.* at 31,172.

203. Order No. 2000 states:

> Other commenters argue that a reevaluation of transmission pricing is needed because it is absolutely critical that the transmission grid support competitive generating markets, and the only way that the Commission can ensure this will happen is to pursue pricing policies that encourage it. Some commenters suggest that because the contribution of transmission to total costs of energy is relatively small, overinvestment in transmission will not significantly affect delivered electricity prices. Further, the Commission should be much more concerned about underinvestment, not overinvestment, in the transmission grid. Stated another way, an efficient transmission grid is a prerequisite to achieving competive generating markets....

Id. at 31:191.

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DCF methodology, we therefore assume that it is free to do so.[211]

The court noted, however, that the Commission "appears quite wedded to DCF analysis and to efficient market theory as its theoretical mainstay. . . ."[212] Accordingly, as a matter of administrative law, the Commission would be required to acknowledge a rejection of the DCF and "explain the change."[213]

American Electric Power. A recent initial decision by a FERC ALJ acknowledged the fact that the FERC is not constitutionally bound to use a particular method for calculating the ROE. In *American Electric Power Co., Central and South West Corp.*,[214] the ALJ observed that "[a]pplying the [*Bluefield* and *Hope*] standards requires the analysis of all available data. Thus, rather than rely on a single methodology, [a witness for the applicant] considered several methods of determining the cost of common equity."[215] Significantly, the ALJ rejected the "conventional" DCF methodology, at least as applied to the facts of this case, stating that it was based on "unrealistic assumptions" which produced ROEs so low (5.65% and 6.44%, respectively, for AEP and CSW) "as to conclusively demonstrate its invalidity."[216] Instead, the ALJ accepted the utilities' alternative methodologies that produced a composite ROE of 11.75% for the merged company.[217] Although the alternative methods were "modifications to [the] conventional DCF methodology," the case nevertheless illustrated the need to assess "all available data" and the fact that no specific method is required.[218]

Southern California Edison. Despite its acknowledged legal discretion, the Commission's trial staff, ALJs, and, to an extent, the Commission itself have tended to adhere to DCF methods.[219] The 1999 Southern California Edison (SoCal Ed or Edison) proceeding[220] provides a good illustration of both the Commission's flexibility and its "conservative" tendencies on the controversial issue of ROE calculations. In this case, the ALJ issued an initial decision (ID) recommending a rate of return on equity of 9.68% for Edison's transmission assets, approximately two percentage points below the return Edison previously received on these same assets from the State of California.[221] The ALJ also would have denied Edison the right to recover about $20 million annually in overhead costs that state

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211. *Tennessee Gas Pipeline Co.*, 926 F.2d at 1211.

212. *Id.*

213. *Tennessee Gas Pipeline Co.*, 926 F.2d at 1211. *See also supra* Part 3 for discussion of administrative law requirements for actions inconsistent with Commission precedent.

214. *American Elec. Power Co.*, 89 F.E.R.C. ¶ 63,007 (1999) (initial decision).

215. *Id.*

216. 89 F.E.R.C. ¶ 63,007.

217. *Id.*

218. 89 F.E.R.C. ¶ 63,007.

219. *See, e.g.*, discussion of Tennessee Gas Pipeline Co. v. FERC *supra* at notes 211 and 212 and accompanying text.

220. *Southern California Edison Co.*, 86 F.E.R.C. ¶ 63,014 (1999) (initial decision).

221. *Id.*

does not signal an abandonment of DCF methods for determining the ROE under the just and reasonable standard. Indeed, the Commission emphasized the hoary status of the "standard" constant growth method. The Commission nevertheless acknowledged that "[s]hould circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary."[231]

The more significant aspect of the Commission's decision was its consideration of risk in choosing an ROE level within the zone of reasonableness established by the constant growth DCF method it employed. Although the Commission regarded much of the evidence presented on risk as "disputed" or "speculative," it nevertheless acknowledged that the risks faced by Edison were higher than those in the proxy group of companies used in the Commission's DCF analysis.[232] Because the proxy companies were otherwise comparable but had not transferred their transmission assets to an ISO, the Commission adjusted Edison's rate upward within the zone of reasonableness established on the basis of the constant growth DCF calculation.[233]

Order No. 2000. In Order No. 2000, the Commission acknowledged that traditional methods of calculating the ROE may no longer be adequate: "We . . . recognize that historical data typically used to evaluate ROEs may not be reliable since it reflects a different industry structure from the one that exists recently."[234] The Commission further acknowledged that "new approaches" to the ROE calculation are warranted.[235] The regulatory text of the Order requires the Commission to consider rates of return that are "(a) formulary; (b) consider risk premiums and account for demonstrated adjustments in risk; or (c) do not vary with capital structure. . . ."[236]

Formula Rates. A formula rate would "decouple a transmission owner's earnings from its own equity valuation, and would tie it more to external standards such as industry-wide performance."[237] This approach would be "consistent with the benchmarking that may occur under PBR."[238] As discussed below, PBR-type "benchmarking" is consistent with the just and reasonable standard, provided that the end result is reasonable. Also, as discussed, the just and reasonable standard does not require the Commission to use a particular method or formula; a formula rate proposed by an RTO applicant would thus be permissible, provided that the

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231. *Id.* at 61,261.

232. 92 F.E.R.C. ¶ 61,070, at 61,261.

233. *Id.*

234. Order No. 2000, *supra* note 2, at 31,193.

235. *Id.* The Order apparently would not, however, be used as a "vehicle for generic reform of the current discounted cash flow method for calculating return." Joshua Z. Rokach, *Stand-Alone Transmission: RTOs in the New Millennium*, 39 (No. 2) INFRASTRUCTURE (ABA Section of Public Utility, Communications, and Transportation Law) (Winter 2000).

236. 18 C.F.R. § 35.34(e)(2)(ii)

237. Order No. 2000, *supra* note 2, at 31,193.

238. *Id.*

tion 212(a), as summarized in the TPPS, requires transmission rates to permit the recovery of all "legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. . . ."[247]

Incremental Pricing. Traditionally, the cost basis for transmission rates consisted of the "rolled-in embedded cost" of the transmission facilities on a non-distance-sensitive or "postage stamp" basis, including the costs of new facilities or improvements to existing facilities.[248] As the 1994 TPPS notes, the Commission began in the early 1990s to "address the industry's changing needs by modifying its historical transmission pricing policy. . . ."[249] Specifically, the Commission began to permit certain types of "incremental" cost pricing, whereby utilities were allowed to charge transmission-only customers either the embedded costs for the entire system, including improvements, or incremental expansion costs, but not both. This has been called "or" pricing or *Northeast Utilities* Pricing, referring to the Commission decision that established this policy.[250]

In 1994, the TPPS declared that "the Commission is prepared to move beyond 'or' pricing to consider other pricing alternatives."[251] For example, the Commission expressed willingness to consider including "various combinations" of the following pricing approaches: "(1) a traditional contract path approach or a flow-based approach; (2) costs aggregated at the utility level, at a zonal level, or at the line-by-line level; and (3) various cost concepts for rate design, such as embedded cost, 'or' cost, incremental cost, or short-run marginal cost."[252] The TPPS also expresses openness to certain methods that would "exceed the traditional revenue requirement," such as "[r]eplacement cost methods" and "long-run marginal cost methods."[253]

The TPPS emphasized, however, that "[n]ot all of these possible combinations, however, would necessarily satisfy our principles."[254] Specifically, the Commission named "postage-stamp 'and' pricing" as an example of an "unacceptable" pricing method.[255] "And" pricing means setting rates that compensate a transmission provider for both the costs of existing facilities (embedded average costs) and the additional costs of expansion (incremental cost), for the use of a given facility by a transmission-only

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Bliley, Appendix B, § 11, Dec. 23, 1999. Curiously, however, Chairman Hoecker did not express support for the proposed section 217; instead he recommended deleting the pricing reform provision from the bill "to avoid confusion and unnecessary litigation." *Id.*

247. TPPS, *supra* note 198, at 31,140.

248. *Id.* at 31,137.

249. TPPS, *supra* note 198, at 31,137.

250. *Id.* at 31,138 (citing *Northeast Utils. Serv. Co.*, 58 F.E.R.C. ¶ 61,070).

251. TPPS, *supra* note 198, at 31,138

252. *Id.* at 31,145.

253. TPPS, *supra* note 198, at 31,147.

254. *Id.* at 31,145.

255. TPPS, *supra* note 198, at 31,146.

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would not necessarily be an unjust end result. On the contrary, the fact that transmission customers must pay both the incremental cost of new construction and a share of embedded costs arguably does not necessarily run afoul of the just and reasonable standard, for three reasons. First, the transmission-only customers are both the occasion for the new construction (and should, therefore, be responsible for incremental costs), and are users of the existing system (and should pay for a pro rata share of such use). Second, the method may be a superior approach to ensuring that transmitting utilities are justly compensated for their opportunity costs when lines are congested and encouraging the expansion of transmission facilities while such congestion remains an obstacle to system efficiency.[264]

Third, as *TAPS* makes clear, there is nothing inherently unjust or unreasonable in charging different rates for different categories of customers, provided an adequate policy rationale exists.[265] In *TAPS*, certain petitioners claimed that the FERC acted arbitrarily and capriciously by "determining that just and reasonable transmission rates include retail stranded cost recovery in some circumstances but not others."[266] The court rejected this argument, citing the broad discretion of the Commission to fashion rates that reasonably serve its policy objectives. "In making this argument, the [petitioners] ignore the wide discretion the FPA affords [the] FERC to determine what constitute 'just and reasonable rates' and 'undue discrimination,' as well as the unusual circumstances created by an industry change as fundamental as Order [No.] 888's open access requirement."[267] Furthermore, "[j]ust because some transmission rates include retail stranded costs while others does not alone make Order [No.] 888 arbitrary and capricious; rather, petitioners must show that there is no reason for the difference."[268] Similarly, under Order No. 2000, the Commission would include incremental costs in some rates, but not others. This distinction, provided it is supported with reasoned justification, would not be unjust or unreasonable.[269]

In addition to "and" pricing, Order No. 2000 lists two other novel rate treatments related to cost calculation: (1) "[n]on-traditional depreciation schedules for new transmission investment;"[270] and (2) "[t]ransmission rates based on levelized recovery of capital costs."[271]

Non-Traditional Depreciation Schedules. Specifically, the Commission is willing to consider accelerated depreciation as a means of recover-

264. *See generally id.* at 31,143 (discussing opportunity costs when lines are congested).

265. TAPS v. FERC, 2000 WL 762706 (D.C. Cir. 2000).

266. *Id.* at *48.

267. *TAPS*, 2000 WL 762706 at *49.

268. *Id.* (citing *AGD*, 824 F.2d at 1009).

269. As noted, a rate treatment filed by an RTO applicant must include a detailed explanation of why the treatment is just and reasonable. Such explanation would assist the Commission in articulating a reasoned justification for its rate order.

270. 18 C.F.R. § 35.34(e)(2)(iii).

