UCID-19227-93

U.S. Energy Flow–1993

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October 1994

Lawrence Livermore
National Laboratory

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Abstract

With continued improvement in the economic health of the nation, energy consumption in 1993 increased by almost 2.5%. Use of energy in all major end-use sectors increased, with the largest gains registered in the residential/commercial sector. In this sector, substantial increase in the use of natural gas reflected a harsh 1993–1994 winter as well as broader availability of the fuel for space heating. Energy demand in the transportation sector reached record levels.

Crude oil imports rose 8% but stood below the all-time high set in 1977. About half of the increase reflected declining domestic oil production. Imports of natural gas, principally from Canada, increased as they have every year since 1986. They comprise 11% of supply and supplement domestic production, which has similarly risen over the same time span. Increased demand for natural gas is evident in most sectors but especially in the industrial sector, where a growing number of cogenerators of electricity burn natural gas. Similarly growing is the number of enhanced oil operations and nonutility electrical generators using natural gas. Although coal consumption in the United States rose 3% in 1993, domestic coal production declined by a greater margin due to a coal strike. Because of increased international competition, exports fell 27%.

Electricity transmitted by the utilities again increased, following a decade-long trend interrupted only in 1992 by the national economic recession. The provisions of the Energy Policy Act of 1992 dealing with transport of nonutility-generated electricity by the public utilities began to be implemented in 1993. The provisions of the Energy Policy Act as well as those of the Public Utility Regulatory Policies Act of 1978 are setting the stage for increased competition for customers and for what promises to be a restructuring of the historically monopolistic industry. Nuclear power from the United States's 109 operable reactors constituted 21% of utility-generated electricity. With the continued retirement of outmoded and flawed reactors, nuclear capacity factors attained 71% in 1993, up from 56% a decade earlier.

Introduction

United States energy flow charts tracing primary resource supply and end-use have been prepared by members of the Energy Program and Planning groups at the Lawrence Livermore National Laboratory since 1972.[1,2] They are convenient graphical devices to show relative size of energy sources and end-uses since all fuels are compared on a common Btu basis. The amount of detail on a flow chart can vary substantially, and there is some point where complexity begins to interfere with the main objectives of the presentation. The charts shown here have been drawn so as to remain clear and be consistent with assumptions and style used previously.

Energy Flow Charts

Figures 1 and 2 are energy flow charts for calendar years 1993 and 1992,[3] respectively. (These figures are printed as the center spread, pages 10 and 11.) The 1993 chart is based on provisional data published by the Energy Information Administration of the Department of Energy.[4] Conventions and conversion factors used in the construction of the charts are given in the Appendix.

For comparison with earlier years, consumption of energy resources is given in Table 1. These data in many instances contain revisions of data previously reported in this series.

Comparison of Energy Use with 1992 and Earlier Years

Energy consumption grew almost 2.5% in 1993 reflecting the continued strong recovery from the recession (Tables 1 and 2). The nation's largest industrial corporations made profits in 1993, and the average unemployment rate fell to 6.8%;[5] however, there were regions where the recession persisted. California's high unemployment rate of 8.7% at year-end reflected the loss of 900,000 jobs since 1990, mostly in the defense industry.[6] Of the three principal end-use sectors, consumption increased the most in the residential/commercial sector by 0.7 quads or 4.3%. The increase was divided equally between use of natural gas and electricity. Transportation use increased again and exceeded pre-recession levels.

Use of all fossil fuels increased; however, domestic production of crude oil and coal declined. Coal production was impacted by a strike and a sharply curtailed demand for exports; however, the increased use of coal for electric generation contributed to a 4% increase in the amount of power transmitted by the utilities. Net imports for natural gas and petroleum increased 11.3% and 8.6% respectively.

Table 1. Comparison of annual energy use in United States.

	Quads (10^{15} Btu)							
	1986	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**
Natural gas production	16.54	17.14	17.60	17.85	18.36	18.28	18.37	18.88
Net imports	0.75	0.99	1.30	1.39	1.55	1.67	1.94	2.16
Crude oil and NGL								
Domestic crude & NGL	20.53	19.89	19.54	18.28	17.74	18.01	17.59	16.87
Foreign imports (incl. products and SPR)	13.20	14.17	15.75	17.17	17.12	16.34	16.91	18.30
Exports	1.68	1.63	1.74	1.84	1.82	2.13	2.00	2.11
SPR storage reserve[a]	0.11	0.17	0.11	0.12	0.04	–0.10	0.03	0.07
Net consumption[b]	32.20	32.87	34.22	34.21	33.55	32.85	33.53	33.77
Coal production (including exports)	19.51	20.14	20.74	21.35	22.46	21.57	21.59	20.43
Electricity								
Hydroelectric (net)								
Utility	0.99	0.85	0.76	0.90	0.96	0.94	0.82	0.90
Imports	0.36	0.46	0.32	0.11	0.02	0.23	0.29	0.30
Geothermal & other (net)	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
Nuclear (gross)	4.47	4.91	5.66	5.68	6.16	6.58	6.61	6.52
Fossil fuel (gross)	18.59	19.37	20.12	20.54	20.32	20.07	19.97	20.70
Gas	2.69	2.94	2.71	2.87	2.88	2.86	2.83	2.74
Coal	14.44	15.17	15.85	15.99	16.19	16.03	16.21	16.91
Oil	1.45	1.26	1.56	1.69	1.25	1.18	0.95	1.05
Total transmitted energy	**8.86**	**9.25**	**9.56**	**9.61**	**9.60**	**9.87**	**10.13**	**10.53**
Resident. & Comm.[c]	14.79	15.15	16.00	16.26	15.57	15.99	16.09	16.78
Industrial[d]	20.10	21.12	22.09	22.27	22.84	22.55	23.50	23.64
Transportation	20.79	21.42	22.27	22.55	22.50	22.09	22.43	22.80
Total consumption[e] (DOE/EIA)	**74**	**77**	**80**	**81**	**81**	**81**	**82**	**84**

Source: *Monthly Energy Review*, U.S. Department of Energy, DOE/EIA-0035(94/04) (April 1994); *Annual Energy Review—1993*, U.S. Department of Energy (July 1994).

