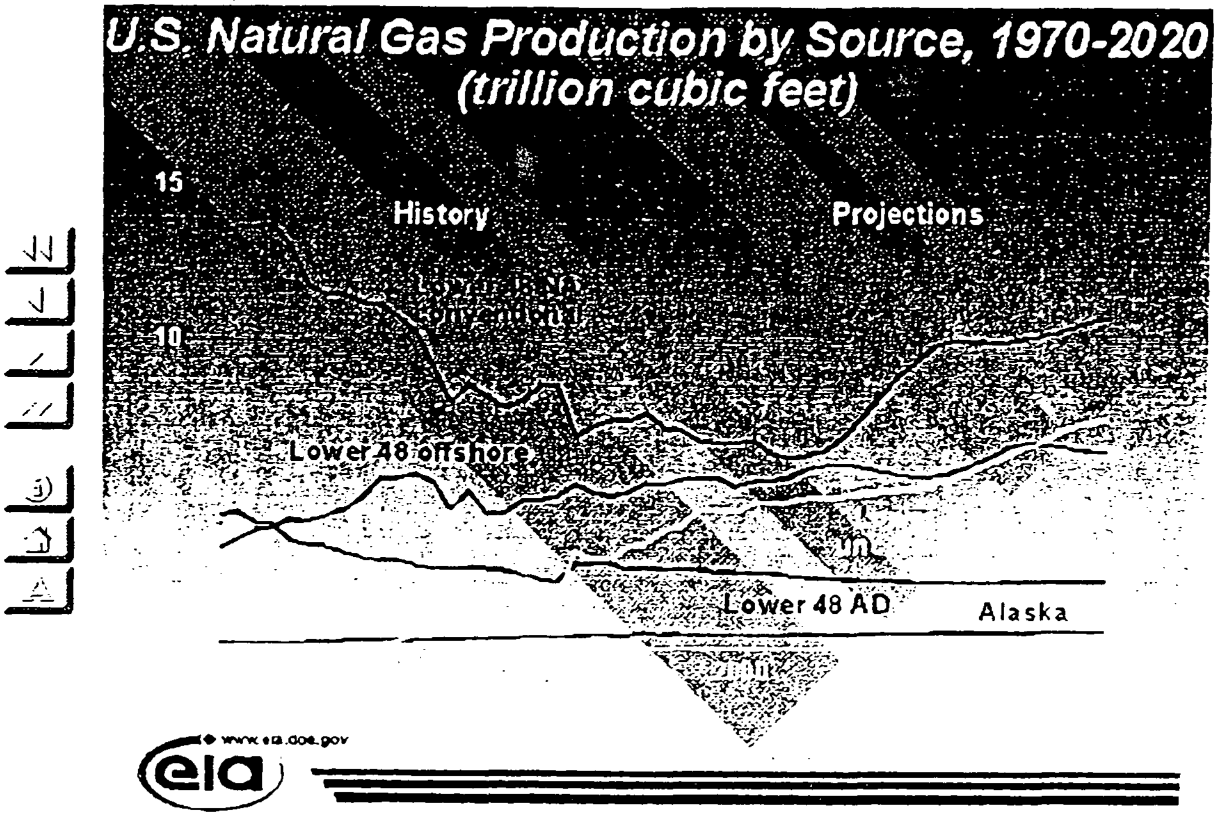

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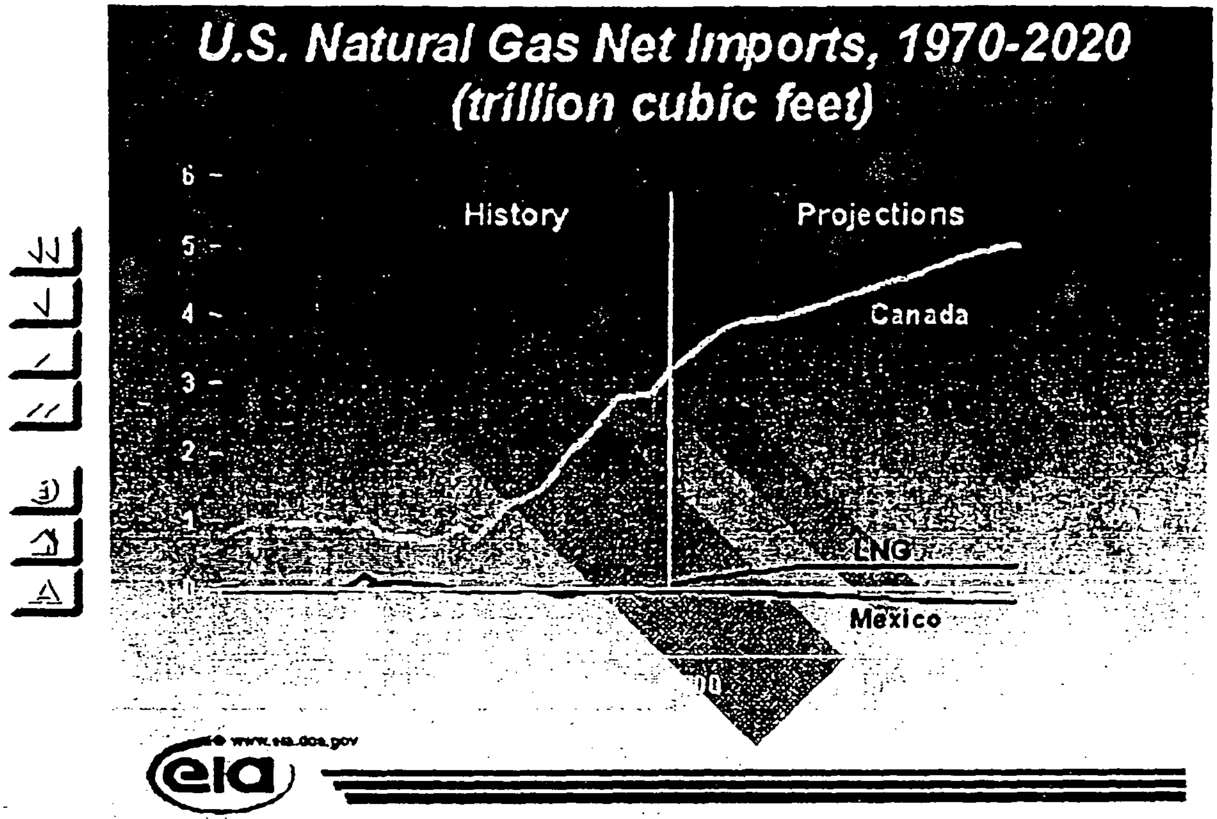

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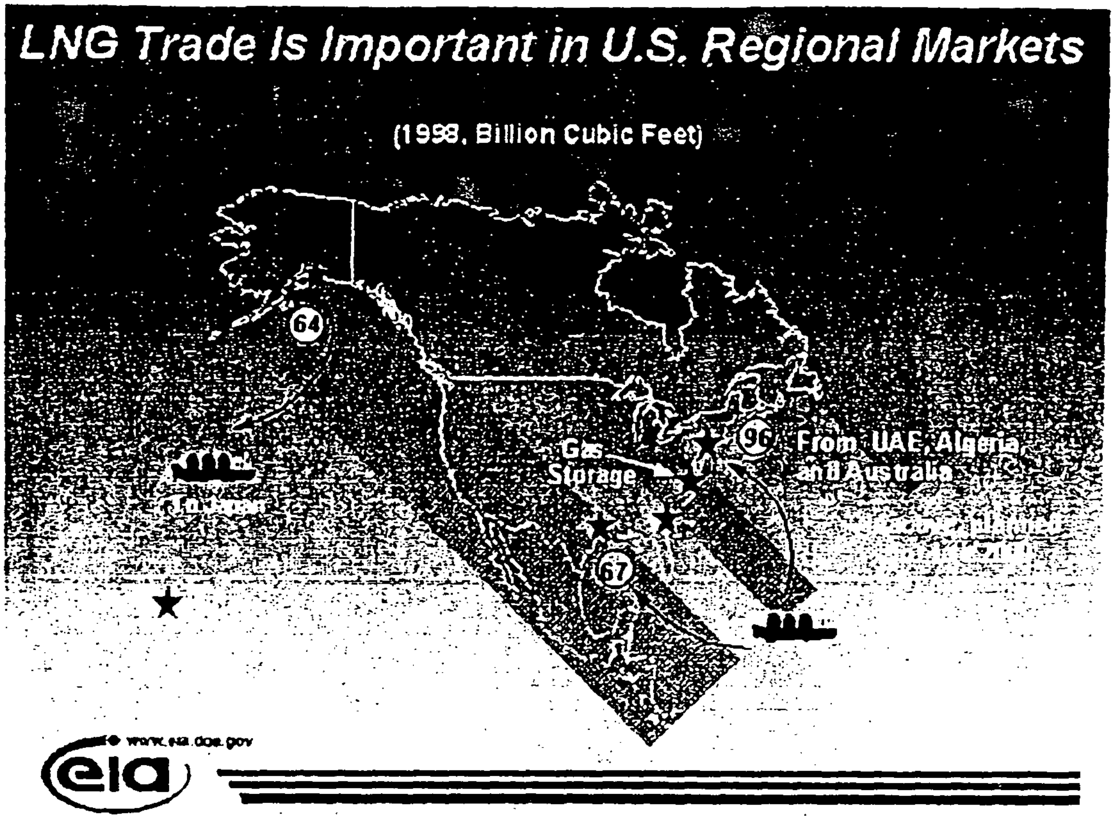

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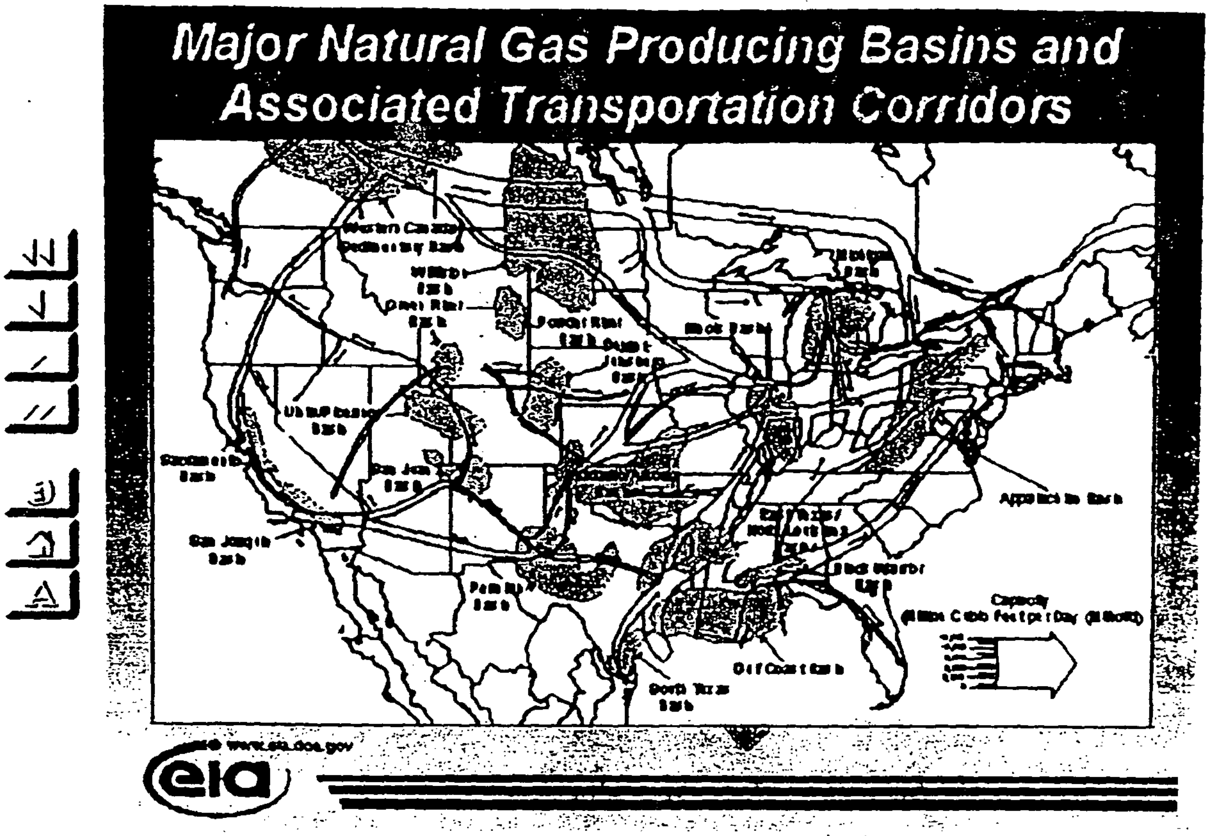

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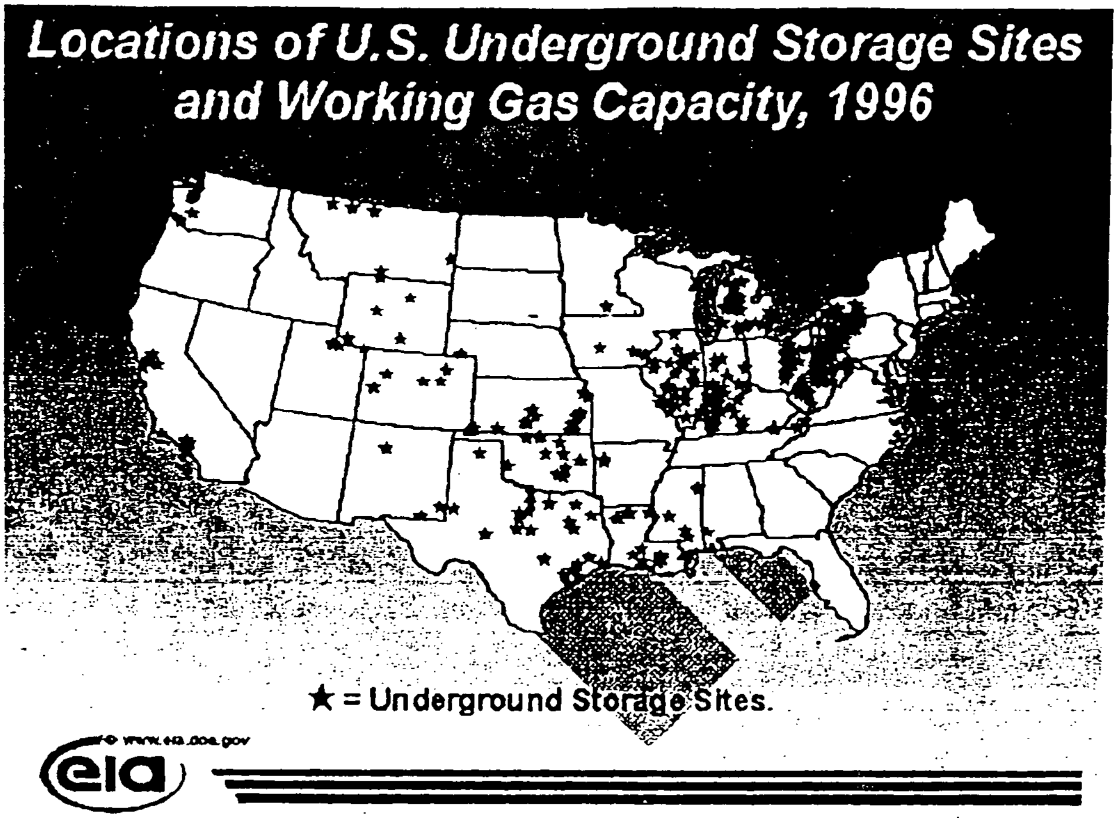

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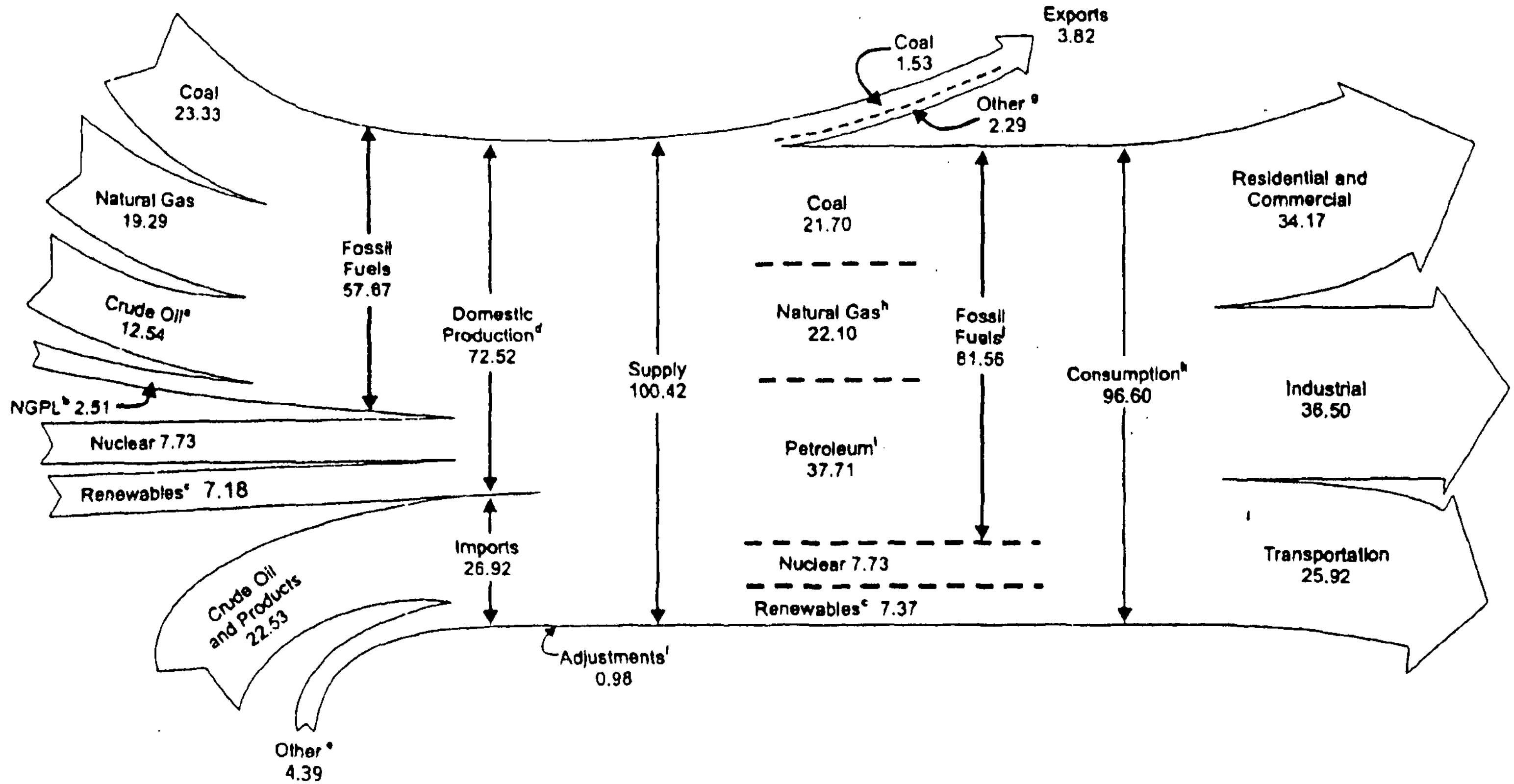
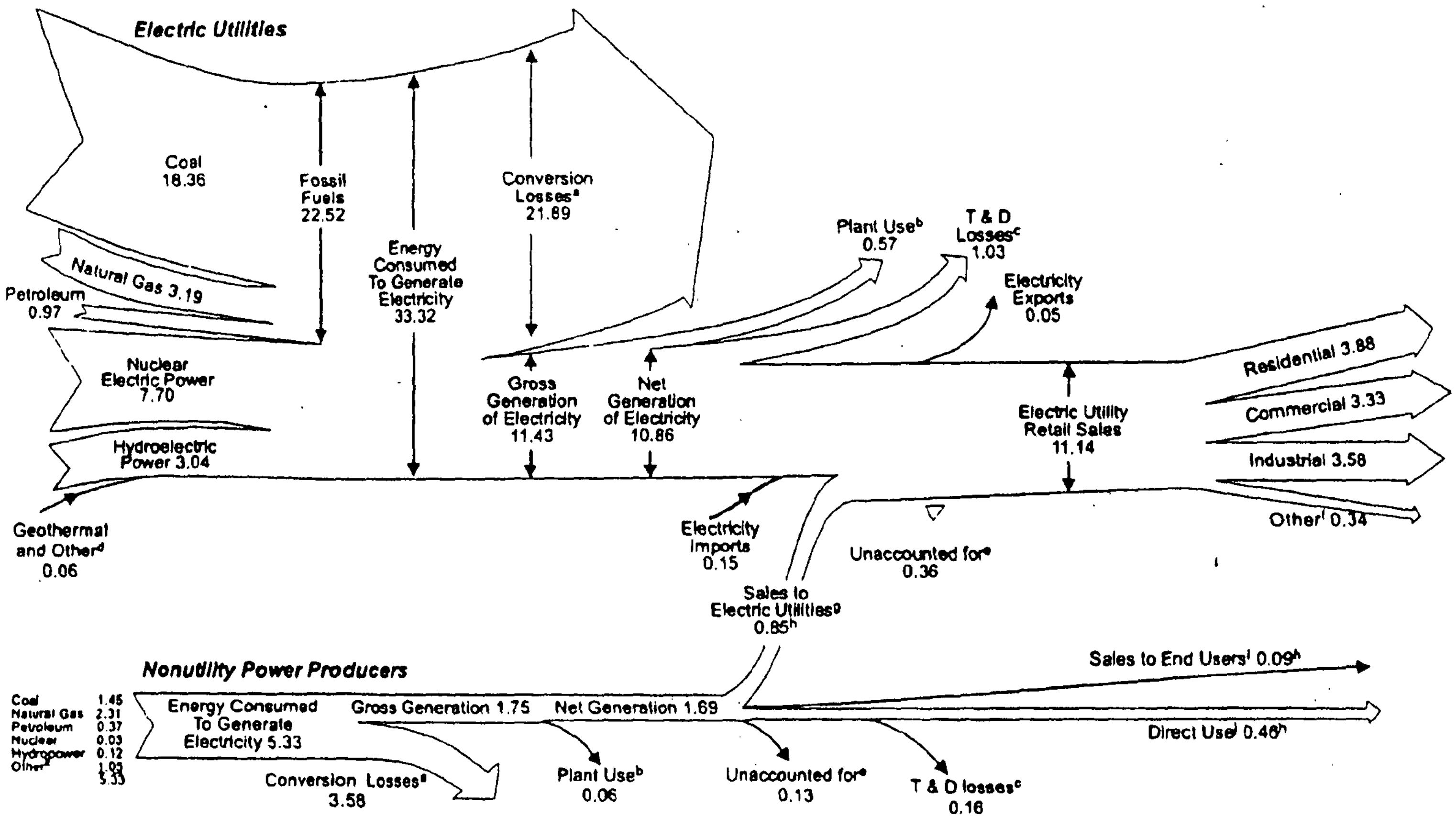
Diagram 1. Energy Flow, 1999
(Quadrillion Btu)



[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 0.08 quadrillion Btu coal coke net imports.
[k] Includes, in quadrillion Btu, 0.11 net imported electricity from nonrenewable sources; -0.08 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.

Diagram 5. Electricity Flow, 1999
(Quadrillion Btu)



[a] Approximately two-thirds of all energy used to generate electricity. See Note 1 at end of section.

[b] The electric energy used in the operation of power plants. For utilities, plant use is estimated as 5 percent of gross generation. See Note 1 at end of section.

[c] Transmission and distribution losses are estimated as 9 percent of gross generation of electricity. See Note 1 at end of section.

[d] Wood, waste, wind, and solar energy used to generate electricity. See Table 8.3.

[e] Balancing item to adjust for 1998 data used to estimate 1999 values for some small series; data collection frame differences; and nonsampling error.

[f] Public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

[g] Sales, interchanges, and exchanges of electric energy with utilities.

[h] 1999 data not available; this is the 1998 value.

[i] Includes sales, interchanges, and exchanges of electric energy with other nonutilities.

[j] Direct use is facility use of onsite net electricity generation.

[k] Geothermal, wood, waste, wind, and solar energy used to generate electricity. See Table 8.4.

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

Sources: Tables 8.1, 8.3, 8.8, 8.9, 8.14, and A6.

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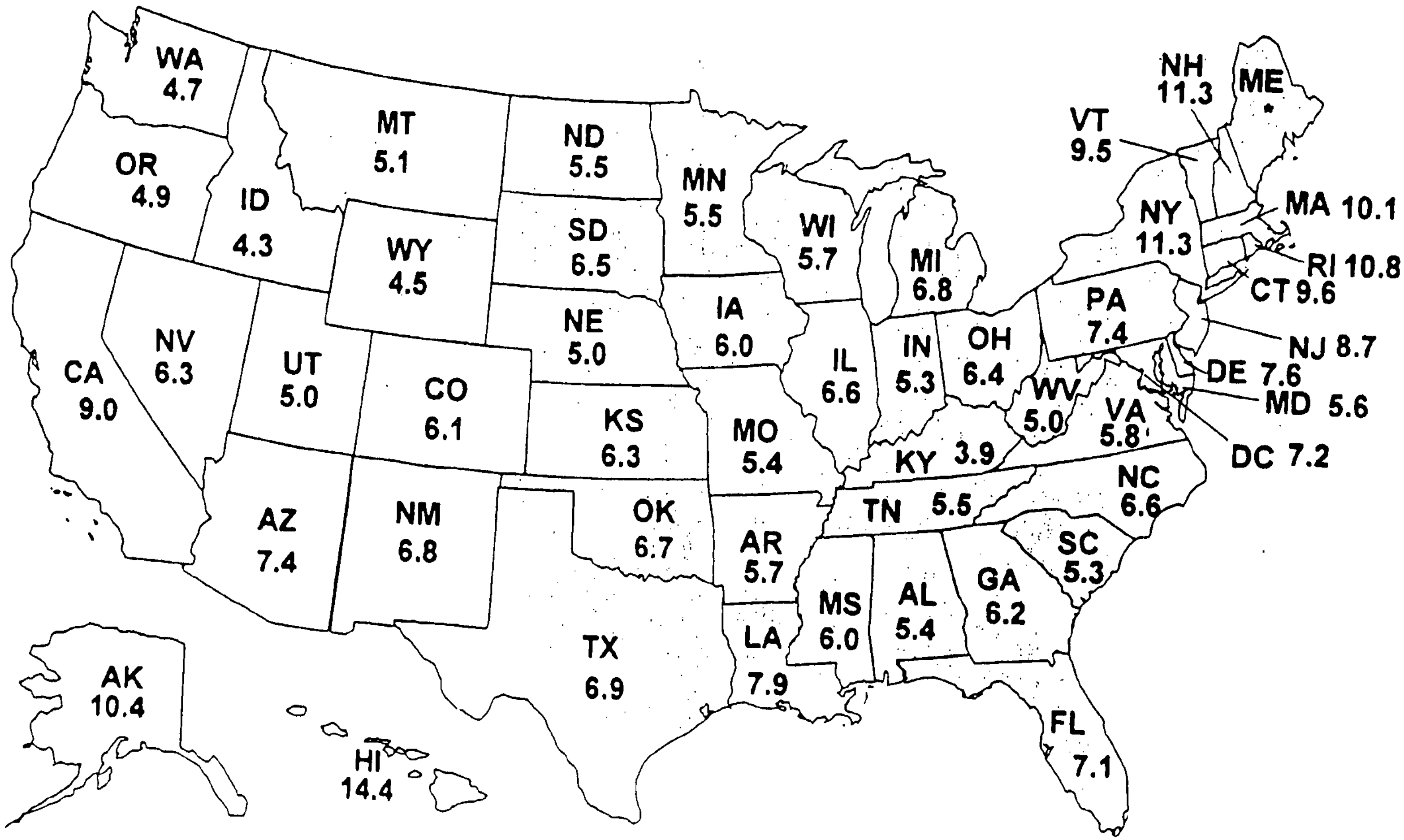
Table 5.2 Crude Oil Production and Oil Well Productivity, 1954-1999

(Thousand Barrels per Day, Except as Noted)

Year	Geographic Location		Site		Type		Total Production	Oil Well Productivity	
	Lower 48	Alaska	Onshore	Offshore	Crude Oil	Lease Condensate		Producing Wells [1] (thousands)	Average Productivity [2] (barrels per day per well)
1954	6,342	0	6,209	133	6,342	(3)	6,342	511	12.6
1955	6,807	0	6,645	162	6,807	(3)	6,807	524	13.2
1956	7,151	0	6,951	201	7,151	(3)	7,151	551	13.3
1957	7,170	0	6,940	229	7,170	(3)	7,170	569	12.6
1958	6,710	0	6,473	236	6,710	(3)	6,710	575	11.7
1959	7,053	1	6,779	274	7,054	(3)	7,054	583	12.2
1960	7,034	2	6,716	319	7,035	(3)	7,035	591	12.0
1961	7,166	17	6,817	365	7,183	(3)	7,183	595	12.1
1962	7,304	28	6,888	444	7,332	(3)	7,332	598	12.3
1963	7,512	29	7,026	515	7,542	(3)	7,542	589	12.7
1964	7,584	30	7,027	587	7,614	(3)	7,614	588	12.9
1965	7,774	30	7,140	665	7,804	(3)	7,804	589	13.3
1966	8,256	39	7,473	823	8,295	(3)	8,295	583	14.2
1967	8,730	80	7,802	1,009	8,810	(3)	8,810	565	15.3
1968	8,915	181	7,808	1,287	8,660	436	9,096	554	16.2
1969	9,035	203	7,797	1,441	8,778	460	9,238	542	16.9
1970	9,408	229	8,060	1,577	9,180	457	9,637	531	18.0
1971	9,245	218	7,779	1,684	9,032	431	9,463	517	18.1
1972	9,242	199	7,780	1,660	8,998	443	9,441	508	18.4
1973	9,010	198	7,592	1,616	8,784	424	9,208	497	18.3
1974	8,581	193	7,285	1,489	8,375	399	8,774	498	17.6
1975	8,183	191	7,012	1,362	8,007	367	8,375	500	16.8
1976	7,958	173	6,868	1,264	7,776	356	8,132	499	16.3
1977	7,781	464	7,069	1,176	7,875	370	8,245	507	16.4
1978	7,478	1,229	7,571	1,136	8,353	355	8,707	517	17.0
1979	7,151	1,401	7,485	1,067	8,181	371	8,552	531	16.3
1980	6,980	1,617	7,562	1,034	8,210	386	8,597	548	15.9
1981	6,962	1,609	7,537	1,034	8,178	395	8,572	557	15.4
1982	6,953	1,696	7,538	1,110	8,261	387	8,649	580	14.9
1983	6,974	1,714	7,492	1,196	8,688	(3)	8,688	603	14.4
1984	7,157	1,722	7,596	1,283	8,879	(3)	8,879	621	14.3
1985	7,146	1,825	7,722	1,250	8,971	(3)	8,971	647	13.9
1986	6,814	1,867	7,426	1,254	8,680	(3)	8,680	623	13.9
1987	6,387	1,962	7,153	1,196	8,349	(3)	8,349	620	13.5
1988	6,123	2,017	6,949	1,191	8,140	(3)	8,140	612	13.5
1989	5,739	1,874	6,486	1,127	7,613	(3)	7,613	603	12.6
1990	5,582	1,773	6,273	1,082	7,355	(3)	7,355	602	12.2
1991	5,618	1,798	6,245	1,172	7,417	(3)	7,417	614	12.1
1992	5,457	1,714	5,953	1,218	7,171	(3)	7,171	594	12.1
1993	5,264	1,582	5,606	1,241	6,847	(3)	6,847	584	11.7
1994	5,103	1,559	5,291	1,370	6,662	(3)	6,662	582	11.4
1995	5,076	1,484	5,035	1,525	6,560	(3)	6,560	574	11.4
1996	5,071	1,393	4,902	1,562	6,465	(3)	6,465	574	11.3
1997	5,156	1,296	4,803	1,648	6,452	(3)	6,452	573	11.3
1998	R5,077	1,175	R4,560	R1,692	R6,252	(3)	R6,252	R562	R11.1
1999P	4,875	1,050	4,521	1,405	5,925	(3)	5,925	554	10.7

[1] As of December 31.
[2] For 1954-1976, average productivity is based on the average number of producing wells. For 1977 forward, average productivity is based on the number of wells producing at end of year.
[3] Included in crude oil.
R=Revised. P=Preliminary.
Note: Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/oil_gas/petroleum/pet_frame.html.
Sources: Offshore: • 1954-1969—U.S. Geological Survey, *Outer Continental Shelf Statistics*, June 1979. • 1970-1975—Bureau of Mines, Mineral Industry Surveys, *Petroleum Statement, Annual*, annual reports. • 1976-1980—Energy Information Administration (EIA), Energy Data Reports, *Petroleum Statement, Annual*, annual reports. • 1981-1998—EIA, *Petroleum Supply Annual*, annual reports. • 1999—EIA, *Petroleum Supply Monthly* (February 2000). Oil Well Productivity: • 1954-1975—Bureau of Mines, *Minerals Yearbook*, "Crude Petroleum and Petroleum Products" chapter. • 1976-1980—EIA, Energy Data Reports, *Petroleum Statement, Annual*, annual reports. • 1981-1994—Independent Petroleum Association of America, *The Oil Producing Industry in Your State*. • 1995 forward—Gulf Publishing Co., *World Oil*, February issue. All Other Data: • 1954-1975—Bureau of Mines, Mineral Industry Surveys, *Petroleum Statement, Annual*, annual reports. • 1976-1980—EIA, Energy Data Reports, *Petroleum Statement, Annual*, annual reports. • 1981-1998—EIA, *Petroleum Supply Annual*, annual reports. • 1999—EIA, *Petroleum Supply Monthly* (February 2000).

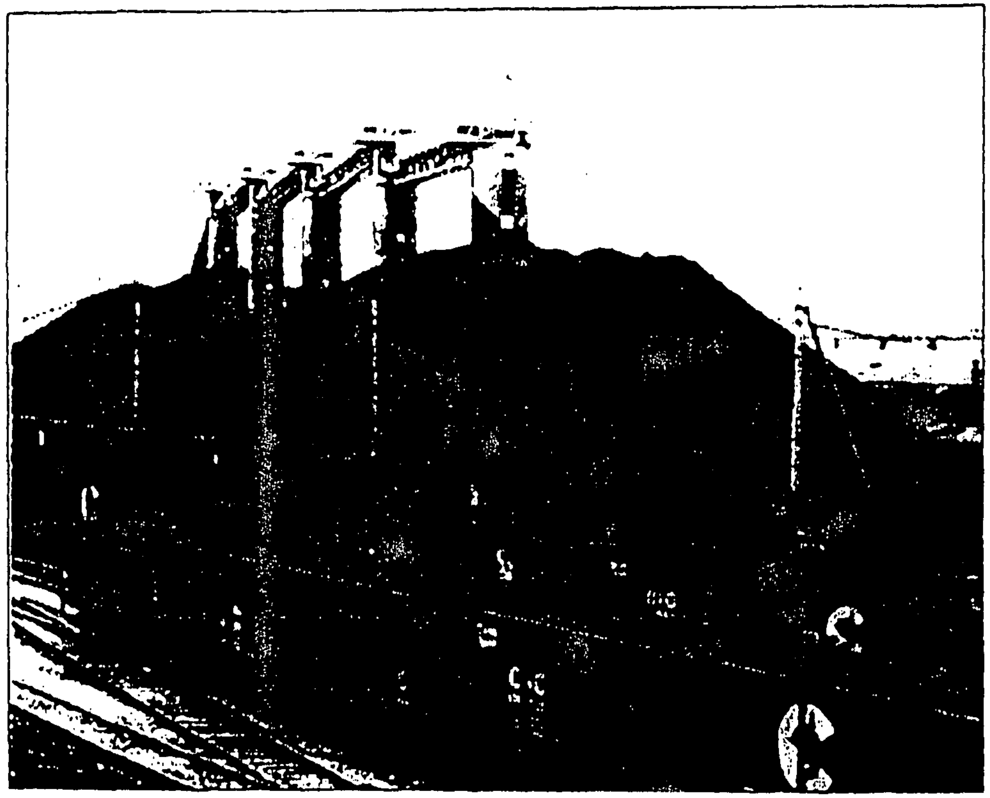
Average Electricity Prices by State, October 2000
(2000 cents per kilowatthour)



* Data for the state of Maine are unavailable due to deregulation activity.

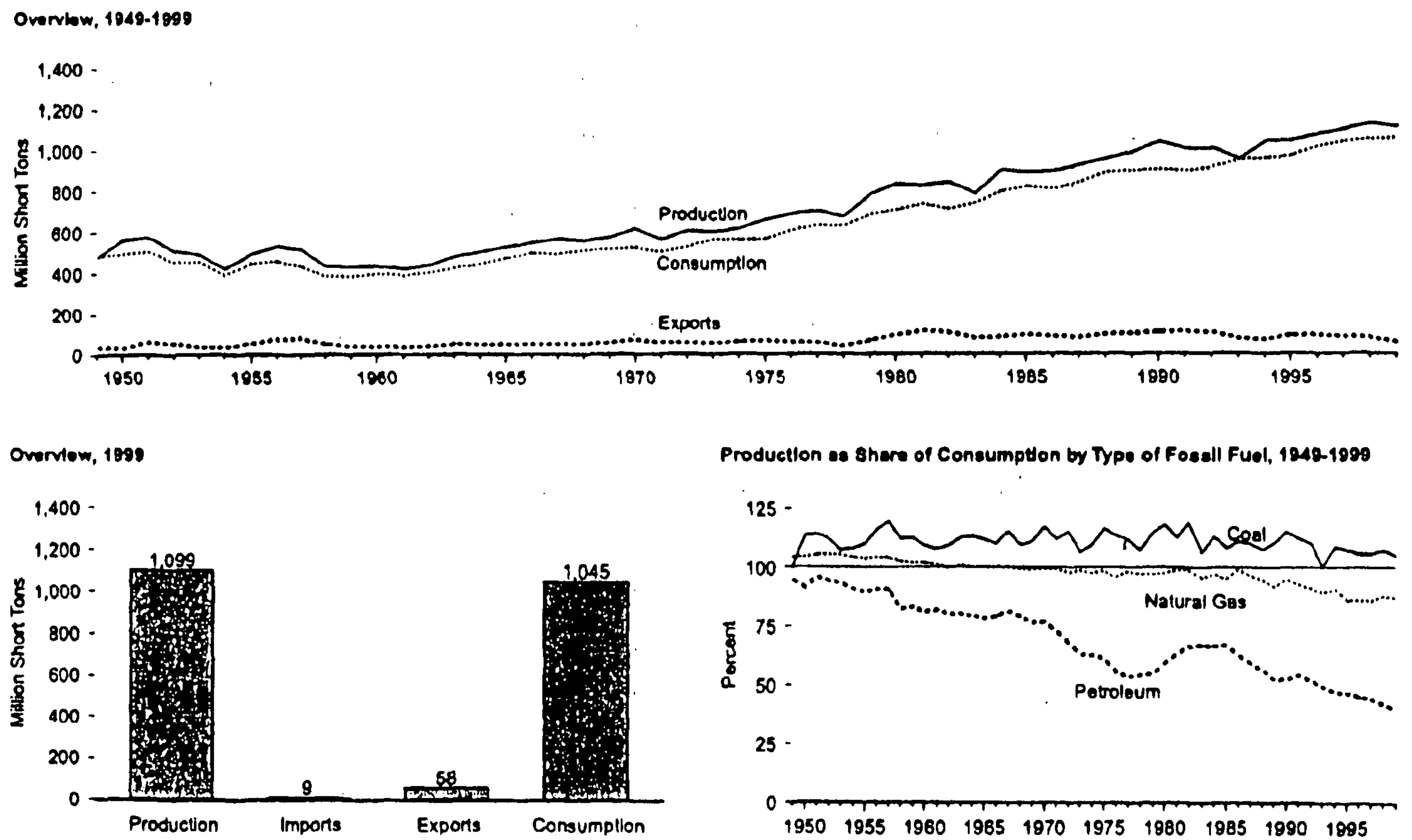
7

Coal



Coal yard, Curtis Bay, Maryland. Source: U.S. Department of Energy.

Figure 7.1 Coal Overview



Sources: Tables 5.1, 6.1, and 7.1.

Table 7.1 Coal Overview, 1949-1999

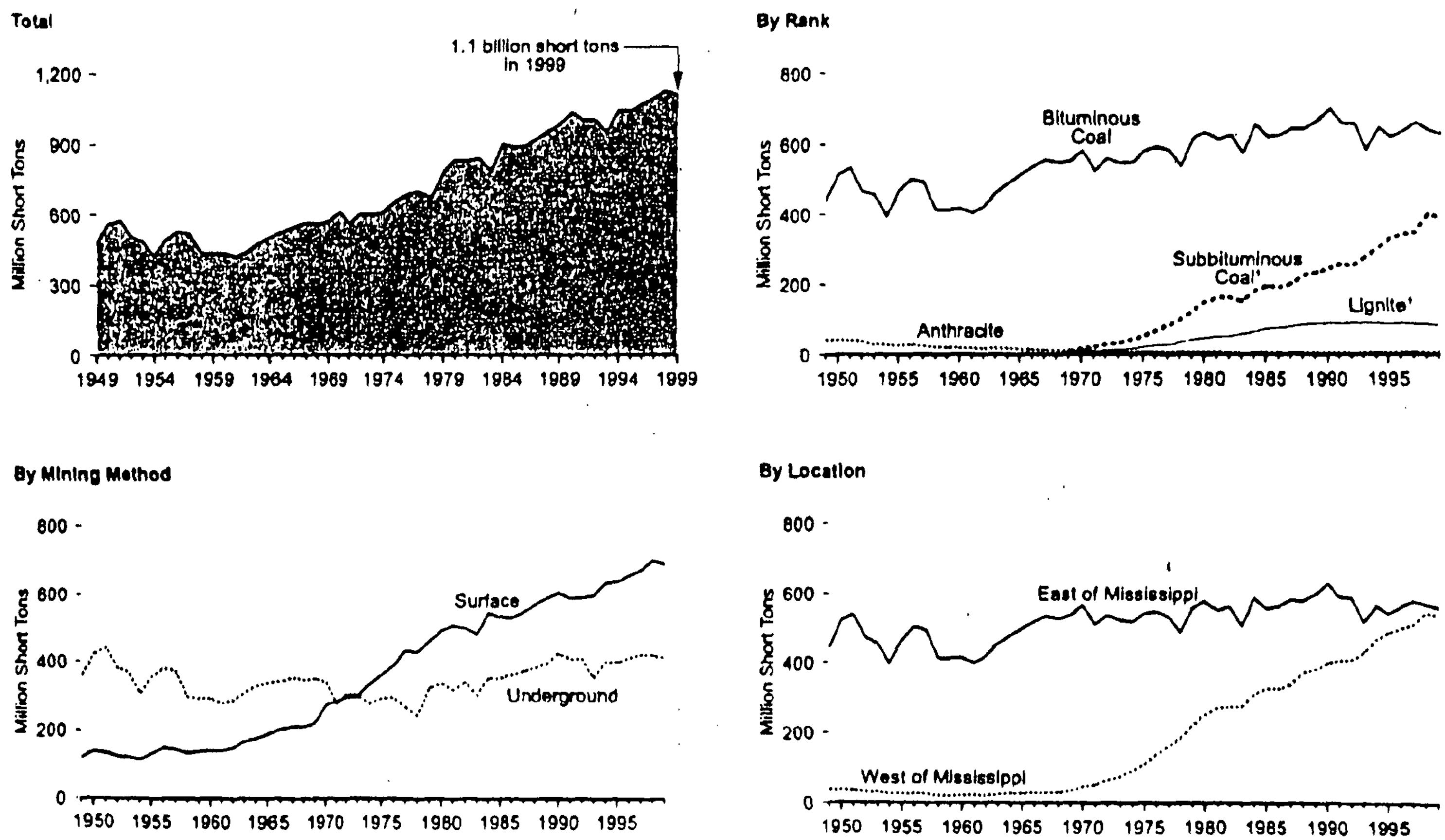
(Million Short Tons)

Year	Production	Imports	Exports	Stock Change [1]	Losses and Unaccounted for [2]	Consumption [3]
1949	480.6	0.3	32.8	[4]	[5]-35.1	483.2
1950	560.4	0.4	29.4	[4]	[5]9.5	494.1
1951	576.3	0.3	62.7	[4]	[5]3.5	505.9
1952	507.4	0.3	52.2	[4]	[5]0.8	454.1
1953	488.2	0.3	36.5	[4]	[5]-8.9	454.8
1954	420.8	0.2	33.9	[4]	[5]8.1	389.9
1955	490.8	0.3	54.4	[4]	[5]-6.3	447.0
1956	529.8	0.4	73.8	[4]	[5]-10.2	456.9
1957	518.0	0.4	80.8	[4]	[5]0.8	434.5
1958	431.6	0.3	52.6	[4]	[5]-1.3	385.7
1959	432.7	0.4	39.0	[4]	[5]9.2	385.1
1960	434.3	0.3	38.0	[4]	[5]1.7	398.1
1961	420.4	0.2	36.4	[4]	[5]-4.0	390.4
1962	439.0	0.2	40.2	[4]	[5]-1.5	402.3
1963	477.2	0.3	50.4	[4]	[5]3.3	423.5
1964	504.2	0.3	49.5	[4]	[5]4.0	445.7
1965	527.0	0.2	51.0	[4]	[5]2.2	472.0
1966	546.8	0.2	50.1	[4]	[5]2.2	497.7
1967	564.9	0.2	50.1	[4]	[5]4.8	491.4
1968	556.7	0.2	51.2	[4]	[5]3.5	509.8
1969	571.0	0.1	56.9	[4]	[5]2.9	516.4
1970	612.7	(s)	71.7	[4]	[5]6.8	523.2
1971	560.9	0.1	57.3	[4]	[5]4.2	501.8
1972	602.5	(s)	56.7	[4]	[5]-4.3	524.3
1973	598.6	0.1	53.6	[4]	[5]-17.9	562.6
1974	610.0	2.1	60.7	-8.9	2.0	558.4
1975	654.6	0.9	66.3	32.2	-5.5	562.6
1976	684.9	1.2	60.0	8.5	13.8	603.8
1977	697.2	1.6	54.3	22.6	-3.4	625.3
1978	670.2	3.0	40.7	-4.9	12.1	625.2
1979	781.1	2.1	66.0	36.2	0.4	680.5
1980	829.7	1.2	91.7	25.8	10.8	702.7
1981	823.8	1.0	112.5	-19.0	-1.4	732.6
1982	838.1	0.7	106.3	22.6	3.1	706.9
1983	782.1	1.3	77.8	-29.5	-1.6	736.7
1984	895.9	1.3	81.5	26.7	-4.3	791.3
1985	883.6	2.0	92.7	-27.9	2.8	818.0
1986	890.3	2.2	85.5	4.0	-1.2	804.2
1987	918.8	1.7	79.6	6.5	-2.5	836.9
1988	950.3	2.1	95.0	-24.9	-1.3	883.6
1989	980.7	2.9	100.8	-13.7	6.8	889.7
1990	1,029.1	2.7	105.8	26.5	3.9	895.5
1991	996.0	3.4	109.0	-0.9	3.7	887.6
1992	997.5	3.8	102.5	-3.0	-5.8	[3]907.7
1993	945.4	[R]8.2	74.5	-51.9	[R]-13.1	944.1
1994	1,033.5	[R]8.9	71.4	23.6	[R]-4.1	951.5
1995	1,033.0	[R]9.5	88.5	-0.3	[R]-7.9	962.0
1996	1,063.9	[R]8.1	90.5	-17.5	[R]-6.6	1,006.8
1997	1,089.9	7.5	83.5	-11.3	-4.1	1,029.2
1998	[R]1,117.5	8.7	[R]78.0	[R]24.2	[R]-16.1	[R]1,040.1
1999	[P]1,099.1	[P]9.1	[P]58.5	[P]6.2	[P]-1.6	[E]1,045.2

[1] Includes changes in stocks at electric utilities, coke plants, other industries, retail dealers, producers and distributors. A negative value indicates a net decrease in stocks; a positive value indicates a net increase in stocks.
[2] "Losses and Unaccounted for" is calculated as the sum of production and imports minus exports, stock change, and consumption.
[3] Independent power producers' use of coal (nonutility power producers in SIC 49, "Electric Gas, and Sanitary Services") are included beginning in 1992. See Table 7.3.
[4] Included in "Losses and Unaccounted for."
[5] Includes "Stock Change."
R=Revised. P=Preliminary. E=Estimate. (s)=Less than 0.05 million short tons.

Note: Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/fuelcoal.html.
Sources: • 1949-1975—Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters. • 1976—Energy Information Administration (EIA), Energy Data Report, *Coal-Bituminous and Lignite in 1976* and *Coal-Pennsylvania Anthracite 1976*. • 1977 and 1978—EIA, Energy Data Reports, *Bituminous Coal and Lignite Production and Mine Operations-1977; 1978* and *Coal-Pennsylvania Anthracite 1977; 1978*. • 1979 and 1980—EIA, Energy Data Report, *Weekly Coal Report*. • 1981-1988—EIA, *Weekly Coal Production* and *Coal Production*, annual reports. • 1989-1998—EIA, *Coal Industry Annual*, annual reports. • 1999—Tables 7.2, 7.3, 7.4, 7.5, of this report, and EIA, *Quarterly Coal Report October-December 1999* (May 2000), Table 6.

Figure 7.2 Coal Production, 1949-1999



¹ Included with bituminous coal prior to 1969.
Note: Because vertical scales differ, graphs should not be compared.

Source: Table 7.2.

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Table 7.2 Coal Production, 1949-1999

(Million Short Tons)

Year	Rank				Mining Method		Location		Total
	Bituminous Coal	Subbituminous Coal	Lignite	Anthracite	Underground	Surface	West of the Mississippi	East of the Mississippi	
1949	437.9	(1)	(1)	42.7	358.9	121.7	36.4	444.2	480.6
1950	516.3	(1)	(1)	44.1	421.0	139.4	36.0	524.4	560.4
1951	533.7	(1)	(1)	42.7	442.2	134.2	34.6	541.7	576.3
1952	466.8	(1)	(1)	40.6	381.2	126.3	32.7	474.8	507.4
1953	457.3	(1)	(1)	30.9	367.4	120.8	30.6	457.7	488.2
1954	391.7	(1)	(1)	29.1	306.0	114.8	25.4	395.4	420.8
1955	464.6	(1)	(1)	26.2	358.0	132.9	26.6	464.2	490.8
1956	500.9	(1)	(1)	28.9	380.8	148.9	25.8	504.0	529.8
1957	492.7	(1)	(1)	25.3	373.6	144.5	24.7	493.4	518.0
1958	410.4	(1)	(1)	21.2	297.6	134.0	20.3	411.3	431.6
1959	412.0	(1)	(1)	20.6	292.8	139.8	20.3	412.4	432.7
1960	415.5	(1)	(1)	18.8	292.6	141.7	21.3	413.0	434.3
1961	403.0	(1)	(1)	17.4	279.6	140.9	21.8	398.6	420.4
1962	422.1	(1)	(1)	16.9	287.9	151.1	21.4	417.6	439.0
1963	458.9	(1)	(1)	18.3	309.0	168.2	23.7	453.5	477.2
1964	487.0	(1)	(1)	17.2	327.7	176.6	25.7	478.5	504.2
1965	512.1	(1)	(1)	14.9	338.0	189.0	27.4	499.5	527.0
1966	533.9	(1)	(1)	12.9	342.6	204.2	28.0	518.8	546.8
1967	552.6	(1)	(1)	12.3	352.4	212.5	28.9	536.0	564.9
1968	545.2	(1)	(1)	11.5	346.6	210.1	29.7	527.0	556.7
1969	547.2	8.3	5.0	10.5	349.2	221.7	33.3	537.7	571.0
1970	578.5	16.4	8.0	9.7	340.5	272.1	44.9	567.8	612.7
1971	521.3	22.2	8.7	8.7	277.2	283.7	51.0	509.9	560.9
1972	556.8	27.5	11.0	7.1	305.0	297.4	64.3	538.2	602.5
1973	543.5	33.9	14.3	6.8	300.1	298.5	76.4	522.1	598.6
1974	545.7	42.2	15.5	6.6	278.0	332.1	91.9	518.1	610.0
1975	577.5	51.1	19.8	6.2	293.5	361.2	110.9	543.7	654.6
1976	588.4	64.8	25.5	6.2	295.5	389.4	136.1	548.8	684.9
1977	581.0	82.1	28.2	5.9	266.6	430.6	163.9	533.3	697.2
1978	534.0	96.8	34.4	5.0	242.8	427.4	183.0	487.2	670.2
1979	612.3	121.5	42.5	4.8	320.9	480.2	221.4	559.7	781.1
1980	628.8	147.7	47.2	6.1	337.5	492.2	251.0	578.7	829.7
1981	608.0	159.7	50.7	5.4	316.5	507.3	269.9	553.9	823.8
1982	620.2	160.9	52.4	4.6	339.2	499.0	273.9	564.3	838.1
1983	568.6	151.0	58.3	4.1	300.4	481.7	274.7	507.4	782.1
1984	649.5	179.2	63.1	4.2	352.1	543.9	308.3	587.6	895.9
1985	613.9	192.7	72.4	4.7	350.8	532.8	324.9	558.7	883.6
1986	620.1	189.6	76.4	4.3	360.4	529.9	325.9	564.4	890.3
1987	636.6	200.2	78.4	3.6	372.9	545.9	336.8	581.9	918.8
1988	638.1	223.5	85.1	3.6	382.2	568.1	370.7	579.6	950.3
1989	659.8	231.2	86.4	3.3	393.8	586.9	381.7	599.0	980.7
1990	693.2	244.3	88.1	3.5	424.5	604.5	398.9	630.2	1,029.1
1991	650.7	255.3	86.5	3.4	407.2	588.8	404.7	591.3	996.0
1992	651.8	252.2	90.1	3.5	407.2	590.3	409.0	588.6	997.5
1993	576.7	274.9	89.5	4.3	351.1	594.4	429.2	516.2	945.4
1994	640.3	300.5	88.1	4.6	399.1	634.4	467.2	566.3	1,033.5
1995	613.8	328.0	86.5	4.7	396.2	636.7	488.7	544.2	1,033.0
1996	630.7	340.3	88.1	4.8	409.8	654.0	500.2	563.7	1,063.9
1997	653.8	345.1	86.3	4.7	420.7	669.3	510.6	579.4	1,089.9
1998	R631.7	R394.8	R85.8	R5.3	R417.7	R699.8	R547.0	570.6	R1,117.5
1999	E621.3	E388.3	E84.4	E5.2	E410.8	E688.3	E537.9	E561.2	P1,099.1

[1] Included in bituminous coal.

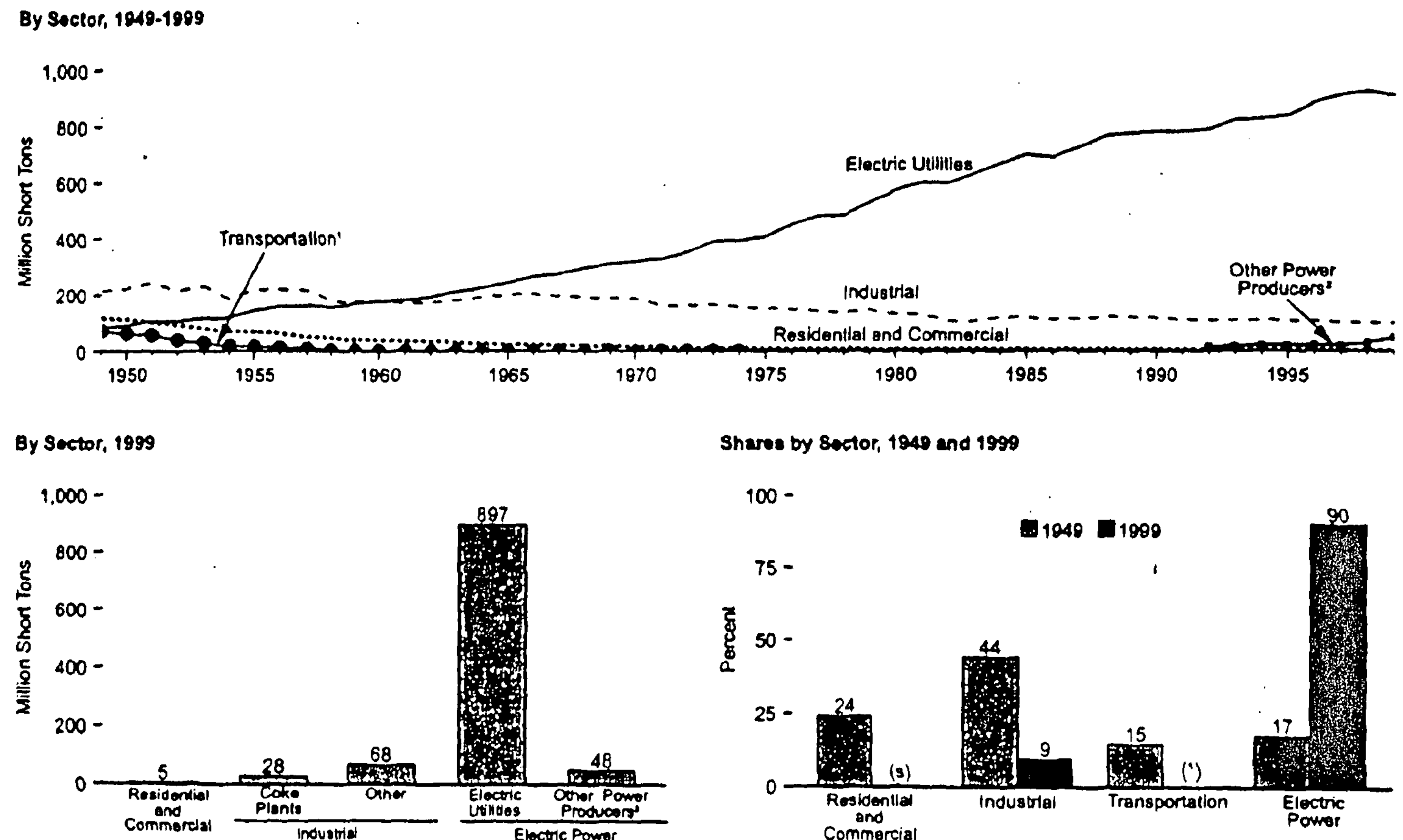
R=Revised. P=Preliminary. E=Estimated.

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

Web Page: http://www.eia.doe.gov/fuelcoal.html.

Sources: • 1949-1975—Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters. • 1976—Energy Information Administration (EIA), Energy Data Report, *Coal-Bituminous and Lignite in 1976* and *Coal-Pennsylvania Anthracite 1976*. • 1977 and 1978—EIA, Energy Data Report, *Bituminous Coal and Lignite Production and Mine Operations-1977; 1978, Coal-Pennsylvania Anthracite 1977; 1978*, and *Coal Production*, annual reports. • 1979 and 1980—EIA, Energy Data Report, *Weekly Coal Report* and *Coal Production*, annual reports. • 1981-1988—EIA, *Weekly Coal Production* and *Coal Production*, annual reports. • 1989-1997—EIA, *Coal Industry Annual*, annual reports. • 1998—EIA, Form EIA-7A, "Coal Production Report." • 1999—EIA estimates and *Quarterly Coal Report October-December 1999* (May 2000), Table 4.

Figure 7.3 Coal Consumption by Sector



[1] Quantities for 1975, 1976, and 1977 are less than 0.5 million short tons. After 1977, small amounts of coal consumed by the transportation sector are included in "Industrial."

[2] Nonutility wholesale producers of electricity and cogeneration plants not included in the end-use sectors.

(s)=Less than 0.5 percent.

Source: Table 7.3.

DOE006-0153

2796

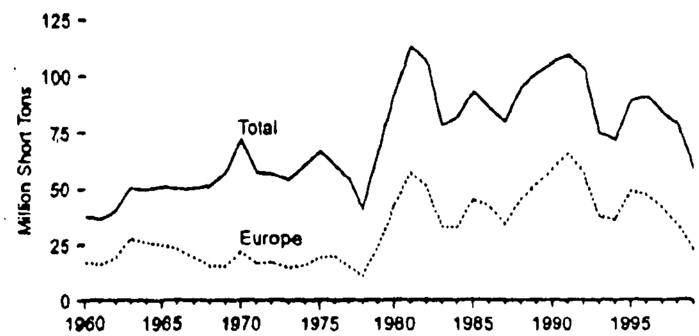
Table 7.3 Coal Consumption by Sector, 1949-1999
(Million Short Tons)

Year	End-Use Sectors[1]					Electric Power Sector			Total
	Residential and Commercial	Industrial			Transportation	Electric Utilities	Other Power Producers[2]	Total	
		Coke Plants	Other	Total					
1949	116.5	91.4	121.2	212.6	70.2	84.0	NA	84.0	483.2
1950	114.6	104.0	120.6	224.6	63.0	91.9	NA	91.9	494.1
1951	101.5	113.7	128.7	242.4	56.2	105.8	NA	105.8	505.9
1952	92.3	97.8	117.1	214.9	39.8	107.1	NA	107.1	454.1
1953	79.2	113.1	117.0	230.1	29.6	115.9	NA	115.9	454.8
1954	69.1	85.6	98.2	183.9	18.6	118.4	NA	118.4	389.9
1955	68.4	107.7	110.1	217.8	17.0	143.8	NA	143.8	447.0
1956	64.2	106.3	114.3	220.6	13.8	158.3	NA	158.3	456.9
1957	49.0	108.4	106.5	214.9	9.8	160.8	NA	160.8	434.5
1958	47.9	76.8	100.6	177.4	4.7	155.7	NA	155.7	385.7
1959	40.8	79.6	92.7	172.3	3.6	168.4	NA	168.4	385.1
1960	40.9	81.4	96.0	177.4	3.0	176.7	NA	176.7	398.1
1961	37.3	74.2	95.9	170.1	0.8	182.2	NA	182.2	390.4
1962	36.5	74.7	97.1	171.7	0.7	193.3	NA	193.3	402.3
1963	31.5	78.1	101.9	180.0	0.7	211.3	NA	211.3	423.5
1964	27.2	89.2	103.1	192.4	0.7	225.4	NA	225.4	445.7
1965	25.7	95.3	105.6	200.8	0.7	244.8	NA	244.8	472.0
1966	25.6	96.4	108.7	205.1	0.6	266.5	NA	266.5	497.7
1967	22.1	92.8	101.8	194.6	0.5	274.2	NA	274.2	491.4
1968	20.0	91.3	100.4	191.6	0.4	297.8	NA	297.8	509.8
1969	18.9	93.4	93.1	186.6	0.3	310.6	NA	310.6	516.4
1970	16.1	96.5	90.2	186.6	0.3	320.2	NA	320.2	523.2
1971	15.2	83.2	75.6	158.9	0.2	327.3	NA	327.3	501.6
1972	11.7	87.7	72.9	160.6	0.2	351.8	NA	351.8	524.3
1973	11.1	94.1	68.0	162.1	0.1	389.2	NA	389.2	562.6
1974	11.4	90.2	64.9	155.1	0.1	391.8	NA	391.8	558.4
1975	9.4	83.6	63.6	147.2	(s)	406.0	NA	406.0	562.6
1976	8.9	84.7	61.8	146.5	(s)	448.4	NA	448.4	603.8
1977	9.0	77.7	61.5	139.2	(s)	477.1	NA	477.1	625.3
1978	9.5	71.4	63.1	134.5	(3)	481.2	NA	481.2	625.2
1979	8.4	77.4	67.7	145.1	(3)	527.1	NA	527.1	680.5
1980	6.5	66.7	60.3	127.0	(3)	569.3	NA	569.3	702.7
1981	7.4	61.0	67.4	128.4	(3)	596.8	NA	596.8	732.6
1982	8.2	40.9	64.1	105.0	(3)	593.7	NA	593.7	706.9
1983	8.4	37.0	66.0	103.0	(3)	625.2	NA	625.2	736.7
1984	9.1	44.0	73.7	117.8	(3)	664.4	NA	664.4	791.3
1985	7.8	41.1	75.4	116.4	(3)	693.8	NA	693.8	818.0
1986	7.7	35.9	75.6	111.5	(3)	685.1	NA	685.1	804.2
1987	6.9	37.0	75.2	112.1	(3)	717.9	NA	717.9	836.9
1988	7.1	41.9	76.3	118.1	(3)	758.4	NA	758.4	883.6
1989	6.2	40.5	76.1	116.6	(3)	766.9	NA	766.9	889.7
1990	6.7	38.9	76.3	115.2	(3)	773.5	NA	773.5	895.5
1991	6.1	33.9	75.4	109.3	(3)	772.3	NA	772.3	887.6
1992	6.2	32.4	74.0	106.4	(3)	779.9	15.2	[4]795.1	[4]907.7
1993	6.2	31.3	74.9	106.2	(3)	813.5	18.1	831.6	944.1
1994	6.0	31.7	75.2	106.9	(3)	817.3	21.3	838.5	951.5
1995	5.8	33.0	73.1	106.1	(3)	829.0	21.2	850.2	962.0
1996	6.0	31.7	70.9	102.6	(3)	874.7	22.2	896.9	1,005.6
1997	6.5	30.2	70.6	100.8	(3)	900.4	21.6	922.0	1,029.2
1998	R4.9	R28.2	R68.1	R96.3	(3)	910.8	R28.1	R938.9	R1,040.1
1999E	4.9	27.9	68.0	95.9	(3)	896.6	47.8	944.4	1,045.2

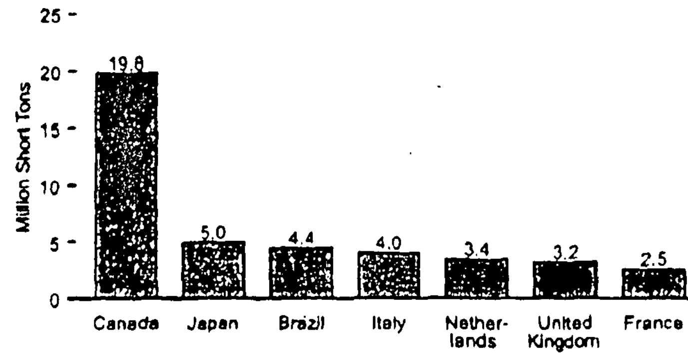
[1] Over half of the coal consumption at nonutility power producers is included in the end-use sectors.
[2] Nonutility wholesale producers of electricity, and nonutility cogeneration plants that are not included in the end-use sectors.
[3] After 1977, small amounts of coal consumed by the Transportation Sector are included in "Other" under the Industrial Sectors.
[4] There is a discontinuity in this time series between 1991 and 1992 due to the addition of the coal consumed by independent power producers beginning in 1992.
R=Revised. E=Estimated. NA=Not available. (s)=Less than 0.05 million short tons.
Notes: • See Note at end of section. • Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/fuelcoal.html.
Sources: • 1949-1975—Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters. • 1976—Energy Information Administration (EIA), *Energy Data Report*, *Coal-Bituminous and Lignite in 1976* and *Coal-Pennsylvania Anthracite 1976*. • 1977 and 1978—EIA, *Energy Data Report*, *Coal-Pennsylvania Anthracite 1977; 1978*, and *Weekly Coal Report*. • 1979 and 1980—EIA, *Energy Data Report*, *Weekly Coal Report*. • 1981-1998—EIA, *Quarterly Coal Report October-December*, quarterly reports. • 1999—Table 6.8 of this report and EIA, *Monthly Energy Review* (March 2000), Table 6.2.

Figure 7.4 Coal Exports by Country of Destination

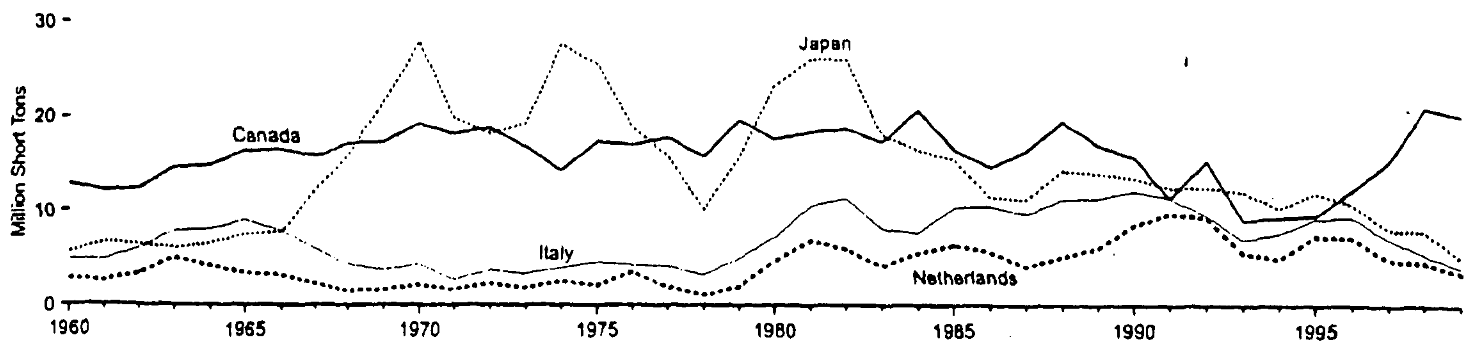
Total and Europe, 1960-1999



By Selected Country, 1999



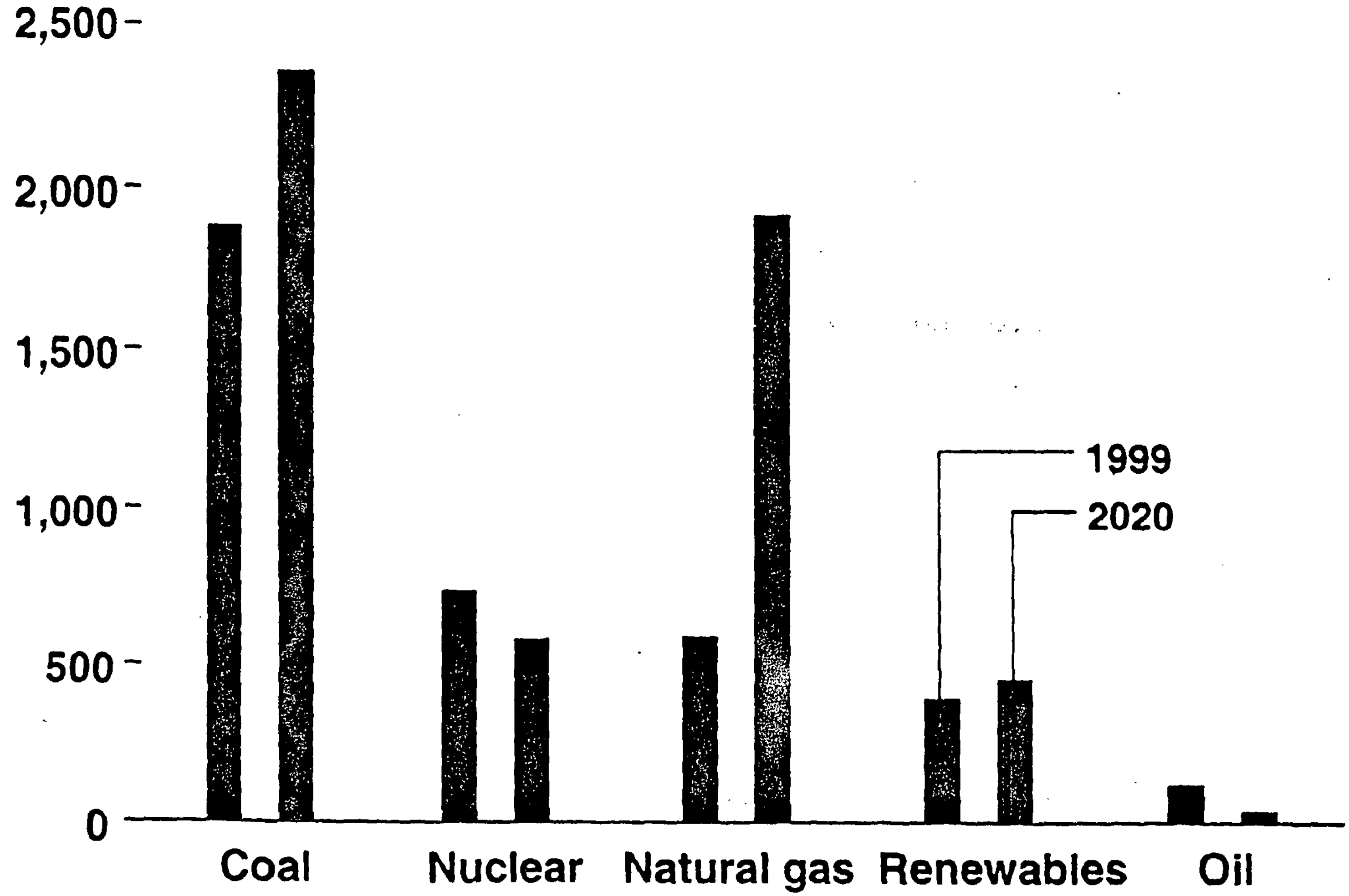
By Selected Country, 1960-1999



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

Source: Table 7.4.