271. *Id.*

regulation in that it . . . divorce[s] rates from the underlying cost-of-service."[280] Incentive regulation is consistent with the Commission's authority under the FPA, provided the end result is "just and reasonable."[281] As the Commission stated "[i]ncentive ratemaking is consistent with our general ratemaking authority. The Commission is not required to follow any specific type of ratemaking formula and is not limited to designing rates based upon traditional cost-of-service ratemaking under either the Natural Gas Act (NGA) or the Federal Power Act (FPA)."[282] In the same policy statement, the Commission recognized the benefits of incentive regulation: "[i]n order to enhance productive efficiency in non-competitive markets, the Commission will allow utilities to propose incentive rate mechanisms as alternatives to traditional cost-of-service regulation. Such proposals should result in lower rates to consumers, and provide utilities the opportunity to earn higher returns."[283] The Commission cited numerous natural gas cases in support of its authority to implement incentive rates.[284]

Subsequently, in the TPPS, the Commission acknowledged that "the electric utility industry is continuing to evolve and we must ensure that our policies do not impede the continued development of competitive bulk power markets, or the development of new market structures and transmission arrangements."[285] It also expressed openness to "consider pricing proposals necessary to accommodate such developments," noting that "[s]ome of the proposals discussed in this proceeding may exceed the traditional embedded cost revenue requirement."[286]

Order No. 2000. In Order No. 2000, the Commission recapitulated its previous statements of support for incentive pricing: "the Commission has been receptive to PBR proposals, at least since issuance of the Policy

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280. *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities*, 61 F.E.R.C. ¶ 61,168, 61,588 (1992).

281. As the Court observed in *Permian Basin*, "a regulatory method that excluded as immaterial all but current or projected costs could not properly serve the consumer interests placed under the Commission's protection." Permian Basin Area Rate Cases, 390 U.S. 747, 815 (1968). *See also supra* Part I discussion of Permian Basin and non-cost factors in Part I.

282. 61 F.E.R.C. ¶ 61,168, at 61,593.

283. *Id.* at 61,587.

284. "These cases affirm that the Commission is not required to follow any specific type of ratemaking formula and is not limited to designing rates for the utilities it regulates based on traditional cost-of-service ratemaking. The Commission is free to set rates to provide incentives so long as there is a correlation between the incentive and the result induced." 61 F.E.R.C. ¶ 61,168, at 61,594, (citing, e.g., Public Serv. Comm'n, State of N.Y. v. FPC, 487 F.2d 1043 (D.C. Cir. 1973); City of Charlottesville v. FERC, 661 F.2d 945, 949 (D.C. Cir. 1981) ("The Natural Gas Act fails to prescribe specific standards for ratemakers to follow."); Farmer's Union Cent. Exchange Co. v. FERC, 734 F.2d 1486 (D.C. Circuit), *cert. denied sub nom.* 469 U.S. 1034 (1984) (stating that "changing characteristics of regulated industries may justify the agency's decision to take a new approach to the determination of just and reasonable rates . . . [and that] non-cost factors may legitimize departure from a rigid cost-based approach")).

285. TPPS, *supra* note 198, at 31,147.

286. *Id.*

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rates are essentially a form of cost-based ratemaking.[294] Although the incentive lies partly in the opportunity to trim costs below the initial cost baseline, and thus widen profit margins, the incentive rate nevertheless presupposes a traditional cost baseline. Under incentive plans, the utility remains subject to Commission rate determinations, albeit under terms allowing greater flexibility. Under negotiated or market based rate plans, by contrast, the regulator must (within limits) withdraw from rate review, allowing the market or at least arms-length transactions between certain qualified parties to dictate the price of the utility's service.

As competition has developed in the wholesale power markets, the Commission has begun to accept rates that are negotiated between the parties without using the seller's cost basis as a required baseline. These rates apply only to wholesale electric power transactions, not to transmission services. It has been the conventional wisdom that transmission is a "natural monopoly," and that market-based transmission rates would therefore not be possible under the just and reasonable standard.[295] Accordingly, the Commission has not approved market based rates for transmission services on interconnected alternating current (AC) grids.[296] The Commission has nevertheless recognized the possibility of market-based rates for transmission services on interconnected facilities in the future. The TPPS addresses this issue as follows, "[t]he electric utility industry of today is very different from the electric utility industry that existed only [twenty] years ago and even five years ago. Just as we today change our policies to reflect recent changes, we must remain flexible if we are to respond to future changes."[297] Moreover, "it is clear that there is no single appropriate ratemaking method under the FPA. The end result is the appropriate yardstick against which to measure the legality of a rate order, not the ratemaking method."[298]

294. Order No. 2000 emphasizes that the Commission, by providing rate treatments to encourage RTO formation, is not "abandoning the fundamental underpinnings of our traditional transmission pricing policies, i.e., that transmission prices must reflect the costs of providing the service. While many aspects of transmission pricing reform are labeled incentive pricing, many are aimed at eliminating disincentives to the efficient use and expansion of regional transmission grids. . . ." Order No. 2000, *supra* note 2, at 31,173.

295. "Because transmission remains a natural monopoly, we believe it will be difficult for transmission owners to support such pricing under the FPA, particularly market-based transmission rates." TPPS, *supra* note 198, at 31,140.

296. It should be noted, however, that in the recent proceeding of *TransEnergie, U.S., Ltd.*, 91 F.E.R.C. ¶ 61,230 (2000), the Commission approved market based rates for a direct current (DC) line connecting control areas of the New York Independent System Operator (New York ISO) and the New England Independent System Operator (New England ISO). The Commission found that "competitive conditions exist in the markets served by both ends of the [DC line], and that as an independent line not part of the integrated AC grid, it 'does nothing to constrain these competitive conditions,' and may serve to increase competitive generation in those markets." *Id.* at 61,836. Although this decision should not be construed as signaling imminent change in the Commission's policy concerning market-based rates, it suggests that the transmission service on interconnected AC grids is increasingly subject to limited competition in the form of substitute connections that by-pass the grids.

297. TPPS, *supra* note 198, at 31,140.

298. *Id.* at 31,141.

In Order No. 2000, the Commission reiterated its position that market-based rates (for wholesale sales) can be appropriate under certain conditions: "The Commission has a responsibility under FPA sections 205 and 206 to ensure that rates for wholesale power sales are just and reasonable, and has found that market-based rates can be just and reasonable where the seller has no market power."[303]

Conclusion of Part 4. This Part provided an overview of the Commission's ratemaking policies to show that the Commission has advocated reform in numerous areas over the past decade. Recent attention to the apparently ever-widening transmission investment gap, however, suggests that the Commission's project of reform is far from complete. Order No. 2000 challenges practitioners and utilities to propose innovative rates. Significantly, the Commission has demonstrated its openness to certain reforms in specific proceedings.[304] The next section, Part 5, discusses legislative options for encouraging or directing the Commission to implement such reforms as may be needed to promote new investment in transmission infrastructure.

PART 5. LEGISLATIVE OPTIONS

The preceding parts of this Article discussed the boundaries of the FERC's legal authority to reform its transmission pricing policies. This Article concludes that the Commission has very broad discretion to use new pricing methods that will better reflect the risks and circumstances of the restructured transmission industry. The Commission has made strong statements and taken significant actions towards meaningful pricing reform, particularly in Order No. 2000. It has been argued, however, that much remains to be done. What if internal political or ideological divisions, or simply inertia, prevent the Commission from implementing an effective reform policy? If the Commission lacks the resources to reform its policies, what external actions could encourage the Commission to act more quickly and decisively?

New commissioners appointed by a new President could change the Commission's policies substantially.[305] Beyond changes in the composition

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FPC v. Texaco was in the context of lack of effective competition and that a determination by the Commission that such competition exist was sufficient justification for permitting market-based rates: and (2) that the just and reasonable standard does not require use of "any single pricing formula." *Elizabethtown Gas*, 10 F.3d at 870 (quoting Mobil Oil Exploration v. United Dist. Co., 498 U.S. 211, 224 (1991)).

303. Order No. 2000, *supra* note 2, at 31,044.

304. *See, e.g.*, International Transmission Company, 92 F.E.R.C. ¶ 61,276 (2000). In this proceeding, the Commission permitted, contingent upon the satisfaction of several significant conditions, "innovative rates" for the International Transmission Company (ITC). Such rates would be higher than the wholesale rates of the ITC's predecessor in interest, Detroit Edison Company, by 0.8 mils per kWh or, according to intervenors, 48%. Significantly, one of the conditions for approval is that ITC become a "fully independent transco," defined as a transco with "no active or passive ownership interests by market participants."

305. *See also* Chevron v. Natural Resources Defense Council, 467 U.S. 837, 865 (1984) (agency may legitimately take into account the views of the "incumbent administration" in revising its policies)

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promote "the economically efficient transmission . . . , the expansion of transmission networks, the introduction of new transmission technologies, and the provision of transmission services by regional transmission organizations."[311] Subsection (c) further requires that such rates shall prevent cost-shifting to non-jurisdictional services and be "just and reasonable and not unduly discriminatory or preferential."[312]

These provisions require the Commission to permit recovery of "all" transmission-related costs. Does this include costs that the Commission deems to have been imprudently incurred, or does it otherwise provide a perverse incentive for a utility to "pad" its transmission-rate base? No. This provision must be read in light of the further requirement that such rates be "just and reasonable." Under the just and reasonable standard, the Commission is free to exclude costs that it deems were imprudently incurred or otherwise unreasonable.[313] It should also be noted that the essentially identical term "all the costs" appears in FPA section 212(a).[314]

Otherwise, the "all costs" provision simply directs the Commission to do what it has always done in reviewing rates under the FPA: permit the utility to recover its costs. Such costs must include the costs of enlargement of transmission facilities. This would be consistent with the usage of FPA sections 211 and 212.[315] As noted, the Commission's 1994 Transmission Policy Statement embraced the cost recovery requirements of section 212(a) for all transmission rates.[316]

The requirement that the Commission take into account the "incremental cost and benefit to interconnected transmission systems" is essentially the same as the policy set forth in the 1994 TPPS, which recognized the need for incremental cost pricing and closely tracks the language of section 212(a). The requirement that rates promote "economically efficient transmission" closely tracks the requirements of FPA section 212(a). Using the legislative history of section 212(a) as a guide, this provision would apparently encourage, but not require, the Commission to withdraw from review in cases where negotiated ratemaking would achieve a just and reasonable result.[317] This provision should not, however, be construed

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311. H.R. 2944, *supra* note 309.

312. *Id.*

313. *See generally* Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168 (D.C. Cir. 1987) (denying recovery of certain costs deemed imprudently incurred).

314. FPA, § 212(a), 16 U.S.C. 824k. These provisions are quoted in full *supra* Part 2.

315. Section 211(a), in reference to increasing transmission capacity, states:

> Any electric utility, federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.

16 U.S.C. § 824j. The term "enlargement" is also used with respect to expansion of generation capacity. *See also* FPA § 207 (16 U.S.C. 824f).

316. *See also supra* Part 4.

317. *See also* 138 CONG. REC. S17,566, S17,619 (daily ed. Oct. 8, 1992) (statement of Sen. Wallop). According to Senator Wallop:

> Adding the modifier 'economically' to the word 'efficient' calls to the FERC's attention that

without this language, all rates would still be subject to the just and reasonable standard under sections 205 and 206. It has been suggested that the transmission pricing provisions of H.R. 2944 could be an unwarranted departure from the established FPA standards, and that the language would somehow violate the FPA's just and reasonable standard or force the FERC to set transmission rates that go beyond the "zone of reasonableness."[322] The standards set forth in the proposed section 217 are, on the contrary, wholly consistent with the just and reasonable standard as it is set forth in the text of the Act and as it has been interpreted by the courts. Use of the phrase just and reasonable in the proposed section 217, removes any doubt regarding the consistency of such standards with the historic just and reasonable standard, emphasizing that the clarifications of subsections (a) and (c) would not "preempt" that standard, or in any way require the Commission to exceed the bounds of the standard as previously interpreted by the courts. Thus, such additional specifications would be consistent with the just and reasonable standard.