[a]Strategic petroleum reserve storage began in October 1977.
[b]Excludes exports but takes account of refinery gains, SPR additions, and other stock changes as well as unaccounted crude oil.
[c]Excludes electrical losses.
[d]Includes field use of natural gas and non-fuel category and excludes electrical losses.
[e]Note that this total is not the sum of entries above.

Table 2. Gross domestic product by major type of product.
(Billions of constant 1987 dollars)

	1991	1992	1993
Gross domestic product	4821	4986	5136
Goods	1911	2006	2084
Services	2498	2535	2586
Structures	412	446	466

Source: *Survey of Current Business*, Table 1.4, **73,** No. 3 (March 1993); and **74,** No. 3 (March 1994).

At the beginning of 1993 the Clinton Administration proposed an energy tax to deal with the national deficit. Various proposals included a gasoline excise tax, an excise tax on fossil fuels based on relative carbon content, an oil import fee, and either an ad valorem or Btu tax imposed on the producer based on the sales value of the product or on the energy content of the fuel, respectively. The version formally proposed to Congress was a Btu tax on fuels used by the utilities.[7] By midyear the Administration had abandoned the tax because it was unlikely to win approval in the Senate although it had passed the House of Representatives by a small margin.[8] The proposal was vigorously opposed by almost every energy trade group as well as by the U.S. Chamber of Commerce, the National Association of Manufacturers, and the National Consumers League. Analysts opined that the tax proposed to affect everyone, and as a consequence everyone was against it.[8]

There is growing opinion that improvements in industrial energy efficiency in the United States are slowing significantly.[9] The arguments are that the easiest technological improvements have already been made and that further efficiency advances will require large investments in relatively unproved equipment and processes. Industrial energy intensity has fallen steadily since 1970 because of the changing makeup of the nation's industrial base. Although industrial output has increased, heavy industries have given way to less energy-dependent businesses such as computers and communications. Somewhere between one-third to one-half of the decline in manufacturing's energy intensity, i.e., energy use, can be attributed to a shift in the mix of output. This has been called "deindustrialization" of the United States, a trend driven by the high energy prices of the late 1970s and 1980s and by the imposition of stringent pollution regulations that forced many "smokestack" industries to either close their doors or move overseas.

Supply and Demand of Fossil Fuels

Oil Supply

Domestic Production

U.S. oil production continued its long decline (Fig. 3) and at the end of 1993 was 20% below 1973 levels. The 1993 decline was despite the fact that a new field came on stream in Alaska and that the long-delayed production from the giant Point Arguello field offshore California was expanded 35,000 barrels per day when permission to off-load crude oil to tankers from offshore platforms was obtained.[10] All indicators of exploratory activity—seismic crew counts, exploratory oil well completions, development oil well completions—were down in keeping with the shift of U.S. oil companies' focus to the international scene.[11] All of this portends a continuing decline in domestic production.

At year's end the Department of Energy introduced a Domestic Natural Gas and Oil Initiative designed to encourage domestic oil and gas production. It was not well received by the oil and gas industry because in the industry's view it did not come to grips with the prevailing low crude oil prices and with the inaccessibility of areas with high production potential in Alaska and offshore in the lower 48 states.[12] Oil industry spokesmen said that too many of the plan's 49 action items proposed studies or reviews. Nevertheless the initiative did propose to offer more attractive terms to encourage drilling in deep coastal waters; however, it was noted that if those areas are "marginal," better terms are immaterial.[13]

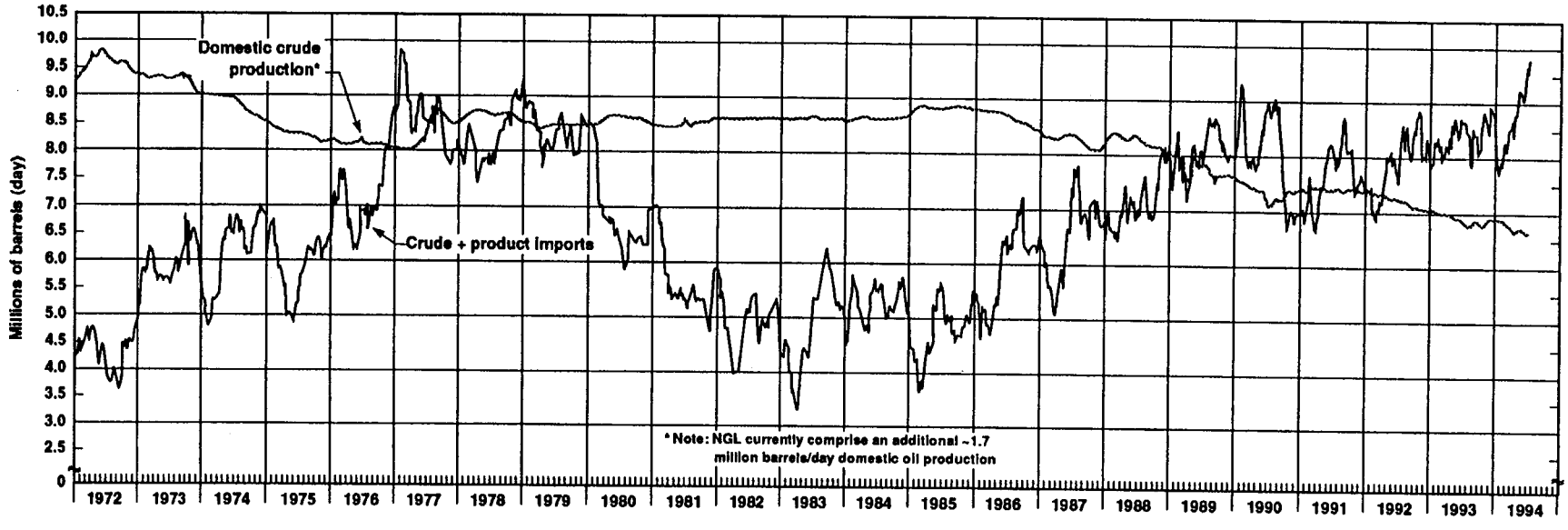
Oil Imports

Combined imports of crude oil and petroleum products almost exactly accounted for 50% of U.S. consumption, which is 3.3% greater than in 1992. Nonetheless net imports of petroleum products have declined substantially since 1988 due to increased domestic refinery production and reduced demand for selective products such as residual fuel oil.[14] In a continuing trend, the source of more than half the imports is production in non-OPEC countries. There was an oversupply of oil on world markets that severely depressed prices. OPEC has found it impossible to impose production ceilings on its members and expect compliance.