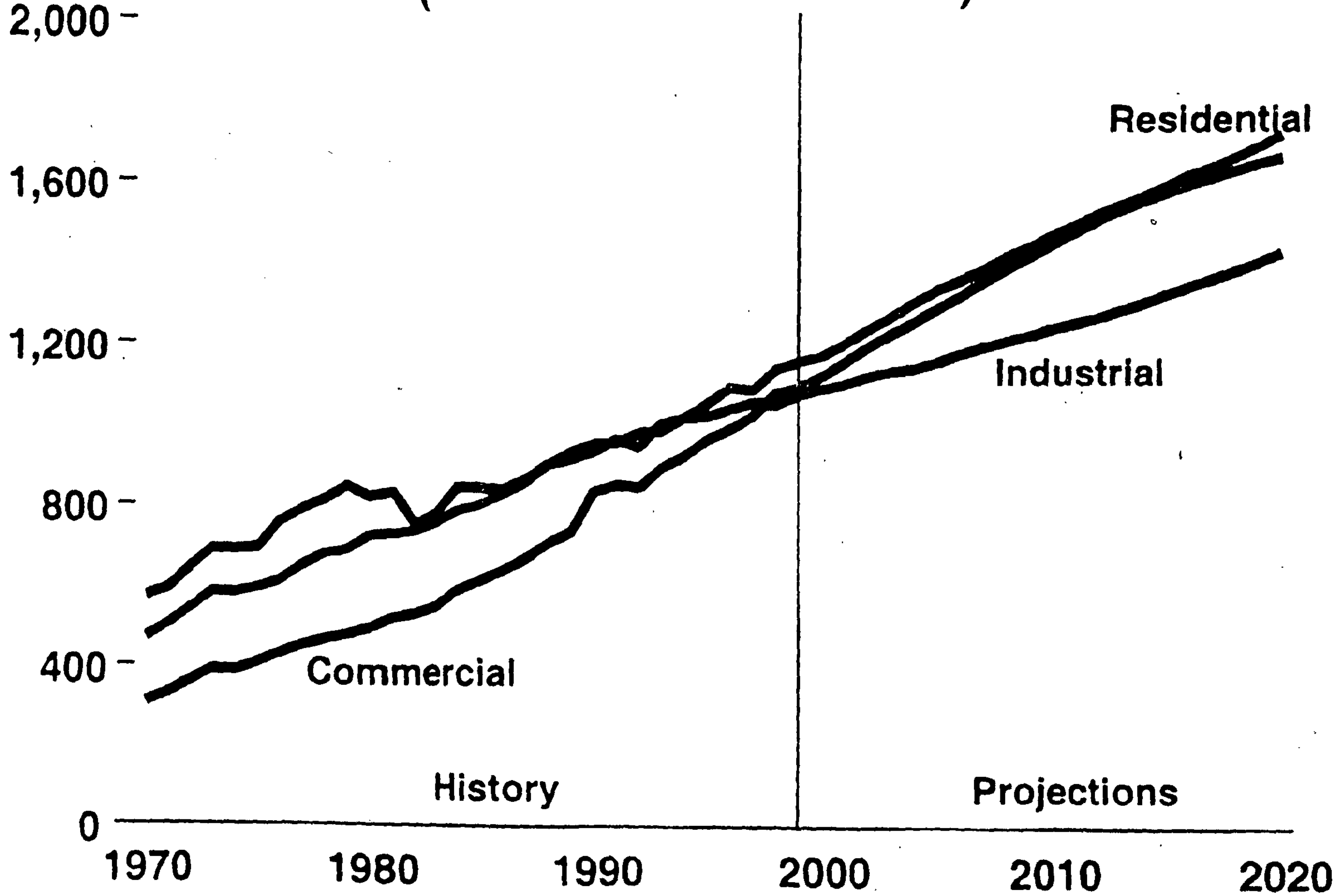
Figure -. Historical and Projected Electricity Generation by Fuel, 1999 and 2020 (billion kilowatthours)



DOE006-0156

2799

Figure -. Annual Electricity Sales by Sector, 1970-2020 (billion kilowatthours)



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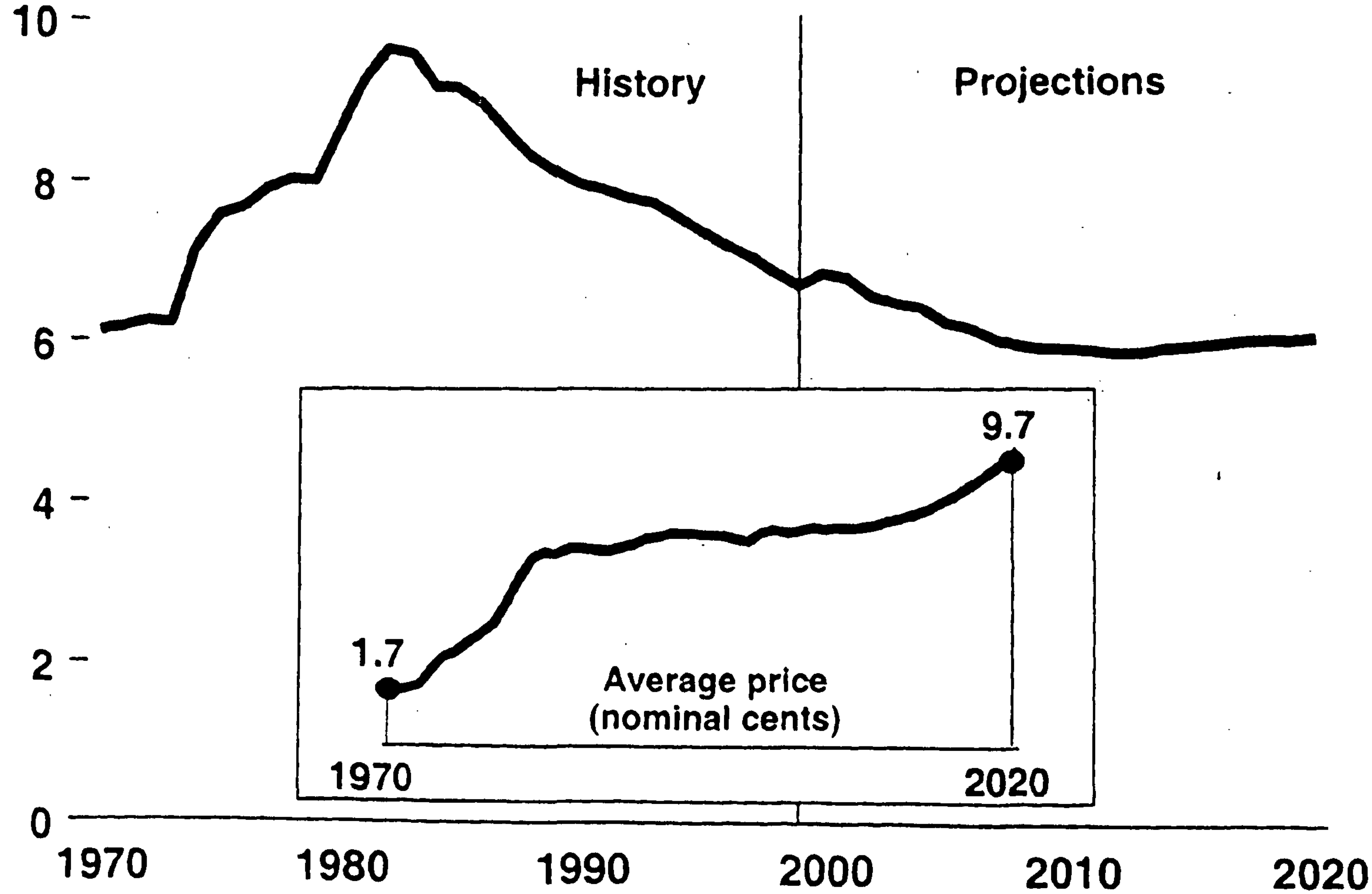
2800

Figure -. Average U.S. Retail Electricity Prices, 1970-2020 (1999 cents per kilowatthour)



DOE006-0158

2801

Figure -. Fuel Prices to Electricity Generators, 1990-2020
(1999 dollars per million Btu)

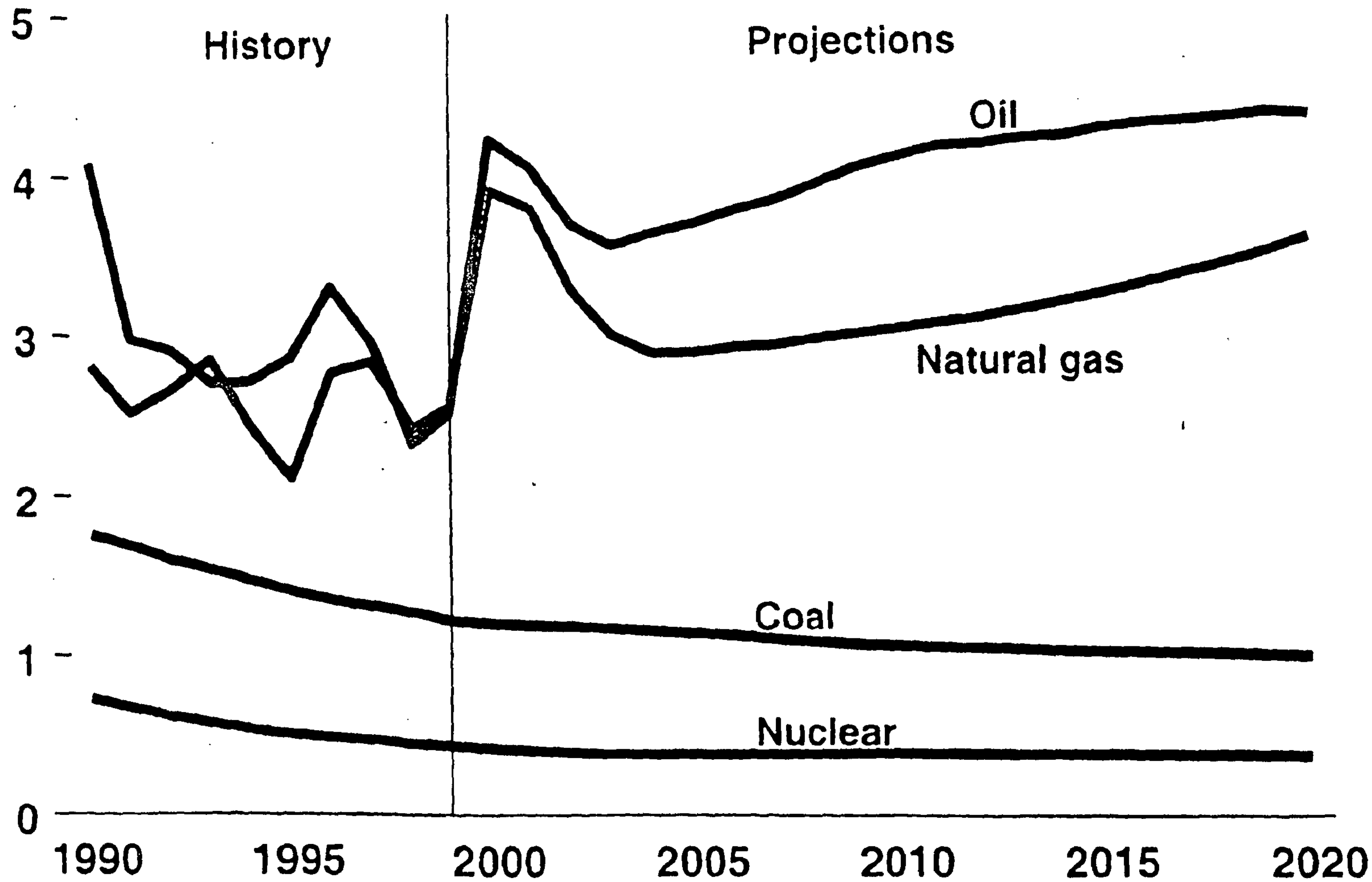


Figure -. Projected Electricity Generation Capacity Additions by Fuel Type, Including Cogeneration, 2000-2020 (gigawatts)

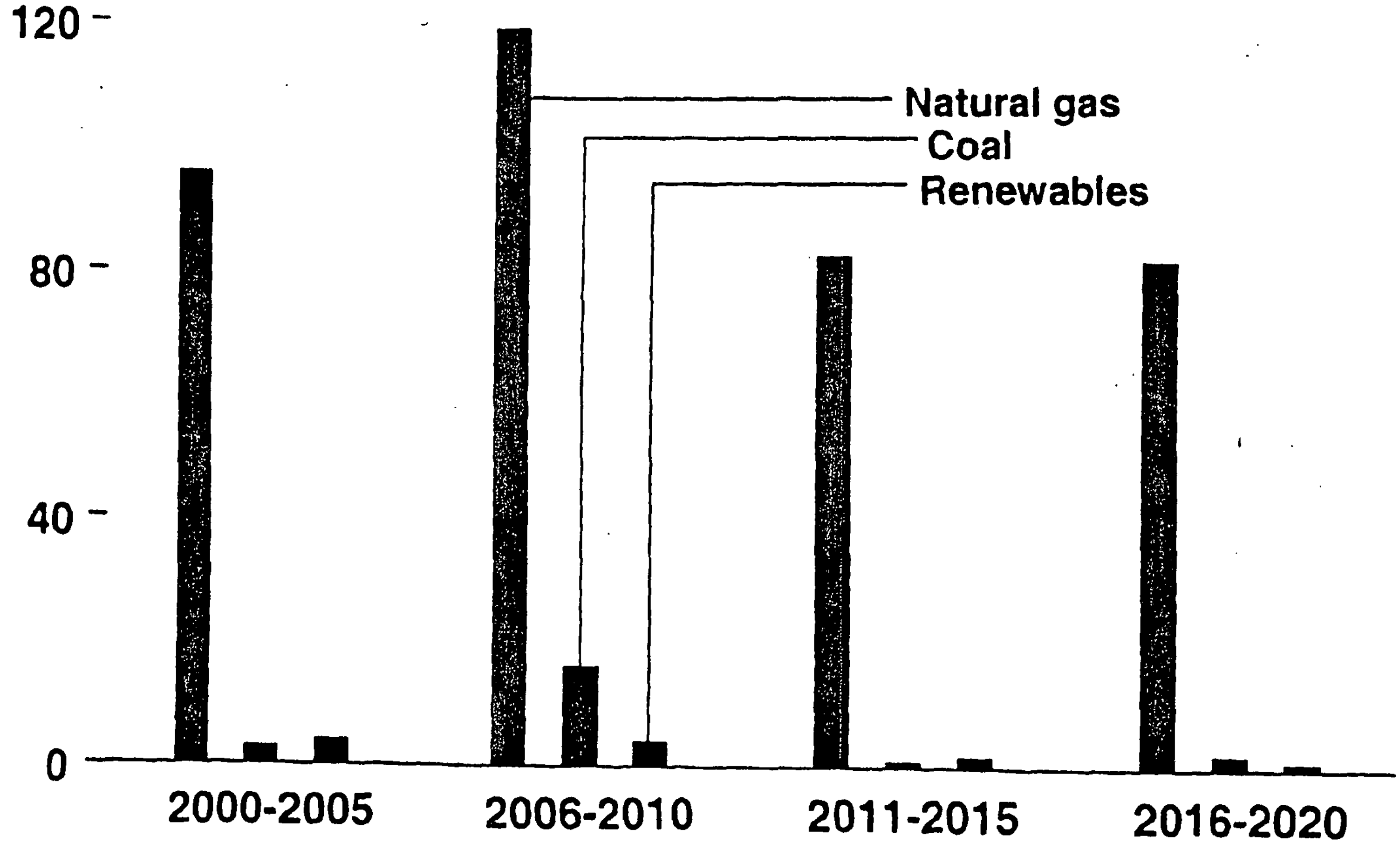
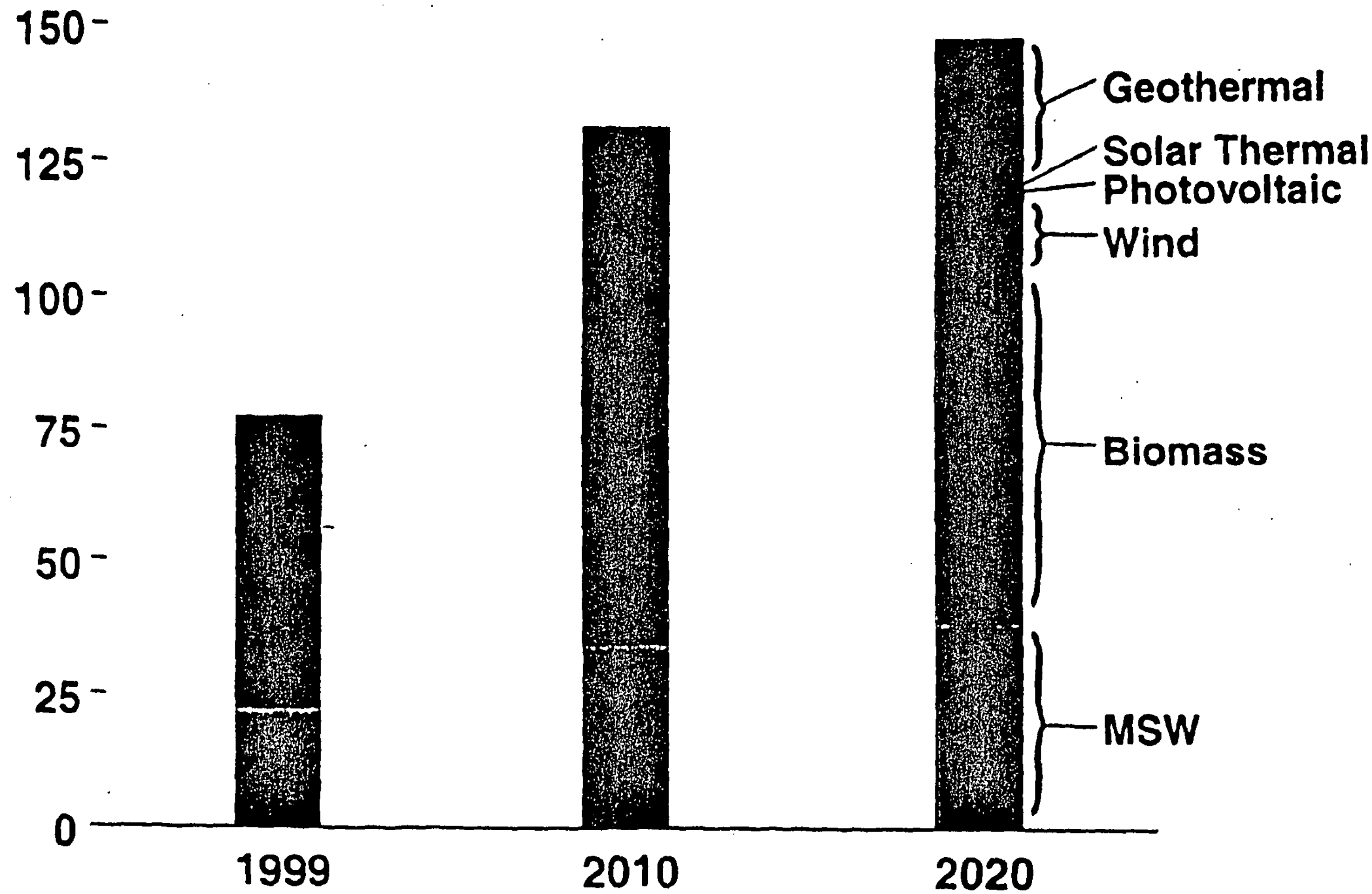
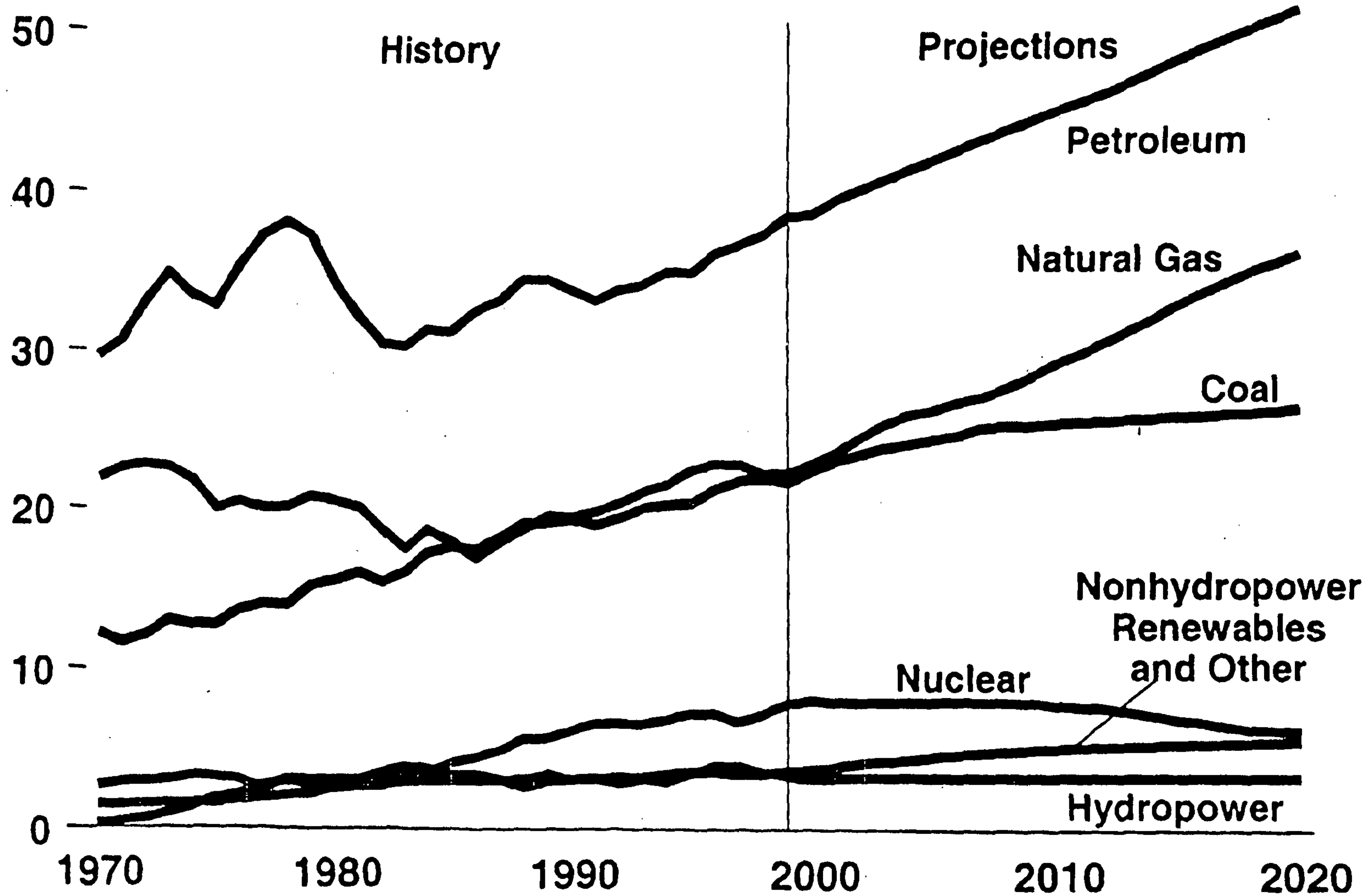


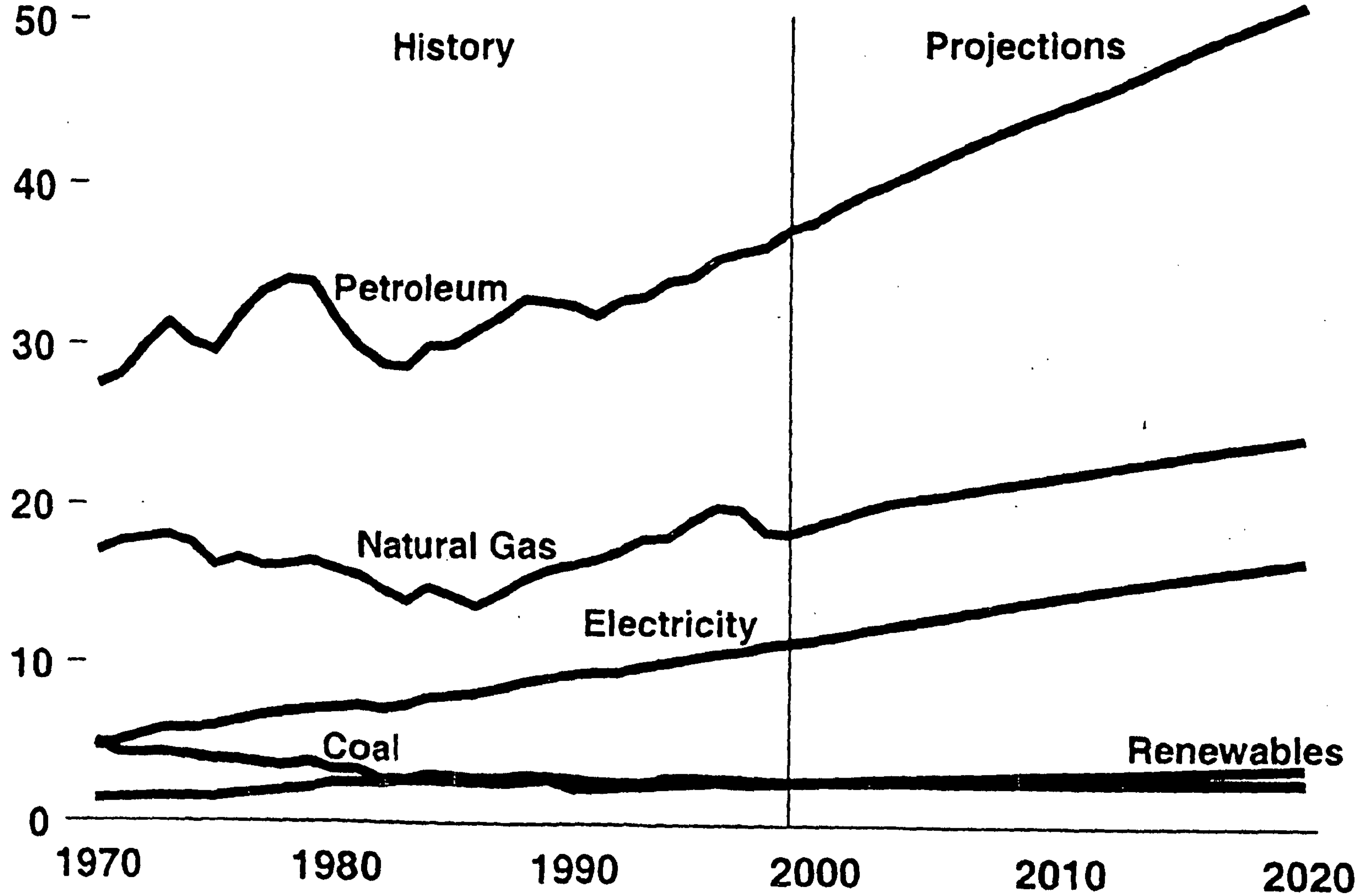
Figure -. Projected Nonhydroelectric Renewable Electricity Generation by Energy Source, 2010 and 2020 (billion kilowatthours)



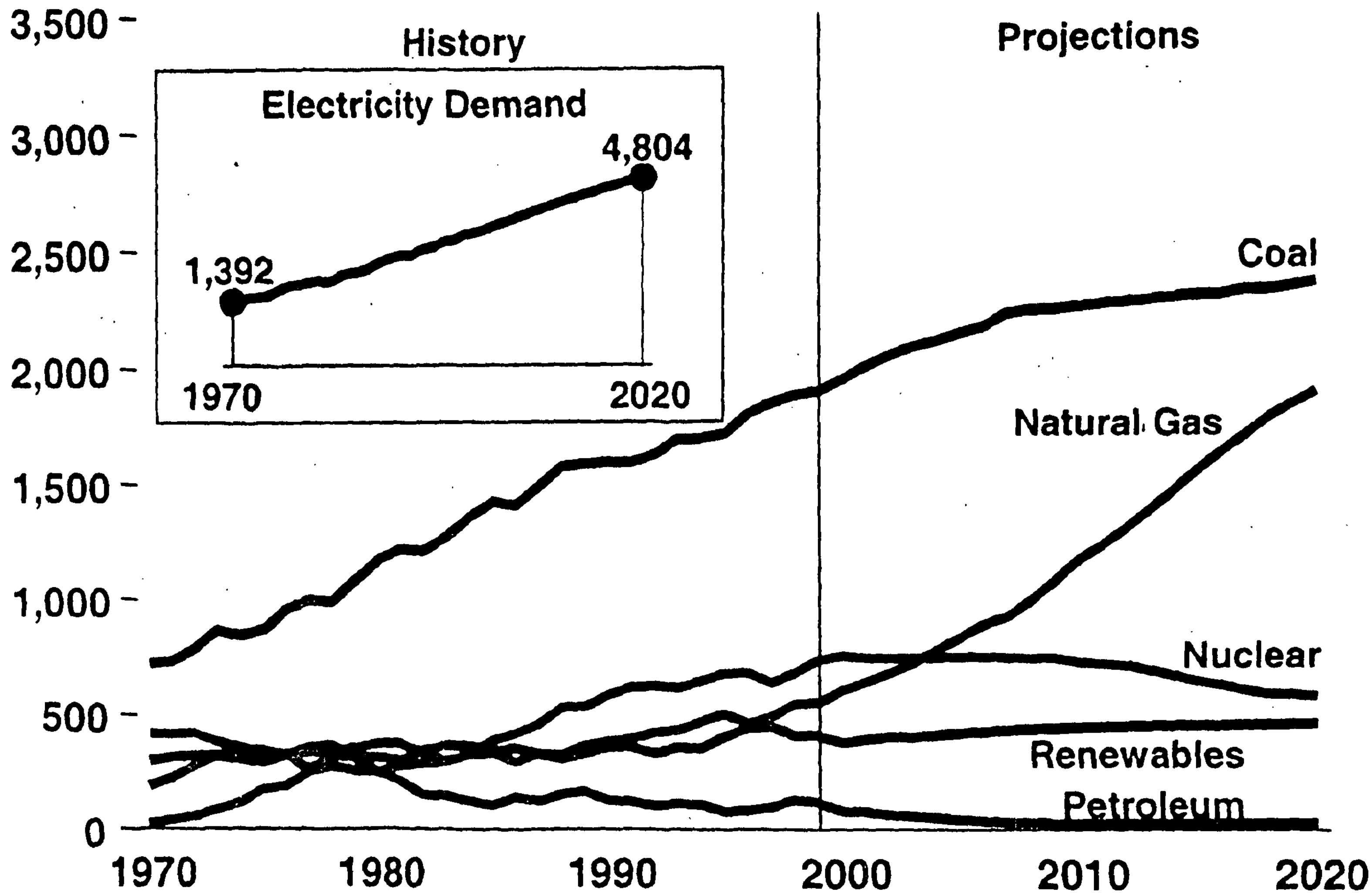
Primary Energy Consumption by Fuel, 1970-2020
(quadrillion Btu)



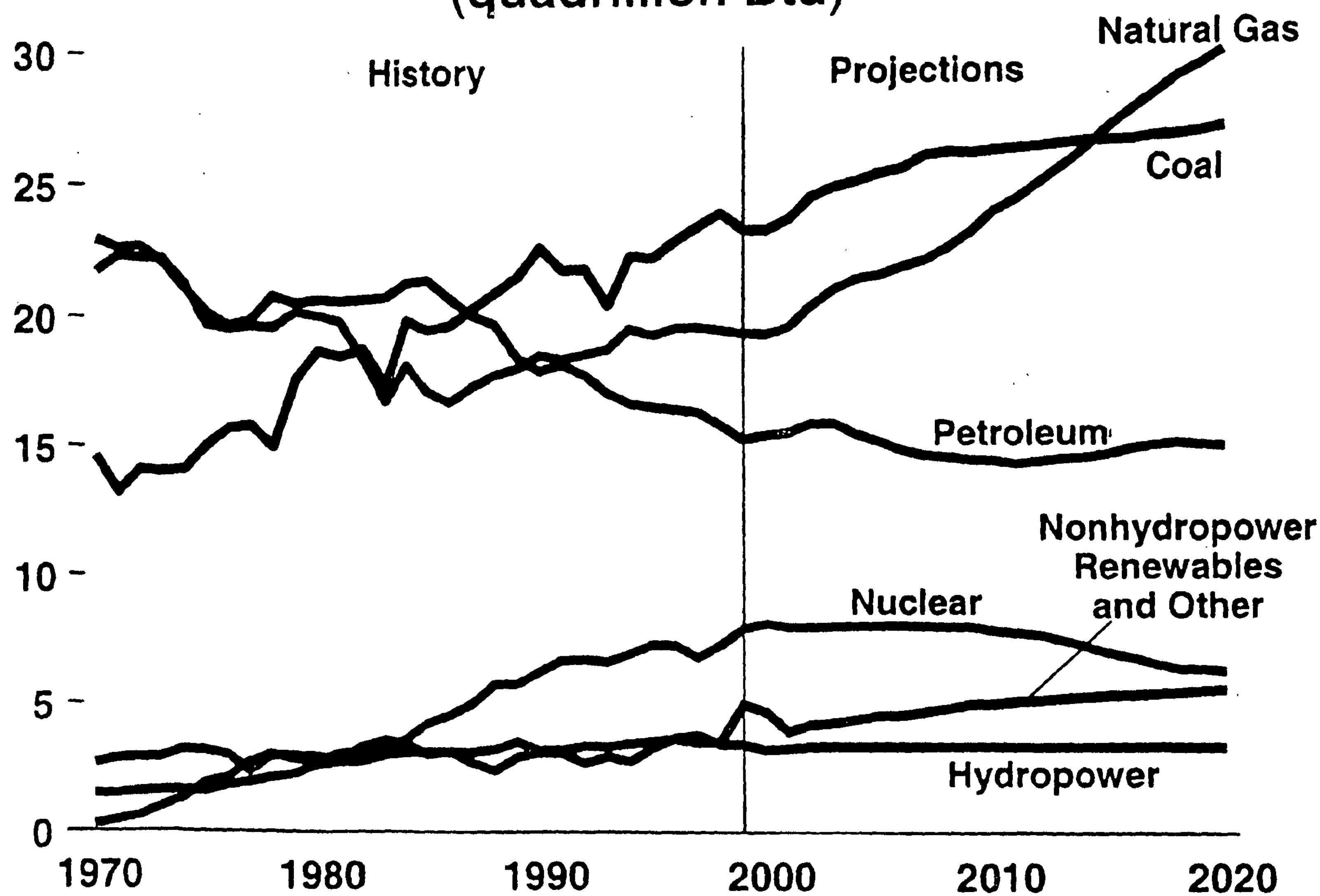
Delivered Energy Consumption by Fuel, 1970-2020
(quadrillion Btu)



Electricity Generation by Fuel, 1970-2020
(billion kilowatthours)



Energy Production by Fuel, 1970-2020
(quadrillion Btu)



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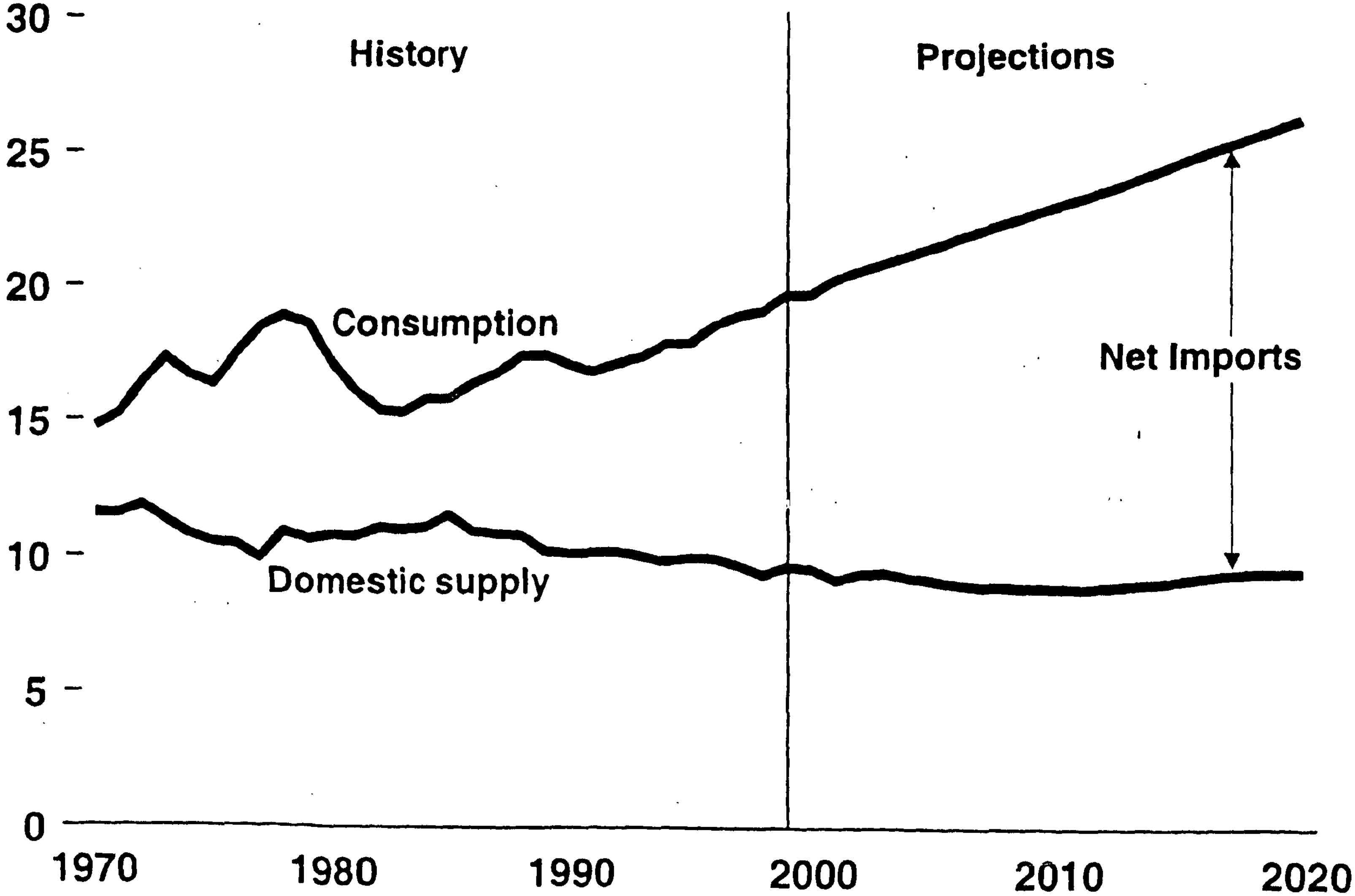
2808

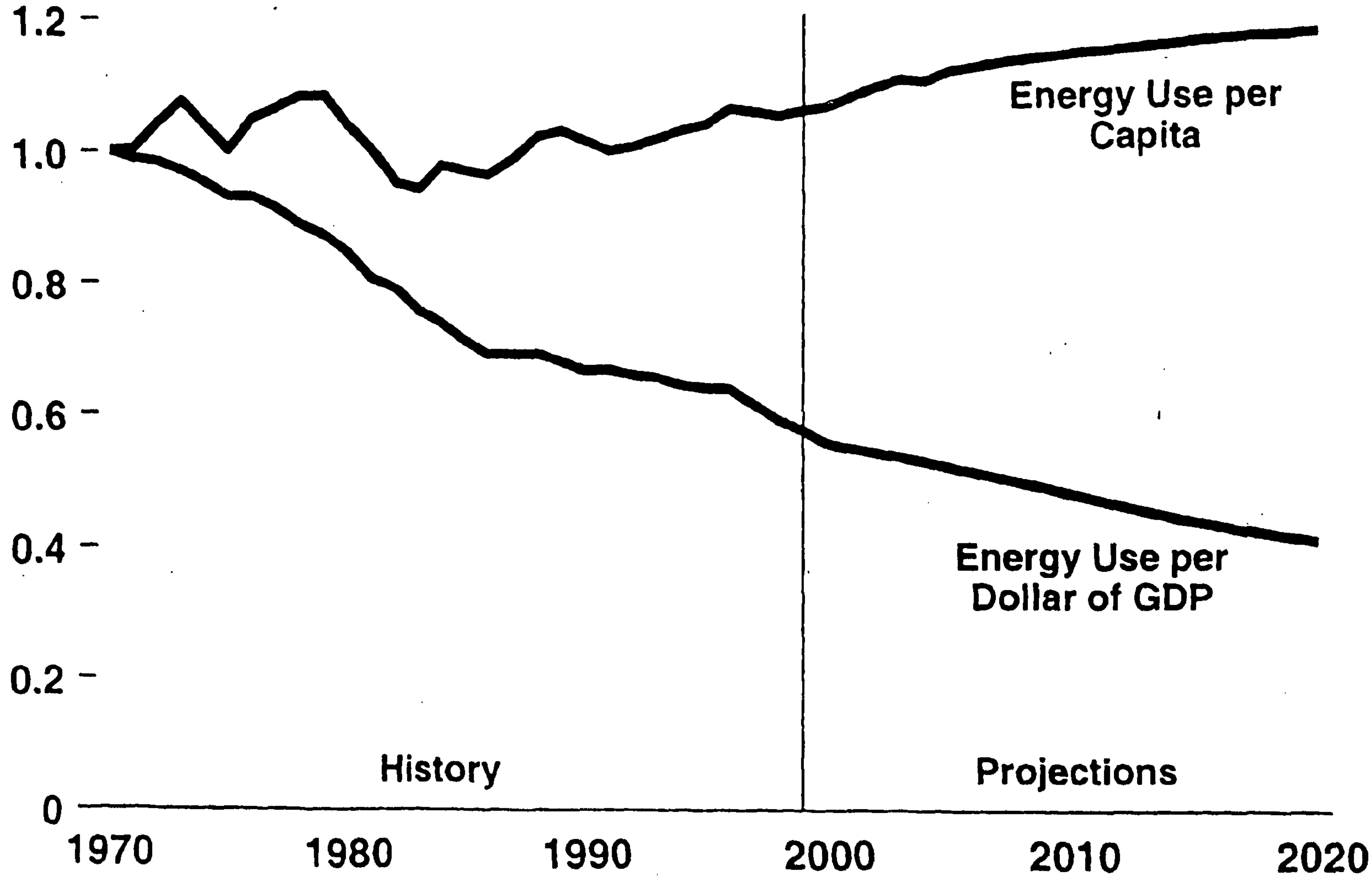
Petroleum Supply, Consumption, and Imports, 1970-2020 (million barrels per day)



DOE006-0166

2809

Energy Use per Capita and per Dollar of Gross Domestic Product, 1970-2020 (index, 1970 = 1)

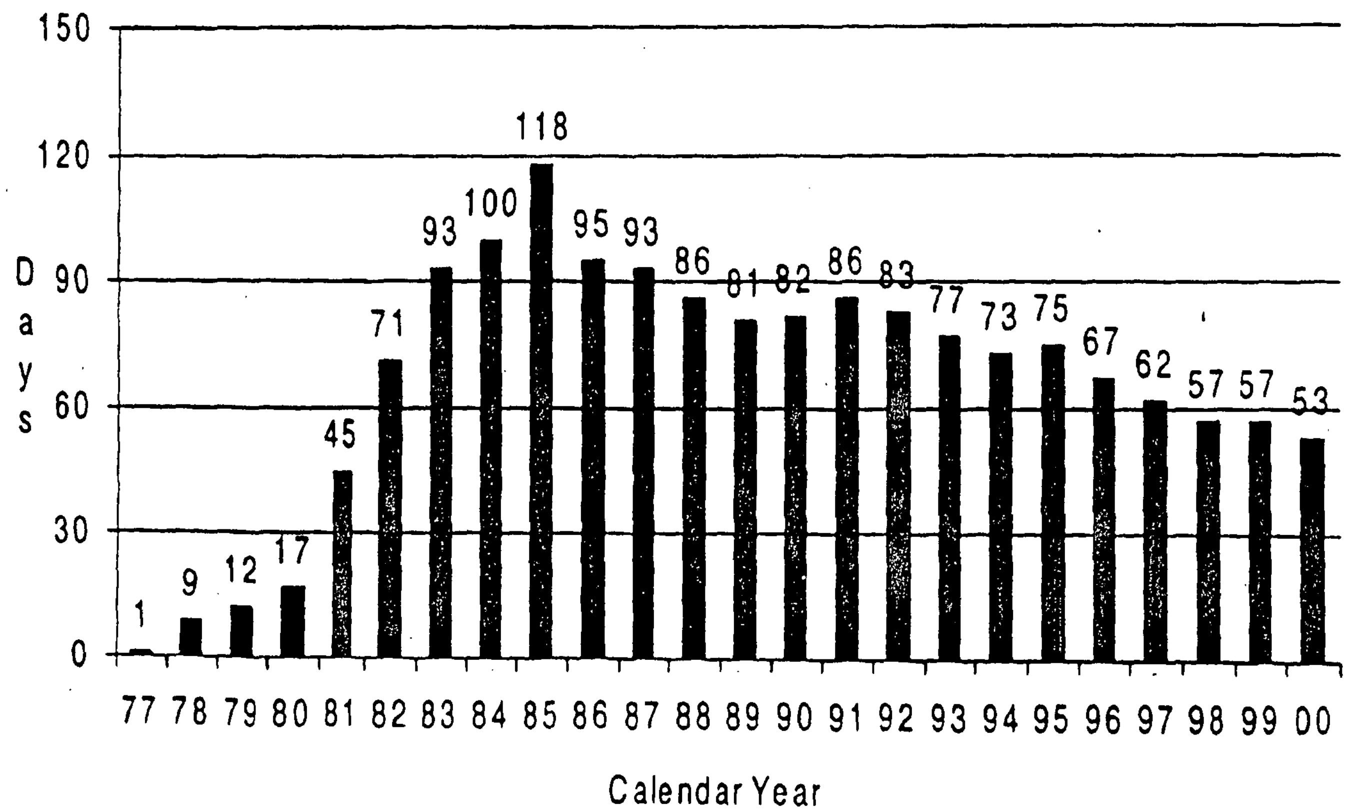


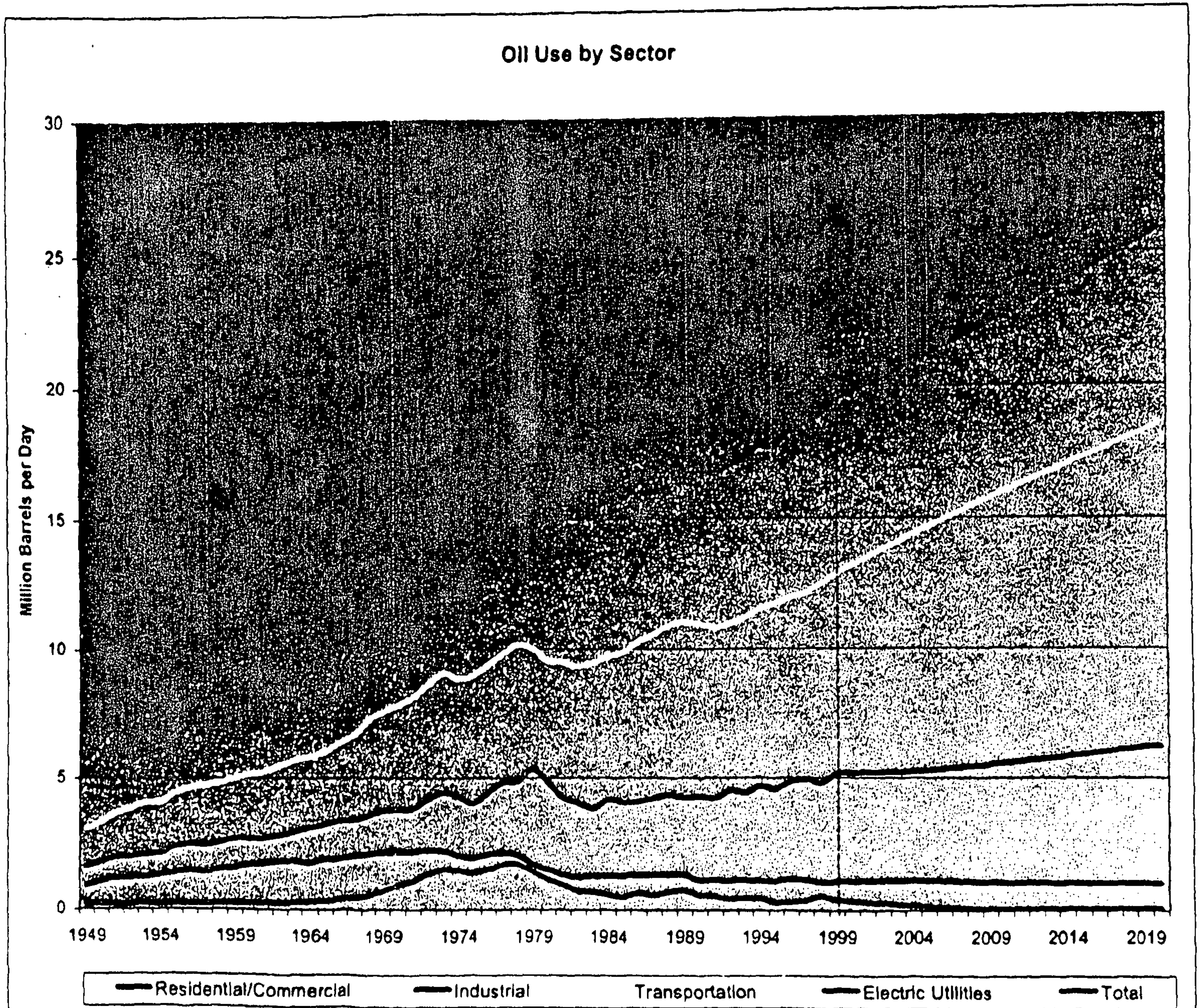
DOE006-0167

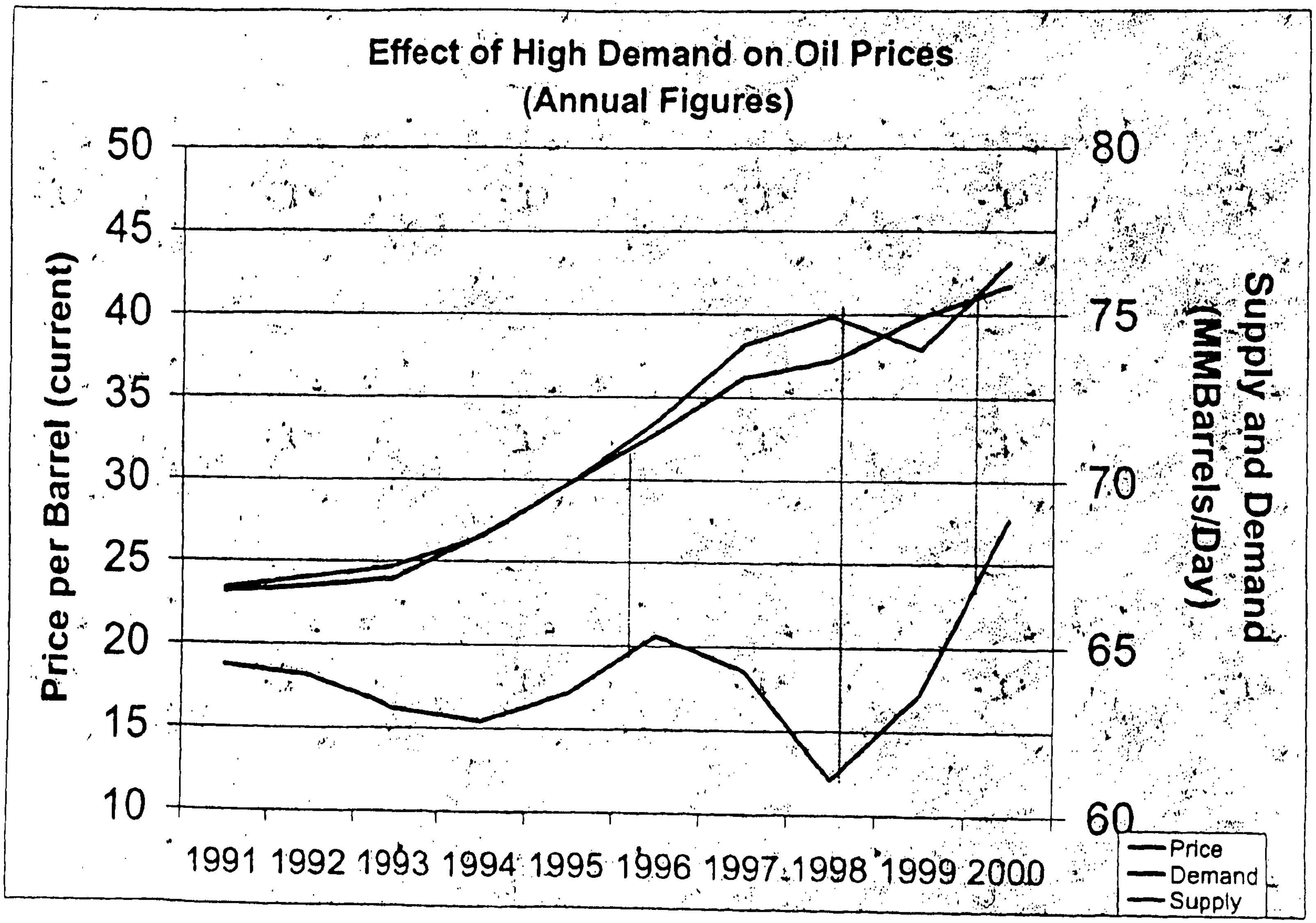
2810

Days of Net Import Protection (1977-2000)

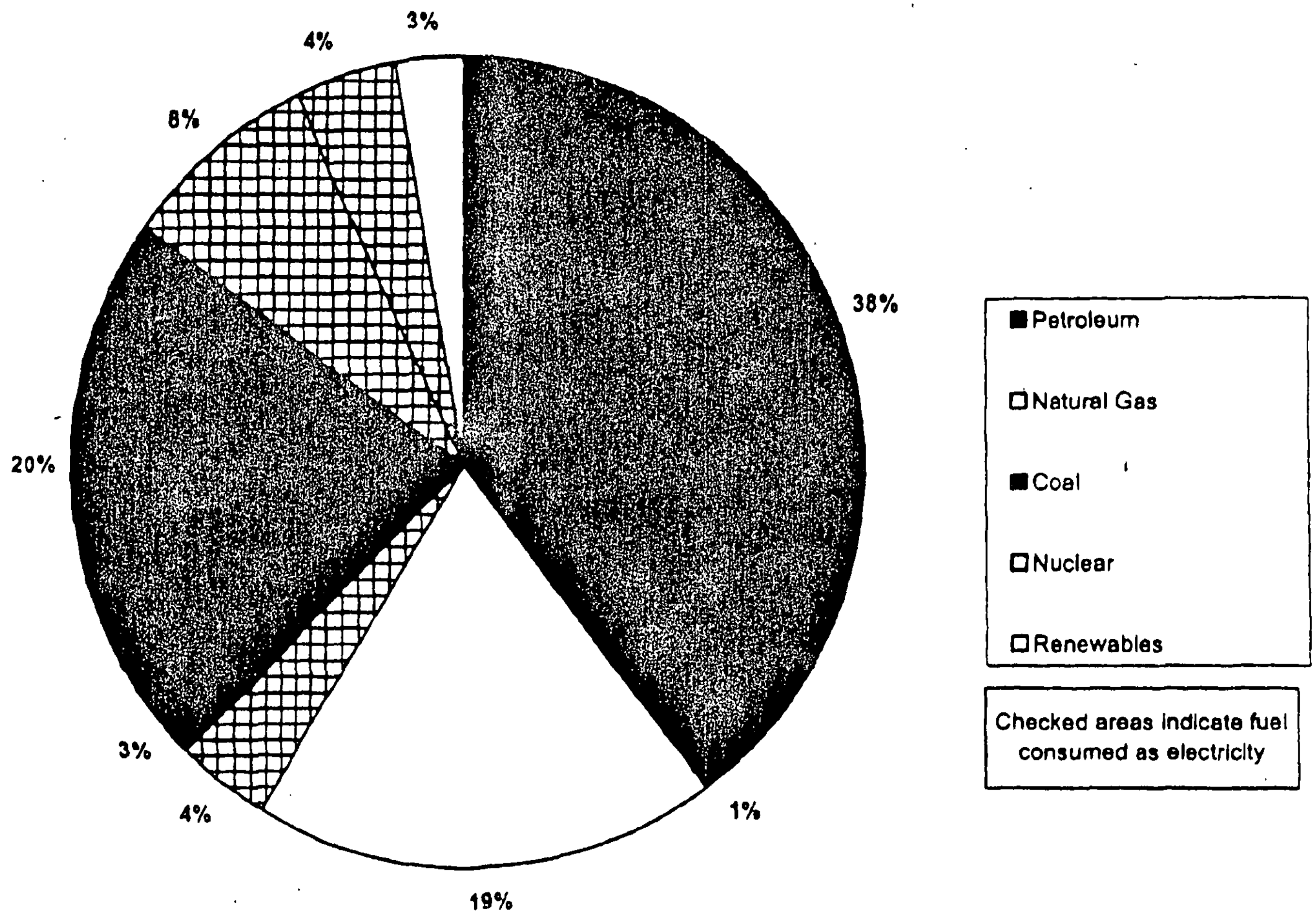
<u>SPR Inventory (Year End)</u>
U.S. Net Petroleum Imports/Day (Year Average)



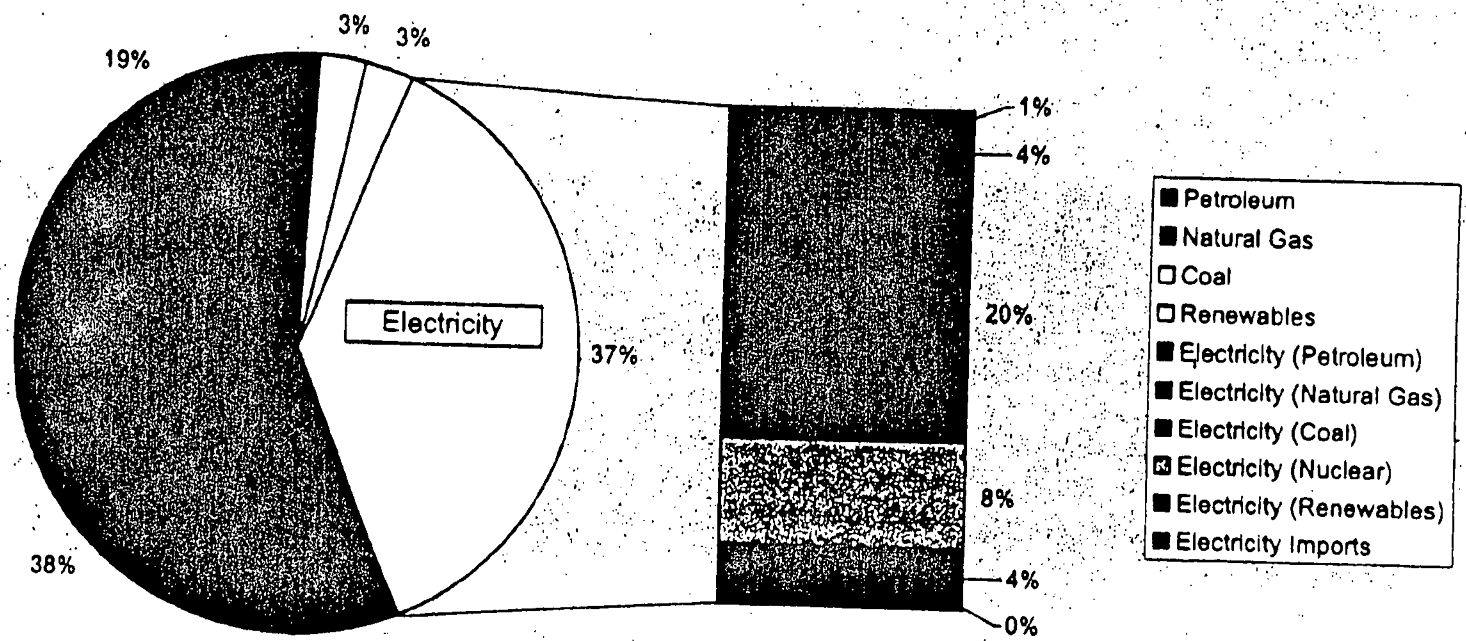

Oil Use by Sector
Million Barrels per Day
30
25
20
15
10
5
0
1949
1954
1959
1964
1969
1974
1979
1984
1989
1994
1999
2004
2009
2014
2019
Residential/Commercial
Industrial
Transportation
Electric Utilities
Total

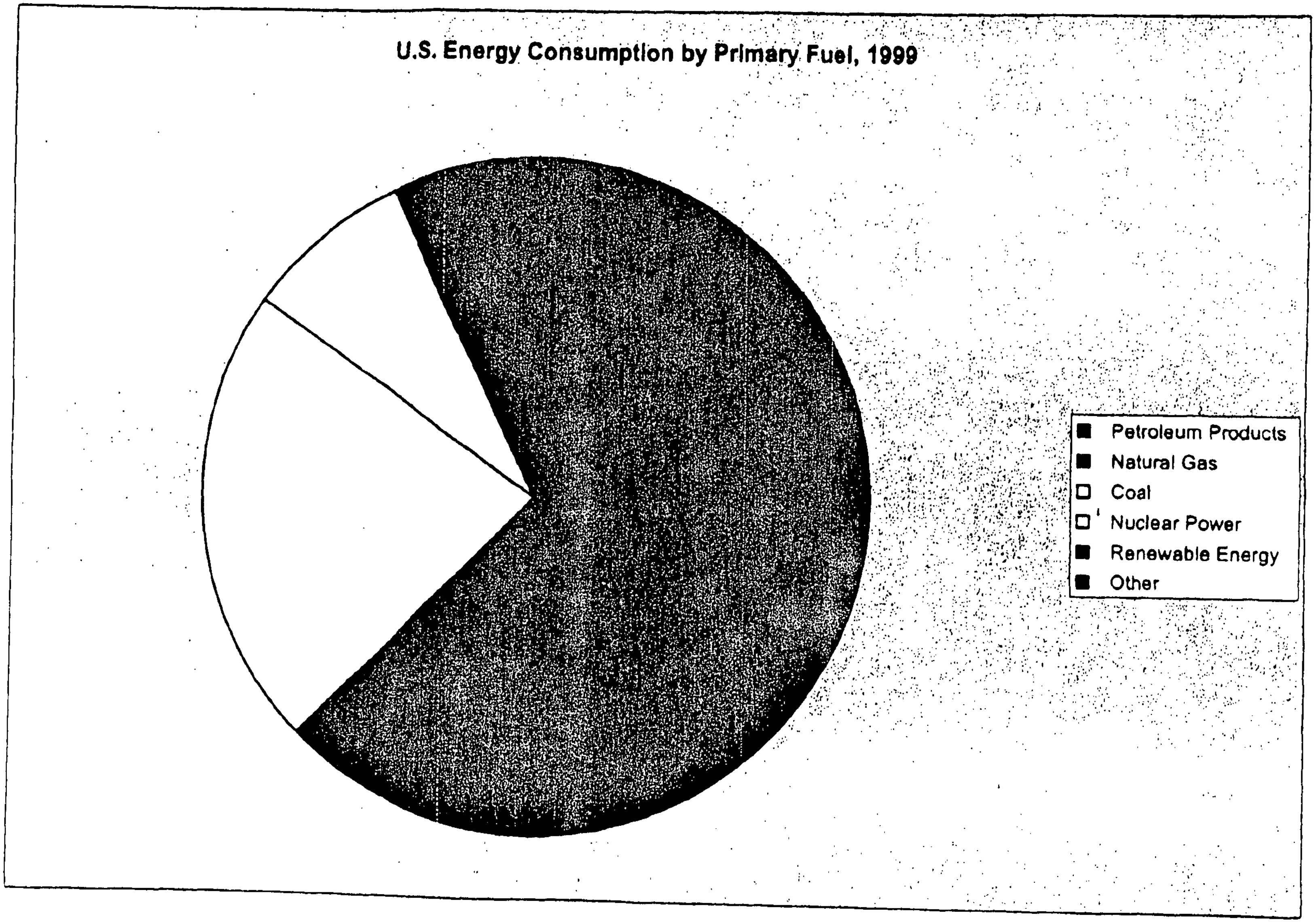

Effect of High Demand on Oil Prices
(Annual Figures)
Price per Barrel (current)
Supply and Demand (MMBarrels/Day)
50
45
40
35
30
25
20
15
10
80
75
70
65
60
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000
Price
Demand
Supply

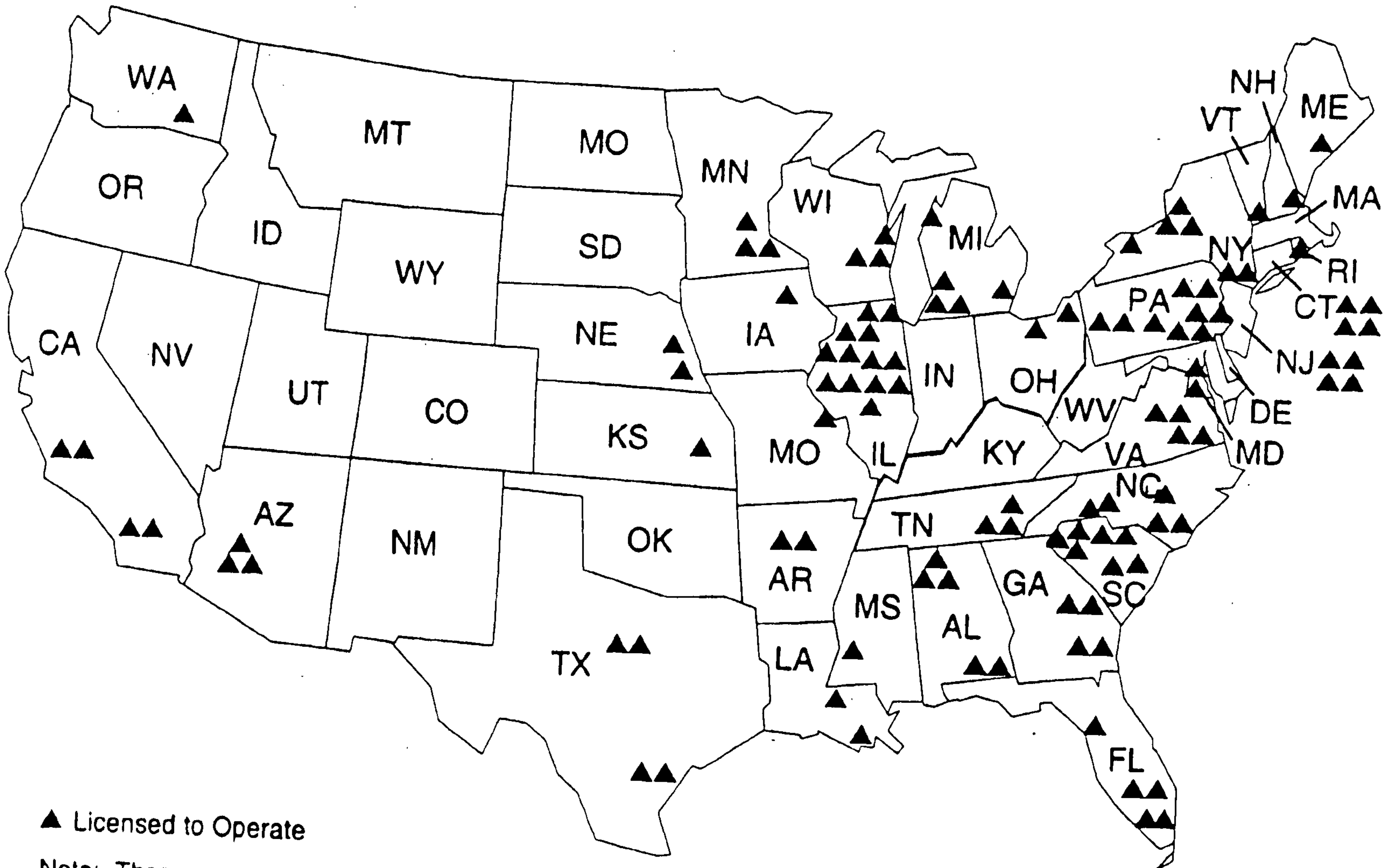
U.S. Energy Consumption, 1999



U.S. Delivered Energy Consumption Including Electricity-Related Losses




U.S. Energy Consumption by Primary Fuel, 1999
Petroleum Products
Natural Gas
Coal
Nuclear Power
Renewable Energy
Other

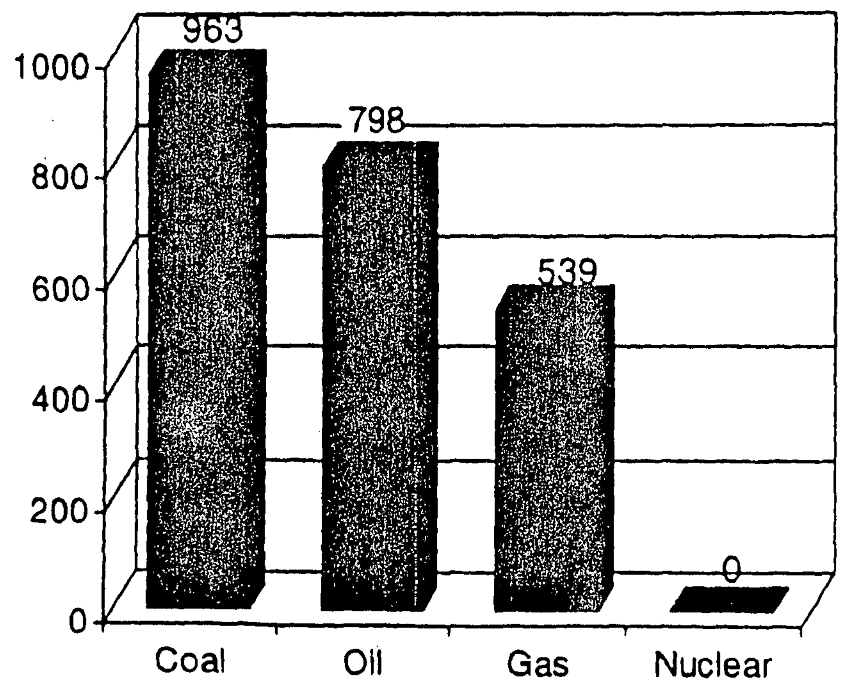


▲ Licensed to Operate

Note: There are no commercial reactors in Alaska or Hawii

Nuclear power produces
essentially zero carbon, SO_2, or
NOX gas emissions

Metric Tons of CO_2 per GWH

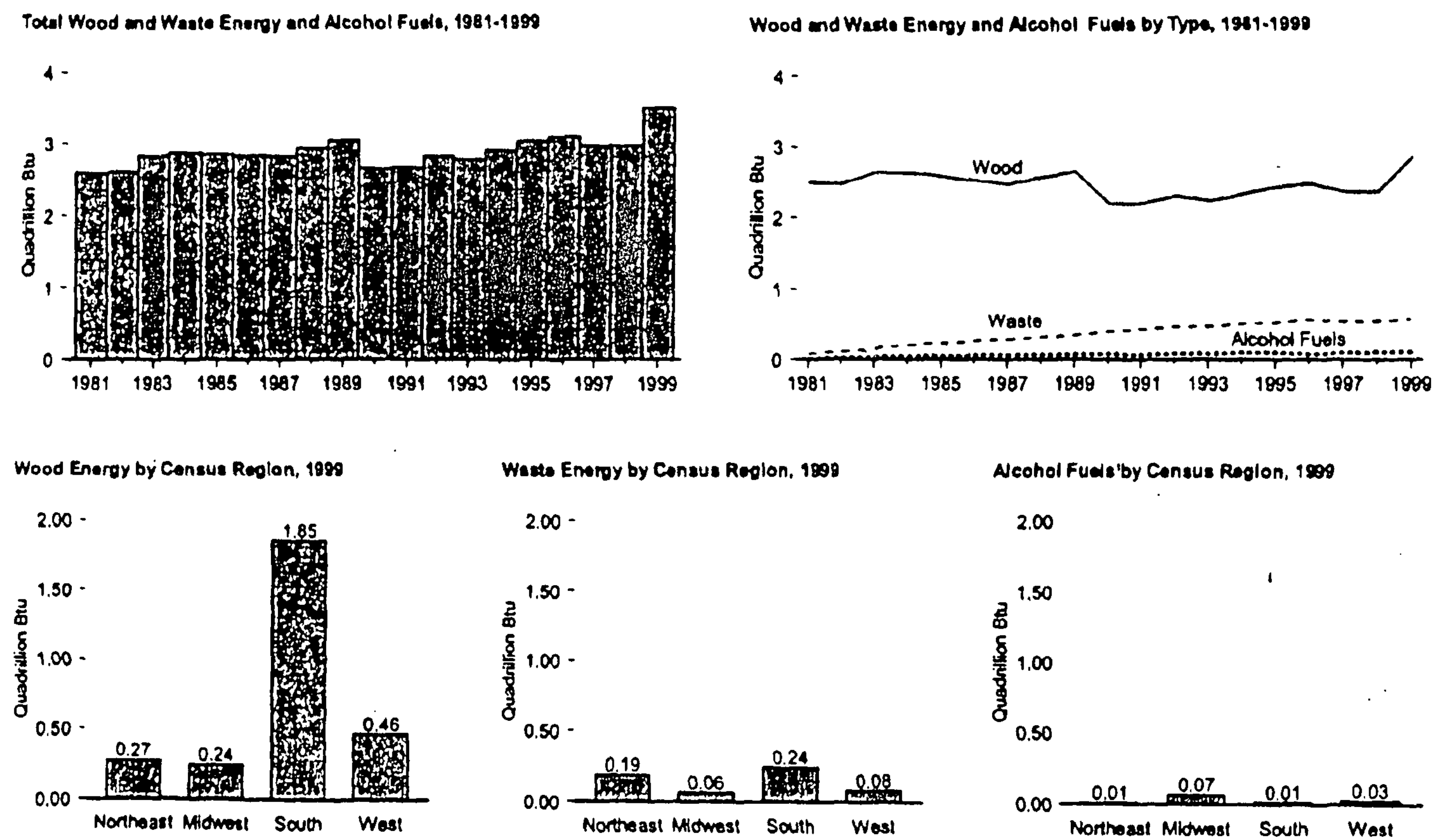


Source: EIA Annual Energy Outlook 2000

DOE006-0175

2818

Figure 10.3 Wood and Waste Energy and Alcohol Fuels Consumption Estimates



[1] Ethanol blended into motor gasoline.

Notes: • Not all data were available for 1985, 1986, and 1988; therefore, values were interpolated. • Beginning in 1989, includes expanded coverage of nonutility consumption. • See Appendix D for Census regions. • Because vertical scales differ, graphs should not be compared.

Source: Table 10.3.

DOE006-0176

2819

Table 10.3 Wood and Waste Energy and Alcohol Fuels Consumption Estimates by Type and Census Region, 1981-1999

(Trillion Btu)

Year	Wood[1]					Waste[2]					Alcohol Fuels[3]					Total
	Northeast	Midwest	South	West	Total	Northeast	Midwest	South	West	Total	Northeast	Midwest	South	West	Total	
1981	395	335	1,349	416	2,495	16	5	37	30	88	(s)	4	1	2	7	2,590
1982	368	343	R1,391	385	R2,477	20	13	50	36	R119	(s)	11	4	4	19	R2,615
1983	380	323	1,526	411	R2,639	38	17	56	46	157	(s)	22	8	5	35	R2,831
1984	R348	R340	R1,480	R460	R2,629	39	21	57	91	208	(s)	25	13	5	43	R2,880
1985[4]	350	388	1,374	464	2,576	46	30	74	85	235	(s)	29	17	5	51	2,862
1986[4]	352	432	1,266	468	2,518	53	38	91	80	262	(s)	34	22	4	60	2,840
1987	R354	R479	R1,160	R472	R2,465	60	47	108	74	289	(s)	38	26	4	R68	R2,822
1988[4]	398	519	1,166	469	2,552	72	56	127	63	318	(s)	38	26	6	70	2,940
1989	R437	R559	R1,175	R464	R2,635	84	64	145	51	344	(s)	38	26	7	71	R3,050
1990	R260	R335	R1,081	R513	R2,188	119	89	114	73	395	(s)	55	17	10	82	R2,665
1991	R228	R295	R1,187	R477	R2,188	R133	R98	R108	87	426	(s)	45	11	9	65	R2,679
1992	R269	R291	R1,255	R474	R2,288	148	84	128	100	460	(s)	55	13	10	R78	R2,826
1993	277	222	R1,404	324	R2,226	161	65	130	102	468	(s)	R62	R15	11	88	R2,782
1994	284	228	R1,468	335	R2,314	169	59	204	71	503	(s)	R69	16	12	97	R2,914
1995	R389	R269	R1,100	R660	R2,418	172	56	219	73	521	(s)	R73	R17	R13	104	R3,044
1996	R267	R254	1,523	R422	R2,465	187	63	235	80	565	7	43	8	16	74	R3,104
1997	R263	R213	R1,488	R394	R2,348	191	61	213	72	538	9	56	11	21	97	R2,982
1998	R237	R206	R1,513	R389	R2,346	R185	63	R217	R75	R540	R9	61	12	23	105	R2,991
1999	273	243	1,652	464	2,632	188	64	241	80	571	10	65	12	25	112	3,315

[1] Wood, wood waste, black liquor, red liquor, spent sulfite liquor, pitch, wood sludge, peat, railroad ties, and utility poles. Beginning in 1989, includes expanded coverage of nonutility consumption (see Table 8.4).

[2] Municipal solid waste, landfill gas, methane, digester gas, liquid acetonitrile waste, tall oil, waste alcohol, medical waste, paper pellets, sludge waste, solid byproducts, tires, agricultural byproducts, closed looped biomass, fish oil, and straw. Beginning in 1989, includes expanded coverage of nonutility consumption (see Table 8.4).

[3] Ethanol blended into motor gasoline.

[4] Not all data were available; therefore, values were interpolated.

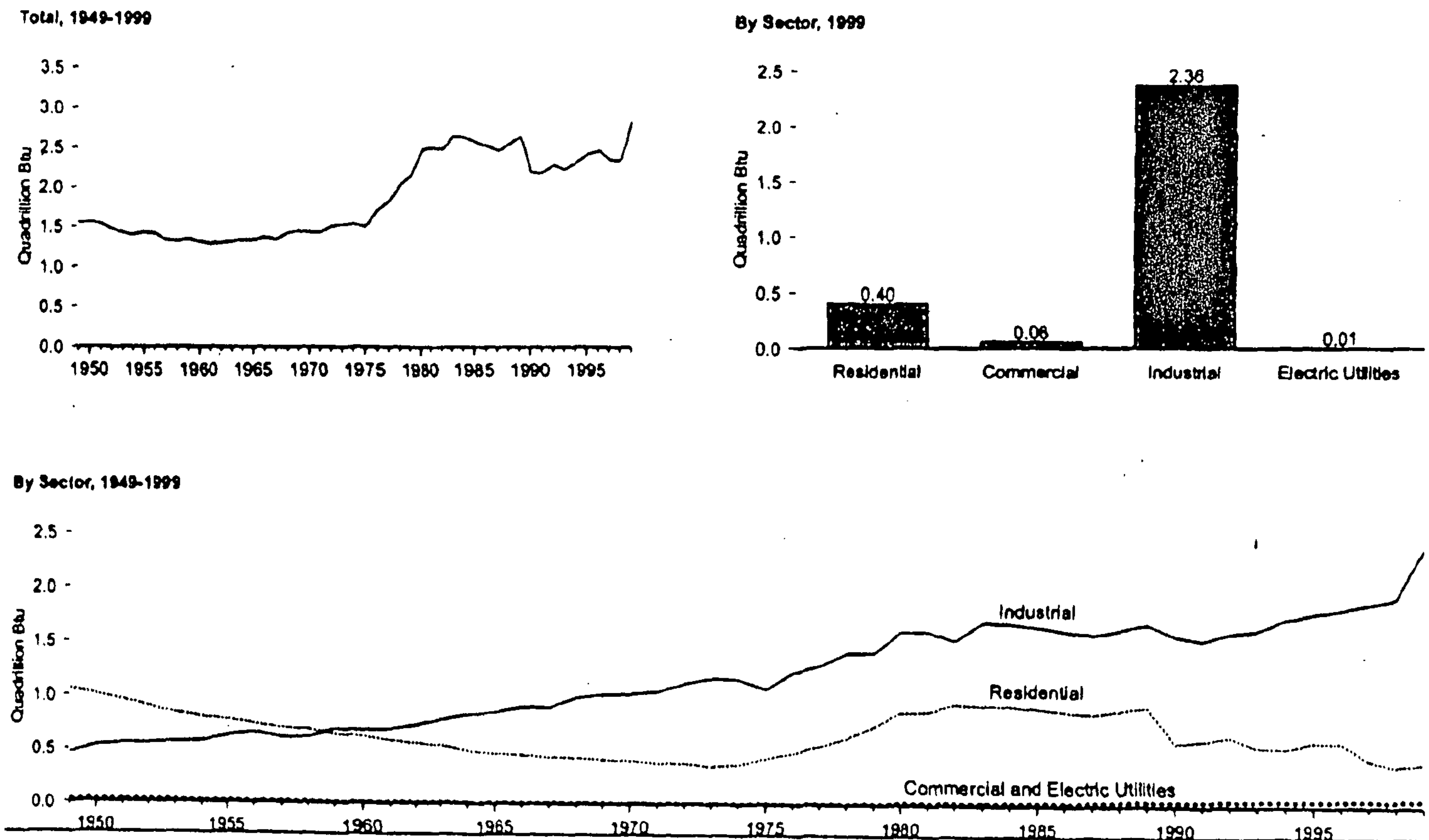
R=Revised. (s)=Less than 0.5 trillion Btu.

Notes: • See Appendix D for Census regions. • Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1981-1983, Wood—EIA, *Estimates of U.S. Wood Energy Consumption, 1980-1983* (November 1984), Tables ES1 and ES2. • 1981-1983 Waste and Alcohol Fuels, and 1984 Data—EIA, Office of Coal, Nuclear, Electric and Alternate Fuels, unpublished data. • 1987—EIA, *Estimates of Biofuels Consumption in the United States During 1987*, Tables ES1 and ES2.• 1989Wood, Industrial Sector: American Paper Institute, *Fact Sheet on 1990 Energy Use in the U.S. Pulp and Paper Industry* (July 31, 1991). All Other Data: EIA, *Estimates of U.S. Biofuels Consumption 1989* (April 1991), Table ES1. • 1990Wood, Industrial Sector: American Paper Institute, *Fact Sheet on 1990 Energy Use in the U.S. Pulp and Paper Industry* (July 1991). Wood, Residential Sector: EIA, "1990 Residential Energy Consumption Survey." Waste: EIA, *Estimates of U.S. Biofuels Consumption 1990* (October 1991), Table ES1. Alcohol Fuels: U.S. Department of Transportation, *Monthly Motor Fuel Reported by States*, FHWA-PL-92-011 (September 1991); U.S. Department of Treasury, Bureau of Alcohol, Tobacco, and Firearms, *Monthly Distilled Spirits Report*, Report Symbol 76 (June 1991), *Alcohol Fuels Report*, internal quarterly report (September 1991), and EIA, *Petroleum Supply Monthly*, various issues. • 1991 and 1992: EIA, *Estimates of U.S. Biomass Energy Consumption 1992* (May 1994). • 1993-1999Wood, Residential Sector: EIA, Form EIA-457, "1993 Residential Energy Consumption Survey," extrapolations from "1993 Residential Energy Consumption Survey" for 1994 through 1996 estimates, and "1997 Residential Energy Consumption Survey" for 1997, and extrapolations for 1998 and 1999. Wood, Commercial Sector: EIA, Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), estimates. Wood, Industrial Sector: EIA, CNEAF, estimates derived from information from other government agencies, trade journals, industry association reports, Form EIA-846, "1991 Manufacturing Energy Consumption Survey," and Form EIA-846, "1994 Manufacturing Energy Consumption Survey." Wood, Electric Utility: EIA, Form EIA-861, "Annual Electric Utility Report," and Form EIA-759, "Monthly Power Plant Report." Waste: Government Advisory Associates, *Resource Recovery Yearbook*, and *Methane Recovery Yearbook*, and CNEAF estimates. Alcohol Fuels: EIA, Form EIA-819M, "Monthly Oxygenate Telephone Report."

Figure 10.4 Wood Energy Consumption Estimates



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

Source: Table 10.4.

Table 10.4 Wood Energy Consumption Estimates by Sector, 1949-1999

(Trillion Btu)

Year	Residential	Commercial	Industrial	Electric Utilities	Total
1949	1,055	20	468	6	1,549
1950	1,006	19	532	5	1,562
1951	958	16	553	5	1,535
1952	899	17	552	6	1,474
1953	832	16	566	5	1,418
1954	800	15	576	3	1,394
1955	775	15	631	3	1,424
1956	739	14	661	2	1,416
1957	702	13	616	2	1,334
1958	688	13	620	2	1,323
1959	647	12	692	2	1,353
1960	627	12	680	2	1,320
1961	587	11	695	1	1,295
1962	560	11	728	1	1,300
1963	537	10	776	1	1,323
1964	499	9	827	2	1,337
1965	468	9	855	3	1,335
1966	455	9	902	3	1,369
1967	434	8	895	3	1,340
1968	426	8	982	4	1,419
1969	415	8	1,014	3	1,440
1970	401	8	1,019	1	1,429
1971	382	7	1,040	1	1,430
1972	380	7	1,113	1	1,501
1973	354	7	1,165	1	1,527
1974	371	7	1,159	1	1,538
1975	425	8	1,063	(s)	1,497
1976	482	9	1,220	1	1,711
1977	542	10	1,281	3	1,837
1978	622	12	1,400	2	2,036
1979	728	14	1,405	3	2,150
1980	860	21	1,600	3	2,483
1981	869	21	1,602	3	2,495
1982	937	22	1,516	2	R2,477
1983	925	22	1,690	R2	R2,639
1984	923	22	1,679	R5	R2,629
1985	[1]899	[1]24	[1]1,645	8	[1]2,576
1986	[1]878	[1]27	[1]1,610	5	[1]2,516
1987	852	[1]29	1,576	R6	R,[1]2,465
1988	[1]885	[1]32	[1]1,625	10	[1]2,552
1989	918	[1]34	1,673	R10	R,[1]2,635
1990	581	[1]37	1,562	R8	R,[1]2,188
1991	613	[1]39	1,528	R8	R,[1]2,188
1992	645	[1]42	1,593	R8	R,[1]2,288
1993	548	44	1,625	R9	R2,226
1994	537	45	1,724	R8	R2,314
1995	596	45	1,771	R7	R2,418
1996	595	49	1,813	R8	R2,465
1997	433	R47	1,860	R8	R2,348
1998	R377	R47	1,914	R7	R2,346
1999	404	57	2,384	7	2,832

[1] No data were available, therefore, values were interpolated.
R=Revised. (s)=Less than 0.5 trillion Btu.
Note: Totals may not equal sum of components due to independent rounding.
Web Page: http://www.eia.doe.gov/fuelrenewable.html.
Sources: • 1949-1980 Calculated from Energy Information Administration (EIA), *Estimates of U.S. Wood Energy Consumption from 1949 to 1981*, Table A2, and EIA, *Annual Energy Review 1999*, Table 8.3. Plotted at yearly intervals. • 1980: EIA, *Estimates of U.S. Wood Energy Consumption 1980-1983*, Table ES1, and calculation from *Annual Energy Review 1999*, Table 8.3. • 1981-1983: EIA, *Estimates of U.S. Wood Energy Consumption, 1980-1983* (November 1984), Tables ES1 and ES2. • 1989Industrial Sector: American Paper Institute, *Fact Sheet on 1990 Energy Use in the U.S. Pulp and Paper Industry* (July 31, 1991). All Other Data: EIA, *Estimates of U.S. Biofuels Consumption 1989* (April 1991), Table ES1. • 1990Industrial Sector: American Paper Institute, *Fact Sheet on 1990 Energy Use in the U.S. Pulp and Paper Industry* (July 1991). Residential Sector: EIA, "1990 Residential Energy Consumption Survey." • 1991 and 1992: EIA, *Estimates of U.S. Biomass Energy Consumption 1992* (May 1994). • 1993-1999: EIA, Form EIA-457, "1993 Residential Energy Consumption Survey," extrapolations from "1993 Residential Energy Consumption Survey" for 1994 through 1996 estimates, and "1997 Residential Energy Consumption Survey" for 1997, and extrapolations for 1998 and 1999. Commercial Sector: EIA, Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), estimates. Industrial Sector: EIA, CNEAF, estimates derived from information from other government agencies, trade journals, industry association reports, Form EIA-846, "1991 Manufacturing Energy Consumption Survey," and Form EIA-846, "1994 Manufacturing Energy Consumption Survey." Electric Utility: EIA, Form EIA-861, "Annual Electric Utility Report," and Form EIA-759, "Monthly Power Plant Report."

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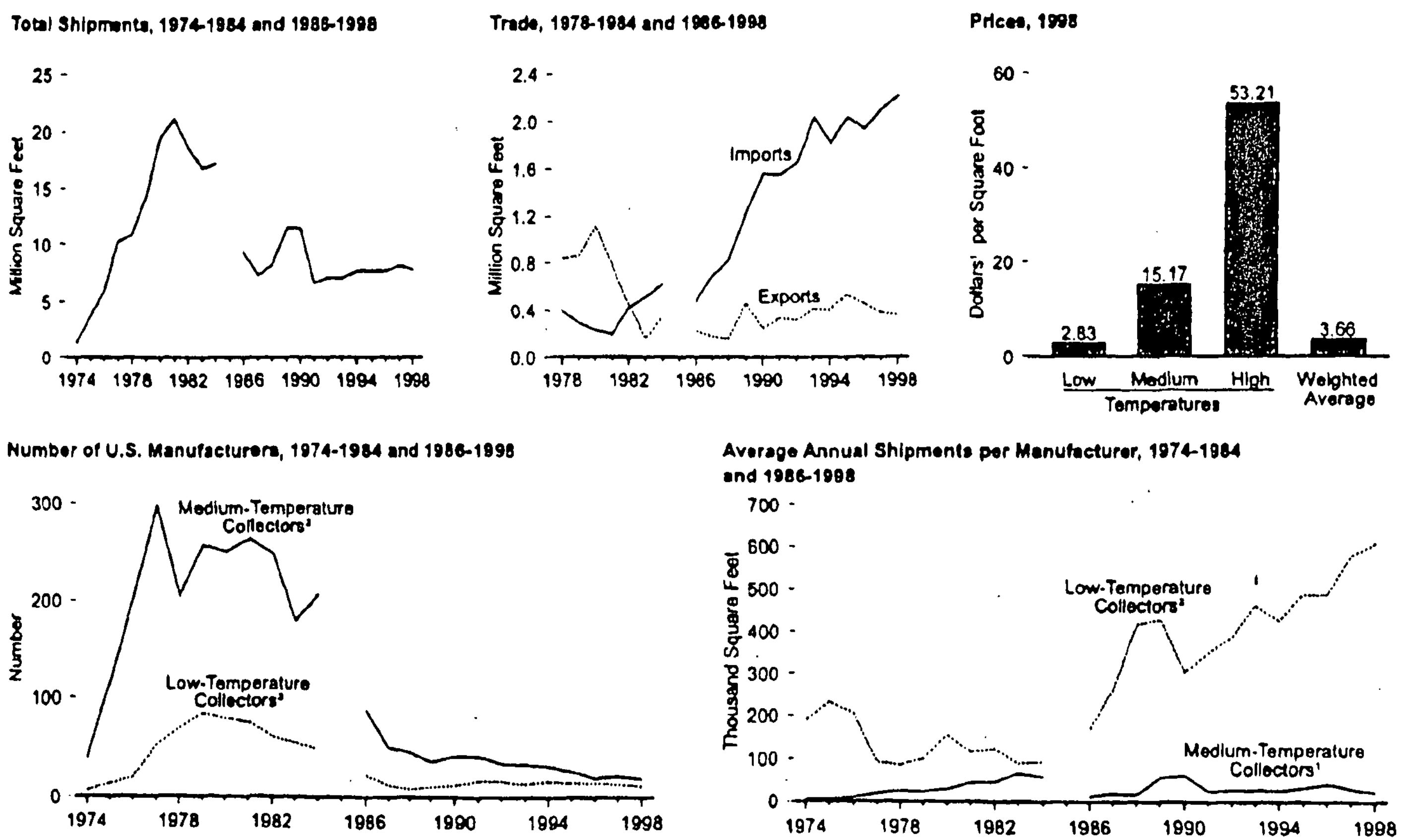
Figure 10.5 Solar Thermal Collector Shipments by Type, Price, and Trade



[1] Nominal dollars.
[2] Collectors that generally operate in the temperature range of 140 degrees Fahrenheit to 180 degrees Fahrenheit but can also operate at temperatures as low as 110 degrees Fahrenheit.
[3] Collectors that generally operate at temperatures below 110 degrees Fahrenheit.

Notes: • Data were not collected for 1985. • Medium-temperature collectors include special collectors. • Because vertical scales differ, graphs should not be compared.
Source: Table 10.5.

Table 10.5 Solar Thermal Collector Shipments by Type, Price, and Trade, 1974-1998

(Thousand Square Feet, Except as Noted)

Year	Low-Temperature Collectors [1]				Medium-Temperature Collectors [2]				High-Temperature Collectors [3]		Total Shipments [4]		Imports	Exports
	Number of U.S. Manufacturers	Quantity Shipped	Shipments per Manufacturer	Price [5] (dollars per square foot)	Number of U.S. Manufacturers	Quantity Shipped	Shipments per Manufacturer	Price [5] (dollars per square foot)	Quantity Shipped	Price [5] (dollars per square foot)	Quantity Shipped	Price [5] (dollars per square foot)		
1974	6	1,137	189.5	NA	39	137	3.5	NA	NA	NA	1,274	NA	NA	NA
1975	13	3,026	232.8	NA	118	717	6.1	NA	NA	NA	3,743	NA	NA	NA
1976	19	3,876	204.0	NA	203	1,925	9.5	NA	NA	NA	5,801	NA	NA	NA
1977	52	4,743	91.2	NA	297	5,569	18.8	NA	NA	NA	10,312	NA	NA	NA
1978	69	5,872	85.1	NA	204	4,988	24.5	NA	NA	NA	10,860	NA	396	840
1979	84	8,394	100.0	NA	257	5,856	22.8	NA	NA	NA	14,251	NA	290	855
1980	79	12,233	154.8	NA	250	7,165	28.7	NA	NA	NA	19,398	NA	235	1,115
1981	75	8,677	115.7	NA	263	11,456	43.6	NA	NA	NA	21,133	NA	196	771
1982	61	7,476	122.6	NA	248	11,145	44.9	NA	NA	NA	18,621	NA	418	455
1983	55	4,853	88.2	NA	179	11,975	66.9	NA	NA	NA	16,828	NA	511	159
1984	48	4,479	93.3	NA	206	11,939	58.0	NA	773	NA	17,191	NA	621	348
1985	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1986	22	3,751	170.5	R2.30	87	1,111	12.8	R18.30	4,498	NA	9,360	R6.14	473	224
1987	12	3,157	263.1	R2.18	50	957	19.1	R13.50	3,155	NA	7,269	R4.82	691	182
1988	8	3,326	415.8	2.24	45	732	16.2	R14.86	4,116	NA	8,174	R4.56	814	158
1989	10	4,283	428.3	2.60	36	1,989	55.3	R11.74	5,209	R17.76	11,482	R10.92	1,233	461
1990	12	3,645	303.8	2.90	41	2,527	61.6	7.68	5,237	15.74	11,409	R9.86	1,562	245
1991	16	5,585	349.0	2.90	41	989	24.1	11.94	1	31.94	6,574	4.26	1,543	332
1992	16	6,187	386.7	R2.50	34	897	26.4	10.96	2	75.66	7,086	3.58	1,650	318
1993	13	6,025	463.5	R2.60	33	931	28.2	R11.74	12	R22.12	6,968	3.96	2,039	411
1994	16	6,823	426.0	R2.54	31	803	26.0	R13.54	2	R177.00	7,627	R3.74	1,815	405
1995	14	6,813	487.0	R2.32	26	840	32.0	10.48	13	53.28	7,666	R3.30	2,037	530
1996	14	6,821	487.0	2.67	19	785	41.0	14.48	10	18.75	7,616	3.91	1,930	454
1997	13	7,524	579.0	2.60	21	606	29.0	15.17	7	26.00	8,138	3.56	2,102	379
1998	12	7,292	607.0	2.83	19	443	23.0	15.17	21	53.21	7,756	3.86	2,206	360

[1] Low-temperature collectors are solar thermal collectors that generally operate at temperatures below 110 degrees Fahrenheit.

[2] Medium-temperature collectors are solar thermal collectors that generally operate in the temperature range of 140 degrees Fahrenheit to 180 degrees Fahrenheit but can also operate at temperatures as low as 110 degrees Fahrenheit. Special collectors are included in this category. Special collectors are evacuated tube collectors or concentrating (focusing) collectors. They operate in the temperature range from just above ambient temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

[3] High-temperature collectors are solar thermal collectors that generally operate at temperatures above 180 degrees Fahrenheit.

[4] Total shipments as reported by respondents include all domestic and export shipments and may include imports that subsequently were shipped to domestic or to foreign customers.

[5] Prices, in nominal dollars, equal shipment value divided by quantity shipped. Value includes charges for advertising and warranties. Excluded are excise taxes and the cost of freight or transportation for the shipments.