At most, such additional requirements would constitute a limitation or channeling of the FERC's discretion within the historic bounds of the just and reasonable standard, not a grant of new or broader authority. The new standards certainly would not require the Commission to approve "unjust" or "unreasonable" rates. Nor would these standards authorize the Commission to set rates that fall outside the zone of reasonableness under current law; rather, they would simply require that the Commission take into account, within the "zone of reasonableness," the need for expanded and improved transmission facilities in determining what constitutes a just and reasonable rate.

It should be noted that section 212(a) also provides that rates set pursuant to section 211 "shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential."[323] It should be noted that the just and reasonable language of this section was drawn verbatim from the original just and reasonable language of FPA sections 205 and 206.[324] Thus, the additional requirements of the section do not override the just and reasonable standard, as the legislative history confirms.[325] On the contrary, sec-

322. The official section-by-section summary of H.R. 2944, issued by the House Commerce Committee after the markup, suggests that the proposed pricing provisions are potentially inconsistent with current law:

> it is unclear how FERC should balance current law and the new provisions. For example, under current law FERC has authority to approve rates that range from confiscatory to monopoly rents, the "zone of reasonableness." The pricing provisions added by the Sawyer amendment appear to require FERC to approve rates that are higher than it would approve under current law – and closer to monopoly rents – if such rates promote the economically efficient transmission of electric energy or promote expansion.

STAFF OF HOUSE COMM. ON COMMERCE, 1ST SESS., SECTION-BY-SECTION SUMMARY OF H.R. 2944 5-6 (Comm. Print 1999).

323. 16 U.S.C. § 824k.

324. *See also supra* Part 2.

325. According to Senator Johnston, section 212(a), including the language requiring that rates

Similarly, the cost recovery provisions of H.R. 2944 would channel the FERC's discretion, but would not require or authorize the FERC to set transmission rates at levels beyond or outside the zone of reasonableness or otherwise inconsistent with the just and reasonable standard.

H.R. 2944: Voluntary Innovative Pricing Provisions. Subsection (d) would require the Commission to "encourage innovative pricing policies voluntarily filed by transmitting utilities," including policies that (1) provided incentives to transmitting utilities to participate in RTOs; (2) limit charging of multiple rates for transmission service by RTOs; (3) minimize cost-shifting among existing customers within an RTO; (4) encourage "efficient and reliable operation" of transmission networks through congestion management, performance-based or incentive ratemaking, and "other measures;" and (5) encourage "efficient and adequate investment in and expansion of" RTO transmission facilities.

These provisions are consistent with the policy of Order No. 2000 to promote efficient use of and investment in RTO transmission facilities. The Commission has ample legal authority to implement incentive or performance based rate treatments.[329] Rate treatments that encourage efficiency, reliability, and transmission investment and expansion are consistent with the requirements of the *Hope* and *Bluefield* cases that rates be adequate to attract capital needed for the discharge of a utility's public duties. Such treatments would also advance the FPA policies in favor of adequate and reliable transmission. By incenting RTO formation, these policies would also further the purposes of FPA section 202(a), which directs the Commission to "encourage the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. . . ."[330]

It should be noted that the innovation pricing provisions of H.R. 2944 require only that the Commission consider such treatments. It does not require that they be approved, even if they were to meet the standards set forth in Order No. 2000. Also, the burden of development of such rate treatments remains on the RTO applicant and no special provision is made for advance declaration by the Commission of whether a particular rate treatment would be approved. These provisions would nevertheless send a clear signal that Congress intends the Commission to give serious consideration to such treatments for all transmitting utilities applying to participate in RTOs.

H.R. 2944: Negotiated Rates and Effective Competition. Sections (e) and (f), respectively, provides that the Commission "may permit" negotiated transmission rates (without regard to costs) between willing parties, and where the Commission finds effective competition, market-based transmission rates. These sections do not require the Commission to permit such rates, and in the case of market-based rates, would permit such

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Id.

329. *See also supra* Part 4.

330. 16 U.S.C. § 824a(a).

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cannot seriously be contended that the Constitution prevents state legislatures from giving specific instructions to their utility commissions. We have never doubted that state legislatures are competent bodies to set utility rates."[334]

The same reasoning applies, *a fortiori*, to Congress's authority over the Commission. Alternative legislative approaches within Congress' authority could include codifying Order No. 2000's incentive rate provisions or other standards clarifying the application of the just and reasonable standard to transmission rates. Congress could also enact procedural provisions to reduce the uncertainties related to voluntary filings. For example, the Commission could be required to issue declaratory orders advising prospective RTO applicants of whether their proposed innovative rate filings would be consistant with applicable standards.

CONCLUSION

This Article is intended to inform or, more likely, remind the reader that the constitutional and statutory requirements for ratemaking by the Commission remain constant, even if, as has been the case over the last decade, there is major change in the circumstances in which those requirements are applied. The fundamentals are clear. Rates must be sufficient to attract the capital necessary for the "proper discharge of public duties," but the time-honored just and reasonable standard is flexible. The Commission must permit rates that will enable the transmission provider to remain healthy enough to discharge its public duties, but it has ample discretion to employ any ratemaking method it chooses, even to permit "market-based rates," so long as it supports its choice by substantial evidence. Both the FPA and governing principles of administrative law repose significant authority with the Commission. In light of changes in the electric industry structure in recent years, and the growing consensus that the transmission investment gap threatens both reliability and competition, the Commission has recognized its ability to adopt new methods for judging rates. The Commission has even invited transmission providers to submit innovative rates. This situation presents a challenge for transmission providers, their advocates, and policymakers, specifically for Commissioners and Members of Congress. Practitioners should reexamine the contours of the Commission's constitutional and statutory mandate as outlined in cases that may be so familiar as to be overlooked. Closing the transmission investment gap should strengthen reliability of electric service, spur development of new technology to improve transmission operations, and permit more vigorous competition. To accomplish this goal through transmission rate policies will require rigorous discovery of the facts and a fresh application of the time-honored just and reasonable stan-

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must be just and reasonable and meet certain incremental cost requirements).

334 Duquesne Light Co. v. Barasch, 488 U.S. 299, 313 (1989) (rejecting petitioner's argument that legislative mandate of a "used and useful" standard in valuing utility property impermissibly interfered with the public utility commission's duty to balance consumer and investor interests)

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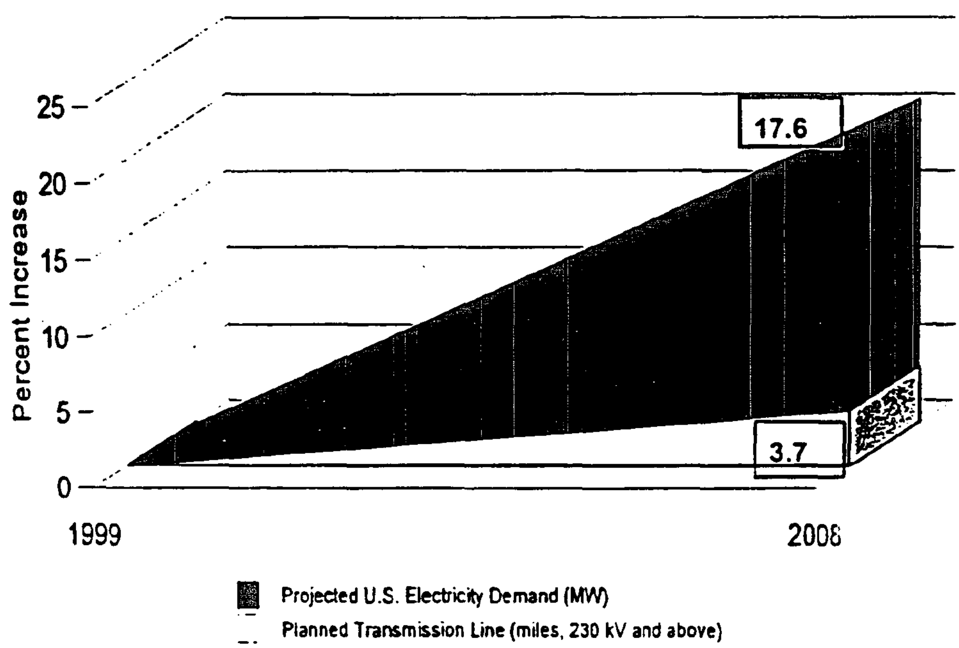
THE TRANSMISSION CAPACITY GAP:
COMPARISON OF PROJECTED INCREASES IN ELECTRIC DEMAND AND TRANSMISSION CAPACITY, 1999-2008
(Source: North American Reliability Council, Reliability Assessment 1999-2008)



Short Term

- Transmission congestion will worsen and as a result, transactions will continue to be curtailed until . . . appropriate congestion relief methods are implemented.
- As competitive electricity markets continue to develop, it is likely that the transmission system will be operated at levels of power flows and in configurations not previously experienced.

Long Term

- Unless proper incentives can be developed to encourage investment in new transmission facilities and siting problems can be resolved, few new transmission facilities and reinforcements will be constructed.

(Source. North American Reliability Council. Reliability Assessment 2000-2009)

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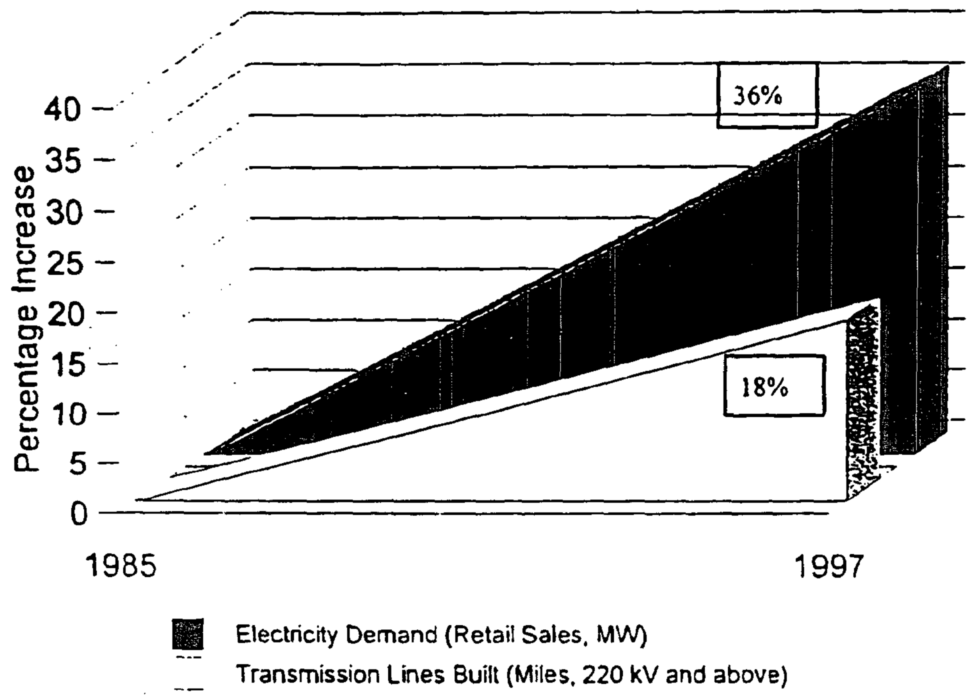
THE TRANSMISSION CAPACITY GAP:

COMPARISON OF PAST INCREASES IN ELECTRIC DEMAND AND TRANSMISSION CAPACITY, 1985-1997

(Source: Edison Electric Institute)



- While additions to transmission are anemic, new generation projects are being added seemingly every week.
  --Rick Stouffer, "'Puny' Additions to Transmission System Won't Cut It," *EnergyInsight*, November 17, 2000.