In a candid and surprising statement, John Lichtblau, president of the Petroleum Industry Research Association and long-time savant in international oil and gas affairs, said that "the current and projected level of U.S. oil imports does not present a demonstrable threat to U.S. national security."[15] His argument is that anything imposed in an effort to reduce imports significantly would raise the price of oil to the point where it would cause measurable

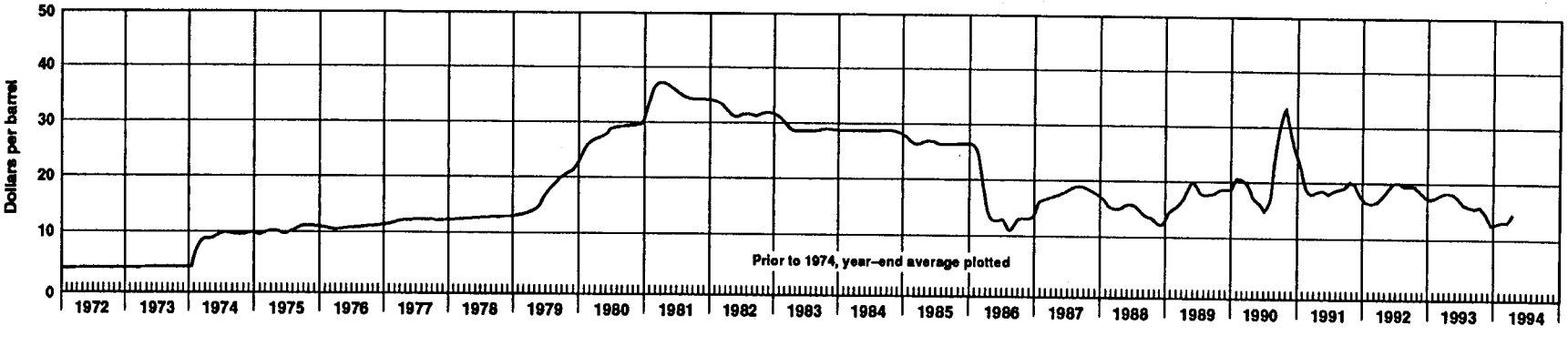
PETROLEUM IMPORTS AND DOMESTIC PRODUCTION

Moving four week average



REFINER ACQUISITION COST OF CRUDE OIL

Composite domestic and imported



Oil Imports Chart 8-1-94

C. Briggs

Figure 3. Petroleum imports and domestic production; refiner acquisition cost of crude oil.

damage to the U.S. economy. Because this is a tacit argument against imposition of price supports, many oil producers did not like the message. Instead, Lichtblau recommends a government policy to stimulate the industry through tax incentives, royalty waivers and removal of federal and state offshore acreage restrictions. He views such support to be desirable because of its positive regional economic impact rather than its impact on oil imports.

Oil Demand

Consumption of petroleum products has been unfettered by high prices since the collapse of world oil prices in 1986 (Figs. 3 and 4). Nonetheless between 1988 and 1991 oil consumption declined. In 1992 and 1993 demand rose because of increased use within the transportation sector, which was only mildly impacted by the recession. Demand for both gasoline and jet fuel increased by 3% and 1%, respectively, in 1993. In the same time frame, improvements in passenger car efficiency have not been noteworthy. The last data available (1992) from the U.S. Department of Transportation put average passenger-car fuel consumption at 21.6 miles per gallon. An increase in the number of passenger vehicles on the road and the number of miles traveled per vehicle have coupled to offset any improvements in fuel efficiency. In addition, "off road" vehicles and small trucks are not included in passenger car statistics. It is possible that the growing popularity of these notoriously fuel-inefficient vehicles accounts to some degree for the increased use of highway fuels.

Natural Gas Supply

In 1993 the natural gas supply was able to meet growing demand, but barely. The long-lived domestic "gas bubble," which is the difference between maximum feasible gas capacity and actual deliveries, had shrunk to about 4%.[16] Total use by all end-use sectors rose 0.65 quads or by 3.2%. About one-third of the increase was supplied by larger imports from Canada; and the remainder from increased domestic production and from withdrawals from storage.[4] For the first time the value of natural gas production in the United States exceeded that of crude oil.[17] The reasons relate to the sharp increase in wellhead prices in 1993 ($2.02/Mcf up sharply from $1.74/Mcf the previous year) driven by the demands of the very cold winter of 1993–1994. The Natural Gas Supply Association reported that the 30 largest natural gas reserve holders replaced 87% of their reserves in 1993, as compared with 69% a year earlier.[18] If all producers are taken into account, it is believed that 100% of production was replaced by new reserve additions.[18] The 10-year average is 90%. The strong performance was attributed to the high prices gas commanded, which promoted increased drilling.