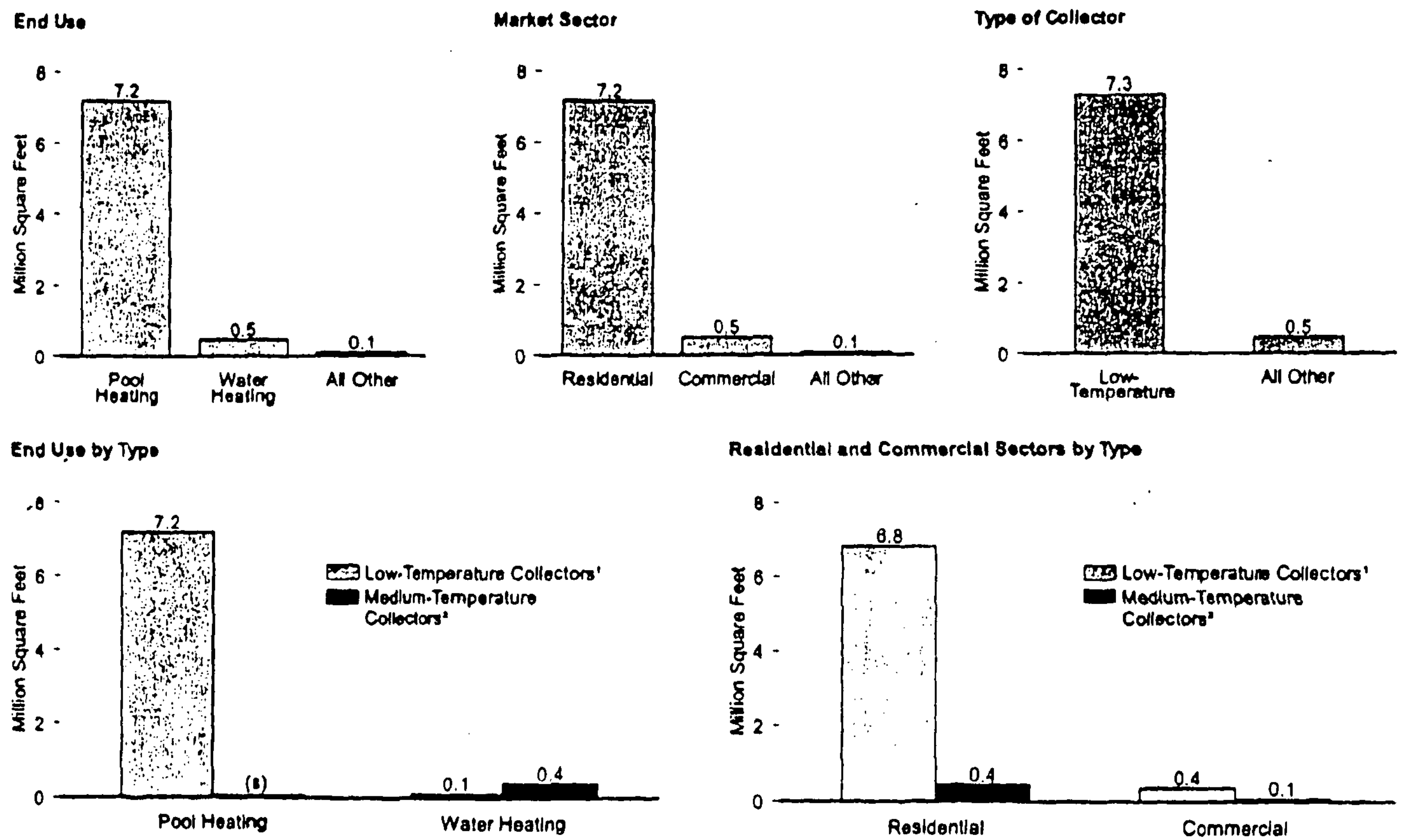
R=Revised. NA=Not available.

Notes: • Manufacturers producing more than one type of collector are accounted for in both groups. • No data are available for 1985. • High-temperature collector shipments were dominated by one manufacturer.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1974-1992—Energy Information Administration (EIA), *Solar Collector Manufacturing Activity*, annual reports. • 1993 forward—EIA, *Renewable Energy Annual*, annual reports.

Figure 10.6 Solar Thermal Collector Shipments by End Use, Market Sector, and Type, 1998



[1] Collectors that generally operate at temperatures below 110 degrees Fahrenheit.

[2] Collectors that generally operate in the temperature range of 140 degrees Fahrenheit to 180 degrees Fahrenheit but can also operate at temperatures as low as 110 degrees Fahrenheit.

(s)=Less than 0.05 million square feet.

Source: Table 10.6.

Table 10.6 Solar Thermal Collector Shipments by End Use, Market Sector, and Type, 1998

(Thousand Square Feet)

End Use	Low-Temperature Collectors [1]	Medium-Temperature Collectors [2]	High-Temperature Collectors [3]	Total
End-Use Total	7,285	443	21	[4] 7,757
Pool Heating	7,164	37	0	7,201
Water Heating	60	385	18	463
Space Heating	53	14	0	67
Space Cooling	0	0	0	0
Combined Space and Water Heating	8	7	(s)	15
Process Heating	0	0	0	0
Electricity Generation	0	0	2	[4] 10
Other [5]	(s)	0	1	1
Market Sector Total	7,285	443	21	[4] 7,757
Residential	6,810	355	0	7,165
Commercial	429	70	18	517
Industrial	44	18	0	62
Electric Utility	0	0	2	[4] 10
Other [6]	2	0	1	3

[1] Low-temperature collectors are solar thermal collectors that generally operate at temperatures below 110 degrees Fahrenheit.

[2] Medium-temperature collectors are solar thermal collectors that generally operate in the temperature range of 140 degrees Fahrenheit to 180 degrees Fahrenheit but can also operate at temperatures as low as 110 degrees Fahrenheit. Special collectors are included in this category. Special collectors are evacuated tube collectors or concentrating (focusing) collectors. They operate in the temperature range from just above ambient temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

[3] High-temperature collectors are solar thermal collectors that generally operate at temperatures above 180 degrees Fahrenheit. These are Parabolic dish/trough collectors used primarily by independent power producers to generate electricity for the electric grid.

[4] Totals include other types of collectors not shown.

[5] "Other" includes shipments of solar thermal collectors for other uses, such as cooking foods, water pumping, water purification, desalinization, distilling, etc.

[6] "Other" includes shipments of solar thermal collectors to other sectors, such as government, including the military but excluding space applications.

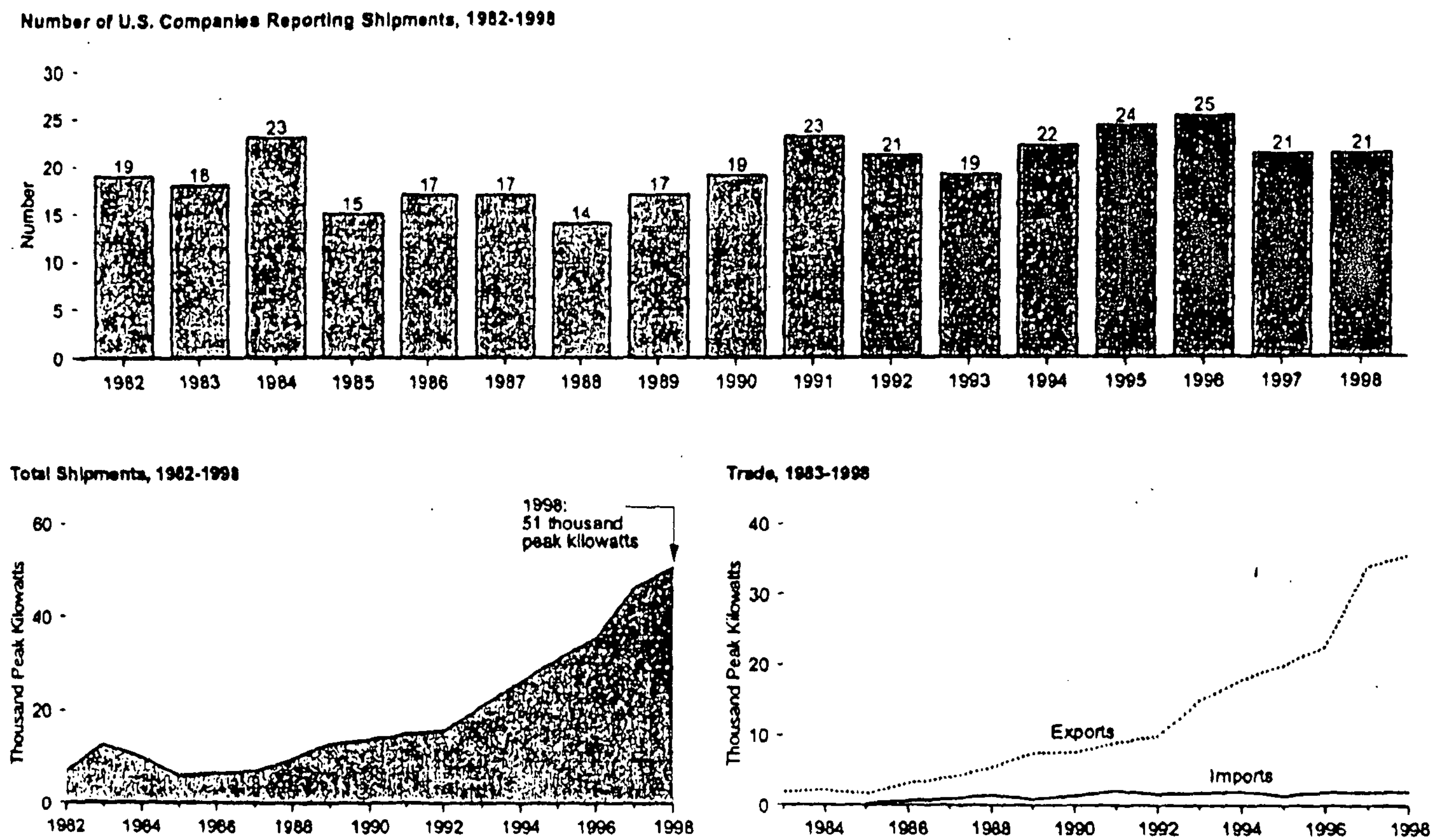
(s)=Less than 0.5 thousand square feet.

Notes: • Data represent shipments from U.S. manufacturers only. • Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Source: Energy Information Administration, *Renewable Energy Annual 1999* (March 2000), Table 19.

Figure 10.7 Photovoltaic Cell and Module Shipments and Trade



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

Source: Table 10.7.

Table 10.7 Photovoltaic Cell and Module Shipments by Type, Price, and Trade, 1982-1998

Year	Number of U.S. Companies Reporting Shipments	Shipments: Crystalline Silicon	Shipments: Thin-Film Silicon	Shipments: Total [2]	Imports	Exports	Prices [1]: Modules	Prices [1]: Cells
		Peak Kilowatts					Dollars per Peak Watt	
1982	19	NA	NA	6,897	NA	NA	NA	NA
1983	18	NA	NA	12,620	NA	1,903	NA	NA
1984	23	NA	NA	9,912	NA	2,153	NA	NA
1985	15	5,461	303	5,769	285	1,670	NA	NA
1986	17	5,806	518	6,333	678	3,109	NA	NA
1987	17	5,613	1,230	6,850	921	3,821	NA	NA
1988	14	7,364	1,895	9,676	1,453	5,358	NA	NA
1989	17	10,747	1,828	12,825	826	7,363	5.14	R3.08
1990	[3]19	12,492	1,321	[3]13,837	1,398	7,544	5.69	3.84
1991	23	14,205	723	14,939	2,059	8,905	6.12	4.06
1992	21	14,457	1,075	15,583	1,802	9,823	6.11	3.21
1993	19	20,146	782	20,951	1,767	14,814	5.24	5.23
1994	22	24,785	1,061	26,077	1,960	17,714	4.46	2.97
1995	24	29,740	1,266	31,059	1,337	19,871	4.56	2.53
1996	25	33,996	1,445	35,464	1,864	22,448	4.09	2.80
1997	21	44,314	1,886	46,354	1,853	33,793	4.16	2.78
1998	21	47,186	3,318	50,562	1,931	35,493	3.94	3.15

[1] Prices, in nominal dollars, equal shipment value divided by quantity shipped. Value includes charges for advertising and warranties. Excluded are excise taxes and the cost of freight or transportation for the shipments.

[2] Total shipments include all types of photovoltaic cells and modules (single-crystal silicon, cast silicon, ribbon silicon, thin-film silicon, and concentrator silicon) and internationally traded cells and modules. Shipments of cells and modules for space and satellite applications are not included.

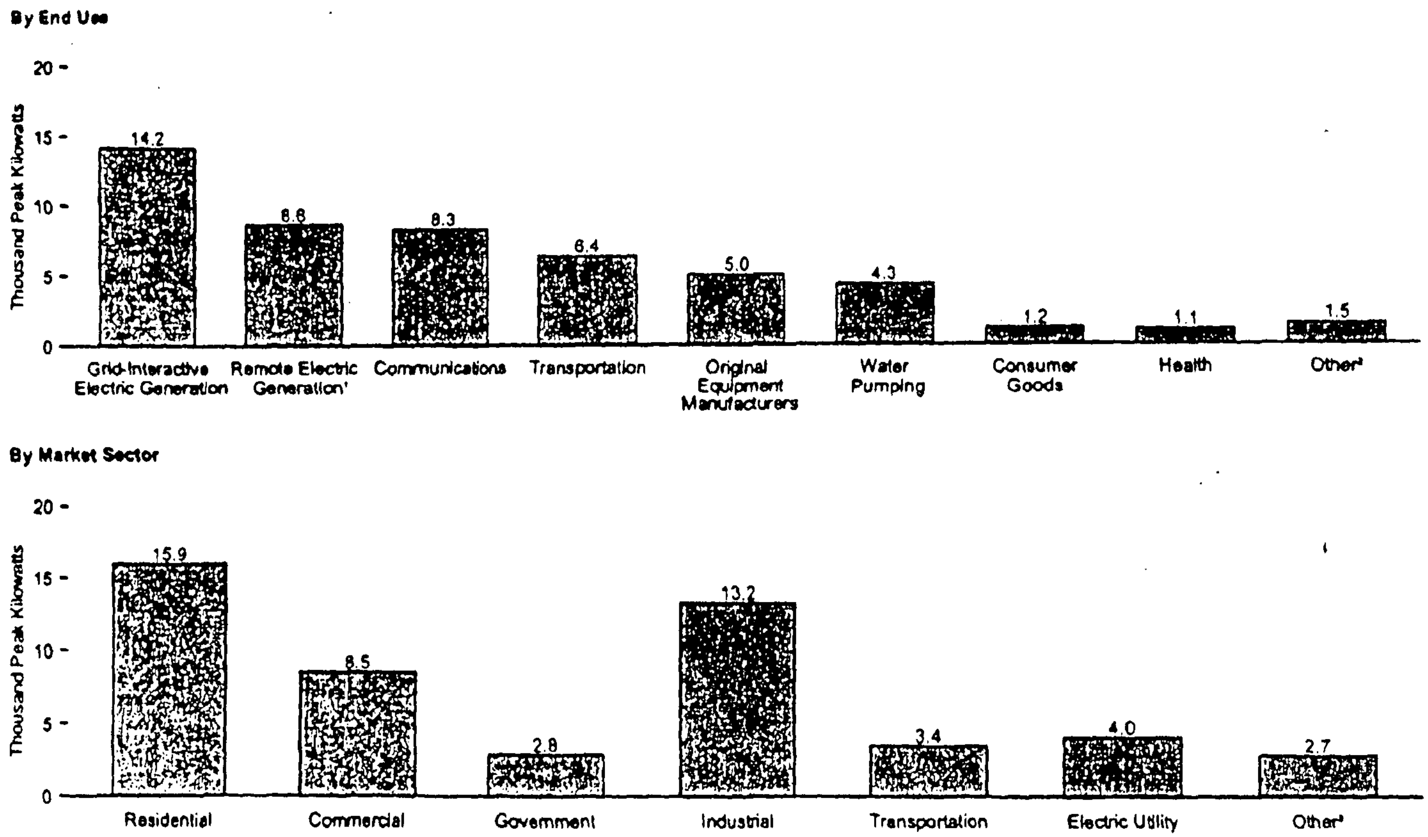
[3] Data were imputed for one nonrespondent who exited the industry during 1990.

R=Revised data. NA=Not available.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1982-1992—Energy Information Administration (EIA), *Solar Collector Manufacturing Activity*, annual reports. • 1993 forward—EIA, *Renewable Energy Annual*, annual reports.

Figure 10.8 Photovoltaic Cell and Module Shipments by End Use and Market Sector, 1998



¹ Units designed for installations that are not grid-interactive.
² Represents such applications as cooking food, desalinization, and distilling.
³ Shipments to foreign governments and for specialty purposes.
Source: Table 10.8.

Table 10.8 Photovoltaic Cell and Module Shipments by End Use and Market Sector, 1989-1998

Year	End Use									Market Sector							Total
	Communications	Consumer Goods	Electric Generation[1]		Health	Original Equipment Manufacturers[2]	Transportation	Water Pumping	Other[3]	Residential	Commercial	Government	Industrial	Transportation	Electric Utility	Other[4]	
			Grid-Interactive	Remote													
	Amount Shipped (peak kilowatts)																
1989	2,590	2,788	1,251	2,620	6	1,595	1,196	711	69	1,439	3,850	1,077	3,993	1,130	765	551	12,825
1990	4,340	2,484	469	3,097	5	1,119	1,069	1,014	240	1,701	6,066	1,002	2,817	974	826	432	13,837
1991	3,538	3,312	856	3,594	61	1,315	1,523	729	13	3,624	3,345	815	3,947	1,555	1,275	377	14,939
1992	3,717	2,566	1,227	4,238	67	828	1,602	809	530	4,154	2,388	1,063	4,279	1,673	1,553	477	15,583
1993	3,848	946	1,096	5,761	674	2,023	4,238	2,294	74	5,237	4,115	1,325	5,362	2,564	1,503	856	20,951
1994	5,570	3,239	2,296	9,253	79	1,849	2,128	1,410	254	6,632	5,429	2,114	6,855	2,174	2,364	510	26,077
1995	5,154	1,025	4,585	8,233	776	3,188	4,203	2,727	1,170	6,272	8,100	2,000	7,196	2,383	3,759	1,347	31,059
1996	6,041	1,063	4,844	10,864	977	2,410	5,196	3,261	769	8,475	5,176	3,126	8,300	3,995	4,753	1,639	35,464
1997	7,383	347	8,273	8,630	1,303	5,245	6,705	3,783	4,684	10,993	8,111	3,909	11,748	3,574	5,651	2,367	46,354
1998	8,280	1,198	14,193	8,634	1,061	5,044	6,356	4,306	1,491	15,936	8,460	2,806	13,232	3,440	3,965	2,720	50,562
	Percent of Total																
1989	20.2	21.7	9.8	20.4	(s)	12.4	9.3	5.5	0.5	11.2	30.0	8.4	31.1	8.8	6.1	4.3	100.0
1990	31.4	18.0	3.4	22.4	(s)	8.1	7.7	7.3	1.7	12.3	44.0	7.2	20.4	7.0	6.0	3.1	100.0
1991	23.7	22.2	5.7	24.1	0.4	8.8	10.2	4.9	0.1	24.3	22.4	5.5	26.4	10.4	8.5	2.5	100.0
1992	23.9	16.5	7.9	27.2	0.4	5.3	10.3	5.2	3.4	26.7	15.3	6.8	27.5	10.7	10.0	3.1	100.0
1993	18.4	4.5	5.2	27.5	3.2	9.7	20.2	10.9	0.4	25.0	19.6	6.3	25.5	12.2	7.2	4.1	100.0
1994	21.4	12.4	8.8	35.5	0.3	7.1	8.2	5.4	1.0	25.4	20.8	8.1	26.3	8.3	9.1	2.0	100.0
1995	16.6	3.3	14.8	26.5	2.5	10.3	13.5	8.8	3.8	20.2	26.1	6.4	23.2	7.7	12.1	4.3	100.0
1996	17.0	3.0	13.7	30.7	2.8	6.8	14.7	9.2	2.2	23.9	14.6	8.8	23.4	11.3	13.4	4.6	100.0
1997	15.9	0.7	17.8	18.6	2.8	11.3	14.5	8.2	10.1	23.7	17.6	8.4	25.3	7.7	12.2	5.1	100.0
1998	16.4	2.4	28.1	17.1	2.1	10.0	12.6	8.5	2.9	31.5	16.7	5.6	26.2	6.8	7.8	5.4	100.0

[1] Grid-interactive means connection to the electrical distribution system; remote means electricity, for general use, that does not interact with the electrical distribution system, such as at an isolated residential site or mobile home. The other end uses in this table also include electricity generation but only for the specific use cited.

[2] Original Equipment Manufacturers are non-photovoltaic manufacturers that combine photovoltaic technology into existing or newly developed product lines.

[3] Represents such applications as cooking food, desalinization, and distilling.

[4] Shipments to foreign governments and for specialty purposes.

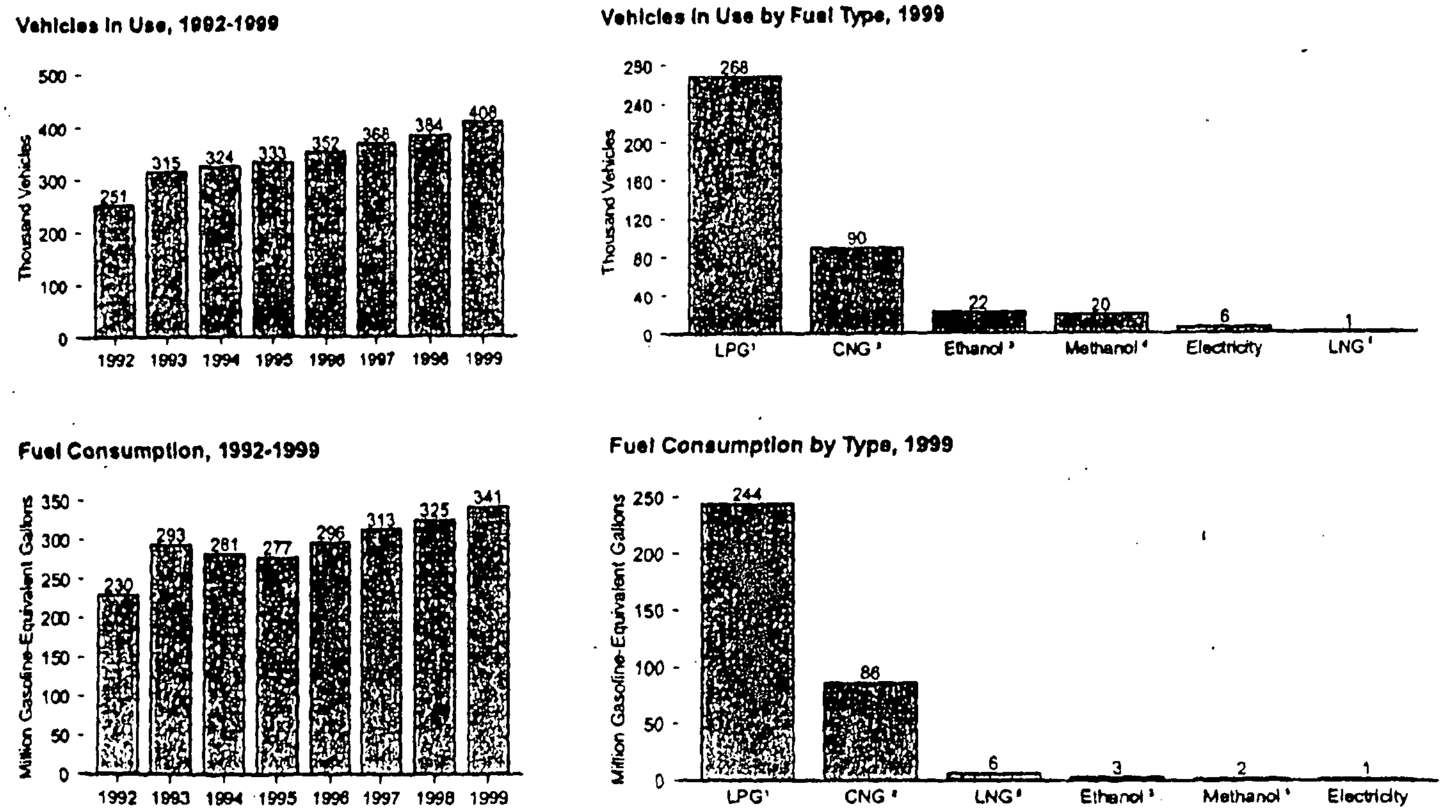
(s)=Less than 0.05 percent.

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

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1989-1992—Energy Information Administration (EIA), *Solar Collector Manufacturing Activity*, annual reports. • 1993 forward—EIA, *Renewable Energy Annual*, annual reports.

Figure 10.9 Alternative-Fueled Vehicles and Fuel Consumption by Type



[1] Liquefied petroleum gases.
[2] Compressed natural gas.
[3] Ethanol, 85 percent and ethanol, 95 percent.
[4] Methanol, 85 percent, and methanol, neat.
[5] Liquefied natural gas.

Note: Because vertical scales differ, graphs should not be compared.
Source: Table 10.9.

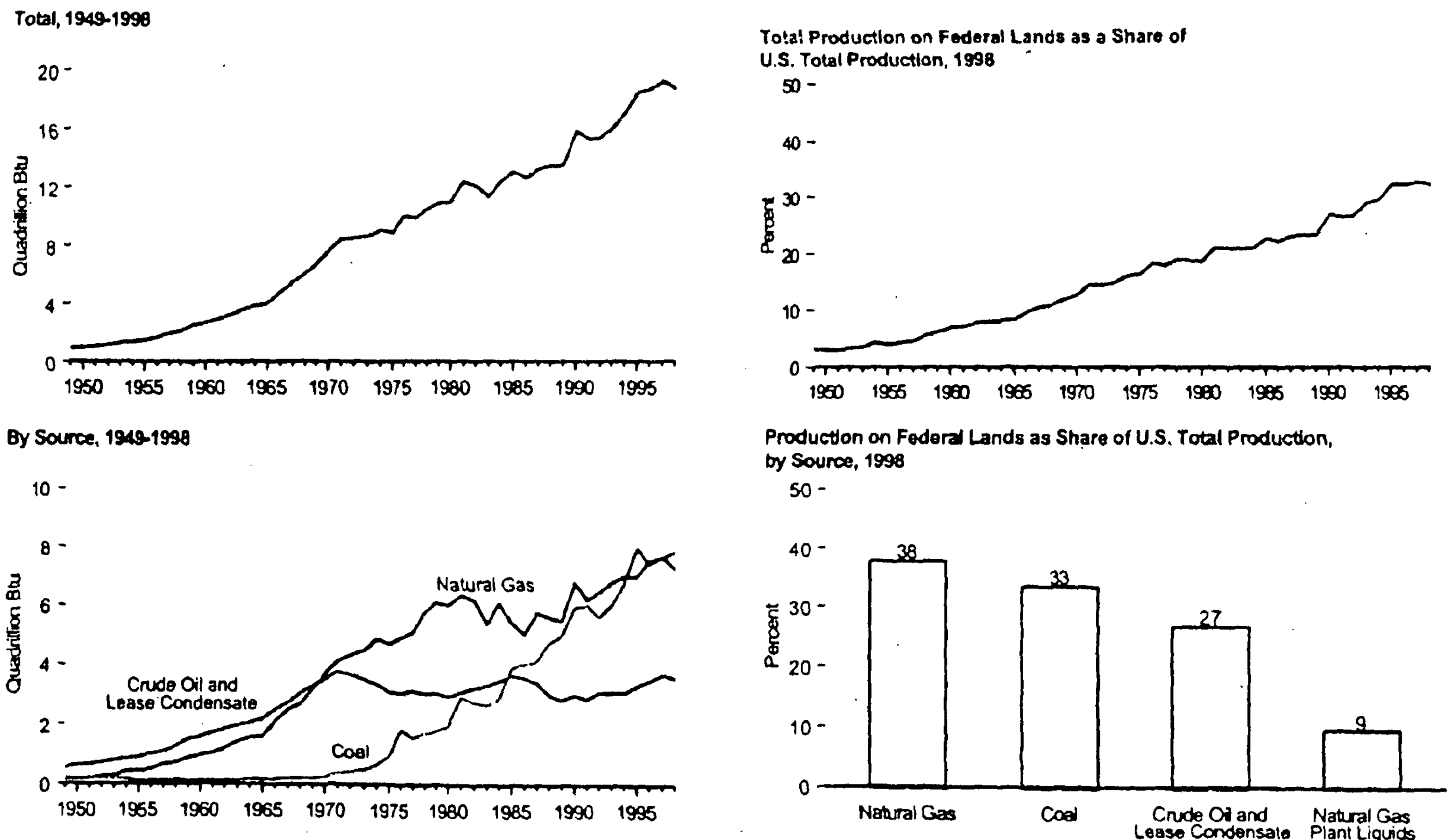
Table 10.9 Alternative-Fueled Vehicles and Fuel Consumption by Type, 1992-1999

Year	Liquefied Petroleum Gases [1]	Compressed Natural Gas	Liquefied Natural Gas	Methanol, 85 Percent [2]	Methanol, Neat	Ethanol, 85 Percent [2]	Ethanol, 95 Percent [2]	Electricity	Total
	Estimated Number of Vehicles in Use								
1992	221,000	23,191	90	4,850	404	172	38	1,607	251,352
1993	269,000	32,714	299	10,263	414	441	27	1,690	314,848
1994	264,000	41,227	484	15,484	415	605	33	2,224	324,472
1995	259,000	50,218	603	18,319	386	1,527	136	2,860	333,049
1996	263,000	60,144	663	20,265	172	4,536	361	3,280	352,421
1997	263,000	R68,571	813	21,040	172	9,130	347	4,453	R367,526
1998	R266,000	R78,782	R1,172	R19,648	R200	R12,788	14	R5,243	R383,847
1999P	268,000	89,633	1,422	19,497	200	22,359	14	6,417	407,542
	Estimated Fuel Consumption (Thousand Gasoline-Equivalent Gallons)								
1992	208,142	18,823	585	1,069	2,547	21	85	359	229,631
1993	264,655	21,603	1,901	1,583	3,166	48	80	288	293,334
1994	248,487	24,160	2,345	2,340	3,190	80	140	430	281,152
1995	232,701	35,162	2,759	2,023	2,150	190	995	663	276,643
1996	239,158	48,923	3,247	1,775	347	694	2,699	773	295,816
1997	238,356	R65,192	3,714	1,554	347	1,280	1,136	1,010	R312,589
1998	R241,563	R73,251	R5,343	R1,212	R449	R1,727	59	R1,202	R324,826
1999P	243,648	86,073	6,062	1,108	449	2,489	59	1,458	341,348

[1] Vehicles in use represent lower bound estimates, rounded to the nearest thousand.
[2] Remaining portion is motor gasoline.
R=Revised data. P=Preliminary data.

Note: Totals may not equal sum of components due to independent rounding.
Source: Web Page: http://www.eia.doe.gov/fuelrenewable.html.

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.

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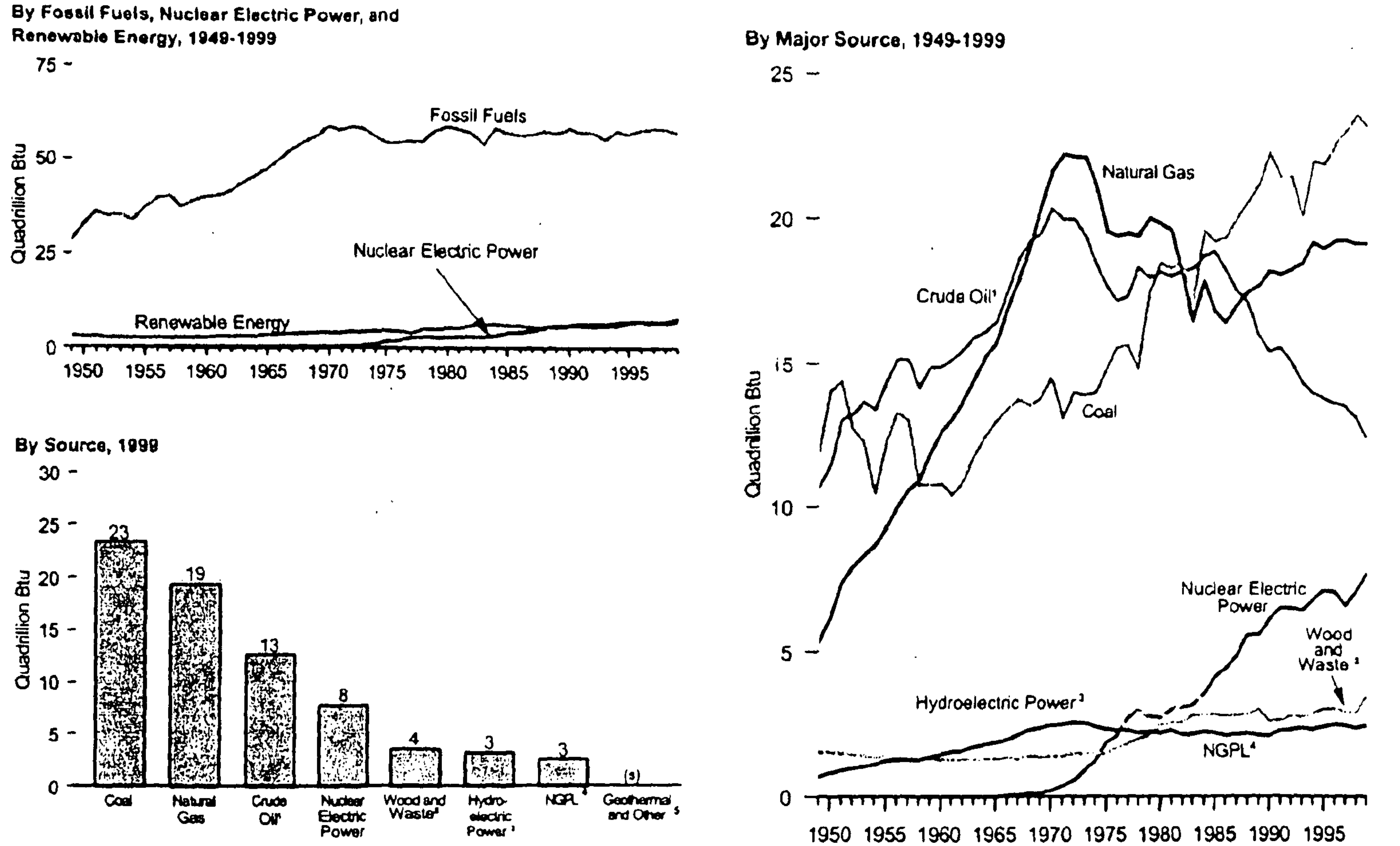
Figure 1.2 Energy Production by Source



[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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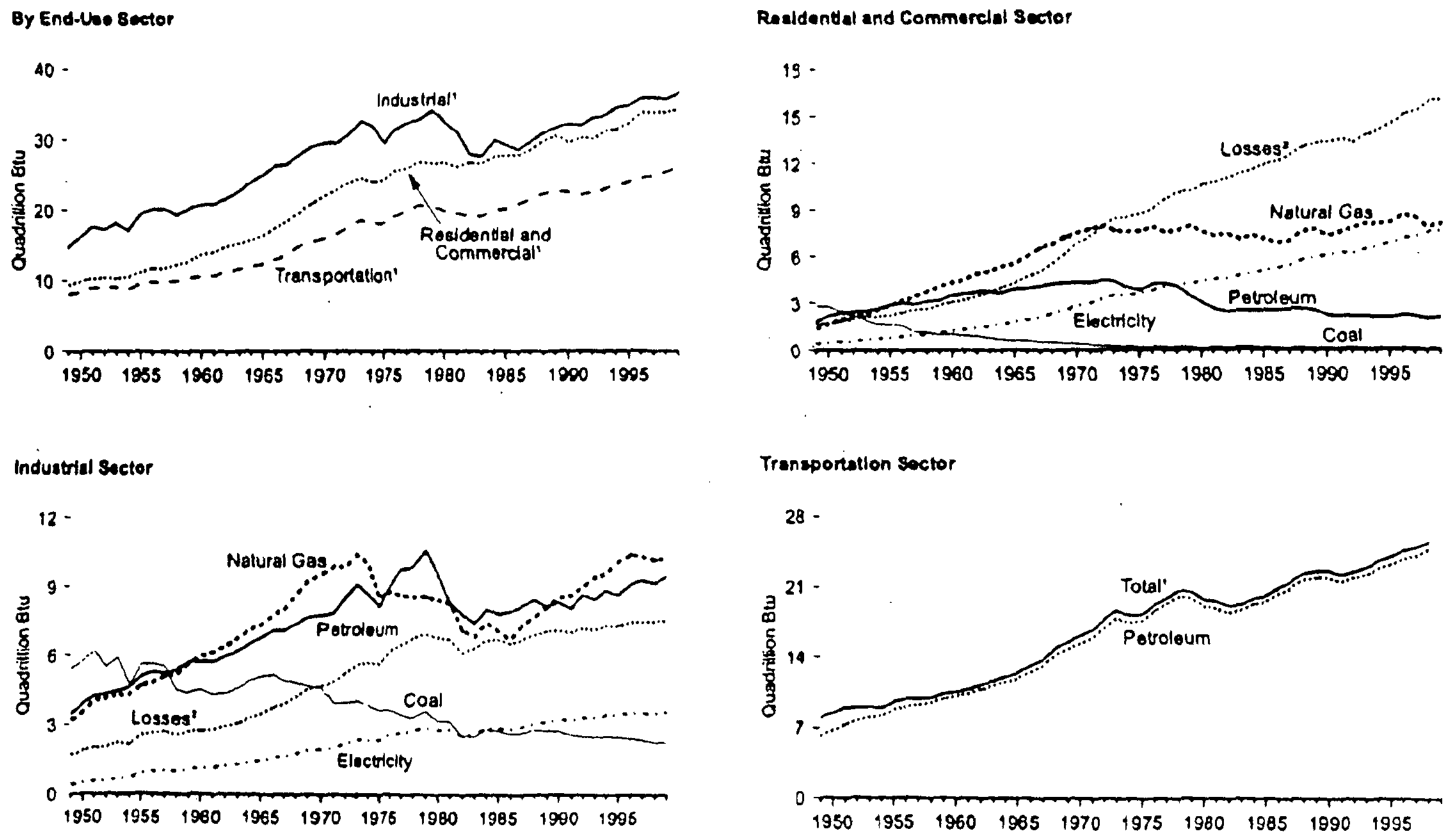
Figure 2.1 Energy Consumption by End-Use Sector, 1949-1999



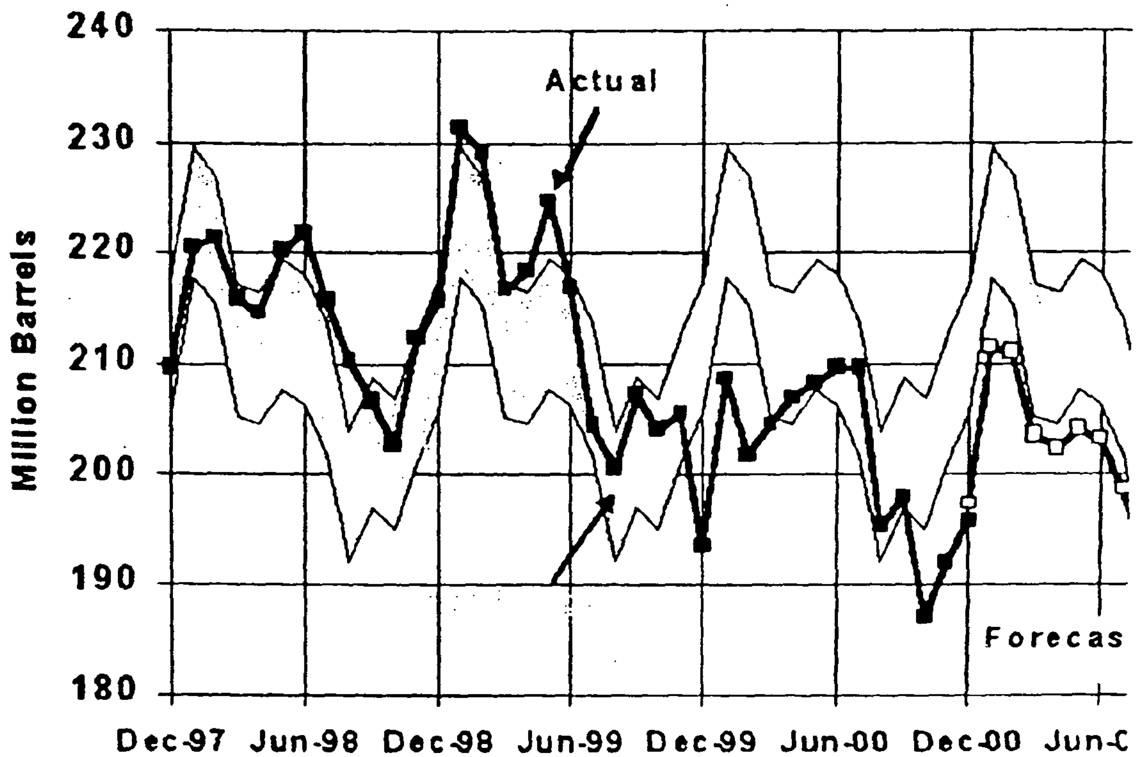
[1] There is a discontinuity in this time series between 1988 and 1989 due to the expanded coverage of renewable energy beginning in 1989.

[2] Electrical system energy losses associated with the generation, transmission, and distribution of energy in the form of electricity.

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

Source: Table 2.1.

U.S. Total Gasoline Inventory Outlook



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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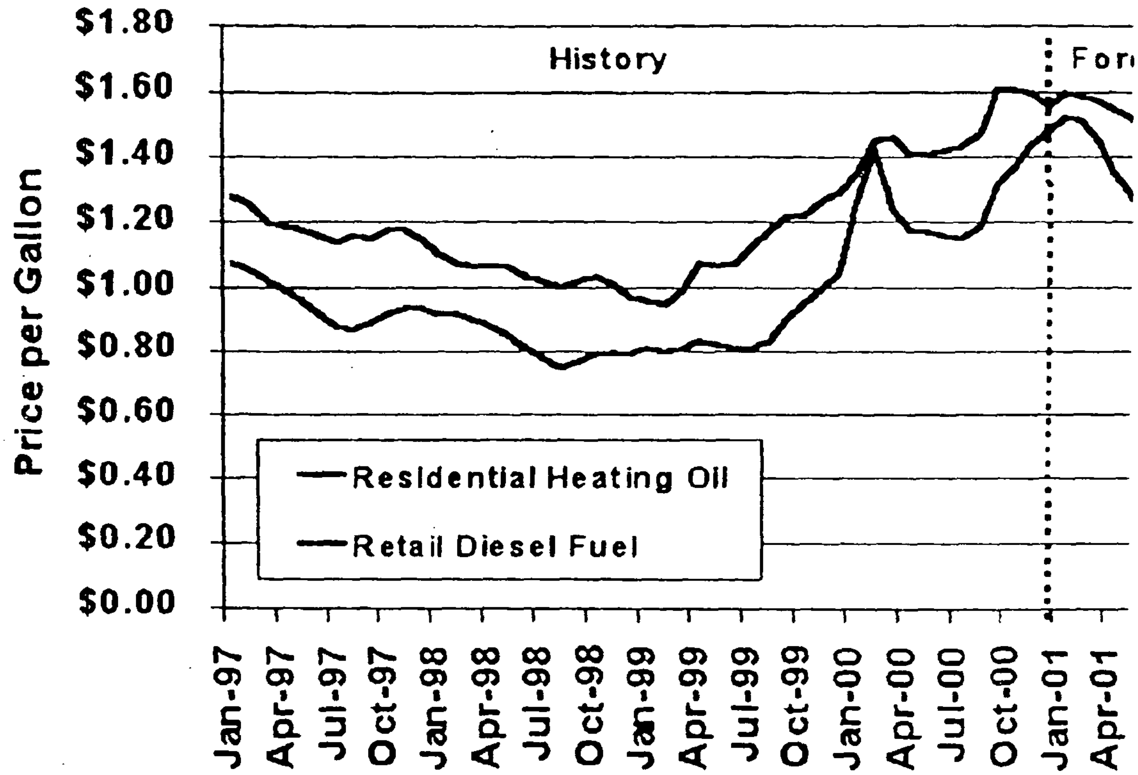
Notes:

- Gasoline inventories in the United States began last summer's driving season at low levels and ended at low levels.
- In October 2000, with the market focusing on distillate, gasoline inventories slipped well below the normal range.
- At the end of December, gasoline inventories were about 194 million barrels, which is almost 5 percent below the 5-year average level for this time of year, but slightly above the end of 1999. As

of January 19, the most recent weekly data, gasoline stocks have risen to nearly 201 million barrels, about a million barrels less than a year ago.

- EIA's current forecast is for gasoline markets to remain relatively tight entering the driving season and through next year. Low inventory levels raise the risk of price volatility, especially in response to regional supply problems.

Retail Heating Oil and Diesel Fuel Prices



Sources: History: EIA; Projections: Short-Term Energy Outlook, January 2001.

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Notes:

- Because of the higher projected crude oil prices and because of increased tightening in the Northeast heating oil market since the last Outlook, we now expect prices this winter for residential heating oil deliveries to peak at about $1.52 per gallon in January. This is significantly above the monthly peak reached last winter. Because these figures are monthly averages, we expect some price movements for a few days to be above the values shown on the graph.
- This winter's expected peak price would be the highest on record in nominal terms, eclipsing the high set in February 2000. However, in real (constant dollar) terms, both of these prices remain

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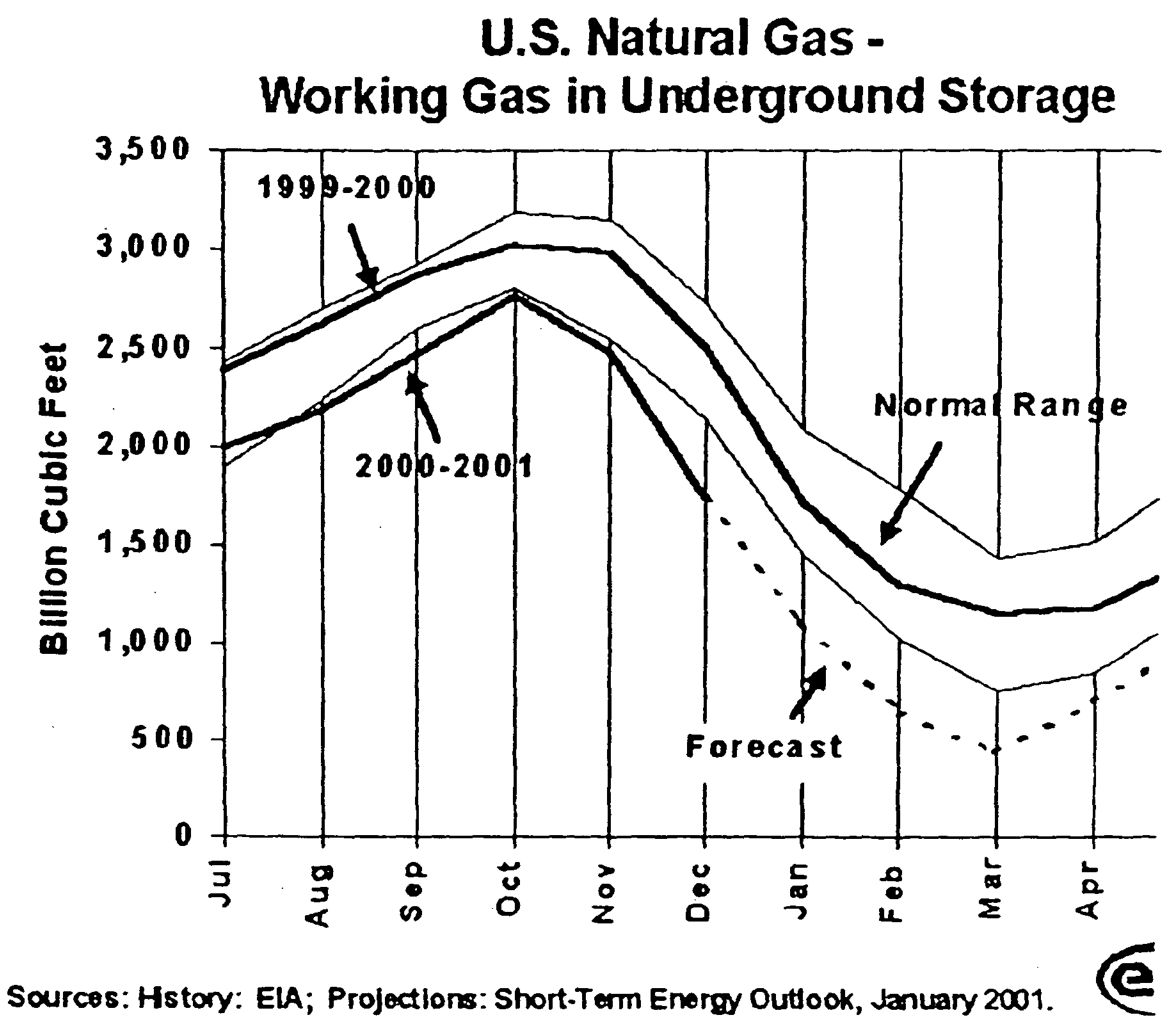
well below the peak reached in March 1981, when the average residential heating oil price was $1.29 per gallon, equivalent to over $2.50 per gallon today.

- After the current heating season ends, we expect to see a gradual decline in heating oil and diesel fuel prices, reflecting somewhat lower demand and more stable crude oil prices.



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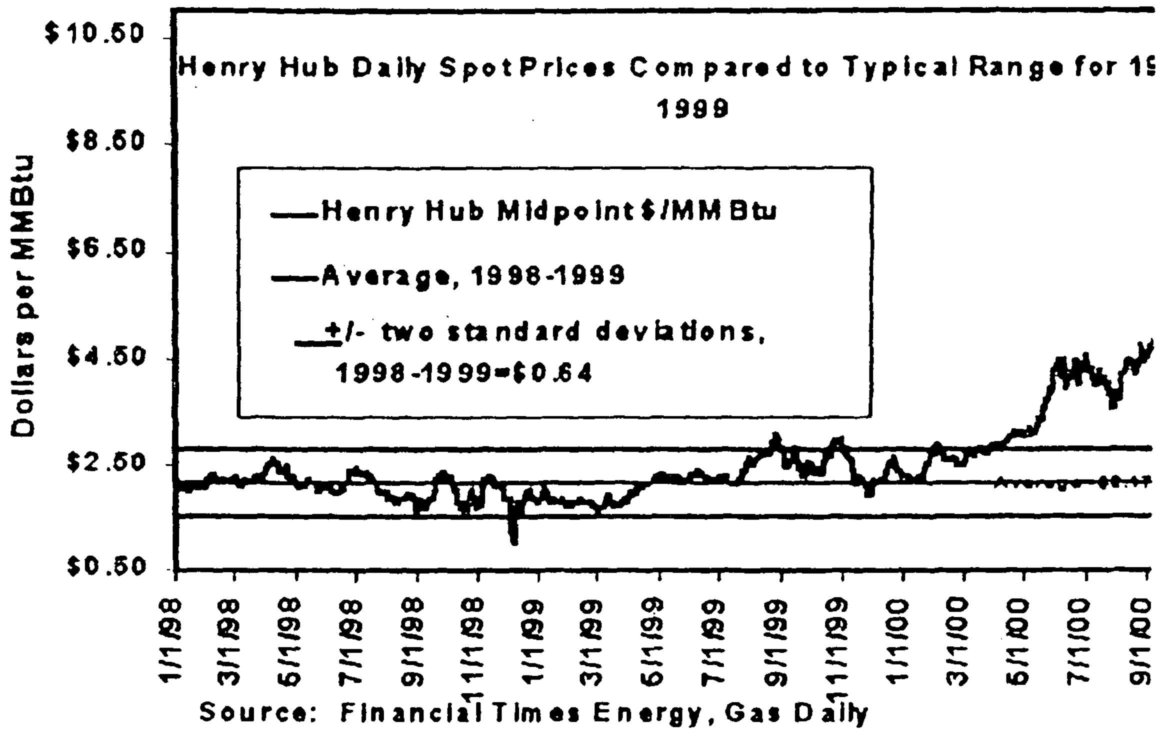
Notes:

- Working gas in storage is estimated to have been below 1,800 billion cubic feet at the end of December, more than 20% below the previous 5-year average. The estimated end-year level is the lowest for the period of time that EIA has records.

- The current outlook for winter demand and supply suggests that storage is likely to remain very low this winter. In the base case, we project that gas storage will fall to about 470 billion cubic feet at the end of the heating season (March 31, 2001). The previous 30-year observed low was 758 billion cubic feet at the end of the winter of 1995-1996.

- If summer gas demand next year is as strong as we currently expect it to be, the low end-winter storage levels will present a strong challenge to the North American gas supply system to maintain flexibility and provide additional gas in preparation for the subsequent winter season.

Current Natural Gas Spot Prices: Well Above the Recent Price Range



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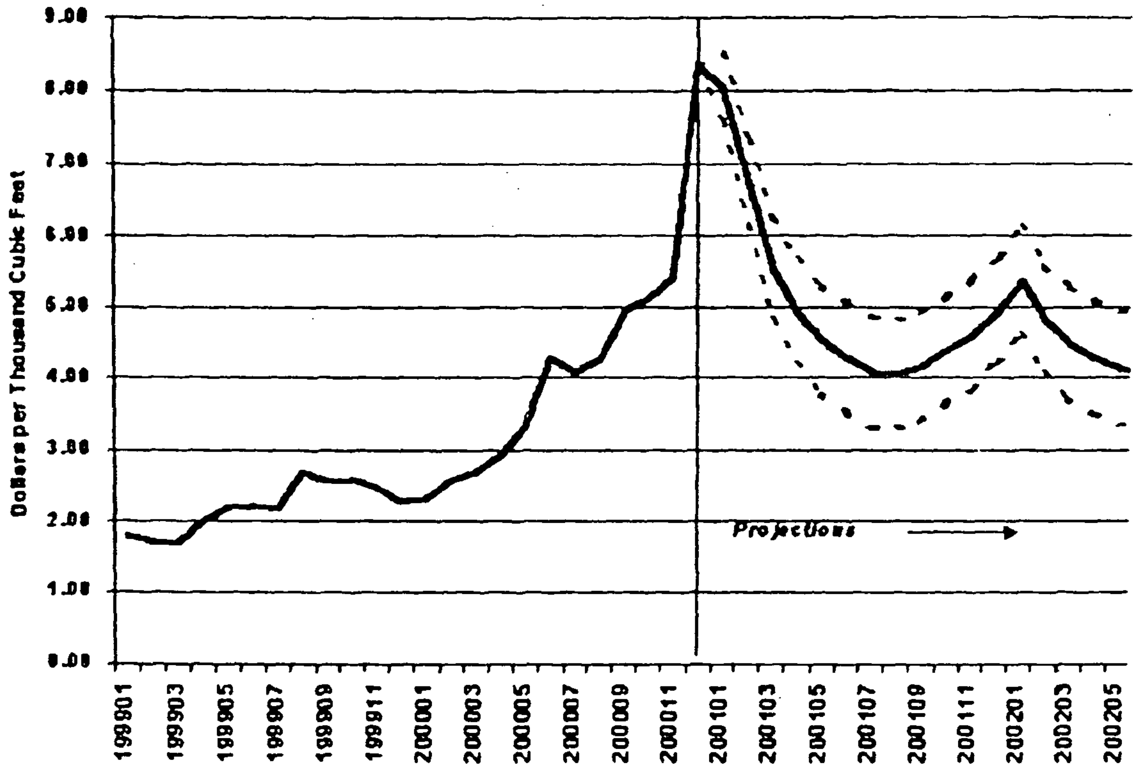
Notes:

- The surge in spot prices at the Henry Hub since April has taken prices well above a typical range for 1998-1999 (in this context, defined as the average, +/- 2 standard deviations)
- The upper bound on the typical range for 1998-99 is less than one-third of recent spot prices.
- The Henry Hub spot price spiked at $10.53 per MMBtu on December 29.

- Reasons for the price run-up include:
  - relatively flat natural gas production for several years
  - increased demand for natural gas as the economy has grown, especially from the electric generating sector
  - expectations for a colder winter than experienced in the last few years (generally borne out so far this heating season)
  - low levels of natural gas in storage
  - high prices for oil limiting the economic incentive to switch to petroleum-based fuels

- Natural gas spot prices have dropped in the past few weeks, with Henry Hub falling under $7 per MMBtu on January 24.

Natural Gas Spot Prices: Base Case and 95% Confidence Interval



Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, January 2001.

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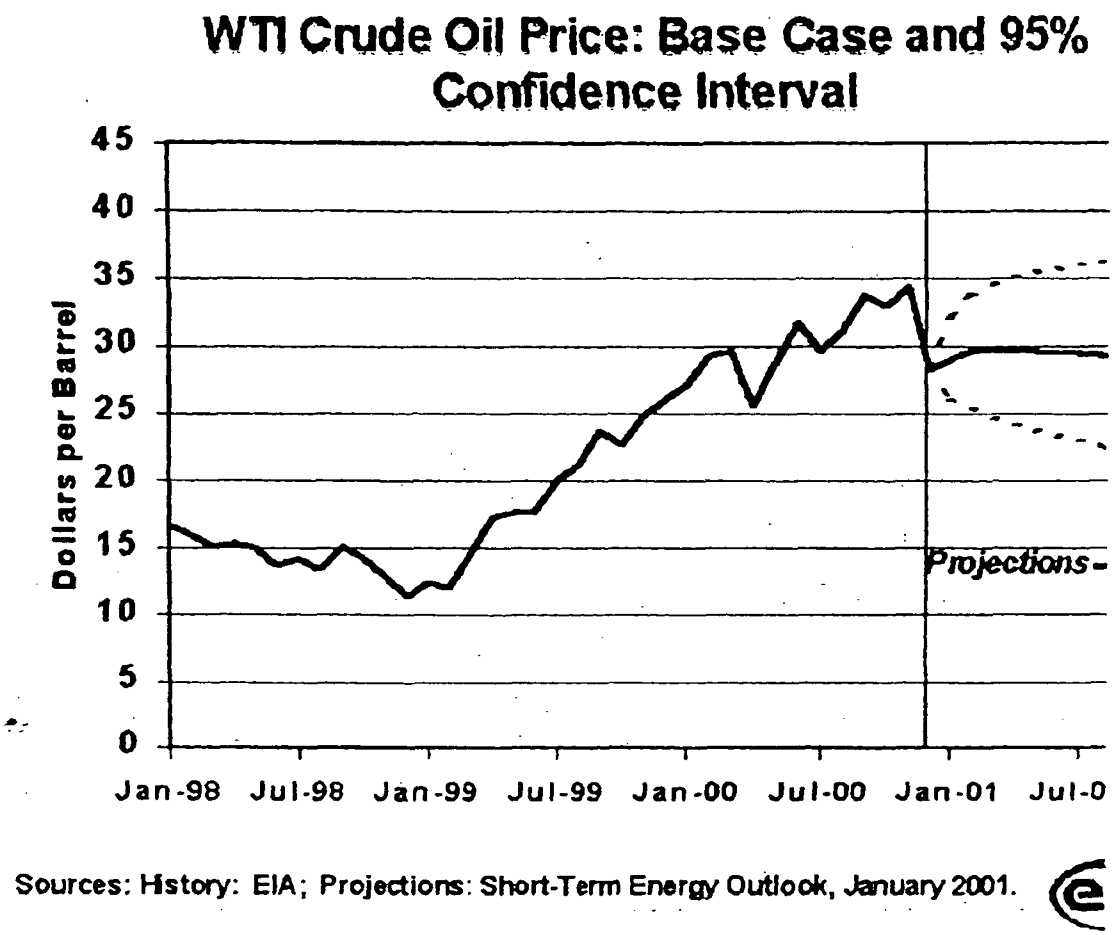
Notes:

- We expect to see peak monthly spot wellhead prices this winter of over $8.40, the monthly average reported for December 2000. Recently, concern about cold weather and low stocks pushed daily spot gas prices over $10.50 per mcf. However, in early January of this year, forecasts of warm weather pushed the price down by more $1.00 per mcf in one day, indicating the extraordinary volatility in the current U.S. market.

- The gas storage situation in the United States has not improved over the last few months, a sign that demand remains strong. We believe that the 30-year records for (seasonally adjusted) storage lows may be challenged throughout the heating season.



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Notes:

- Spot WTI prices broke $35 and even $36 per barrel in November as anticipated boosts to world supply from OPEC and other sources did not show up in actual stocks data.
- The recent decline in prices seems to be more the result of an unraveling of speculative pressures than a change in underlying fundamentals.
  - o Prices had been running higher than supply/demand fundamentals would have indicated throughout the fall months as a result of rising Mideast tensions, concern over the adequacy of distillate supplies, and expectations of Iraqi supply interruptions.

'12/2001

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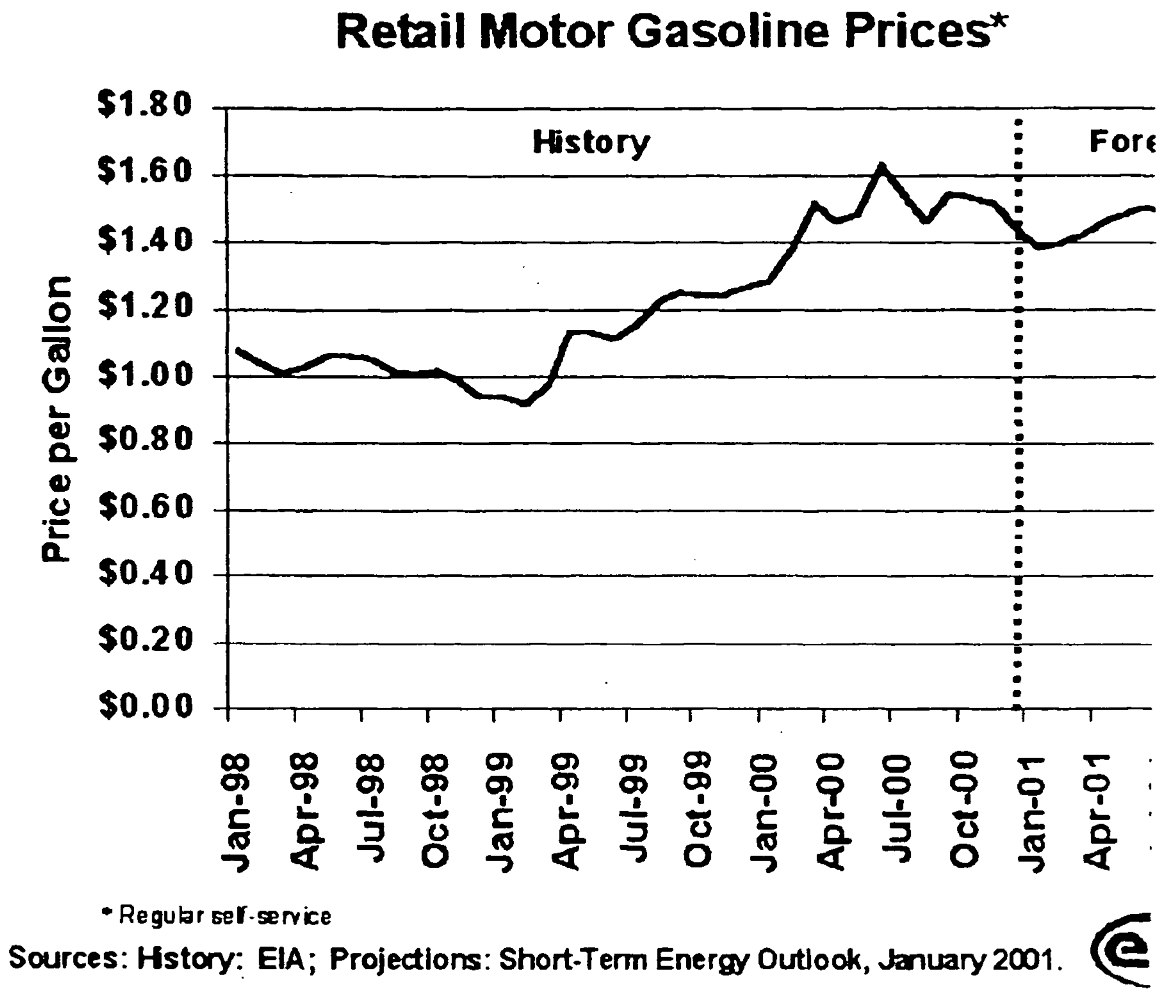
- But Mideast tensions seemed to ease in December and the market appeared to perceive a quick return of Iraqi crude oil supplies at full capacity. Pledges by Saudi Arabia/OPEC to offset a longer term Iraqi disruption added to a market sense of oversupply.
- Relatively mild weather in Europe allowed distillate stocks to normalize there and has kept crude demand relatively stable.
- All these factors seemed to refocus speculators on the downside potential for price, at least through December.

- EIA still sees a very tenuous supply/demand balance. With low inventories, a severe cold snap in Europe and the U.S. would increase refinery demand for crude, and push prices up. If the Iraqi disruption is thought to be indefinite, prices could be as high as $3-$5/barrel above those shown on this graph.

- However, EIA believes the market will move toward a more typical balance during 2001 and that prices will remain around $30 per barrel until the middle of the year, as the match of supply and demand improves.



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Notes:

- Assuming that our base case crude oil price path holds, we project that retail motor gasoline prices will continue to recede this winter, then begin to rise ahead of the summer driving season. By year's end, the monthly average retail price of regular unleaded (self-service) motor gasoline is projected to be about $1.38 per gallon.

- As was the case with heating oil, last year's peak average gasoline price, at $1.633 per gallon in June, was the highest ever recorded in nominal terms. However, in real (constant dollar) prices, the highest observed price was in March 1981, when the average was $1.417 per gallon, equivalent to almost $2.80 per gallon today.

Section 1. Energy Overview

Energy production during October 2000 totaled 6.1 quadrillion Btu, a 1.8-percent increase compared with the level of production during October 1999. Production of coal increased 7.0 percent; crude oil decreased 2.1 percent; natural gas plant liquids decreased 1.8 percent; natural gas (dry) increased 1.5 percent; and nuclear electric power decreased 0.6 percent, compared with the level of production during October 1999.

Energy consumption during October 2000 totaled 7.8 quadrillion Btu, 0.4 percent below the level of consumption during October 1999. Consumption of coal increased 3.9 percent; natural gas decreased 1.7 percent; petroleum decreased 0.8 percent; and nuclear electric power decreased 0.6 percent, compared with the level 1 year earlier.

Net imports of energy during October 2000 totaled 2.0 quadrillion Btu, 3.2 percent above the level of net imports 1 year earlier. Net imports of petroleum products decreased 23.3 percent; crude oil increased 3.5 percent; and natural gas rose 1.4 percent. Net imports of coal coke increased 48.2 while net imports of coal fell 41.3 percent, compared with the level in October 1999.

Table 1.1 Energy Summary for October 2000

(Quadrillion Btu)

	October			Cumulative January Through October				
	2000	1999	Percent Change[a]	2000	2000 Daily Rate	1999	1999 Daily Rate	Percent Change[b]
Production[c]	6.071	5.966	1.8	60.142	0.197	60.284	0.198	-0.5
Fossil Fuels	4.964	4.833	2.7	47.782	.157	47.828	.157	-.5
Coal	2.058	1.924	7.0	19.199	.063	19.419	.064	-1.5
Natural Gas (Dry)	E 1.637	1.613	1.5	E 16.030	E .053	15.984	.053	.0
Crude Oil[d]	E 1.046	1.069	-2.1	E 10.312	E .034	10.343	.034	-.6
Natural Gas Plant Liquids	.223	.227	-1.8	2.220	.007	2.082	.007	6.3
Nuclear Electric Power	.587	.591	-.6	6.655	.022	6.364	.021	4.2
Renewable Energy	.524	.548	-4.3	5.773	.019	6.127	.020	-6.1
Consumption[e]	7.784	7.813	-.4	81.139	.266	80.363	.264	.6
Fossil Fuels[f]	6.677	6.667	.1	68.642	.225	67.860	.223	.8
Coal	1.812	1.745	3.9	18.320	.060	17.980	.059	1.6
Natural Gas[g]	F 1.589	1.627	-1.7	E 18.628	E .061	18.243	.060	1.8
Petroleum[h]	3.254	3.282	-.8	31.522	.103	31.523	.104	-.3
Nuclear Electric Power	.587	.591	-.6	6.655	.022	6.364	.021	4.2
Renewable Energy[e]	.537	.571	-5.9	6.002	.020	6.289	.021	-4.9
Net Imports	2.016	1.954	3.2	20.225	.066	20.041	.066	.6
Fossil Fuels[i]	2.003	1.931	3.7	19.997	.066	19.879	.065	.3
Coal[j]	-.082	-.139	-41.3	-1.003	-.003	-1.112	-.004	-10.2
Coal Coke	.006	.004	48.2	.061	(s)	.043	(s)	41.8
Natural Gas	E .305	.301	1.4	E 2.921	E .010	2.892	.010	.7
Crude Oil[k]	1.632	1.576	3.5	16.077	.053	15.741	.052	1.8
Petroleum Products[l]	.136	.178	-23.3	1.829	.006	2.245	.007	-18.6
Renewable Energy[m]	E .013	E .023	-44.0	E .228	E .001	E .163	E .001	40.1

[a] Based on data prior to rounding.
[b] Based on daily rates prior to rounding.
[c] Total production also includes hydroelectricity generated from pumped storage.
[d] Includes lease condensate.
[e] Alcohol (ethanol blended into motor gasoline) is included in both "Petroleum" and "Renewable Energy," but is counted only once in total energy consumption.
[f] Fossil fuel consumption also includes coal coke net imports and electricity net imports from fossil fuels.
[g] Includes supplemental gaseous fuels.
[h] Petroleum products supplied, including natural gas plant liquids and crude oil burned as fuel.
[i] Fossil fuel net imports also include electricity net imports from fossil fuels.
[j] Minus sign indicates exports are greater than imports.
[k] Crude oil, lease condensate, and imports of crude oil for the Strategic Petroleum Reserve.
[l] Petroleum products, unfinished oils, pentanes plus, and gasoline blending components.
[m] Electricity net imports derived from hydroelectric power or geothermal energy.
(s)=Less than +0.5 trillion Btu and greater than -0.5 trillion Btu.
E=Estimate. F=Forecast.
Notes: • Totals may not equal sum of components due to independent rounding. • Geographic coverage is the 50 States and the District of Columbia.
Sources: Tables 1.3, 1.4, and 1.5.

This table is redesigned to incorporate additional renewable energy data. See Appendix E for further information.

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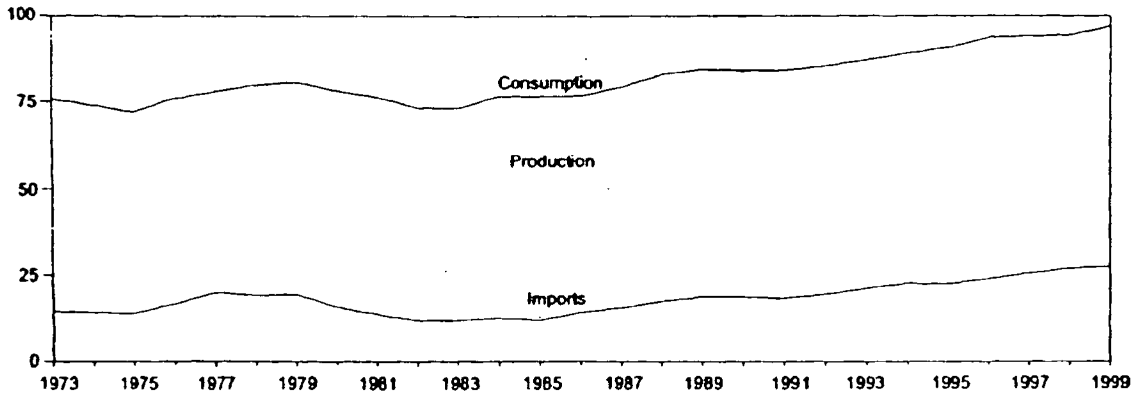
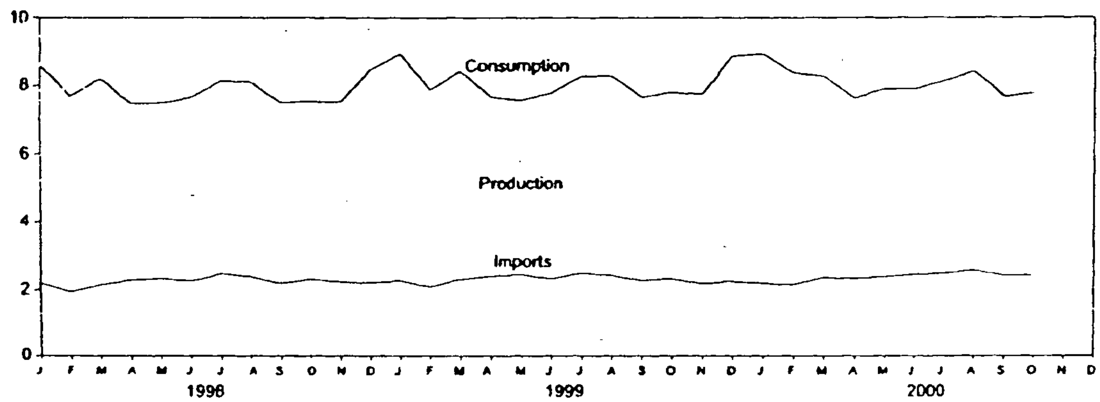
Figure 1.1 Energy Overview
(Quadrillion Btu)

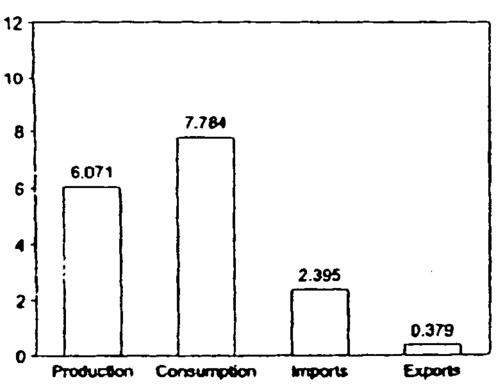
Consumption, Production, and Imports, 1973-1999



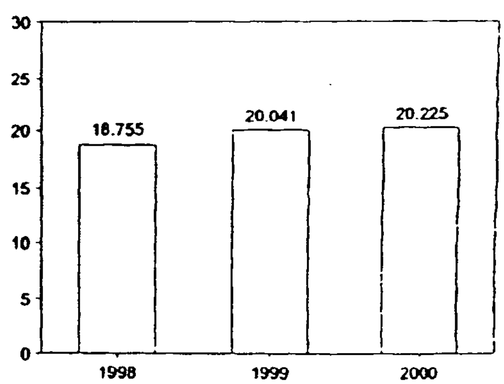
Consumption, Production, and Imports, Monthly



Overview, October 2000



Net Imports, January-October



Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.2.

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Table 1.2 Energy Overview

(Quadrillion Btu)

	Production	Consumption[a]	Imports	Exports	Net Imports
1973 Total	R63.585	R75.808	14.731	2.051	12.680
1974 Total	R62.372	R74.080	14.413	2.223	12.190
1975 Total	R61.357	R72.042	14.111	2.359	11.752
1976 Total	R61.602	R76.072	16.837	2.188	14.648
1977 Total	R62.052	R78.122	20.090	2.071	18.019
1978 Total	R63.137	R80.123	19.254	1.931	17.323
1979 Total	R65.948	R81.044	19.618	2.870	16.748
1980 Total	R67.241	R78.435	15.971	3.723	12.247
1981 Total	R67.007	R76.569	13.975	4.329	9.646
1982 Total	R66.574	R73.440	12.092	4.633	7.460
1983 Total	R64.106	R73.317	12.027	3.717	8.310
1984 Total	R68.832	R76.972	12.767	3.804	8.963
1985 Total	R67.720	R76.778	12.103	4.231	7.872
1986 Total	R67.178	R77.065	14.438	4.055	10.382
1987 Total	R67.760	R79.633	15.764	3.853	11.911
1988 Total	R69.025	R83.068	17.564	4.415	13.149
1989 Total	R69.457	R84.607	R18.955	4.767	R14.188
1990 Total	R70.822	R84.214	R18.952	4.865	R14.087
1991 Total	R70.315	R84.271	R18.497	5.157	R13.339
1992 Total	R70.056	R85.491	R19.577	4.957	R14.621
1993 Total	R68.367	R87.281	R21.498	4.283	R17.215
1994 Total	R70.836	R89.189	R22.728	4.075	R18.651
1995 Total	R71.281	R90.924	R22.541	4.536	R18.005
1996 Total	R72.583	R93.902	R23.992	4.658	R19.334
1997 Total	R72.532	R94.307	25.516	4.574	20.942
1998 January	R6.362	R8.614	2.190	.414	1.776
February	R5.705	R7.694	1.937	.324	1.614
March	R6.268	R8.201	2.144	.366	1.778
April	R5.979	R7.506	2.273	.375	1.897
May	R6.123	R7.503	2.327	.406	R1.921
June	R6.051	R7.657	2.240	.377	1.863
July	R6.099	R8.140	2.467	.371	2.096
August	R6.095	R8.101	2.374	.333	2.041
September	R5.841	R7.522	2.178	.351	1.825
October	R6.090	R7.576	2.305	.359	1.946
November	R5.847	R7.541	2.223	.313	1.910
December	R6.093	R8.478	2.201	.354	1.847
Total	R72.553	R94.537	26.857	4.344	22.513
1999 January	R6.183	R8.947	2.256	.307	1.948
February	R5.809	R7.872	2.077	.252	1.825
March	R6.303	R8.440	2.296	.292	2.004
April	R5.829	R7.675	2.382	.357	2.025
May	R5.921	R7.580	2.435	.305	2.131
June	R6.014	R7.788	2.306	.321	1.984
July	R6.114	R8.285	2.480	.322	2.158
August	R6.174	R8.303	2.404	.333	2.071
September	R5.950	R7.661	2.250	.308	1.942
October	R5.966	R7.813	2.303	.349	1.954
November	R5.968	R7.748	2.158	.324	1.834
December	R6.171	R8.875	2.223	.356	1.867
Total	R72.404	R96.991	27.569	3.826	23.743
2000 January	R6.057	R8.953	2.174	.329	1.845
February	R5.768	R8.397	2.132	.270	1.862
March	R6.286	R8.284	2.340	.373	1.967
April	R5.742	R7.636	2.315	.317	1.998
May	R6.038	R7.911	2.360	.333	2.027
June	R5.990	R7.898	2.435	.333	2.101
July	R6.023	R8.149	2.477	.327	2.149
August	R6.286	R8.439	2.575	.388	2.187
September	R5.882	R7.688	R2.403	.330	R2.073
October	6.071	7.784	2.395	.379	2.016
10-Month Total	60.142	81.139	23.605	3.380	20.225
1999 10-Month Total	60.264	80.363	23.188	3.147	20.041
1998 10-Month Total	60.612	78.513	22.433	3.678	18.755

[a] The sum of domestic energy production and net imports of energy does not equal domestic energy consumption. The difference is attributed to stock changes; losses and gains in conversion, transportation, and distribution; the addition of blending compounds; shipments of anthracite to U.S. Armed Forces in Europe; and adjustments to account for discrepancies between reporting systems.

R=Revised.

Notes: • For definitions, see Notes 1 through 4 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: • Production: Table 1.3. • Consumption: Table 1.4. • Imports and Exports: Tables 3.1b, 4.3, 6.1, 7.1, A2-A8, E3b, and Section 2, "Energy Consumption Notes and Sources," Note 5. • Net Imports: Table 1.5.

Revised data reflect the incorporation of additional renewable energy data. See Tables 1.3, 1.4, 1.5, and Appendix E for further information.