- Transmission investments (in constant, inflation adjusted dollars) have been declining for almost 25 years at an average rate of $115 million per year.
  --Eric Hirst, *Expanding U.S. Transmission Capacity* (2000)

- Between 1989 and 1998, transmission capacity normalized by summer peak demand declined in each of the ten reliability council regions.
  --Eric Hirst, *Expanding U.S. Transmission Capacity* (2000)

- Utility projections of future transmission-capacity additions show continued declines between 1998 and 2008.
  --Eric Hirst, *Expanding U.S. Transmission Capacity* (2000)

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Kelliher, Joseph

From: Angulo, Veronica
Sent: Thursday, March 22, 2001 3:50 PM
To: Kelliher, Joseph
Subject: DEM ENERGY PLAN SUMMARY

You may already have seen this:

FACTBOX: DEMOCRAT, REPUBLICAN ENERGY PLANS DETAILED

WASHINGTON, March 22 (Reuters) - Democratic lawmakers offered a broad energy plan on Thursday to encourage conservation and alternative energy sources.

The legislation follows a wide-ranging Republican bill in February that proposed to boost domestic oil and gas drilling by opening the Arctic National Wildlife Refuge.

President George W. Bush, a former Texas oilman, has endorsed drilling in the Arctic refuge and appointed a White House task force to make additional energy recommendations. That report is due in April.

The following outlines key points in the Democrats' and Republicans' energy bills:

DEMOCRAT BILL:

* Require Transportation Department to develop regulations to increase automobile fuel efficiency.
* Require states to review ways to increase oil and gas production on state and private lands.
* Offer tax credits for domestic drilling when the price of oil is "extremely low" to maintain stable supplies.
* Offer grants and tax incentives for new electric power lines and expansion of natural gas pipelines.
* Require the Minerals Management Service to proceed with an oil and gas lease sale in the deepwater area of the Gulf of Mexico.
* Offer financial incentives for smaller power generation facilities like fuel cells and renewable energy sources.
* Streamline pipeline and hydropower dam certification procedures.
* Offer incentives for consumers to replace old appliances with more efficient models.
* Require the Environmental Protection Agency to streamline gasoline specifications to ease distribution problems and reduce price spikes.

REPUBLICAN BILL

* Open 1.5 million acres of the Arctic National Wildlife Refuge in Alaska to oil and natural gas drilling, with 10-year leases granted to companies.
* Provide a break for big oil companies by reducing their cash royalty payments to the government when oil prices fall below $18 a barrel and natural gas prices drop below $2.30 per thousand cubic feet for 90 consecutive days.
* Provide a $3 per barrel tax credit to owners of wells producing less than 25 barrels per day when crude oil prices fall below $18 a barrel, for the first 1,095 barrels of oil equivalent produced.
* Provide a 50-cent tax credit on each 1,000 cubic feet of natural gas produced from low-volume wells when gas prices fall below $2.00 per thousand cubic feet.
* Reduce royalty payments to the government on oil and natural gas drilled in waters depth of more than 200 meters, when crude oil prices are below $28 per barrel and natural gas is below $3.50 per million Btus.
* Reduce time and cost of obtaining federal permits to build natural gas pipelines that cross state borders.
* Expand existing tax credits for electricity generated by renewable resources to include biomass, agricultural and animal waste, incremental hydropower, geothermal, landfill gas and steel co-generation.
* Offer tax credits of up to $100 million for clean coal technology to generate electricity with reduced air emissions. The technology would also exempt a qualifying system from any stricter emission control requirements for 10 years under the Clean Air Act.

* Offer consumer tax credits of $50 for an energy efficient refrigerator and $100 for a more efficient clothes washers.
Thursday, 22 March 2001 13:11:49
RTRS [nN22418199]

Department of Energy
Washington, DC 20585

March 16, 2001

NOTE FOR: JOE KELLIHER

FROM: LARRY PETTIS Larry Pettis
ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

Attached are two charts sent to Vice President's Task Force following Monday's briefing.

Attachments

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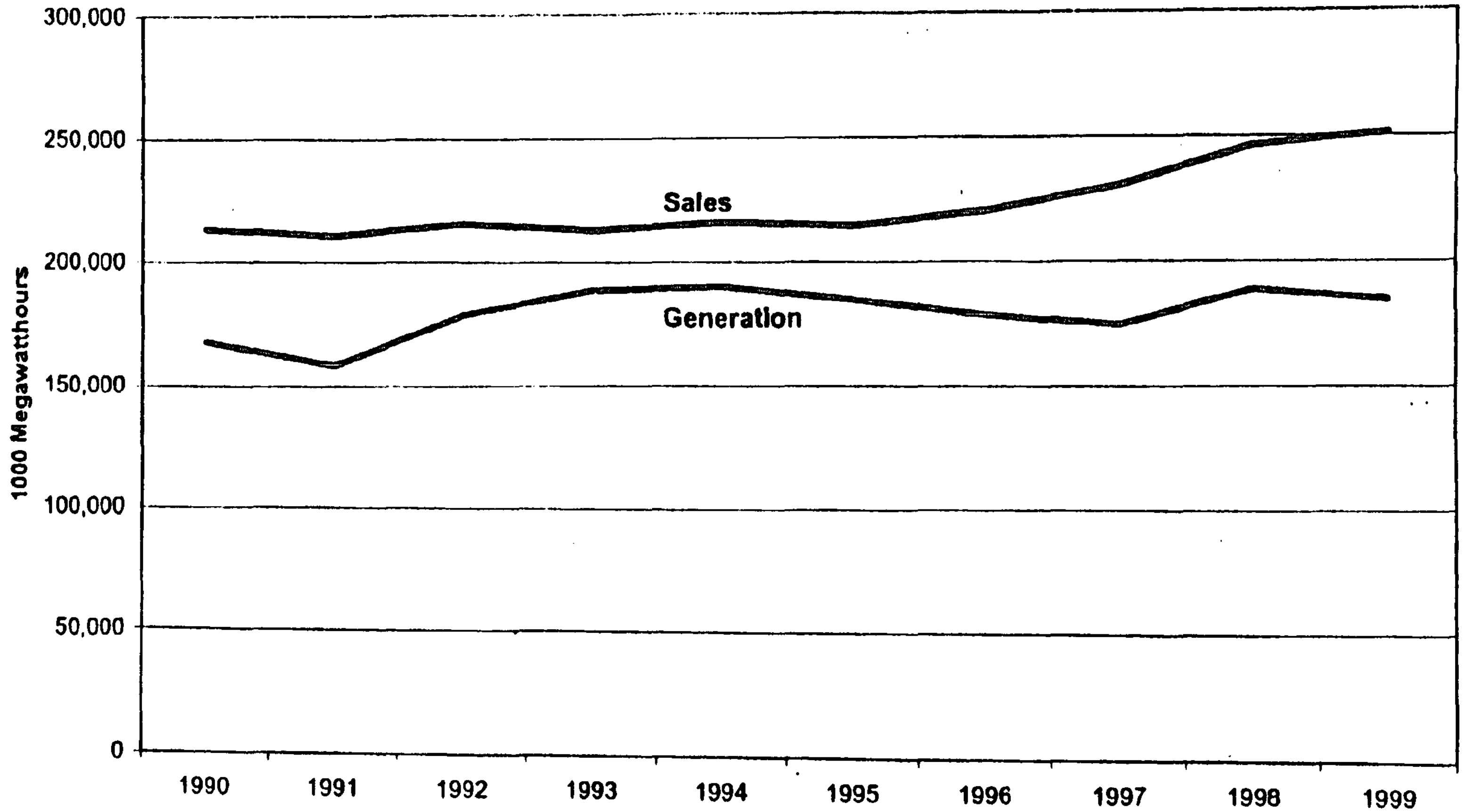
California In-State Sales and Generation



Sources: Energy Information Administration, Electric Power Annual, 1990-1999. 1990 nonutility generation not available so 1991 used as a proxy.

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California In-State Sales and Generation

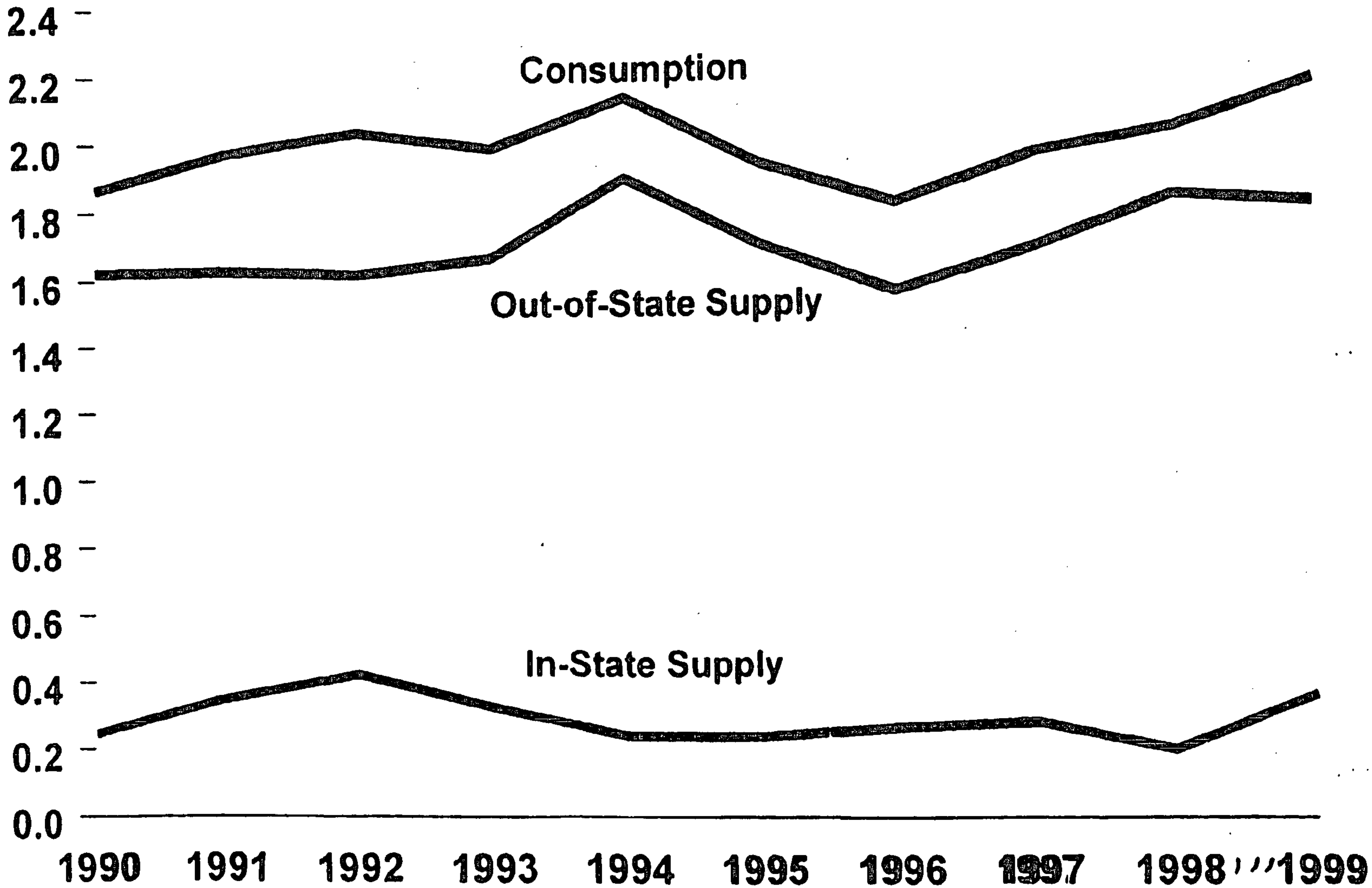
(Thousand Megawatthours)

	End-Use Sales			Generation			Ratio -In State Generation to Sales
	Utilities	Nonutilities	Total	Utilities	Nonutilities	Total	
1990	211,093	1,872	212,965	114,528	53,006	167,534	78.67%
1991	208,650	1,872	210,522	104,968	53,006	157,974	75.04%
1992	213,447	1,954	215,401	119,310	59,296	178,606	82.92%
1993	210,500	2,014	212,514	125,782	62,753	188,535	88.72%
1994	213,684	2,128	215,812	126,749	63,156	189,905	88.00%
1995	212,605	1,607	214,212	121,881	62,832	184,713	86.23%
1996	218,112	2,105	220,217	114,706	63,935	178,641	81.12%
1997	227,876	2,434	230,310	112,183	62,422	174,605	75.81%
1998	226,396	19,842	246,238	114,928	73,832	188,760	76.66%
1999	211,981	39,174	251,155	87,875	96,754	184,629	73.51%

Sources: Electric Power Annuals, 1990-1999, Form EIA-860b and predecessor form.