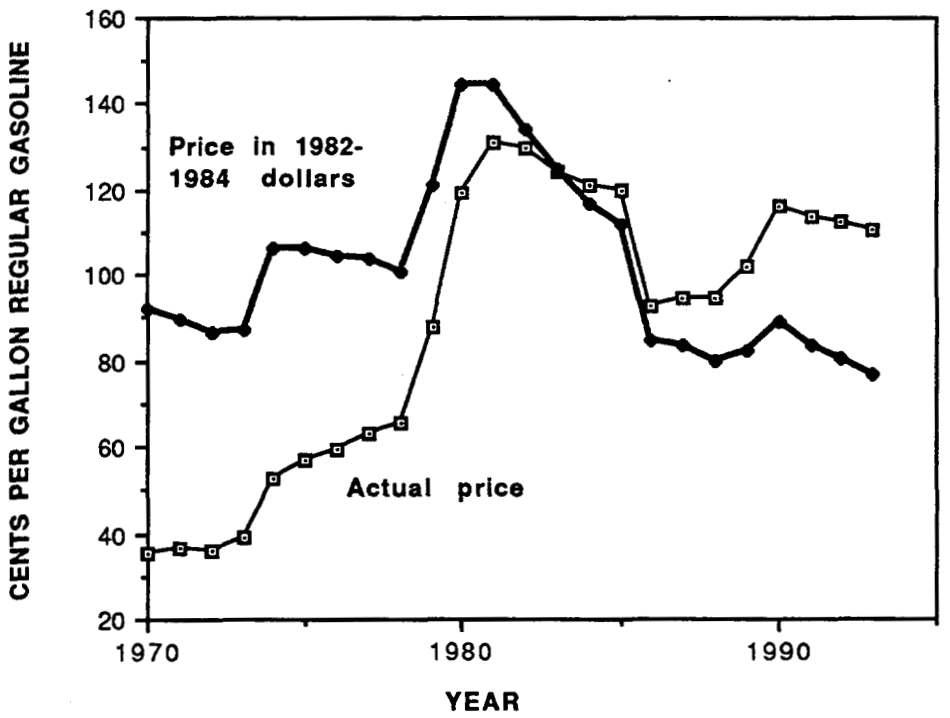


Figure 4. Decline in the price of regular gasoline 1970–1993.
Source: *Oil and Gas J.*, p. 23, (Dec. 20, 1993).

At the end of 1992 natural gas pipelines either completed or under construction amounted to 11 Bcf/d and proposals totaled another 13 Bcf/d.[19] It was no surprise that all parts of this ambitious program did not survive because it implied an unrealistically rapid increase in gas demand within a short period of time—approximately 43% above 1992 levels. In 1993 the total of all categories of pipeline construction fell to 15.3 Bcf/d of new capacity, of which 5.5 Bcf/d were completed or under construction and 9.8 Bcf/d were in the proposal stage.[20] Completed in 1993 were Pacific Gas Transmission Corp.'s 805-mile line to deliver 903 million cf/d of Canadian gas to California markets and Northwest Pipeline's 433 million cf/d line from the San Juan Basin in New Mexico to Oregon. In 1993 imports of Canadian gas supplied a little more than 10% of U.S. demand, up from about 7% in 1989; from all indications the Canadian contribution will continue to climb with the slow but steady increase in demand for natural gas in all sectors.

Natural Gas Demand

The only sector not showing increased natural gas consumption was power generation by the electrical utilities. On the other hand, the preferred fuel of nonutility generators (NUG) is

natural gas, and if they were included, the electrical generating industry as a whole would have also shown increased gas consumption. For the first time Canadian gas was exported to a NUG facility with a project-specific export license.[21] This first export sale was to the Midland Cogeneration Venture in Michigan, the former site of a nuclear power plant. Because the pipelines are now required to transport gas for customers other than utilities, it is expected that more and more NUGs will follow this lead. The Canadian gas exporters have been very successful in penetrating the U.S. market because the exporters offer key elements to customers: competitive prices, long-term contracts, and dedicated reserves. At the end of 1993, NUG projects receiving Canadian gas had 3.4 GW of generating capacity.[21]

As noted, the untoward winter of 1993–94 led to a substantial increase in the use of natural gas for space heating in the residential/commercial sector. Industrial demand increased as well; the increase reflects the growing use of natural gas in enhanced oil recovery and in gas-fired cogeneration of electricity in conjunction with industrial processes. Increased use of natural gas is one of three priorities being promoted by the Department of Energy: the use of natural-gas-powered vehicles, energy efficiency, and alternative fuels. It was inevitable that natural gas would become the government's sinecure for abating air pollution and dealing with the declining domestic supplies of our former most important energy fuel—oil. At this junction, the various types of renewable energy are not available on a large enough scale to substitute for oil.