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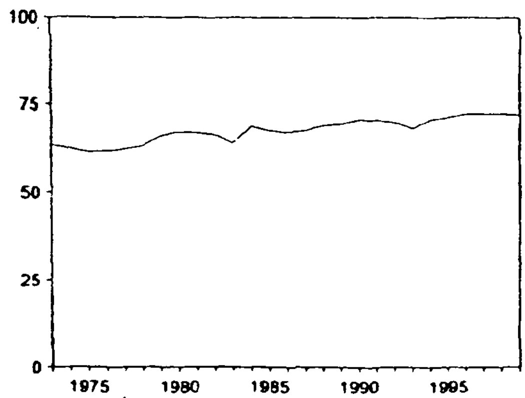
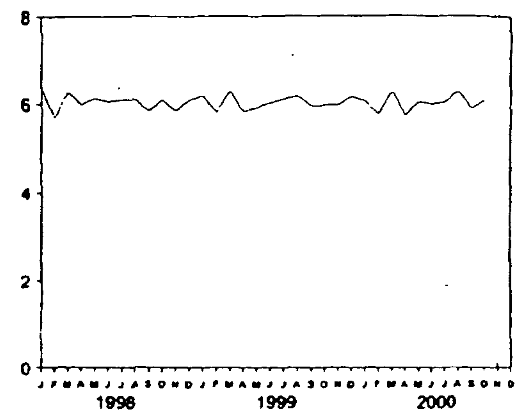
DOE006-0209

Figure 1.2 Energy Production
(Quadrillion Btu)

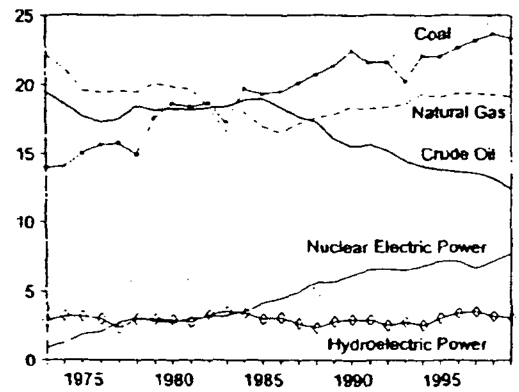
Total, 1973-1999



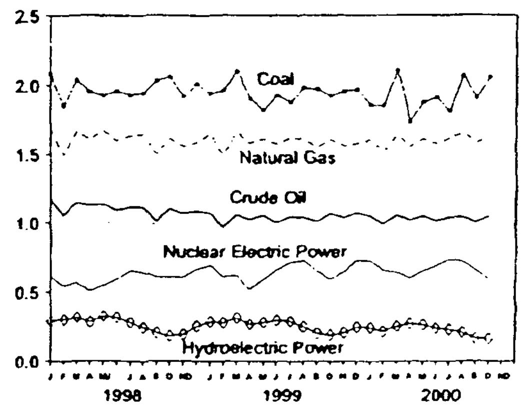
Total, Monthly



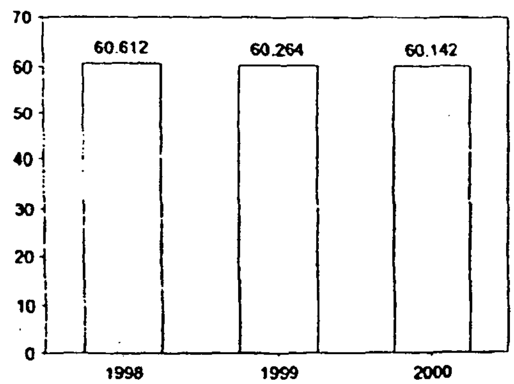
By Major Sources, 1973-1999



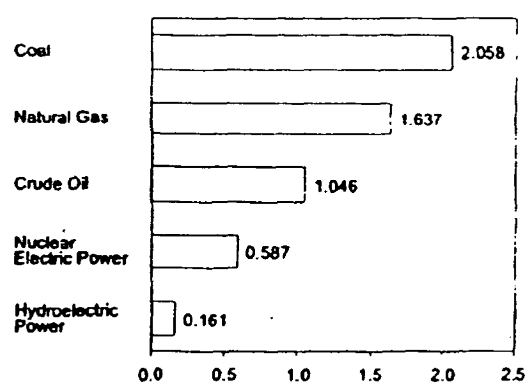
By Major Sources, Monthly



Total, January-October



By Major Sources, October 2000



Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.3

2853

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Table 1.3 Energy Production by Source
(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	(•)	2.861	1.529	0.043	NA	4.433	R 63.585
1974 Total	14.074	21.210	18.575	2.471	56.331	1.272	(•)	3.177	1.540	.053	NA	4.769	R 62.372
1975 Total	14.989	19.640	17.729	2.374	54.733	1.900	(•)	3.155	1.499	.070	NA	4.723	R 61.357
1976 Total	15.654	19.480	17.262	2.327	54.723	2.111	(•)	2.976	1.713	.078	NA	4.768	R 61.602
1977 Total	15.755	19.565	17.454	2.327	55.101	2.702	(•)	2.333	1.838	.077	NA	4.249	R 62.052
1978 Total	14.910	19.485	18.434	2.245	55.074	3.024	(•)	2.937	2.038	.064	NA	5.039	R 63.137
1979 Total	17.540	20.076	18.104	2.286	58.006	2.776	(•)	2.931	2.152	.084	NA	5.166	R 65.948
1980 Total	18.598	19.908	18.249	2.254	59.008	2.739	(•)	E 2.900	2.485	.110	NA	5.494	R 67.241
1981 Total	18.377	19.699	18.146	2.307	58.529	3.008	(•)	E 2.758	2.590	.123	NA	5.471	R 67.007
1982 Total	18.639	18.319	18.309	2.191	57.458	3.131	(•)	E 3.266	2.615	.105	NA	5.985	R 66.574
1983 Total	17.247	16.593	18.392	2.184	54.416	3.203	(•)	E 3.527	2.831	.129	(s)	6.488	R 64.106
1984 Total	19.719	18.008	18.848	2.274	58.849	3.553	(•)	E 3.386	2.880	.165	(s)	6.431	R 68.832
1985 Total	19.325	16.980	18.992	2.241	57.539	4.149	(•)	E 2.970	E 2.864	.198	(s)	6.033	R 67.720
1986 Total	19.509	16.541	18.376	2.149	56.575	4.471	(•)	E 3.071	E 2.841	.219	(s)	6.132	R 67.178
1987 Total	20.141	17.136	17.675	2.215	57.167	4.906	(•)	E 2.635	E 2.823	.229	(s)	5.687	R 67.760
1988 Total	20.738	17.599	17.279	2.260	57.875	5.661	(•)	E 2.334	E 2.937	.217	(s)	5.489	R 69.025
1989 Total	21.346	17.847	16.117	2.158	57.468	f 5.677	(•)	2.855	E 3.050	.323	.063	6.311	R 69.457
1990 Total	22.456	18.362	15.571	2.175	58.564	6.162	-.036	3.046	E 2.646	.343	.094	6.132	R 70.822
1991 Total	21.594	18.229	15.701	2.306	57.829	6.580	-.047	3.021	E 2.687	.346	.097	6.153	R 70.515
1992 Total	21.629	18.375	15.223	2.363	57.590	6.608	-.043	2.617	E 2.831	.355	.097	5.901	R 70.056
1993 Total	20.249	18.584	14.494	2.408	55.736	6.520	-.042	2.892	2.791	.368	.102	6.153	R 68.367
1994 Total	22.111	19.348	14.103	2.391	57.952	6.838	-.035	2.684	2.926	.364	.107	6.080	R 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	R 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	R 72.583
1997 Total	23.211	19.394	13.658	2.495	58.758	6.678	-.042	3.718	2.991	.322	.107	7.138	R 72.532
1998 January	2.081	1.688	1.176	.211	5.156	.615	(s)	E .298	E .256	E .029	E .009	.591	R 6.362
February	1.850	1.493	1.052	.196	4.591	.542	.001	E .308	E .230	E .025	E .008	.571	R 5.705
March	2.042	1.669	1.152	.217	5.079	.571	(s)	E .326	E .255	E .029	E .009	.610	R 6.268
April	1.955	1.610	1.128	.211	4.904	.505	-.005	E .295	E .246	E .025	E .009	.574	R 5.979
May	1.926	1.674	1.141	.214	4.956	.547	-.008	E .341	E .253	E .025	E .009	.627	R 6.123
June	1.962	1.604	1.091	.198	4.854	.592	-.007	E .332	E .245	E .025	E .009	.611	R 6.051
July	1.931	1.636	1.114	.185	4.865	.653	-.007	E .296	E .254	E .028	E .009	.587	R 6.099
August	1.944	1.647	1.115	.201	4.908	.641	-.007	E .261	E .255	E .029	E .009	.553	R 6.095
September	2.034	1.499	1.007	.194	4.735	.608	-.003	E .218	E .247	E .028	E .009	.502	R 5.841
October	2.063	1.620	1.104	.204	4.991	.610	-.005	E .199	E .256	E .030	E .009	.494	R 6.090
November	1.920	1.562	1.068	.200	4.750	.609	-.005	E .210	E .247	E .028	E .009	.494	R 5.847
December	2.011	1.686	1.087	.169	4.872	.664	(s)	E .262	E .258	E .028	E .009	.557	R 6.093
Total	23.719	19.288	13.235	2.420	58.662	7.157	-.046	3.345	3.003	.327	.104	6.780	R 72.553
1999 January	R 1.942	1.653	1.072	.192	4.859	.695	-.006	.301	E .299	E .027	E .007	.635	R 6.183
February	R 1.966	1.494	.969	.181	4.609	.608	-.004	.297	E .267	E .024	E .007	.596	R 5.809
March	R 2.099	1.660	1.058	.207	5.024	.622	-.004	.332	E .293	E .027	E .008	.661	R 6.303
April	R 1.906	1.581	1.024	.203	4.714	.513	-.005	.286	E .286	E .025	E .009	.607	R 5.829
May	R 1.818	1.617	1.056	.208	4.699	.593	-.007	.302	E .294	E .028	E .012	.636	R 5.921
June	R 1.930	1.576	1.002	.210	4.720	.659	-.006	.312	E .286	E .032	E .011	.642	R 6.014
July	R 1.878	1.623	1.042	.221	4.764	.710	-.006	.304	E .296	E .035	E .012	.647	R 6.114
August	R 1.982	1.611	1.039	.217	4.849	.725	-.008	.264	E .296	E .036	E .011	.607	R 6.174
September	R 1.975	1.556	1.010	.215	4.756	.648	-.004	.218	E .288	E .035	E .009	.550	R 5.950
October	R 1.924	1.613	1.069	.227	4.833	.591	-.005	.209	E .295	E .036	E .008	.548	R 5.966
November	R 1.961	1.563	1.037	.219	4.780	.645	-.005	.220	E .287	E .033	E .007	.548	R 5.968
December	R 1.971	1.579	1.071	.227	4.848	.727	-.004	.261	E .298	E .033	E .008	.601	R 6.171
Total	R 23.351	19.126	12.451	2.528	57.456	7.738	-.064	3.306	3.486	.374	.110	7.275	R 72.404
2000 January	1.857	E 1.611	E 1.049	.226	4.742	.723	-.005	.254	E .308	E .027	E .009	.598	R 6.057
February	1.849	E 1.519	E .991	.215	4.574	.656	-.005	.226	E .288	E .023	E .008	.543	R 5.768
March	2.110	E 1.646	E 1.056	.230	5.042	.643	-.008	.269	E .305	E .023	E .009	.607	R 6.286
April	1.732	E 1.558	E 1.018	.221	4.529	.598	-.004	.287	E .297	E .024	E .011	.620	R 5.742
May	1.879	E 1.615	E 1.049	.225	4.768	.653	-.005	.279	E .303	E .025	E .012	.620	R 6.036
June	1.918	E 1.581	E 1.013	.216	4.728	.686	-.008	.258	E .290	E .026	E .010	.582	R 5.990
July	R 1.814	E 1.620	E 1.041	.223	4.699	.735	-.003	.244	E .311	E .028	E .010	.593	R 6.023
August	R 2.071	RE 1.656	E 1.045	.226	4.998	.722	-.004	.224	E .309	E .028	E .009	.571	R 6.286
September	R 1.911	E 1.587	E 1.003	.216	4.718	.654	-.006	.182	E .298	E .027	E .009	.516	R 5.882
October	2.058	E 1.637	E 1.046	.223	4.964	.587	-.004	.175	E .311	E .028	E .010	.524	6.071
10-Month Total	19.199	E 16.030	E 10.312	2.220	47.762	6.655	-.048	2.397	E 3.019	E .259	E .098	5.773	60.142
1999 10-Month Total	19.419	15.984	10.343	2.082	47.828	6.364	-.055	2.825	E 2.900	E .307	E .094	6.127	60.264
1998 10-Month Total	19.788	16.140	11.080	2.031	49.040	5.883	-.041	E 2.873	E 2.498	E .272	E .087	5.730	60.612

[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] 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 A5. • 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

This table is redesigned to incorporate additional renewable energy data. See Appendix E for further information.

2854

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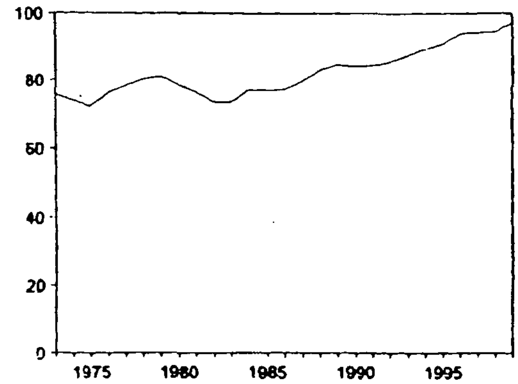
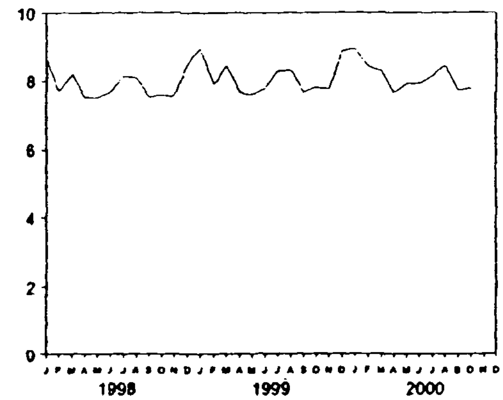
Figure 1.3 Energy Consumption
(Quadrillion Btu)

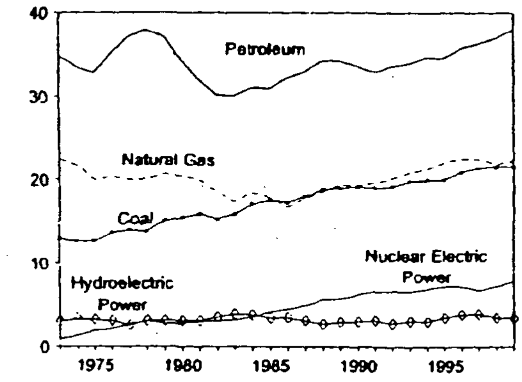
Total, 1973-1999



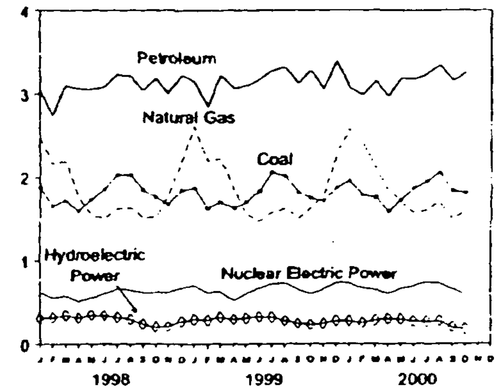
Total, Monthly



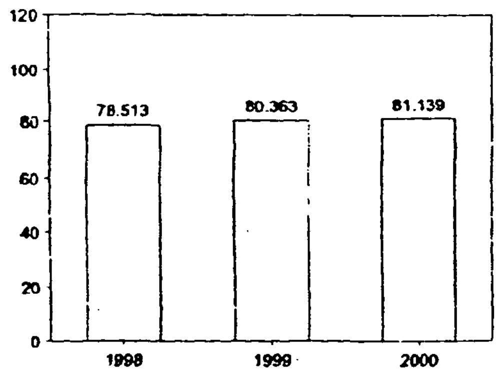
By Major Sources, 1973-1999



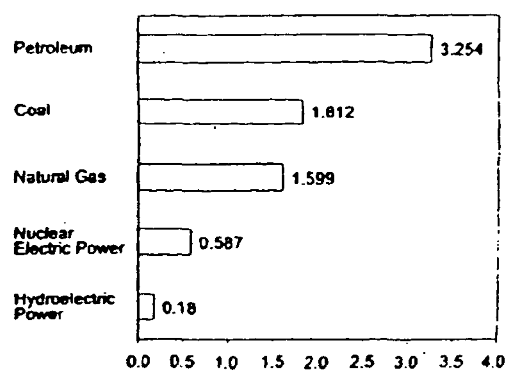
By Major Sources, Monthly



Total, January-October



By Major Sources, October 2000



Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.4.

2855

DOE006-0212

Table 1.4 Energy Consumption by Source
(Quadrillion Btu)

	Fossil Fuels				Nuclear Electric Power	Hydroelectric Pumped Storage[e]	Renewable Energy[a]					Total[f]
	Coal	Natural Gas[b]	Petroleum[c]	Total[d]			Conventional Hydroelectric Power	Wood, Waste, Alcohol[f]	Geothermal	Solar and Wind	Total	
1973 Total	12.971	22.512	34.840	70.316	0.910	(g)	3.010	1.529	0.043	NA	4.581	R 75.808
1974 Total	12.663	21.732	33.455	67.906	1.272	(g)	3.309	1.540	.053	NA	4.902	R 74.080
1975 Total	12.663	19.948	32.731	65.355	1.900	(g)	3.219	1.499	.070	NA	4.788	R 72.042
1976 Total	13.584	20.345	35.175	69.104	2.111	(g)	3.066	1.713	.078	NA	4.857	R 76.072
1977 Total	13.922	19.931	37.122	70.989	2.702	(g)	2.515	1.838	.077	NA	4.431	R 78.122
1978 Total	13.766	20.000	37.965	71.856	3.024	(g)	3.141	2.038	.064	NA	5.243	R 80.123
1979 Total	15.040	20.666	37.123	72.892	2.776	(g)	3.141	2.152	.084	NA	5.377	R 81.044
1980 Total	15.423	20.394	34.202	69.984	2.739	(g)	E 3.118	2.485	.110	NA	5.712	R 78.435
1981 Total	15.908	19.928	31.931	67.750	3.008	(g)	E 3.105	2.590	.123	NA	5.818	R 76.569
1982 Total	15.322	18.505	30.231	64.036	3.131	(g)	E 3.572	2.615	.105	NA	6.292	R 73.440
1983 Total	15.894	17.357	30.054	63.290	3.203	(g)	E 3.899	2.831	.129	(s)	6.860	R 73.317
1984 Total	17.071	18.507	31.051	66.617	3.553	(g)	E 3.800	2.880	.165	(s)	6.845	R 76.972
1985 Total	17.478	17.834	30.922	66.221	4.149	(g)	E 3.398	E 2.864	.198	(s)	6.460	R 76.778
1986 Total	17.260	16.708	32.196	66.148	4.471	(g)	E 3.446	E 2.841	.219	(s)	6.507	R 77.065
1987 Total	18.008	17.744	32.865	68.626	4.906	(g)	E 3.117	E 2.823	.229	(s)	6.170	R 79.633
1988 Total	18.846	18.552	34.222	71.660	5.661	(g)	E 2.662	E 2.937	.217	(s)	5.817	R 83.069
1989 Total	h 18.944	19.384	34.211	72.536	i 5.677	(g)	2.998	E 3.050	.334	.083	6.465	R 84.607
1990 Total	19.136	19.296	33.553	71.910	6.162	-.036	3.146	E 2.648	.355	.094	6.241	R 84.214
1991 Total	18.985	19.606	32.845	71.505	6.580	-.047	3.159	E 2.687	.363	.097	6.306	R 84.271
1992 Total	19.144	20.131	33.527	72.889	6.608	-.043	2.818	E 2.831	.374	.097	6.121	R 85.481
1993 Total	19.758	20.827	33.841	74.500	6.520	-.042	3.119	2.791	.387	.102	6.399	R 87.281
1994 Total	19.924	21.288	34.670	76.081	6.838	-.035	2.903	2.925	.388	.107	6.414	R 89.180
1995 Total	20.016	22.163	34.553	76.915	7.177	-.028	3.481	3.056	.333	.106	6.976	R 90.924
1996 Total	20.940	22.559	35.757	79.398	7.168	-.032	3.882	3.114	.346	.110	7.461	R 93.902
1997 Total	21.444	22.530	36.266	80.395	6.678	-.042	3.961	2.991	.322	.107	7.382	R 94.307
1998 January	1.874	2.476	3.045	7.404	.815	(s)	.312	E .256	E .029	E .009	.606	R 8.814
February	1.651	2.177	2.743	6.578	.542	.001	.321	E .230	E .025	E .008	.585	R 7.694
March	1.712	2.189	3.098	7.006	.571	(s)	.342	E .255	E .029	E .009	.635	R 8.201
April	1.595	1.758	3.056	6.420	.506	-.005	.315	E .246	E .025	E .009	.595	R 7.506
May	1.726	1.547	3.047	6.326	.547	-.008	.358	E .253	E .025	E .009	.645	R 7.503
June	1.852	1.507	3.078	6.450	.592	-.007	.351	E .245	E .025	E .009	.630	R 7.657
July	2.023	1.621	3.228	6.887	.653	-.007	.324	E .254	E .028	E .009	.515	R 8.140
August	2.027	1.632	3.208	6.891	.641	-.007	.294	E .255	E .029	E .009	.586	R 8.101
September	1.842	1.517	3.032	6.403	.608	-.003	.240	E .247	E .028	E .009	.524	R 7.522
October	1.755	1.528	3.182	6.472	.610	-.005	.215	E .256	E .030	E .009	.510	R 7.576
November	1.672	1.771	2.996	6.442	.609	-.005	.221	E .247	E .028	E .009	.505	R 7.541
December	1.838	2.195	3.220	7.257	.664	(s)	.275	E .258	E .028	E .009	.570	R 8.478
Total	21.589	21.821	36.934	80.539	7.157	-.046	3.569	3.003	.328	.104	7.005	R 94.537
1999 January	1.868	2.610	3.143	7.627	.695	-.006	.308	E .299	E .027	E .007	.641	R 8.947
February	1.627	2.195	2.850	6.675	.608	-.004	.303	E .267	E .024	E .007	.602	R 7.872
March	1.699	2.237	3.220	7.164	.622	-.004	.339	E .293	E .027	E .008	.667	R 8.440
April	1.627	1.845	3.081	6.550	.513	-.005	.304	E .286	E .026	E .009	.625	R 7.675
May	1.695	1.554	3.090	6.349	.593	-.007	.320	E .294	E .028	E .012	.654	R 7.580
June	1.833	1.472	3.171	6.485	.650	-.006	.330	E .286	E .033	E .011	.660	R 7.780
July	2.061	1.578	3.274	6.924	.710	-.006	.322	E .298	E .035	E .012	.665	R 8.285
August	2.011	1.622	3.319	6.968	.725	-.008	.284	E .296	E .036	E .011	.627	R 8.303
September	1.815	1.504	3.114	6.449	.648	-.004	.245	E .288	E .035	E .009	.577	R 7.661
October	1.745	1.627	3.282	6.667	.591	-.005	.232	E .295	E .036	E .008	.571	R 7.813
November	1.708	1.767	3.051	6.547	.645	-.005	.244	E .287	E .033	E .007	.572	R 7.748
December	1.871	2.272	3.386	7.545	.727	-.004	.282	E .298	E .033	E .008	.621	R 8.875
Total	21.560	22.289	37.960	81.957	7.736	-.064	3.513	3.486	.374	.110	7.483	R 96.991
2000 January	1.957	2.586	3.071	7.628	.773	-.005	.275	E .308	E .027	E .009	.619	R 8.953
February	1.778	2.411	2.981	7.190	.655	-.005	.249	E .286	E .023	E .008	.566	R 8.397
March	1.750	2.119	3.149	7.033	.643	-.006	.288	E .305	E .023	E .009	.626	R 8.284
April	1.590	1.839	2.971	6.415	.598	-.004	.305	E .297	E .024	E .011	.638	R 7.636
May	1.720	1.701	3.195	6.634	.653	-.005	.301	E .303	E .025	E .012	.641	R 7.911
June	1.867	1.569	3.170	6.620	.686	-.006	.278	E .290	E .026	E .010	.604	R 7.898
July	R 1.952	1.608	3.235	6.811	.735	-.003	.270	E .311	E .028	E .010	.619	R 8.149
August	R 2.057	R 1.695	3.340	7.122	.722	-.004	.265	E .309	E .028	E .009	.611	R 8.439
September	R 1.837	R 1.501	3.155	6.512	.654	-.006	.206	E .298	E .027	E .009	.541	R 7.688
October	1.812	F 1.599	3.254	6.677	.587	-.004	.188	E .311	E .028	E .010	.537	7.784
10-Month Total	18.320	E 18.628	31.522	68.642	6.655	-.048	2.625	E 3.019	E .260	E .098	6.002	81.139
1999 10-Month Total	17.980	18.243	31.523	67.860	6.364	-.055	2.987	E 2.900	E .307	E .094	6.289	80.363
1998 10-Month Total	18.058	17.950	30.717	66.834	5.883	-.041	3.073	E 2.498	E .272	E .087	5.930	78.513

[a] End-use consumption, electric utility and nonutility electricity net generation, and net imports of electricity.
[b] Includes supplemental gaseous fuels.
[c] Petroleum products supplied, including natural gas plant liquids and crude oil burned as fuel.
[d] Includes coal coke net imports and electricity net imports from fossil fuels. See Table 1.5.
[e] Pumped storage facility production minus energy used for pumping.
[f] Alcohol (ethanol blended into motor gasoline) is included in both "Petroleum" and "Alcohol," but is counted only once in total energy consumption.
[g] Included in conventional hydroelectric power.
[h] Beginning in 1989, includes coal consumed by "Other Power Producers." See Table 6.2.
[i] Beginning in 1989, includes electricity generated by nonutility nuclear units.

R=Revised. NA=Not available. E=Estimate. F=Forecast. (s)=Less than +0.5 trillion Btu and greater than -0.5 trillion Btu.

Notes: • See Note 2 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 A5. • Natural Gas: Tables 4.1 and A4. • Petroleum: Tables 3.1a and A3. • Nuclear Electric Power: Tables 8.1 and A6. • Hydroelectric Pumped Storage: Tables 7.2 and A6. • Renewable Energy: Table E1.

This table is redesigned to incorporate additional renewable energy data. See Appendix E for further information.

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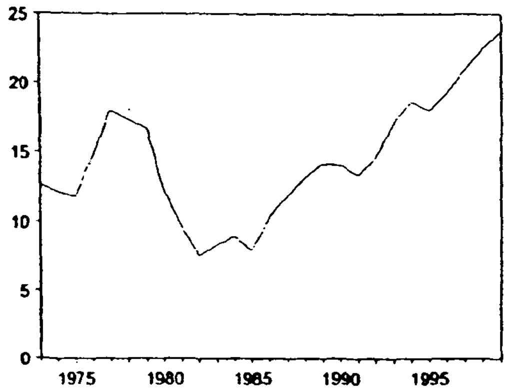
DOE006-0213

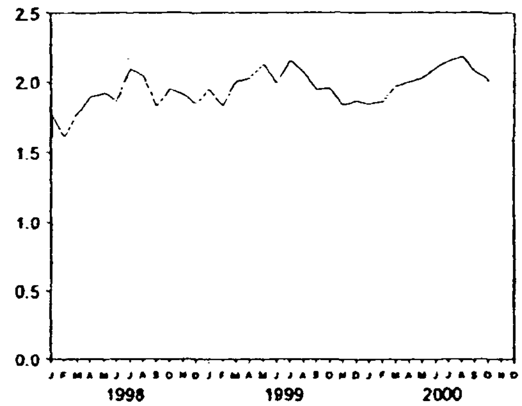
Figure 1.4 Energy Net Imports

(Quadrillion Btu, Except as Noted)

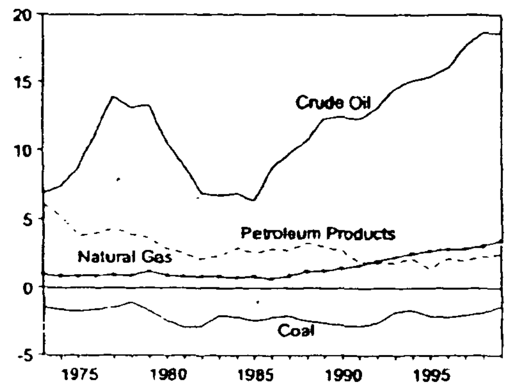
Total, 1973-1999



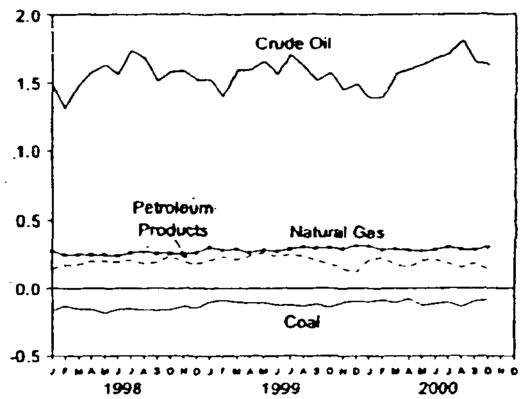
Total, Monthly



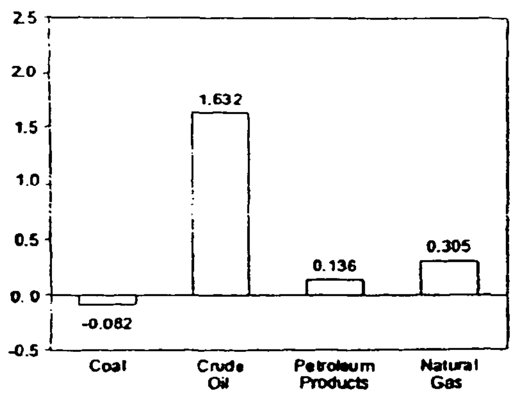
By Major Sources, 1973-1999



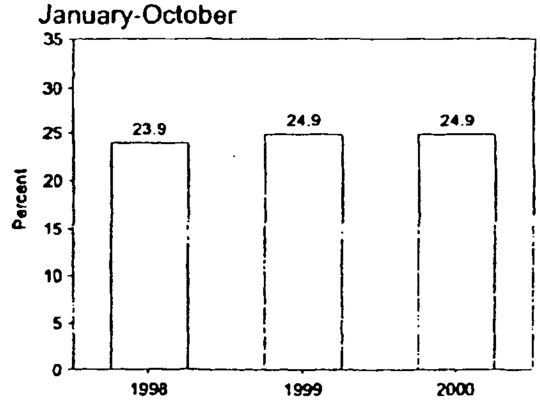
By Major Sources, Monthly



By Major Sources, October 2000



As Share of Consumption, January-October



Note: Because vertical scales differ, graphs should not be compared.
Sources: Tables 1.4 and 1.5.

2857

DOE006-0214

Table 1.5 Energy Net Imports by Source

(Quadrillion Btu)

	Fossil Fuels							Renewable Energy			
								Electricity[a]			
	Coal	Coal Coke	Natural Gas	Crude Oil[b]	Petroleum Products[c]	Electricity[d]	Total	Hydro-power[e]	Geo-thermal	Total	Total
1973 Total	-1.422	-0.007	0.981	6.883	6.097	([f])	12.631	0.148	([f])	0.148	12.780
1974 Total	-1.568	.056	.907	7.389	5.273	([f])	12.058	.133	([f])	.133	12.190
1975 Total	-1.738	.014	.904	8.708	3.800	([f])	11.688	.064	([f])	.064	11.752
1976 Total	-1.567	(s)	.922	11.221	3.982	([f])	14.559	.089	([f])	.089	14.648
1977 Total	-1.401	.015	.981	13.921	4.321	([f])	17.837	.182	([f])	.182	18.019
1978 Total	-1.004	.125	.941	13.125	3.932	([f])	17.118	.204	([f])	.204	17.323
1979 Total	-1.702	.063	1.243	13.328	3.603	([f])	16.535	.211	([f])	.211	16.746
1980 Total	-2.391	-.035	.957	10.586	2.912	([f])	12.030	.217	([f])	.217	12.247
1981 Total	-2.918	-.016	.857	8.854	2.522	([f])	9.298	.347	([f])	.347	9.646
1982 Total	-2.764	-.022	.890	6.917	2.128	([f])	7.153	.306	([f])	.306	7.460
1983 Total	-2.013	-.016	.885	6.731	2.351	([f])	7.938	.372	([f])	.372	8.310
1984 Total	-2.119	-.011	.782	6.918	2.970	([f])	8.549	.414	([f])	.414	8.963
1985 Total	-2.389	-.013	.894	6.381	2.570	([f])	7.445	.428	([f])	.428	7.872
1986 Total	-2.183	-.017	.686	8.676	2.855	([f])	10.007	.375	([f])	.375	10.382
1987 Total	-2.040	.000	.937	9.748	2.784	([f])	11.428	.483	([f])	.483	11.911
1988 Total	-2.446	.040	1.221	10.698	3.308	([f])	12.821	.328	([f])	.328	13.149
1989 Total	-2.566	.030	1.278	12.296	3.029	-.034	14.034	.143	.011	.154	R 14.188
1990 Total	-2.705	.005	1.464	12.536	2.757	-.080	13.977	.098	.011	.110	R 14.087
1991 Total	-2.760	.010	1.666	12.308	1.912	.059	13.186	.138	.015	.153	R 13.339
1992 Total	-2.587	.035	1.941	13.065	1.895	.053	14.401	.201	.019	.219	R 14.621
1993 Total	-1.758	.027	2.250	14.542	1.854	.059	16.970	.227	.018	.246	R 17.215
1994 Total	-1.657	.058	2.518	15.131	2.128	.141	18.317	.309	.025	.334	R 18.651
1995 Total	-2.081	.061	2.745	15.432	1.434	.121	17.712	.274	.019	.293	R 18.005
1996 Total	-2.165	.023	2.847	16.075	2.132	.100	19.021	.300	.014	.313	R 19.334
1997 Total	-2.006	.046	2.904	17.648	1.997	.100	20.698	.244	(s)	.244	20.942
1998 January	-.166	.008	.276	1.497	.143	E .002	1.761	E .015	E (s)	E .015	1.776
February	-.128	.003	.245	1.309	.169	E .002	1.600	E .013	E (s)	E .013	1.614
March	-.149	.003	.249	1.481	.174	E .003	1.761	E .017	E (s)	E .017	1.778
April	-.152	.004	.246	1.576	.196	E .006	1.877	E .020	E (s)	E .020	1.897
May	-.183	.005	.248	1.633	.198	E .003	1.903	E .017	E (s)	E .017	R 1.921
June	-.155	.009	.236	1.560	.191	E .003	1.844	E .019	E (s)	E .019	1.863
July	-.150	.007	.261	1.736	.205	E .009	2.068	E .028	E (s)	E .028	2.096
August	-.156	.010	.270	1.684	.185	E .014	2.008	E .033	E (s)	E .033	2.041
September	-.163	.006	.256	1.512	.186	E .006	1.803	E .022	E (s)	E .022	1.825
October	-.157	.007	.259	1.584	.237	E (s)	1.930	E .015	E (s)	E .015	1.946
November	-.132	.004	.251	1.586	.191	E -.001	1.899	E .011	E (s)	E .011	1.910
December	-.141	.002	.265	1.525	.181	E .001	1.834	E .013	E (s)	E .013	1.847
Total	-1.830	.067	3.064	18.684	2.258	.048	22.289	.224	.001	.225	22.513
1999 January	-.099	.005	.305	1.527	.204	E (s)	1.942	E .006	E (s)	E .006	1.948
February	-.085	.002	.280	1.390	.231	E .001	1.819	E .006	E (s)	E .006	1.825
March	-.100	.007	.292	1.593	.206	E (s)	1.998	E .007	E (s)	E .007	2.004
April	-.105	.009	.264	1.592	.238	E .008	2.006	E .018	E (s)	E .018	2.025
May	-.104	.003	.284	1.660	.261	E .008	2.113	E .018	E (s)	E .018	2.131
June	-.118	.002	.274	1.563	.237	E .008	1.966	E .018	E (s)	E .018	1.984
July	-.119	.003	.290	1.708	.248	E .009	2.139	E .019	E (s)	E .019	2.158
August	-.130	.008	.306	1.617	.241	E .010	2.051	E .020	E (s)	E .020	2.071
September	-.113	.002	.296	1.515	.201	E .015	1.915	E .027	E (s)	E .027	1.942
October	-.139	.004	.301	1.576	.178	E .011	1.931	E .023	E (s)	E .023	1.954
November	-.103	.009	.293	1.451	.147	E .012	1.809	E .024	E (s)	E .025	1.834
December	-.092	.006	.315	1.493	.115	E .009	1.847	E .021	E (s)	E .021	1.867
Total	-1.307	.058	3.500	18.686	2.507	.082	23.535	.207	.001	.208	23.743
2000 January	-.099	.004	.314	1.390	.204	E .011	1.824	E .020	E (s)	E .020	1.845
February	-.081	.007	.286	1.390	.224	E .012	1.839	E .023	E (s)	E .023	1.862
March	-.107	.006	.293	1.570	.176	E .009	1.948	E .019	E (s)	E .019	1.967
April	-.071	.006	.283	1.599	.155	E .008	1.980	E .018	E (s)	E .018	1.998
May	-.126	.008	.274	1.636	.204	E .010	2.006	E .022	E (s)	E .022	2.027
June	-.111	.004	.286	1.684	.207	E .010	2.079	E .022	E (s)	E .022	2.101
July	-.100	.006	E .307	1.714	.185	E .011	2.124	E .026	E (s)	E .026	2.149
August	-.133	.008	E .287	1.813	.149	E .022	2.146	E .040	E (s)	E .041	2.187
September	-.093	.007	RE .285	1.650	.187	E .012	2.049	E .024	E (s)	E .024	R 2.073
October	-.082	.008	E .305	1.632	.138	E .005	2.003	E .013	E (s)	E .013	2.016
10-Month Total	-1.003	.061	E 2.921	16.077	1.829	E .111	19.997	E .228	E .001	E .228	20.225
1999 10-Month Total	-1.112	.043	2.892	15.741	2.245	E .079	19.879	E .162	E .001	E .163	20.041
1998 10-Month Total	-1.558	.062	2.547	15.572	1.884	E .048	18.555	E .199	E .001	E .200	18.755

[a] Through 1988, all electricity imports and exports are included in "Hydropower." From 1989, includes only electricity imports and exports derived from hydroelectric power or geothermal energy.
[b] Crude oil, lease condensate, and imports of crude oil for the Strategic Petroleum Reserve.
[c] Petroleum products, unfinished oils, pentanes plus, and gasoline blending components.
[d] May include some nuclear-generated electricity.
[e] Conventional hydroelectric power.
[f] Included in "Hydropower."
R=Revised. E=Estimate. (s)=Less than +0.5 trillion Btu and greater than -0.5 trillion Btu.

Notes: • See Notes 3 and 4 at end of section. • Net imports equal imports minus exports. Minus sign indicates exports are greater than imports. • 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 A5. • Coal Coke: Section 2, "Energy Consumption Notes and Sources," Note 5, and Table A5. • Natural Gas: Tables 4.1 and A4. • Crude Oil and Petroleum Products: Tables 3.1b, A2, and A3. • Fossil Fuel Electricity: Derived from Table 7.1 sources and Table A6. • Renewable Energy: Table E3b.

This table is redesigned to incorporate additional renewable energy data. See Appendix E for further information.

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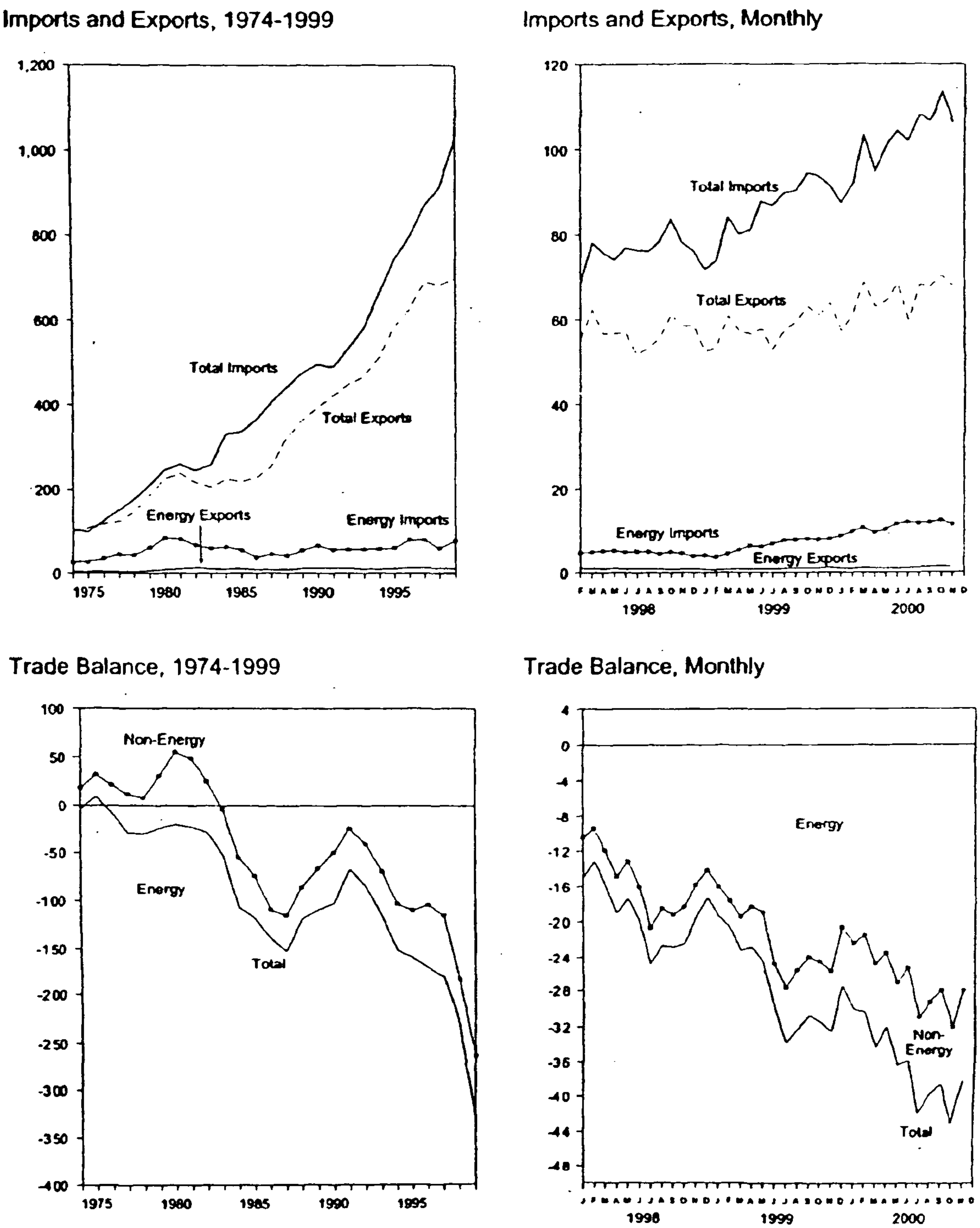
DOE006-0215

Figure 1.5 Merchandise Trade Value
(Billion Dollars)



Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.6.

Table 1.6 Merchandise Trade Value
(Million Dollars)

	Petroleum[a]			Energy[b]			Non-Energy Balance	Total Merchandise		
	Exports	Imports	Balance	Exports	Imports	Balance		Exports	Imports	Balance
1974 Total	792	24,668	-23,876	3,444	25,454	-22,010	18,126	99,437	103,321	-3,884
1975 Total	907	25,197	-24,290	4,470	26,476	-22,006	31,557	108,856	99,305	9,551
1976 Total	998	32,226	-31,228	4,226	33,996	-29,770	21,950	116,794	124,614	-7,820
1977 Total	1,276	42,368	-41,093	4,184	44,537	-40,354	12,001	123,182	151,534	-28,353
1978 Total	1,561	39,526	-37,965	3,881	42,096	-38,215	8,010	145,847	176,052	-30,205
1979 Total	1,914	56,715	-54,801	5,621	59,998	-54,377	30,455	186,363	210,285	-23,922
1980 Total	2,833	78,637	-75,803	7,982	82,924	-74,942	55,246	225,566	245,262	-19,696
1981 Total	3,696	76,659	-72,963	10,279	81,360	-71,081	48,814	238,715	260,982	-22,267
1982 Total	5,947	60,458	-54,511	12,729	65,409	-52,680	25,170	216,442	243,952	-27,510
1983 Total	4,557	53,217	-48,659	9,500	57,952	-48,452	-3,957	205,639	258,048	-52,409
1984 Total	4,470	56,924	-52,454	9,311	60,980	-51,669	-55,033	223,976	330,678	-106,703
1985 Total	4,707	50,475	-45,768	9,971	53,917	-43,946	-73,765	218,815	336,526	-117,712
1986 Total	3,640	35,142	-31,503	8,115	37,310	-29,195	-109,084	227,159	365,438	-138,279
1987 Total	3,922	42,285	-38,363	7,713	44,220	-36,508	-115,611	254,122	406,241	-152,119
1988 Total	3,693	38,787	-35,094	8,235	41,042	-32,806	-85,720	322,426	440,952	-118,526
1989 Total	5,021	49,704	-44,683	9,869	52,779	-42,910	-66,490	363,812	473,211	-109,399
1990 Total	6,901	61,583	-54,682	12,233	64,661	-52,428	-50,068	393,592	496,088	-102,496
1991 Total	6,854	51,350	-44,496	12,081	54,629	-42,548	-24,175	421,730	488,453	-66,723
1992 Total	6,412	51,217	-44,805	11,254	55,256	-44,002	-40,500	448,164	532,665	-84,501
1993 Total	6,215	51,046	-44,831	9,756	55,900	-46,144	-69,425	465,091	580,659	-115,568
1994 Total	5,659	50,835	-45,176	8,911	56,391	-47,480	-103,149	512,626	663,256	-150,629
1995 Total	6,321	54,368	-48,047	10,358	59,109	-48,751	-110,050	584,742	743,543	-158,801
1996 Total	7,984	72,022	-64,038	12,181	78,086	-65,905	-104,309	625,075	795,289	-170,214
1997 Total	8,592	71,152	-62,560	12,682	78,277	-65,595	-114,927	689,182	869,704	-180,522
1998 January	715	4,996	-4,281	1,056	5,645	-4,589	-10,463	55,172	70,224	-15,052
February	597	4,074	-3,477	855	4,587	-3,732	-9,428	55,234	68,394	-13,160
March	589	4,189	-3,600	905	4,770	-3,865	-11,934	62,297	78,096	-15,799
April	602	4,492	-3,890	896	5,056	-4,160	-14,909	56,675	75,744	-19,069
May	585	4,549	-3,964	915	5,112	-4,197	-13,129	56,672	73,998	-17,326
June	524	4,145	-3,621	836	4,741	-3,905	-16,019	56,994	76,916	-19,924
July	523	4,278	-3,755	840	4,901	-4,061	-20,699	51,577	76,337	-24,760
August	522	4,229	-3,707	802	4,867	-4,065	-18,529	53,420	76,014	-22,594
September	513	3,878	-3,365	833	4,409	-3,576	-19,231	55,627	78,434	-22,807
October	476	4,280	-3,804	780	4,864	-4,084	-18,315	61,313	83,712	-22,399
November	415	3,892	-3,477	728	4,520	-3,792	-15,833	58,395	78,020	-19,625
December	514	3,260	-2,746	806	3,853	-3,047	-14,198	58,762	76,007	-17,245
Total	6,574	50,264	-43,690	10,251	57,323	-47,072	-182,686	682,138	911,896	-229,758
1999 January	460	3,428	-2,968	692	4,075	-3,383	-15,947	52,436	71,766	-19,330
February	380	3,025	-2,645	600	3,561	-2,961	-17,609	53,279	73,849	-20,570
March	440	3,809	-3,369	683	4,373	-3,690	-19,493	60,889	84,072	-23,183
April	579	4,668	-4,089	804	5,264	-4,460	-18,237	57,283	79,980	-22,697
May	563	5,630	-5,067	773	6,307	-5,534	-18,943	56,489	80,965	-24,477
June	565	5,432	-4,867	789	6,105	-5,316	-24,739	57,825	87,880	-30,055
July	560	6,146	-5,586	781	6,906	-6,125	-27,653	52,998	86,775	-33,778
August	630	6,786	-6,156	888	7,614	-6,726	-25,584	57,439	89,749	-32,310
September	623	6,908	-6,285	869	7,760	-6,891	-23,922	59,431	90,244	-30,813
October	738	7,197	-6,459	982	8,022	-7,040	-24,447	62,973	94,460	-31,487
November	700	6,949	-6,249	925	7,854	-6,929	-25,704	60,948	93,581	-32,633
December	884	7,190	-6,306	1,094	7,962	-6,868	-20,621	63,808	91,296	-27,489
Total	7,118	67,173	-60,055	9,880	75,803	-65,923	-262,898	695,797	1,024,618	-328,821
2000 January	796	7,836	-7,040	1,021	8,790	-7,769	-22,378	57,221	87,368	-30,147
February	625	9,016	-8,391	796	9,799	-9,003	-21,494	61,325	91,822	-30,497
March	877	9,943	-9,066	1,117	10,696	-9,579	-24,748	68,740	103,067	-34,327
April	793	8,832	-8,039	970	9,555	-8,585	-23,443	62,786	94,815	-32,028
May	687	9,452	-8,765	935	10,266	-9,331	-27,133	64,262	100,726	-36,464
June	673	10,546	-9,873	915	11,542	-10,627	-25,265	68,271	104,164	-35,892
July	723	10,734	-10,011	983	11,952	-10,969	-31,108	59,707	101,784	-42,077
August	929	10,441	-9,512	1,210	11,754	-10,544	-29,432	67,965	107,941	-39,976
September	962	10,502	-9,540	1,207	11,869	-10,662	-28,048	67,639	106,349	-38,710
October	1,180	11,080	-9,900	1,422	12,381	-10,959	R -32,141	R 70,371	R 113,471	R -43,100
November	988	9,979	-8,991	1,315	11,438	-10,123	-28,044	67,716	105,882	-38,167
11-Month Total	9,230	108,360	-99,130	11,890	120,042	-108,152	-293,234	716,004	1,117,390	-401,386
1999 11-Month Total	6,238	59,978	-53,740	8,786	67,841	-59,055	-242,278	631,990	933,321	-301,333
1998 11-Month Total	6,061	47,002	-40,941	9,446	53,472	-44,026	-168,489	623,376	835,891	-212,515

[a] Crude oil, petroleum preparations, liquefied propane and butane, and other mineral fuels.

[b] Petroleum, coal, natural gas, and electricity.

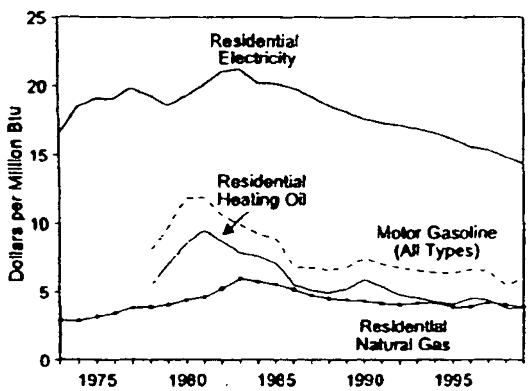
R=Revised.

Notes: • Monthly data are not adjusted for seasonal variations. • See Note 5 at end of section. • Totals may not equal sum of components due to independent rounding. • The U.S. import statistics reflect both government and nongovernment imports of merchandise from foreign countries into the U.S. customs territory, which comprises the 50 States, the District of Columbia, Puerto Rico, and the Virgin Islands.

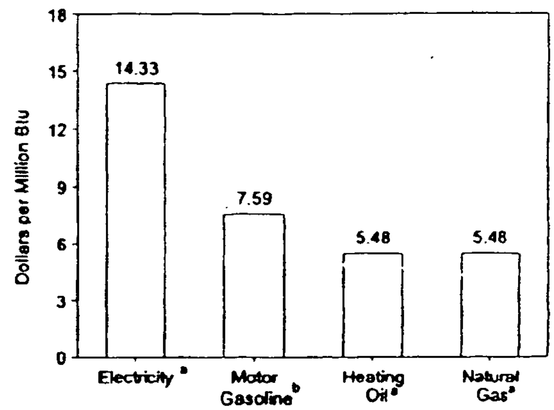
Source: U.S. Department of Commerce, Bureau of the Census, Foreign Trade Division. For details, see "Sources for Table 1.6" at the end of this section.

Figure 1.6 Cost of Fuels to End Users in Constant (1982-1984) Dollars

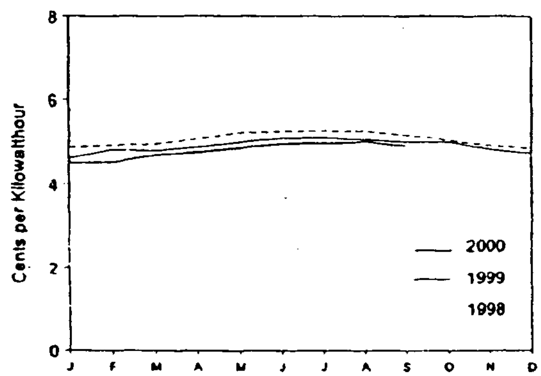
Costs, 1973-1999



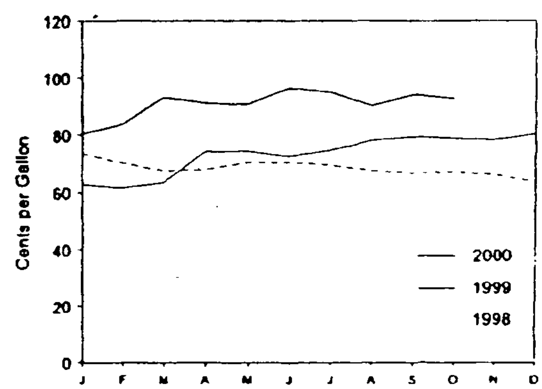
Costs, September 2000



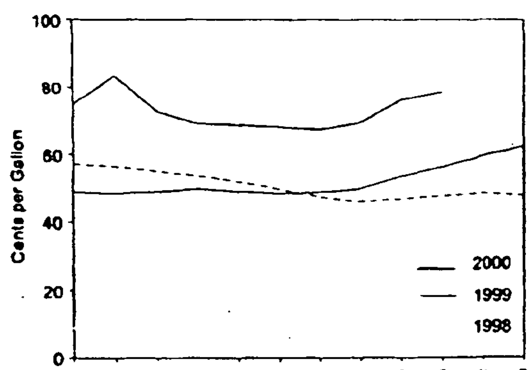
Residential Electricity, Monthly



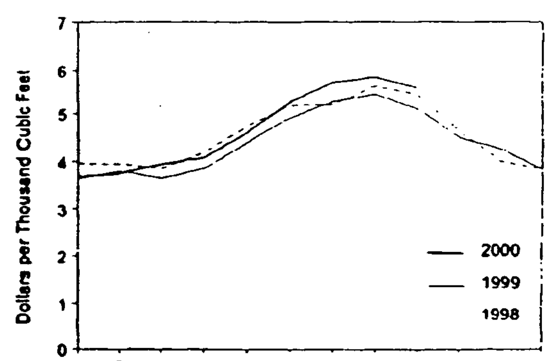
Motor Gasoline (All Types), Monthly



Residential Heating Oil, Monthly



Residential Natural Gas, Monthly



[a]Residential.
[b]All types.
NA=Not available.
Note: Because vertical scales differ, graphs should not be compared.

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Table 1.7 Cost of Fuels to End Users in Constant (1982-84) Dollars

	Consumer Price Index (Urban)[a]	Motor Gasoline (All Types)		Residential Heating Oil		Residential Natural Gas		Residential Electricity	
	Index 1982-1984=100	Cents per Gallon	Dollars per Million Btu	Cents per Gallon	Dollars per Million Btu	Cents per Thousand Cubic Feet	Dollars per Million Btu	Cents per Kilowatthour	Dollars per Million Btu
1973 Average	44.4	NA	NA	NA	NA	290.5	2.85	5.6	16.50
1974 Average	49.3	NA	NA	NA	NA	290.1	2.83	6.3	18.43
1975 Average	53.8	NA	NA	NA	NA	317.8	3.12	6.5	19.07
1976 Average	56.9	NA	NA	NA	NA	348.0	3.41	6.5	19.06
1977 Average	60.6	NA	NA	NA	NA	387.8	3.81	6.8	19.83
1978 Average	65.2	100.0	8.00	75.2	5.42	392.8	3.86	6.6	19.33
1979 Average	72.6	121.5	9.71	97.0	6.99	410.5	4.03	6.3	18.57
1980 Average	82.4	148.2	11.85	118.2	8.52	446.8	4.36	6.6	19.21
1981 Average	90.9	148.8	11.90	131.4	9.47	471.9	4.60	6.8	19.99
1982 Average	96.5	132.7	10.61	120.2	8.67	535.8	5.22	7.2	20.96
1983 Average	99.6	123.0	9.83	108.2	7.80	608.4	5.90	7.2	21.19
1984 Average	103.9	115.3	9.22	105.0	7.57	589.0	5.72	6.88	20.17
1985 Average	107.6	111.2	8.89	97.9	7.06	568.8	5.52	6.87	20.13
1986 Average	109.6	84.9	6.79	76.3	5.50	531.9	5.17	6.77	19.84
1987 Average	113.6	84.2	6.74	70.7	5.10	487.7	4.73	6.56	19.22
1988 Average	118.3	81.4	6.51	68.7	4.96	462.4	4.49	6.32	18.53
1989 Average	124.0	85.5	6.83	72.6	5.23	454.8	4.41	6.17	18.08
1990 Average	130.7	93.1	7.44	81.3	5.86	443.8	4.31	5.99	17.56
1991 Average	136.2	87.8	7.02	74.8	5.39	427.3	4.14	5.90	17.30
1992 Average	140.3	84.8	6.78	66.6	4.80	418.8	4.07	5.85	17.15
1993 Average	144.5	81.2	6.49	63.0	4.55	428.3	4.15	5.76	16.88
1994 Average	148.2	79.2	6.36	59.6	4.30	432.5	4.20	5.65	16.57
1995 Average	152.4	78.1	6.37	56.9	4.10	397.6	3.87	5.51	16.15
1996 Average	156.9	82.1	6.61	63.0	4.54	404.1	3.93	5.33	15.62
1997 Average	160.5	80.4	6.48	61.3	4.42	432.4	4.21	5.25	15.39
1998 January	161.6	73.4	5.91	57.2	4.13	396.7	3.84	4.87	14.27
February	161.9	70.2	5.66	56.6	4.08	395.9	3.83	4.92	14.43
March	162.2	67.6	5.45	55.2	3.98	387.8	3.75	4.94	14.47
April	162.5	68.1	5.48	54.0	3.89	419.1	4.06	5.06	14.84
May	162.8	70.4	5.67	52.1	3.76	473.0	4.58	5.21	15.28
June	163.0	70.4	5.68	49.8	3.59	522.1	5.05	5.23	15.34
July	163.2	69.5	5.60	47.6	3.43	522.7	5.06	5.26	15.41
August	163.4	67.8	5.46	46.2	3.33	566.1	5.48	5.24	15.37
September	163.6	66.7	5.37	47.1	3.39	547.7	5.30	5.15	15.10
October	164.0	67.0	5.40	47.9	3.46	463.4	4.49	5.03	14.74
November	164.0	66.2	5.34	48.7	3.51	401.2	3.88	4.90	14.37
December	163.9	63.8	5.14	48.1	3.47	386.8	3.74	4.83	14.16
Average	163.0	68.4	5.51	52.3	3.77	418.4	4.05	5.07	14.85
1999 January	164.3	62.8	5.06	49.0	3.53	365.2	3.55	4.61	13.52
February	164.5	61.6	4.97	48.6	3.51	382.4	3.72	4.81	14.11
March	165.0	63.5	5.12	49.1	3.54	367.3	3.57	4.79	14.03
April	166.2	74.1	5.97	49.9	3.60	387.5	3.77	4.87	14.27
May	166.2	74.2	5.98	49.3	3.56	439.2	4.27	4.98	14.58
June	166.2	72.4	5.84	48.6	3.50	493.4	4.80	5.07	14.87
July	166.7	74.6	6.01	48.9	3.53	529.7	5.15	5.09	14.93
August	167.1	78.3	6.31	50.0	3.60	547.0	5.32	5.04	14.77
September	167.9	79.5	6.40	53.7	3.87	514.0	5.00	4.98	14.59
October	168.2	79.0	6.37	56.4	4.07	449.5	4.37	4.98	14.58
November	168.3	78.4	6.32	59.5	4.29	424.8	4.13	4.81	14.09
December	168.3	80.4	6.48	62.1	4.48	388.8	3.76	4.72	13.83
Average	166.6	73.3	5.91	52.6	3.79	401.6	3.91	4.90	14.36
2000 January	168.8	80.3	6.47	74.5	5.37	369.7	3.58	4.51	13.21
February	169.8	83.7	6.75	83.7	6.04	376.9	3.67	4.52	13.26
March	171.2	93.1	7.50	72.4	5.22	396.0	3.85	4.69	13.75
April	171.3	91.1	7.34	68.7	4.95	409.2	3.98	4.75	13.91
May	171.5	90.5	7.29	68.2	4.91	459.5	4.47	4.85	14.22
June	172.4	96.6	7.79	67.5	4.86	529.0	5.15	4.94	14.47
July	172.8	95.0	7.66	66.7	4.81	574.1	5.58	4.96	14.54
August	172.8	90.2	7.27	68.9	4.97	585.6	5.70	4.98	14.60
September	173.7	94.1	7.59	R 76.1	5.48	563.0	5.48	4.89	14.33
October	174.0	92.7	7.47	78.6	5.67	NA	NA	NA	NA

[a] Consumer Price Index, All Urban Consumers, All Items, 1982-1984 = 100.0.

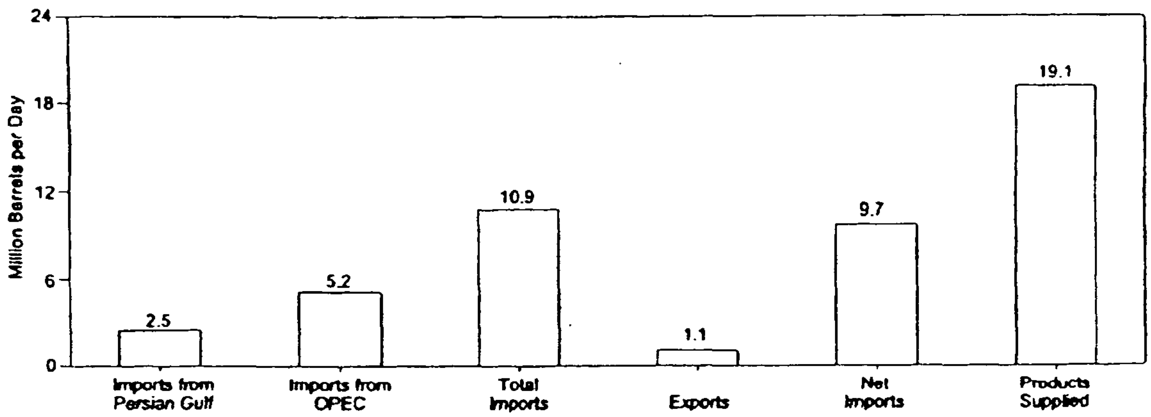
R=Revised. NA=Not available.

Notes: • Fuel costs are calculated by using the Urban Consumer Price Index (CPI) developed by the Bureau of Labor Statistics. • Annual averages may not equal average of months due to independent rounding. • Geographic coverage is the 50 States and the District of Columbia.

Sources: • Fuel Prices: Tables 9.4 (All Types), 9.8c, 9.11, and 9.9, adjusted by the CPI. • CPI: 1973-1995—*Economic Report of the President*, February 2000, Table B-60. 1996 forward—Council of Economic Advisers, *Economic Indicators*, December 2000, "Consumer Prices - All Urban Consumers." • Conversion Factors: Tables A1, A3, A4, and A6.

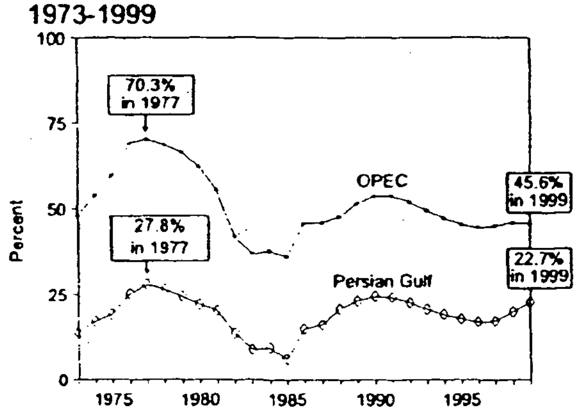
Figure 1.7 Overview of U.S. Petroleum Trade

Overview, November 2000

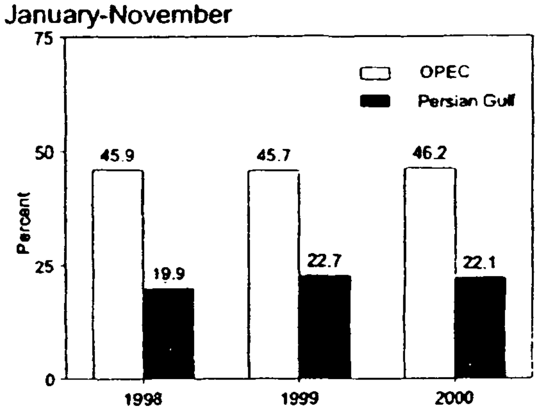


Imports from OPEC and the Persian Gulf as a Share of Total Imports

1973-1999

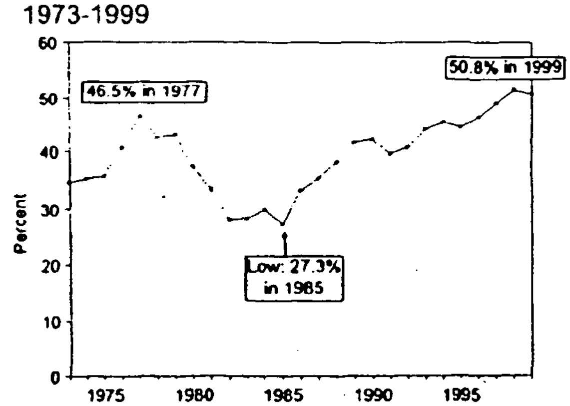


January-November

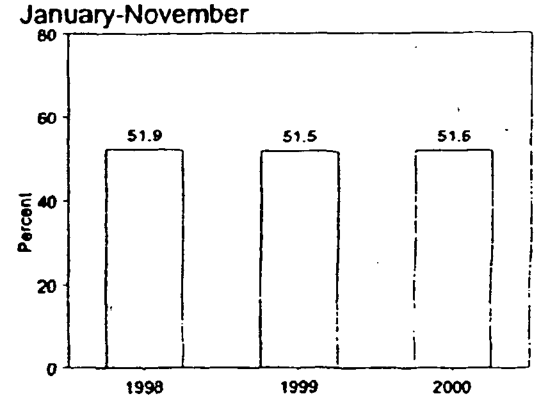


Net Imports as Share of Products Supplied

1973-1999



January-November



OPEC=Organization of Petroleum Exporting Countries.
Note: Because vertical scales differ, graphs should not be compared.
Source: Table 1.8, 3.1a, and 3.1b.

Table 1.8 Overview of U.S. Petroleum Trade

	Imports from Persian Gulf[a]	Imports from OPEC[b]	Total Imports	Exports	Net Imports	Products Supplied	As Share of Products Supplied: Imports from Persian Gulf[a]	As Share of Products Supplied: Imports from OPEC[b]	As Share of Products Supplied: Total Imports	As Share of Products Supplied: Net Imports	As Share of Total Imports: Imports from Persian Gulf[a]	As Share of Total Imports: Imports from OPEC[b]
	Thousand Barrels per Day						Percent					
1973 Average	848	2,993	6,256	231	6,025	17,308	4.9	17.3	36.1	34.8	13.6	47.8
1974 Average	1,039	3,280	6,112	221	5,892	16,653	6.2	19.7	36.7	35.4	17.0	53.7
1975 Average	1,165	3,601	6,056	209	5,846	16,322	7.1	22.1	37.1	35.8	19.2	59.5
1976 Average	1,840	5,066	7,313	223	7,090	17,461	10.5	29.0	41.9	40.6	25.2	69.3
1977 Average	2,448	6,193	8,807	243	8,565	18,431	13.3	33.6	47.8	46.5	27.8	70.3
1978 Average	2,219	5,751	8,363	362	8,002	18,847	11.8	30.5	44.4	42.5	26.5	68.8
1979 Average	2,069	5,637	8,456	471	7,985	18,513	11.2	30.5	45.7	43.1	24.5	66.7
1980 Average	1,519	4,300	6,909	544	6,365	17,056	8.9	25.2	40.5	37.3	22.0	62.2
1981 Average	1,219	3,323	5,996	595	5,401	16,058	7.6	20.7	37.3	33.6	20.3	55.4
1982 Average	696	2,146	5,113	815	4,298	15,296	4.5	14.0	33.4	28.1	13.6	42.0
1983 Average	442	1,862	5,051	739	4,312	15,231	2.9	12.2	33.2	28.3	8.8	36.9
1984 Average	506	2,049	5,437	722	4,715	15,726	3.2	13.0	34.6	30.0	9.3	37.7
1985 Average	311	1,830	5,067	781	4,286	15,726	2.0	11.6	32.2	27.3	6.1	36.1
1986 Average	912	2,837	6,224	785	5,439	16,281	5.6	17.4	38.2	33.4	14.7	45.6
1987 Average	1,077	3,060	6,678	764	5,914	16,665	6.5	18.4	40.1	35.5	16.1	45.8
1988 Average	1,541	3,520	7,402	815	6,587	17,283	8.9	20.4	42.8	38.1	20.8	47.6
1989 Average	1,861	4,140	8,061	859	7,202	17,325	10.7	23.9	46.5	41.6	23.1	51.4
1990 Average	1,966	4,296	8,018	857	7,161	16,988	11.6	25.3	47.2	42.2	24.5	53.6
1991 Average	1,845	4,092	7,627	1,001	6,626	16,714	11.0	24.5	45.6	39.6	24.2	53.7
1992 Average	1,778	4,092	7,888	950	6,938	17,033	10.4	24.0	46.3	40.7	22.5	51.9
1993 Average	1,782	4,273	8,620	1,003	7,618	17,237	10.3	24.8	50.0	44.2	20.7	49.6
1994 Average	1,728	4,247	8,996	942	8,054	17,718	9.8	24.0	50.8	45.5	19.2	47.2
1995 Average	1,573	4,002	8,835	949	7,886	17,725	8.9	22.6	49.8	44.5	17.8	45.3
1996 Average	1,604	4,211	9,478	981	8,498	18,309	8.8	23.0	51.8	46.4	16.9	44.4
1997 Average	1,755	4,569	10,162	1,003	9,158	18,620	9.4	24.5	54.6	49.2	17.3	45.0
1998 January	1,804	4,382	10,127	1,133	8,994	18,362	9.8	23.9	55.2	49.0	17.8	43.3
February	1,826	4,469	9,991	1,003	8,988	18,316	10.0	24.4	54.5	49.1	18.3	44.7
March	2,066	4,915	10,034	948	9,087	18,685	11.1	26.3	53.7	48.6	20.6	49.0
April	2,111	5,056	11,105	1,048	10,057	19,044	11.1	26.6	58.3	52.8	19.0	45.5
May	1,915	5,058	11,104	1,053	10,051	18,375	10.4	27.5	60.4	54.7	17.3	45.6
June	2,207	4,956	10,926	987	9,939	19,182	11.5	25.8	57.0	51.8	20.2	45.4
July	2,351	5,407	11,649	998	10,651	19,466	12.1	27.8	59.8	54.7	20.2	46.4
August	2,486	5,247	11,032	780	10,252	19,347	12.8	27.1	57.0	53.0	22.5	47.6
September	2,383	4,753	10,499	863	9,636	18,895	12.6	25.2	55.6	51.0	22.7	45.3
October	2,194	5,181	10,861	851	10,011	19,188	11.4	27.0	56.6	52.2	20.2	47.7
November	2,153	4,837	10,860	782	10,078	18,673	11.5	25.9	58.2	54.0	19.8	44.5
December	2,116	4,560	10,258	893	9,365	19,419	10.9	23.5	52.8	48.2	20.6	44.5
Average	2,136	4,905	10,708	945	9,764	18,917	11.3	25.9	56.6	51.6	19.9	45.8
1999 January	2,129	4,819	10,424	896	9,529	19,029	11.2	25.3	54.8	50.1	20.4	46.2
February	2,383	5,110	10,650	756	9,894	19,107	12.5	26.7	55.7	51.8	22.4	48.0
March	2,801	5,109	10,658	764	9,894	19,497	14.4	26.2	54.7	50.7	26.3	47.9
April	2,633	5,679	11,618	1,196	10,422	19,152	13.8	29.7	60.7	54.4	22.7	48.9
May	2,479	5,079	11,511	915	10,596	18,705	13.3	27.2	61.5	56.6	21.5	44.1
June	2,590	5,040	11,160	907	10,253	19,836	13.1	25.4	56.3	51.7	23.2	45.2
July	2,427	5,016	11,697	918	10,779	19,820	12.2	25.3	59.0	54.4	20.8	42.9
August	2,514	5,137	11,142	902	10,240	20,093	12.5	25.6	55.5	51.0	22.6	46.1
September	2,457	4,825	10,657	889	9,768	19,483	12.6	24.8	54.7	50.1	23.1	45.3
October	2,480	4,645	10,595	944	9,651	19,868	12.5	23.4	53.3	48.6	23.4	43.8
November	2,336	4,431	10,033	950	9,083	19,067	12.2	23.2	52.6	47.6	23.3	44.2
December	2,331	4,564	10,065	1,230	8,835	20,498	11.4	22.3	49.1	43.1	23.2	45.3
Average	2,464	4,953	10,852	940	9,912	19,519	12.6	25.4	55.6	50.8	22.7	45.6
2000 January	2,036	4,115	9,795	1,006	8,789	18,592	11.0	22.1	52.7	47.3	20.8	42.0
February	2,256	4,653	10,396	870	9,526	19,296	11.7	24.1	53.9	49.4	21.7	44.8
March	2,189	5,013	10,768	1,159	9,609	19,064	11.5	26.3	56.5	50.4	20.3	46.6
April	2,365	5,087	11,091	1,131	9,960	18,590	12.7	27.3	59.7	53.6	21.3	45.7
May	2,218	4,843	10,981	856	10,125	19,345	11.5	25.0	56.8	52.3	20.2	44.1
June	2,586	5,517	11,681	925	10,756	19,833	13.0	27.8	58.9	54.2	22.1	47.2
July	2,588	5,143	11,344	900	10,444	19,564	13.2	26.3	57.9	53.3	22.8	45.3
August	2,787	5,851	11,849	1,073	10,776	20,224	13.8	28.9	58.6	53.3	23.5	49.4
September	2,819	5,357	11,512	1,059	10,453	19,741	14.3	27.1	58.3	53.0	24.5	46.5
October	2,519	5,331	11,018	1,292	9,726	19,701	12.8	27.1	55.9	49.4	22.9	48.4
November	2,482	5,174	10,857	1,108	9,749	19,064	13.0	27.1	56.9	51.1	22.9	47.7
11-Month Average	2,440	5,097	11,027	1,035	9,992	19,368	12.6	26.3	56.9	51.6	22.1	46.2
1999 11-Month Average	2,476	4,989	10,925	913	10,012	19,428	12.7	25.7	56.2	51.5	22.7	45.7
1998 11-Month Average	2,138	4,937	10,750	949	9,801	18,871	11.3	26.2	57.0	51.9	19.9	45.9

[a] Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates.

[b] Organization of Petroleum Exporting Countries. See Glossary.

Notes: • Readers of Table 1.8 may be interested in a feature article, "Measuring Dependence on Imported Oil," that was published in the August 1995 *Monthly Energy Review*. • Petroleum is crude oil, lease condensate, unfinished oils, petroleum products, natural gas plant liquids, and nonhydrocarbon compounds blended into finished petroleum products. • Beginning in October 1977, petroleum imported for the Strategic Petroleum Reserves is included. • Annual averages may not equal average of months due to independent rounding. • U.S. geographic coverage is the 50 States and the District of Columbia. U.S. exports include shipments to U.S. territories, and imports include receipts from U.S. territories.

Sources: • Column 1: Table 3.3b. • Column 2: Table 3.3d. • Columns 3-5: Table 3.1b. • Column 6: Table 3.1a. • Columns 7-12: Calculated by Energy Information Administration.

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Figure 1.8 Energy Consumption per Dollar of Gross Domestic Product
(Thousand Btu per Chained (1996) Dollar)

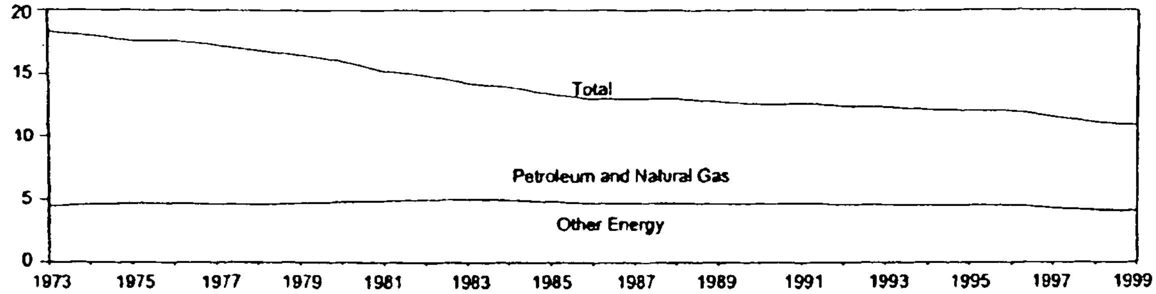

Table 1.9 Energy Consumption per Dollar of Gross Domestic Product
(Seasonally Adjusted at Annual Rates)

	Energy Consumption			Gross Domestic Product (GDP)	Energy Consumption per Dollar of GDP		
	Petroleum and Natural Gas	Other Energy[a]	Total		Petroleum and Natural Gas	Other Energy[a]	Total
	Quadrillion Btu			Billion Chained (1996) Dollars	Thousand Btu per Chained (1996) Dollar		
1973 Year	57.352	R18.456	R75.808	4,123.4	13.91	R4.48	R18.38
1974 Year	55.187	R18.893	R74.080	4,099.0	13.46	R4.61	R18.07
1975 Year	52.678	R19.364	R72.042	4,084.4	12.90	R4.74	R17.64
1976 Year	55.520	R20.552	R76.072	4,311.7	12.88	R4.77	R17.64
1977 Year	57.053	R21.069	R78.122	4,511.8	12.65	R4.67	R17.32
1978 Year	57.966	R22.158	R80.123	4,760.6	12.18	R4.65	R16.83
1979 Year	57.789	R23.255	R81.044	4,912.1	11.76	R4.73	R16.50
1980 Year	54.596	R23.839	R78.435	4,900.9	11.14	R4.86	R16.00
1981 Year	51.859	R24.710	R76.569	5,021.0	10.33	R4.92	R15.25
1982 Year	48.736	R24.704	R73.440	4,919.3	9.91	R5.02	R14.93
1983 Year	47.411	R25.906	R73.317	5,132.3	9.24	R5.05	R14.29
1984 Year	49.558	R27.413	R76.972	5,505.2	9.00	R4.98	R13.98
1985 Year	48.756	R28.022	R76.778	5,717.1	8.53	R4.90	R13.43
1986 Year	48.904	R28.161	R77.065	5,912.4	8.27	R4.76	R13.03
1987 Year	50.609	R29.024	R79.633	6,113.3	8.28	R4.75	R13.03
1988 Year	52.774	R30.294	R83.068	6,368.4	8.29	R4.76	R13.04
1989 Year	53.595	b,c,R31.012	b,c,R84.607	6,591.8	8.13	R4.70	R12.84
1990 Year	52.849	R31.365	R84.214	6,707.9	7.88	R4.68	R12.55
1991 Year	52.452	R31.819	R84.271	6,676.4	7.86	R4.77	R12.62
1992 Year	53.657	R31.834	R85.491	6,880.0	7.80	R4.63	R12.43
1993 Year	54.668	R32.613	R87.281	7,062.6	7.74	R4.62	R12.36
1994 Year	55.958	R33.231	R89.189	7,347.7	7.62	R4.52	R12.14
1995 Year	56.717	R34.207	R90.924	7,543.8	7.52	R4.53	R12.05
1996 Year	58.316	R35.585	R93.902	7,813.2	7.46	R4.56	R12.02
1997 Year	58.795	R35.512	R94.307	8,159.5	7.21	R4.35	R11.56
1998 1st Quarter	57.846	NA	NA	8,404.9	6.88	NA	NA
2nd Quarter	59.616	NA	NA	8,465.6	7.04	NA	NA
3rd Quarter	60.043	NA	NA	8,537.6	7.03	NA	NA
4th Quarter	57.898	NA	NA	8,654.5	6.69	NA	NA
Year	58.855	R35.683	R94.537	8,515.7	6.91	R4.19	R11.10
1999 1st Quarter	60.773	NA	NA	8,730.0	6.96	NA	NA
2nd Quarter	60.295	NA	NA	8,783.2	6.86	NA	NA
3rd Quarter	60.280	NA	NA	8,905.8	6.77	NA	NA
4th Quarter	59.634	NA	NA	9,084.1	6.56	NA	NA
Year	60.248	R36.743	R96.991	8,875.8	6.79	R4.14	R10.93
2000 1st Quarter	60.666	NA	NA	9,191.8	6.60	NA	NA
2nd Quarter	61.564	NA	NA	9,318.9	6.61	NA	NA
3rd Quarter	60.760	NA	NA	R9,369.5	6.48	NA	NA

[a] Coal, nuclear electric power, renewable energy, and pumped storage hydroelectric generation.
[b] Beginning in 1989, includes electricity generated by nonutility nuclear units.
[c] Beginning in 1989, includes coal consumed by "Other Power Producers." See Table 6.2.
R=Revised. NA=Not available. E=Estimate.
Notes: • Quarterly data are seasonally adjusted and shown at annual rates. • Yearly data may not equal average of quarters due to seasonality adjustments and independent rounding. • Totals may not equal sum of components due to independent rounding. • Geographic coverage is the 50 States and the District of Columbia.
Sources: • Energy Consumption: Table 1.4. • Gross Domestic Product: 1973-1997—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, November 1999, Table 3B. 1998 forward—U.S. Department of Commerce, Bureau of Economic Analysis, *BEA News Release*, December 21, 2000, Table 3, which is available at website www.bea.doc.gov/bea/newsrel/gdp100p.htm.

Revised data reflect the incorporation of additional renewable energy data. See Table 1.4 and Appendix E for further information.

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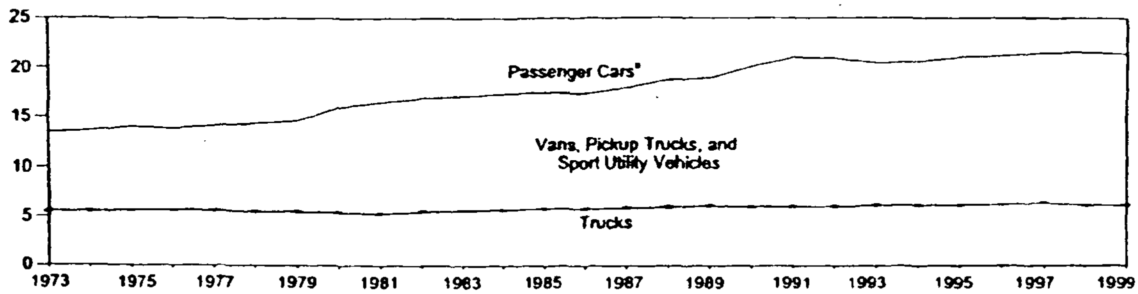
Figure 1.9 Motor Vehicle Fuel Rates

(Miles per Gallon)



[a] Includes motorcycles through 1989.

Table 1.10 Motor Vehicle Mileage, Fuel Consumption, and Fuel Rates

	Passenger Cars			Vans, Pickup Trucks, and Sport Utility Vehicles[a]			Trucks[b]			All Motor Vehicles[c]		
	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)
1973	[d]9,884	[d]737	[d]13.4	9,779	931	10.5	15,370	2,775	5.5	10,099	850	11.9
1974	[d]9,221	[d]677	[d]13.6	9,452	862	11.0	14,995	2,708	5.5	9,493	789	12.0
1975	[d]9,309	[d]665	[d]14.0	9,829	934	10.5	15,167	2,722	5.6	9,627	790	12.2
1976	[d]9,418	[d]681	[d]13.8	10,127	934	10.8	15,438	2,764	5.6	9,774	806	12.1
1977	[d]9,517	[d]676	[d]14.1	10,607	947	11.2	16,700	3,002	5.6	9,978	814	12.3
1978	[d]9,500	[d]665	[d]14.3	10,968	948	11.6	18,045	3,263	5.5	10,077	816	12.4
1979	[d]9,062	[d]620	[d]14.6	10,802	905	11.9	18,502	3,380	5.5	9,722	776	12.5
1980	[d]8,813	[d]551	[d]16.0	10,437	854	12.2	18,736	3,447	5.4	9,458	712	13.3
1981	[d]8,873	[d]538	[d]16.5	10,244	819	12.5	19,016	3,565	5.3	9,477	697	13.6
1982	[d]9,050	[d]535	[d]16.9	10,276	762	13.5	19,931	3,647	5.5	9,644	686	14.1
1983	[d]9,118	[d]534	[d]17.1	10,497	767	13.7	21,083	3,769	5.6	9,760	686	14.2
1984	[d]9,248	[d]530	[d]17.4	11,151	797	14.0	22,550	3,967	5.7	10,017	691	14.5
1985	[d]9,419	[d]538	[d]17.5	10,506	735	14.3	20,597	3,570	5.8	10,020	685	14.6
1986	[d]9,464	[d]543	[d]17.4	10,764	738	14.6	22,143	3,821	5.8	10,143	692	14.7
1987	[d]9,720	[d]539	[d]18.0	11,114	744	14.9	23,349	3,937	5.9	10,453	694	15.1
1988	[d]9,972	[d]531	[d]18.8	11,465	745	15.4	22,485	3,736	6.0	10,721	688	15.6
1989	[d]10,157	[d]533	[d]19.0	11,676	724	16.1	22,926	3,776	6.1	10,932	688	15.9
1990	10,504	520	20.2	11,902	738	16.1	23,603	3,953	6.0	11,107	677	16.4
1991	10,571	501	21.1	12,245	721	17.0	24,229	4,047	6.0	11,294	669	16.9
1992	10,857	517	21.0	12,381	717	17.3	25,373	4,210	6.0	11,558	683	16.9
1993	10,804	527	20.5	12,430	714	17.4	26,262	4,309	6.1	11,595	693	16.7
1994	10,992	531	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	4,315	6.1	11,793	700	16.8
1996	11,330	534	21.2	11,811	685	17.2	26,092	4,221	6.2	11,813	700	16.9
1997	11,581	539	21.5	12,115	703	17.2	27,032	4,218	6.4	12,107	711	17.0
1998	11,754	544	21.6	12,173	707	17.2	25,397	4,135	6.1	12,211	721	16.9
1999[e]	11,850	552	21.4	11,958	700	17.1	26,015	4,282	6.1	12,206	729	16.8

[a] Includes a small number of trucks with 2 axles and 4 tires, such as step vans.
[b] Single-unit trucks with 2 axles and 6 or more tires, and combination trucks.
[c] *Includes buses and motorcycles, which are not shown separately.*
[d] Includes motorcycles.
[e] Preliminary.
Notes: Geographic coverage is the 50 States and the District of Columbia.
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: • *1973-1994: Federal Highway Administration (FHWA), Highway Statistics Summary to 1995*, Table VM-201A. • 1995 forward: FHWA, *Highway Statistics*, annual, Table VM-1.

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Table 1.11 Heating Degree-Days by Census Division

Census Divisions	December 1 through December 31					Cumulative July 1 through December 31				
				Percent Change					Percent Change	
	Normal[a]	1999	2000	Normal to 2000	1999 to 2000	Normal[a]	1999	2000	Normal to 2000	1999 to 2000
New England Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	1,110	980	1,221	10	25	2,439	2,212	2,612	7	18
Middle Atlantic New Jersey, New York, Pennsylvania	1,012	900	1,180	17	31	2,131	1,881	2,332	9	24
East North Central Illinois, Indiana, Michigan, Ohio, Wisconsin	1,143	1,051	1,442	26	37	2,402	2,184	2,708	13	24
West North Central Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota	1,247	1,063	1,559	25	47	2,596	2,222	2,969	14	34
South Atlantic Delaware, Florida, Georgia, Maryland and the District of Columbia, North Carolina, South Carolina, Virginia, West Virginia	571	530	736	29	39	1,084	1,010	1,327	22	31
East South Central Alabama, Kentucky, Mississippi, Tennessee	718	668	977	36	47	1,380	1,248	1,684	22	35
West South Central Arkansas, Louisiana, Oklahoma, Texas	523	460	709	36	54	877	784	1,202	37	57
Mountain Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming	950	881	931	-2	6	2,145	1,868	2,293	7	23
Pacific[b] California, Oregon, Washington	564	513	526	-7	2	1,227	1,033	1,284	3	22
U.S. Average[b]	838	755	999	20	32	1,724	1,532	1,953	13	28

[a] "Normal" is based on calculations of data from 1961 through 1990.
[b] Excludes Alaska and Hawaii.

Notes: Degree-days are relative measurements of outdoor air temperature used as an index for heating and cooling energy requirements. Heating degree-days are the number of degrees that the daily average temperature falls below 65° F. Cooling degree-days are the number of degrees that the daily average temperature rises above 65° F. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. For example, a weather station recording an average daily temperature of 40° F would report 25 heating degree-days for that day (and 0 cooling degree-days). If a weather station recorded an average daily temperature of 78° F, cooling degree-days for that station would be 13 (and 0 heating degree days).

Sources: See end of section.