Notes: Nonutility generation and power marketer sales in California for 1990 was not published so 1991 value was used as proxy.
Nonutility end-use sales includes power markerter sales.
Power marketer data is only available for 1997 and later.

California Natural Gas Consumption and Supply
(trillion cubic feet)



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California Natural Gas Consumption and Supply
(trillion cubic feet)

	Consumption	Out-of-State Supply	In-State Supply
1990	1.86	1.62	0.24
1991	1.97	1.62	0.35
1992	2.03	1.61	0.42
1993	1.98	1.65	0.32
1994	2.12	1.89	0.24
1995	1.93	1.69	0.23
1996	1.81	1.55	0.26
1997	1.95	1.67	0.28
1998	2.01	1.82	0.20
1999	2.15	1.79	0.35

ACEEE
Feb. 2001

Energy Efficiency Policy Recommendations for the New Administration and Congress

February, 2001

There are a variety of energy challenges confronting the United States at this time. First, electricity reliability problems and price surges have become a major crisis in California and are threatening to reach the crisis level in other regions of the country. Second, natural gas prices have increased by 100% or more in many parts of the country, causing skyrocketing home energy bills this winter. And high natural gas prices are expected to continue due to tight supplies and growing demand. Third, our reliance on imported oil has grown due to a combination of declining domestic oil supply and growing demand linked to the lack of fuel efficiency improvement in motor vehicles.

These interrelated challenges have increased public concern and propelled energy policy back to the "front burner" among national policy issues. The Bush Administration has established a new Energy Policy Task Force and various members of Congress are developing energy legislation. Prospects for adopting comprehensive new energy legislation are better today than they have been for the past decade.

New energy legislation is likely include sections aimed at expanding domestic energy supply as well as restraining growth in energy demand. It is critical that this legislation include a strong set of initiatives to increase the efficiency of energy use. Increasing energy efficiency should be the cornerstone of national energy policy since it provides a host of economic, environmental, and national security benefits. In particular, increasing energy efficiency will:

- reduce energy waste and increase productivity, without forcing consumers or businesses to cut back on energy services or amenities;
- save consumers and businesses money since the energy savings more than pay for any increase in first cost;
- reduce the risk of energy shortages and improve the reliability of overtaxed electric systems;
- reduce energy imports;
- reduce air pollution of all types since burning fossil fuels is the main source of most types of air pollution;
- lower U.S. greenhouse gas emissions and thereby help to slow the rate of global warming.

Furthermore, increasing energy efficiency does not present a trade-off between enhancing national security and reliability on the one hand and protecting the environment on the other, as do a number of our energy supply options (e.g., opening up the Arctic National

Wildlife Refuge and other environmentally sensitive areas to oil exploration). Increasing energy efficiency is a "win-win" strategy from the perspective of economic growth, national security and reliability, and environmental protection.

This set of energy efficiency policy recommendations will increase the efficiency of energy use in our homes, commercial buildings, factories, and vehicles. It will lead to significant reductions in future demand for electricity, oil, natural gas, and coal. It does not entirely solve our nation's energy problems–other policies to increase the energy supplies, especially cleaner energy supplies, also are needed. But adopting these policies will significantly reduce energy demand growth over the next 20 years, thereby reducing the problems and need for other policies that are not "win-win" options; i.e., that involve trade-offs between greater domestic production and security, economic well-being, and environmental protection.

The policy recommendations are listed below. They involve a wide range of mechanisms including financial incentives, financing, voluntary initiatives, stronger efficiency standards, expanded R&D, and better information and education. No one approach is adequate for transforming markets and increasing the efficiency of energy use on a large scale throughout the economy. For each recommendation, we present background, the specific proposal, precedents, and estimated impacts.[1]

List of Recommendations

1. Public Benefit Trust Fund
2. Voluntary Agreements and Incentives to Reduce Industrial Energy Use
3. Tougher Fuel Economy Standards on New Cars and Light Trucks
4. Tax Credits of Fuel Cell and Hybrid Electric Vehicles
5. Expand Gas Guzzler Tax and Rebates for Efficient Vehicles
6. Improved Vehicle Labeling
7. New Appliance Efficiency Standards
8. Tax Credits for Efficient Appliances, Heating, and Air Conditioning Equipment
9. Expand Labeling and Promotion of Energy-Efficient Products
10. Financing and Technical Assistance for Efficiency Investments in Public Buildings
11. Expand Use of Combined Heat and Power through Environmental Permitting Reform
12. Expand Use of Combined Heat and Power through Enhanced Utility Grid Access

[1] For estimates of the overall impacts that these policies could have if adopted together, see Geller, Bernow and Dougherty 1999; Interlaboratory Working Group 2000.

Policy: Raise the Corporate Average Fuel Economy (CAFÉ) Standards for cars and light trucks

Background

The average fuel economy of new passenger vehicles (cars and light trucks) has declined from a high of 25.9 miles per gallon (mpg) in 1988 to 23.8 mpg in 1999 due to increasing vehicle size and power, the rising market share of light trucks, and the lack of tougher Corporate Average Fuel Economy (CAFE) standards. The original CAFE standards for cars were adopted in 1975 and reached their maximum level in 1985. The standard for light trucks was increased via rulemaking just 0.2 mpg since 1987. For the past five years, the Congress has prevented the Department of Transportation from carrying out a rulemaking to consider raising the CAFÉ standards.

Proposal

We propose increasing the CAFE standards for cars and light trucks 5% per year so that they reach 45 mpg for cars and 34 mpg for light trucks by 2010, with further improvements beyond 2010 (i.e., standards of 65 mpg for cars and 48 mpg for light trucks by 2020). Alternatively, the separate standards for cars and light trucks could be combined into one value for all new passenger vehicles, specifically 39 mpg by 2010 and 55 mpg by 2020 for all new cars and light trucks combined. This level of fuel economy improvement is technically feasible and cost effective for consumers according to studies conducted by ACEEE and the Union of Concerned Scientists. The 5% annual fuel economy improvement is the rate of improvement that Ford has indicated it will achieve voluntarily for its SUVs over the next five years. If this rate can be achieved in SUVs, it can be achieved in all new vehicles made by Ford as well as other manufacturers, and the rate of improvement can continue for ten years or more.

Tougher CAFE standards can be met through technological improvements, both refinements to conventional vehicle designs in the near term and advanced vehicle technologies (lightweight materials, hybrid drivetrains, and fuel cells) over time. Two mass-produced hybrid electric vehicles with 50-75 percent greater fuel efficiency compared to typical new cars in their size class were introduced in the United States in 2000 and other hybrid electric vehicles have been announced. ACEEE and UCS estimate that the 2010 fuel efficiency target can be met with an average incremental vehicle cost of $830 and the 2020 target at an average incremental cost of $1,755 (retail cost expressed in 1996 dollars).

Precedents

The initial CAFE standards enacted in 1975 were largely responsible for the near doubling in the average fuel economy of cars and more than 50 percent increase in light truck fuel economy from 1975 to 1987. The standards were met largely through cost-effective technologies (e.g., weight reduction, engine efficiency improvement, etc.) and without negative side effects. Cars got both safer and less polluting at the same time they became more fuel efficient. In fact the traffic fatality rate (deaths per million vehicle miles of travel) declined by

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about 50% between 1975 and 1997. The Department of Transportation has the authority to raise the standards via a rulemaking; however the Department has been prohibited from doing so by the Congress via riders attached to annual Appropriations bills in spite of overwhelming public support in favor of raising the standards.

Impacts

The CAFE standards proposed here could result in about 4 quads of energy savings by 2010 and 8 quads by 2020, relative to modest improvements in new vehicle fuel efficiency in the absence of the policies. These savings are equivalent to about 1.9 million barrels of petroleum per day by 2010 and 3.8 million barrels per day by 2020. The avoided carbon emissions would reach about 82 million metric tons of carbon equivalent by 2010 and 164 million metric tons by 2020.

In order to realize these energy and carbon savings, a cumulative investment of about $115 billion in vehicle efficiency measures is needed through 2020. But the energy bill savings over the same time period would reach about $500 billion, leading to net economic benefits of about $385 billion (all values in discounted 1996 dollars).

documents

Energy Efficiency Policy Recommendations for the New Administration and Congress

American Council for an Energy-Efficient Economy
February, 2001

There are a variety of energy challenges confronting the United States at this time. First, electricity reliability problems and price surges have become a major crisis in California and are threatening to reach the crisis level in other regions of the country. Second, natural gas prices have increased by 100% or more in many parts of the country, causing skyrocketing home energy bills this winter. And high natural gas prices are expected to continue due to tight supplies and growing demand. Third, our reliance on imported oil has grown due to a combination of declining domestic oil supply and growing demand linked to the lack of fuel efficiency improvement in motor vehicles.

These interrelated challenges have increased public concern and propelled energy policy back to the "front burner" among national policy issues. The Bush Administration has established a new Energy Policy Task Force and various members of Congress are developing energy legislation. Prospects for adopting comprehensive new energy legislation are better today than they have been for the past decade.

New energy legislation is likely include sections aimed at expanding domestic energy supply as well as restraining growth in energy demand. It is critical that this legislation include a strong set of initiatives to increase the efficiency of energy use. Increasing energy efficiency should be the cornerstone of national energy policy since it provides a host of economic, environmental, and national security benefits. In particular, increasing energy efficiency will:

- reduce energy waste and increase productivity, without forcing consumers or businesses to cut back on energy services or amenities;
- save consumers and businesses money since the energy savings more than pay for any increase in first cost;
- reduce the risk of energy shortages and improve the reliability of overtaxed electric systems;
- reduce energy imports;
- reduce air pollution of all types since burning fossil fuels is the main source of most types of air pollution;
- lower U.S. greenhouse gas emissions and thereby help to slow the rate of global warming.

Furthermore, increasing energy efficiency does not present a trade-off between enhancing national security and reliability on the one hand and protecting the environment on the other, as do a number of our energy supply options (e.g., opening up the Arctic National Wildlife Refuge and other environmentally sensitive areas to oil exploration). Increasing energy efficiency is a "win-win" strategy from the perspective of economic growth, national security and reliability, and environmental protection.