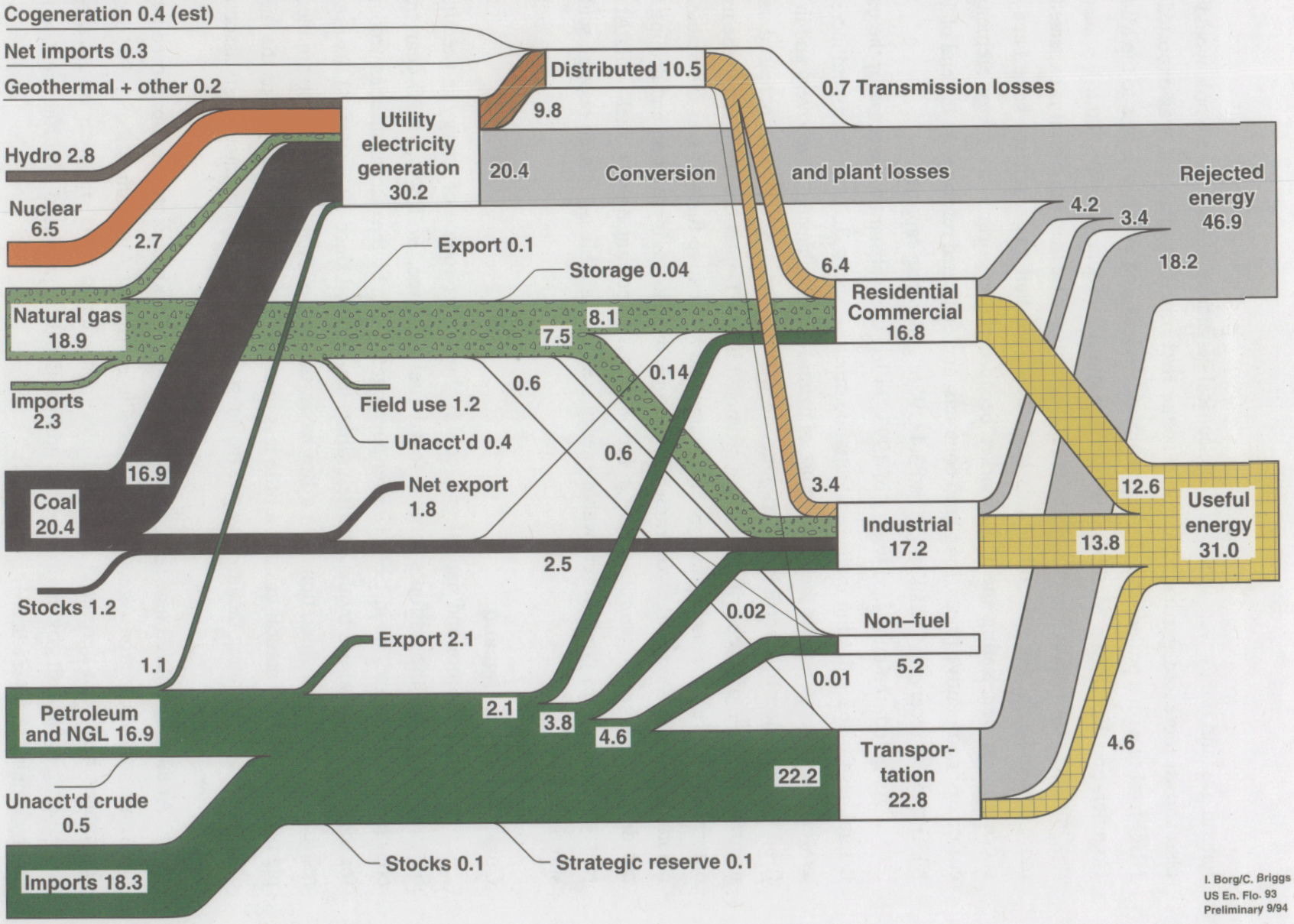
Coal Supply and Demand

After petroleum and natural gas, coal is the largest source of energy in the United States. It remains the nation's largest fossil fuel resource. Following a 20-year trend, consumption increased 3% in 1993. Use for power generation by the electric utilities accounted for the increase. Coal use by the electric utilities has doubled since 1973 (Ref. 4). Its use is a reflection on cost considerations. On a Btu basis, the cost of coal received at steam electric plants is half that of natural gas and a little less than half that of oil. Coal remains the fuel of choice at large generating facilities despite the substantial pollution abatement costs associated with its use.

At the end of 1993 new regulations concerning sulfur emissions were proposed by the Environmental Protection Agency. Under the Clean Air Act Amendments of 1990, certain allowances had been permitted reflecting cleanups prior to 1991, the year of enactment. Responding to lawsuits by environmental groups, the EPA proposed to further reduce acid rain by limiting these credits.[22]

Because of a strike by the United Mine Workers of America, coal production actually fell 5%.[4] A decline in exports is attributed to intense global competition, rising U.S. prices, and a European recession.[23] South African, Colombian, and Russian coal exports have swamped

U.S. Energy Flow – 1993
Net Primary Resource Consumption 84 Quads



Other: wood, waste, photovoltaic, solar

Figure 1. U.S. Energy Flow—1993, in quads. One quad equals one quadrillion (10^{15}) Btu's.

U.S. Energy Flow – 1992
Net Primary Resource Consumption 82 Quads

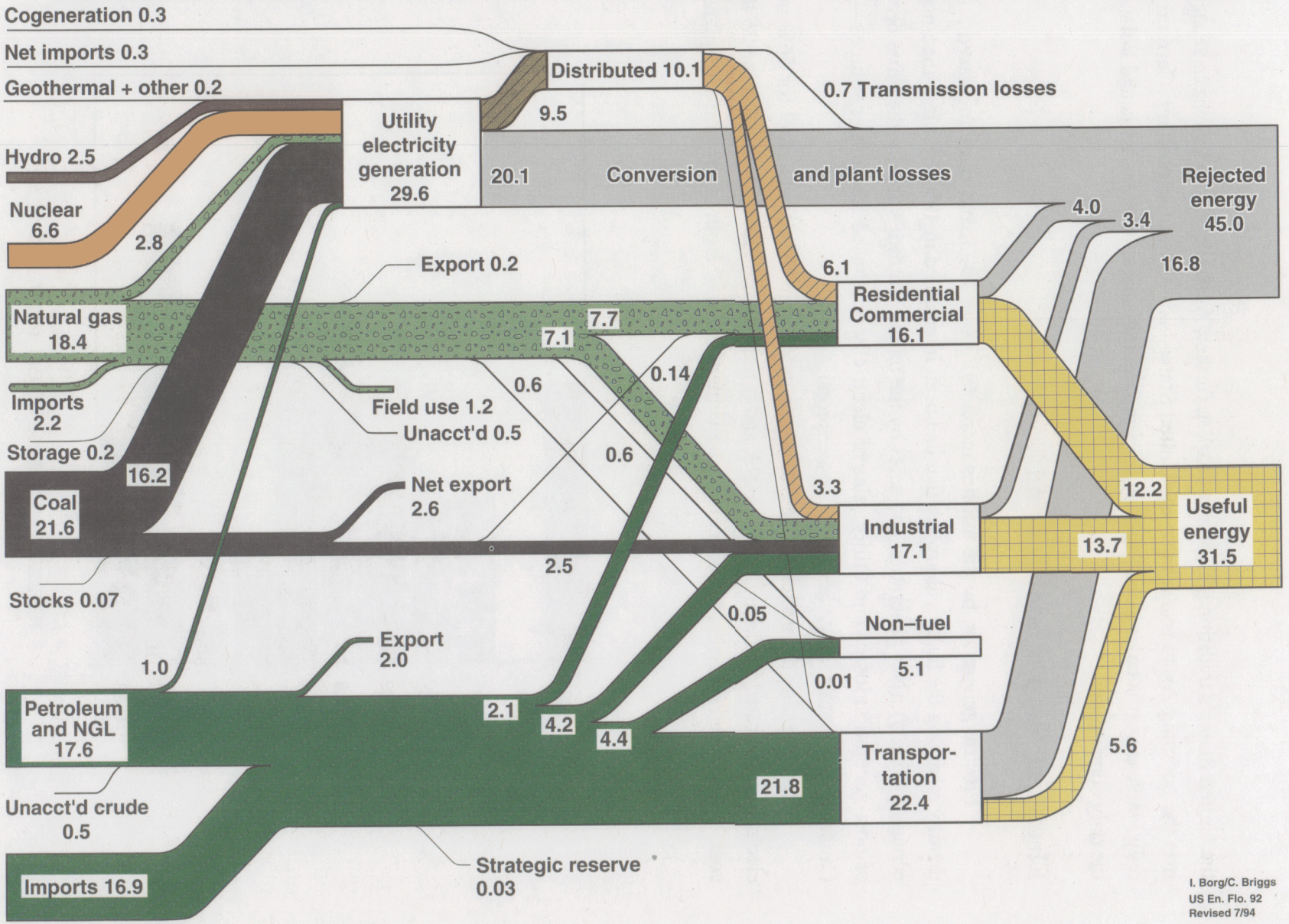


Figure 2. U.S. Energy Flow—1992, in quads.

the United States's traditional European market; further, Australia and Indonesia have stepped into the booming Asian market that the United States had hopes of exploiting. Currently the only viable export is coking coal used by foreign steel industries; here Australia and Poland are the only competitors.