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DOE006-0224

Table 1.12 Cooling Degree-Days by Census Division

Census Divisions	December 1 through December 31					Cumulative January 1 through December 31				
				Percent Change					Percent Change	
	Normal[a]	1999	2000	Normal to 2000	1999 to 2000	Normal[a]	1999	2000	Normal to 2000	1999 to 2000
New England Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	0	0	0	([c])	([c])	420	588	369	-12	-37
Middle Atlantic New Jersey, New York, Pennsylvania	0	0	0	([c])	([c])	675	823	622	-8	-24
East North Central Illinois, Indiana, Michigan, Ohio, Wisconsin	0	0	0	([c])	([c])	736	803	662	-10	-18
West North Central Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota	0	0	0	([c])	([c])	981	925	997	2	8
South Atlantic Delaware, Florida, Georgia, Maryland and the District of Columbia, North Carolina, South Carolina, Virginia, West Virginia	30	25	23	([c])	([c])	1,927	2,039	1,953	1	-4
East South Central Alabama, Kentucky, Mississippi, Tennessee	3	1	0	([c])	([c])	1,565	1,747	1,780	14	2
West South Central Arkansas, Louisiana, Oklahoma, Texas	10	10	0	([c])	([c])	2,460	2,653	2,862	16	8
Mountain Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming	0	0	0	([c])	([c])	1,173	1,235	1,440	23	17
Pacific[b] California, Oregon, Washington	0	0	0	([c])	([c])	694	655	736	6	12
U.S. Average[b]	7	5	4	([c])	([c])	1,192	1,280	1,252	5	-2

[a] "Normal" is based on calculations of data from 1961 through 1990.
[b] Excludes Alaska and Hawaii.
[c] Percent change is not meaningful: normal is less than 100 or ratio is incalculable.

Notes: Degree-days are relative measurements of outdoor air temperature used as an index for heating and cooling energy requirements. Cooling degree-days are the number of degrees that the daily average temperature rises above 65° F. Heating degree-days are the number of degrees that the daily average temperature falls below 65° F. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. For example, if a weather station recorded an average daily temperature of 78° F, cooling degree-days for that station would be 13 (and 0 heating degree-days). A weather station recording an average daily temperature of 40° F would report 25 heating degree-days for that day (and 0 cooling degree-days).

Sources: See end of section.

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Energy Overview Notes

1. Energy Production: Includes production of fossil fuels (coal, dry natural gas, crude oil and lease condensate, and natural gas plant liquids), nuclear electric power, pumped-storage hydroelectric power, and renewable energy. Renewable energy production is assumed to be equivalent to: end-use consumption of wood, waste, alcohol fuels, geothermal heat pump and direct use energy, and solar thermal direct use energy; and electric utility and nonutility net electricity generation from conventional hydroelectric power, wood, waste, geothermal, solar, and wind. Approximate heat contents (Btu values) are derived by using the conversion factors provided in Appendix A. See Appendix E for further information on renewable energy.

2. Energy Consumption: Includes consumption of fossil fuels (coal, natural gas, and petroleum), some secondary energy derived from fossil fuels (supplemental gaseous fuels, coal coke net imports, and electricity net imports from fossil fuels), nuclear electric power, pumped-storage hydroelectric power, and renewable energy. Renewable energy consumption includes: end-use consumption of wood, waste, alcohol fuels, geothermal heat pump and direct use energy, and soler thermal direct use energy; electric utility and nonutility net electricity generation from conventional hydroelectric power, wood, waste, geothermal, solar, and wind; and net imports of electricity from hydroelectric power and geothermal energy. Approximate heat contents (Btu values) are derived by using the conversion factors provided in Appendix A. See Appendix E for further information on renewable energy.

3. Energy Imports: Includes imports of fossil fuels (coal, natural gas, and petroleum, including crude oil imported for the Strategic Petroleum Reserve), some secondary energy derived from fossil fuels (coal coke imports, and electricity imports from fossil fuels), and renewable energy (electricity imports derived from hydroelectric power and geothermal energy). Approximate heat contents (Btu values) are derived by using the conversion factors provided in Appendix A. See Appendix E for further information on renewable energy.

4. Energy Exports: Includes exports of fossil fuels (coal, natural gas, and petroleum), some secondary energy derived from fossil fuels (coal coke exports, and electricity exports from fossil fuels), and renewable energy (electricity exports derived from hydroelectric power). Approximate heat contents (Btu values) are derived by using the conversion factors provided in Appendix A. See Appendix E for further information on renewable energy.

5. Merchandise Trade Value: Import data presented are based on the customs value. That value does not include insurance and freight and is consequently lower than the cost, insurance, and freight (CIF) value, which is also reported by the Bureau of the Census. All export data, and import data prior to 1981, are on a free alongside ship (f.a.s.) basis.

"Balance" is exports minus imports; a positive balance indicates a surplus trade value and a negative balance indicates a deficit trade value. "Energy" includes mineral fuels, lubricants, and related material. "Non-Energy Balance" and "Total Merchandise" include foreign exports (i.e., re-exports) and nonmonetary gold and Department of Defense Grant-Aid shipments. The "Non-Energy Balance" is calculated by subtracting the "Energy" from the "Total Merchandise Balance."

"Imports" consist of government and nongovernment shipments of merchandise into the 50 States, the District of Columbia, Puerto Rico, the U.S. Virgin Islands, and the U.S. Foreign Trade Zones. They reflect the total arrival from foreign countries of merchandise that immediately entered consumption channels, warehouses, the Foreign Trade Zones, or the Strategic Petroleum Reserve. They exclude shipments between the United States, Puerto Rico, and U.S. possessions, shipments to U.S. Armed Forces and diplomatic missions abroad for their own use, U.S. goods returned to the United States by its Armed Forces, and in-transit shipments.

Sources for Table 1.6

U.S. Department of Commerce, Bureau of the Census, Foreign Trade Division:

Petroleum Exports
1974-1987: "U.S. Exports," FT410, December issues.
1988: "Report on U.S. Merchandise Trade, 1988 Final Revisions."
1989: "Report on U.S. Merchandise Trade, 1989 Revisions."
1990: "U.S. Merchandise Trade, 1990 Final Report."
1991: "U.S. Merchandise Trade, 1991 Final Report," May 13, 1992.
1992: "U.S. Merchandise Trade, 1992 Final Report," May 12, 1993.
1993: "U.S. International Trade in Goods and Services, Annual Revision for 1993."
1994: "U.S. International Trade in Goods and Services, Annual Revision for 1994."
1995: "U.S. International Trade in Goods and Services, Annual Revision for 1995."
1996: "U.S. International Trade in Goods and Services, Annual Revision for 1996."
1997: "U.S. International Trade in Goods and Services, Annual Revision for 1997."
1998: "U.S. International Trade in Goods and Services, Annual Revision for 1998."
1999 and 2000: "U.S. International Trade in Goods and Services," FT-900, monthly.

Petroleum Imports
1974-1987: "U.S. Merchandise Trade," FT900, December issues, 1975-1988.
1988: "Report on U.S. Merchandise Trade, 1988 Final Revisions."
1989: "Report on U.S. Merchandise Trade, 1989 Revisions."
1990: "U.S. Merchandise Trade, 1990 Final Report."
1991: "U.S. Merchandise Trade, 1991 Final Report," May 13, 1992, and "U.S. Merchandise Trade, October 1992," December 17, 1992, page 3.
1992: "U.S. Merchandise Trade, 1992 Final Report," May 12, 1993.
1993: "U.S. Merchandise Trade, 1992 Final Report," May 12, 1994.
1994: "U.S. International Trade in Goods and Services, Annual Revision for 1994."
1995: "U.S. International Trade in Goods and Services, Annual Revision for 1995."
1996: "U.S. International Trade in Goods and Services, Annual Revision for 1996."
1997: "U.S. International Trade in Goods and Services, Annual Revision for 1997."
1998: "U.S. International Trade in Goods and Services, Annual Revision for 1998."
1999 and 2000: "U.S. International Trade in Goods and Services," FT-900, monthly.

Energy Exports and Imports
1974-1987: U.S. merchandise trade press releases and database printouts for adjustments.
1988: January-July, monthly FT-900 supplement, 1989 issues. August-December, monthly FT-900, 1989 issues.
1989: Monthly FT-900, 1990 issues.
1990: "U.S. Merchandise Trade, 1990 Final Report."
1991: "U.S. Merchandise Trade, 1991 Final Report," May 13, 1992, and "U.S. Merchandise Trade, October 1992," December 17, 1992, page 3.
1992: "U.S. Merchandise Trade, 1992 Final Report," May 12, 1993.
1993: "U.S. International Trade in Goods and Services, Annual Revision for 1993."
1994: "U.S. International Trade in Goods and Services, Annual Revision for 1994."
1995: "U.S. International Trade in Goods and Services, Annual Revision for 1995."
1996: "U.S. International Trade in Goods and Services, Annual Revision for 1996."
1997: "U.S. International Trade in Goods and Services, Annual Revision for 1997."
1998: "U.S. International Trade in Goods and Services, Annual Revision for 1998."
1999 and 2000: "U.S. International Trade in Goods and Services," FT-900, monthly.

Petroleum, Energy, and Non-Energy Balances
Calculated by the Energy Information Administration.

Total Merchandise
1974-1987: U.S. merchandise trade press releases and database printouts for adjustments.
1988: "Report on U.S. Merchandise Trade, 1988 Final Revisions," August 18, 1989.
1989: "Report on U.S. Merchandise Trade, 1989 Revisions," July 10, 1990.
1990: "U.S. Merchandise Trade, 1990 Final Report," May 10, 1991, and "U.S. Merchandise Trade, December 1992," February 18, 1993, page 3.
1991: "U.S. Merchandise Trade, 1992 Final Report," May 12, 1993.
1992: "U.S. International Trade in Goods and Services, Annual Revision for 1994."
1993 and 1994: "U.S. International Trade in Goods and Services, Annual Revision for 1995."
1995 and 1996: "U.S. International Trade in Goods and Services, Annual Revision for 1996."
1997 and 1998: "U.S. International Trade in Goods and Services, Annual Revision for 1998."
1999 and 2000: "U.S. International Trade in Goods and Services," FT-900, monthly.

Sources for Tables 1.11 and 1.12

There are several degree-day databases maintained by the National Oceanic and Atmospheric Administration. The information published here is developed by the National Weather Service Climate Analysis Center, Camp Springs, MD. The data are available weekly with monthly summaries and are based on mean daily temperatures recorded at about 200 major weather stations around the country. The temperature information recorded at those weather stations is used to calculate statewide degree-day averages based on population.

The State figures are then aggregated into Census Divisions and into the national average. The population weights currently used represent resident State population data estimated for 1990 by the U.S. Department of Commerce, Bureau of the Census. The data provided here are available sooner than the Historical Climatology Series 5-1 (heating degree-days) and 5-2 (cooling degree-days) developed by the National Climatic Data Center, Asheville, NC, which compiles data from some 8,000 weather stations.

Meeting the Challenges of the Nation's Growing Natural Gas Demand

PRESENTATION FOR

THE VICE PRESIDENT'S ENERGY POLICY TASK FORCE

U.S. DEPARTMENT OF ENERGY

NATIONAL PETROLEUM COUNCIL

MARCH 27, 2001

U.S. DEPARTMENT OF ENERGY
NATIONAL PETROLEUM COUNCIL

NATURAL GAS BRIEFING PARTICIPANTS

March 27, 2001

U.S. DEPARTMENT OF ENERGY

Robert S. Kripowicz, Acting Assistant Secretary, Fossil Energy, U.S. Department of Energy

NATIONAL PETROLEUM COUNCIL

Edward J. Gilliard, Senior Advisor, Planning and Acquisitions, Burlington Resources, Inc.

John S. Hull, Director, Energy Market Analysis, Texaco Natural Gas

Paul L. Kelly, Senior Vice President, Rowan Companies, Inc.

Marshall W. Nichols, Executive Director, National Petroleum Council

Thomas B. Nusz, Vice President, Acquisitions, Burlington Resources, Inc.

Blaise N. Poole, Manager, Marketing and Strategy, El Paso Gas Services Company

Bryon S. Wright, Vice President, Strategy, El Paso Corporation

BACKGROUND INFORMATION ON THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent studies undertaken by the NPC at the request of the Secretary include:

- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation – The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1983, 1984)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government – Methods for Providing Petroleum Industry Expertise During Emergencies* (1991)
- *Short-Term Petroleum Outlook – An Examination of Issues and Projections* (1991)
- *Petroleum Refining in the 1990s – Meeting the Challenges of the Clean Air Act* (1991)
- *The Potential for Natural Gas in the United States* (1992)
- *U.S. Petroleum Refining – Meeting Requirements for Cleaner Fuels and Refineries* (1993)
- *The Oil Pollution Act of 1990: Issues and Solutions* (1994)
- *Marginal Wells* (1994)
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry* (1995)
- *Future Issues – A View of U.S. Oil & Natural Gas to 2020* (1995)
- *Issues for Interagency Consideration – A Supplement to the NPC's Report: Future Issues – A View of U.S. Oil & Natural Gas to 2020* (1996)
- *U.S. Petroleum Product Supply—Inventory Dynamics* (1998)
- *Meeting the Challenges of the Nation's Growing Natural Gas Demand* (1999)
- *U.S. Petroleum Refining—Assuring the Adequacy and Affordability of Cleaner Fuels* (2000).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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Presentation

Meeting the Challenges of the Nation's Growing Natural Gas Demand

PRESENTATION FOR

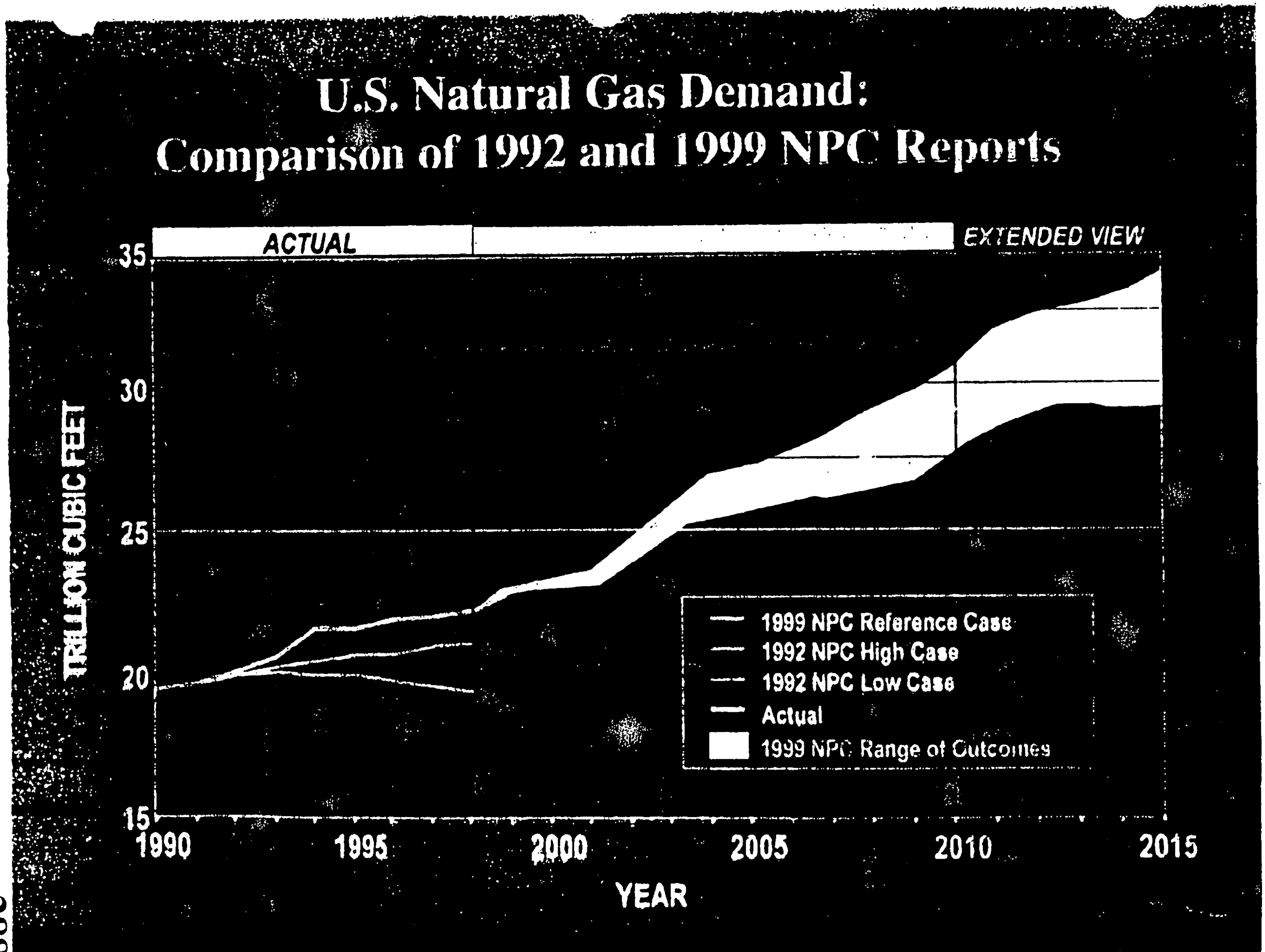
THE VICE PRESIDENT'S ENERGY POLICY TASK FORCE

U.S. DEPARTMENT OF ENERGY
NATIONAL PETROLEUM COUNCIL

MARCH 27, 2001

OVERVIEW

- Introductions
- NPC Background
  - 1992 NPC Report
  - 1999 NPC Report
- 2001 DOE Workshop
  - 23+ TCF in 2000
  - 1999 NPC Report still valid
  - Short-term trends confirm urgency of addressing critical factors and recommendations



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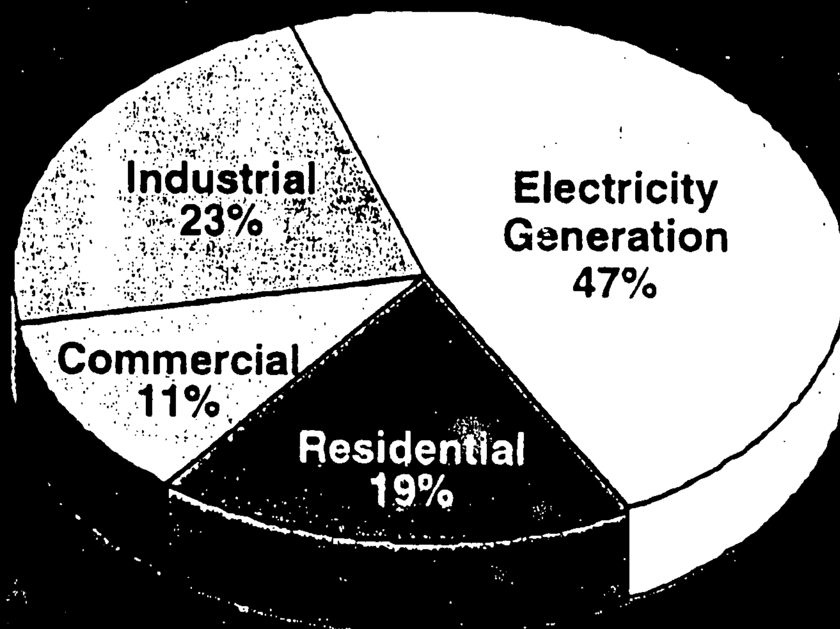
2885

Growth in Reference Case Demand (1998-2010)

Distribution of 7 TCF Increase by Sector

1999 NPC Report

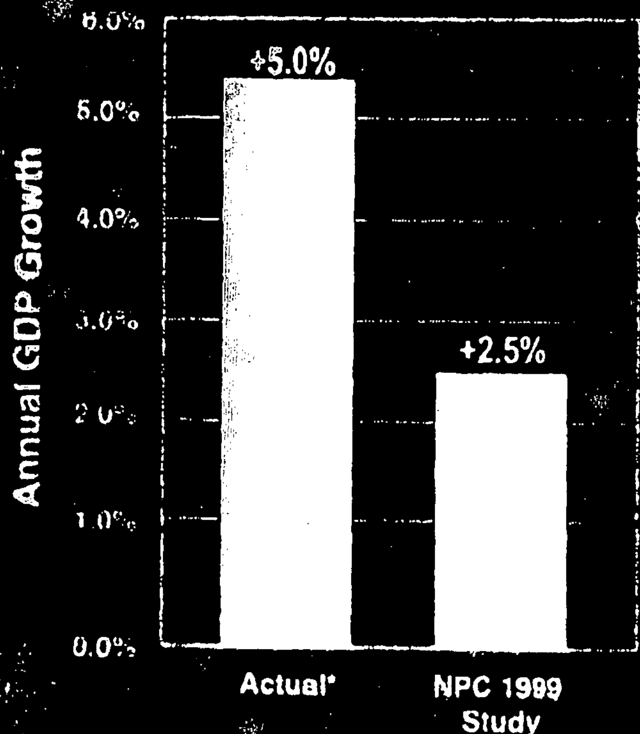


- Natural gas can make an important contribution to the Nation's energy portfolio
- Reliability is key -- 14 million new customers by 2015
- Conservation and energy efficiency still needed

Factors Behind Increased Gas Demand

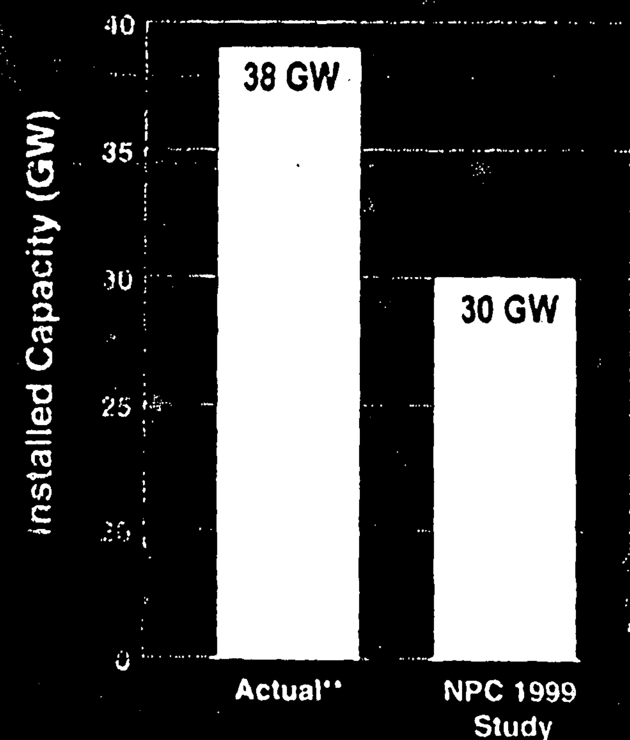
2001 DOE Workshop

Faster GDP Growth
(2000)



*EIA, Short Term Energy Outlook, Jan 2001
**EEA

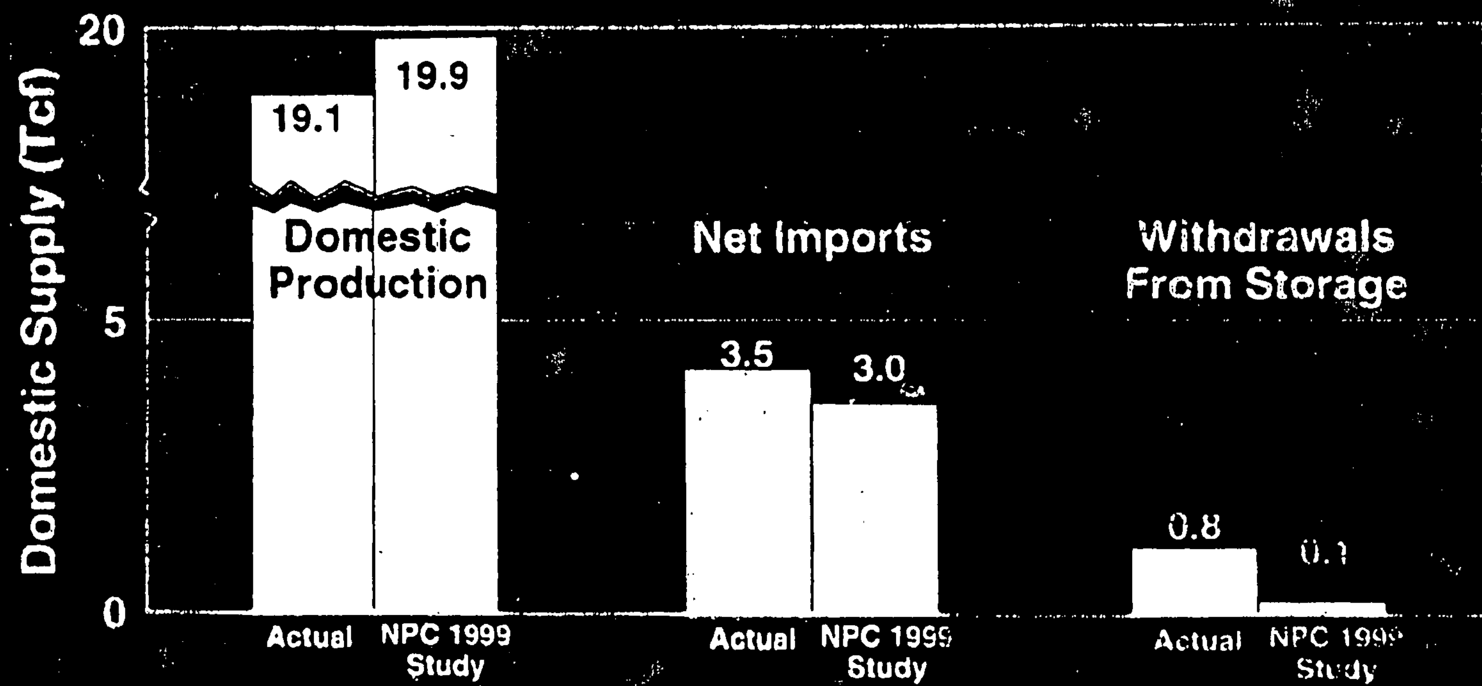
Increased Gas/Oil-Fired Electric Power Capacity
(1998-2000)



Natural gas for electricity -- 4 years ahead of NPC projection

Actual vs. Expected Sources of Natural Gas Supply (2000)

2001 DOE Workshop



Source: EIA

U.S. Lower-48 Natural Gas Resource Base Estimates

1999 NPC Report

Total Resource Base (TCF)	1,466
Proven Reserves	157
Total Unproven Resource Base	1,309
Exploitation of Existing Fields	305
New Fields to be Discovered	633
Nonconventional Sources (Coalbed Methane, Tight Gas, Shale)	371

Known with some level of certainty

Requires:

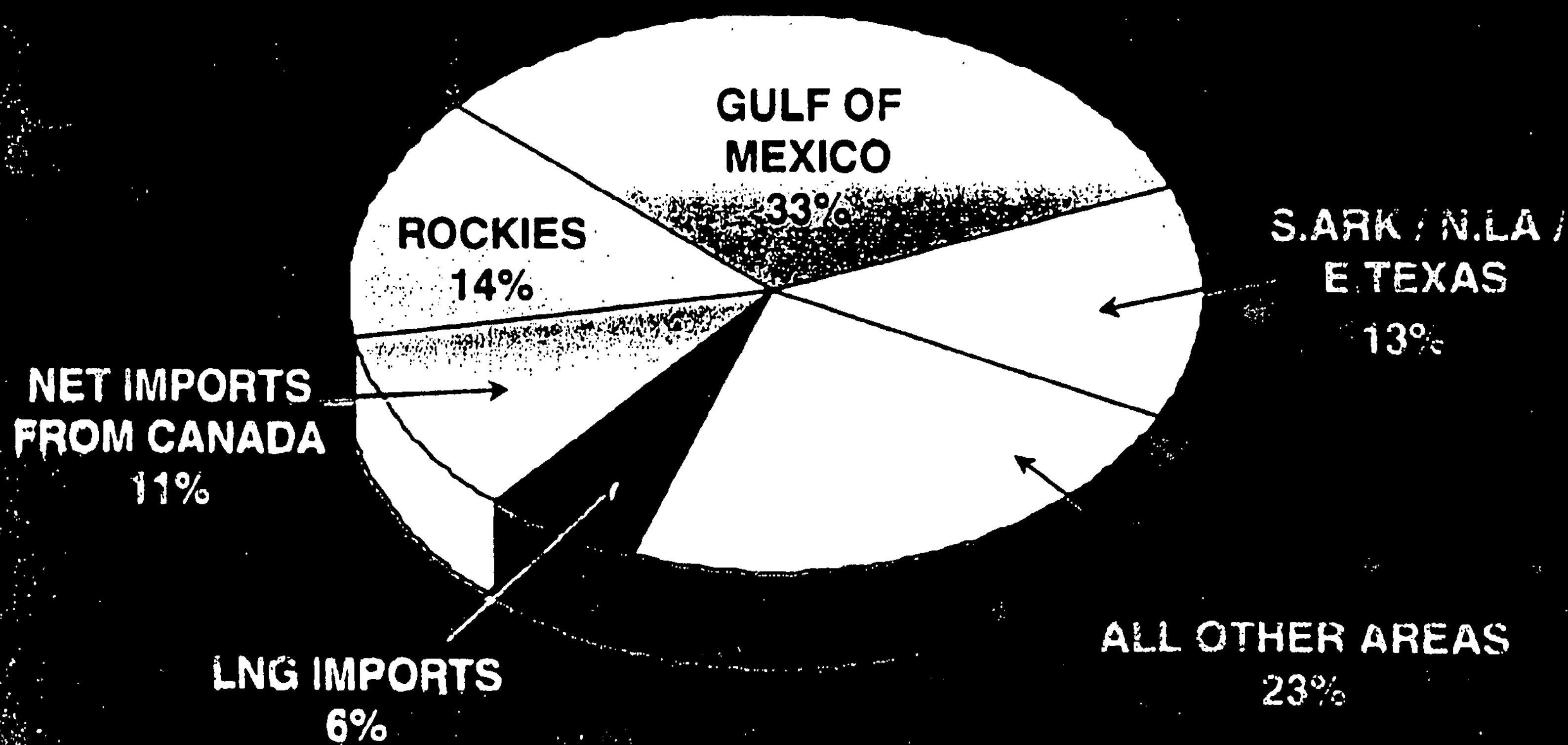
- Additional drilling
- Technology evolution
- Accessibility

Entails a higher degree of risk

Growth in Reference Case Supply (1998-2010)

Distribution of 7 TCF Increase by Source

1999 NPC Report



CRITICAL FACTORS

1999 NPC Report

- Access
- Technology
- Financial Requirements
- Skilled Workers
- Rigs
- Lead Times
- Requirements of New Customers

UPDATE ON CRITICAL FACTORS +/-

2001 DOE Workshop

Access

- Forest Service Roadless Policy (- 7 TCF)
- Sale 181 (- 9 TCF)
- Destin Dome (- 2 or more TCF)
- OCS Bright Spots
- Transmission and Distribution (siting constraints)

Technology

- Smaller Footprint, More Efficient -- recent downward trend (+/-)
- Reduced R&D Expenditures by Producers
- Unique Needs of Independent Producers -- 73% of U.S. production

Capital / Infrastructure

- Rigs and Skilled Workers in Short Supply
- $1.5 Trillion Through 2015 -- includes $781B for capital investments

UPDATE ON CRITICAL FACTORS +/-

2001 DOE Workshop

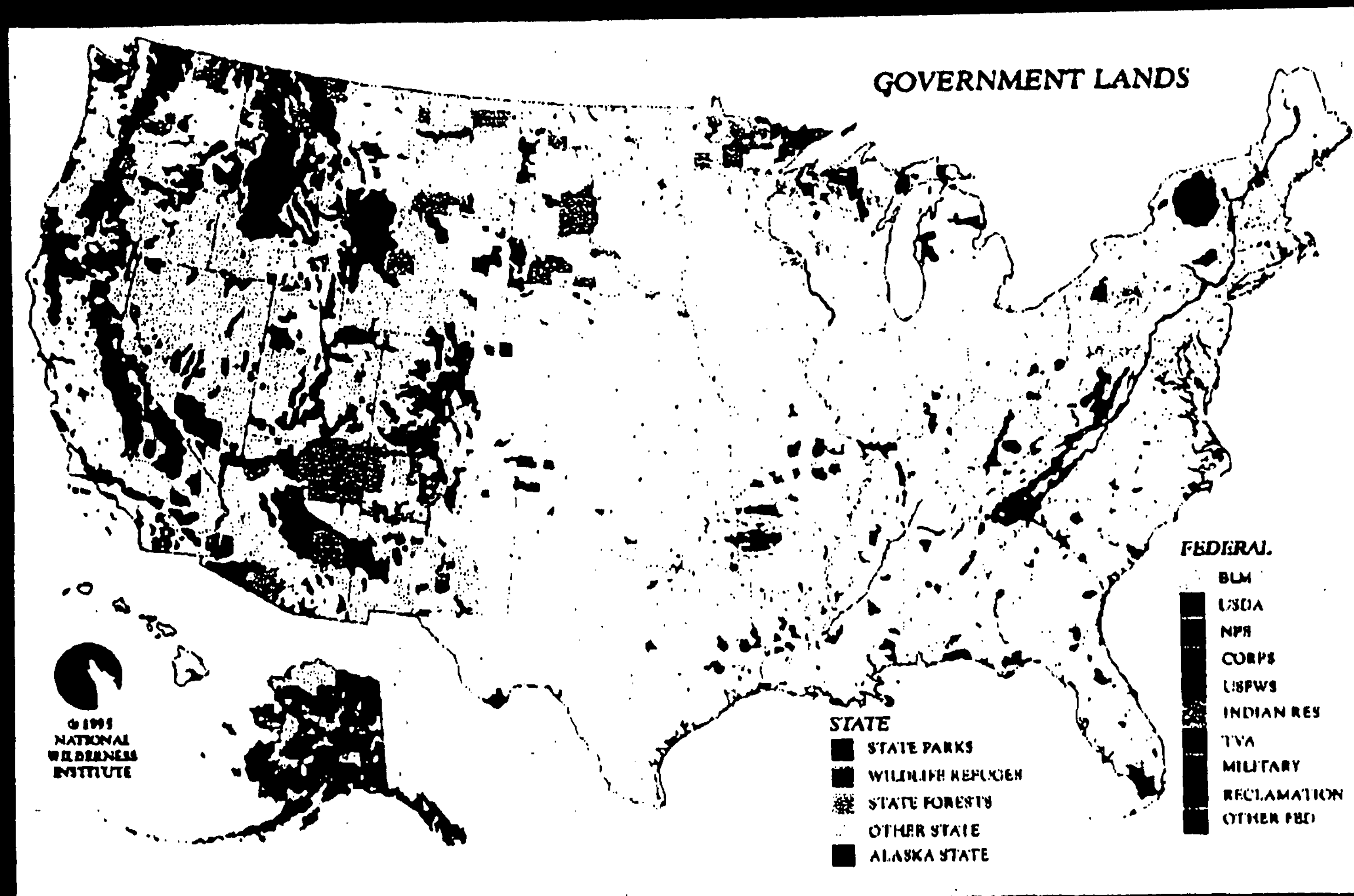
Lead Times / Regulatory Climate

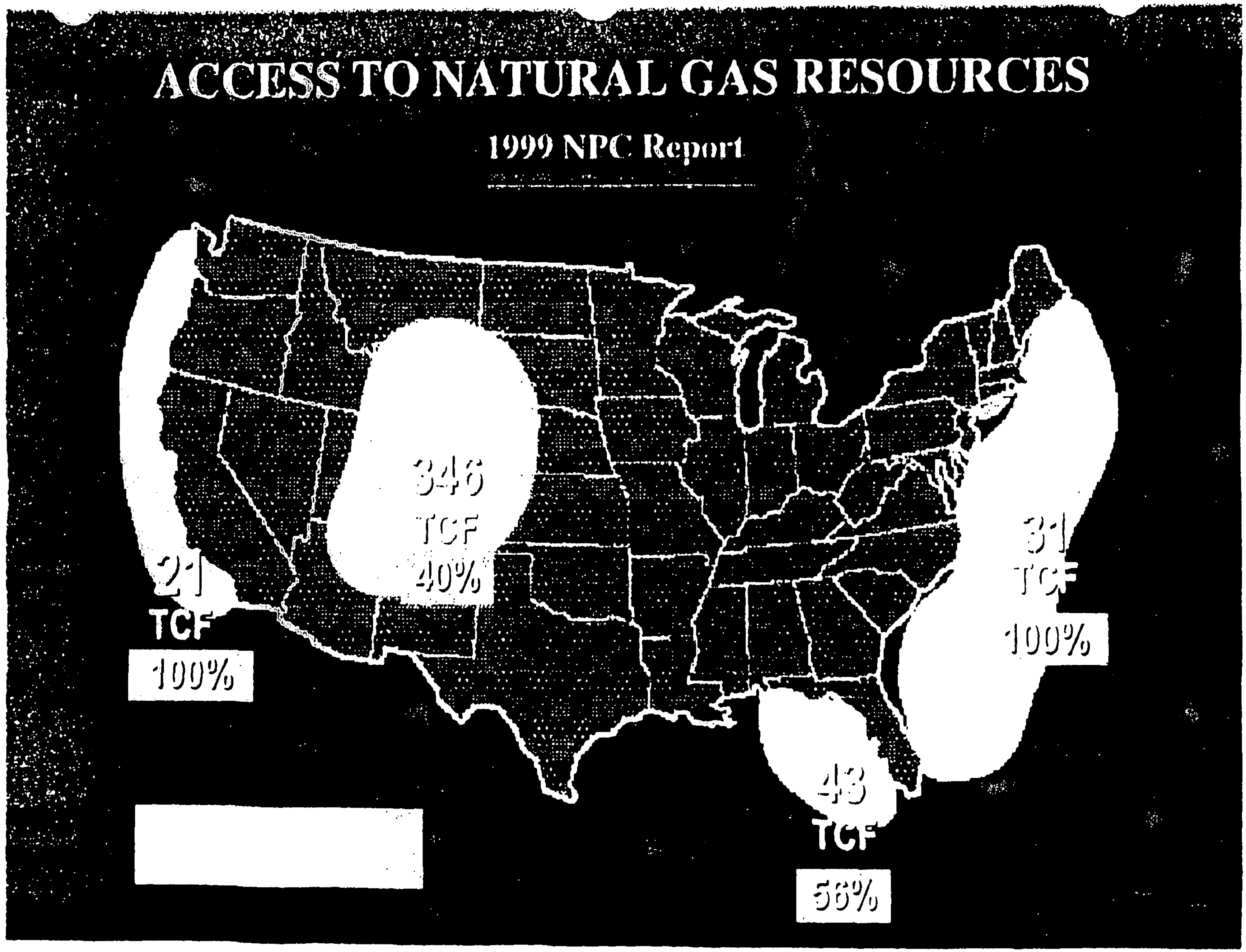
- Expedited Permitting -- further progress needed, onshore and offshore
- Transmission and Distribution Pipelines -- 300,000 new miles still needed by 2015 with related permits/approvals

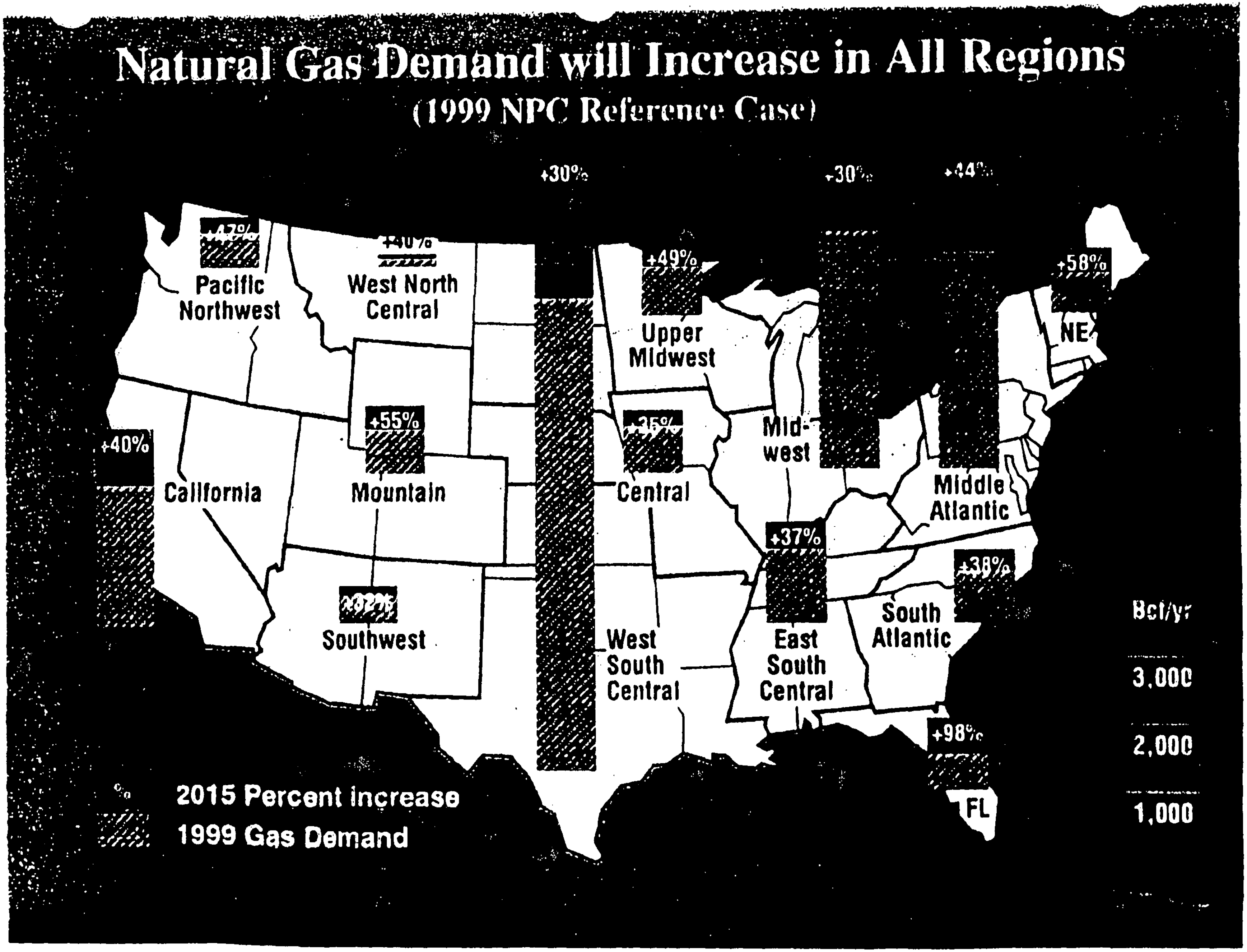
Changing Customer Needs

- New Pipelines to Reach Supplies in Frontier Areas
- Expansion of Existing Pipelines to Meet Regional Demand
- New Laterals to Serve Electricity Plants
- Unique Service Requirements

Government Lands




ACCESS TO NATURAL GAS RESOURCES
1999 NPC Report
21
TCF
100%
346
TCF
40%
31
TCF
100%
43
TCF
56%



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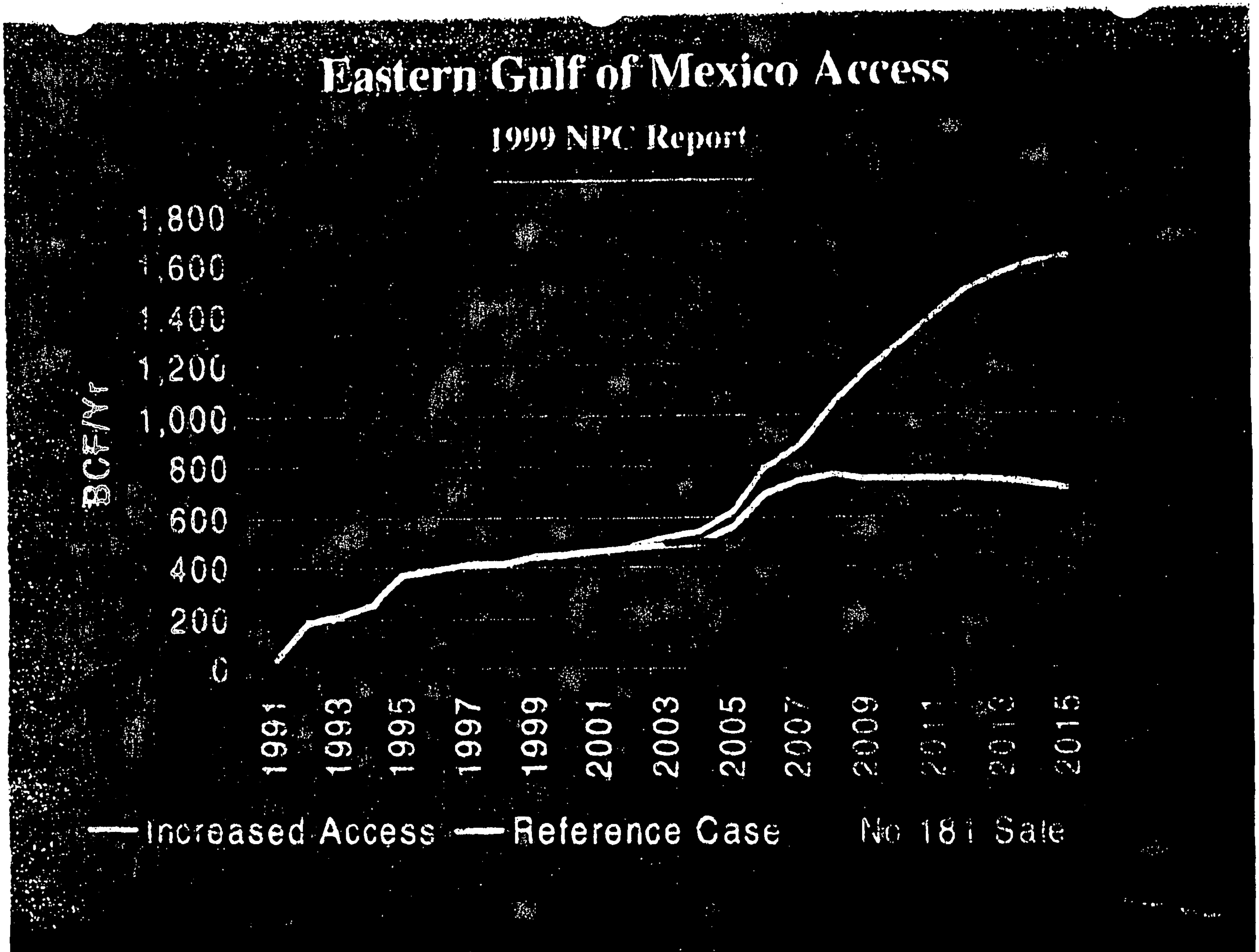

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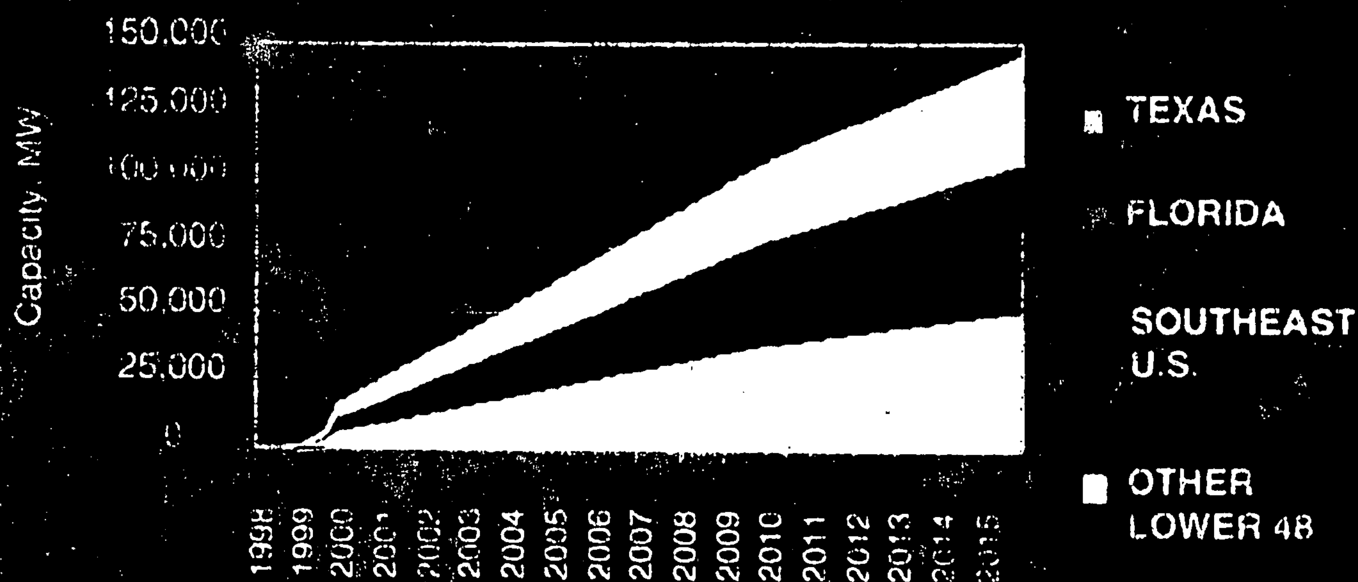
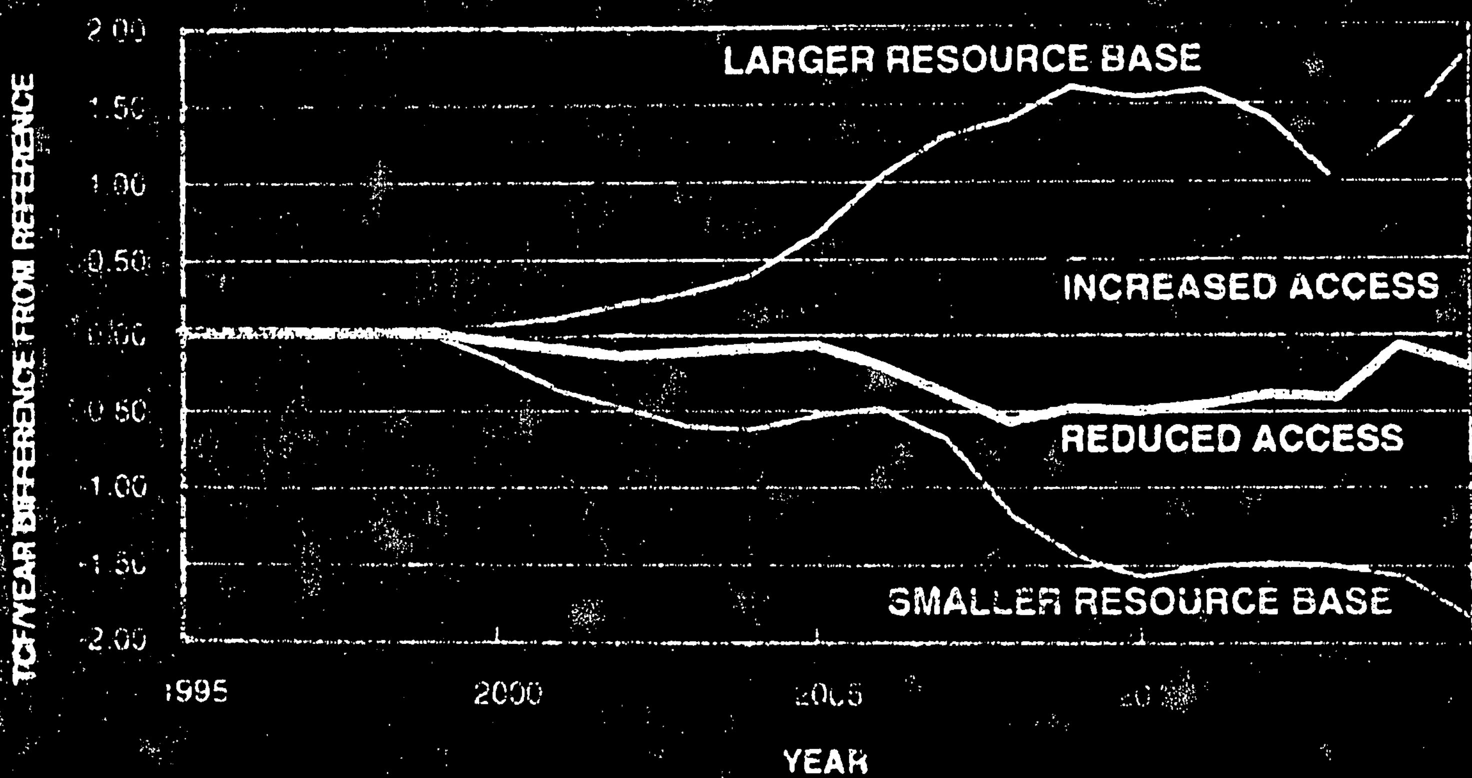
New Gulf Coast Gas Fired Electrical Capacity

1999 NPC Report



Impact of Size of Resource Base and Access on U.S. Natural Gas Production

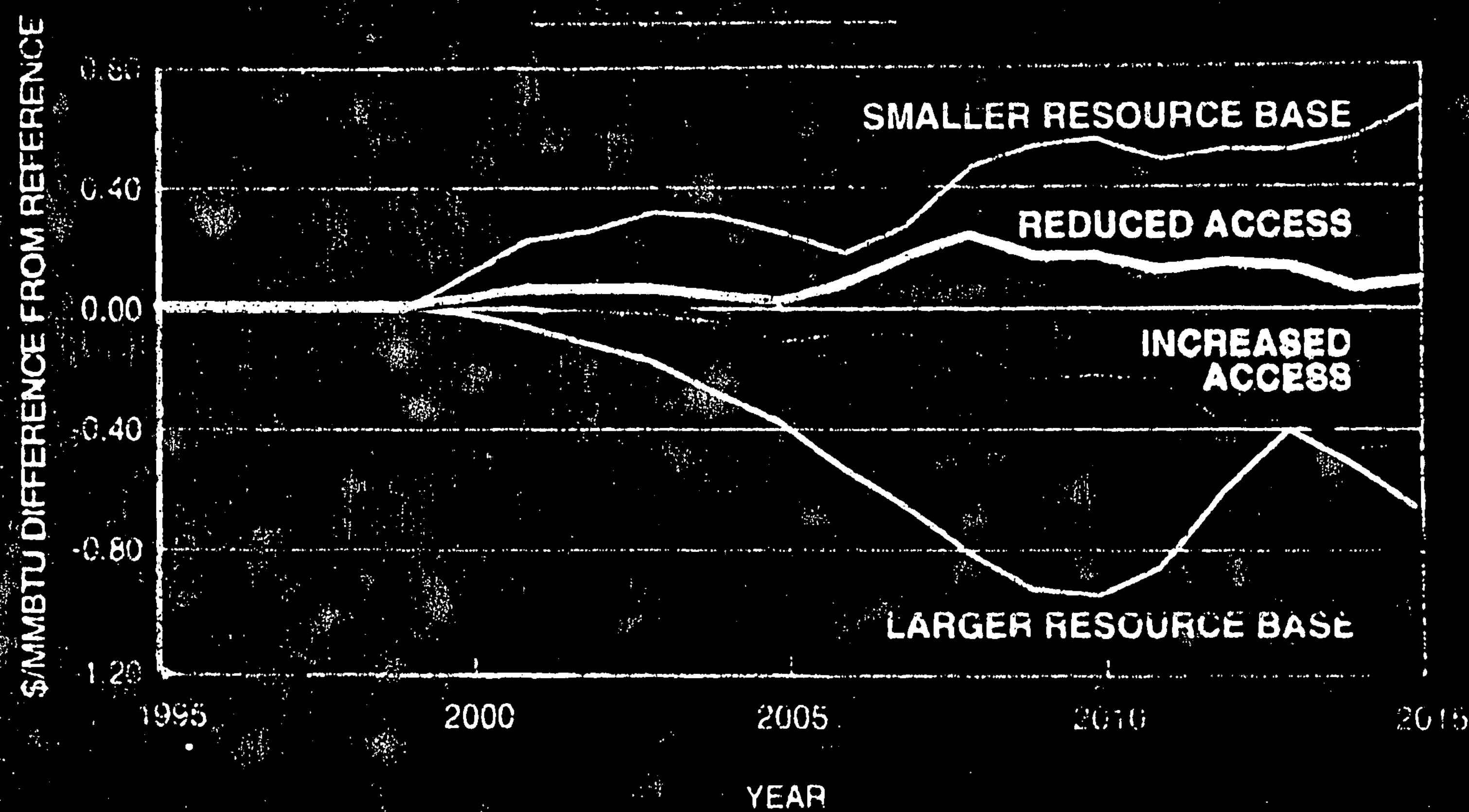
1999 NPC Report



Increased access and a larger resource base are closely linked

Impact of Size of Resource Base and Access on U.S. Natural Gas Price

1999 NPC Report



Increased access and a larger resource base are closely linked

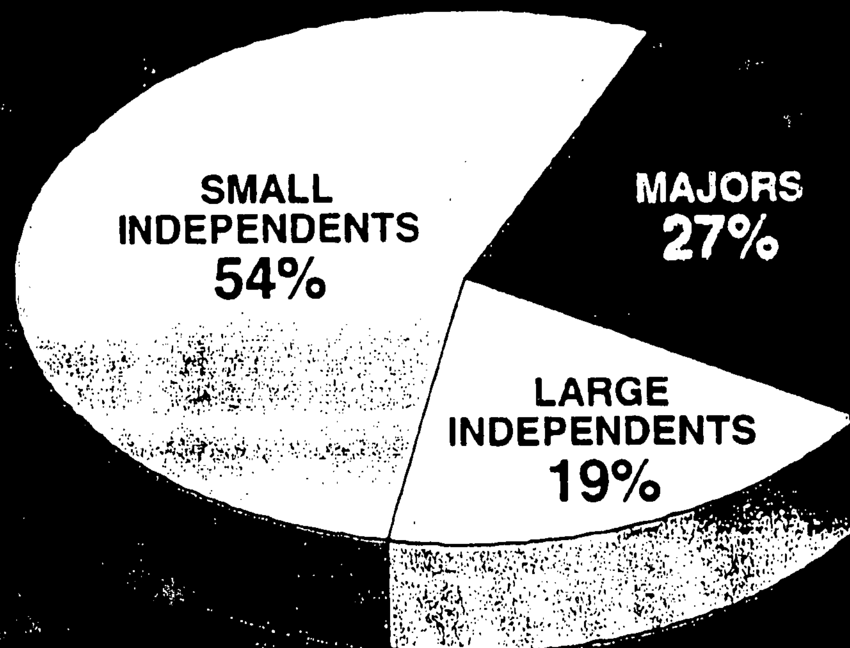
ACCESS ISSUES FOR TRANSMISSION AND DISTRIBUTION

1999 NPC Report

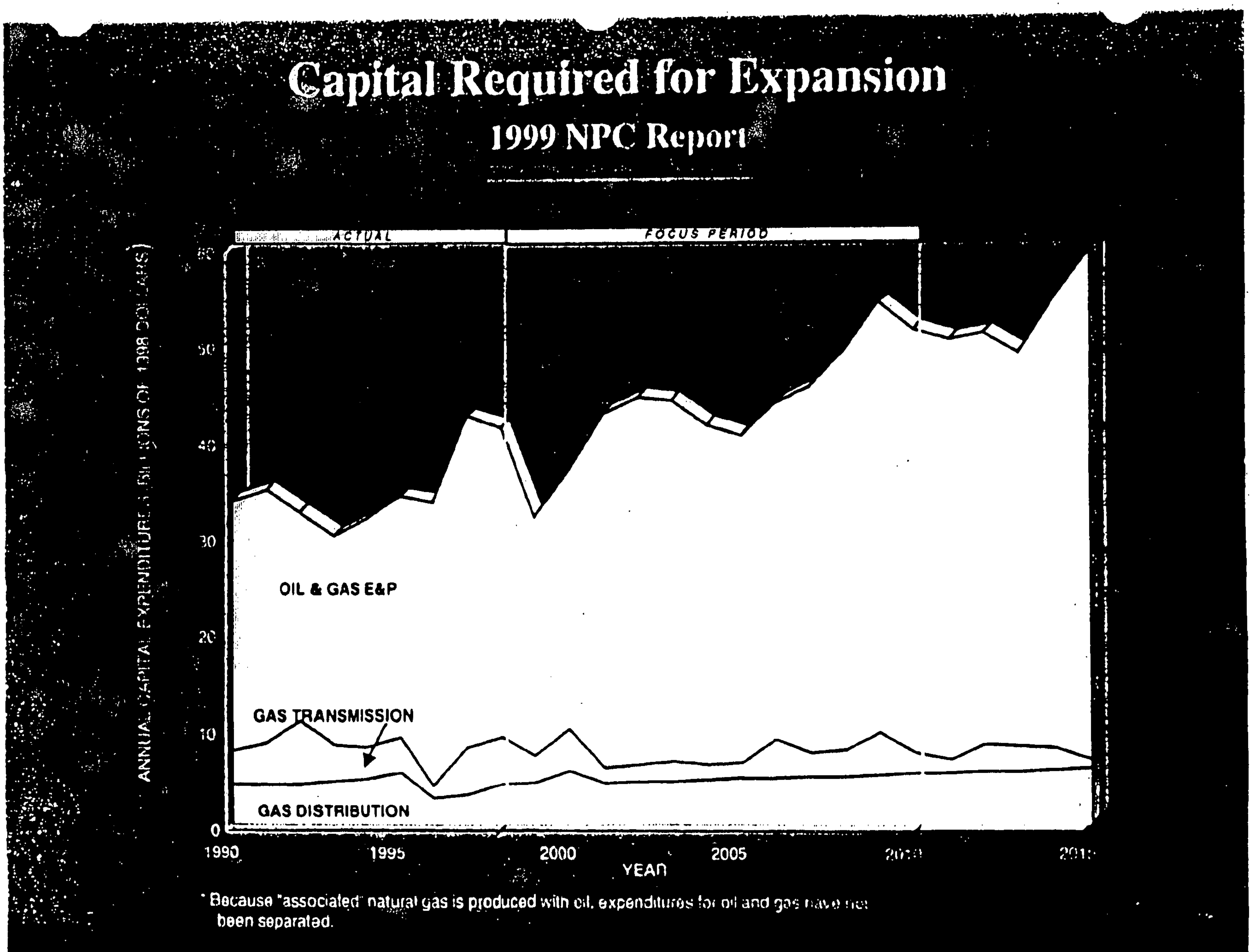
- Acquisition of Right-of-Way on Public Lands
- Encroachment on Existing Right-of-Way
- Increasing Community Awareness and Resistance to New Infrastructure
- More Restrictive Permitting Driven by Environmental Concerns

GAS PRODUCER PROFILE

1998 U.S. Natural Gas Production



Burden for Natural Gas Production Falls Primarily on Independents



DOE006-0260

2903

RECOMMENDATIONS

1999 NPC Report

- Establish a Strategy – at the Highest Level – for Natural Gas in the Nation's Energy Portfolio
- Form a White House Interagency Work Group
- Establish a Balanced, Long-Term Approach for Responsibly Developing the Nation's Resource Base
  - Assess Impact of Existing Restrictions
  - Prioritize Restricted Areas
  - Develop Supply in Selected Areas
  - Plan for Long-Term Sustainability

OTHER RECOMMENDATIONS

1999 NPC Report

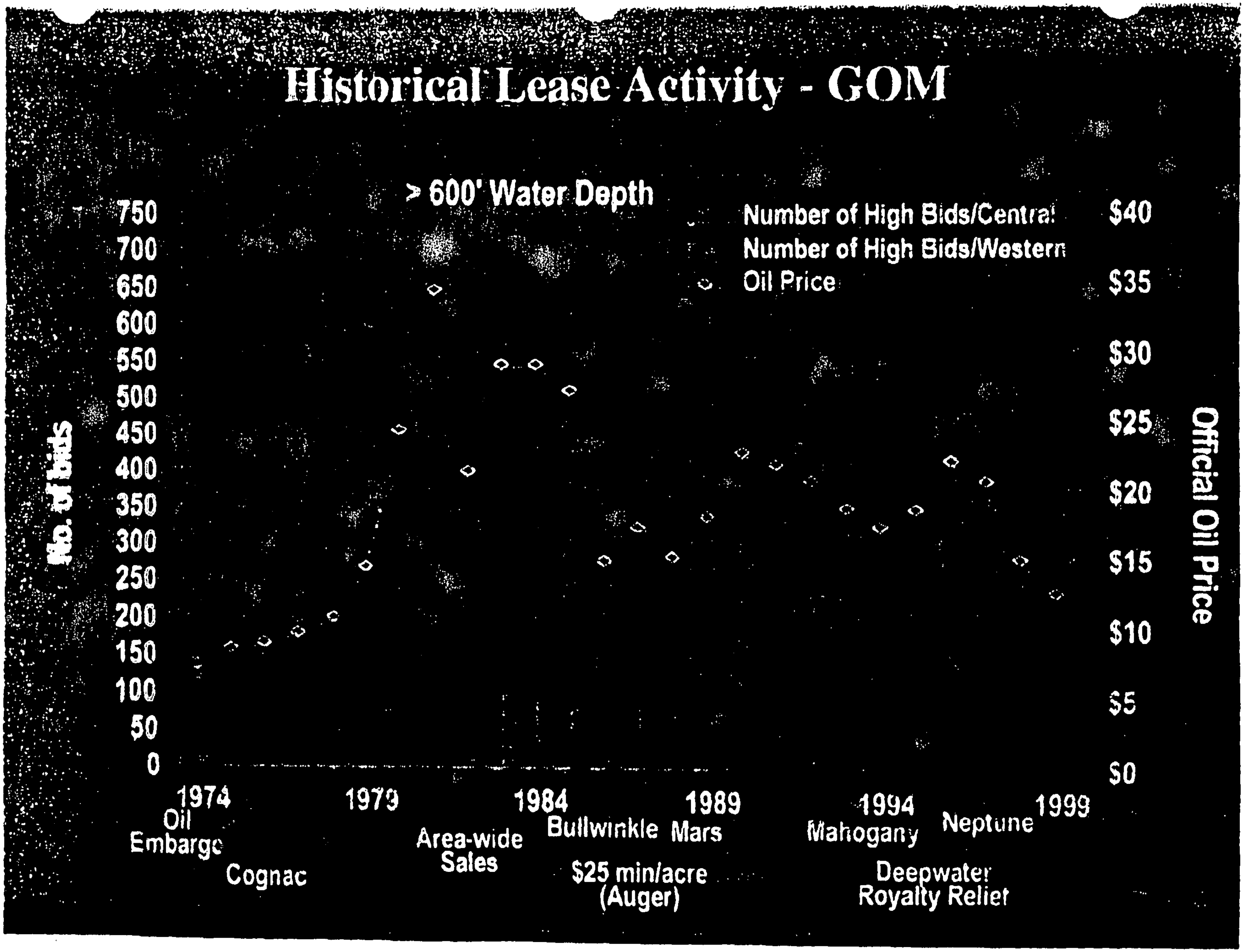
- Drive Research and Technology Development at a Rapid Rate
- Plan for Capital, Infrastructure, and Human Resource Needs
- Streamline Processes that Impact Gas Development
- Assess the Impact of Environmental Regulation on Natural Gas Demand and Supply
- Design New Services to Meet Changing Customer Needs

POTENTIAL ENERGY POLICY ACTIONS

- Institutionalize Interagency Coordination (building on work of Vice President's Energy Task Force)
- Establish a Strategic Plan for Natural Gas
- Review Existing and Proposed Regulations and Policies that May Impact Natural Gas Supply (Energy Policy Directive)
- Increase Access to Resources and Rights-of-Way (Federal Lands Inventory, Sale 181, Destin Dome, OCS Bright Spots) (*Regional Supply for Regional Demand*)
- Streamline Permitting and Approval Processes for Supply and Transmission and Distribution (including NEPA decisions, applications for permits to drill on Federal lands, and Coastal Zone Management Act reviews)
- Consult with States (maintaining a national perspective)
- Maintain View of North American Gas Market and International Sources of Supply
- Encourage Technology Development
- Evaluate Royalty Relief and Other Financial Incentives (onshore, offshore, and Infrastructure)
- Monitor Progress on the 7 Critical Factors

DOE006-0263

2906



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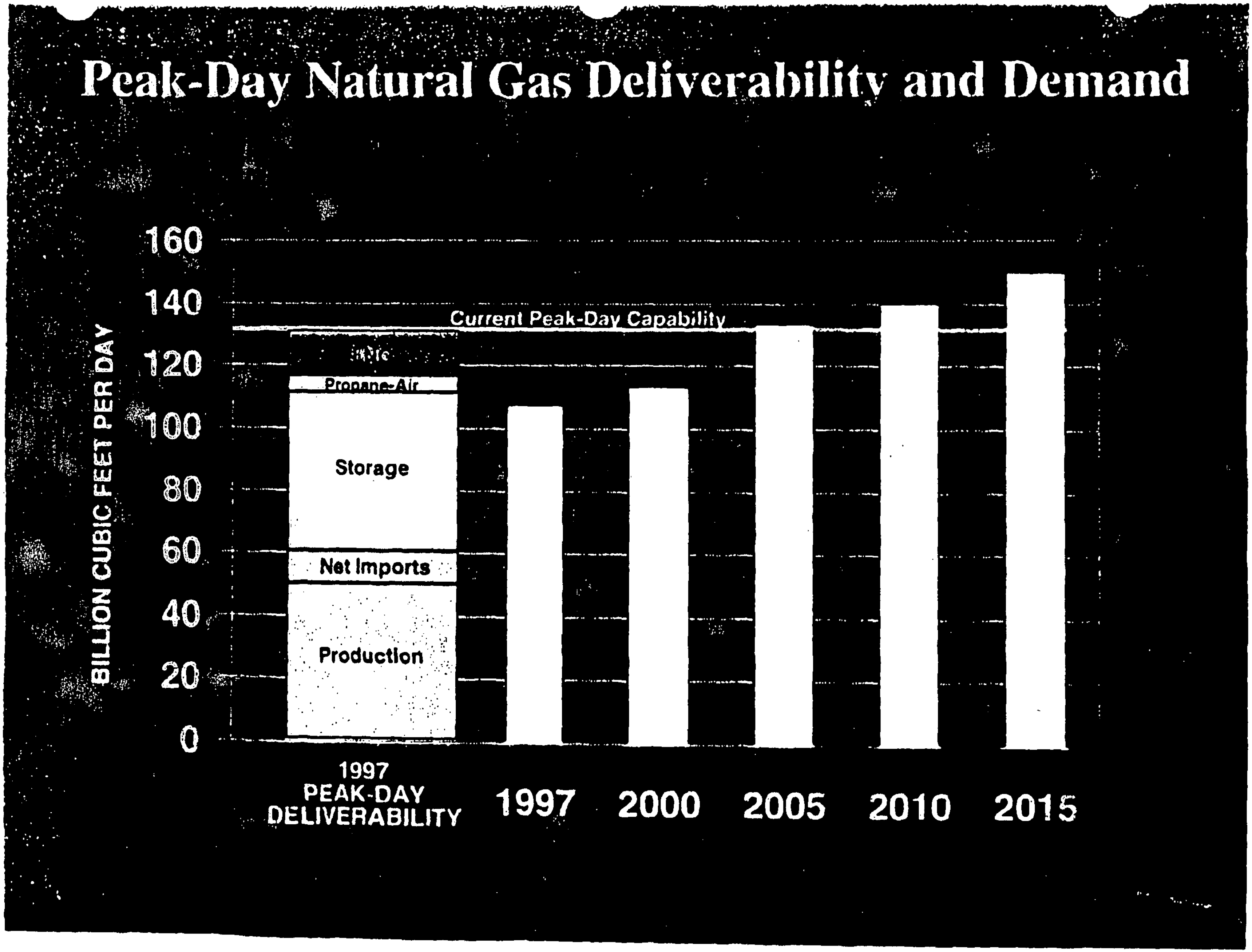
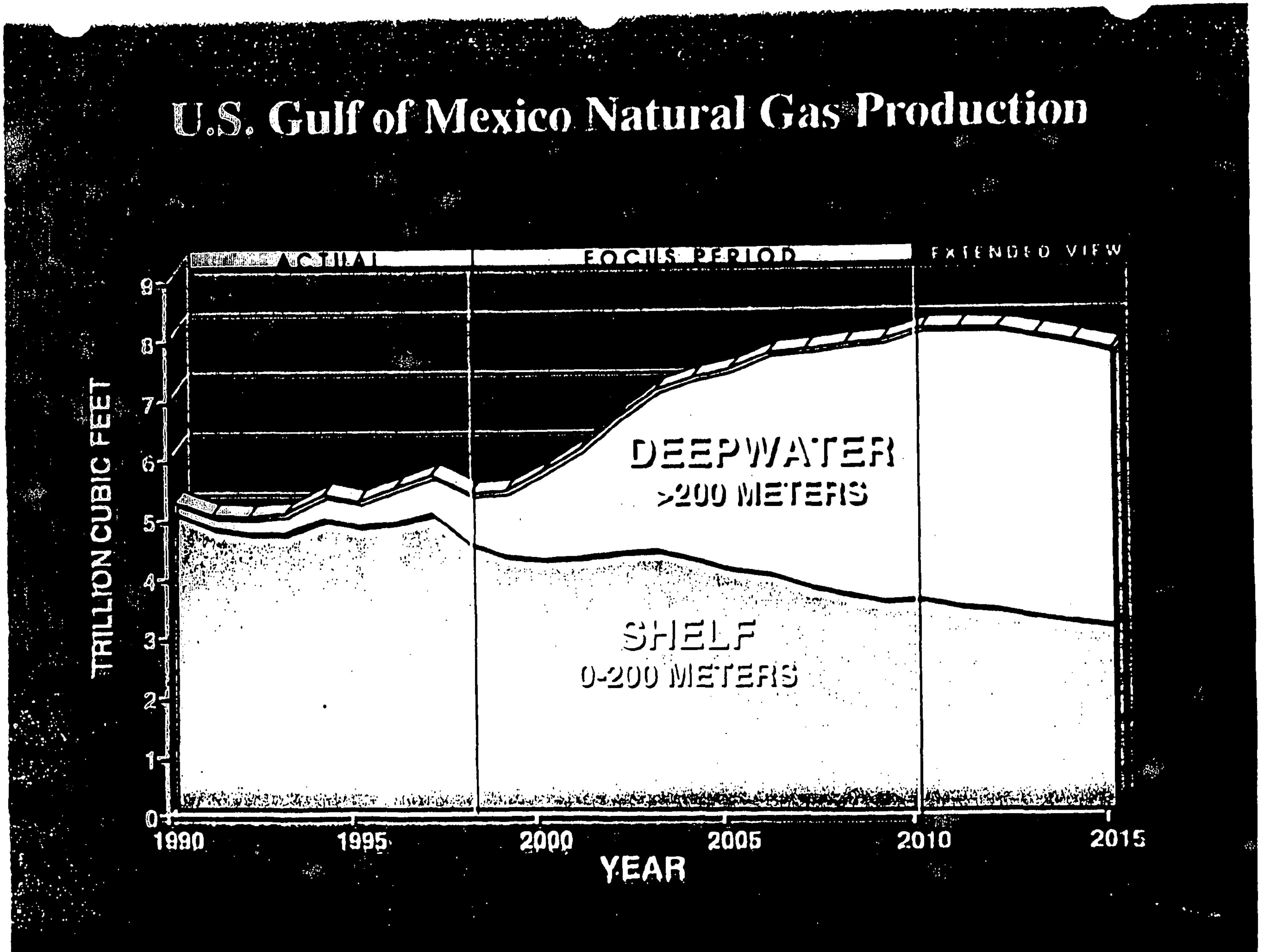
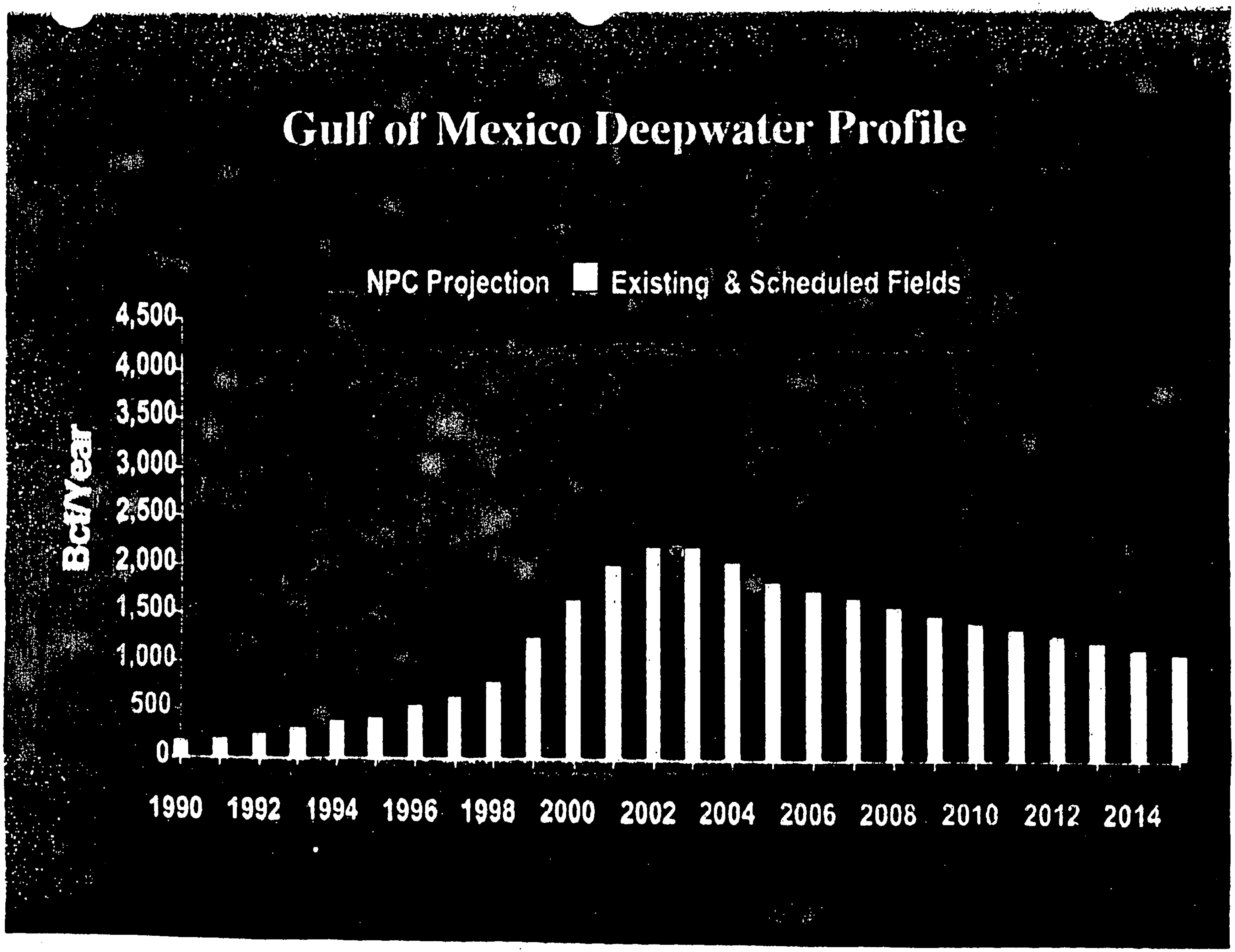
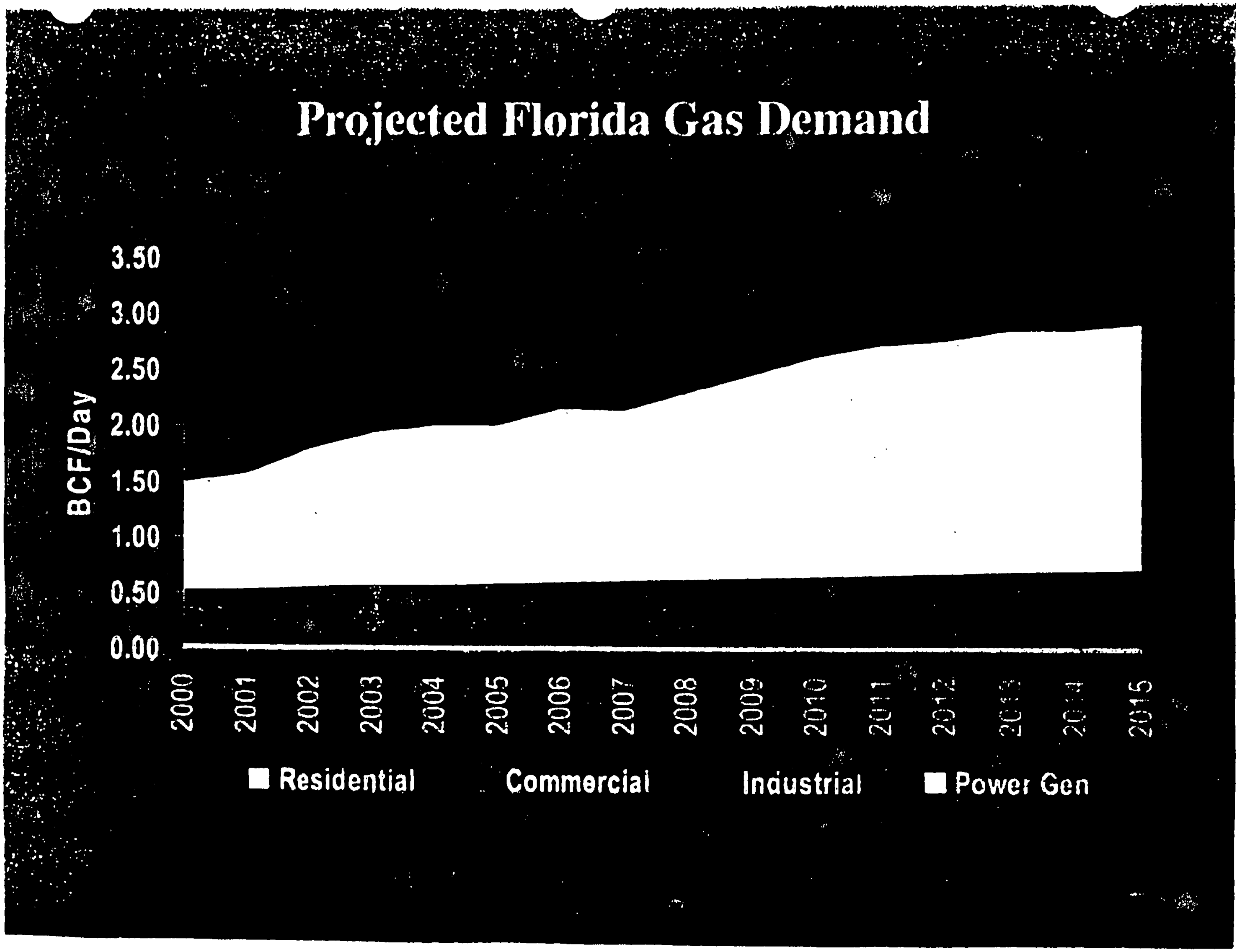
2907

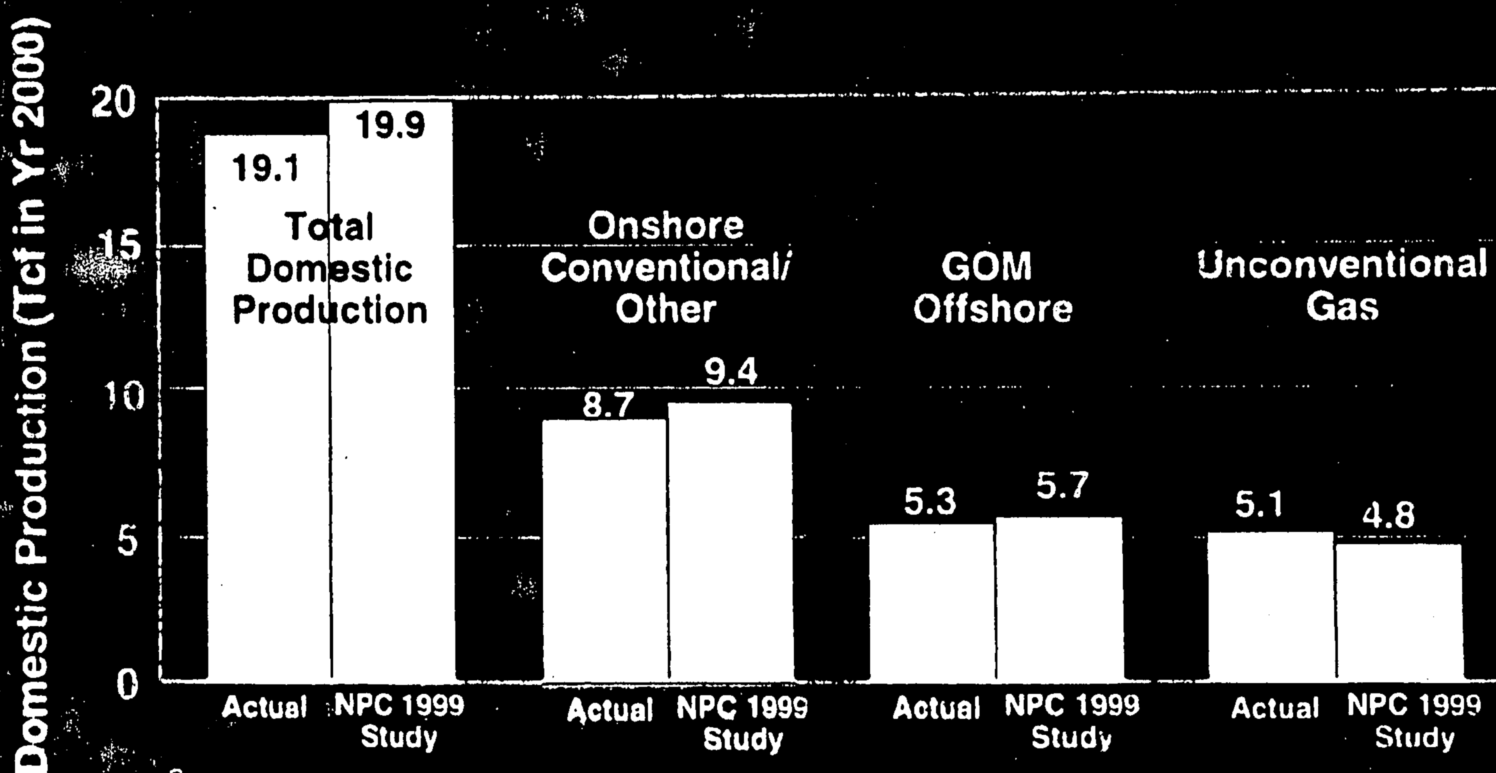

Peak-Day Natural Gas Deliverability and Demand
BILLION CUBIC FEET PER DAY
160
140
120
100
80
60
40
20
0
Current Peak-Day Capability
Propane-Air
Storage
Net Imports
Production
1997
PEAK-DAY
DELIVERABILITY
1997
2000
2005
2010
2015