This set of energy efficiency policy recommendations will increase the efficiency of energy use in our homes, commercial buildings, factories, and vehicles. It will lead to significant reductions in future demand for electricity, oil, natural gas, and coal. It does not entirely solve our nation's energy problems–other policies to increase the energy supplies, especially cleaner energy supplies, also are needed. But adopting these policies will significantly reduce energy demand growth over the next 20 years, thereby reducing the problems and need for other policies that are not "win-win" options; i.e., that involve trade-offs between greater domestic production and security, economic well-being, and environmental protection.

The policy recommendations are listed below. They involve a wide range of mechanisms including financial incentives, financing, voluntary initiatives, stronger efficiency standards, expanded R&D, and better information and education. No one approach is adequate for transforming markets and increasing the efficiency of energy use on a large scale throughout the economy. For each recommendation, we present background, the specific proposal, precedents, and estimated impacts.[1]

List of Recommendations

1. Public Benefit Trust Fund
2. Voluntary Agreements and Incentives to Reduce Industrial Energy Use
3. Tougher Fuel Economy Standards on New Cars and Light Trucks
4. Tax Credits of Fuel Cell and Hybrid Electric Vehicles
5. Expand Gas Guzzler Tax and Rebates for Efficient Vehicles
6. Improved Vehicle Labeling
7. New Appliance Efficiency Standards
8. Tax Credits for Efficient Appliances, Heating, and Air Conditioning Equipment
9. Expand Labeling and Promotion of Energy-Efficient Products
10. Financing and Technical Assistance for Efficiency Investments in Public Buildings
11. Expand Use of Combined Heat and Power through Environmental Permitting Reform
12. Expand Use of Combined Heat and Power through Enhanced Utility Grid Access

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[1] For estimates of the overall impacts that these policies could have if adopted together, see Geller, Bernow and Dougherty 1999; Interlaboratory Working Group 2000.

Policy: Public Benefit Trust Fund as Part of Electric Utility Restructuring

Background

Electric utilities historically have funded programs to encourage more efficient energy use, assist low-income families with home weatherization and energy bill payment, promote the development of renewable energy sources, and undertake research and development. However, increasing competition and restructuring have led to a decline in these "public benefit expenditures" over the past five years. Total utility spending on all demand side management programs (i.e., energy efficiency and peak load reduction) fell by nearly 50% from a high of $3.0 billion in 1993 to $1.6 billion in 1998 (1998 dollars).

Proposal

In order to ensure that public benefits activities continue following restructuring, 15 states have established public benefits funds through a small charge on all kilowatt-hours (kWhs) flowing through the transmission and distribution grid. This policy would create a national public benefits trust fund, similar in concept to the public benefits fund included in the Clinton Administration's federal utility restructuring proposal. The federal trust fund would provide matching funds to states for eligible public benefits expenditures. This policy would encourage states and utilities to continue or in some cases expand energy efficiency and other public benefits activities. The size of the public benefits trust fund we recommend is based on a non-bypassable wires charge of two-tenths of a cent per kWh.

Once a public benefits fund is adopted, utilities, state agencies, or some other state-designated "fund manager" would carry out energy efficiency programs. In a more competitive, "restructured" utility market, these programs typically focus on assisting consumers unlikely to receive energy efficiency services by the private sector (i.e., low-income households or small businesses), expanding the private energy services industry, and encouraging market transformation. The programs lead to efficiency improvements in appliances, lighting, HVAC systems, motor systems, etc.—areas where there is still enormous cost-effective energy efficiency potential.

Precedents

As noted above, 15 states including California, New York, New Jersey, Wisconsin, and various New England states already have enacted state public benefit funds to support energy efficiency and other programs. The Clinton Administration has proposed a nation public benefits trust fund based on a charge of one-tenth of a cent per kWh, half the level proposed here. Our recommendation is included in utility restructuring bills sponsored by Senator Jeffords' (S. 1369) and Rep. Pallone's (H.R. 2569).

Impacts

Our analysis estimates the incremental investment in and savings from energy efficiency measures as a result of the federal public benefits trust fund. We do not include savings from public benefit programs already underway or likely to occur in the absence of a federal fund. In particular, we assume that states gradually expand their eligible programs, using 90 percent of the maximum funds available by 2005 and thereafter. Based on historical trends, we assume that energy efficiency programs represent 59 percent of the public benefits expenditures and that energy savings typically cost $0.03/kWh on a levelized basis. We also assume that 20 percent of all participants are "free riders" (i.e., consumers who would invest in efficiency measures in the absence of state/utility programs).

These assumptions result in incremental end-use electricity savings of 131 TWh (3.6%) in 2005, 343 TWh (8.8%) in 2010, and 756 TWh (17.4%) in 2020, according to the ACEEE. Most of these savings are likely to be in the residential and commercial sectors since they are the main focus of state/utility efficiency programs using public benefits funds. The total investment in efficiency measures stimulated by the federal public benefits fund is estimated to be $106 billion while the energy bill savings are expected to reach $238 billion. (net present value through 2020), meaning net benefits of $132 billion. Furthermore, ACEEE estimates that this policy will reduce CO2 emissions by 103 MMT of carbon by 2010 and 207 MMT by 2020, when implemented together with other energy efficiency and renewable energy initiatives.

Background

The industrial sector accounts for about 39 percent of total U.S. energy consumption. Manufacturing represents about two-thirds of industrial energy use, with six energy-intensive sectors dominating (petroleum refining, chemicals, primary metals, paper and pulp, food and kindred products, and stone, clay, and glass products). There is substantial potential for cost-effective efficiency improvement in both energy-intensive and non-energy-intensive industries. For example, an in-depth analysis of 49 specific energy efficiency technologies for the iron and steel industry found a total cost-effective energy savings potential of 18 percent.

Proposal

In order to stimulate widespread energy efficiency improvements in the industrial sector, we propose that U.S. government (White House or DOE) establish voluntary agreements with individual companies or entire sectors. Companies or entire sectors would pledge to reduce their overall energy and carbon emissions intensities (energy and carbon per unit of output) by a significant amount, say at least 15-20 percent over 10 years. The government would encourage participation and support implementation by: (1) providing technical and financial assistance to participating companies that request assistance, (2) offering to postpone consideration of more drastic regulatory or tax measures if a large portion of industries participate and achieve their goals, and (3) expanding federal R&D and demonstration programs.

In order to get a large fraction of industries making serious commitments and entering into voluntary agreements with the federal government, it may be necessary for the government to threaten to take more drastic action. For example, the government could indicate that is was going to issue carbon emissions standards or energy efficiency standards on major types of industrial processes (e.g., steelmaking, aluminum production, paper and pulp making, petroleum refining, etc.), or adopt energy or carbon taxes, if industries did not enter into meaningful voluntary agreements.

Precedents

A number of major companies are demonstrating that it is possible to significantly reduce energy and carbon intensity while enhancing productivity and profitability, and have set voluntary goals for doing so. For example, Johnson and Johnson set a goal in 1995 of reducing energy costs 10 percent by 2000 through adoption of "best practices" in its 96 U.S. facilities. As of April 1999, they were 95 percent of the way towards this goal, with the vast majority of projects providing a payback of three years or less. In 1998, British Petroleum announced it would voluntarily reduce its carbon emissions to 10 percent below 1990 levels by 2010, representing an almost 40 percent reduction from projected emissions levels in 2010 given "business-as-usual" emissions growth. And DuPont announced it would reduce its GHG emissions worldwide by 65 percent relative to 1990 levels while holding total energy use flat and increasing renewable energy resources to 10 percent of total energy inputs by 2010. DuPont is on track for achieving earlier commitments to reduce energy intensity 15 percent and total GHG emissions 50 percent by 2000, relative to 1990 levels. If J&J, BP, and DuPont can make and deliver on these voluntary commitments, so can other companies.

Voluntary agreements between government and industry along the lines proposed here have resulted in substantial energy intensity reductions in some European nations such as Germany, the Netherlands, and Denmark. Voluntary agreements between government and industry have been used on a limited basis to achieve energy or environmental gains in the United States. For example, ...

Impacts

In order to estimate the impacts of this policy, we rely on a recent, detailed analysis of voluntary agreements carried out by a team from national laboratories. Based on this analysis, we estimate that widespread adoption of voluntary agreements and supporting activities could reduce primary energy use in the industrial sector by about 4.2 quads (11 percent) in 2010 and 6.9 quads (16 percent in 2020), relative to energy consumption levels otherwise forecast by the Energy Information Administration. About 40 percent of this savings comes from electricity (measured on a primary energy basis), with smaller portions coming from petroleum products, natural gas, and coal. The corresponding reductions in CO2 emissions are 71 million metric tons of carbon by 2010 and 95 million metric tons by 2020.

In order to realize these energy savings, a cumulative investment in efficiency measures of about $36 billion through 2020 is needed. But the energy bill savings would equal around $98 billion, leading to net economic benefits of about $60 billion (all values are in discounted 1996 dollars).

Policy: Raise the Corporate Average Fuel Economy (CAFÉ) Standards for cars and light trucks

Background

The average fuel economy of new passenger vehicles (cars and light trucks) has declined from a high of 25.9 miles per gallon (mpg) in 1988 to 23.8 mpg in 1999 due to increasing vehicle size and power, the rising market share of light trucks, and the lack of tougher Corporate Average Fuel Economy (CAFE) standards. The original CAFE standards for cars were adopted in 1975 and reached their maximum level in 1985. The standard for light trucks was increased via rulemaking just 0.2 mpg since 1987. For the past five years, the Congress has prevented the Department of Transportation from carrying out a rulemaking to consider raising the CAFÉ standards.

Proposal

We propose increasing the CAFE standards for cars and light trucks 5% per year so that they reach 45 mpg for cars and 34 mpg for light trucks by 2010, with further improvements beyond 2010 (i.e., standards of 65 mpg for cars and 48 mpg for light trucks by 2020). Alternatively, the separate standards for cars and light trucks could be combined into one value for all new passenger vehicles, specifically 39 mpg by 2010 and 55 mpg by 2020 for all new cars and light trucks combined. This level of fuel economy improvement is technically feasible and cost effective for consumers according to studies conducted by ACEEE and the Union of Concerned Scientists. The 5% annual fuel economy improvement is the rate of improvement that Ford has indicated it will achieve voluntarily for its SUVs over the next five years. If this rate can be achieved in SUVs, it can be achieved in all new vehicles made by Ford as well as other manufacturers, and the rate of improvement can continue for ten years or more.

Tougher CAFE standards can be met through technological improvements, both refinements to conventional vehicle designs in the near term and advanced vehicle technologies (lightweight materials, hybrid drivetrains, and fuel cells) over time. Two mass-produced hybrid electric vehicles with 50-75 percent greater fuel efficiency compared to typical new cars in their size class were introduced in the United States in 2000 and other hybrid electric vehicles have been announced. ACEEE and UCS estimate that the 2010 fuel efficiency target can be met with an average incremental vehicle cost of $830 and the 2020 target at an average incremental cost of $1,755 (retail cost expressed in 1996 dollars).

Precedents

The initial CAFE standards enacted in 1975 were largely responsible for the near doubling in the average fuel economy of cars and more than 50 percent increase in light truck fuel economy from 1975 to 1987. The standards were met largely through cost-effective technologies (e.g., weight reduction, engine efficiency improvement, etc.) and without negative side effects. Cars got both safer and less polluting at the same time they became more fuel efficient. In fact the traffic fatality rate (deaths per million vehicle miles of travel) declined by about 50% between 1975 and 1997. The Department of Transportation has the authority to raise the standards via a rulemaking; however the Department has been prohibited from doing so by the Congress via riders attached to annual Appropriations bills in spite of overwhelming public support in favor of raising the standards.