Electrical Supply and Demand

Electric generation by the utilities increased 3% in 1993, and sales increased 3.8%,[4] thereby resuming the historical growth that had been interrupted in 1992 by a less-than-normal economy (Fig. 5). (Net generation and sales by the nation's utilities are not the same because of post-generation losses and utility sales of electricity purchased from other sources—e.g., Canada, cogenerators, and independent power producers.)

Coal remains the principal fuel for power production. It provided fuel for 56% of the electricity generated by the utilities in 1993, and it remains the fuel used in 23 of the 25 least-cost, steam-based electricity producers in the United States.[24] Both of the non-coal plants on

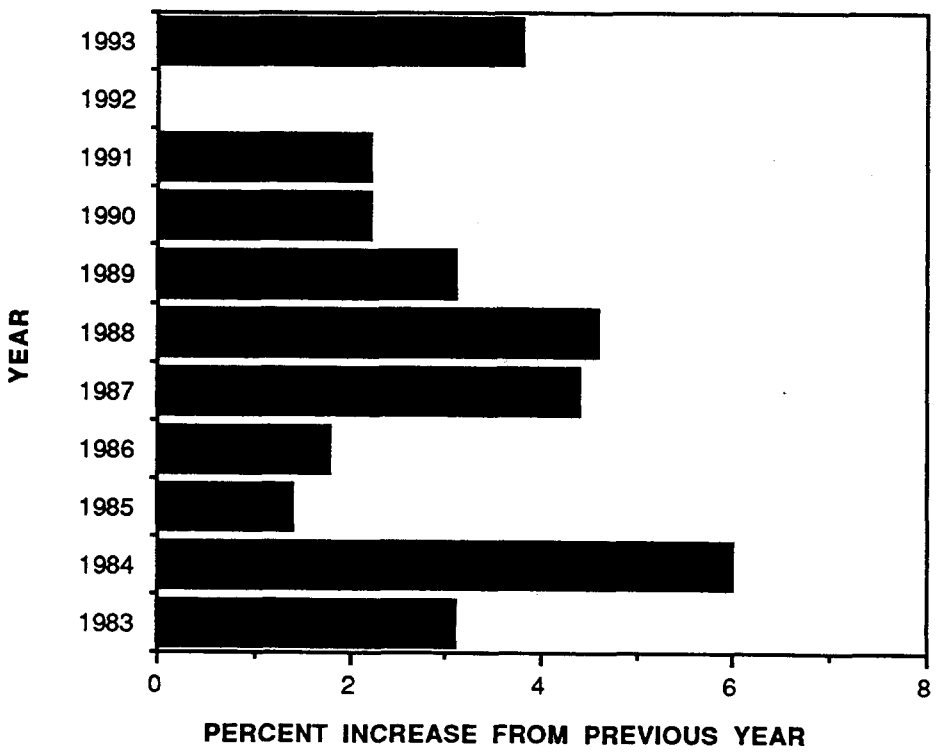


Figure 5. Growth in electrical utility sales 1983–1993.
Source: *Monthly Energy Review*, Department of Energy, Washington DC, DOE/EIA-0035(94/05) Table 7.2 (May 1994).

the list are nuclear. There were no oil- or gas-burning plants on the list. Of the top 10 plants, all burn subbituminous coal, and all are west of the Mississippi River. Average expenses at the Laramide River plant in Wyoming, which topped the list, were $9.00 per MWh.

The year saw the beginning of implementation of provisions of the Energy Policy Act of 1992 having to do with wholesale "wheeling" of electricity by the vertically integrated utilities on behalf of independent power producers.[25] Most observers see retail "wheeling," i.e., nonutility electrical distribution, in the not-so-distant future.[26,27] Changes in the traditional role the utilities play in electrical power transmission are the last of the numerous changes that have impacted the formerly monopolistic industry. It has been suggested that, in the end, a highly segmented industry will develop, where the generation of power is the exclusive purview of some utility and nonutility generators, and the transmission and distribution of electricity are the exclusive charge of another group of utilities.[27] The role of the rate regulators in such an increasingly competitive environment is moot. The federal goals behind the regulations that have shaped the industry have been to introduce more competition and, earlier, to foster fledgling renewable or alternative electrical energy technologies. Because of the escalating cost of large-baseload power plants, some of the most highly capitalized enterprises in the world, the utilities for a decade have given low priority to planning for large, new facilities. It has become clear, as competition in the industry increases, that to survive the utilities must pay greater attention to their large industrial customers' needs and demands, even if that involves building on-site cogeneration units for them. Such a proposal by Virginia Power Co. is before the Virginia State Corporation Commission.[26] The utility's view is that the units will be built in any event.

Because of the increased nominal cost of generating electricity starting in the late 1970s (Fig. 6), many large users in the industrial sector began to consider alternatives to utility purchases. The Public Utility Regulatory Policies Act (PURPA) of 1978 overcame many obstacles to independent power production by requiring electric utilities to purchase nonutility-generated electricity, to pay a fair price for it, and to provide backup services if needed. Since then, both nonutility installed capacity and gross generation have increased annually; and the power sold to the public utilities has become an important element in the supply picture (Fig. 1). The independent producers have provoked controversy from the outset because many utilities claim that they are forced to buy power at prices that exceed the costs of their own projects and facilities or that even exceed the cost of purchases from other power sources.[28] Most recently Niagara Mohawk Power Corp. in New York, following the lead of California utilities, has requested the New York Public Service Commission's permission to monitor and enforce the contractual obligations of qualifying facilities (QF) from whom they buy