U.S. Gulf of Mexico Natural Gas Production
ACTUAL
FOCUS PERIOD
EXTENDED VIEW
TRILLION CUBIC FEET
0
1
2
3
4
5
6
7
8
9
DEEPWATER
>200 METERS
SHELF
0-200 METERS
1980
1995
2000
2005
2010
2015
YEAR


Gulf of Mexico Deepwater Profile
NPC Projection
Existing & Scheduled Fields
Bcf/Year
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014


Projected Florida Gas Demand
BCF/Day
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Residential
Commercial
Industrial
Power Gen

Domestic Natural Gas Production for 2000 is Below Expectations, Except Unconventional Gas



Source:
- *Total – EIA Monthly Energy Review, Jan 2001 (0.4 Tcf of Difference Due to Calibration [illegible] NPC vs EIA)*
- *Offshore – ARI estimates.*
- *Unconventional – ARI estimates.*

DOE006-0269

2912

NATIONAL PETROLEUM COUNCIL

an advisory body to the Secretary of Energy

GROWING U.S. NATURAL GAS DEMAND

1992 Report

- 19 TCF (1990)

1999 Report

- 22 TCF (1998)
- 23+ TCF (2000)
- 29 TCF (2010)
- 31 TCF (2015)

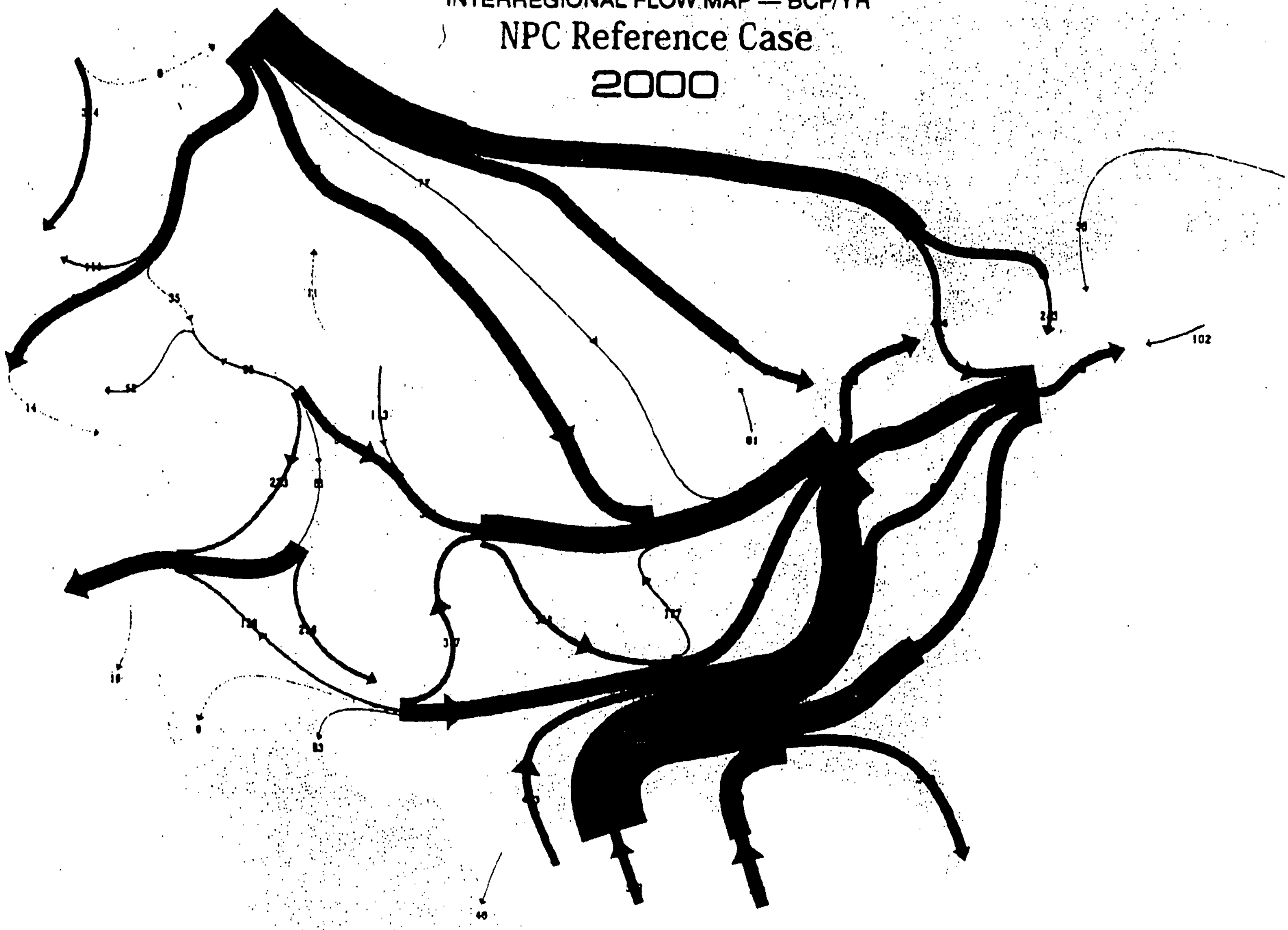
2001 Department of Energy Workshop

- 1999 NPC Report still valid
- Short-term trends confirm urgency of addressing critical factors and recommendations

INTERREGIONAL FLOW MAP — BCF/YR

NPC Reference Case

2000



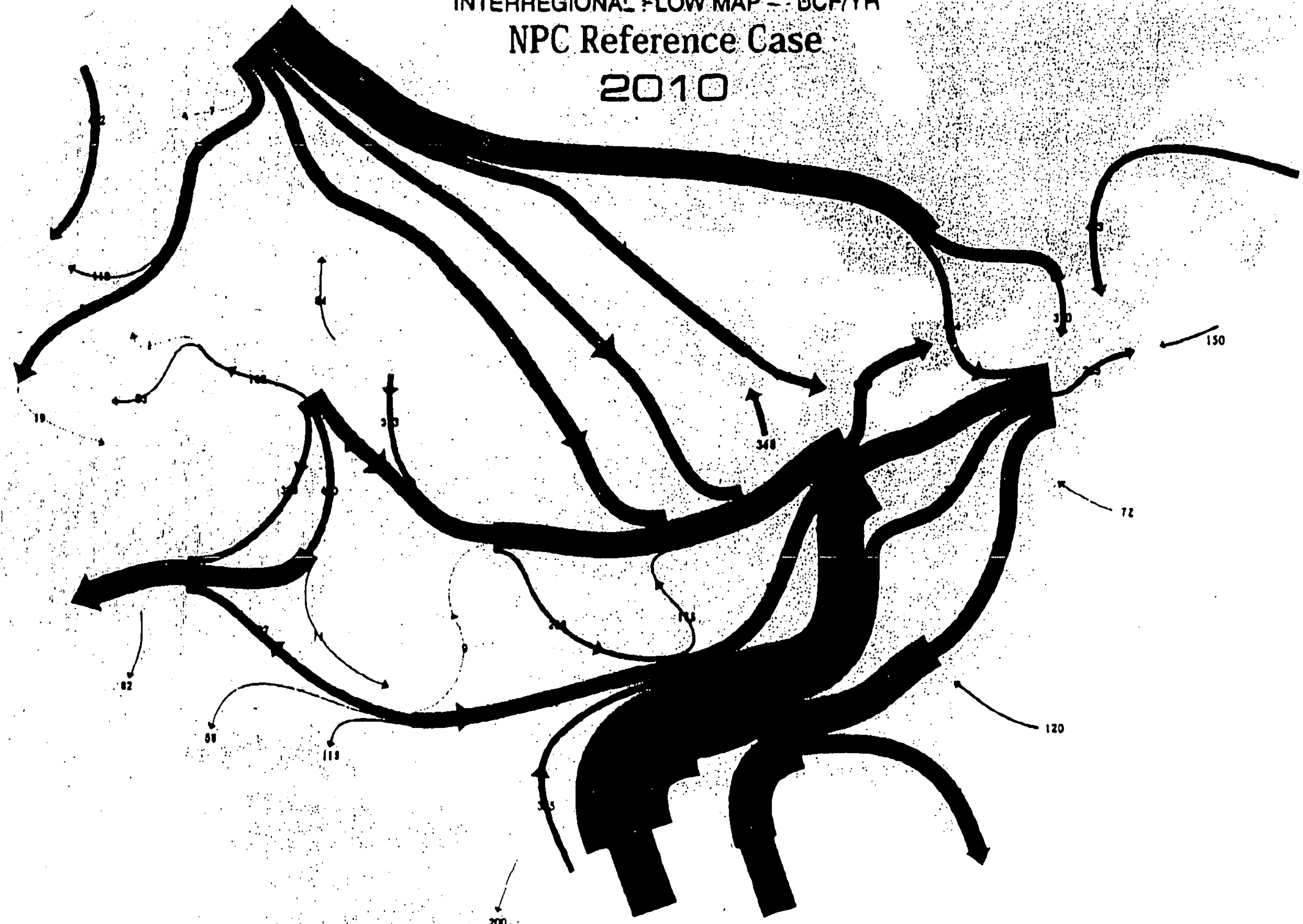
DOE006-0271

2914

INTERREGIONAL FLOW MAP -- BCF/YR

NPC Reference Case

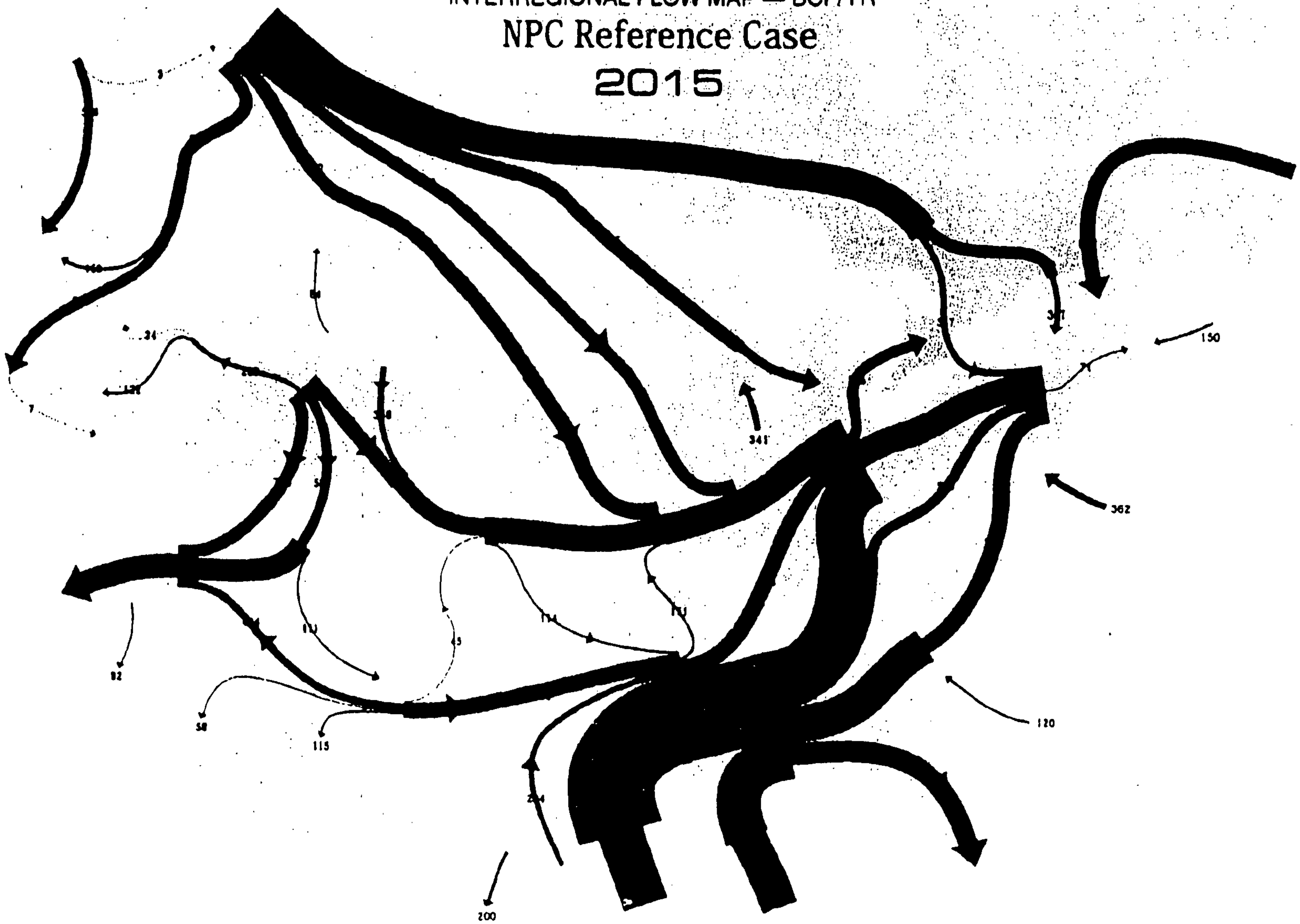
2010



INTERREGIONAL FLOW MAP — BCF/YR

NPC Reference Case

2015



DOE006-0273

2916

NATURAL GAS

Meeting the Challenges of the Nation's Growing Natural Gas Demand

Volume I
SUMMARY REPORT

A Report of the
National Petroleum Council

December 1999

DOE006-0274

NATIONAL PETROLEUM COUNCIL

An Oil and Natural Gas Advisory Committee to the Secretary of Energy

1625 K Street, N.W.
Washington, D.C. 20006-1656

Phone: (202) 393-6100
Fax: (202) 331-8539

December 15, 1999

Dear Mr. Secretary,

On behalf of the members of the National Petroleum Council, I am pleased to submit to you the results of the 1999 study on natural gas, entitled *Meeting the Challenges of the Nation's Growing Natural Gas Demand*. The objective for the study was to provide the requested advice on the potential contribution of natural gas in meeting the nation's future economic, energy, and environmental goals.

The Council is pleased to report that natural gas can make an important contribution to the nation's energy portfolio well into the twenty-first century. Demand for natural gas will continue to increase as economic growth, environmental concerns, and the restructuring of the electricity markets encourage the use of natural gas. More than 14 million new customers will be connected to natural gas supply by 2015 and many more will find their growing electricity needs met by gas-fired generators.

The estimated natural gas resource base is adequate to meet this increasing demand for many decades, and technological advances continue to make more of those resources technically and economically available. However, realizing the full potential for natural gas use in the United States will require focus and action on certain critical factors. These factors include:

- Access to resources and rights-of-way
- Continued technological advancements
- Financial requirements for developing new supply and infrastructure
- Availability of skilled workers
- Expansion of the U.S. drilling fleet
- Lead times for development
- Changing customer needs.

Each of these factors can be positively influenced, but government, industry, and other stakeholders must act quickly, cooperatively, and purposefully to ensure the availability of competitively priced natural gas.

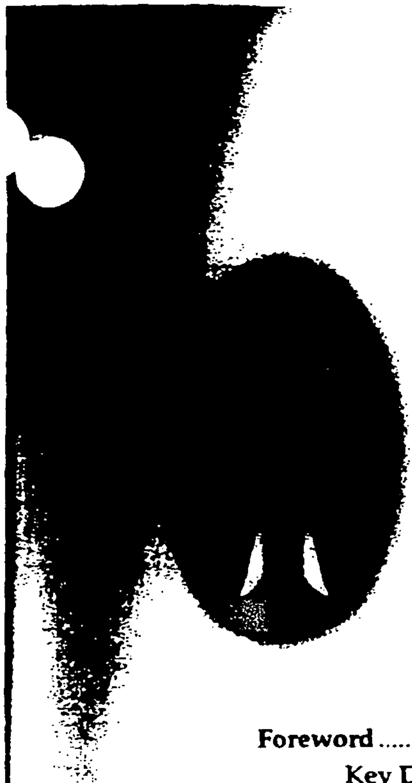
The National Petroleum Council stands ready to work with government to further discuss the results of this report and to implement the recommendations in order to meet the nation's growing gas demand.

Respectfully submitted,

Joe B. Foster

Joe B. Foster
NPC Chair

2918



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Foreword

The National Petroleum Council is pleased to report to the Secretary of Energy that, given immediate focus on key issues, natural gas can make an important contribution to the nation's increasing energy needs and its environmental goals through 2015 and beyond. The natural gas industry has evolved into a competitive industry offering its expanding and reliable services on a nationwide basis. Between 1990—the reference point for the 1992 NPC report—and 1998, total U.S. gas consumption grew from 19.3 trillion cubic feet (TCF) to an estimated 22 TCF and continues to represent approximately a quarter of the nation's fuel needs. Using the study methods described in this report, the Council concludes that gas demand is likely to increase to 29 TCF in 2010 and could increase beyond 31 TCF in 2015. Further, the resource base exists to support the indicated levels of future demand and adequate gas supplies can potentially be produced to meet that market. The additional supply required can be brought to market at competitive prices through an expanded network of pipeline, storage, and distribution facilities. However, the Council recognizes that meeting the significant challenges that accompany such vigorous market growth will require strenuous effort by the industry and substantial support on key issues by the government.

The initial impetus for the current study (hereinafter referred to as "the 1999 Study") came from a letter dated May 6, 1998, in which then-U.S. Energy Secretary Federico Peña requested the National Petroleum Council to:

> Reassess its 1992 report [*Potential for Natural Gas in the United States*] taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

In making his request, the Secretary noted that "at least two major forces ... are beginning to take shape which will profoundly affect energy choices in the future – the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality." Further, the Secretary stated that "For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand." (See Appendix A for this letter and

Secretary Bill Richardson's follow-up letter expressing his interest in receiving the Council's advice on these matters.)

To respond to this request, the Council established a Committee on Natural Gas under the Chairmanship of Peter I. Bijur, Chairman of the Board and Chief Executive Officer, Texaco Inc. T. J. Glauthier, Deputy Secretary of Energy, served as the Committee's Government Cochair, with H. Leighton Steward, Vice Chairman of the Board, Burlington Resources, Inc., and William A. Wise, President and Chief Executive Officer, El Paso Energy Corp., serving as Vice Chairs for Supply and for Transmission & Distribution, respectively. The Committee was assisted by a Coordinating Subcommittee, chaired by Rebecca B. Roberts, Strategic Partner, Global Alignment, Texaco Inc., with Robert S. Kripowicz, Principal Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, serving as Government Cochair. (Appendix B contains the Committee roster along with the rosters of its Coordinating Subcommittee and three Task Groups on Demand, Supply, and Transmission & Distribution.)

Key Differences from 1992

The Secretary was correct in noting that the U.S. energy markets have changed significantly since the 1992 NPC study on natural gas (hereinafter referred to as "the 1992 Study"). The U.S. economy is growing more rapidly than was anticipated in 1992, and with that growth has come a higher natural gas demand than was expected. Environmental regulations that favor natural gas consumption are more firmly in place than in 1992 and environmental restrictions on fossil fuel-burning facilities are increasingly stringent. In fact, gas demand has grown at a rate that exceeds even the most robust scenario projected in the 1992 Study. Continued economic growth as well as concerns about air quality and climate change favor the continued expansion of natural gas demand.

Since 1992, the gas industry has undergone a significant restructuring. The primary impetus came from Federal Energy Regulatory Commission (FERC) regulations, which over time have converted interstate pipelines from sellers and transporters of natural gas to solely transporters. State regulators and local distribution companies (LDCs) are moving toward a similar result in many jurisdictions. This restructuring has driven changes in roles and risks for industry participants because a number of market functions and obligations formerly managed under the auspices of the LDCs and pipelines must now be accepted and carried out by other market participants. Since the 1992 Study, new market structures—market hubs/centers, futures trading for natural gas, and a capacity release market (a secondary pipeline capacity market)—have either developed or matured. Other financial tools have been developed to reduce the risk of price change to buyers and sellers over extended time periods. In short, the gas market has become highly efficient and sophisticated, with numerous participants ensuring competitive prices. Increased confidence in the functionality of the gas market and in competitive gas prices has played a significant role in increasing gas demand.

The industry has benefited from remarkable progress in technology in areas that were not fully anticipated in 1992. For example, three-dimensional (3D) imaging now allows scientists to virtually "see" underground rock formations in graphic detail and to reduce drilling risk by more accurately predicting locations for hydrocarbon deposits. Progress in 3D and 4D seismic technology, in conjunction with imaging technology, has allowed producers to spot small hydrocarbon accumulations. Improved drilling techniques enable production companies to more precisely hit drilling targets and accomplish difficult maneuvers such as drilling a vertical well, turning a corner, and then drilling horizontally over five miles. New technology now allows producers to access supply in ocean waters that are more than a mile deep. These improvements, along with many more, have resulted in significant reserve additions and prospects of new production in areas that were once considered physically or economically unreachable.

Technological progress has also been evident in the transmission and distribution segments of the industry and has contributed to a steady and significant decline in transmission and distribution charges since the mid-1980s. Technological advances have taken place in areas such as gas measurement, pipeline monitoring, compression, and storage management. The dramatic improvements in information and communications technology have contributed to more efficient data management systems that support marketing activities and capacity scheduling. New end-use gas technologies, such as higher efficiency residential furnaces, natural gas cooling, and combined cycle power plants, continue to offer consumers higher efficiency, lower costs, and cleaner energy.

Although market confidence has grown and technology has improved the state of the industry, recent events have led to questions about the industry's ability to meet the demand growth potential. The downturn in world oil prices between late 1997 and early 1999 dealt a heavy blow to the exploration and production sectors of the U.S. gas industry, particularly to the oilfield supply/service contractors and the independent producers who supply over half of the nation's natural gas needs. Industry participants experienced an extended period of poor economic returns and, fearing a repeat of the 1984–89 depression in the industry, responded with significant downsizing and cutbacks in spending. Investment capital for developing new production, which for most industry participants is highly dependent on cash flow from crude oil and gas sales, declined dramatically in 1999. As a result, new supply development in the United States has slowed considerably. Although oil prices have now rebounded, these events have highlighted the boom and bust nature of the business and have made industry participants and investors very cautious.

Several other trends highlight the challenges that could impact the future of gas production and delivery. The broadening and extension of moratoria have reduced access to a portion of the nation's natural gas resource base. The economic hardship experienced by the oilfield supply/service sector has limited construction of rigs and other infrastructure, giving rise to questions on the industry's ability to respond to future drilling needs. Decreased spending on research and development raises concerns regarding future technological breakthroughs. Continued cutbacks and layoffs impair the industry's ability to attract new employees.

While these issues are significant, the Council wishes to emphasize that the industry has successfully met difficult challenges in the past and has proved to be resilient and resourceful. Each of the challenges identified in this study can be met if immediate, cooperative, and focused actions are taken by the industry and the government.

Approach to the 1999 Study

In conducting the 1999 Study, the NPC Committee on Natural Gas and its Coordinating Subcommittee and three Task Groups developed projections for gas demand, gas supply, and transmission and distribution. The primary focus of the 1999 Study was to test supply and delivery systems against significantly increased demand. As in the case of the 1992 Study, the Committee on Natural Gas selected Energy and Environmental Analysis, Inc. (EEA) to run econometric models for the analysis. The Coordinating Subcommittee and its Task Groups provided data and assumptions to EEA for inclusion in the development of a Reference Case for the focus period of 1999 to 2010. The assumptions used in the Reference Case represent a plausible view of the future and were selected with full understanding that, in reality, each could vary significantly. Each of the Task Groups developed sensitivity analyses to test the Reference Case through 2010 and to develop an extended view through 2015. The results of the Reference Case and the sensitivity analyses form a framework for better understanding the factors that influence supply and demand balances. This approach was particularly useful in exploring the potential range of outcomes beyond 2010, a point at which uncertainties in assumptions begin to escalate. Throughout this report, data are reported for the focus period of 1999 to 2010, with an extended view for the more uncertain period of 2011 through 2015. While the study did not attempt to model supply and demand beyond 2015, the issue of long-term sustainability is addressed.

The study participants focused on the broader industry implications and dynamics indicated by the data rather than attempt to forecast specific end results. Issues such as new regulations for climate change were not examined in detail, but other factors that increase demand were specifically analyzed and some correlations can be made. Changes that are occurring in the areas of electricity generation, such as distributed generation, were not studied, but the overall impact of increases in gas demand due to electricity generation was examined.

Results of the 1999 Study are presented in a three-volume report as follows:

- Volume I, *Summary Report*, provides conclusions and recommendations on the potential contribution of natural gas in meeting the nation's growing demand for energy in the residential, commercial, industrial, and electric power generation sectors. Also included are summaries of key findings from the study's three Task Groups: Demand, Supply, and Transmission & Distribution. Volume I can be viewed and downloaded from the NPC web site, http://www.npc.org.

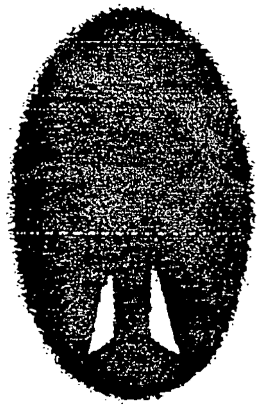
- Volume II, *Task Group Reports*, contains the results of the analyses conducted by the three Task Groups and provides further supporting details for the conclusions, recommendations, and findings presented in Volume I.

- Volume III, *Appendices*, includes output of the study's computer modeling activities as well as various source and reference materials developed for or utilized by the Task Groups in the course of their analyses. The Council believes that these materials will be of interest to the readers of the report and will help them better understand the results. The members of the National Petroleum Council were not asked to endorse or approve all of the statements and conclusions contained in Volume III but, rather, to approve the publication of these materials as working papers of the study.

  Enclosed with Volume III is a CD-ROM containing further model output on a regional basis. The CD also contains digitized maps, which were used in assessing a key critical factor—access to resources and rights-of-way. These maps provide a comprehensive inventory of acreage by land-use categories associated with related USGS gas plays for the several key Rocky Mountain resource areas analyzed in the 1999 NPC Study.

An outline of the full report and a form for ordering additional copies can be found in the back of this volume.

The National Petroleum Council believes that the results of the 1999 Study are amply supported by the rigorous analyses conducted by the Committee on Natural Gas and its subgroups. Further, the Council wishes to emphasize that the significant growth in demand that is projected in this study is based on long-term trends and should not be interpreted as a "goal" of the industry. However, as natural gas demand continues to expand, the natural gas industry stands ready to work with all stakeholders to economically develop the natural gas resources and infrastructure necessary for continuing the nation's economic growth and meeting its environmental goals.



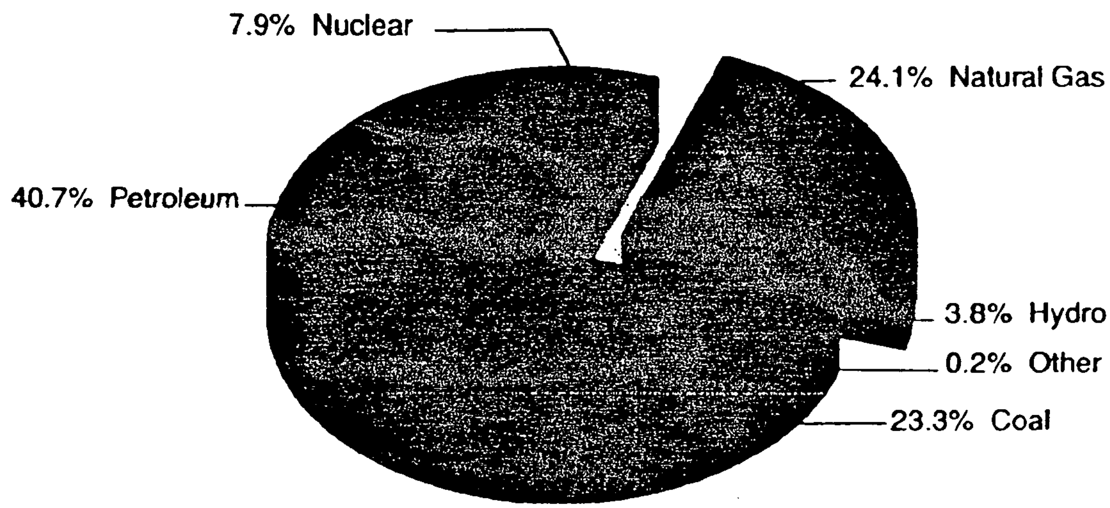
Conclusions

The emphasis on natural gas is good news for the economy, the environment, and society as a whole. In recent years, the United States has enjoyed a thriving economy, which has been driven in part by the ready availability of energy at competitive prices. Natural gas has played a vital role in meeting those energy requirements and today provides almost a quarter of the nation's energy portfolio (Figure 1). As this study demonstrates, natural gas can be a growing source of energy to power our economy for many years to come.

Actual U.S. gas demand has outpaced the 1992 Study High Reference Case projection by more than 1 TCF over the period from 1990 through 1998 (Figure 2). The 1999 Study projects that U.S. gas demand will grow from 22 TCF (including net storage fill) in 1998 to approximately 29 TCF in 2010 and could rise beyond 31 TCF in 2015. Each key consumption sector—residential, commercial, industrial, and electricity generation—will increase (Figure 3a). However, the electricity generation sector alone will account for almost 50% of the increase through 2010 (Figure 3b). Over 110 gigawatts of new gas-fired generation capacity is projected to be in service by 2010, and a total of 140 gigawatts by 2015. Natural gas is now the preferred fuel for new electricity generation facilities, with 98% of the nearly 250 recently announced new generation projects planning to burn natural gas. This dramatic shift to natural gas is driven by improved efficiencies, lower capital costs, reduced construction time, more expeditious permitting of natural gas-burning facilities, and environmental compliance advantages. However, the service requirements and price sensitivity of this additional load present many challenges to suppliers and transporters of natural gas.

Growth in gas demand will remain subject to changes in such key variables as growth in the economy, price of competing fuels, nuclear retirements, and the capacity utilization of coal-fired electricity generation plants. For example, if 30 gigawatts of nuclear capacity are retired rather than the 15 gigawatts assumed in the Reference Case, demand could increase another 0.7 TCF. If coal capacity utilization remains at current levels instead of increasing from 64% to 75% as assumed in the Reference Case, demand could rise as much as 1.7 TCF. New environmental regulations, beyond those that are currently scheduled for implementation, have not been factored into this analysis and could also further increase natural gas demand. While this study did not attempt to quantify the impacts of additional environmental regulations on demand, incremental increases from Kyoto-related regulation were estimated in independent studies at 2–12% by the Energy Information Administration and 10–22% by the Edison Electric Institute beyond their respective reference cases.

Figure 1. Total U.S. Energy Consumption by Primary Energy Source, 1998



Natural gas supplies almost a quarter of the nation's energy needs.

Source: DOE/EIA, *Monthly Energy Review*, September 1999.

The role that natural gas plays in improving the nation's environment has been widely recognized. A recent Minerals Management Service (MMS) report, *OCS Resource Management and Sustainable Development* (September 1999), pointed out the benefits of natural gas:

> Natural gas is the least polluting fossil fuel. It is thought by many, including the present administration, to be the fuel of the early part of the next century that will power our economy into the sustainable fuels of the later decades and beyond. Even in the short run, conversion of more of our fuel burning facilities to natural gas will greatly diminish air pollution and improve the long run sustainability of forests, waters, and farmlands now being negatively affected by acid deposition.

The MMS report also noted the following regarding income from offshore resources:

> ...royalties and taxes enable government to carry on programs which are beneficial to the oil and gas industry as well as society as a whole. For example, an average of 60 percent of the collections from Federal offshore sources [$126 billion since offshore leasing began in 1953] went into the U.S. Treasury General Fund. Among other expenditures the Government uses a portion of these funds to invest in social infrastructure, which helps make the U.S. economy one of the most productive in the world. One of the

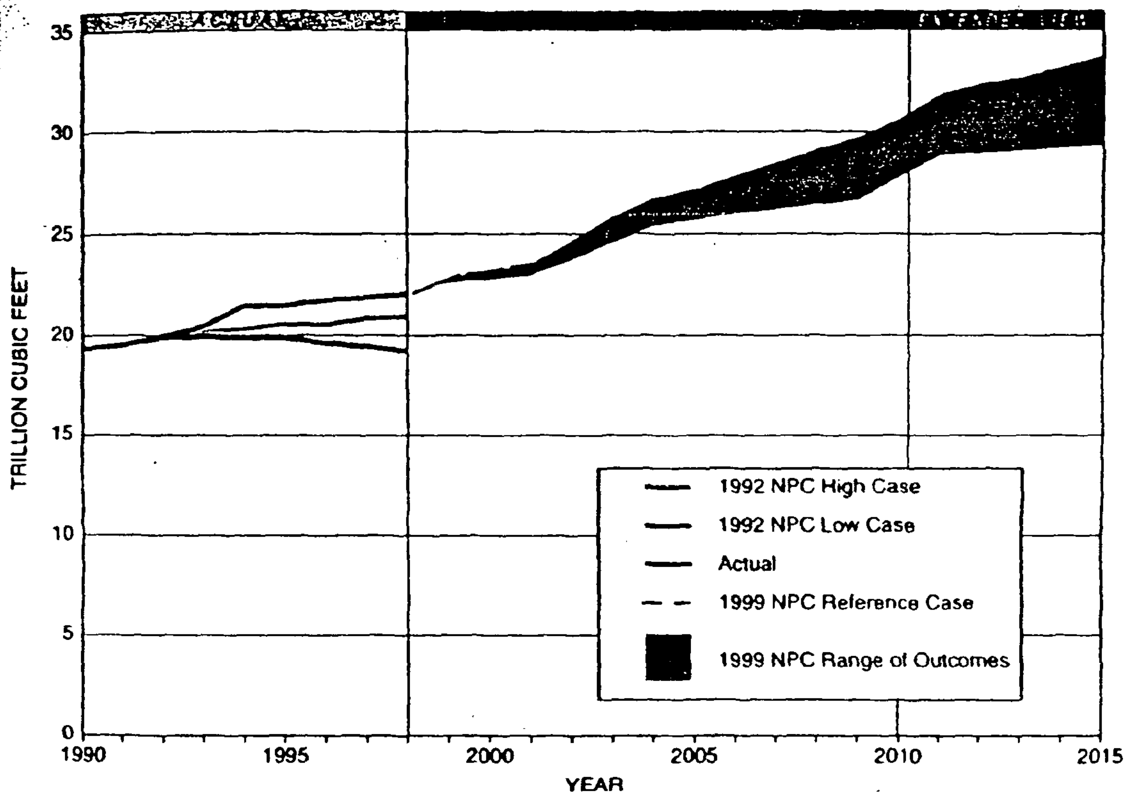
reas in which some of this money is invested is in renewable energy, including many forms of energy conservation.

In onshore areas, federal, state, and local rnments receive royalty income and col- taxes from natural gas production. The revenues that are collected from these sources allow these entities to provide essential services expected by their citizens, such as funding for education.

This study estimates the U.S. natural gas resource base, excluding Alaska, to be 1,466

Figure 2. U.S. Natural Gas Demand

Comparison of 1992 and 1999 NPC Study Results



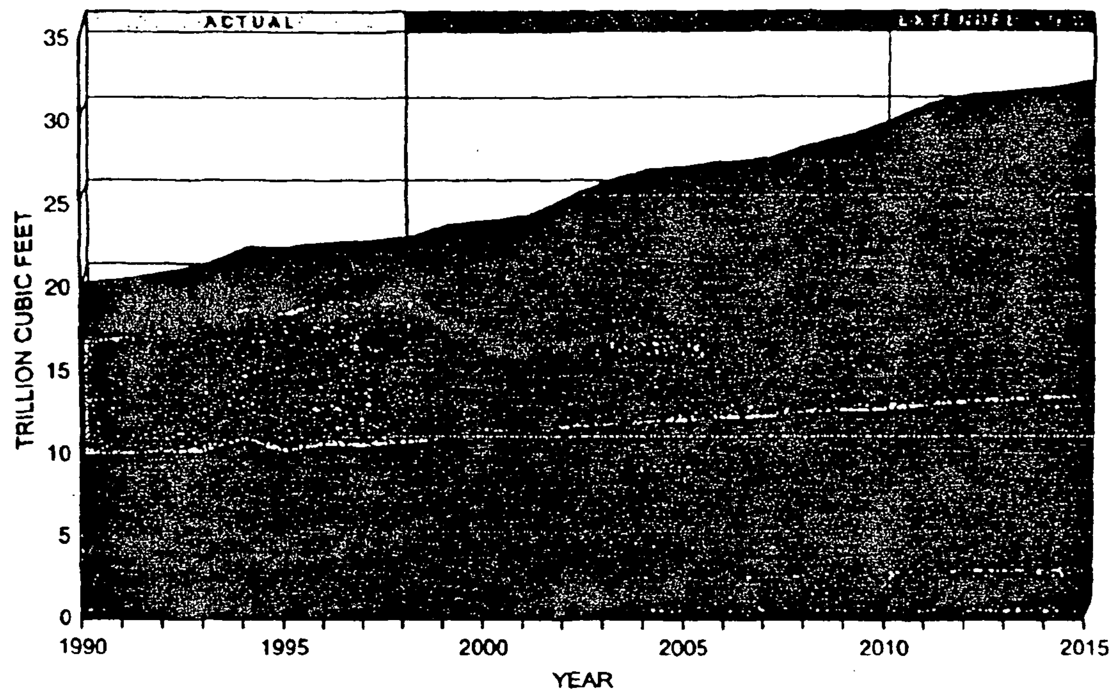
[illegible] projections

[illegible] to 29 TCF by 2010 [illegible]

[illegible] supply will be needed by 2010

Source of historical data: DOE/EIA, *Natural Gas Monthly*, September 1999.

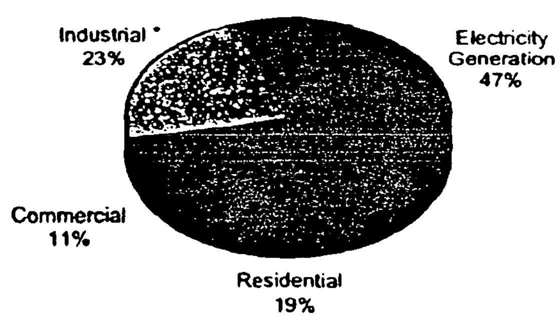
Figure 3a. U.S. Natural Gas Demand by Sector



- Demand will grow in all sectors.
- Almost 50% of demand growth will be due to electricity generation.

Figure 3b. Growth in Reference Case Demand, 1998–2010

(Distribution of 7 TCF Increase by Sector)



* *Historical data include all gas use for industrial cogeneration and independent power producers; all gas for new power plants except cogeneration is included in the electricity generation sector.*

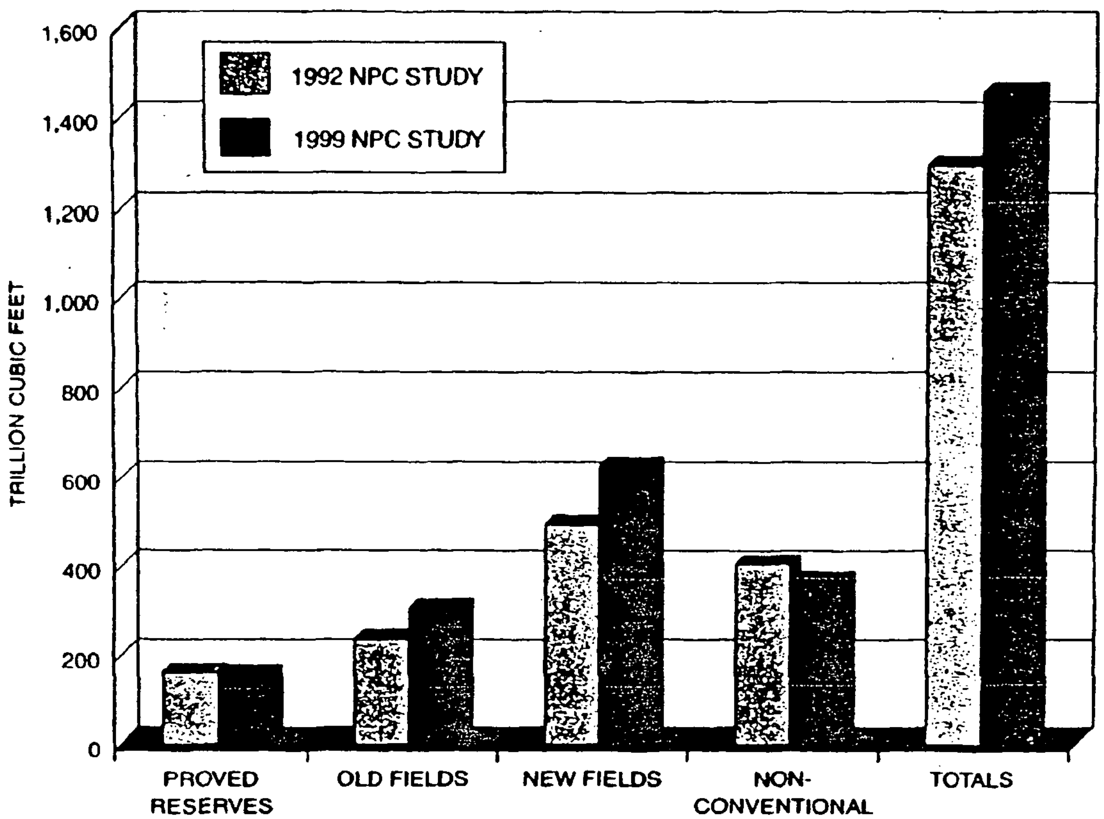
Source: DOE/EIA, *Natural Gas Monthly*, September 1999.

TCF (Figure 4). This total represents a net increase of 171 TCF over the 1,295 TCF estimated in the 1992 Study. Taking into account the 124 TCF that has been produced in the lower-48 states since then, the estimate of the resource base has increased 23% since the last study. The increase is largely due to technology breakthroughs that have opened new frontiers such as the deepwater Gulf of Mexico and have provided improved information and better tools for evaluating—and more fully recovering—resources.

U.S. gas demand will be filled with U.S. production, along with increasing volumes from Canada and a small, but growing, contribution from liquefied natural gas (LNG)

Figure 4. Lower-48 Natural Gas Resource Base Estimates

Comparison of 1992 and 1999 NPC Study Results



- Estimate of remaining resource base has grown 171 TCF to 1,466 TCF.
- Resource base estimate increased 23%, considering 124 TCF of production.
- Growth is primarily from New Fields, especially in deep water.

imports (Figure 5a). Two regions—deepwater Gulf of Mexico and the Rockies—will contribute most significantly to the new supply (Figure 5b). U.S. production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010, and could approach 27 TCF in 2015. Deeper wells, deeper water, and nonconventional sources will be key to future supply. For example, deepwater production (water depths greater than 200 meters), which in 1998 provided 0.8 TCF annually, will increase to over 4.5 TCF in 2010 (Figure 6). Onshore production from nonconventional formations is projected to increase by 50% from 4.4 TCF in 1998 to almost 7 TCF in 2010, with much of it coming from the Rocky Mountain region. By 2015, nonconventional gas production could be approaching 9 TCF. Production is likely to decrease in more traditional areas such as the Gulf of Mexico shelf and onshore Louisiana, each dropping by roughly one-third by 2015. It is important to note that approximately 14% of current natural gas supply is "associated," meaning that it is produced from oil wells. This associated gas will continue to be an important component of the overall supply, particularly in deepwater Gulf of Mexico.

Imports from Canada are projected to increase from 3 TCF in 1998 to almost 4 TCF by 2010, continuing to represent 13–14% of U.S. demand. Canada's remaining resource base is estimated at approximately 670 TCF in this study, down from 740 TCF in 1992. The decrease in the estimated Canadian resource base is due to depletion and reassessment of the nonconventional resources. Challenges similar to those confronting the U.S. industry will be faced by the Canadian producers, compounded by the fact that much of this gas is in frontier areas such as the Mackenzie Delta in far northwest Canada. Reaching this frontier will require significant capital expenditures as well as considerable lead times. Continued cooperation between the United States and Canada will be essential to ensure the timely availability of Canadian gas.

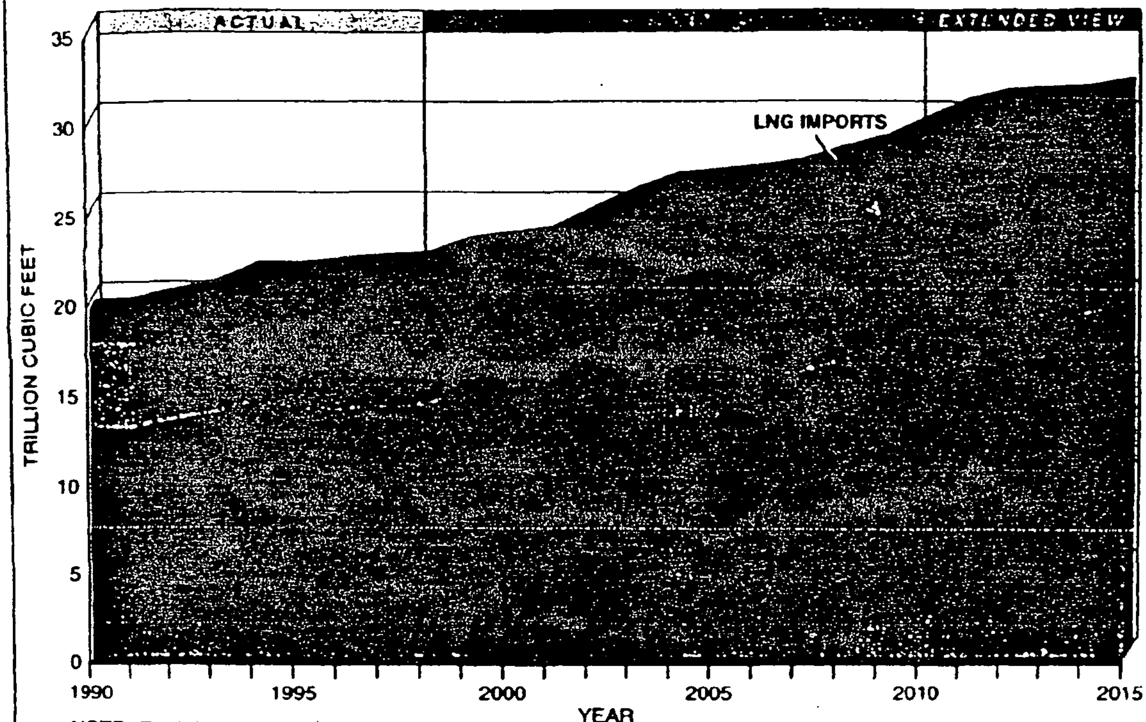
LNG imports are projected to reach a maximum of approximately 0.9 TCF, based on a 75% average capacity utilization rate for existing facilities. The assumption was made that no additional LNG import facilities would be built in the 1999–2015 period. Also, the assumption was made that exports to Mexico would reach a maximum of 0.4 TCF to serve Mexico's gas demand near the U.S. border.

The infrastructure required to deliver gas to market must be optimized and expanded to accommodate the increase in demand as well as the changing logistics of getting new supply to new customers. Future needs include new pipelines to reach supplies in the frontier regions, expansion of existing pipeline systems, new laterals to serve electricity plants, and expansion and construction of storage facilities to meet seasonal and peak-day requirements. By 2015, more than 14 million new customers will be added to the natural gas delivery system. To serve this growing market through 2015, over 38,000 miles of new transmission line are projected to be needed as well as 263,000 miles of distribution mains and almost 0.8 TCF of new working gas storage capacity.

The current delivery system (transmission, distribution, and storage) was built and optimized over decades to meet the design peak-day requirements of firm service customers that were primarily residential, commercial, and to a lesser extent, industrial customers. The anticipated growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as peak-day requirements that will increase from 111 BCF per day in 1997 to over 152 BCF per day in 2015. Meeting requirements of the electricity generators on a significantly larger scale will entail changes in operational procedures, communications, tariffs, and contracting. Further, these changes must be accomplished without degrading the historically reliable service to the residential, commercial, and industrial markets.

The Council believes that an unprecedented and cooperative effort among industry, government, and other stakeholders will be required to develop production from new and existing fields and build infrastructure at sufficient rates to meet the high level of demand indicated in this study. The ability to meet the anticipated demand hinges on addressing the following critical factors: access, technology, financial requirements, skilled workers, drilling rigs, lead times, and changes in customer requirements.

Figure 5a. U.S. Natural Gas Supply by Source



NOTE: Total does not net out exports to Mexico.

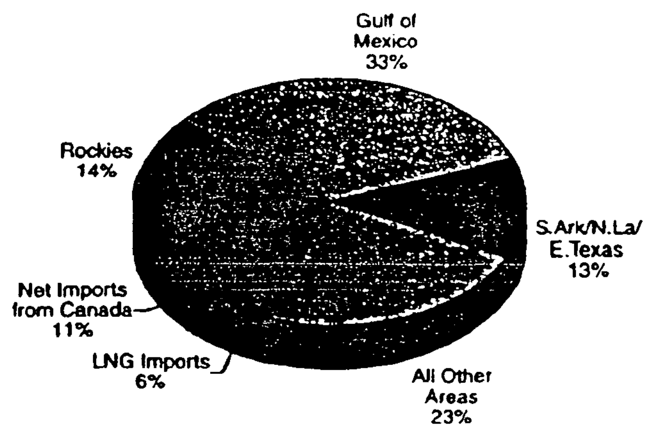
Natural gas demand will be met primarily with [illegible]

Robust growth in [illegible] production will [illegible]

[illegible] Canada will continue [illegible] an important [illegible] of supply.

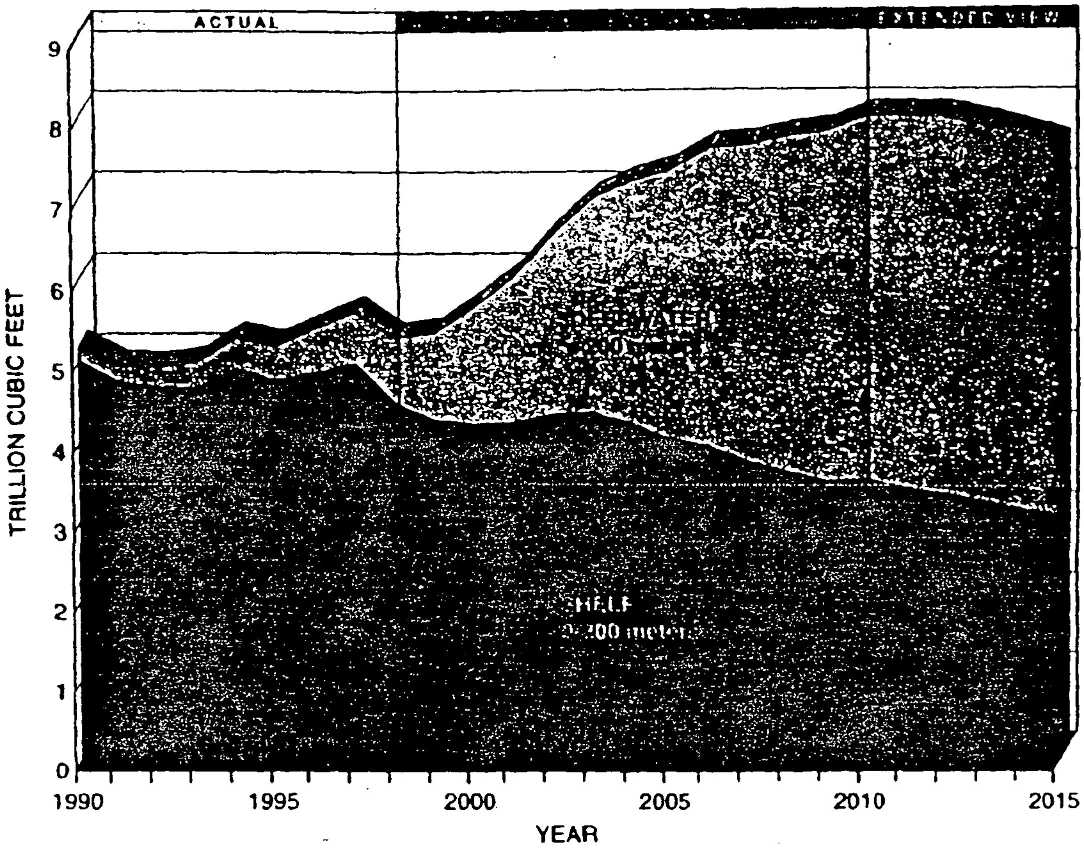
Figure 5b. Growth in Reference Case Supply, 1998–2010

(Distribution of 7 TCF Increase by Source)



Source of historical data: DOE/EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Reports,* 1990–1997.

Figure 6. U.S. Gulf of Mexico Natural Gas Production



- Gulf of Mexico production increases by 2.7 TCF by 2010.
- Deepwater production increases from less than 1 to over 4.5 TCF/year.
- Gradual decline is projected for shelf production.

Source of historical data: PI/Dwights production reports, June 1999.

Critical Factors

Access

Much of the nation's 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 (Figure 7). 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 TCF—of potential gas resource in the Rockies is on federal

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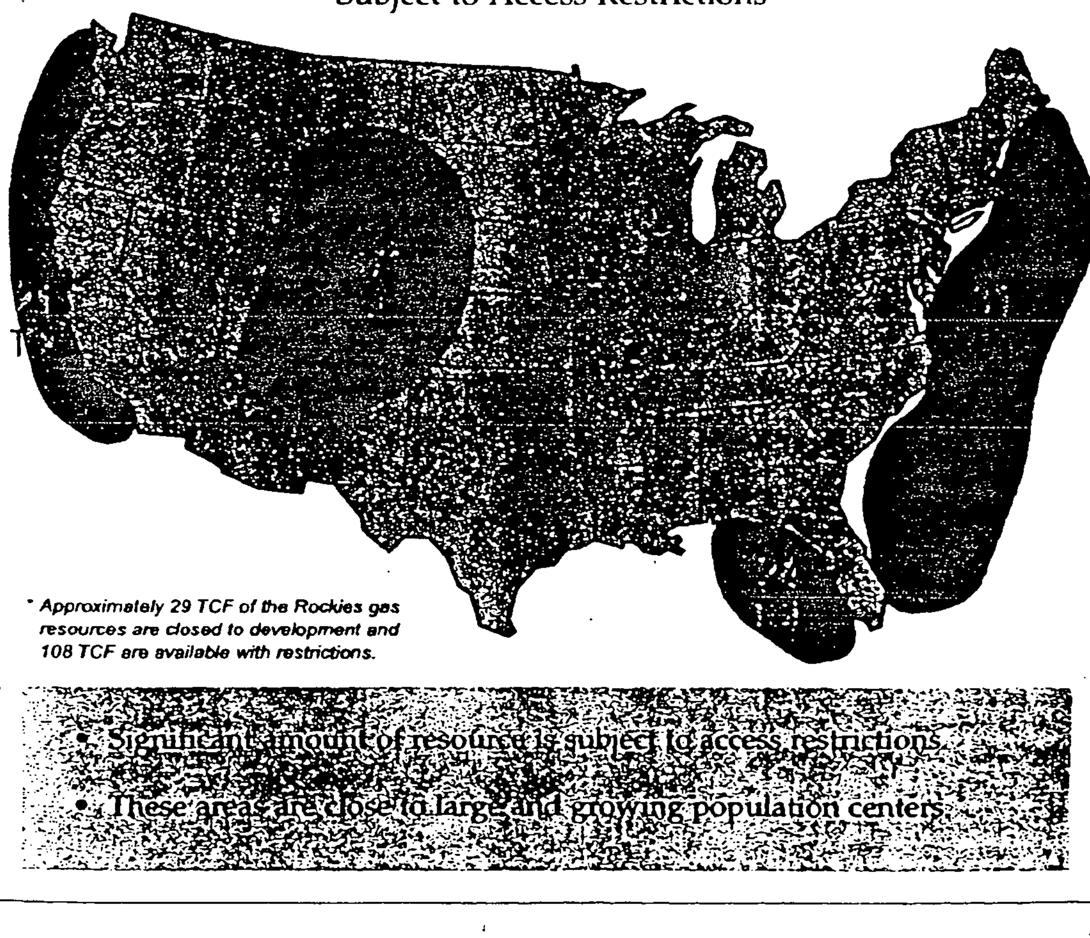
land that is either closed to exploration or is open under restrictive provisions. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. The eastern Gulf of Mexico is largely closed to exploration and the limited areas that 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 recent 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.

This study assumes that planned lease sales for areas in the Outer Continental Shelf (OCS) will continue on schedule and that further restrictions will not be applied to those lands currently open to development. These assumptions may be optimistic in light of recent statements by some public officials. Further restrictions would increase the challenge of meeting the projected gas demand with cost-competitive supply. Conversely, opening hydrocarbon-rich areas for development would greatly improve the industry's potential to respond to market needs.

Figure 7. Lower-48 Natural Gas Resources Subject to Access Restrictions



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Access is also an issue for the transmission and distribution sectors of the industry as they seek rights-of-way for pipeline facilities. The permitting and construction processes have become more complex over time. Restrictions for wetlands, wildlife refuges, and other sensitive federal and state lands impact the routing and construction of pipelines throughout the United States, not just the frontier areas. Other issues arise from the encroachment of urban development on existing rights-of-way, heightened community awareness of and resistance to pipeline construction, and increasingly restrictive government policies and regulations. Resolution of these issues—which must be addressed for each pipeline addition—is costly and time-consuming and often results in project delays or abandonment of projects.

Most of the access restrictions are due to environmental concerns or multiple-use conflicts even though industry has made tremendous improvements in reducing the "footprint" of exploration, production, and transportation activities, and in maintaining clean, safe operations. As stated in a recent Department of Energy report, "Resources underlying arctic regions, coastal and deep offshore waters, sensitive wetlands and wildlife habitats, public lands, and even cities and airports can now be contacted and produced without disrupting surface features above them."[1] An excellent example of the dramatic improvements in environmental footprints can be found in Alaska where significant efforts have been made to minimize the impact of drilling operations on the tundra. A report to the Secretary of the Interior in 1997 by the Alaska Oil and Gas Association stated that in the 1970s, pads for drilling operations took up about 65 acres whereas the pads for recent operations are now less than 10 acres. The report further explained that cluster drilling and extended reach drilling enable producers to access hydrocarbon deposits 3–4 miles away from the pad, thus greatly reducing the number of drilling locations and associated roads and pipelines. Lateral extensions of 18,000 feet are common on the Alaskan North Slope today. More recent efforts in other parts of the world have extended the drilling reach to 5–6 miles. This has the same effect as setting up drilling operations on the White House lawn and extracting hydrocarbons from beneath most of Washington, D.C., and into its suburbs (Figure 8).

Equally impressive improvements in environmental impacts have been demonstrated offshore, where much of the natural gas production is associated with oil production. As reported to President Clinton by the Cabinet in *Turning to the Sea: America's Ocean Future* (September 1999), "Advances in technology have made offshore oil and gas production cleaner and safer than ever. Since 1980, 6.9 billion barrels of Outer Continental Shelf oil have been produced with a spillage rate of less than 0.001%. Despite these advances, however, environmental concerns have led to congressional and executive moratoria since 1981, and many of our coastal areas are now closed to new leasing through the year 2012."

This study has determined that access issues, and associated environmental concerns, must be addressed. Access to some portion of the federal gas resource base currently closed or significantly restricted to appraisal or development, as well as acquisition of rights-of-way, is essential to meeting the projected demand with cost-competitive gas supply.

Technology

Even though the estimated resource base is adequate to last many decades, technological challenges and the degree of difficulty in reaching, evaluating, and producing the resource base continue to escalate. The previously referenced report by the Office of Fossil Energy of the U.S. Department of Energy[2] highlights the importance of research and development to the oil and gas industry:

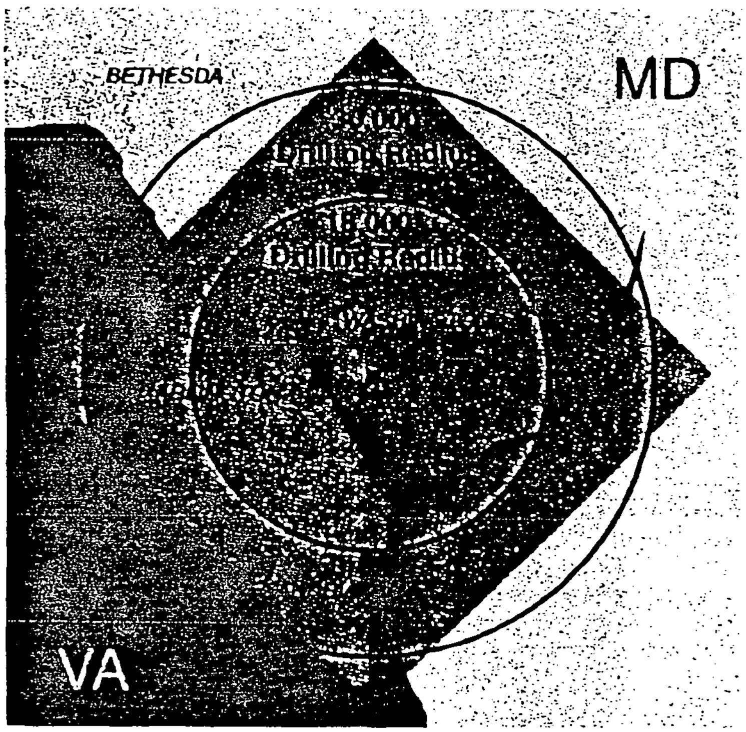
> In the past three decades, the petroleum business has transformed itself into a high-technology industry. Dramatic advances in technology for exploration, drilling and completion, production, and

[1] U.S. Department of Energy, Office of Fossil Energy, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*, October 1999, pg. 13.

[2] Ibid, p.1.

site restoration have enabled the industry to keep up with the ever-increasing demand for reliable supplies of oil and natural gas at reasonable prices. The productivity gains and cost reductions attributable to these advances have been widely described and broadly recognized... Looking forward, the domestic oil and gas industry will be challenged to continue extending the frontiers of technology. Ongoing advances in E&P productivity are essential if producers are to keep pace with steadily growing demand for oil and gas, both in the United States and worldwide. Continuing innovation will also be needed to sustain the industry's leadership in the intensely competitive international arena, and to retain high-paying oil and gas industry jobs at home. Progressively cleaner, less intrusive, and more efficient technology will be instrumental in enhancing environmental protection in the future.

Figure 8. Reducing Environmental Impact with Extended-Reach Drilling



- Improvements in extended-reach drilling allow access to resources [illegible] from the drilling site
- Similar technologies for minimizing environmental impact continue to be developed.

Technology improvements are particularly important given the more difficult conditions accompanying new resources. Deeper wells encounter extreme temperatures and pressures and increased potential for intensely corrosive environments. These conditions require high-strength materials and advanced drilling methods. Current deepwater endeavors involve exploration wells in over 8,000 feet of water and complex production projects in more than 5,000 feet of water. Subsea pipelines must be built to withstand powerful currents, shifting ocean floors and external pressures that are greater than those inside the pipe. Innovative design, fabrication, and installation techniques must emerge to enable these new resources to reach existing markets at attractive prices.

Technology improvements are also needed for expanding and managing the delivery system and improving efficiency at the burnertip. The increased challenges of serving a growing market and changing load must not jeopardize the historical reliability and favorable economics of the transmission and distribution system. Pipelines and LDCs will continue to rely on technology for reducing operation and maintenance expenses and minimizing environmental impacts of facilities construction. Information and communications technology will play an ever-increasing role in safe and efficient operations as well as in supply management and customer service enhancements.

Technology advances are essential in all industry segments for improving operational efficiencies, reducing resource development time, increasing production, developing frontier areas, controlling costs, and minimizing environmental impact. This study assumes that technology improvements will continue at an aggressive pace. However, recent industry trends in research and development spending have raised concerns regarding this assumption. Industry restructuring, consolidations, and spending cuts have resulted in reductions in research budgets. Producers are turning to the service sectors to develop new technology for specific applications. Industry consortia have been formed to address critical technology challenges such as deepwater development. While many of these changes improve the efficiency with which research and development dollars are spent, concerns have been widely expressed that basic and long-term research are not being adequately addressed.

Financial Requirements

Adequate financial performance must be demonstrated in order to compete for and attract the investments required to meet the growing demand. Companies will need to balance short-term performance demands with long-term planning to achieve the needed growth. Almost $1.5 trillion ($1998) will be required to fund the industry through 2015. This amount includes over $700 billion for operating expenses and an estimated $781 billion for capital investments. Approximately $658 billion of capital is projected to be spent for oil and gas supply development and about $123 billion for transmission, storage, and distribution infrastructure expansion (Figure 9). This equates to an average annual increase in capital expenditures from $34 billion per year between 1990 and 1998 to $46 billion between 1999 and 2015. Many of these expenditures will involve higher risk projects—such as large deepwater projects or pipelines to new frontiers—each of which can easily exceed $1 billion.

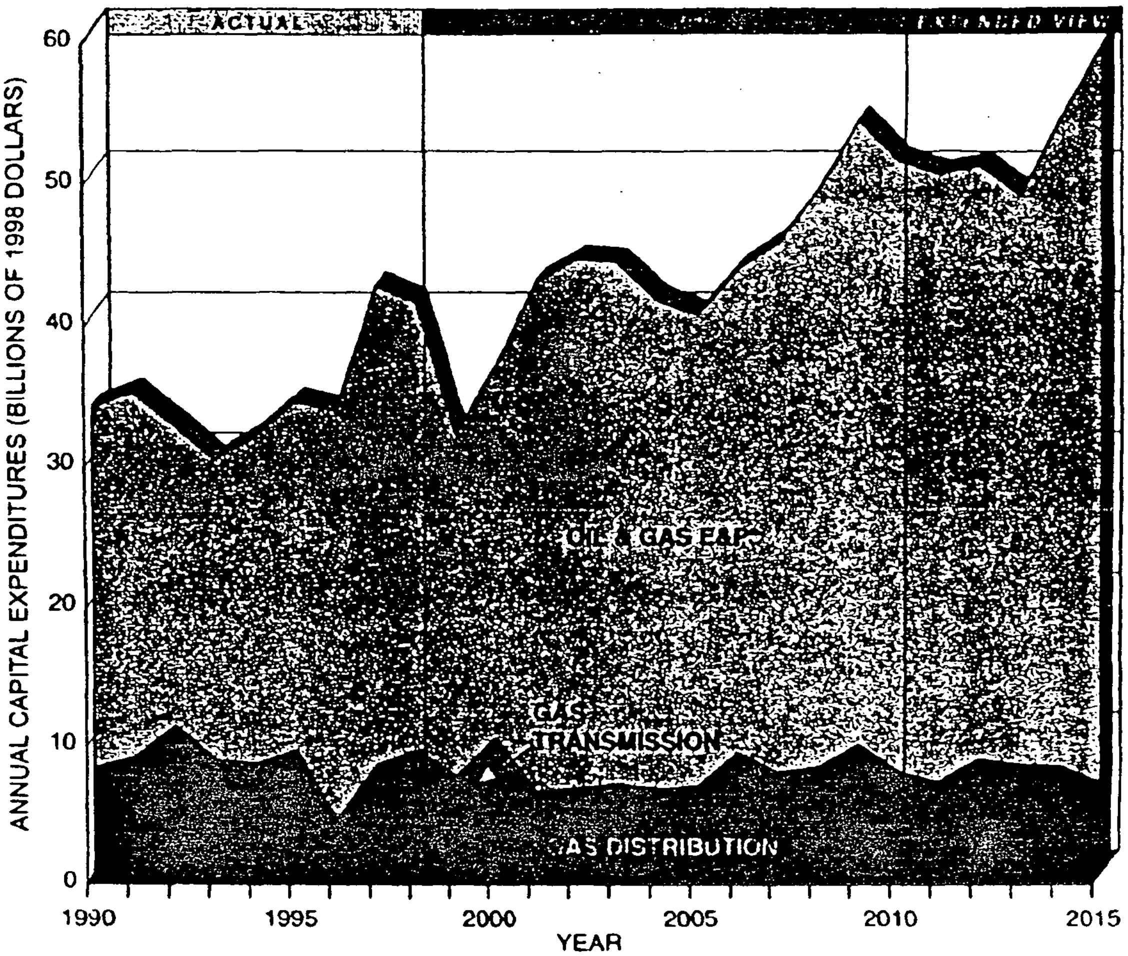
While much of the required capital will come from reinvested cash flow, capital from outside the industry is essential to continued growth. To achieve this level of capital investment, industry must be able to compete with other investment opportunities. This poses a challenge to all sectors of the industry, many of which have historically delivered returns lower than the average reported for Standard and Poors 500 companies.

The transmission and distribution sectors of the industry also face challenges in attracting investments to future projects. Expanding the infrastructure of the delivery system to accommodate increased demand and changing requirements of new customers will involve changes in financial risks. For example, expiring long-term LDC contracts for pipeline capacity, which historically provided the financial backing for pipeline expansions, will be replaced by shorter term contracts with new non-utility customers. Uncertainty exists with future rate structures and obligations to serve, as electricity and gas restructuring continues. Industry participants and regulators must work together to find an appropriate balance for these risks so that the needed infrastructure expansions can be accomplished.

Skilled Workers

A significant concern of the industry is the future availability of skilled workers at all levels to produce the increased supply and construct the necessary infrastructure. Company consolidations and volatile fluctuations in oil prices have resulted in cuts in exploration and production budgets, leading to layoffs at all levels in exploration and pro-

Figure 9. Capital Required for Expansion



* *Because "associated" natural gas is produced with oil, expenditures for oil and gas have not been separated.*

- Substantial increase in capital expenditures will be required.
- Total capital expenditures for 1999–2015 will be $785 billion.

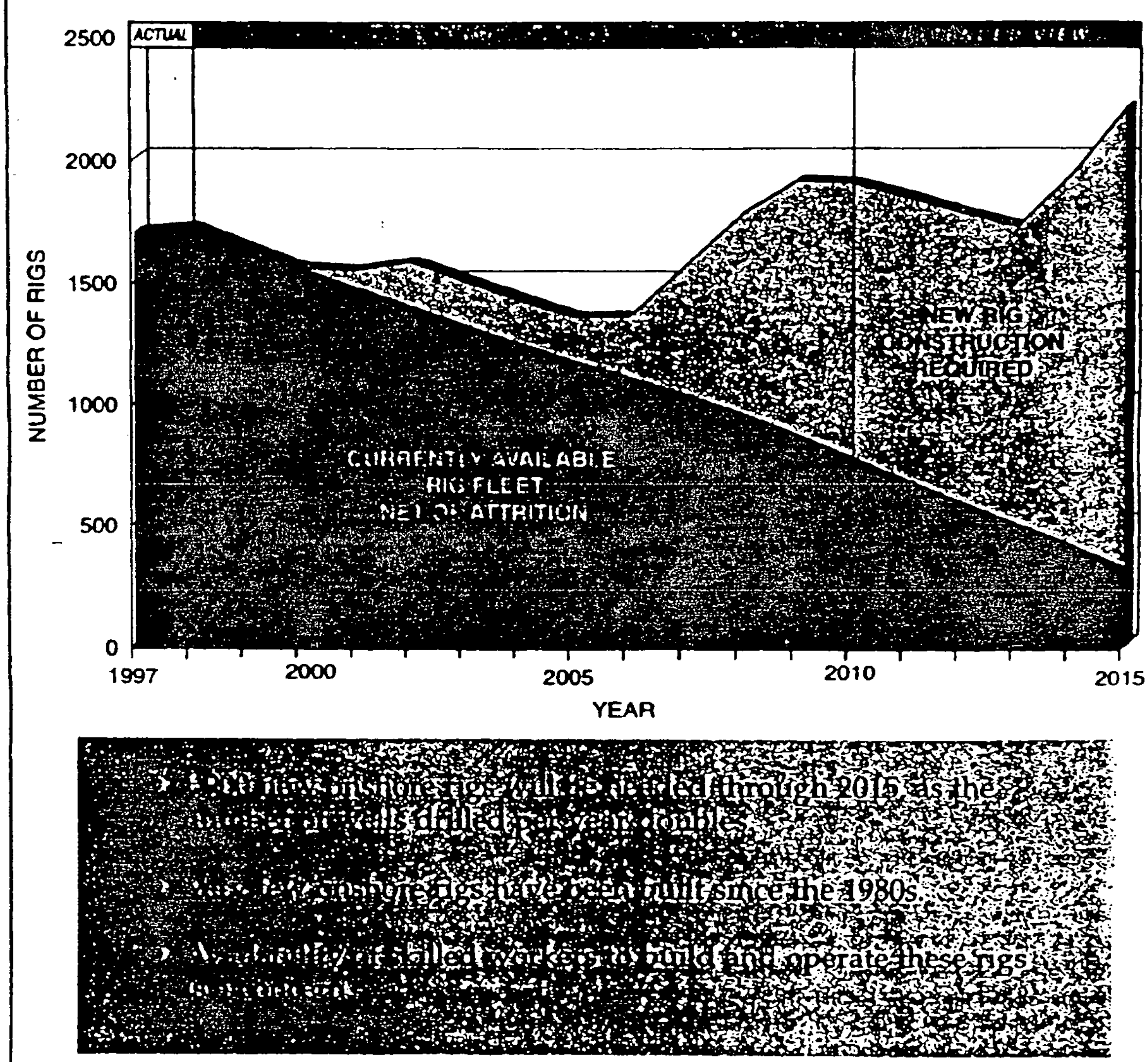
Source of historical data: American Gas Association, *1998 Gas Facts;* and estimates from EEA, Inc.

duction companies and in service/supply companies. Approximately 500,000 jobs have been eliminated from the industry since the early 1980s, with over 40,000 job cuts occurring in the producing sector alone in the past year. Simultaneous reduction in industry hiring rates in the last 20 years has resulted in a disproportionate percentage of the workforce reaching retirement age in the next decade—an average of 40% in a sampling of major producers. Furthermore, the next generation of workers is not choosing to enter the industry, as indicated by the significant decrease in enrollment in some energy-related college curricula since the mid-1980s. The oilfield service/supply sector faces a similar situation as many laborers and supervisory personnel have left the industry in search of more stable work. Higher wage scales are likely to be required to attract workers back into the industry.

Drilling Rigs

The U.S. drilling fleet must expand to undertake the dramatic increase in activity that will be required over the next decade to produce the additional supply. The total number of oil and gas wells drilled per year (including dry holes) will have to double, from approximately 24,000 in 1998 to over 48,000 by 2015. Even taking into account anticipated improvements in drilling efficiencies, approximately 2,300 active rigs (over 2,100 land rigs and 180 offshore) would be needed to achieve this level of drilling. This

Figure 10. Onshore Drilling Rig Fleet



Source of historical data: "Reed Rig Census," 1997–1998 (published in *World Oil*); and estimates from EEA, Inc.

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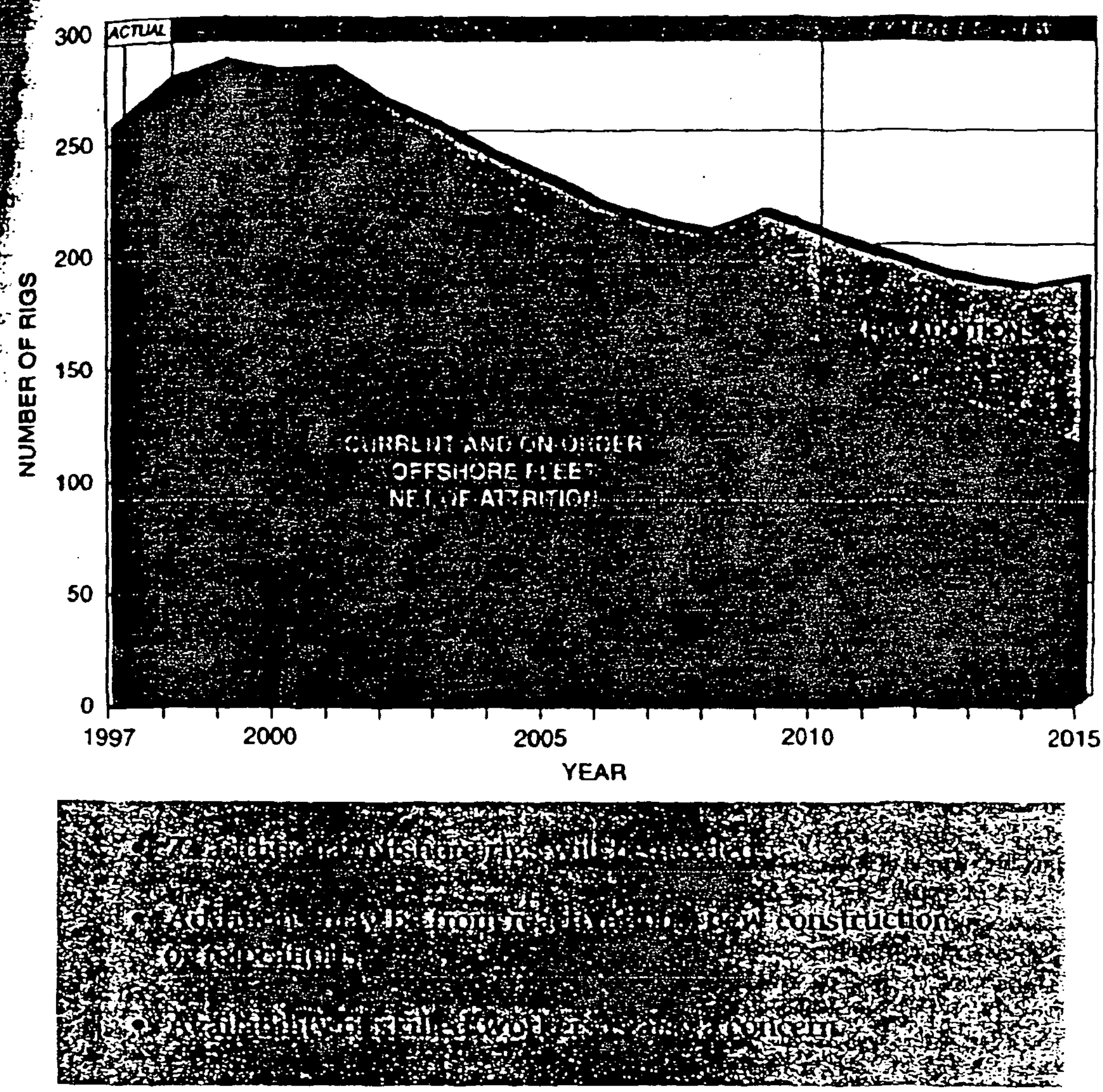
Figure 11. Offshore Drilling Rig Fleet



Source of historical data: Offshore Data Services, *Rig Locator*, September 24, 1999.

represents an 80% increase over the 1,250 average active rig count estimated for 1999.

Rig availability, which is crucial to exploration and development, will be a challenge for the industry. The oilfield supply and service sectors have been hit particularly hard by the boom and bust cycles. Very few new onshore drilling rigs have been built since the mid-1980s. If the 5% per year historical attrition rate were to continue, most of the existing 1,700 onshore rigs would be retired by 2015 and a total of almost 1,900 onshore rigs would have to be built (Figure 10). Additions to the offshore rig fleet will also be needed and are projected to include 10 deepwater drilling rigs, 32 platform rigs, and 30 jack-up rigs and barges (Figure 11). Although the number of new offshore rigs is smaller, the average cost per rig is significantly higher than that of onshore rigs. The drilling sector and the manufacturers of drilling equipment are not currently positioned to undertake this level of expansion.

Lead Times

Reduction of development lead times—from lease acquisition and prospect identification, to the beginning of exploration, to pipeline construction for delivery to the burner tip—is critical to meeting the gas demand projected in this study. For example, as many as 10 years—or two-thirds of the time period of this study—may elapse between the time a block in the offshore is leased until production flows to market. Industry and government are working diligently to reduce development time by streamlining processes and applying new technology. However, access limitations and cumbersome permitting and approval processes often negate those improvements. For example, increases in time required to perform studies previously conducted by government agencies, and obtain multi-agency permits have resulted in production project delays of up to two years on federal lands in the Rocky Mountain region. While the MMS has improved the approval process for offshore development by serving as the facilitator for the process, production and pipeline projects on land still require extensive interactions with multiple levels and agencies of federal, state, and local governments. For example, the recently constructed Portland Natural Gas Transmission System involved the acquisition of over 150 permits and/or approvals from federal, state, and municipal government agencies. Most of the agencies involved in these processes have different data requirements, forms, and processes. Additional improvements are needed immediately in order to impact the development in the outer years of this study.

Changing Customer Needs

The ongoing regulatory restructuring of the natural gas and electricity markets changes the roles and responsibilities of all industry participants. As restructuring continues to unfold at the state level, the roles and obligations of LDCs and electric utilities will be changing. Other energy market participants may accept some aspects of the former roles of the LDCs and electric utilities as services are unbundled. These other participants, such as producers, generators, marketers, energy service providers, and end-users will contract for and use capacity differently than the LDCs and traditional electric utilities. In addition, new flexible services will be required to meet the anticipated increase in gas demand for electricity generation as projected in this study. For example, natural gas-fueled turbines (simple and combined cycle) have unique operating requirements in terms of inlet pressures and operations. Since electricity cannot be stored, the electricity generation systems must be constantly monitored and adjusted to change output instantaneously as electricity demand changes. Thus corresponding changes in natural gas demand occur constantly throughout the day. These changes in roles, services, and customer requirements will cause all sectors of both the natural gas and electricity industries to manage their assets differently.

Sensitivity Analyses

As discussed earlier in this report, sensitivity analyses provided some important information regarding the importance of the critical factors (see Figure 12a). Demand, for example, can increase by 0.6 TCF in 2010 if gross domestic product (GDP) grows by 3.0% annually instead of 2.5%. Conversely, GDP growth of 2.0% could result in a decrease in demand of 0.9 TCF by 2010. If crude oil price averaged $22.00 rather than $18.50 as assumed in the Reference Case, demand could increase by 0.7 TCF in 2010. However, demand would be 1.0 TCF lower if crude oil price averaged $15.00.