Impacts

The CAFE standards proposed here could result in about 4 quads of energy savings by 2010 and 8 quads by 2020, relative to modest improvements in new vehicle fuel efficiency in the absence of the policies. These savings are equivalent to about 1.9 million barrels of petroleum per day by 2010 and 3.8 million barrels per day by 2020. The avoided carbon emissions would reach about 82 million metric tons of carbon equivalent by 2010 and 164 million metric tons by 2020.

In order to realize these energy and carbon savings, a cumulative investment of about $115 billion in vehicle efficiency measures is needed through 2020. But the energy bill savings over the same time period would reach about $500 billion, leading to net economic benefits of about $385 billion (all values in discounted 1996 dollars).

Proposal: Provide tax credits to purchasers of highly fuel efficient vehicles

Background

Although the average fuel economy of new cars and light trucks is not rising, a great amount of R&D and demonstration of innovative vehicle fuel efficiency measures has occurred over the past decade as part of the Partnership for New Generation Vehicles (PNGV) and other programs. Vehicle manufacturers are starting to commercialize fuel-efficient hybrid electric vehicles such as the Honda Insight and Toyota Prius, which achieve 50–85% greater fuel economy than equivalent conventional vehicles. These cars employ a variety of technologies including innovative engine designs, weight reduction, and the hybrid electric powertrain to reach these impressive fuel economy levels. Other manufacturers plan to introduce hybrid electric vehicles in the next few years.

Some vehicle manufacturers also have indicated that they will start mass producing fuel cell electric vehicles starting around 2005. A limited number of fuel cell electric buses have already been produced and field tested. Fuel cell electric vehicles have the potential for even greater fuel economy and lower emissions than vehicles employing an internal combustion engine, as do the current set of commercially available and prototype hybrid vehicles.

Cost is a major obstacle to the widespread production and sale of highly efficient hybrid and fuel cell vehicles. Honda and Toyota are absorbing a substantial portion of the cost for their initial hybrid vehicles (i.e., selling them at a loss). While costs are expected to decline over time as technology advances and economies of scale occur, it is unclear how fast this "learning" will occur and whether or not hybrid and fuel cell vehicles will reach cost competitiveness and widespread market shares without significant public support. Given the enormous public benefits–lower oil consumption, lower criteria pollutant emissions, and lower greenhouse gas emissions–that such vehicles promise, it is reasonable for the government to provide financial incentives initially in order to stimulate mass production and support initial sales of these innovative vehicles.

Proposal

The Clinton Administration and U.S. auto manufacturers have proposes extending the current tax credit of up to $4,000 for electric and fuel cell vehicles and also offering a tax credit of up to $3,000 for qualifying hybrid electric vehicles. Under this proposal, the amount of the hybrid vehicle credit would be based on the capacity of the energy storage system and amount of regenerative breaking. Also, the hybrid vehicle credit would not start until 2003 even though some hybrid vehicles already are mass produced and sold.

We propose extending the current tax credit for electric and fuel cell vehicles through 2008 but suggest fixing the credit at a flat $4,000 per vehicle. This change would give manufacturers further incentive to reduce the cost of and price of electric and fuel cell vehicles. Regarding hybrid vehicles, we propose offering tax credits tied to fuel efficiency and emissions levels, similar to the scheme proposed by the Clinton Administration in 1999. However, the credits should start in 2001; they should be extended to all high efficiency vehicles—not just hybrid vehicles– that are at least 50% more efficient than typical new vehicles in any particular class; the credits should end or should phase down by 2006 or so; and they should be given only to vehicles meeting forward-looking emissions standards such as the California ULEV or SULEV standards. Also, tax credits should be extended to purchasers (or manufacturers) of hybrid and fuel cell buses or medium-duty trucks. Such provisions would reward fuel efficiency innovation of all types and ensure significant energy and environmental benefits.

Precedents

Extending the tax credits for electric and fuel cell vehicles is supported by the Clinton Administration and is included in a number of bills introduced in the 106th Congress with bipartisan sponsorship. Tax credits for hybrid vehicles also are supported by the Clinton Administration and are included in a number of bills introduced in the 106th Congress. However, as noted above, these bills do not include all of the features suggested above.

Impacts

It is reasonable to assume that on the order of 0.5-1.0 million electric and fuel cell vehicles and 1.0-1.5 million hybrid electric (or equivalent high fuel efficiency) vehicles would qualify for the tax credits suggested above, assuming the former run through 2008 and the latter through 2006. Roughly speaking, these are the number of qualifying vehicles assumed by the Clinton Administration in their estimates of costs and impacts from their tax credit proposals. Participation on this scale would have relatively modest direct impacts on energy use and CO2 emissions– energy savings of xxx and avoided carbon emissions of 1.5-2.5 million metric tons per year. However, if the credits are successful in helping to build markets and advance the technologies so that these innovative vehicles become competitive in the marketplace and markets continue to grow after the credits are phased out, the indirect impacts could be many times greater than the direct impacts; e.g., providing a total carbon emissions reduction of at least 10 million metric tons by 2015. On the other hand, if the tax credits are adopted in conjunction with stronger CAFE standards, then it is important not to double-count savings. Thus, the savings from the tax credits should be subsumed under those from the CAFE standards if both policies are adopted.

Proposal: Expand the Gas Guzzler Tax to Include Light Trucks and Provide Rebates to Purchasers of Efficient Vehicles

Background

The average fuel economy of new passenger vehicles is declining due to the growing market share of inefficient light trucks (SUVs, pickups, and minivans) and the lack of standards or financial incentives stimulating higher fuel economy in all new vehicles. Relatively inefficient cars–those with composite fuel economy rating below 22.5 MPG–are subject to a gas guzzler tax. The tax starts at $1,000 for vehicles 21.5-22.5 MPG and increases to a maximum of $7,700 as fuel economy drops. This policy, enacted in 1978, was relatively successful in "pulling up" the bottom end of the vehicle fleet. Relatively few new cars are subject to the gas guzzler tax today. However, millions of gas guzzling light trucks are sold today and used mainly as passenger vehicles. These vehicles are not subject to the gas guzzler tax, creating a loophole that encourages production and marketing of these inefficient and polluting vehicles. Furthermore, the revenue generated by the gas guzzler tax goes to the general Treasury rather than being used to stimulate greater production and purchase of efficient "gas sipping" vehicles.

Proposal

First, the gas guzzler tax loophole should be closed by having the current gas guzzler tax apply to all new passenger vehicles. If a consumer or business wants to by an inefficient vehicle, they should have to pay for the right to excessively pollute the atmosphere and increase U.S. dependence on oil imports. Given the sales and fuel economy of light-duty SUVs, pickup trucks, and minivans sold in 1999, automakers would have paid an additional $10.2 billion in gas guzzler taxes on their vehicles that year if this policy had been in place. Of course, the objective is to discourage sales of gas guzzlers and improve fuel economy, so that actual revenue collected after this policy is announced and takes affect could be significantly lower. But it is likely that the policy would generate billions of dollars in new tax revenue each year, at least initially.

In conjunction with closing the gas guzzler tax loophole and the revenues this would generate, we recommend providing tax credits to either manufacturers or consumers for vehicles that are "gas sippers"–significantly more efficient than the average fuel economy of all new vehicles. The combination of fees on gas guzzling vehicles and rebates or credits on gas sipping vehicles is sometimes referred to as "feebates". The credits could start at say 20% above the average fuel economy of new vehicles (i.e., now about 24 MPG based on the EPA composite rating) and could increase as the fuel economy rating increases, mirroring the way the gas guzzler tax is designed (e.g., $200 credit for vehicles 28.5-29.5 MPG, $400 credit for 29.5-30.5 MPG, etc.). Alternatively, the credits could normalized based on some measure of vehicle size (e.g., vehicles would need to be x% more efficient than the average for the vehicle class rather than the overall average for all new vehicles). In either case, a sliding scale should be used and the reference point should be adjusted as the overall fuel economy of new vehicles increases. Also, vehicles should be ineligible for tax credits via feebates if they receive separate tax credits offered to innovative hybrid and fuel cell vehicles.

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Precedents

Feebates have been proposed at both the federal and state level. In 1991, then Senator Gore proposed a bill (S. 210 in the 102nd Congress) that included fees and rebates based vehicle fuel economy in each size class. Other bills in this period (H.R. 1583 and H.R. 2960 in the 102nd Congress) proposed similar schemes. At the state level, the California legislature enacted feebates based on both fuel economy and criteria emissions in 1990, but then Goveror Deukmejian vetoed this bill. In 1992, Maryland enacted a modest feebate scheme as an add-on to the state's vehicle title tax. However, implementation was blocked by a Department of Transportation opinion stating that state fuel economy incentive programs are federally preempted.

Impacts

Estimates of the impacts of feebates by Lawrence Berkeley Laboratory show that relatively modest rebates of up to about $1,000 per vehicle could have a significant impact on the average fuel economy of the new vehicle fleet, leading to about a 10-20% improvement in rated fuel economy of new vehicles within 10 years. In the short run, consumers shift towards more fuel-efficient vehicles available in the marketplace. Over the longer run, the selection of vehicles being marketed changes as manufacturers respond by adding efficiency measures. Overall, fuel savings could reach 7-8 billion gallons of gasoline annually by 2010, equivalent to about 1.0 Quads of energy savings or about 23 million metric tons of avoided carbon emissions each year.

If feebates are adopted in conjunction with stronger CAFE standards, then it is important not to double-count savings. Thus, the savings from feebates should be subsumed under those from the CAFE standards if both policies are adopted and the standards are relatively stringent. Feebates and tougher fuel economy standards are complementary, with the incentives helping to move the market towards regulatory compliance.

Policy: Promotion of High Efficiency and Cleaner Vehicles through Improved Labeling and Promotion

Background

There is considerable variation in the fuel economy and emissions levels of new vehicles in any particular vehicle class (e.g., compact cars, minivans, large SUVs, etc.). This variation is in fact growing as manufacturers introduce relatively fuel-efficient and low-emitting hybrid vehicles like the Honda Insight, Toyota Prius, as well as conventional "ultra low emissions" vehicles. Some efforts are underway to better identify and promote these vehicles, including a DOE/EPA-sponsored web site and the ACEEE Green Book that provides overall environmental ratings of new cars and light trucks. However, more can and should be done to promote purchase of "best-in-class" and innovative vehicles.

Proposal

The federal government could take a number of actions to increase awareness of and interest in buying fuel-efficient and cleaner vehicles. These actions would be voluntary in the sense that they do not require consumers or businesses to participate. But they would complement other policies such as stronger CAFE standards, expansion of the gas guzzler tax, and tax credits to promote the commercialization and sales of hybrid, fuel cell, and other innovative highly efficient vehicles, as part of a comprehensive market transformation strategy.

First, we propose extending "Energy Star" labeling to high fuel efficiency and low-emitting cars and light trucks. This would make it easy for consumers to identify "greener vehicles", and would make it easy for fleet owners to commit to "buying green". We recommend that the Energy Star designation be based on a combination of fuel economy and tailpipe emissions, which is how the ACEEE environmental scoring is done, and would apply to the best vehicles in each vehicle category. The specifications for qualification should change over time as manufacturers introduce more efficient and cleaner vehicles. Manufacturers should be encouraged to display the Energy Star label on cars in showrooms (where applicable) and dealers trained to properly explain the label.