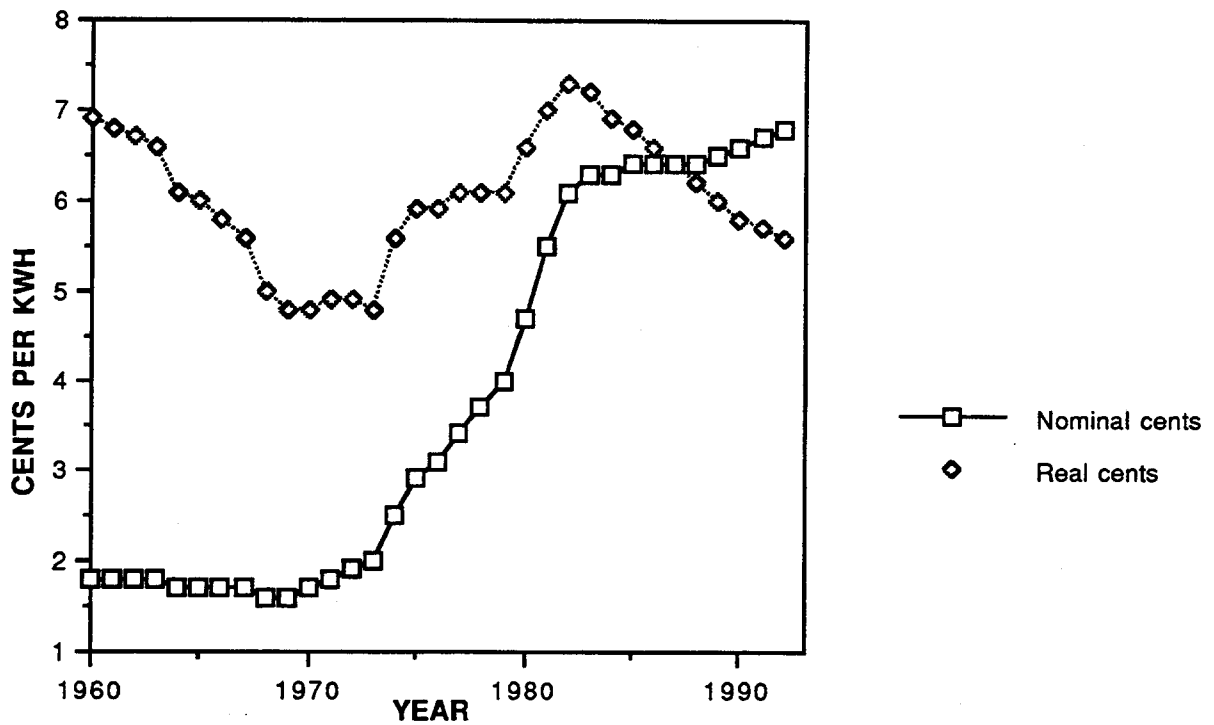


Figure 6. Price of electricity in real and deflated (1987 dollars).
Source: *Annual Energy Review—1992*, Table 8.11 (June 1993).

power. The proposed monitoring is designed to verify whether the QFs live up to the strict PURPA regulations with respect to size and type of fuel used. California's Pacific Gas and Electric Co. found 3–4% of its QF contracts out of compliance in 1992, which was higher than anticipated.

Starting in 1991, the Department of Energy's Information Administration began to collect data on nonutility contributions (Table 3).

Nonutility power producers are of three sorts: cogenerators that use the steam or heat produced in a second industrial process, small power producers that generate electricity by using renewable forms of energy as primary energy sources, and independent power producers that do not qualify as public utilities under the Federal Energy Regulatory Commission's definitions. The bulk of the power generated by the nonutility power producers—73%—is by cogeneration. The fuel preferred by all is natural gas, which accounts for more than half of gross generation by nonutilities. Natural gas imports from Canada to nonutility generators are anticipated to increase five-fold between 1990/1991 and 1995/1996.[21] Of the renewable fuels,

Table 3. Installed capacity and gross generation of nonutility electric generators larger than 5 MW.

Year	Installed capacity (GW)	Increase (%)	Gross Generation (Billion kWh)	Increase (%)
1989	36.64		187.1	
1990	42.55	16.1	215.2	15.0
1991	48.2	13.3	248.5	15.5
1992	55.1	14.3	289.9	16.7

Source: "Statistics on nonutility power producers," reprinted from *Monthly Energy Review* (Aug. 1992 data) (Oct. 1992); *Electric Power Annual—1992*, Table 1 (U.S. Department of Energy, Washington, DC) DOE/EIA-0348(92) (Jan. 1994).

biomass (wood, wood waste, peat, railroad ties, pitch, municipal solid waste, agricultural waste, straw, tires, landfill gases, etc.) is most important and is used for 18% of gross generation.[29]

Because at the date of this manuscript data for nonutility generation in 1993 were not available from the Department of Energy, we have used an estimate of nonutility generation's contribution to the amount of electricity sold to and distributed by the utilities, based upon the 32% increase between 1991 and 1992. Estimates indicate that 2.9 MW of new projects came on-line in 1993.[30]

The net amount of electricity sold to the utilities in 1992 was 91.7 billion kWh[30] or 0.3 quadrillion Btu (quads) (Fig. 2). Thus by noting in Table 3 that gross generation was at least 289.9 billion kWh or 1.0 quads, it is apparent that most (0.7 quads) of the power produced by the nonutilities was used "in house," i.e., by the facility producing the power. Use of this self-generated electricity has no expression in Fig. 1 or 2; only the fuels used to generate or cogenerate it are accounted for in the slate of fuels used by the industrial sector. Thus the actual amount of electricity used by industry in 1992 was about 4 quads: 3.3 quads purchased from the utilities (Fig. 2) and 0.7 quads produced "in house."

Nuclear Power

Nuclear energy's contribution to U.S. net generation of electricity was more than twice that recorded a decade earlier. In that time interval, the number of operable reactors increased from 80 to 109, and average capacity factor, a measure of the efficiency of operation, rose from 54% to 71%. Nuclear power provided 21% of net electricity generated by U.S. public utilities (Table 4). Although the United States has the largest number of nuclear reactors, this

Table 4. Electrical generation from nuclear power.