The model's output on price also served as a gauge for quantifying the impact of certain assumptions (Figures 12b and 13). While the model projects an average production weighted U.S. wellhead gas price through 2010 of approximately $2.74 per million British thermal units (MMBtu), prices in the sensitivity analyses change significantly. For example, the model projects that gas prices could be as much as $0.32 per MMBtu lower in 2010 if technology improvements are significantly better than assumed in the Reference

Figure 12a. Influence of Key Assumptions on Natural Gas Demand

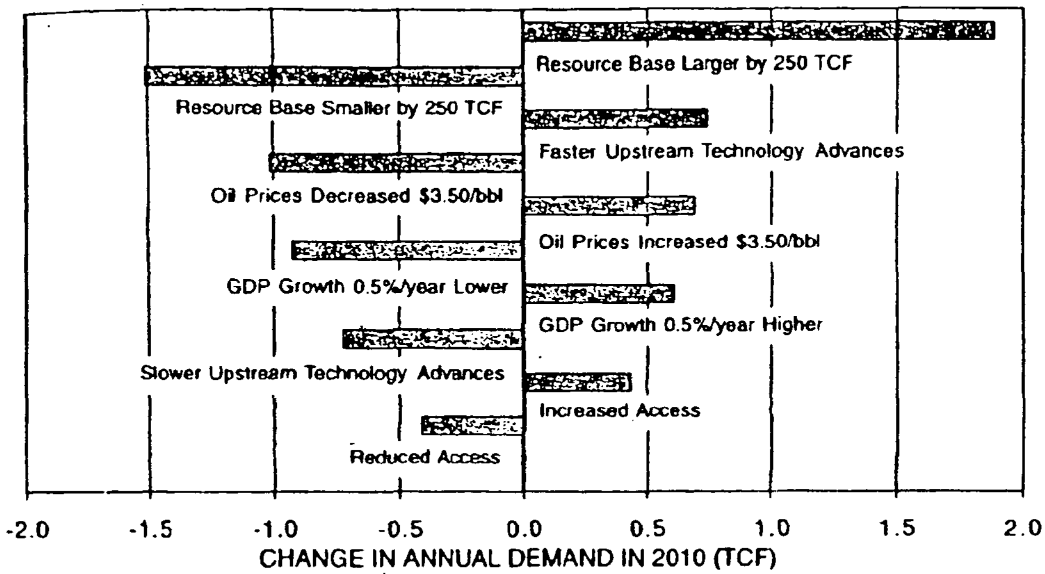
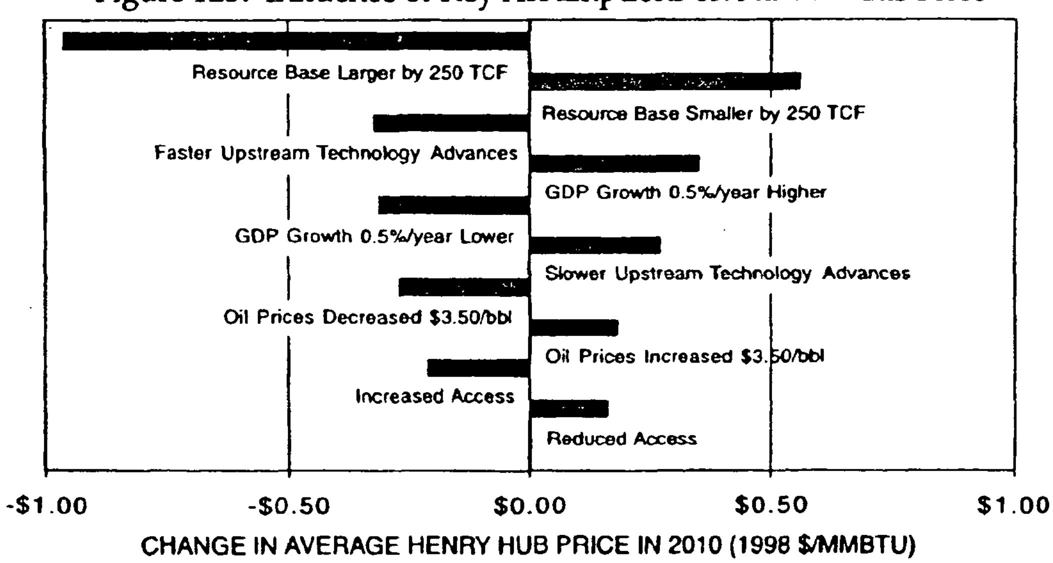


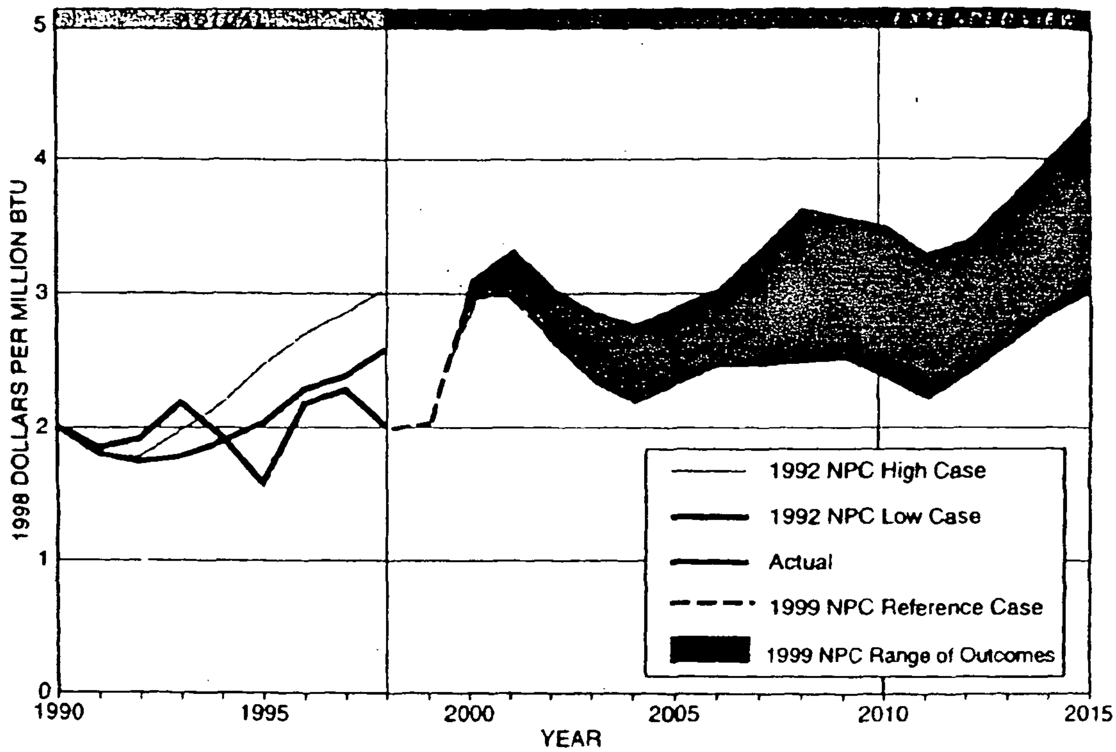
Figure 12b. Influence of Key Assumptions on Natural Gas Price



- A 15-20% change in the resource base has substantial impact on projected price and demand.
- Pace of technological advancement also has significant influence on projected price and demand.

NOTE: See Figures 14a and 14b for more details on resource base and access cases.

Figure 13. Historical and Projected U.S. Natural Gas Prices*
Lower-48 Weighted Average Wellhead Price



* *Prices are NOT intended to be a forecast. Seasonal factors such as abnormal weather and demand fluctuation have not been taken into account.*

- Actual price for [illegible] averaged [illegible] versus 1992 study projections of [illegible]
- Price volatility will likely continue.
- Sensitivity analyses demonstrate the range of outcomes for key assumptions.
- The market will ultimately determine the price of natural gas.

Source: DOE/EIA, *Monthly Energy Review*, September 1999.

Case. Conversely, a slower pace of technology improvements could drive the price up by $0.27 per MMBtu.

The single most significant assumption in the Reference Case is the size of the resource base. The model projects that the price of gas could be lowered by as much as $0.96 per MMBtu in 2010 if the economically recoverable resource base were found to be 250 TCF larger than assumed in the Reference Case. In this case, demand increases by 1.9 TCF and U.S. production increases by 1.5 TCF. A second sensitivity was run to examine the impact of a smaller resource base, although it should be noted that the resource base estimates have always increased over time. If estimates of the resource base are lowered by 250 TCF, prices could be as much as $0.56 per MMBtu higher, demand would be 1.5 TCF lower, and U.S. production would be 1.6 TCF lower. While this sensitivity was run to evaluate the impact of learning more about the resource base, it also provides some insight to the impact of access restrictions. Access is an important factor because it removes potential supply from the available resource base. Access restrictions also limit the opportunity to better assess the resource size in those areas.

To better quantify the impact of access restrictions, two additional sensitivity cases were developed. The first case tightened access restrictions in the Rocky Mountain region and eliminated the planned MMS Lease Sale 181. In this reduced access case, price increased $0.16 per MMBtu in 2010 and demand decreased by 0.4 TCF. U.S. production decreased by 0.5 TCF. The second sensitivity case relaxed access restrictions in the Rockies and made currently restricted offshore regions available for leasing in 2004. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, an increase in demand of 0.4 TCF and a corresponding decrease in price of $0.21 per MMBtu. More importantly, a dramatic shift occurred in the Extended View period of the increased access case with an increase in demand of 1.5 TCF in 2015, a corresponding increase in U.S. production of 1.6 TCF (primarily from the Rockies and the eastern Gulf of Mexico), and a corresponding decrease in price of $0.45 per MMBtu (Figures 14a and 14b).

The most important conclusion derived from these sensitivity analyses is that the future availability and cost of natural gas can be influenced. While some variables cannot be controlled, factors such as the rate of technology development, knowledge of the resource base, and access to the resource base can be impacted—either positively or negatively—by the actions of the industry and the government.

The Council wishes to emphasize that the price output of the model is not to be used as a forecast, but rather as an indicator of the relative influence of the critical factors and assumptions. Seasonal factors that affect price, such as abnormal weather and demand fluctuations, have not been taken into account. The market will ultimately determine the price of natural gas. However, actions can be taken by industry and government to ensure that adequate supply is available, that it can be delivered to the market, and that the ultimate price is competitive through the study period and beyond.

In summary, affordable energy is necessary to sustain continued growth of the nation's economy and quality of life. Natural gas will play an important role, particularly as it helps the nation meet its environmental goals. By 2015, more than 14 million new customers will be connected to natural gas supply through over 300,000 miles of new transmission pipelines and distribution mains. Many more customers will use electricity that is fueled by natural gas as over 140 gigawatts of new electricity generation capacity—almost entirely gas-burning units—go into service. These new customers, as well as the existing customer base, are counting on long-term availability of reliable, competitively priced natural gas to meet their energy needs and to support the nation's environmental goals. Industry, government, and other stakeholders must act quickly, cooperatively, and purposefully to meet those expectations.

Figure 14a. Impact of Size of Resource Base and Access on U.S. Natural Gas Production

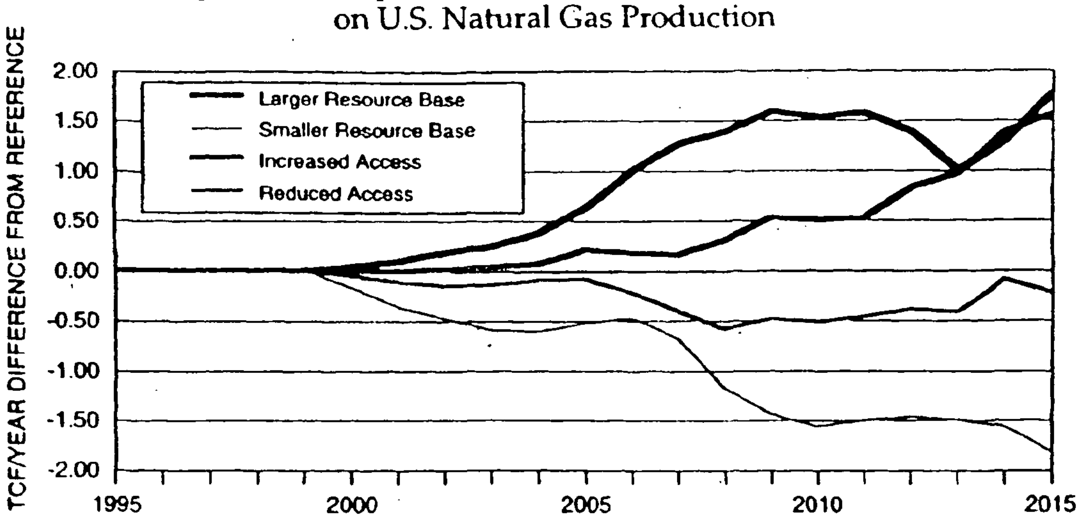
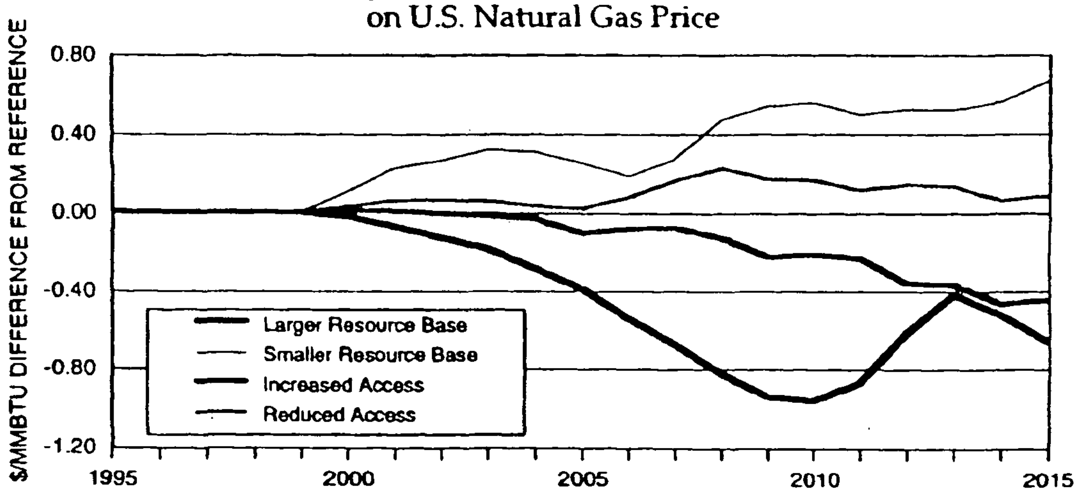
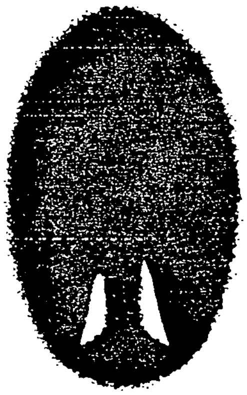


Figure 14b. Impact of Size of Resource Base and Access on U.S. Natural Gas Price



- Larger resource base would increase U.S. natural gas production [illegible] TCF in 2015 and decrease price [illegible]
- Smaller resource base would decrease U.S. natural gas production [illegible] TCF and increase price [illegible]
- Increased access would increase U.S. natural gas production 1.5 TCF in 2015 and decrease price [illegible]
- Reduced access would decrease U.S. natural gas production [illegible] TCF in 2015 and increase price [illegible]



Recommendations

The Council wishes to emphasize that gas supply, and the associated infrastructure, can be expanded to meet growing demand if the critical factors are adequately addressed. The following recommendations are made by the Council to ensure that the mutual goals of government, industry, and consumers are met. While recommendations are made to the government for specific actions, the Council does not advocate regulations or legislation that artificially alter market signals. Instead, the Council encourages changes that remove impediments which hinder the development of supply and infrastructure to meet market needs.

Recommendation 1:
Government and industry must take a leadership position in establishing—at the highest level—a strategy for natural gas in the nation's energy portfolio. An Interagency Work Group on Natural Gas should be established to work with industry and other stakeholders to formulate the strategy and resolve issues.

The government can help to overcome the barriers to meeting future natural gas demand by establishing a national strategy for natural gas. This strategy should include the areas of supply, demand, and transmission/distribution and should address the issues of access to the resource base, technology development, environmental regulation, education of the future workforce, and financial incentives. It should also affirm and describe the role of natural gas in balancing the national objectives of economic growth, environmental protection, and energy security. The strategy must provide a proper balance between conflicting environmental and land-use interests, yet reflect a sense of urgency about developing natural gas supply and the delivery infrastructure given the long lead times required.

The Council recommends that an Interagency Work Group on Natural Gas be established within the National Economic Council to formulate this comprehensive natural gas strategy and identify and aggressively resolve the issues associated with the development of natural gas supply and supporting delivery systems. This Interagency Work Group should be analogous to, but distinct from, the Interagency Working Group on Energy that has been set up under the National Economic Council to address oil industry issues. This new Work Group should oversee the implementation of government-related recommendations contained in this report. It should also monitor, on a biennial basis, trends for the assumptions used in this study and progress on the identified critical factors in order to anticipate changes in the supply/demand equation.

All federal agencies that have a role in natural gas policy, technology, and resource assessments should be members. The Work Group should make every effort to include input from industry and other stakeholder groups, including states with natural gas production or potential for production, in its strategy-setting process. This solicitation of stakeholder views should be as interactive as possible.

The industry must also step up to the leadership challenge and work with government and other stakeholders to identify and understand their issues associated with developing supply and delivery systems and to seek practical solutions. Industry must work with customers to understand future supply and delivery needs and work with government to shape appropriate strategy and policies so that the required services can be provided in the most cost-effective manner while ensuring safety and reliability. Industry councils and trade associations can play an integral role in this effort.

Recommendation 2:
Establish a balanced, long-term approach for responsibly developing the nation's natural gas resource base.

As seen in the analysis of critical factors in this report, the estimated size of the resource base is the single most important factor in projecting availability of competitively priced natural gas. While the ultimate size of the resource base cannot be changed and cannot be precisely known, industry can continue to improve its knowledge of the size and characteristics of the resource base, thus improving the likelihood of locating and producing new supply. However, access to a significant portion of this resource base for either assessment or development is subject to restrictions due to environmental and land-use concerns. These concerns are appropriate for consideration in granting access to potential supply areas, but significant improvements in the industry's environmental footprints warrant a new look at these restrictions.

Given the compelling need for developing economic natural gas supply, the following actions are recommended:

- *Government agencies and industry representatives should continue the work begun with this study to inventory existing information on the resource base in the Rocky Mountain region and analyze the impact of access restrictions.* A significant portion of work associated with this study included a first-time assessment of resource impacts associated with land access restrictions and related environmental stipulations in six areas in the Rockies. The results were then extrapolated to the entire region. This involved a cooperative effort between members of the Supply Task Group and representatives from the federal government, including the U.S. Department of Energy, the Bureau of Land Management, and the U.S. Forest Service. Representatives from state and local governments, as well as other stakeholders, also participated. This analysis, and the cooperative approach, should be continued and expanded beyond this study to increase understanding of the impact of access restrictions in the Rockies.
- *Industry should work with the government to prioritize restricted areas on the basis of resource potential as well as environmental sensitivity.* Certain restricted areas should be more fully assessed to determine the potential for gas supply. Those with higher potential and lower sensitivity should be opened for additional geological assessment. Industry should work with the government to identify methods and technologies that could be practically applied to minimize the environmental impact of the assessment.
- *A comprehensive approach should then be established for developing gas supply in selected restricted areas.* Existing moratoria should be reviewed and modified as appropriate. Industry should continue to develop practical techniques that minimize environmental impact, particularly for these sensitive areas. Once a long-term development plan is in place, the affected agencies should work together to coordinate their roles in assisting that development. A template for long-term planning

and coordination among multiple agencies can be found in the MMS and their management of the offshore region.

- *Long-term sustainability of natural gas supply should be addressed.* The current study finds that, with focused effort, the gas demand through 2015 and well beyond can be met with sustainable gas supplies from U.S. and Canadian resources. The life of the resource base can be further extended by encouraging efficiency at the burner tip. However, the Council also recognizes that at some point in the future—though probably not within the timeframe contemplated by this report—the United States will need to develop resources in what are now regarded as far frontiers. Such sources might include Alaska, large-scale LNG imports from a variety of foreign sources, and possibly gas transported by pipeline from the Caribbean and Latin America.

  Gas hydrates—frozen crystals of methane and water found both below the ocean floor and in Arctic regions—could also be a potential source of natural gas. In *Turning to the Sea: America's Ocean Future* (September 1999), the Secretaries of Commerce and Navy recommend the acceleration of scientific research on ocean hydrates. In addition, the Department of Energy's Office of Fossil Energy issued a document, *A Strategy for Methane Hydrates Research & Development* (August 1998), that provides for a comprehensive national research program that includes both marine and Arctic hydrate resources.

  Projects to reach the far frontiers will be very expensive and will have extremely long lead times. At some point during the study period, government and industry must begin a cooperative, public planning process to lay the groundwork for far frontier projects.

The recommended Interagency Work Group could play a very important role in addressing access issues and the long-term sustainability of natural gas supply. The Work Group should be assigned the following responsibilities:

- Establish a set of principles that would guide federal land management policy. These principles should balance the national goals of economic growth, environmental protection, and energy security and should recognize the unique role of natural gas in meeting national objectives in the areas of clean air, climate change, electricity industry deregulation, and domestic energy supply. The guiding principles should also emphasize the need for multiple use of public land. Recognizing that it is the primary responsibility of the Secretaries of the Interior and Agriculture to establish land management policies within their jurisdictions, the guiding principles should help put those policies and priorities in a national policy context with respect to natural gas. The principles should be used by the appropriate land management and regulatory agencies to establish policies that promote domestic production of natural gas in order to meet national goals.

- Address the barriers that restrict access to natural gas resources in the Outer Continental Shelf and on onshore federal lands, particularly in the Rocky Mountain region where the majority of the onshore public gas resource is found. The goal of this effort should be to maximize the amount of economic natural gas resource available for development (consistent with effective environmental protection), reduce delays in natural gas exploration, production, and transportation, and improve consistency among federal and state agencies. The Work Group should oversee the continuing effort to inventory the impact of access restrictions on natural gas resources as discussed above. It should also evaluate the process by which access to the natural gas resource base and pipeline rights-of-way has been restricted in the past and may be further restricted in the future. The Work Group should look at the following categories of barriers:

  — Land withdrawals that put natural gas resources off limits

  — Regulatory and policy decisions that make natural gas resources effectively off limits or impractical to recover, such as:

    - "no surface occupancy" designations

- use of stipulations more restrictive than needed to protect environmental resources

- old access restrictions that don't account for the effect of technology improvements that might allow development of natural gas in environmentally sensitive areas

- air quality issues that threaten to delay or limit natural gas exploration and production.

— Decisions and applications of regulations and policies that increase the cost of or impose unnecessary delays in natural gas recovery and transportation, such as:

- "combined hydrocarbon" leasing that imposes unnecessary costs on producers

- a cumbersome Coastal Zone Management process that imposes delays on OCS leasing.

Recommendation 3: Drive research and technology development at a rapid rate.

Technology is another highly critical factor affecting both supply availability and price. Accelerating the development of technology is in the best interests of all stakeholders. The following industry and government actions are recommended:

- *Industry participants must aggressively build on past successes in advancing technologies by investing in research and supporting additional industry consortia.* Transmission and distribution companies should continue to invest in improving the efficiency of the delivery systems. All industry segments should explore additional applications that advanced information and communication technology can provide. Industry must continue to fund basic research, both independently and through grants to universities. Industry must also continue to invest in the development of technologies that reduce the environmental impact of exploration, production, and construction of infrastructure. Industry and consumers should continue to develop more efficient gas consumption equipment, thereby improving energy efficiency and yielding lower costs to consumers.

- *The government should continue investing in research and development through collaborations with industry, state organizations, national laboratories, and universities.* Efforts should be made to define key research and development priorities to support increased reserve growth in existing fields and new field discoveries in areas with the largest potential resource and to support expansion of the delivery infrastructure. Examples of specific research that government might sponsor include:

  — Reservoir detection and characterization technology targeted at exploration and field development

  — Technologies to reduce the cost of environmental compliance

  — Innovative geologic and engineering concepts based on novel technologies such as 3D and 4D seismic and horizontal drilling

  — Technologies to further ensure the reliability, security, and integrity of the delivery system.

  Particular consideration should be given to long-term technology needs for ultra-deep water, low permeability, and non-conventional reservoirs that will contribute more of the nation's gas supply in the future. Policy issues that affect technological developments should also be addressed.

- *The government should promote high-efficiency gas technologies such as fuel cells, gas cooling, and high-efficiency turbines.* Due to the inherent environmental advantages of natural gas and the high efficiencies offered by new gas equipment, the use of gas in place of other fossil energy forms promotes both energy conservation and environmental improvement (e.g., in areas such as acid rain, ozone formation, particulate emissions, and solid waste disposal). All energy efficiency evaluations and standards should be based on a "total energy efficiency" concept, that is, energy efficiency measurements should include energy used or lost from the point of production through consumption.

The recommended Interagency Work Group on Natural Gas can play a significant role in overseeing technology investments made by the government. Industry and state agencies should be actively involved with the Work Group in directing these efforts.

Recommendation 4: Plan for capital, infrastructure, and human resource needs.

The long-term demand growth projected in this study translates to long-term opportunities for the industry and the government. The increase in demand provides the opportunity for industry participants to expand their markets and to increase their service offerings. Benefits to the government extend beyond meeting environmental goals and include increases in revenues from royalties, rentals, and bonuses from the leasing of federal lands and development of the resources. For example, income generated by the Offshore Mineral Management Program alone generates about $4 billion annually. However, taking full advantage of these opportunities will require long-term resource planning on the part of industry and government. The following areas should be specifically addressed:

- *Industry must immediately address concerns regarding the future availability of skilled workers.* Several years are required to train highly skilled workers to perform their jobs knowledgeably, efficiently, and safely. Given the projected increase in activity and the impending increase in retirements, aggressive action must be taken to attract, train, and retain qualified workers at all levels. Industry must also undertake initiatives to attract high school students with strong math and science skills to replenish college enrollments in petroleum, geotechnical, and other energy-related disciplines. Government funding of energy-related studies in universities can also help to populate these disciplines.

- *Producers, drilling companies, and equipment manufacturers should form a joint industry task force, headed by the International Association of Drilling Contractors, to gather additional information on infrastructure needs.* Of particular concern is the projected need to increase the number of wells drilled per year and increase the drilling rigs and equipment required to accomplish that task. The task force can begin its study by collecting data, such as drilling success rates in deeper formations and drilling rates for deep vertical wells, that are needed for assessing future needs. The task force should include rig builders and shipyard operators as well as industry groups such as the Petroleum Equipment Suppliers Association.

- *Government should examine possible new financial incentives, such as limited-duration tax and royalty incentives, that would accelerate the development of high-risk, high-cost natural gas resources onshore and offshore.* Past support from the government, such as tax credits and deepwater royalty relief, has promoted development activity. The MMS, in their January 1999 publication on deepwater development facts, states "The Deepwater Royalty Relief Act, passed in 1995, has contributed significantly to the increase in deepwater activity by providing the opportunity to lease new prospects in deepwater." The MMS reports that Gulf of Mexico OCS bids for leases in water greater than 800 meters increased from 49 in 1994 to 1,138 in 1997 and 817 in 1998. Other types of incentives should also be explored with input from industry advisors. These incentives, if properly targeted, can convert non-economic resources into economic supply.

Recommendation 5: Streamline processes that impact gas development.

Once a high level policy is established, all agencies involved in the development of supply and delivery systems should review and align existing policy to eliminate conflicting directives and remove obstructions. Processes that affect development must be streamlined to eliminate duplicative efforts, follow more predictable time-lines, and eliminate unnecessary costs to the industry, government, and, ultimately, consumers. Approval processes involving multiple levels of government, and agencies should be coordinated in order to resolve conflicts in a timely manner.

The Council recommends that the following areas be evaluated:

- Updating of resource management plans for federal lands
- Potential for sharing land management and environmental assessment resources, such as data bases and personnel, among agencies
- Designation of sufficient budgets for required land-management planning and studies
- Adequacy of legislation for land-management policy and procedures
- Opportunities for coordinating permitting/approval processes among agencies.

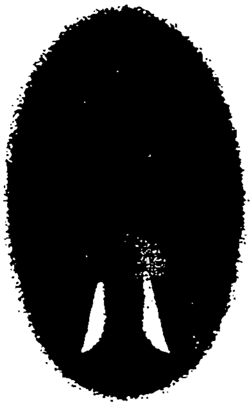
Recommendation 6: Assess the impact of environmental regulation on natural gas supply and demand.

Additional evaluation is needed to fully assess the impact of existing and proposed environmental regulations on natural gas supply and demand. As shown in this study, regulations that address issues such as climate change and emissions controls on electricity generation could have a significant impact on natural gas demand and the ability of the industry to meet that demand. Changes in regulations and additional moratoria or extensions of existing moratoria that reduce access to natural gas supply should be examined in the context of the need for increasing gas supply. The recommended Interagency Work Group could play an important role in this analysis by developing and coordinating a process for reviewing any proposed regulations to ensure that the benefits of increasing natural gas use are considered in the regulatory process.

Recommendation 7: Design new services to meet changing customer needs.

In response to the ongoing restructuring of the natural gas and electricity markets, all industry participants must offer new or reconfigured services specifically designed to meet changing customer needs. For example, individual pipelines and many LDCs are implementing new services to meet customer needs through filings for services such as parking, loaning, balancing, peaking, and hourly firm transportation. While industry-wide changes may take some time to implement, individual pipeline changes can be developed and approved in far less time. When new services are offered to gas customers, maximum choice should be ensured by allowing all parties to compete for the provision of those services in a non-discriminatory manner.

The members of the National Petroleum Council stand ready to further discuss and implement the recommendations made in this report. Members will assist the Interagency Work Group in identifying impediments and solutions to the mutual goals of government, industry, and consumers for increased availability of competitively priced, environmentally desirable natural gas.



Summary of Key Findings

The following information supplements the conclusions and recommendations with an overview of the findings from the three task groups. Additional detail on the findings, assumptions, sensitivities, and model output can also be found in the task group reports.

The various projections and sensitivities presented in this report were prepared using market simulation models developed by Energy and Environmental Analysis, Inc. (EEA). The oil and gas supply projections were prepared using the GRI Hydrocarbon Supply Model, which was integrated with the gas demand, storage, and transportation elements of EEA's Gas Market Data and Forecasting System.

The GRI Hydrocarbon Supply Model was originally developed by EEA for the Gas Research Institute (GRI) in the early 1980s and was the basis for the gas supply projections and scenario analysis for the 1992 NPC Study on natural gas. The model characterizes oil and gas exploration, development, and production in nineteen U.S. and five Canadian regions. Each region is further broken down into four to eight subareas, usually representing drilling depths for onshore regions or water depths for offshore regions. Proved reserves and undiscovered resources for gas are divided into associated-dissolved gas, conventional high permeability gas, tight gas, shales, and coalbed methane. The Hydrocarbon Supply Model provides the user with a wide range of options for selecting assumptions for resource base, drilling and development cost, technological improvements, upstream environmental compliance costs, land access, and financial parameters.

The Hydrocarbon Supply Model's projection of future natural gas deliverability by region was used in the Gas Market Data and Forecasting System to solve for monthly gas production, storage activity, pipeline flows, end-use consumption, and prices at locations in the United States, Canada, and the Mexico/U.S. border. This model was used to project gas demand in the United States and Canada and to determine the pipeline and storage infrastructure that would be economically justified in the various cases developed for this report. Key inputs to the model that can be varied among cases include a wide variety of drivers to gas demand and infrastructure-related parameters such as the cost of new pipeline and storage facilities.

Each task group established key assumptions and identified the variables that could significantly influence the model in their study area. Some of the key assumptions used in the 1999 Study for the 1999–2015 period are listed in Table 1. As indicated in Table 1, the model uses a U.S. GDP growth rate of 2.5% per year throughout the study period. This rate is below the rate at which GDP has grown in recent years. However, history has shown that recessions have interrupted periods of significant growth and resulted in a lower average growth over an extended period. The

TABLE 1 KEY MODEL ASSUMPTIONS	
U.S. GDP Growth	2.5% per year
Canadian GDP Growth	2.2% per year
U.S. [illegible] Inflation	3.0% per year
U.S. [illegible]	2.5% per year
Crude Oil Price (WTI)*	$18.50/bbl in 1999 dollars
Crude Oil Price (RACC)**	$16.50/bbl in 1999 dollars

* West Texas Intermediate

** Refiner Acquisition Cost of Crude in the United States

Council concluded that a 2.5% growth rate was reasonable, but sensitivity analyses were conducted to test the effects of both higher and lower rates. The Canadian GDP growth rate was assumed to be 2.2%, or 0.3% lower than the U.S. rate, reflecting a relative value that has prevailed over the last 10 years.

The crude oil prices used in the model were selected to approximate the average real prices experienced in the 70 years from 1929 to 1998. These crude oil prices affect the outcome of the model by determining the wellhead values of crude oil and natural gas, thereby setting the price of fuel oils that compete with natural gas in end-use markets. The oil prices also strongly influence the amount of capital that producers have available for reinvestment in exploration and production development. Sensitivity analyses were run to test the effect of both higher and lower oil prices.

Findings of the Demand Task Group

Demand Finding 1: Rapid growth exceeded expectations of the 1992 Study.

Consumption of natural gas grew much faster in the 1990–98 period than was anticipated. Despite the warmer-than-normal weather that prevailed in 1998, demand grew over that nine-year period in all end-use categories. The various studies of natural gas demand that have been conducted in the past decade have consistently underestimated actual growth in demand. The 1992 NPC Study was no exception, as shown in Figure 2. The High Reference Case in the 1992 Study projected that total demand could grow from 19.3 TCF in 1990 to 24.8 TCF in 2010, with 1998 projected at 20.9 TCF. Actual demand in 1998 was 22 TCF (including net storage fill), or about 1 TCF ahead of the level forecast for 1998 in the 1992 Study.

Several factors caused the 1992 Study to underestimate actual growth in gas demand. Growth in GDP was assumed to be 2.4% annually and actual growth for the 1990–98 period was 2.6%. Although energy intensity measured by Btu per unit of growth declined between 1990 and 1998, it declined at a much slower rate than the 1992 Study had anticipated. Most of the increased gas demand occurred because of an increase in total energy demand.

Gas demand grew during this period, even as the market was restructured significantly. In 1990, prior to the restructuring, over 90% of the gas moving in interstate pipelines was owned by the pipeline companies. FERC actions in the early 1990s have transformed interstate pipelines from sellers and transporters to solely open-access transporters. Many state regulatory agencies and LDCs are moving toward the same type of transformation.

In addition, major consolidations have occurred within the gas industry in anticipation of and response to the restructuring of the gas and electric industries. Numerous combinations of energy service providers have occurred within and across industry segments, as evidenced by the combinations of gas and electric companies. In most cases, mergers have been driven by the need to improve competitive position through economies of scale, greater geographic spread, more diversified services, and acquisition of expertise. These actions, along with increasing competition, have resulted in services that are generally more responsive to customer needs and are provided at lower prices.

The gas delivery system has remained the safest form of transport and continues to provide reliable service despite these massive changes. *Natural gas consumption has grown to a degree that its most ardent supporters would have found amazing at the time the 1992 NPC tudy was prepared.*

Demand Finding [illegible] Demand is projected to increase by 32% between 1998 and 2010.

U.S. natural gas consumption is projected to grow from 22 TCF in 1998 to 29 TCF in 2010 and could increase beyond 31 TCF in 2015 (see Table 2). Canadian gas demand is expected to rise from 2.8 TCF in 1998 to 3.5 TCF in 2010 and 3.8 TCF in 2015.

The most significant growth in gas demand is projected to be for electricity generation. In the 1992 Study, increased penetration of the electricity generation market was an *expectation*. Today—as result of dramatic improvements in heat rate for combined-cycle gas/oil generating equipment, the relatively low capital cost of such plants, the relatively short construction time required to bring them on line, tighter emission standards for electricity generation, and the deregulation of the electricity industry—gas is the *preferred choice* of the electricity generation industry for new generating plants. Currently, 98% by capacity of the 243 electricity generating plants that have been announced for construction in the next five years are to be gas-fired; the remaining 2% by capacity will be fueled by coal, oil, wastewood, wood, wind, and other.[1]

A number of key assumptions were made concerning electricity generation. One assumption was that 113 gigawatts of gas/oil combined-cycle and gas-fired combustion turbine capacity would be operating by 2010 (an increase from 25 gigawatts in 1998) and a total of 140 gigawatts by 2015 to satisfy incremental electricity demand. The 1999 Study determined that, through 2010, the cost of electricity generated from new coal plants (including capital costs) would not be competitive with electricity from new gas units, but that after 2010 an estimated 20 gigawatts of new coal capacity would be built. Heat rates for all classes of electricity generation are assumed to improve 3 percentage points between 1998 and 2015. Seventy percent of

[1] Source: Online data base at Resource Data International, Inc. (July 1999).

TABLE 2
U.S. NATURAL GAS CONSUMPTION
(Trillion Cubic Feet)

	1998	2005	2010	2015
Total Consumption	22.0	26.3	29.0	31.3
Total End-Use	19.4	24.0	26.4	28.7
Residential	*4.5*	*5.6*	*5.8*	*6.1*
Commercial	*3.0*	*3.7*	*3.8*	*4.1*
*Industrial**	*8.6*	*9.6*	*10.2*	*10.8*
Electricity Generation	*3.3*	*5.1*	*6.6*	*7.8*
Lease, Plant & Pipeline Fuel	2.0	2.2	2.5	2.5
Net Storage Fill/Balancing	0.6	0.1	0.1	0.0

* Historical data include all gas use for industrial cogeneration and independent power producers; all gas for new power plants except cogeneration is included in the electricity generation sector.

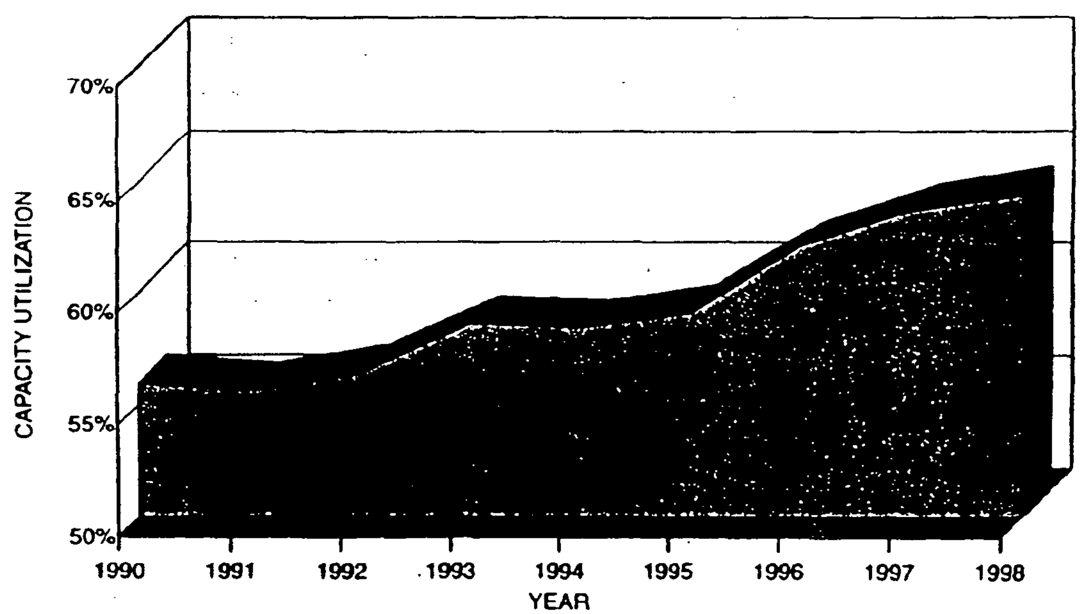
Source of historical data: Energy Information Administration, *Natural Gas Monthly*, September 1999.

combined-cycle plants are assumed to be capable of burning either gas or oil and would therefore switch fuels depending on cost. Coal capacity utilization was assumed to increase 11 percentage points from 64% in 1997 to 75% by 2015, continuing the trend observed in the last 10 years (Figure 15). However, this continuing increase in capacity utilization is recognized as a significant challenge for those facilities. Adding to this concern is the legal action taken in November 1999 by the EPA against several large utility companies, charging that their coal-fired plants had effectively added to their capacity during maintenance without installing new pollution control equipment. This recent action could have the impact of lowering coal capacity utilization, thus increasing demand for natural gas.

No new nuclear capacity was projected to be developed in the timeframe of this study and an estimated 15 gigawatts of nuclear generation capacity is projected to retire by 2015 as some licenses expire. The Demand Task Group projected that 15 gigawatts of nuclear capacity would be relicensed, and that a total nuclear capacity of approximately 80 gigawatts would remain in operation in 2015. The electricity generation industry has increasingly relied on its nuclear generation capacity, as seen in Figure 16. With the resumption of service at the Clinton, LaSalle, and Millstone units in the spring of 1999, nuclear capacity utilization reached an unprecedented peak of 96.5% in August 1999. This compares to the previous peak capacity utilization of 86% in July 1998 and the historical average of approximately 75%. The average annual capacity utilization of nuclear generating capacity is assumed to increase from 75% to 80% over the study period. Nuclear retirements beyond the few projected in this study could significantly increase natural gas demand in the 2010–2015 time frame.

Hydroelectric and renewable generation are assumed to remain nearly constant throughout this case, although hydroelectric generation could diminish due to environmental concerns about the adverse impact of dams on anadromous fish populations, espe-

Figure 15. U.S. Central Utility Coal-Fired Electricity Generation Capacity Utilization



Source: DOE/EIA, *Electric Power Annual*, 1990–1998.

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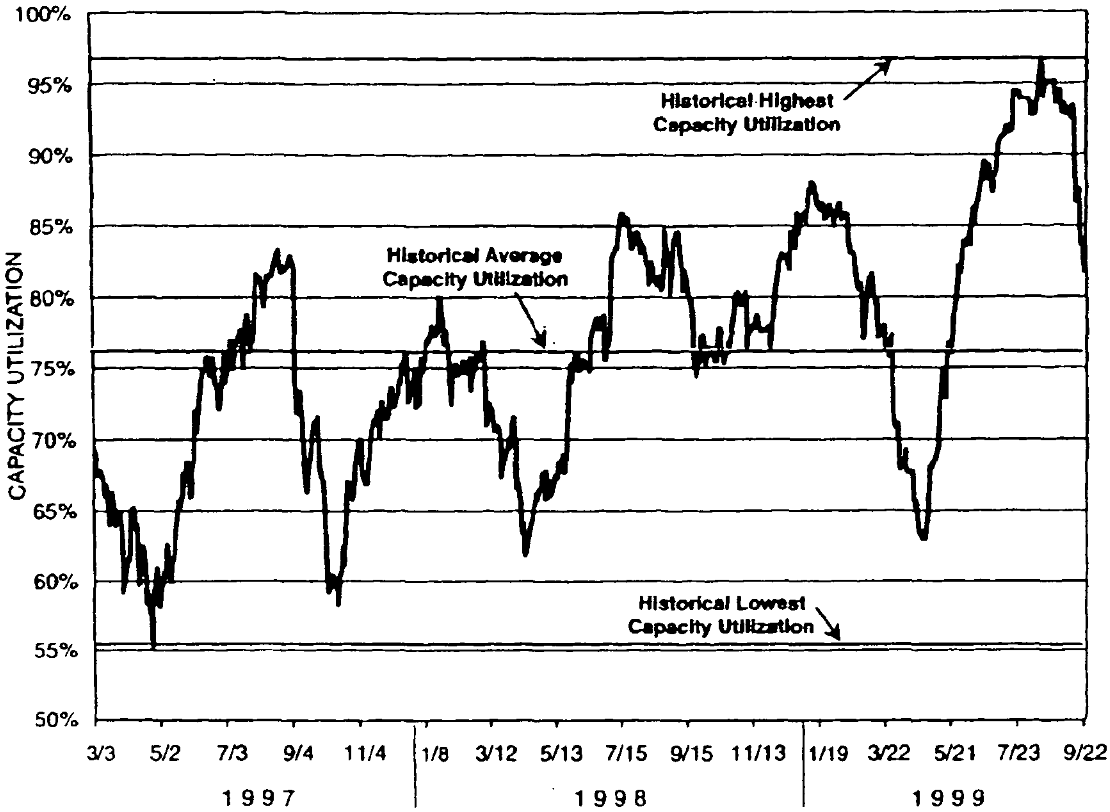
Figure 16. Total U.S. Daily Nuclear Capacity Utilization



Source: U.S. nuclear complex activity data, *BTU Daily*.

cially in the Pacific Northwest. However, such declines are assumed to be nearly offset by increased generation from renewable energy such as wind and solar. Increases in renewable capacity are evident because of existing and growing demand for "green power," and state-level legislation calling for renewable portfolio standards.

The Demand Task Group recognized that assumptions for key variables have a significant impact on ultimate demand. As discussed, assumptions were made for the Reference Case about the rate of increase in GDP, prices of competitive fuels (e.g., fuel oil and coal), construction of new gas-fired generating plants, the retirement of nuclear plants, and utilization rates of gas, coal, and nuclear plants. The highest-impact variables were tested with sensitivity analyses. GDP growth and oil prices proved to be significant drivers of gas demand. For example, if GDP growth were to average 3.0% per year rather than 2.5%, demand could increase by 0.6 TCF in 2010. An average GDP growth of 2.0% could result in 0.9 TCF lower demand in 2010. If oil prices were $3.50 higher than assumed in the Reference Case, demand could increase by 0.7 TCF. Conversely, if oil prices were $3.50 lower, demand could be 1.0 TCF lower than the Reference Case.

The assumptions regarding other fuels that are used for electricity generation can also have a large impact on demand. For example, if the capacity utilization factor of coal-fired plants is 65% rather than the 75% assumed in this study, gas demand could increase by 1.7 TCF. If an additional 15 gigawatts of nuclear retirements were to occur, demand could increase as much as 0.7 TCF. Further detail on these sensitivities is included in the Demand Task Group Report.

Demand Finding 4: Environmental regulations could add significant incremental demand.

The potential 29 TCF demand projected for 2010 does not include the effect of environmental and other regulations that are not currently scheduled for implementation. New legislation or policy initiatives that might be implemented to address global climate change could substantially increase gas demand. For example, the Energy Information Administration (EIA) and the Edison Electric Institute (EEI) have conducted separate studies of the impact of meeting the U.S. target under the Kyoto protocol. These studies, which are discussed in the Demand Task Group Report, confirm that substantial reductions in coal and oil consumption would be required with a concomitant increase in gas demand. These studies examine various scenarios and indicate an increase in gas demand of 2–12% in the case of EIA, and 10–22% in the case of EEI above their respective reference cases.

While the 1999 NPC Study did not specifically analyze the effect of new environmental regulation, correlations can be made with other factors that affect demand and price. For example, the sensitivity analysis that examined a decrease in the utilization rate of coal-fired electricity generation capacity—which could easily occur with new environmental regulation—indicated that a significant corresponding increase in demand would occur.

Findings of the Supply Task Group

Supply Finding 1: Sufficient resources exist to meet growing demand well into the twenty-first century.

The estimated resource base of 1,466 TCF for the lower-48 states in the 1999 Study represents a 171 TCF increase from the 1,295 TCF used in the 1992 Study (see Figure 4 and Table 3). In addition, Canada's resource base is estimated at 667 TCF. Canada's resource base is approximately 73 TCF lower than determined in the 1992 Study due to depletion and reassessment of nonconventional resources.

The Supply Task Group's team of industry experts on resource assessment conveys a high level of confidence in the robustness of the U.S. resource base. This team notes that the 171 TCF increase in the resource base has occurred despite production in the lower-48 states of 124 TCF of reserves from 1991 through 1997. The increase in the estimated resource base is primarily derived from technology improvements. For example, advances in computer technology have yielded breakthroughs in data processing, integration, and imaging, which have in turn vastly improved reservoir modeling. This information enables better projections of the size and location of hydrocarbon deposits. Technology has also played a significant role in improving drilling and completion techniques, thus improving access to the resource base. The major contributors to increases in the resource base are:

- **Old Field Reserve Appreciation.** The application of new technology has helped in the assessment of hydrocarbons in known fields. The new information has resulted in an increase of 69 TCF in the estimates of the resource base in "Old Fields."
- **New Fields Primarily in the Deepwater Gulf of Mexico.** New information and improved interpretations have also yielded increases in projections for New Fields—fields that are theoretically in place but are yet to be discovered. For example, estimates of New Fields resources in deepwater Gulf of Mexico have increased to 140 TCF, a 145% increase from the 57 TCF estimate in the 1992 Study.

Figures 17a and 17b show the U.S. and Canadian assessment regions and the "Assessed Additional Resources" for each region, which is the sum of Old Field growth, New Field discoveries, and nonconventional gas sources. Two areas, the Rocky Mountain Foreland and the Central and Western Gulf of

TABLE 3

U.S. AND CANADIAN NATURAL GAS RESOURCES
(Trillion Cubic Feet)

	1992 NPC Study* (1-1-91)	1999 NPC Study (1-1-98)
LOWER-48 RESOURCES		
Proved Reserves	160	157
Assessed Additional Resources	1,135	1,309
Old Fields (Reserve Appreciation)	*236*	*305*
New Fields	*493*	*633*
Nonconventional	*406*	*371*
Total Remaining Resources (Proved + Assessed Additional)	**1,295**	**1,466**
Cumulative Production	758	881
Total All-Time Recovery	2,053	2,347
ALASKAN RESOURCES†		
Proved Reserves	9	10
Assessed Additional Resources	171	303
Old Fields (Reserve Appreciation)	*30*	*32*
New Fields	*84*	*214*
Nonconventional	*57*	*57*
Total Remaining Resources (Proved + Assessed Additional)	**180**	**313**
Cumulative Production	5	9
Total All-Time Recovery	185	322
CANADIAN RESOURCES		
Proved Reserves	72	64
Assessed Additional Resources	668	603
Old Fields (Reserve Appreciation)	*24*	*22*
Discovered Undeveloped	*47*	*35*
New Fields	*379*	*384*
Nonconventional	*218*	*162*
Total Remaining Resources (Proved + Assessed Additional)	**740**	**667**
Cumulative Production	65	103
Total All-Time Recovery	805	770

*Assessed Additional Resources from the 1992 Study reflect re-allocation of tight gas resources among categories consistent with 1999 Study allocations.

†Old Fields resource includes 25 TCF for Prudhoe Bay; New Fields resource is based on 1995 USGS/MMS assessment; and Nonconventional resource is PGC coalbed methane resource.

Figure 17a. U.S. and Canadian Assessment Regions

* Alaskan resources were not assessed in this study.

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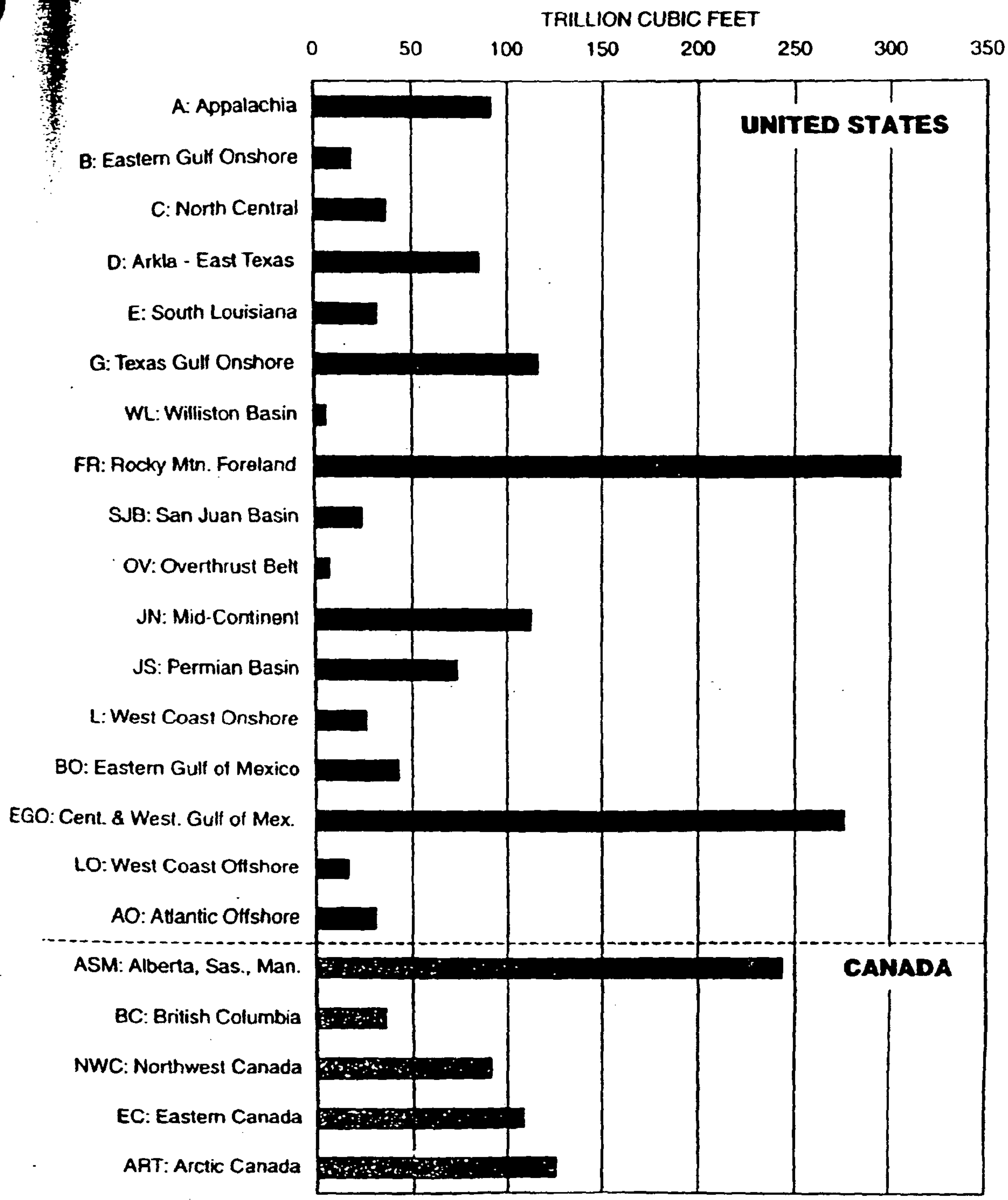
Figure 17b. Assessed Additional Resources by Region



Mexico, contribute almost half of the U.S. total. In Canada, the Western Sedimentary Basin (model region ASM) will provide a significant amount of the additional resource.

U.S. gas production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010 and could approach 27 TCF in 2015. Canadian imports to the United States are projected to increase from 3 TCF in 1998 to 3.8 TCF in 2010 and could reach 4.4 TCF by 2015 (Table 4). Approximately 13–14% of U.S. gas supply will continue to come from Canada. LNG imports will reach 0.9 TCF using an average of 75% of existing U.S. capacity. No additional import facilities are projected in this study. Exports to Mexico are projected to increase in the near term to 0.4 TCF and remain at that level throughout the study period.

Future production will be from deeper wells, deeper water, and more nonconventional sources. As Table 5 demonstrates, lower-48 production will gradually increase from deeper wells. Onshore production from depths below 10,000 feet is projected to increase from 33% in recent years to over 40% by 2010. The industry's ability to achieve production from deeper horizons will be dependent on the appropriate amount of deep drilling infrastructure and the continued evolution of technology.

In the Gulf of Mexico, production from deeper waters will be the driving force in future supply growth, as demonstrated in Table 6. Production from water depths of more than 200 meters is projected to increase from 0.8 TCF in 1998 to over 4.5 TCF in 2010 and maintain approximately that level

TABLE 4
U.S. GAS SUPPLY
(Trillion Cubic Feet)

	1998*	2005	2010	2015
U.S. Gas Production	19.0	22.6	25.1	26.6
Net Imports from Canada	3.0	3.7	3.8	4.3
LNG Imports	0.1	0.4	0.6	0.9
Exports to Mexico and Japan	-0.1	-0.4	-0.5	-0.5
Total Supply	**22.0**	**26.3**	**29.0**	**31.3**
Canada as a % of Total	14%	14%	13%	13%

*Historical data from Energy Information Administration, *Natural Gas Monthly*, September 1999. Data include synthetic natural gas.

TABLE 5
ONSHORE LOWER-48 GAS PRODUCTION BY DEPTH INTERVAL

	1998*	2005	2010	2015
0–5,000 ft	28%	27%	25%	25%
5–10,000 ft	39%	37%	34%	32%
10–15,000 ft	26%	26%	29%	32%
> 15,000 ft	7%	10%	12%	11%

*Energy and Environmental Analysis, Inc., estimates adapted from PI/Dwights production reports.

TABLE 6

GULF OF MEXICO PRODUCTION BY WATER DEPTH

	1998*	2005	2010	2015
Gulf of Mexico Production (TCF/Year)	5.3	7.4	8.0	7.6
Conventional Production (%)				
Shelf 0–40 meters	49%	27%	20%	19%
Shelf 40–200 meters	35%	24%	20%	17%
Slope 200–1,000 meters	14%	26%	25%	23%
Slope 1,000–1,500 meters	0%	9%	13%	14%
Slope >1,500 meters	1%	8%	15%	18%
Subsalt Production (%)				
Shelf 40–200 meters	<1%	3%	4%	4%
Slope 200–1,000 meters	1%	2%	2%	3%
Slope >1,000 meters	0%	1%	1%	2%

*Energy and Environmental Analysis, Inc., estimates adapted from PI/Dwights production reports.

through 2015. Conversely, Gulf of Mexico shelf production is projected to decrease from 4.5 TCF in 1998 to 3.5 TCF in 2010 and around 3.0 TCF in 2015.

Growth in production from nonconventional sources will be especially pronounced in the Rocky Mountain region. Nonconventional production in this region is projected to increase from 1.9 TCF in 1998 to 2.9 TCF in 2010 and as much as 3.4 TCF in 2015. Production in the lower-48 states from nonconventional sources (i.e., the sum of tight gas, shales, and coalbed methane) accounted for 4.4 TCF of total production in 1998. This volume is projected to increase to 6.8 TCF in 2010 and could reach 8.5 TCF in 2015 (Table 7).

All of these new sources of gas require that significant technology hurdles be

TABLE 7

LOWER-48 PRODUCTION FROM CONVENTIONAL VS. NONCONVENTIONAL SOURCES

	1998*	2005	2010	2015
Associated Gas	14%	13%	14%	13%
High Permeability Gas	60%	62%	59%	54%
Tight Gas & Shale Gas	20%	20%	21%	25%
Coalbed Methane	6%	5%	6%	8%

*Energy and Environmental Analysis, Inc., estimates adapted from PI/Dwights production reports.

addressed and overcome in order to deliver cost-competitive supply. Two sensitivity cases were developed to determine the impact on price and demand if technology develops at either a slower rate or a faster rate. When technology improvements developed more slowly than in the Reference Case, demand in 2010 fell by 0.7 TCF and price increased by $0.27 per MMBtu. Conversely, when the rate of technology improvements increased, demand increased by 0.7 TCF, and price decreased $0.32 per MMBtu.

Sensitivity analyses were also run on the size of the resource base to evaluate the impact of learning more about the resource base. An increase of 250 TCF in the economically recoverable resource base, beyond the 1,466 TCF Reference Case estimate, resulted in a decrease in gas price of $0.96 per MMBtu. Conversely decreasing the estimate of the resource base by 250 TCF from the 1,466 TCF estimate, increased the price by $0.56 per MMBtu. The sensitivity analyses indicated that the assumption on the size of the estimated resource base has the highest impact on the ability to produce competitively priced natural gas. This sensitivity analysis provides some insight into the impact of access issues since access restrictions remove potential supply from the available resource base.

Supply Finding 2: Restricted access limits the availability of supply.

Access issues limit the ability to reach known resources, slow down development in certain areas, and impede the construction of needed pipelines required to deliver natural gas to markets. For the purposes of the 1999 Study, the following assumptions were made with regard to access: (1) all scheduled lease sales will continue on time (including MMS Lease Sale 181 in the eastern Gulf of Mexico); (2) all existing regulatory requirements and restrictions on—and all current rights to drill on—public lands are honored; and (3) rights-of-way will be obtained for constructing and expanding any necessary pipeline infrastructure. If any of these assumptions fall short, the ability to explore for, produce, and deliver adequate supply will be hampered. Enabling access beyond that assumed in the Reference Case is necessary to improve availability and cost-competitiveness of gas supply in the time period of the 1999 Study.

Two areas that will significantly contribute to future gas supply are the Rocky Mountain region and the Gulf of Mexico, both of which have significant access restrictions. For example, approximately 9% of resource-bearing lands in the Rockies are completely inaccessible due to "no leasing" and "no surface occupancy" restrictions. Another 32% of resource-bearing lands are specifically subject to restrictions that delay development activity by an average of two years and add measurably to the cost of drilling wells on these properties. These restrictions mean that over 137 TCF of resources are subject to prohibitions or impediments. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. Regardless of the lack of specific stipulations, nearly all public-lands acreage otherwise accessible for development regularly becomes encumbered to some degree in disputes among stakeholder groups and inconsistent application of regulatory policy by the governmental group(s) charged with managing these lands. These issues result in similar delays and added costs for offshore areas.

The 1999 Study assumes access to those tracts in planned MMS Lease Sale 181, but not the resources in the eastern Gulf of Mexico beyond the Norphlet Trend areas off Mississippi and Alabama. These areas have not been opened up and no plans to do so are currently in progress. Similarly, the Destin Dome area off the Panhandle of Florida was not assumed to be available for development in the Reference Case because the regulatory approval process was taking place during the time of this study.

Two sensitivity cases were developed to evaluate the impact of access on natural gas production. As seen in Table 8, the reduced access case assumed that further restrictions in the Rocky Mountain region would increase development costs and reduce the area that can be leased under standard terms. This case also assumed that the scheduled MMS Lease Sale 181 would not occur. The reduced access case resulted in a price increase of $0.16 per

TABLE 8

SUMMARY OF NPC FEDERAL LANDS AND WATERS ACCESS SENSITIVITIES

	Reference Case	Increased Access Case	Reduced Access Case
Rocky Mountains			
Standard Lease Terms	59%	59%	22%
Off Limits	9%	9%	14%
High Cost	32%	32%	64%
High Cost Penalty per Well	6% of Well Costs	0%	6% of Well Costs
High Cost Delay	2 Years	None	2 Years
Eastern Gulf of Mexico			
Destin Dome	No Development	Production by 2002	No Development
MMS Lease Sale 181	Lease Sale in 2001	Lease Sale in 2001	No Sale
Non-Sale 181 Eastern Gulf	No Sale or Development	Lease Sale in 2004	No Sale or Development
Other Offshore U.S.			
Pacific	No Development	Lease Sale in 2004	No Development
Atlantic	No Development	Lease Sale in 2004	No Development

MMBtu in 2010 and a decrease in U.S. production of 0.5 TCF. The declines in production occurred primarily in the Rockies and the eastern Gulf of Mexico. The decrease in production in 2015 was 0.2 TCF, with a decrease in price of $0.08 per MMBtu. The changes that occurred in the reduced access sensitivity case were not pronounced, primarily because the access assumptions in the Reference Case were already very restrictive.

The second sensitivity case assumed that access restrictions would be relaxed in the Rockies, resulting in the elimination of high-cost delays. Currently restricted offshore areas were assumed to be open to leasing in 2004 and production from the area opened in MMS Lease Sale 181 would begin in 2002. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, 95% of which was in the Rockies and the eastern Gulf of Mexico. A corresponding decrease in price of $0.21 per MMBtu accompanied this production increase. More importantly, a dramatic shift occurred in the Extended View period with an increase in U.S. production in 2015 of 1.6 TCF. This increase continued to be primarily from the Rockies and the Eastern Gulf of Mexico, with some Atlantic offshore production beginning in this time frame. Prices in 2015 decreased by $0.45 per MMBtu.

Supply Finding 3:
A healthy oil and gas industry is critical for natural gas supply to satisfy expected increases in demand.

Adequate financial performance must be demonstrated to compete for and attract financial investment.

The growth in gas demand projected in the 1999 Study will require approximately $658 billion [constant 1998 dollars] in upstream capital expenditures from 1999 through 2015. This figure includes all exploration, development, production, and gathering capital expenditures. A summary of the capital investment requirements projected by the Reference Case in the 1999 to 2015 study period is shown in Figure 9.

This supply growth will require an increased annual average capital expenditure of $39 billion per year from 1999 through 2015, versus an annual average of $27 billion from 1991 through 1998. However, these needed levels of investment will take place only if investors have confidence that competitive rates of return will be earned. In recent years, this has not been the case as the U.S. upstream sector has earned very modest rates of return. According to the Financial Reporting System, the 23 largest producers reported an average return on assets of just 5.4% over the 12-year period from 1986 through 1997.

The assumption for future oil prices in the 1999 Study does not take into account the price volatility that has been experienced and that has caused difficulty in maintaining steady levels of upstream investments. The strong direct correlation between commodity prices and upstream investment means that investments drop rapidly following a significant downturn in oil or gas prices and confidence returns slowly. The historical low rates of return and the degree of volatility jeopardize the steady flow of capital that is needed to achieve the large projected increases in gas production required to meet growing demand.

Aggressive pro-active workforce planning is essential.

Without immediate action, impending shortages of qualified personnel are expected to hinder the ability of the supply sector to find and develop the required gas supply. Three major shocks to employment prospects in the producing sector have occurred in the last 20 years. Each of these shocks (1982, 1986, and 1998) was caused by drastic declines in the world market price of crude oil and resulted in significant reductions in expenditures and jobs. At the same time, companies dramatically decreased hiring rates. As a result, the producing sector now suffers from a very slim "bench" of mid-career workers between the ages of 30 and 40 and is facing a large wave of retirements.

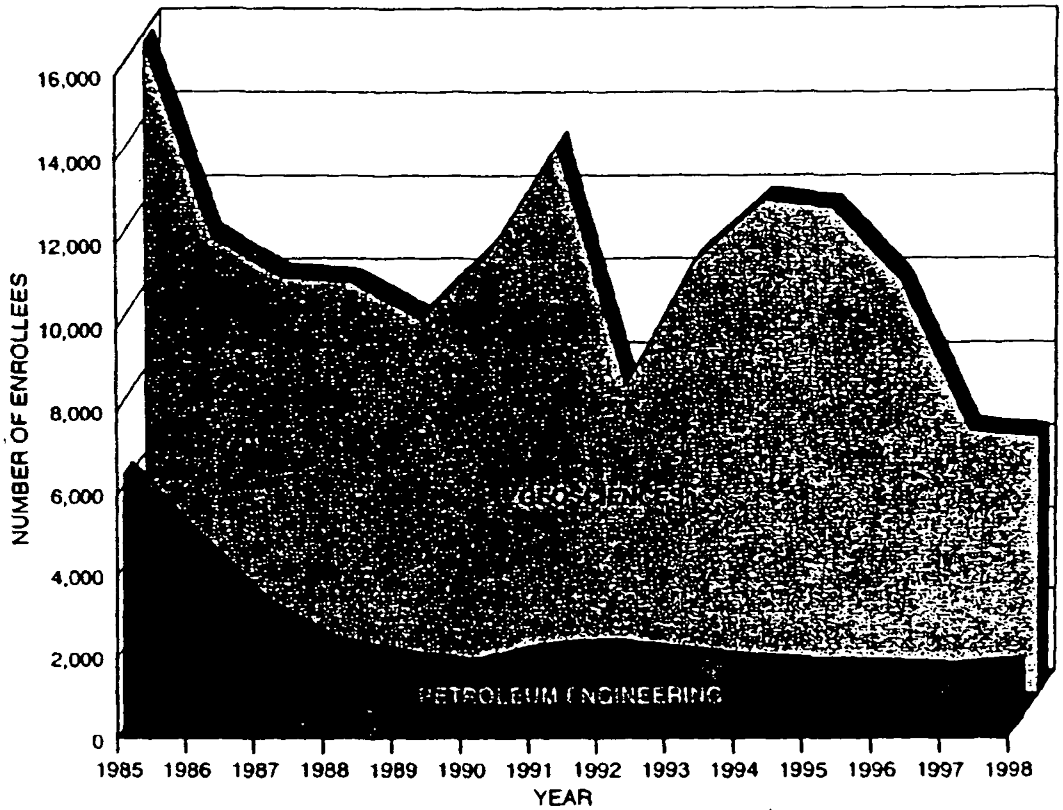
In the aftermath of precipitous declines in crude oil prices in 1981, enrollments in key disciplines that support the producing sector began to decline drastically and gained momentum with the equally devastating oil price drop in 1986. The "farm clubs"—college and university petroleum-related degree programs—continue to have great difficulty attracting promising high school seniors. Enrollments in undergraduate petroleum engineering and geoscience programs have declined by 77% and 60%, respectively, between 1985 and 1998 (see Figure 18).[2]

The oilfield service/supply sector faces similar challenges in meeting engineering and operations requirements. Volatility in the drilling industry has caused many toolpushers and other key supervisory personnel to leave the industry in search of more stable careers. Industry contractors will be challenged to find and train adequate numbers of skilled laborers, such as machinists, electricians, pipefitters, and welders. Higher wage scales are likely to be required to attract workers back into the industry.

Beginning immediately, aggressive pro-active workforce planning is a necessity for producers and contractors to achieve staffing levels that are necessary to meet the challenge of the projected demand increase.

[2] Data from (1) *Petroleum Engineering and Technology Schools 1997-1998*, Society of Petroleum Engineers http://www.pe.ttu.edu/spe_schools_book/html/school.html, (2) *State of Oil and Natural Gas Industry*, Independent Petroleum Association of America, August 4, 1999.

Figure 18. Geoscience Undergraduate and Petroleum Engineering Enrollees



Source: Society of Petroleum Engineers, *Petroleum Engineering and Technology Schools 1997-1998;* and American Geological Institute.

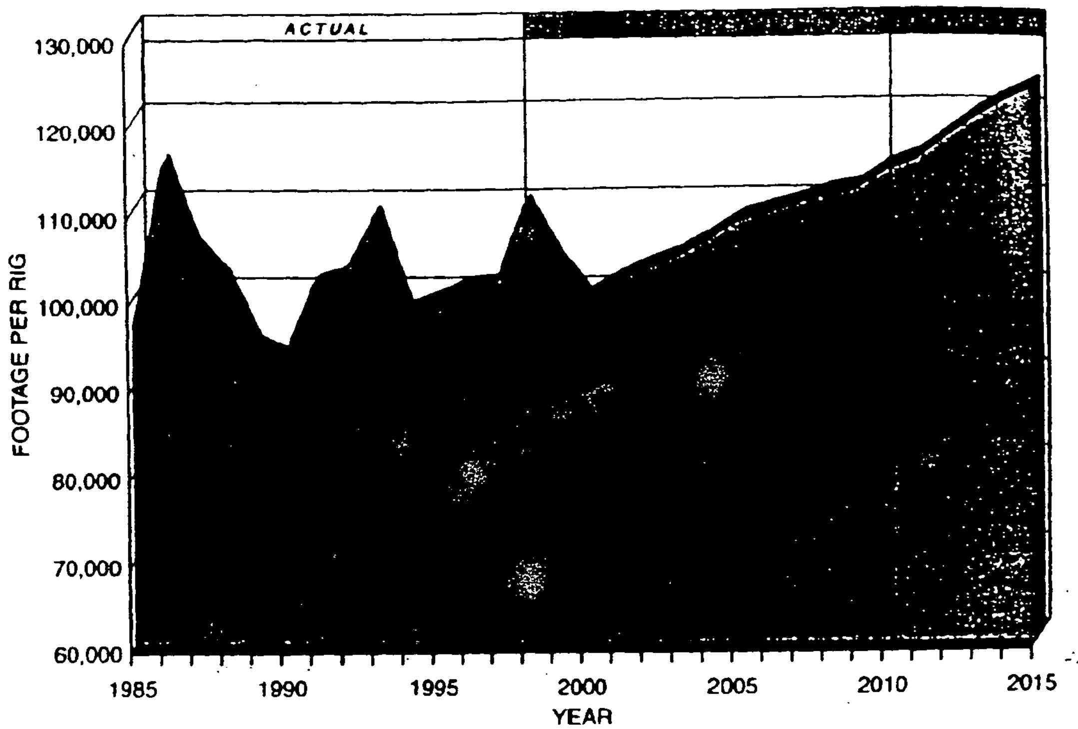
New drilling rigs must be built.

In order to supply the volume of natural gas needed through this study period, the total number of wells drilled annually must increase from 24,000 in 1998 to 37,000 in 2010 and as high as 48,000 by 2015. The well counts include both gas and oil wells because approximately 14% of natural gas produced in the United States is associated gas. In 1998, an average of just over 1,250 onshore rigs of the 1,700 rigs available have been active. While rig efficiency (footage drilled per rig, see Figure 19) has improved since 1985 and is expected to continue to improve over time with technology advancements, increased well depth requirements will likely cause the current number of actual wells drilled each year per active rig to remain relatively constant. Thus, to drill 48,000 wells annually by 2015 an average of 2,100 onshore rigs and 180 offshore rigs will be required to actively drill each month of the year.

With this increased level of drilling, the availability of drilling rigs becomes a primary concern. Over the 1999–2015 time frame, the number of onshore rigs that will be retired or lost to attrition is estimated at 90% of the current fleet. In order to meet estimated rig demand, over 1,125 onshore rigs would need to be constructed by 2010 and as many as 1,894 by 2015. Onshore rig construction will be needed as early as 2001. Capital requirements for onshore rig construction is projected at $12 billion.

Additional offshore drilling rigs will also be needed in this time frame, as shown in

Figure 19. Annual Average Footage Drilled Per Rig



Source of historical data: American Petroleum Institute, *Quarterly Completion Report;* and Baker Hughes, Inc., *Rotary Rigs Running.*

TABLE 9

GULF OF MEXICO DRILLING RIG INVENTORY

	Total	Marketed	Contracted	Not Marketed
Jack-up	*139*	*119*	*105*	*20*
Semis	*38*	*34*	*27*	*4*
Drillships	*3*	*3*	*3*	*0*
Submersibles	*7*	*1*	*1*	*6*
Total Mobile	187	157	136	30
Platform	78	57	37	21
Inland Barges	95	70	34	25
All Offshore	**360**	**284**	**207**	**76**

Source: Offshore Data Services, *Rig Locator*, September 24, 1999.

Table 9. As of September 24, 1999, the offshore fleet actively drilling in the Gulf of Mexico numbered 207, with 30 of those working in deepwater. Included in that total were 76 rigs that were not being marketed. Some of the rigs in this category might not be returned to service due to the costs that would be associated with meeting U.S. Coast Guard certification requirements and classification society standards. Since offshore drilling rigs are mobile, improved market conditions in the Gulf of Mexico could potentially attract rigs to relocate from foreign waters. Taking into account increasing drilling efficiencies as well as annual attrition rates of 5% for deepwater rigs and 7% for all others, the 1999 Study projects that 72 additional rigs—either reactivated, new construction, or relocations—will be needed by 2015 for the increased offshore activity. This total includes 10 deepwater rigs, 32 platform rigs, and 30 jack-up rigs and barges. If all of these additions were met by new construction, capital requirements would be approximately $7 billion.

Supply Finding 4:
Investment in research and development is needed to maintain the pace of advancements in technology.

As stated earlier, technology advancement has played a major role in the increase of the North American resource base by:

- Improving efficiency of drilling, equipment, operating, and other costs
- Increasing recovery factors of discovered oil and gas in place
- Improving success rates (i.e., reducing the number of dry holes)
- Revealing new areas and types of resources for exploitation through innovative geologic and engineering concepts.

The above improvements occurred mainly due to advances in 3D seismic, directional drilling, and improved completion techniques.

Information and communications technology also has had a widespread impact on all facets of the natural gas producing sector. The persistent improvement of computing power at consistently decreasing prices has placed increasingly powerful information technology tools in the hands of even the smallest producers, improving efficiency and reducing cost structures. Processing power is growing and allowing applications to be moved from mainframes to high-efficiency workstations. The advent of object-based and improved data storage technologies have allowed greater access to data with a high level of access in user friendly interfaces. Connectivity has been enhanced by the use of high-capacity networks, fiber, and satellite communication links, and the Internet (intranets, extranets, etc.). More importantly, these types of system advances support new paradigms of multi-disciplinary teaming.

One consideration in this constantly changing environment and workstyle is the manner in which people can adapt, modify work processes, and comfortably utilize these tools. These changes challenge management to ensure that training is constantly updated to match the fast pace of technology growth.

Advances in technology do not happen in a vacuum. All industry stakeholders will have to support continued investment in technology research and development—from the producer who must apply the newest tools/techniques to the next opportunity, to the investor who must at times be willing to sacrifice immediate gains for longer-term viability. Continued and increased funding of research and development is required for the North American resource base to live up to its potential. Cooperative measures by all parties will be required. With continued emphasis and investment, new technologies such as those listed below could have a significant impact on future gas production:

- **Improved Seismic Techniques.** Time-lapse seismic reservoir monitoring, commonly known as 4D seismic, is the comparison of 3D seismic surveys acquired at two or more points in time. This allows scientists to study the movement of fluids in the reservoir. Another technique, multi-component technology, provides a more detailed picture of a subsurface reservoir's internal architecture. The combination of these two technologies with visualization technology allows geoscientists to "see" reservoir events such as a gas cap enlarging as oil is produced. In the future, real-time reservoir models will use these techniques to allow quick updating as new data are available, thus enabling drilling and field development decisions to be made quickly to enhance production.

- **Deep Wireline Measurements.** Deep measurements of gravity and electromagnetic forces provide information that complements the seismic data. Wireline-based deep measurements typically have higher resolution than seismic and can provide enhanced detail about gas location and movement.

- **Integrated Well Planning.** Integrated well planning is the process of effectively and accurately planning for optimum wellbore placement in the reservoir, determining suitable equipment/systems for completion and production, and maximizing reservoir output and economics.

- **Drilling Systems.** A major focus on drilling systems will continue, because drilling time is a major component of rig cost and thus the total cost of the well. Significant strides have been made in the last several years with regard to rates of penetration, equipment dependability, downhole data gathering, and drilling dynamics. The ability to steer and extend the wellbore both vertically and horizontally to zones of interest has increased significantly with the advent of extended reach wells, horizontal drilling, and multi-laterals

- **Deepwater Technology.** As exploration and production activities move deeper into the ocean, new technology will be essential for advancing offshore production systems. Traditional platforms are being replaced with new designs and subsea completions are becoming common place. New systems such as Floating Production Systems may have the potential to significantly extend producing systems to the ultra-deepwater areas if technology and cost challenges can be met.

The 1999 Study presumes that these technology advances and many others will form the basis for new innovations that increase exploratory success and optimize well production capability. Should technology advancements materialize at a slower rate, or should these technologies prove less valuable to producers than expected, the availability of future supply and the cost at which it is delivered could be impacted.

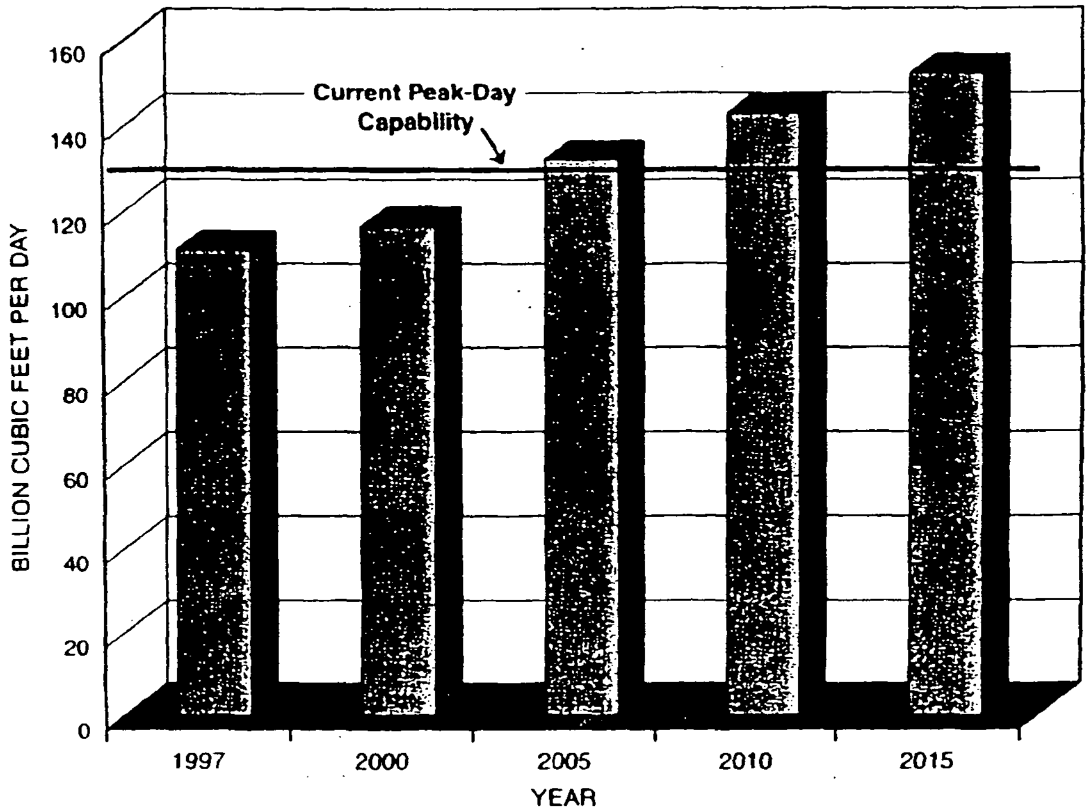
Findings of the Transmission & Distribution Task Group

Transmission/Distribution Finding 1: Significant expansion and enhancements to the delivery system are required to serve the growing demand.

Substantial changes are expected in natural gas supply and consumption patterns by 2015, which creates a need for enhancements to the existing delivery system and construction of new transmission and storage facilities. By 2015, annual requirements are projected to increase beyond 31 TCF, which equates to 88 BCF per day. Peak-day requirements will grow from approximately 111 BCF per day in 1997 to over 152 BCF per day in 2015, as shown in Figure 20. A significant investment in pipeline facilities will be necessary to meet the new demand requirements and shifts in supply locations to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic. These frontier supply basins will have increased pipeline costs because of their more distant location from markets, mitigation of potential environmental impacts, and harsher environments for construction, maintenance, and operation. However, the annual average expenditures projected in this study are consistent with historical trends.

The consumption of natural gas in the United States previously peaked in 1972 at 22.1 TCF. Since then, geographic shifts in supply and demand (such as the decline of the industrial Midwest and increases in supply

Figure 20. Peak-Day Demand by Year



Source: EEA, Inc., Gas Market Data and Forecasting System.

from the Rockies and Canadian imports) has caused the transmission and storage system to expand more slowly than otherwise expected. Today there are more than 270,000 miles of gas transmission pipelines and approximately 3.2 TCF of working gas storage capacity (Figures 21 and 22). The U.S. delivery system also includes another 952,000 miles of gas lines owned by the distribution segment of the industry. Through 2015, approximately 38,000 miles of transmission pipeline and 255,000 miles of distribution mainlines are projected to be needed to meet the requirements of the projected market. This rate of growth is comparable to the expansion experienced in the last few years. In addition, working gas storage will increase by 0.8 TCF.

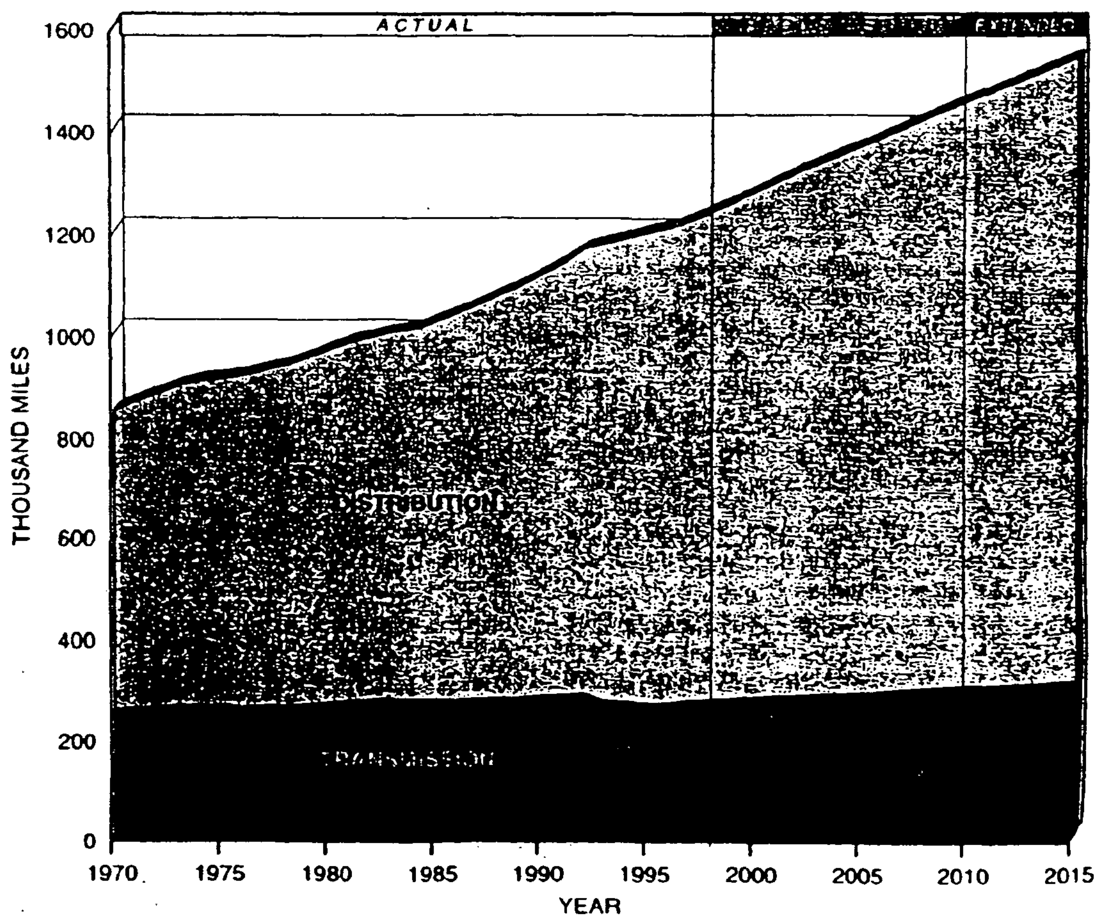
The existing transmission and storage system is capable of meeting its existing firm requirements on an annual and peak-day basis. Analysis indicates that the system had a 1997 annual capacity of 45 TCF and a daily capacity of 131 BCF. This additional capacity above the 1998 annual consumption of 22 TCF, and estimated firm peak-day demand of 111 BCF per day, allows non-firm customers to use this capacity on peak days, provides necessary redundancy, adds reliability, and enables the system to support a growing U.S. gas market.

Peak-day requirements represent the sum of all loads on a system on the day of highest demand (as measured by volume). Any particular system must have the ability to meet its customers' firm requirements on design peak days. Gas utility systems use a combination of flowing gas and storage gas to meet their customers' firm requirements on these days.

The space-heating load is highly dependent on the impact of unpredictable winter weather. For this reason, almost all U.S. gas pipelines and distribution companies experience their peak day during the winter months. During the remaining months of the year, these utilities have unutilized capacity beyond that needed to meet market requirements and to refill storage.