Second, owners of vehicle fleets, both public sector organizations and private companies, should be encouraged to commit to only buying Energy Star vehicles (or high efficiency and cleaner vehicles using some other means of identifying these vehicles). It might also be possible to organize fleet owners into "green vehicle buying cooperatives" with the cooperatives or the federal government negotiating discounts from vehicle manufacturers. The government could promote purchase commitments and buying cooperatives, along the lines of the promotion being carried out and product discounts being obtained for other Energy Star products.

Precedents

The Department of Energy and EPA have extended Energy Star labeling and promotion to a wide range of products, new homes, and commercial buildings. It would be logical to add cars and light trucks to this "green brand" program. The Energy Policy Act of 1992 includes fleet purchase targets and requirements for alternative fuel vehicles (AFVs). DOE initiated a "Clean Cities Program" to promote purchase of and build infrastructure and markets for AFVs at the local level. However, actual purchase of AFVs is well below Energy Policy Act targets due to limited vehicle availability, relatively high cost of these vehicles, and limited fueling infrastructure. Even if the AFV targets were met, there would still be significant potential for promoting commitments to buy highly efficient and low emitting gasoline-fueled vehicles on the part of public and private fleet owners. ACEEE estimates that the target fleet market (after deducting the EPAct AFV requirements) is over 1 million vehicles per year.

Impacts

ACEEE has estimated the potential energy savings and avoided carbon emissions from a "best-in-class" vehicle labeling and promotion program. Assuming a very strong program that affects 30% of fleet purchases and 15% of the general market, the estimated energy savings is about 0.4 quads (2.5% of passenger vehicle fuel use) by 2010, equivalent to 7 MMT of avoided carbon emissions that year. Of course, if the participation is lower, the energy savings and avoided carbon emissions would be reduced. It also should be recognized that if improved labeling and promotion are carried in combination with stronger CAFE standards, these savings should be subsumed under those from the CAFE standards.

Policy: New Appliance Efficiency Standards

Background

Appliance efficiency standards are one of our nation's most effective strategies for saving energy. Appliance standards pioneered by a few states in the 1970s and subsequently adopted at the national level in 1987 have already cut national electricity use by 3%–equivalent to the power supplied by 30 large power plants. This means less fuel is burned to make electricity and less pollution is generated.

National appliance efficiency standards have received bipartisan support. The standards legislation was signed into law in 1987 by President Reagan; new standards were issued during both the Bush and Clinton Administrations. Efficiency standards already adopted will cut U.S. greenhouse gas emissions by about xx million MMT of carbon equivalent by 2010, making this a key part of our national effort to limit global warming. On the economic side, consumers and businesses will save $xxx billion net from efficiency standards already adopted. But additional energy, carbon emissions, and dollar savings are achievable through upgraded or new standards on a wide range of products.

Proposal

First, we recommend that DOE uses its existing authority to upgrade appliance and equipment efficiency standards where technically and economically feasible. Although a new set of standards were issued in January, 2001, DOE is still many years behind schedule in reviewing and upgrading standards on other products. DOE should issue new standards on transformers, refrigerators and freezers, furnaces and boilers, commercial packaged air conditioning equipment, commercial boilers, and dishwashers. These standards should be set at the highest levels justified under the current law, and the standards should be issued without further delay.

Second, we urge that minimum efficiency standards be set, either via rulemaking or new legislation, on a variety of products that DOE is not currently considering standards for. DOE has the authority, but has never used it, to extend standards to additional types of products where standards would be technically and economically feasible and would save a significant amount of energy. In particular, we urge extending standards to TVs, light fixtures, commercial refrigeration equipment, commercial clothes washers, and furnace fan motors.

Precedents

National appliance efficiency standards on products such as refrigerators, clothes washers, water heaters, and air conditioners have been upgraded previously. Appliance and equipment efficiency standards were extended to additional products including motors, various types of lamps, and heating and air conditioning equipment used in commercial buildings as part of the Energy Policy Act of 1992. Efficiency standards on TVs and standby power consumption for some products have been enacted in Japan.

Impacts

Adopting stringent new appliance standards could result in widespread implementation of innovative energy efficiency technologies such as condensing-type gas furnaces and low-loss transformers. Regarding light fixtures, standards could lead to replacement of inefficient and dangerous halogen torchiere lamps with fluorescent-based torchieres. And standards on furnace fan motors could make variable speed motors the norm.

According to ACEEE, new appliance efficiency standards (not covering standards already issued in 2001 or earlier) could save about 50 TWh of electricity and 0.12 quads of natural gas (end-use only) by 2010. By 2020, the savings could grow to 105 TWh and 0.25 quads of natural gas as the appliance stock continues to turn over. Avoided CO2 emissions would reach about 13 MMT of carbon equivalent in 2010 and 22 MMT in 2020. Households and businesses would realize tens of billions of dollars of savings since the energy bill reductions would significantly exceed any increase in purchase cost. Businesses purchasing more efficient transformers and commercial HVAC equipment, for example, would realize cumulative net savings of about $8 billion through 2020.

Proposal: Provide tax credits to purchasers or manufacturers of highly fuel efficient appliances, heating, and air conditioning equipment

Background

There are a host of innovative technologies that could significantly reduce the energy use and thus the pollutant emissions associated with heating, cooling, and appliances used in both residential and commercial buildings. For example, electric heat pump water heaters cut electricity consumption for water heating by 50–70% compared to conventional electric water heaters. Gas-fired heat pumps are about twice as efficient for heating as typical new gas furnaces and also provide space cooling using natural gas as the energy input. Super-efficient electric air conditioners, refrigerators, and clothes washers use 25-50% less energy than typical new models sold today. Fuel cell cogeneration systems offer the potential to power and heat homes or commercial buildings very cleanly and at high overall efficiency. However, none of these technologies are produced yet on a large scale. High first cost is a major barrier preventing more widespread production, marketing, and sale. Without financial incentives, they may never overcome the "initial high cost" barrier and get established in the marketplace.

Given the potential public benefits–lower energy consumption, increased electric grid reliability, lower criteria pollutant emissions, and lower greenhouse gas emissions–that such technologies promise, it is reasonable for the federal government to provide financial incentives in order to stimulate mass production and support initial sales of these innovative technologies. The incentives should be of limited duration and possibly phase down over time so that the cost to the government is limited and the technologies eventually compete (or not compete) without subsidies.

Proposal

We propose providing tax credits to either manufacturers or purchasers of highly efficient building equipment, focusing on innovative "leapfrog" technologies such as those mentioned above. This would minimize the number of "free riders" and provide the biggest "bang per buck" in terms of market transformation. Specifically, we propose tax incentives that are either fixed in value or calculated as a fraction of the first cost (with a cap on the value) for the following products:

- electric heat pump water heaters
- gas-fired heat pumps
- electric air conditioners and heat pumps with SEER > 13.5
- building fuel cell cogeneration systems
- superefficient refrigerators and clothes washers
- highly efficient ground-source heat pumps.

The tax credits should be on the order of 20% of the first cost for the most efficient products, with a sliding scale or lower tier(s) for less efficient but still innovative products. This approach has been followed in the climate technology tax credit proposals put forward by the

Clinton Administration. The tax credits should remain in effect for around 5 years, say 2001-2005, and could ramp down in magnitude in the final year or two.

Precedents

In 1999 and/or 2000, the Clinton Administration proposed tax credits for heat pump water heaters, gas-fired heat pumps, fuel cell cogeneration systems, and high efficiency central air conditioners and electric heat pumps. These proposals, or components of them, were incorporated in a number of bills introduced in the 106th Congress. Also, energy efficiency advocates and appliance manufacturers strongly supported tax credits for super-efficient appliances. Their proposal, involving credits for appliance manufacturers with a cap on the amount any one company could claim, was introduced in the 106th Congress with broad bipartisan support.

Impacts

It is likely that there would be millions of qualifying products sold during the 2001-2005 time period. The total cost to the Treasury might reach on the order of $1.5-2.0 billion, with high efficiency central air conditioners likely being the most costly component of the package. Sales of fuel cell cogeneration systems might reach 200-500 MW of total installed electric capacity, with this product costing the Treasury $80-200 million.

Participation on this scale would have a relatively modest direct impact on energy use and CO_2 emissions–saving on the order of 0.05 quads of primary energy and 1.0-1.5 million metric tons of carbon emissions per year by the end of the eligibility period. However, if the credits help to establish these innovative products in the marketplace and reduce the first cost premium so that the products are viable after the credits are phased out, the indirect impacts could be many times greater than the direct impacts. Total energy savings could reach 0.25-0.5 quads and avoided carbon emissions could reach 5-10 million metric tons by 2015 if the credits are successful.

Policy: Expand Energy-Efficient Product Labeling and Promotion

Background

The Energy Star labeling program implemented by EPA and the Department of Energy covers a wide range of residential and commercial products including appliances, heating and cooling systems, office equipment, and lighting products. The Energy Star program stimulated the wide use of power management in personal computers, photocopiers, printers, and facsimile machines. Power management can reduce the energy use of office equipment by up to 50%. Around 80% of new personal computers, 95% of monitors, 99% of printers, and 65% of copiers now have power management features and thus the Energy Star label. In total, consumers bought more than 100 million Energy Star products in 1999. As a result of cumulative purchases, consumers are saving more than 29 billion kWh per year–worth about $2.3 billion annually. And recognition of the Energy Star label–the national symbol for energy efficiency–is rapidly growing.

Proposal

EPA and DOE should expand the scope and level of promotion associated with the Energy Star program. Energy Star labeling should be extended to additional types of electronic products (cable boxes, telephone equipment, battery chargers, etc.), commercial refrigeration equipment (vending machines, freezer cases, etc.), microwave ovens, motors, and other mass-produced products not currently covered. The new commercial building benchmarking and rating program so far only applies to office buildings. The program should be extended to other sectors including schools, retail buildings, healthcare, and lodging as well. And more funding is needed to expand promotion and training activities in the Energy Star Small Business and new homes programs, as well as to increase consumer awareness and market penetration of energy-efficient Energy Star products of all types.

Precedents

EPA and DOE have been trying to expand the Energy Star program but have faced funding constraints due to the Congress failing to provide adequate funding levels in recent years. Nonetheless, Energy Star labeling has begun for TVs, VCRs, and audio systems with low standby power consumption, and similar efforts are planned for other types of electronic products. Also, the Energy Star brand has been extended to cover highly efficient new homes with over 1,500 builders now participating and more than 17,000 Energy Star new homes already built. These outstanding homes use 35% less energy for heating and cooling on average compared to the current "good practice" homes. The newest product is a performance rating system for commercial buildings that allows labeling and recognition of the most efficient buildings across the country. Funding for EPA's portion of the Energy Star program (a large majority of the program is operated by EPA) will increase in FY2001 in order to support these and other new activities.

Impacts

ACEEE estimates that extending Energy Star labeling to additional types of electronic products, microwave ovens, and commercial refrigeration equipment could save about 13 billion kWh/yr by 2010 and 19 billion kWh/yr by 2020. Expansion of the Energy Star homes program and commercial building benchmarking program new appliance efficiency standards could save just as much if not more energy, as could additional publicity and promotion of all elements of the program. Assuming these combined efforts save 40 TWh/yr by 2010 and 60 TWh/yr by 2020, the avoided CO2 emissions would reach about 9 MMT of carbon equivalent in 2010 and 12 MMT in 2020. Consumers would realize substantial cost savings–on the order of $2-3 billion by 2010 and $3-4 billion by 2020–since there usually is little or no incremental first cost for upgrading products and buildings to the Energy Star levels. [Note: These savings are in addition to those from resulting from ongoing Energy Star activities.]