	1990	1991	1992	1993
Total utility electrical generation (bn kWh)	2808	2825	2797	2883
Nuclear contribution (bn kWh)	577	613	619	610
Percent nuclear	20.6	21.7	22.1	21.1
Installed nuclear capacity* (GWe)	99.6	99.6	99.0	99.1
Number of operable reactors	111	111	109	109
Annual nuclear capacity factor (%)	66.0	70.2	70.9	70.5

*Net summer capability of operable reactors
Source: *Monthly Energy Review*, DOE/EIA-0035(94/05) Sec. 8. U.S. Department of Energy, Washington DC, (May 1994).

percentage is small compared to the nuclear contribution in France (73%), Belgium (60%), Sweden (51%), South Korea (48%), and Switzerland (39%).[31]

In 1993, one reactor, the 17-year-old, 1104-MW Trojan nuclear reactor at Prescott, Oregon, was retired, and a full-power license was issued for the 1150-MW Comanche Peak, Unit 2 at Glen Rose, Texas. The latter is the first reactor in more than two years to receive such a license and may be the last in this century to receive one.[32]

At midyear, cracks were discovered in the steel cylinders called "core shrouds" that direct cooling water of the nuclear core of a boiling water reactor (BWR) owned by Carolina Power and Light Company in North Carolina.[33] Subsequent examination of other BWRs revealed similar cracks, leading the Nuclear Regulatory Commission (NRC) to order that they be shut down until repaired or until it could be proven that the flaws could not cause a major accident. The "core shroud" is around the outside of the nuclear core but inside the reactor vessel. Core shrouds are thus described as outside of critical safety areas. The cracks are apparently the result of years of radiation, of weakening from repeated heating and cooling cycles and the consequent building up of stresses in the cylinders, and of unfavorable water conditions. By the end of 1993, seven BWRs, all built by General Electric Co., were listed as having similar cracks by the NRC, and three more were described as having indications of cracking.[34] Because some of the nation's oldest operating reactors are included in the group, many of those needing repair may be shut down if the cost of repair exceeds that of decommissioning the reactor. Decommissioning the Trojan plant is expected to cost $420 million, which is near the cost of the original construction.[35]

The doldrums that the U.S. nuclear industry finds itself in reflect unfavorable economics to a large degree. Some analysts predict that a quarter of the U.S. nuclear plants will be shut down within the next decade because of increasing operation and maintenance costs.[35] These costs have climbed steadily for more than 10 years. The average cost of nuclear-generated electricity per net megawatt-hour at the beginning of 1993 was $21.61, but at least 25 plants' fuel and non-fuel production costs were between $12.50 and $19.00 per MWh.[36] Although the Energy Policy Act of 1992, by expediting the licensing procedure, makes it easier and faster for utilities to build nuclear plants, new orders have not been forthcoming, and there are only two U.S. nuclear plants under construction. The U.S. nuclear industry has only survived by virtue of foreign orders. Japan, for example, is currently building nine plants, and South Korea, Indonesia, Taiwan, and Pakistan are planning more than a dozen new projects.

Appendix

Data and Conventions Used in Construction of Energy Flow Charts

Data for the flow chart were provided by tables in the Department of Energy's *Monthly Energy Review,*[4] the *Quarterly Coal Report,*[37] and the *Annual Energy Review—1993.*[38]

The residential and commercial sector consists of housing units, non-manufacturing business establishments, health and education institutions, and government office buildings. The industrial sector is made up of construction, manufacturing, agriculture, and mining establishments. The transportation sector combines private and public passenger and freight transportation and government transportation including military operations.

Utility electricity generation includes power sold by both privately and publicly owned companies. The non-fuel category of end-use consists of fuels that are not burned to produce heat, e.g., asphalt, road oil, petrochemical feedstocks such as ethane, liquid petroleum gases, lubricants, petroleum coke, waxes, carbon black, and crude tar. Coking coal traditionally is not included.

The conversion and plant losses associated with utility electrical power generation are a matter of record. Transmission losses are the difference between total transmitted electricity and receipts by the principal end-use sectors. They are approximately 7% of transmitted electricity. In other sectors such as residential/commercial, industrial and transportation, the division between "useful" and "rejected" energy is arbitrary and depends on assumed efficiencies of conversion processes. In the residential and commercial end-use sectors, a 75% efficiency is assumed, which is a weighted average between space heating at approximately 60% and electrical motors and other electrical uses at about 90%. Eighty percent efficiency is assumed in the industrial end-use sector and a generous 20% in transportation. This is below the 25% efficiency we have used in past years. The latter percentage corresponds to the approximate efficiency of the internal combustion engine as measured on the bench by "brake thermal efficiency" tests.

We have persisted in expressing these approximate efficiencies in our flow charts over the years, although we are fully aware of the changes in all end-use sectors that have modified actual efficiencies to some degree over the same time period. Unfortunately we lack quantitative data to improve our estimates. We feel, however, that despite improved mileage for highway vehicles, it is unlikely that transportation efficiencies in reality have reached 20% and certainly not the 25% associated with bench tests. In other end-use sectors, not only have some efficiencies changed but the slate of fuels used by the various end-use sectors have also changed, which influences the average efficiency for the sector. For example, electrical usage has steadily risen in the residential and commercial sectors due to increased use of air conditioners; natural gas has a bigger share of the heating market than in the past. We are

uncertain of the net result of these changes. Another uncertainty has to do with the influence of cogeneration and self-generation of electrical power on overall industrial efficiencies. Clearly the magnitude of the effect relates to the percentage of the waste heat associated with nonutility electric generation that is utilized in other industrial processes. Rather than abandon the approach because of uncertainties, we continue to estimate "rejected" and "useful" energy in order to point out which of the various energy sectors are associated with the largest absolute losses—namely, electrical power production and transportation—and thus to direct attention to the most fertile ground for technological improvements.

There are some minor differences between total energy consumption shown here in the energy flow charts and the DOE/EIA totals given in Table 1. The industrial consumption total in Table 1 agrees with DOE's *net* industrial total. Both totals include natural gas lease and plant fuel and non-fuel ("non-energy") use, which are shown separately in the flow charts (Figs. 1 and 2).

Conversion Factors

The energy content of fuels varies. Some approximate, rounded conversion factors, useful for estimation, are given below.

Fuel	Energy Content (Btu)
Short ton of coal	22,400,000
Barrel (42 gallons) of crude oil	5,800,000
Cubic foot of natural gas	1,000
Kilowatt hour of electricity	3,400

More detailed conversion factors are given in the Department of Energy's *Monthly Energy Review*.

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