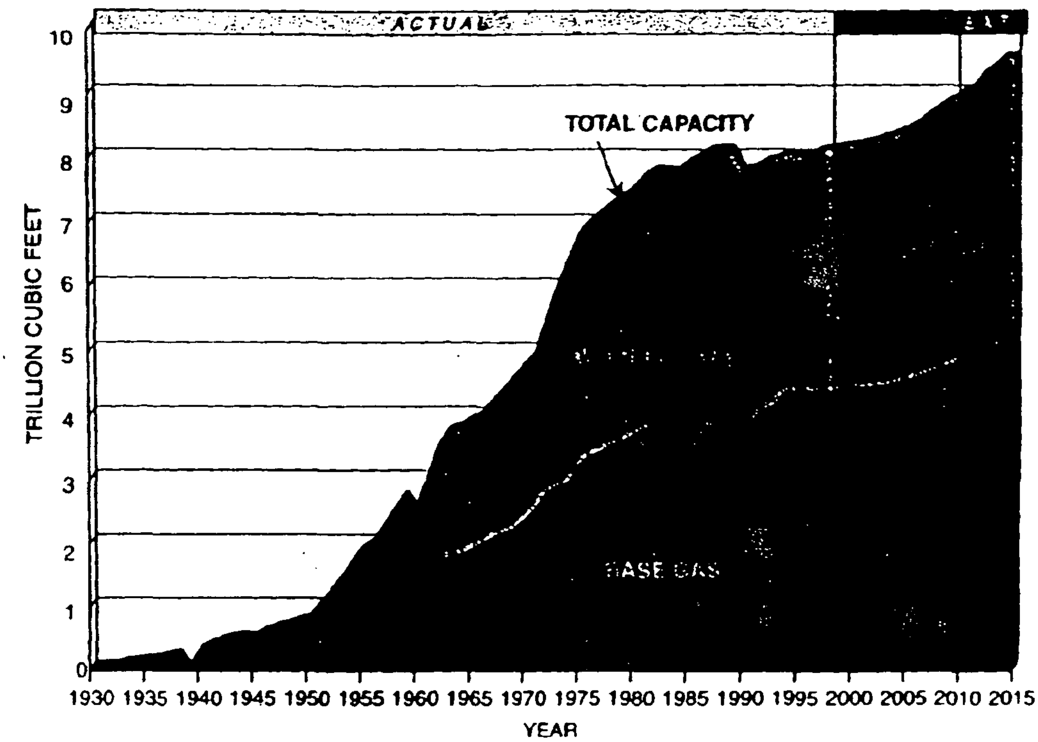
In general, the increased demand projections for 2010 and 2015 in the residential, commercial, and industrial sectors will also increase peak-day requirements and thus necessitate construction of additional pipeline and storage facilities. Contracts with some customers, principally industrials and electricity generators, may limit consumption on peak days and allow (or require) them to switch to another fuel. Some customers are unable to switch fuels due to restrictions from environmental regulations. This is becoming more common, particularly for the new electricity generation facilities, as fuel-switching capabilities are becoming more difficult to permit in some areas of the United States. Thus, the new electricity generation load will likely have a higher impact on peak-day requirements than in the past. However, some level of fuel-switching capability is necessary to handle overall energy needs on peak days and to lessen pipeline and storage expansion needs.

Figure 21. U.S. Natural Gas Pipeline Cumulative Mileage



Source of historical data: American Gas Association, *1998 Gas Facts*.

Figure 22. Underground Natural Gas Storage Capacity



NOTE: Prior to 1962, storage data not distinguished between Base Gas and Working Gas.

Sources: Total Capacity: American Gas Association, Engineering Technical Note, *Underground Storage in the U.S. and Canada–1990*, April 1991.
Base Gas: Energy Information Administration, *Annual Energy Review 1990*, p. 175.
Working Gas = Total minus Base.

Two shifts in the flows on the transmission system have developed recently. The first is the decrease in Gulf Coast and Mid-Continent supply moving to the Midwest (i.e., Chicago area). This was caused by slow market growth in the Midwest and displacement of Gulf Coast and Mid-Continent supply by Rockies and western Canadian supply as additional pipeline infrastructure has come on line. The second is the increase in Gulf Coast supply to the Southeast that was caused by the large increase in market demand. Supply increases from the Rockies and western Canada will be landing in the Midwest area, turning Chicago into a supply hub at some point in the near future. The Reference Case shows that significant new or incremental transmission capacity will be built from the Rockies to California, Canadian Atlantic to New England, Gulf of Mexico to Florida, western Canada to the Pacific Northwest, and the Mackenzie Delta to Alberta.

Transmission/Distribution Finding 2: Access issues impede installation of new infrastructure.

The anticipated shifts in supply regions and regional growth patterns will require building pipelines to tap new supply sources, expanding infrastructure along existing corridors, building laterals to attach new markets, and attaching new storage facilities to the pipeline grid. A fundamental requirement to develop this infrastructure is access to land for attaching, gathering, and processing the natural gas and then transporting the natural gas

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to market or to storage fields for eventual delivery to market.

Issues related to access have become more prominent for the transmission and distribution sectors of the industry. Access issues arise from urban sprawl encroaching on potential and existing rights-of-way and eliminating potential pipeline routes, heightened public resistance to providing easements, and increasingly restrictive government policies and regulations. Some of these issues are exemplified by public protest to recently proposed pipeline projects from the Midwest to serve Northeast markets. Both industry and government have taken action to address the public's concerns. For example, FERC recently amended regulations by adding landowner notification requirements and also issued orders to help facilitate pipeline projects. However, the following examples of proposed policy/regulatory changes demonstrate a movement toward additional requirements for the building and maintenance of pipelines.

- The U.S. Fish & Wildlife Service (FWS) has developed a "Draft Compatibility Policy Pursuant to the National Wildlife Refuge System Act of 1997" that would significantly impact the ability to obtain permits from the FWS for non-wildlife-dependent activities.
- On July 21, 1999, the Corps of Engineers proposed to modify Nationwide Permits in certain areas, which if implemented could affect the ability to obtain permits in a timely and cost-effective manner.
- On September 15, 1999, the Federal Energy Regulatory Commission issued a Statement of Policy (Docket No. PL99-3-000) that it will use in deciding whether to authorize the construction of major new pipeline facilities. The change in policy now requires that an applicant demonstrate that the economic benefits to the public outweigh adverse impacts. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis and consider other interests. Prior to this policy change the economic test was much simpler, relying on the percentage of long-term contracts as the measure of demand for a proposed project.

Careful consideration must be given to these and similar issues in order to balance the myriad of interests that exist. The consequences of conflicting policy and regulations within and across government agencies will lead to higher costs, either directly or via delays. Natural gas has its own environmental benefits that should be taken into account when formulating policy so that an appropriate balance can be achieved.

Transmission/Distribution Finding 3: New services are needed to serve a changing market.

The evolving competitive nature of the natural gas industry requires new mechanisms for existing and new customers to gain access to transportation services at competitive prices. As the LDCs' requirements to hold interstate pipeline capacity decline, marketers, producers, and other end-users will be contracting for the capacity. Many of these customers use capacity differently than the LDCs, because their individual load requirements and physical capabilities differ from the aggregated load and system capabilities of the LDCs.

The current delivery system was built and optimized over decades to meet the design peak-day requirements of firm service customers that are primarily residential, commercial, and to a lesser extent, industrial and electricity generation customers. To date, the "seasonal slack or off-peak slack" in the delivery system has been adequate to meet the levels of demand placed on this system by electricity generators. Looking ahead, the anticipated tremendous growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as growing peak-day requirements. For example, electricity generators (using high-efficiency combustion turbines) require significantly higher inlet pressures and higher hourly flow rates than other end-use customers (and previous generation turbines). In addition, the loads for peaking generators are volatile and of relatively short duration, thereby requiring greater flexibility and quicker responses by the natural gas delivery system. Meeting these requirements, as well as the increasing peak-day requirements of the other sectors, on a significantly larger scale will entail changes in physical capabilities, operational procedures, communications, contracting (supply and transportation), and tariffs.

Transmission/Distribution Finding 4: The restructured market changes the risks associated with investments for new infrastructure.

While the capital required for transmission and distribution infrastructure expansions is not of the same magnitude as for the upstream sectors, investment issues are just as critical. The Reference Case shows that transmission and distribution companies will need to make capital investments of approximately $123 billion through 2015. This total includes $35 billion for transmission pipelines, $84 billion for distribution facilities, and $4 billion for storage. Clearly, companies will need to make considerable investments in infrastructure to serve new customers, manage seasonal and peak-day demand swings, and replace aging facilities. The magnitude of the expenditures is in line with historical averages, but restructuring has introduced new risks associated with investments.

The primary question that looms in this segment of the industry is about who will accept the risk of financing and constructing major new facilities. In the past, downstream investments in gas pipelines and storage fields were heavily regulated. LDCs, as franchise holders, had principal access to the end-use market and thus had a level of certainty that supported the investment in new facilities. The industry restructuring over the last two decades has led to changing roles and obligations—as well as new risks and different risk profiles—for all the industry participants. Many pipeline shippers now attach little value to holding contracts for firm service of more than three years. The shippers' need to limit their long-term exposure does not align with the pipelines' need for long-term contract commitments to justify investment risk. In addition, industry restructuring can impose a myriad of challenges/risks to gas utilities that should be considered in the regulatory process. Faced with these changing conditions, it is not clear who will be willing to accept the risks for building the infrastructure needed to support the growth in natural gas demand.

Appendix A

The Secretary of Energy
Washington, DC 20585
May 6, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

In 1992, the National Petroleum Council released a study entitled, "Potential of Natural Gas in the United States." That study was critical in identifying natural gas as an abundant domestic resource that can make a significantly larger contribution to both this Nation's energy supply and its environmental goals.

Since the release of the study, the Nation has experienced five years of sustained growth in the use of natural gas. In addition, the study did not anticipate at least two major forces that are beginning to take shape, which will profoundly affect energy choices in the future -- the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality. These issues offer opportunities and challenges for our Nation's natural gas supply and delivery system. For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand.

Accordingly, I am requesting that the Council reassess its 1992 study taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

Given the significance of this request, Deputy Secretary Elizabeth Moler will co-chair the study committee. I offer my gratitude to the Council for its efforts since our meeting in December 1997, to assist the Department in defining a more concise study scope. The breadth of issues related to natural gas supply and demand is vast and I recognize that further refinements in scope may be necessary once the study is underway to address the most significant concerns about future natural gas availability.

Sincerely,

Federico Peña

The Secretary of Energy
Washington, DC 20585

November 18, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

This is to convey my approval to establish a Committee on Natural Gas and to appoint industry members as proposed in your letter of October 6, 1998. I also approve the establishment of a coordinating subcommittee and the appointment of subcommittee members identified in your letter.

The Deputy Secretary will serve as the Government co-chair of the committee; the Assistant Secretary for Fossil Energy will co-chair the coordinating subcommittee. Staff involved in this study will be from the Office of Fossil Energy and the Office of Policy and International Affairs. In addition, the Energy Information Administration has expressed an interest in providing technical and analytic support. The Deputy Assistant Secretary for Natural Gas and Petroleum Technology will serve as the alternate for the Government co-chair of the subcommittee.

I agree that it would be appropriate for a representative of the Department of the Interior to be a member of the coordinating subcommittee, and we are pursuing this issue.

For a secure energy future, Government and private sector decision-makers need to be confident that industry has the capability to meet the significant increases in natural gas demand forecasted for the twenty-first century. I am pleased that the National Petroleum Council recognizes the challenge facing the domestic natural gas industry and has agreed to conduct a study of natural gas supply availability. I look forward to the study's results.

Yours sincerely,

Bill Richardson

Bill Richardson

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Description of the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Enhanced Oil Recovery (1984)*
- *The Strategic Petroleum Reserve (1984)*
- *U.S. Petroleum Refining (1986)*
- *Factors Affecting U.S. Oil & Gas Outlook (1987)*
- *Integrating R&D Efforts (1988)*
- *Petroleum Storage & Transportation (1989)*
- *Industry Assistance to Government (1991)*
- *Short-Term Petroleum Outlook (1991)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990—Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues—A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration—A Supplement to the NPC's Report: Future Issues (1996)*
- *U.S. Petroleum Product Supply—Inventory Dynamics (1998).*

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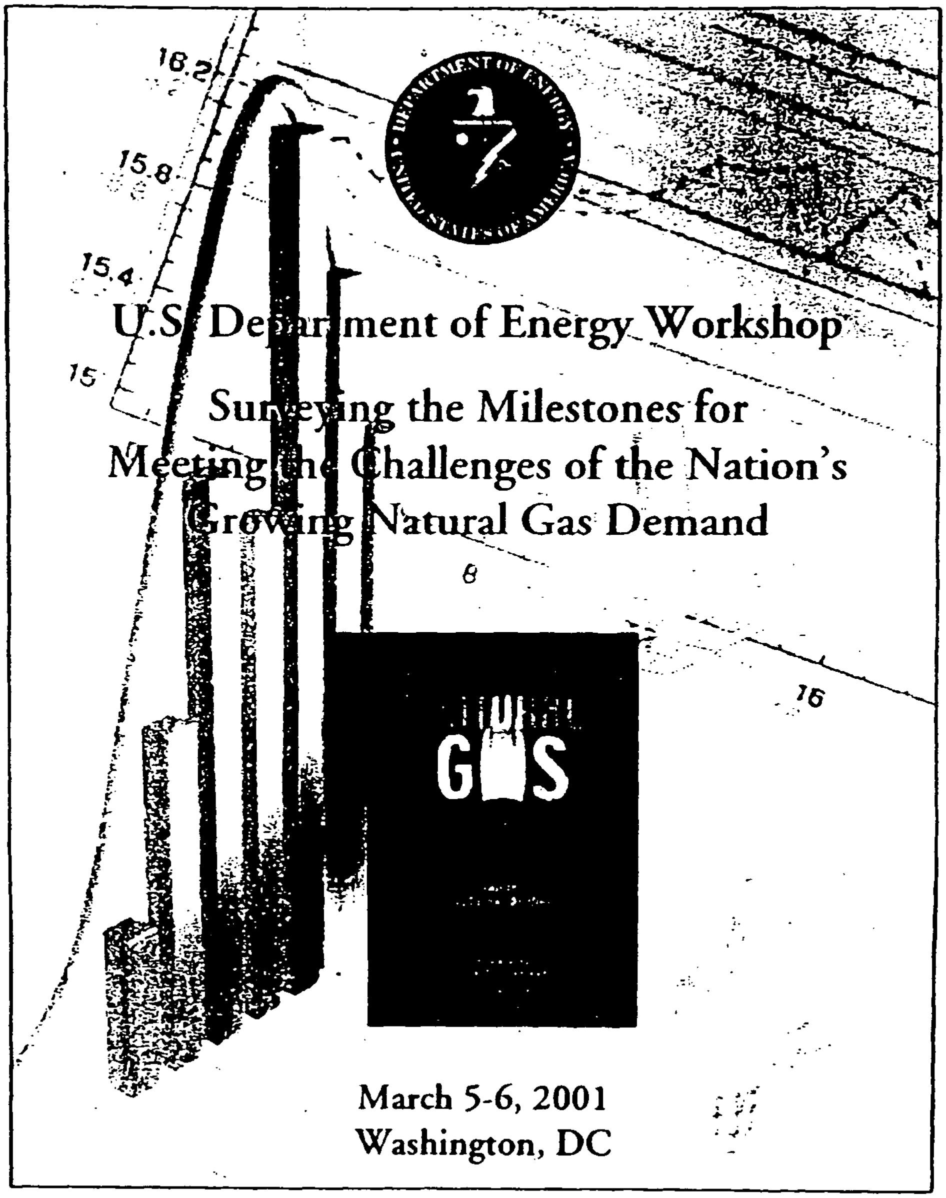
WORKSHOP SUMMARY



U.S. Department of Energy Workshop

Surveying the Milestones for Meeting the Challenges of the Nation's Growing Natural Gas Demand

March 5-6, 2001
Washington, DC

2993

DOE006-0350

Summary of U.S. Department of Energy Workshop on Surveying the Milestones for *Meeting the Challenges of the Nation's Growing Natural Gas Demand*

A Review of the National Petroleum Council's December 1999 Report

March 5-6, 2001

Washington, DC

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Acknowledgments

In the last decade, as the United States has moved towards ever-increasing reliance on natural gas as the fuel-of-choice for the 21st century, the Department of Energy (DOE) has looked to the National Petroleum Council to provide expert analysis and recommendations on the key issues affecting natural gas.

The National Petroleum Council is a federal advisory committee to the Secretary of Energy whose members include representatives of the oil and gas industry, consumer and environmental groups, the financial community, and states, among others. Its sole purpose is to advise, inform, and make recommendations on any matter requested by the Secretary relating to oil and natural gas or to the oil and natural gas industries.

The Secretary of Energy first asked the Council to analyze the domestic natural gas industry and assess its potential to increase its role in the Nation's energy supply mix in 1990. The Council responded with a comprehensive report in 1992 that served as the foundation for much of the natural gas discussions and policy decisions made since that time. As the Nation's move to natural gas grew even faster than anticipated the Council responded to another Secretarial request with a second comprehensive report on natural gas in 1999. More than 150 individuals participated in developing the 1999 report.

The National Petroleum Council has continued to support the Department of Energy in its efforts to keep up to date on evolving issues in the dynamic North American natural gas market. Specifically, it helped the Department organize a workshop on March 5-6, 2001 in Washington, D.C. to survey the milestones on assumptions, findings, and recommendations set forth in the 1999 Council report. More than 50 individuals, representing a wide array of energy interests including natural gas suppliers and transporters, electric utilities, trade associations and federal agencies, participated in the DOE workshop.

The Department expresses its gratitude to the Council for helping to make the March 5-6, 2001 DOE workshop a success. In addition, the Department would like to acknowledge the substantive work and expert advise of: Edward Gilliard, John Guy, John Hull, Paul Kelly, Marshall Nichols, Tommy Nusz, Blaise Poole, Matthew Simmons, Advanced Resources International (Vello Kuuskraa and Jeffrey Eppink), Energy and Environmental Analysis, Inc. (Harry Vidas and Kevin Petak), and Technology & Management Services, Inc. (Feridun Albayrak). Each of the workshop participants made valuable contributions to the discussions. Department of Energy personnel supporting the conduct of the workshop included: David Costello, Guido DeHoratiis, Nancy Johnson, James Kendell, Robert Kripowicz, John Pyrdol, Trudy Transtrum, and William Trapmann.

Workshop Summary

Introduction

In the last ten years, the U.S. has struggled with the decision of what fuel, or fuels, to rely on to power the Nation's economy as we move into the 21st century. Two of the primary criteria in this decision are that the fuel has to be available in secure, reliable, and reasonably-priced volumes, and that the fuel has to contribute to the goal of protecting the environment. Out of this process, natural gas clearly emerged as the fuel-of-choice for the coming decades.

In 1990, when it first became apparent that natural gas might play a bigger role in meeting the country's needs for a clean and reliable fuel, Secretary of Energy James Watkins asked the National Petroleum Council (NPC) to undertake "...a comprehensive analysis of the potential for natural gas to make a larger contribution, not only to our Nation's energy supply, but also to the President's environmental goal." The Council responded with a 5-volume report in 1992 entitled, *The Potential for Natural Gas in the United States*, which concluded that "natural gas has the potential to make a significantly larger contribution both to this Nation's energy supply and its environmental goals." This was a landmark report that encouraged U.S. industry and government to rely on natural gas to meet the Nation's energy and environmental goals.

The NPC 1999 Report

By 1998, it was apparent that the move towards natural gas envisioned in the 1992 NPC report was occurring even faster than expected due to growing industrial demand, slower-than-expected improvements in end-use efficiencies, and restructuring of the electric utility industry. In response, Secretary of Energy Federico Peña asked the Council to "...reassess its 1992 study taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond."

The NPC delivered its report, *Meeting the Challenges of the Nation's Growing Natural Gas Demand*, to Secretary Bill Richardson in December 1999.

Today, natural gas supplies almost a quarter of the Nation's energy needs. As projected in the NPC 1999 report, demand is expected to grow by almost a third by 2010, increasing to 29 trillion cubic feet (Tcf) in 2010 and to beyond 31 Tcf by 2015 (Figure 1). Demand will increase in all consumption sectors—residential, commercial, industrial, and electricity generation—with the largest growth in electricity generation as natural gas remains the preferred fuel for new electricity generation facilities (Figure 2) and in all regions of the country (Figure 3). More than 14 million new customers will be connected to natural gas supply by 2015 and many more will find their growing electricity needs met by gas-fired generators.

As described in the 1999 report, the Council found that the domestic natural gas resource base was adequate to meet increasing gas demand for many decades. It also found, however, that realizing the full potential of natural gas use in the United States would require focus and action on seven critical factors including:

- access to resources and rights-of-way,
- continued technological advancements,
- financial requirements for developing new supply and infrastructure,

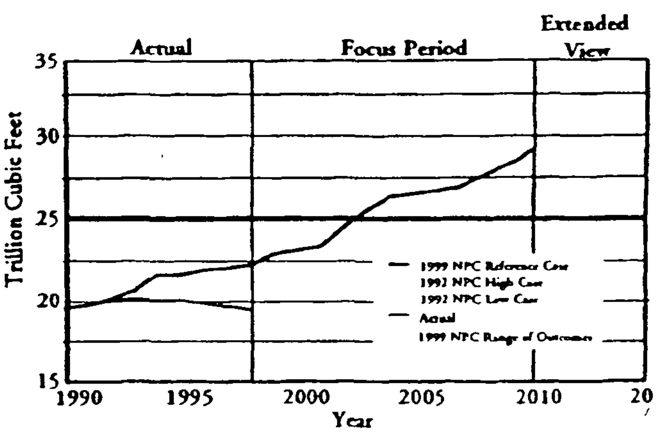
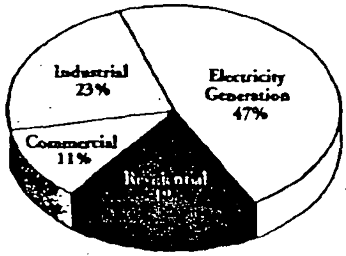


Figure 1. U.S. Natural Gas Demand. Comparison of 1992 and 1999 NPC Reports.

- availability of skilled workers,
- expansion of the U.S. drilling fleet,
- assuring reasonable lead times for development, and
- meeting changing customer needs.



- Natural gas can make an important contribution to the Nation's energy portfolio
- Reliability is key–14 million new customers by 2015
- Conservation and energy efficiency still needed

Figure 2. Natural Gas Demand Growth in NPC Reference Case (1998-2010): Distribution of 7 Tcf Increase by Sector.

In response to these concerns, and to ensure that the mutual goals of government, industry and consumers are met, the Council in 1999 recommended that:

- an interagency group be formed at the highest levels of government to create a strategy for natural gas in the Nation's energy portfolio,
- a balanced, long-term approach for responsibly developing the Nation's natural gas resource base be established,
- technology research and development be emphasized,
- a plan for capital, infrastructure, and human resources be created,
- government processes that impact gas development be streamlined to eliminate duplication and conflicting directives,
- the impact of environmental regulation be assessed to objectively weigh the environmental benefits of natural gas consumption versus the environmental impacts of natural gas exploration and production, and
- new services be designed to meet changing customer needs.

The Council also recommended that, recognizing the Nation's changing energy needs and the dynamic nature of natural gas markets, the Department should periodically monitor trends in the assumptions used in the study and progress in meeting the critical factors identified in the report.

DOE'S Workshop on March 5-6, 2001

Since the NPC report was released in December 1999, the domestic natural gas market has experienced considerable volatility with prices for natural gas reaching as high as $10 per million Btu (MMBtu) on the spot market. In 2000, average wellhead prices were about $3.40 per MMBtu ($1998), 70% higher than the typical $2 per MMBtu price seen in the 1990s (Figure 4). Historically high gas storage withdrawals and imports were required to meet gas demand. In view of these recent market events, and concerns raised that demand for natural gas may be increasing at a rate that the natural gas industry may find difficult to supply, it was clear that a review of the report and its assumptions would be useful.

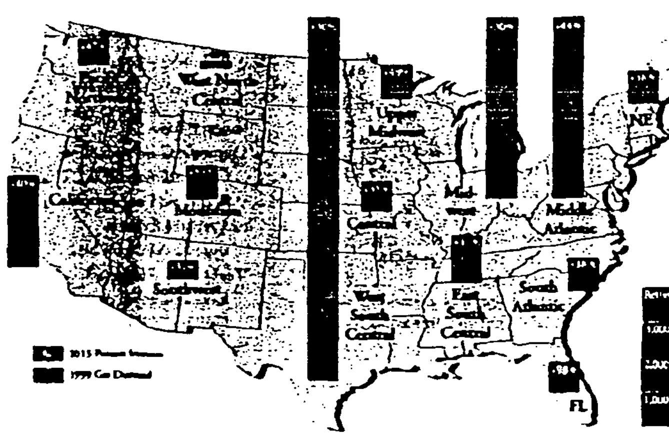


Figure 3. Natural Gas Demand Will Increase In All Regions (1999 NPC Reference Case).

Accordingly, the Department sponsored a workshop on March 5-6, 2001, to provide an opportunity for industry and government executives, especially those individuals who participated in developing the NPC 1999 report, to discuss and share their individual observations on the report and changes that have been seen in the marketplace since the report was released.

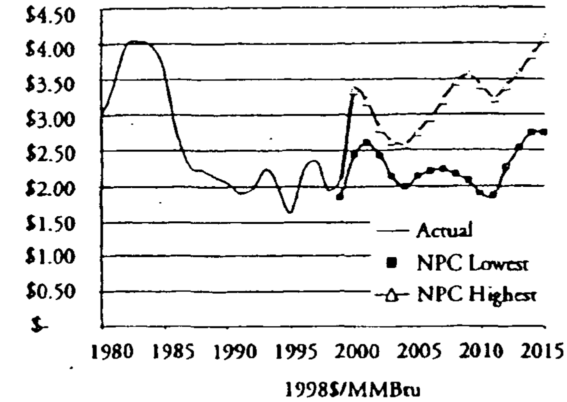


Figure 4. Average U.S. Wellhead Gas Price—1999 NPC Cases.

A "roadmap" highlighting key assumptions from the NPC 1999 report provided the backdrop for workshop discussions (Figure 5). In three areas that corresponded to Task Groups previously organized by the Council —Demand, Supply, and Transportation and Distribution—the workshop participants reviewed:

- assumptions used in the NPC 1999 report Reference Case or derived from the modeling results,
- changes in natural gas market conditions and public policies since the NPC 1999 report was released,
- the magnitude of these changes (e.g., as compared to results or sensitivity analyses from the NPC 1999 report), and
- possible implications these changes may have for the results, findings and recommendations of the NPC 1999 report.

The Department requested that the workshop participants share their expert insights and observations on the recent events in the natural gas industry, and did not seek a consensus view. The purpose of the workshop was for the participants to gain an improved understanding of our Nation's energy situation and the evolving role of natural gas in meeting the energy needs of consumers.

Reference Case

Sensitivity Cases
- Resource Base
- Technology
- Oil Price
- GDP
- Access

Demand

*U.S. GDP Growth
U.S. Industrial Production Index
Canadian GDP Growth
Crude Oil Prices
*Electricity Demand
*New Powerplant Construction
Powerplant Fuel Switching Capability
Nuclear Plant Relicensing
Coal and Nuclear Capacity Utilization
Industrial and Residential/Commercial Natural Gas Demand
Weather

Supply

Resource Base
*Domestic Gas Production
Conventional, GOM, Unconventional
Wells and Footage Drilled
Imports and Exports
Canada, Mexico LNG
*Technology Progress
Exploration Success
Drilling Efficiencies
*Access to Resources
Financial Requirements

Transmission/Distribution

*Major Projects Completed and Planned
Basis Differentials
LNG Imports
*Frontier Pipeline Projects (Alaska, NW Territories)
*Pipeline Construction Costs
Gas Storage Costs
New Services
Access to Rights of Way
Financial Requirements

*Key issues.

Figure 5. NPC Natural Gas Study Roadmap.

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Workshop Commentary

Over the past two years, a number of significant changes have taken place in natural gas markets. Demand has increased significantly, driven primarily by power generation needs, while domestic production has not kept pace with demand. The situation reached levels of significant concern this past December when the "perfect storm" hit domestic gas markets. Following a cold November, December was even colder—over 20% colder than normal. Gas storage had already been heavily drawn down and, the supply/demand balance was tight as end-users that could switch to oil had already done so. As a result, in December 2000, wellhead natural gas prices nationwide averaged $5.55 per MMBtu, almost three times the prices one year earlier, and peaked at over $10.00 per MMBtu.

The increased demand over recent months has been made up mostly by one-time increased drawdown from storage, as well as increased imports from Canada and decreases in demand (fuel switching and reduced consumption in the industrial sector). The extent to which these trends can continue is unclear. It appears that demand will continue to grow as least as quickly as envisioned in the 1999 NPC report, and possibly faster. As a Nation, we need to examine closely how the marketplace will accommodate this increased demand for natural gas.

With respect to oil prices, the NPC Reference Case oil price assumption was $18.50/bbl West Texas Intermediate (WTI) in real 1999 dollars and $16.50 for refiners average cost of crude (RACC). These prices were chosen for the study because they are the actual long-run average over several decades. (High Oil Price and Low Oil Price sensitivity cases assuming long-run WTI oil prices of plus or minus $3.50/bbl were also run.) Actual oil prices (Figure 6) in 1999 and 2000 were higher than even the High Oil Price case. The high oil prices stimulated drilling activity and led indirectly to higher gas prices through much of 2000 when gas competed with distillate and fuel oil at the burner tip.

There was discussion among the participants that if oil prices stayed high, upward pressure would be placed on gas prices because in the NPC Reference Case and in most of the sensitivities, potential gas demand was projected to be switched to oil to balance the market. If oil prices were higher, then gas prices would also be higher than projected. While these higher prices would bring in more gas supply, they might also inhibit long-term gas demand by, for example, making coal more economic for new power plants.

The participants discussed the fact that about 12,000 megawatt (MW) of new coal capacity beyond that projected in the NPC study has already been announced in the last six months due to high gas and oil prices. There was some disagreement as to whether these and other new coal plants that might be planned in the future would add to the NPC projection for coal generation or make up for old coal plants that will be retired due to the high cost of retrofitting environmental controls.

As might be expected, workshop participants presented a range of views, from expectations that the marketplace would shortly come back into balance, albeit at higher price levels than in the past, to more ominous views that acute natural gas shortages may be in the offing in the near future. What became clear, however, was that there may be inadequate data at this time with which to decide among differing views regarding the implications of nascent trends.

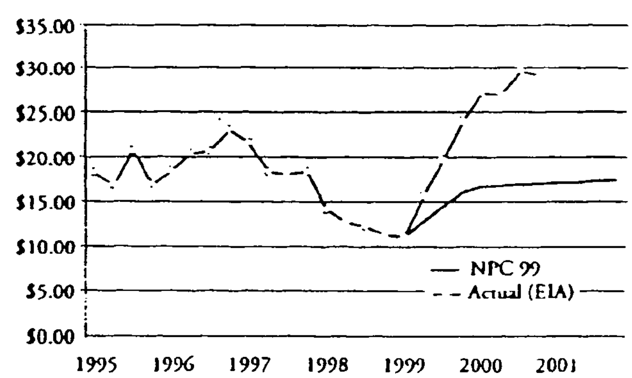

Figure 6. Oil Price (RACC) (Nominal U.S. Dollars per Barrel).

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Participants universally saw the need for increased benchmarking of key demand, supply, and transmission and distribution milestones, which would help clarify the situation. Further, there was a call to reconvene another workshop in six to nine months when improved data on year 2000 and information on trends for 2001 would be available and more meaningful directions could be established.

The NPC 1999 report has been characterized as the most definitive body of information outlining industry's ability to meet future demand for natural gas in the United States. And, overwhelmingly, workshop participants reaffirmed the value of the NPC 1999 report and the validity of the recommendations therein. While the growth in natural gas demand projected in the report may turn out to be conservative if demand increases more rapidly than anticipated, the common theme expressed by workshop participants was that the results, findings and recommendations of the NPC 1999 report are even more critical today and that, as a long-range document, it remains valid. It was stated repeatedly that an even greater sense of urgency should be attached to its findings and recommendations, particularly for decision makers in government and industry.

The balance of this workshop summary presents the key issues and trends identified and discussed by workshop participants on natural gas demand, supply, and transportation and distribution. The report also examines the status of the critical factors set forth in the NPC 1999 report and highlights new issues that have emerged since the issuance of the report. Material from presentations made at the workshop can be found in the Appendix. For the sake of brevity, NPC 1999 report assumptions that were not considered by workshop participants to warrant critical benchmarking are not described.

Natural Gas Demand

The estimated actual gas demand in year 2000 was about 0.5 Tcf higher than expected by the NPC 1999 report reference case (Figure 7).[1] Workshop participants discussed how harsher weather in 2000, together with less electric production from hydro units, had contributed to the strong demand for natural gas. The participants also noted that unusually high net withdrawals from gas storage, both in the U.S. and Canada, helped meet the demand for natural gas when gas supplies were lower than expected in 2000.[2]

As foreseen by workshop participants, higher growth in the Gross National Product (GDP), greater installation of gas-fired power generation capacity, emerging environmental concerns, and government policies that encourage gas use, could all contribute to future gas demand growing even faster than set forth in the NPC 1999 report. Close monitoring and benchmarking of this issue was determined by the workshop participants be a high priority, particularly to provide reliable information to industry.

Given short-term GDP growth of 4.2% in 1999 and 5% in 2000, versus the long-term 2.5% annual growth

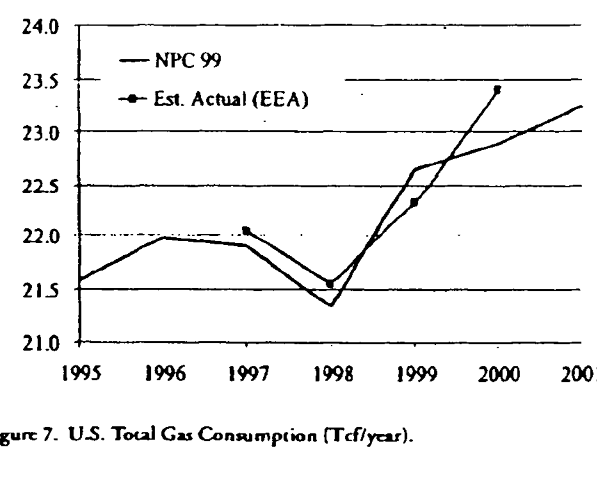

Figure 7. U.S. Total Gas Consumption (Tcf/year).

[1] Estimated actual demand for 1999 and 2000 were calculated by adjusting EIA's consumption data (source: EIA's *Natural Gas Annual and Natural Gas Monthly*) by their "balancing items" to less gas production and greater gas consumption for those years.

[2] While the NPC projection foresaw that the drilling declines in 1999 would lead to a very tight gas market in 2000, it had assumed that fuel switching to oil (rather than storage withdrawals) would balance the market. High prices for oil in 2000 prevented the fuel switching from occurring as anticipated.

assumed in the NPC 1999 report Reference Case (Figure 8), workshop participants stated that consideration should be given to using higher GDP growth rates of about 3% in future analyses of natural gas demand. It was noted that the EIA had increased expected GDP growth rates to 3% annually in recent analyses. (The NPC analysis also included a 3% GDP growth sensitivity case.) Participants observed that, if actual average GDP growth rates continue to be higher than the 2.5% average GDP growth rate used in the NPC Reference Case, the gap between actual natural gas demand and the Reference Case demand could widen significantly as time progresses.

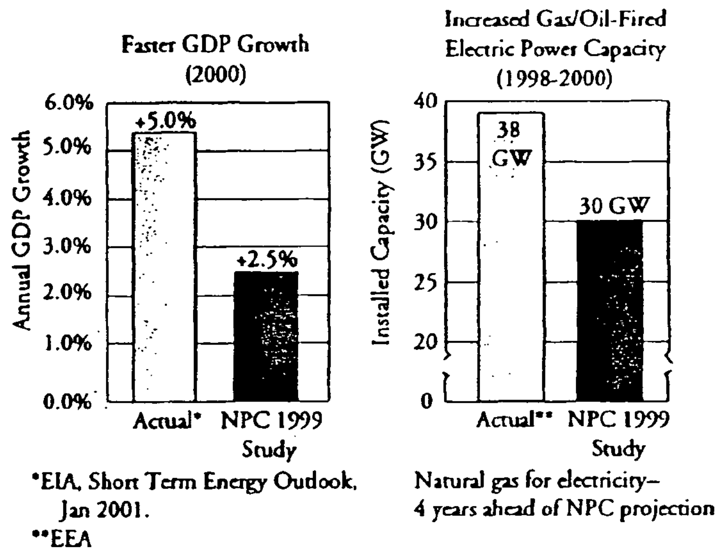

Figure 8. GDP Growth (2000) and Gas/Oil-Fired Electric Power Capacity (1998-2000).

Workshop participants acknowledged that more gas-fired power capacity had been installed in the past two years and that much more would be installed in the next several years than expected in the NPC 1999 report. Participants noted that the availability of data on the role and use of these plants, ranging from peaking to near base load, would be useful to better define new demand for natural gas from power generation.

Much workshop discussion centered on the need for improved data on national as well as regional electricity demand and capacity. Improved data on new gas-fired generating capacity was viewed as particularly important, as companies look to rebuild spare capacity in selected regions of the country, such as California and New England. It was noted that reduced electricity generation from hydropower had exacerbated the California power crisis, although increased utilization of nuclear plants had compensated for shortages in hydropower nationwide.

Considerable workshop discussion centered on establishing how much fuel switching actually took place last year when natural gas prices (on a Btu basis) exceeded distillate oil prices. Also, there were requests for improved data on the physical (and regulatory) ability to switch from gas to distillate and more reliable information on the fuel choices available to the Nation's industrial sector and how much reduction in industrial gas demand occurred this past winter as aluminum and ammonia plants shut down their manufacturing capacity and sold gas back into the marketplace.

Workshop participants expected that actions that may be taken to address concerns over the role of carbon dioxide (CO_2) and greenhouse gas emissions as well as controls on other coal-fired power plant emissions would likely increase the demand for natural gas. Placing CO_2 capture equipment in plants would significantly reduce (by 20 to 25%) the generating capacity of current coal-fired power plants.

Natural Gas Supply

Workshop participants recognized that supply is determined fundamentally by the quality of the resource base and the availability of appropriate technology by which to produce it. In the U.S., the natural gas resource base is large. But, at the same time, participants emphasized that the remaining domestic natural gas resource base is geologically complex and consists of smaller fields. The geologic quality of remaining resources is likely becoming poorer, or as described in the words of one participant, mimicking the popular political slogan, "It's the geology, stupid." One

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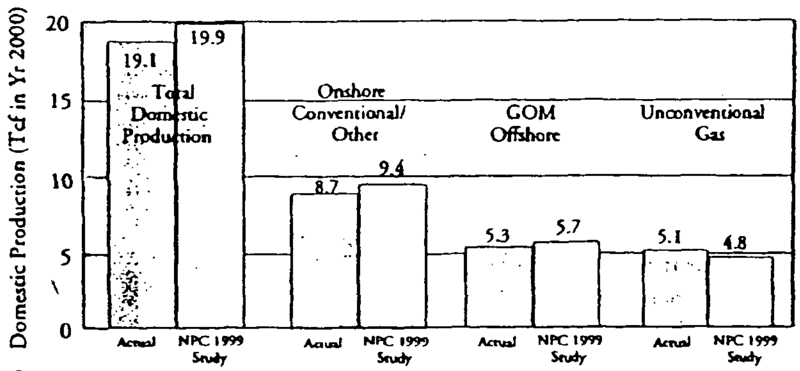
participant observed that his company has drilled prospects down to about 4 Bcf and what is left is smaller, tighter and costly to drill. He also noted that reserves growth is not as great for new fields as was the case in the past, suggesting that reserve growth factors should be monitored. It was stated that frontier areas such as the Arctic and deepwater offshore provide opportunities for improved exploration success and expanding the resource base, but that many of these frontier areas are on public lands and have access constraints. To address these issues, workshop participants suggested that trends in exploration and production (E&P) should be monitored to discern if reserve additions per well and field sizes are truly declining faster than anticipated, implying the need for more drilling and higher costs than anticipated in the NPC 1999 report.



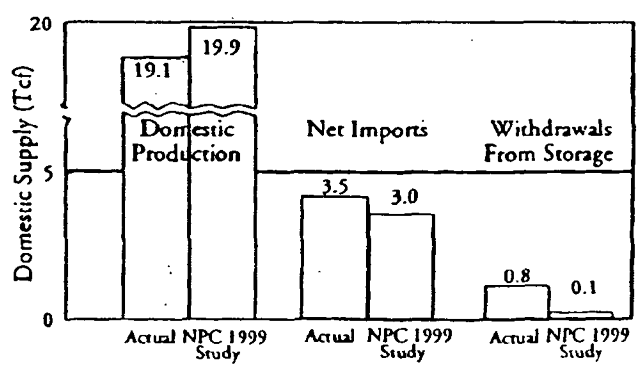
Source:
Total – EIA Monthly Energy Review, Jan 2001 (0.4 Tcf of Difference Due to Calibration Differences, NPC vs EIA).
Offshore – ARI estimates.
Unconventional – ARI estimates

Figure 9. Domestic Natural Gas Production for 2000 Was Below Expectations, Except Unconventional Gas.

In 2000, actual natural gas production in the U.S. relative to the NPC 1999 report Reference Case was lower than projected (Figure 9). Greater natural gas imports and withdrawals from storage were used to meet demand (Figure 10). Workshop participants indicated that prompt analysis of the reasons behind the (thus far) lower-than-expected supply response was essential for understanding the outlook for future natural gas supply.

Although domestic production for 2000 appeared to be less than anticipated in the NPC 1999 report, whether this is due to low prices in previous years inhibiting investment in new drilling, to time lags, or to poorer exploration success rates and drilling efficiencies is not yet clear. Several workshop participants expressed the view that sufficient time had passed for seeing a production response given the speed with which wells are hooked up to the pipeline system in the present market.

In contrast, progress in E&P technology appears to be lagging (Figure 11). The NPC 1999 report Reference Case assumed a 1.5% annual improvement in exploration success, while recent actual success rates appear to have declined. Similarly, drilling efficiency (footage drilled per rig per year) was assumed to improve 1.25% annually for operations onshore and in the shallow Gulf of Mexico (GOM) and 1.5% in the deepwater GOM. While drilling efficiency improved through 1998, recent data appear to show a decline. The group felt strongly that these issues need to be closely monitored, recognizing that more data is needed before it can be determined if these are short-term events or long-term changes in these factors. Ac-



Source: Energy Information Administration

Figure 10. Actual vs. Expected Sources of Natural Gas Supply 2000.

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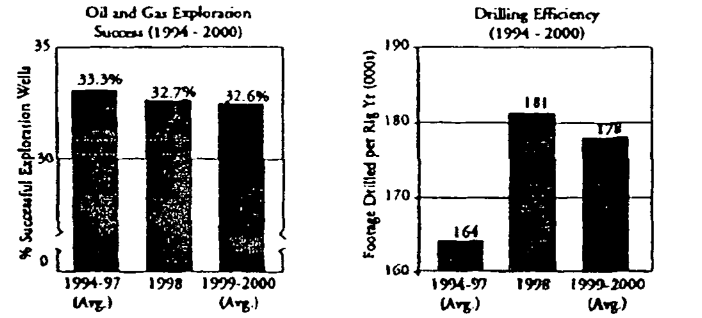

Source: EIA Monthly Energy Review, Jan 2001. Source: EIA Monthly Energy Review, Jan 2001.

Figure 11. Progress in E&P Technology.

celerating depletion rates were cited as one cause for overall flat or falling production and that depletion rates should also be monitored. As demand for natural gas increases, due to smaller field sizes and more rapid depletion, some perceive that industry may be "running in place" to maintain production despite doing all it can to increase the pace of drilling activity.

The group noted that near-term supply response will depend upon production from coalbed methane (CBM) and the deepwater GOM, which are being produced at rates higher than or equal to these projected in 2000.

Longer term, U.S. production will depend on having adequate technology to efficiently develop coalbed methane, deep gas, tight sands and other unconventional gas plays. Independents will continue to play the critical role in developing these new natural gas plays and will be users of newly developed technology. Observations were made that there have been very few "step change" improvements in exploration and production technology over the last decade, most notably being the wider application of 3-D seismic and horizontal drilling.

To meet future natural gas demand, the NPC 1999 report Reference Case projected that 14% of supply would come from the Rocky Mountains and 33% from the Gulf of Mexico. It was commented that when the Deepwater Royalty Relief Act, which has been cited by the Minerals Management Service (MMS) and industry as providing a stimulus to deepwater development, expired in December 2000, an opportunity was missed to continue the program and provide strong incentives for increased deep water production. It was noted, however, that the MMS extended deepwater royalty relief in a reduced form and also provided incentives for natural gas development on the shelf.[3]

Given the delayed domestic production response to drilling, much of the spare supply capacity to meet demand growth was consumed the past year. Canada has been exporting natural gas to the U.S. significantly in excess of NPC 1999 report projections. It was indicated by workshop participants that it is unclear whether Canadian production can uphold this trend. The Maritimes and Northeast pipeline, which came onstream a year earlier than projected at a rate of 440 million cubic feet per day, accounts for a portion of the increase in Canadian imports. Additional gas imports came from drawdown of Canada's gas storage. Participants indicated that further information would be valuable to more fully understand the nature of the gas supply from Canada. One encouraging note was that drilling in Canada is moving further toward frontier areas, northern basins, and deeper formations in established basins.

Participants also noted that pipelines from both Alaska and the MacKenzie Delta may be needed to meet future natural gas demand. Even though natural gas from these areas may not be available to the Lower-48 states until the 2008 to 2010 timeframe, action needs to be taken to preclude further delay. While pipelines from these areas may face economic competition with increased imports of LNG, it was stated that, most likely, both sources of gas supply would be needed.

Expanded supply is also expected to occur from the increased use of existing LNG facilities and the con-

[3] From the perspective of the Department of the Interior, a March 2001 Central Gulf of Mexico lease sale conducted with these terms was extremely successful yielding $505 million in high bids on 54 tracts (68% and 60% increases respectively, over the previous year's result, with increases evident at all water depths). Ninety companies participated, including 11 first time bidders.

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struction of new LNG facilities. New LNG facilities will need to make a positive case to the public on value and safety and will depend upon long-term price and supply in world markets.

Participants noted that exports of about 50 Bcf per year from the U.S. to Mexico may increase given projected growth in Mexican demand for natural gas, especially in border states due to the growing presence of NAFTA-related "maquilladora" manufacturing facilities in Mexico. Environmental compliance involving converting residual oil-fired power plants to natural gas and the manufacturing and population growth in the near-border areas would maintain increasing demand. A number of workshop participants predicted that, even with expanded natural gas development in Mexico's gas basins, Mexico would continue to call on U.S. natural gas supplies.

Finally, volumes of gas in storage at the end of this winter season are likely to be historically low. With the trend towards year-around gas demand for electricity, storage injections are likely to be low during the coming summer, raising concerns as to whether adequate injections can be made in preparation for the next winter season. It was also noted that demand to warrant new and extended storage capacity, while needed by power generators, is "just not yet there."

Transmission and Distribution

The NPC 1999 report assumed that over 5.2 Bcf per day of new pipeline capacity would be built in 1999 and 2000. Actual additions were 7.7 Bcf per day, exceeding expectations. Participants noted that, while this may be good news, future capacity installations face substantial challenges due to constraints on access to rights-of-way, landowner concerns and other factors. Through 2015, in the NPC 1999 report, it was projected that almost 300,000 miles on new transmission pipelines and distribution mainlines would be needed to meet the future natural gas demand. Despite recent gains in pipeline capacity, the need for a significantly expanded natural gas infrastructure remains. Future needs include new pipelines to reach supplies in frontier regions, expansion of existing pipeline systems, and new laterals to serve electricity plants.

While recognizing the continued need for responsible development by industry, new safety regulations were noted as a major concern for the industry by workshop participants. It is anticipated that these regulations may increase capital and operations and maintenance costs, may restrict gas flows, and increase costs to consumers. Additional inspections, valve replacements, making old lines "smart-piggable" and other requirements could add billions of dollars of increased costs. Lost capacity could also result, especially in the critical summertime period, as lines are undergoing inspection and upgrading.

Reliability of supply to end-users was also a concern. And, this issue is currently being reviewed by the Federal Energy Regulatory Commission. Such reliability concerns have to do with serving new power plants that will come online, but which operate only during certain periods of the day, creating new requirements on interstate gas transmission.

Pipeline costs have increased faster than expected, particularly for rights-of-way. In addition, demand pull has bid up contractor costs. It was noted that, although considerable pipeline capacity has been added in the past two years, future pipeline projects face increasing lead times, especially as a more dominant local role in the rights-of-way approval process emerges, leading one participant to comment that "All access is local."

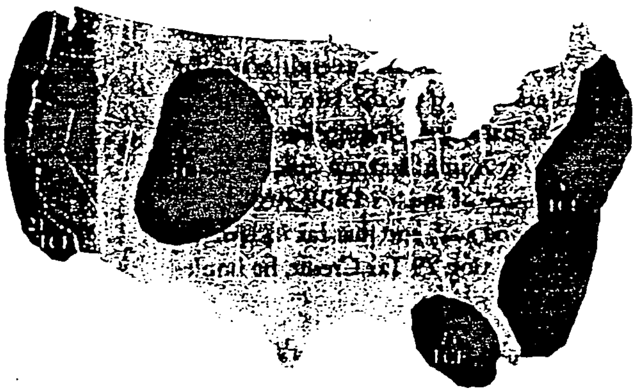
Critical Factors

The participants in the workshop reviewed the status of the seven critical factors that were identified in the NPC 1999 report. Participants stated that the critical factors remain valid and warrant action and close monitoring more than ever. Several workshop participants characterized the situation regarding some critical factors as having lost ground in recent months, rather than making progress towards a more positive outcome.

1. Access. Of the critical factors identified in the original NPC 1999 report, access received the greatest attention from workshop participants. In the Rocky Mountains, pending implementation of the recently established Department of Agriculture, U.S.

Forest Service policy on roadless areas will close an estimated 9 Tcf of technically recoverable natural gas resources to development in addition to the previous 29 Tcf that were identified as off-limits in the NPC 1999 report. With the roadless areas, resources subject to access restrictions in the Rocky Mountain region will now total 144 Tcf (an increase of 7 Tcf) (Figure 12).

It was noted that the industry has advanced technology such as "postage stamp" drillpads with which to drill in environmentally sensitive areas, but the view was expressed that this may not be enough to convince the public and policymakers to grant access. Rather, it may take stark supply consequences to convince the public that access is in the Nation's interest.



* Approximately 38 Tcf of the Rockies gas resources are closed to development and 106 Tcf are available with restrictions.

Figure 12. U.S. Lower-48 Natural Gas Resources Subject to Access Restrictions (NPC 1999 Study Plus Changes Through 2000).

Workshop participants suggested that the current Department of Interior (DOI) and Department of Energy efforts to inventory resources and related access restrictions (called for by the Energy Policy and Conservation Act) would be accelerated. Further comments, however, indicated concerns that DOI and DOE have inadequate funds and other resources to undertake a full and thorough inventory. In some instances, lease stipulations restricting access to federal lands have substantially reduced the drilling window and resulted in reduced rig availability and higher drilling costs.

Concerns were raised about the future of Destin Dome offshore Florida, development offshore California, and Lease Sale 181 in the eastern Gulf of Mexico (which was estimated in the 1999 NPC report to contain about 9 Tcf of resources) and could become closed to access. Concerns were also raised about whether federal land management agencies (e.g., Bureau of Land Management, Minerals Management Service, Forest Service) with jurisdiction over natural gas leasing, development, and permitting have adequate resources for increased, as well as existing, activity.

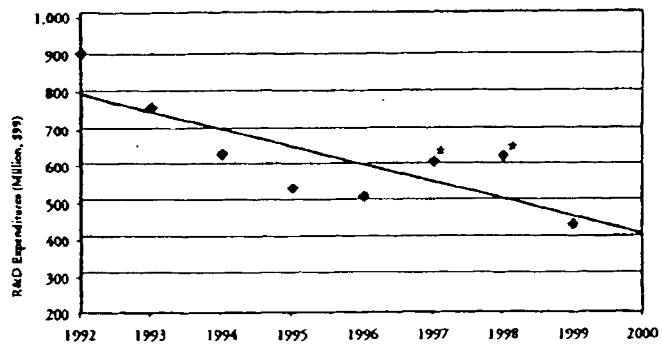
It was stated that, given the success of Canada's Sable Island developments, it would be useful to further assess the Atlantic Outer Continental Shelf (OCS) to provide better information regarding the resource potential in that area.[4] This recommendation was consistent with a prevailing workshop theme suggesting the need to match access to the resource base and regional supply with regional energy needs. ("Regional Supply for Regional Demand").

2. Technology. It was recognized by workshop participants that, although the data are preliminary, progress in technology does not appear to be keeping pace with expectations set forth in the NPC 1999 report. At the same time, workshop participants expressed concern that technology is now more critical than ever. One participant noted that, over the last 15 years, the industry has been able to hold production constant, even with fewer rigs and wells due to the aggressive use of technology. Other workshop participants noted that few, if any, breakthrough technologies appear to be on the immediate horizon.

Research and development (R&D) expenditures by major energy production companies have declined (Figure 13). Although some R&D efforts have been picked up by service companies and independents, data are not available to capture these R&D expenditures. In addition, the comment was made that, although R&D has shifted to the service sector, the research "cupboards are bare" for new technology.

[4] The concept of enabling DOI to gather information on the natural gas resource potential and conduct focused, limited leasing in "OCS Bright Spots" currently constrained by OCS moratoria has been discussed within the DOE OCS Policy Committee and other forums.

Given the severity of market imperfections for R&D, suggestions were made for new institutions and initiatives such as entities similar to those established in the late 1970s and early 1980s, namely the Energy Research and Development Administration (that formed the foundation of today's DOE R&D program in natural gas), and that tax incentives, such as the Section 29 Tax Credit, be implemented.



Source: EIA Performance Profiles of Major Energy Producers, 1999.
*Due to more activity, additional companies added to survey of Major Energy Producers.

Figure 13. R&D Expenditures by Producers for Oil and Gas Recovery Have Fallen by More Than 50% Since 1992.

3. **Financial Requirements.** Workshop participants noted that the recent higher natural gas wellhead prices have increased companies' internal cash flows and access to capital, although constraints remain, particularly for independents. It was noted that the alternative minimum tax was becoming a forefront issue, impacting the return on investment for new projects. There was concern stated that increases in E&P costs (particularly in well drilling and completion) may consume much of the increases in planned capital expenditures, restricting increased activity. Costs increases of 25 to 40% have been experienced already as labor and rig mobilization costs have increased.

4. **Skilled Workers.** Workshop participants noted that the past "boom and bust" cycles have damaged the stability of the production industry's work force. The availability of skilled rig hands and other E&P personnel now represents a serious constraint to increasing supply. Some workshop participants indicated that skilled workers (along with rig limitations) are now the most limiting factors for the industry. It was suggested that the solution will of necessity be a combined industry effort comprising such items as training programs, higher compensation, and assurances of stability. In the near term, labor shortages have resulted in companies in several states employing prisoners on work-release and foreign workers.

5. **Rigs.** Both onshore and offshore rig fleets are near capacity and rig constraints have emerged at least five years sooner than expected in the NPC 1999 report. Time lags of 4 to 6 months exist for securing rigs in South Texas. It was also suggested that new data on drilling costs be collected to benchmark these costs to cost expectations in the NPC 1999 report. Given the even greater-than-expected increase in demand for rigs (nearly 2200 by 2010 in the NPC 1999 report Reference Case), workshop participants cited the need for ideas on how to provide reliable market signals or contractual assurance to the rig construction industry. Given the natural gas price volatility of recent years, neither Wall Street nor the rig construction industry have confidence that prices and rig dayrates will remain high enough to justify investments in new rig construction.

6. **Lead Times.** Cumbersome permitting and approval processes, and lengthy study requirements at federal, state and local levels, remain a concern. Numerous workshop participants noted that problems with lease stipulations and access are increasing drilling costs and development lead times. One participant noted that the Minerals Management Service has done a good job in terms of expediting permitting for offshore drilling, but, onshore drilling is subject to delays, in part due to lack of sufficient Bureau of Land Management staff.

7. **Requirements of New Customers.** Workshop participants indicated that new customer requirements can be met, but that a primary issue is at what cost and how these costs will be recovered.

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DOE006-0365

NPC 1999 Recommendations

Workshop participants overwhelmingly reaffirmed the importance of the recommendations put forth by the Council in its 1999 report. Particular emphasis being placed on:

- government and industry taking a leadership role in establishing a strategy for natural gas in the Nation's energy portfolio (Recommendation 1)—as reflected in commentary on national energy policy, future fuel choices, and the confluence of factors including limited spare capacity in domestic and world energy markets that, if not addressed by government and industry, could increase the Nation's vulnerability to energy supply disruptions and higher energy prices that would adversely affect consumers and the economy;
- establishing a balanced, long term approach to responsibly developing the Nation's natural gas resource base (Recommendation 2)—as reflected in commentary on the importance of access to resources and rights-of-way, onshore and offshore;
- the need for technology advancement (Recommendation 3)—as reflected in commentary on drilling efficiency and the geologic complexity of the remaining natural gas resource base;
- the need for capital, infrastructure and human resources (Recommendation 4)—as reflected in commentary on increasing costs to produce and deliver natural gas to consumers, cash flow, investment markets, and shortages of skilled workers and drilling rigs; and
- streamlining government processes that impact natural gas development (Recommendation 5)—as reflected in concerns about development lead times and the adequacy of staff and other resources at federal land management agencies.

New Issues for Consideration

Public Education/Relations. A common theme expressed by many workshop participants was the need for educating the public regarding the challenges faced by industry in providing adequate and affordable supplies of natural gas to meeting the Nation's growing demand for natural gas. Currently the strong interest by the public in energy presents an opportunity for telling the "natural gas story."

The need for communication was expressed, for example, concerning the issue of access, where consumers may be unaware that restrictions on access drive up natural gas prices by limiting supply and discouraging transmission and distribution construction. Similarly, the public may not fully understand what efforts are necessary to turn a complex resource base into economically recoverable reserves and deliver natural gas to the Nation's homes, offices, and factories. Some workshop participants felt perspectives that individual resource areas such as the Atlantic or Pacific OCS may contain only a few year's supply of natural gas, and therefore should remain closed to access, are misguided. And, some suggested that more information needs to be shared with the public about the environmental benefits of the advanced technology. Effective communication between industry and parties that may be affected by its operations is a necessity.

Benchmarking. Workshop participants expressed satisfaction with the outcomes of the workshop and strongly recommended that, consistent with recommendations in the NPC 1999 report, government should undertake efforts in cooperation with industry to periodically "benchmark" actual market conditions relative to the expectations set forth in the NPC 1999 report. Specific items to benchmark include fuel switching, actual gas demand, field size distribution, production, especially Gulf of Mexico shallow water production, depletion, exploration success rates, reserve additions per well, drilling efficiencies, drilling costs, Canadian supply mix, and T&D costs, among others. It was suggested that another workshop would ideally be convened in the Fall 2001, when improved data on year 2000 and information on trends for the year 2001 would be available.

Conclusions of the Workshop

Due to a confluence of factors, the Nation now faces potential constraints in oil, natural gas, and electricity supply, all of which are needed for a growing economy. The situation is such that there is limited spare capacity and, as noted by some participants, "everything must go right" to meet current and future energy demand. Without prompt action by government and industry, America could face a spate of regional and national energy crises over the next decade. As summarized at the workshop, the solutions to the Nation's energy problems are complex and there is no "silver bullet." The Nation will need a mix of fuels, fossil and renewable, coupled with conservation to meet its future energy needs.

The aspiration among participants to stay informed, and to work to inform others, about the opportunities and challenges of natural gas supply was readily apparent. In the view of many workshop participants, the Nation has not had an adequate energy policy, particularly with respect to natural gas supplies in recent years. Furthermore, misunderstandings about the national energy supply situation and crises such as those experienced this winter tend to increase distrust of industry and the likelihood of what some participants perceive to be ill-conceived public policies, e.g., moratoria and price controls. Given current policies that constrain access to higher quality resource areas and other factors, industry will remain significantly challenged to increase supply.

Public debate is turning to a new focus of fueling the economy of the future. In this regard, a significant opportunity exists to highlight issues of concern such as access, technology progress, the need for expedited permitting, and a national strategy for natural gas as a component of the Nation's energy portfolio.

As highlighted in the Council's 1999 report, increased government and industry cooperation is needed to ensure adequate and affordable supplies of natural gas for American consumers. Similarly, natural gas is predominantly a North American resource, and a cooperative North American energy policy is needed to meet demand growth and accelerate supply development in Canada, Mexico, and the U.S.

Highlights of Workshop Commentary

Potential Actions for Government

- Improve interagency coordination
- Establish a national strategy for natural gas
- Review existing and proposed regulations and policies that may impact natural gas supply
- Increase access to resources and right-of-way (Federal lands inventory, Sale 181, Destin Dome, OCS Bright Spots)
- Streamline permitting and approval processes
- Consult with states (maintaining a national perspective)
- Maintain view of North American gas market and international sources of supply
- Encourage technology development
- Evaluate royalty relief and other financial incentives
- Monitor progress on Critical Factors

Appendices

U.S. Department of Energy Workshop

Surveying the Milestones for Meeting the Challenges of the Nation's Growing Natural Gas Demand

March 5-6, 2001

The Madison Hotel, 15th and M Street, N.W., Washington, D.C.

Meeting Agenda

March 5, 2001

1:00 p.m. Welcome and Overview—Robert Kripowicz, Paul Kelly

- Introductions
- Purpose of Workshop
- Findings and Recommendations of the National Petroleum Council's 1999 Study
- Public Policy Context

1:40 p.m. Agenda Review, Workshop Roadmap and Overview—Nancy Johnson, Vello Kuuskraa

2:00 p.m. Demand Review and Discussion—Matthew Simmons, James Kendell, Harry Vidas

3:00 p.m. Break

3:20 p.m. Supply Review and Discussion—Thomas Nusz, Guido DeHoratiis, Vello Kuuskraa, Jeffrey Eppink

4:20 p.m. Transmission and Distribution Review and Discussion—Blaise Poole, Harry Vidas, Kevin Petak

5:30 p.m. Adjourn

March 6, 2001

9:00 a.m. Summary of Day One and What's Ahead—Robert Kripowicz, Paul Kelly

9:15 a.m. Stepping Back and Assessing the Market and Industry Situation — Paul Kelly, Vello Kuuskraa, James Kendell

- Overall Significance of Changes
- Progress on Critical Issues
- Implications for 1999 Study Results, Findings and Recommendations
- Issues Warranting Continued or New Attention

10:30 a.m. Break

10:45 a.m. Next Steps for Industry and Government — Robert Kripowicz, Paul Kelly

- Workshop Proceedings
- Other

12:00 p.m. Adjourn

U.S. Department of Energy Workshop

Surveying the Milestones for Meeting the Challenges of the Nation's Growing Natural Gas Demand

March 5-6, 2001

The Madison Hotel, Washington, D.C.

Workshop Attendees

Workshop Chairs

Robert S. Kripowicz,* Acting Assistant Secretary for Fossil Energy, U.S. Department of Energy

Paul L. Kelly,* Senior Vice President, Rowan Companies, Inc.

Industry Attendees

Nancy Bagot, Manager, Government Affairs, Enron Corporation

Thomas A. Fry,* III, President, National Ocean Industries Association

Lee Fuller, Vice President, Government Relations, Independent Petroleum Association of America

Wayne Gibbens, President, U.S. Oil and Gas Association

Edward J. Gilliard,* Senior Advisor, Planning and Acquisitions, Burlington Resources, Inc.

John H. Guy, IV,* Deputy Executive Director, National Petroleum Council

James W. Hail, Jr.,* Executive Vice President, DeGolyer and MacNaughton

Patricia A. Hammick,* Retired Senior Vice President, Columbia Energy Group

George C. Hass,* Executive Director, Business Development, CMS Gas Enterprises

John S. Hull,* Director, Energy Market Analysis, Texaco Natural Gas

Hunter L. Hunt,* President, Hunt Power, L.P.

Mark H. LaCroix,* Reservoir Engineering Manager, Prize Energy Corporation

Gregg Nady, Manager, New Business Development, Shell E&P Company

Marshall W. Nichols,* Executive Director, National Petroleum Council

John W. B. Northington,* Vice President, National Environmental Strategies, Inc.

Thomas B. Nusz,* Vice President, Acquisitions, Burlington Resources, Inc.

Blaise N. Poole,* Manager, Marketing and Strategy, El Paso Gas Services Company

Ed Porter, Research Manager, American Petroleum Institute

Rhone Resch, Director of Utility Regulations and Environmental Affairs, Natural Gas Supply Association

Nora Scheller, Washington Representative, ExxonMobil

Richard J. Sharples, President, Anadarko Energy Services Company

Matthew R. Simmons,* President, Simmons and Company International

Walter (Skip) M. Simmons,* Director of Gas, Mirant

Neal Stanley, Senior Vice President, Forest Oil Corporation

David Sweet, Vice President, Natural Gas, Independent Petroleum Association of America

Diemer True, Partner, True Companies

Michael G. Webb,* Senior Vice President, Strategic Planning/Business Development, Kerr-McGee Corp.

George Williams, Governmental Affairs Manager, Sempra Energy

Paul Wilkinson,* Vice President, Policy Analysis, American Gas Association

John C. Wolfmeyer,* Consulting Engineer, Science and Technology Planning, Duke Energy

Byron S. Wright, Vice President, Strategy, El Paso Corporation

Gregory W. Zwick,* Director, Business Strategy, TransCanada PipeLines

Government Attendees

Elizabeth E. Campbell, Director, Natural Gas Division, Data Analysis & Forecasting Branch, Energy Information Administration, U.S. Department of Energy

Walter D. Cruickshank,* Associate Director, Policy and Management Improvement, Minerals Management Service, U.S. Department of the Interior

Guido DeHoratiis,* Acting Deputy Assistant Secretary, Office of Natural Gas and Petroleum Technology, U.S. Department of Energy

Arthur M. Hartstein, Program Manager, Oil and Gas Processing, Office of Natural Gas and Petroleum Technology, U.S. Department of Energy

Nina Rose Hatfield, Acting Director, Bureau of Land Management, U.S. Department of the Interior

Erick V. Kaarlela,* Senior Policy Advisor to the Assistant Director, Minerals, Realty and Resource Protection, Division of Fluid Minerals, Bureau of Land Management, U.S. Department of the Interior

James M. Kendell,* Director, Oil and Gas Division, Office of Integrated Analysis and Forecasting, Energy Information Administration, U.S. Department of Energy

Thomas R. Kitsos, Acting Director, Minerals Management Service, U.S. Department of the Interior

Bruce Ramsey, Associate Director, U.S. Forest Service

Pulak Ray,* Chief Geologist, Minerals Management Service, U.S. Department of the Interior

Special Assistants

David Costello, Energy Information Administration, U.S. Department of Energy

Nancy L. Johnson, Director, Planning and Environmental Analysis, Office of Fossil Energy, U.S. Department of Energy

Elena Subia Melchert, Program Manager, Office of Natural Gas and Petroleum Technology, U.S. Department of Energy

John J. Pyrdol,* Senior Economist, Office of Natural Gas and Petroleum Technology, U.S. Department of Energy

Trudy Transtrum, Communications, Office of Natural Gas and Petroleum Technology, U.S. Department of Energy

William Trapmann, Economist, Energy Information Administration, U.S. Department of Energy

Feridun Albayrak, Vice President, Technology & Management Services, Inc.

Jeffrey Eppink,* Vice President, Advanced Resources International, Inc.

Vello A. Kuuskraa,* President, Advanced Resources International, Inc.

Kevin Petak,* Director, Energy Modeling and Analysis, Energy and Environmental Analysis, Inc.

E. Harry Vidas,* Managing Director, Energy and Environmental Analysis, Inc.

* Indicates participation in the 1999 NPC Natural Gas Study.

Department of Energy

Washington, DC 20585

SAMPLE

Dear Colleague:

The purpose of this letter is to invite you to attend a Department of Energy Office of Fossil Energy workshop on Surveying the Milestones for Meeting the Challenges of the Nation's Growing Natural Gas Demand. The workshop will be held in Washington, D.C. on March 5 and 6, 2001, convening the first day from 1:00 p.m. to 5:30 p.m. and the second day from 9:00 a.m. to 12 noon. Joining me as co-chair of the workshop will be Paul L. Kelly, Senior Vice President, Rowan Companies, Inc.

In December 1999, the National Petroleum Council presented a report to the Secretary of Energy with findings and recommendations for Meeting the Challenges of the Nation's Growing Natural Gas Demand. The report highlighted the potential contribution of natural gas to meeting the Nation's future economic, energy and environmental objectives, as well as critical factors that must be addressed by industry and government to realize the full potential for natural gas use in the United States. The Council's landmark report was distributed widely and has done much to raise awareness of natural gas issues among industry and government decision makers. However, the Nation's energy needs and industry's ability to address these needs are dynamic and will change over time. Accordingly, the Council recommended that government should periodically monitor trends in the assumptions used by the Council and progress on the critical factors in order to anticipate changes in supply and demand. In view of current energy projections, recent changes in natural gas prices and drilling activity, and growth in natural gas demand for electricity generation, it is clear that a review of the report would be useful.

Our aim in conducting this workshop is to offer an opportunity for industry and government executives, especially those individuals who participated in the conduct of the Council's 1999 study, to discuss and share their individual observations about: 1) the assumptions used in the 1999 study, 2) changes in natural gas market conditions and public policies since then, 3) the magnitude of these changes (e.g., as compared to prior modeling results or sensitivity analyses), and 4) what implications these changes may have for the results, findings and recommendations of the Council's 1999 study. While we are not seeking consensus views, we trust these observations can inform industry and government decision makers in understanding our Nation's energy situation and the role of natural gas in meeting the future energy needs of consumers.

To confirm your availability, or if you have questions regarding the workshop, please contact Nancy Johnson, Director of Planning and Environmental Analysis (202-586-6458), or Trudy Transtrum (202-586-7253) with the Office of Fossil Energy. You may also contact Marshall Nichols or John Guy of the National Petroleum Council staff who have kindly assisted us in planning this event. Additional workshop details will be sent to you as soon as they are finalized. I look forward to a comprehensive and enlightening discussion.

Sincerely,

Robert S. Kripowicz
Acting Assistant
Secretary for Fossil Energy

Enclosure

The Secretary of Energy
Washington, DC 20585
May 6, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

In 1992, the National Petroleum Council released a study entitled, "Potential of Natural Gas in the United States." That study was critical in identifying natural gas as an abundant domestic resource that can make a significantly larger contribution to both this Nation's energy supply and its environmental goals.

Since the release of the study, the Nation has experienced five years of sustained growth in the use of natural gas. In addition, the study did not anticipate at least two major forces that are beginning to take shape, which will profoundly affect energy choices in the future -- the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality. These issues offer opportunities and challenges for our Nation's natural gas supply and delivery system. For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand.

Accordingly, I am requesting that the Council reassess its 1992 study taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

Given the significance of this request, Deputy Secretary Elizabeth Moler will co-chair the study committee. I offer my gratitude to the Council for its efforts since our meeting in December 1997, to assist the Department in defining a more concise study scope. The breadth of issues related to natural gas supply and demand is vast and I recognize that further refinements in scope may be necessary once the study is underway to address the most significant concerns about future natural gas availability.

Sincerely,

Federico Peña

The Secretary of Energy
Washington, DC 20585

November 18, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

This is to convey my approval to establish a Committee on Natural Gas and to appoint industry members as proposed in your letter of October 6, 1998. I also approve the establishment of a coordinating subcommittee and the appointment of subcommittee members identified in your letter.

The Deputy Secretary will serve as the Government co-chair of the committee; the Assistant Secretary for Fossil Energy will co-chair the coordinating subcommittee. Staff involved in this study will be from the Office of Fossil Energy and the Office of Policy and International Affairs. In addition, the Energy Information Administration has expressed an interest in providing technical and analytic support. The Deputy Assistant Secretary for Natural Gas and Petroleum Technology will serve as the alternate for the Government co-chair of the subcommittee.

I agree that it would be appropriate for a representative of the Department of the Interior to be a member of the coordinating subcommittee, and we are pursuing this issue.

For a secure energy future, Government and private sector decision-makers need to be confident that industry has the capability to meet the significant increases in natural gas demand forecasted for the twenty-first century. I am pleased that the National Petroleum Council recognizes the challenge facing the domestic natural gas industry and has agreed to conduct a study of natural gas supply availability. I look forward to the study's results.

Yours sincerely,

Bill Richardson

Bill Richardson

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DOE006-0375

U.S. Department of Energy Workshop

Surveying the Milestones for Meeting the Challenges of the Nation's Growing Natural Gas Demand

March 5-6, 2001
Washington, DC

- NPC Natural Gas Study Assumptions Roadmap
- Demand
- Supply
- Transmission & Distribution

Meeting the Challenges of the Nation's Growing Natural Gas Demand

NATIONAL PETROLEUM COUNCIL

KEY MODEL ASSUMPTIONS

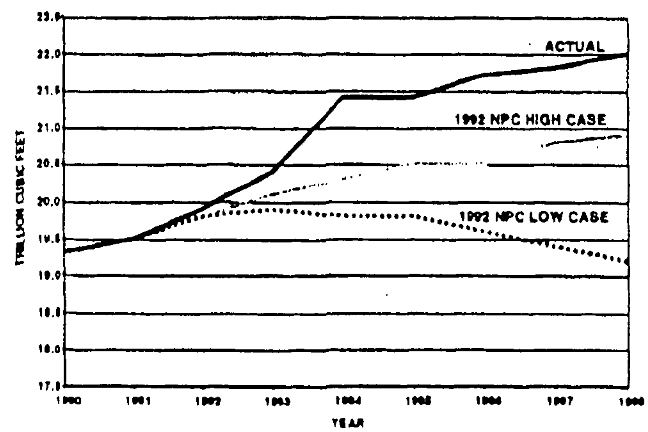
U.S. GDP Growth	2.5% per year
Canadian GDP Growth	2.2% per year
U.S. Industrial Production	3.0% per year
U.S. Inflation Rate	2.5% per year
Crude Oil Price (WTI)	$18.50/BBL in 1999 $
Crude Oil Price (RACC*)	$16.50/BBL in 1999 $

** Refiners' Average Cost of Crude in the United States*

DEMAND KEY FINDINGS

- Finding #1: Rapid Growth Exceeded Expectations of the 1992 Study
- Finding #2: Demand Will Increase by 32% between 1998 and 2010
- Finding #3: Environmental Regulations Could Add Significant Incremental Demand

U.S. Natural Gas Demand, 1990-1998



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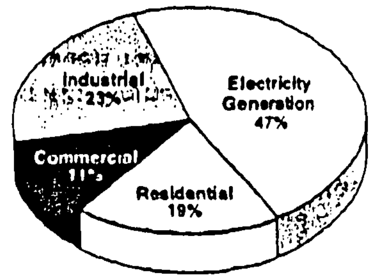
Growth in Reference Case Demand 1998-2010

Distribution of 7 TCF Increase by Sector



NPC

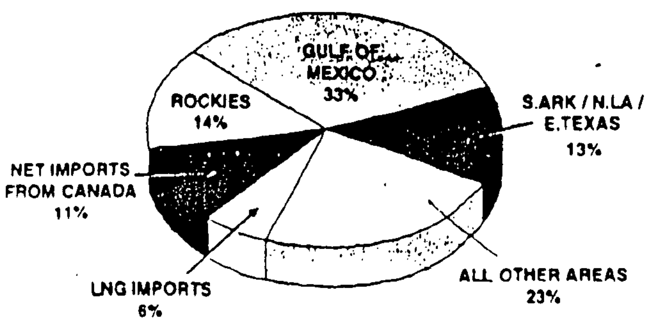
SUPPLY KEY FINDINGS

- Finding #1: Sufficient Resources Exist to Meet Growing Demand
- Finding #2: A Healthy Oil & Gas Industry Is Critical
- Finding #3: Investment in Research and Development Is Needed
- Finding #4: Restricted Access Will Limit the Availability of Supply

NPC

Growth in Reference Case Supply 1998-2010

Distribution of 7 TCF Increase by Source



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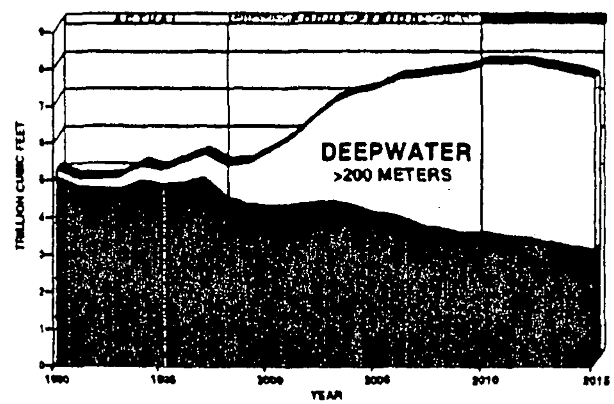
U.S. Gulf of Mexico Natural Gas Production



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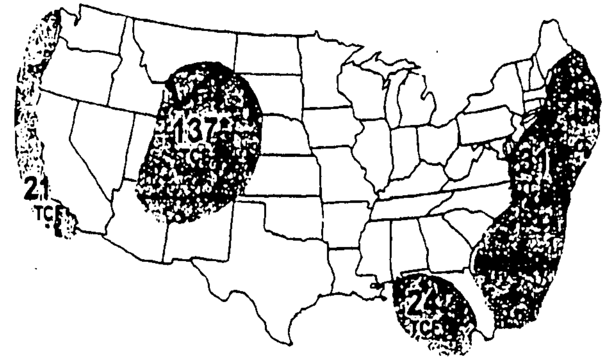
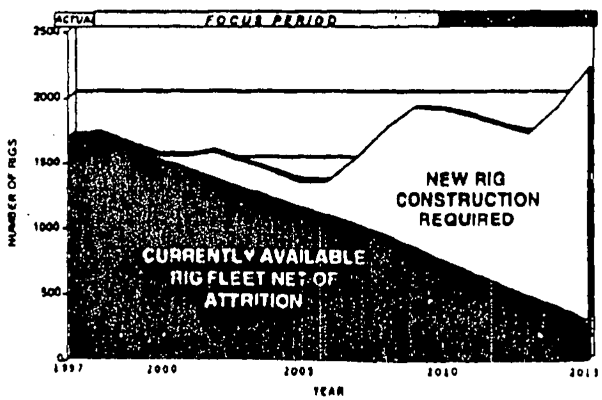
NEW SUPPLY WILL COME FROM

- Deeper Wells
- More Non-Conventional Sources
- Deeper Water

U.S. Lower-48 Natural Gas Resources Subject to Access Restrictions



Onshore Drilling Rig Fleet, 1997–2015



RECENT TRENDS IN TECHNOLOGY DEVELOPMENT

- Industry Consortia for Technology Development Have Been Cost-Effective
- Technology Development Has Shifted from the Majors to the Service Companies
- Investment in Research and Development Down Due to Consolidations and Cutbacks
- Funding for Basic Research Appears To Be Lagging

TRANSMISSION AND DISTRIBUTION KEY FINDINGS

- Finding #1: Delivery System Requires Significant Expansion and Enhancements
- Finding #2: Access Issues Impede Installation of New Infrastructure
- Finding #3: New Services Are Needed for the Changing Market
- Finding #4: Risk Assumption for Pipeline Expansions Is in Question

NPC

MARKET CHANGES

- Restructuring Changes the Roles of Market Participants
  - LDCs / Electric Utilities / Marketers / Energy Service Providers / Producers / Electricity Generators
- Operational Aspects of Gas-Fired Electricity Generation Drive Need for New Services
  - High Minimum Inlet Pressures for Gas-Fired Turbines
  - Swing Capabilities Due to Load-Following Requirement
  - Hourly Scheduling / Nominations

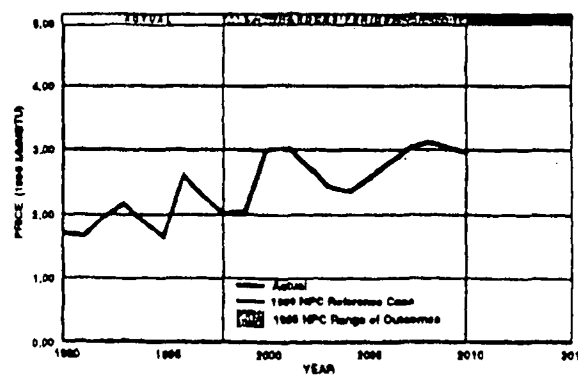
NPC

CRITICAL FACTORS

- Access
- Technology
- Financial Requirements
- Skilled Workers
- Rigs
- Lead Times
- Requirements of New Customers

NPC

Historical and Projected U.S.Natural Gas Prices



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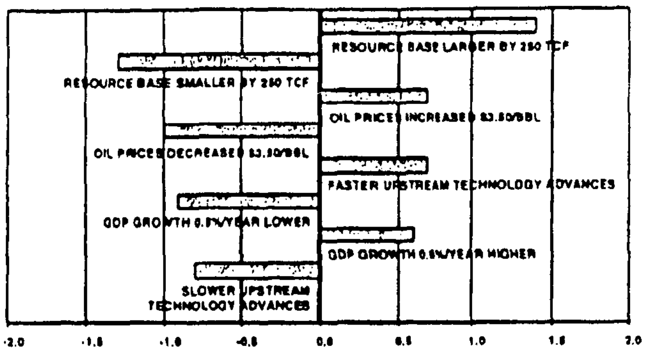
Influence of Key Assumptions on Natural Gas Demand



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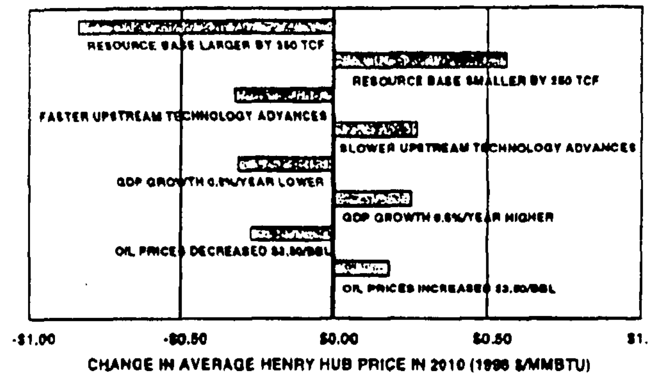
Influence of Key Assumptions on Natural Gas Price



NPC

RECOMMENDATION #1

- Establish a Strategy – at the Highest Level – for Natural Gas in the Nation's Energy Portfolio
- Form an Interagency Work Group under the National Economic Council

NPC

RECOMMENDATION #2

- Establish a Balanced, Long-term Approach for Responsibly Developing the Nation's Resource Base
  - Assess Impact of Existing Restrictions
  - Prioritize Restricted Areas
  - Develop Supply in Selected Areas
  - Plan for Long-Term Sustainability

NPC

RECOMMENDATION #3

- Drive Research and Technology Development at a Rapid Rate
  - Invest in Research
  - Support Additional Industry Consortia
  - Promote High-Efficiency Gas Technology

NPC

RECOMMENDATION #4

- Plan for Capital, Infrastructure, and Human Resource Needs
  - Examine New Financial Incentives
  - Form a Joint Industry Task Force on Drilling
  - Develop Workforce Plan

NPC

- **RECOMMENDATION #5**
  Streamline Processes that Impact Gas Development
- **RECOMMENDATION #6**
  Assess the Impact of Environmental Regulation on Natural Gas Demand and Supply
- **RECOMMENDATION #7**
  Design New Services to Meet Changing Customer Needs

NPC

SURVEYING THE MILESTONES

IN THE

NPC 1999 Study

Prepared By:
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Background and Purpose

The 1999 National Petroleum Council (NPC) study, entitled "Meeting the Challenges of the Nation's Growing Natural Gas Demand", was prepared to provide the Secretary of Energy with forward looking advice and a roadmap for action on natural gas.

In delivering the report, the NPC stated its interest in maintaining the "evergreen" nature of the roadmap and recommended that certain trends in the natural gas industry "should be actively monitored as early warning indicators."

Background and Purpose (cont.)

The purpose of this "survey of the milestones" is to record the performance of the natural gas industry during the past two years and, more importantly, to gain an updated perspective on the critical trends of importance to the industry.

Particular attention will be given to the topics and issues that may require action by government, industry and other stakeholders to ensure reliable, competitively priced natural gas.

1. Domestic Natural Resource Base Is Bountiful.

It is important to highlight that the recent natural gas market issues do not stem from a lack of underlying natural gas resources. As stated in the NPC 1999 Study, the U.S. has a large, rich and diverse natural gas resource base.

Each time industry or resource appraisers have examined the natural gas resource base, they have judged it to be larger.

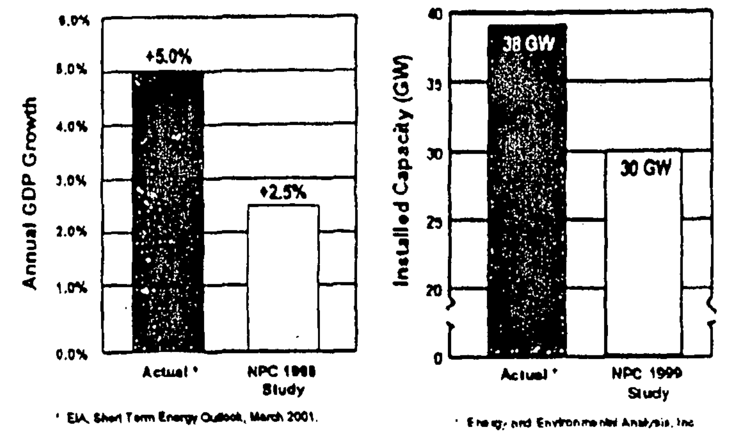
2. Demand For Natural Gas Has Grown Faster Than Anticipated.

Natural gas demand has grown by 1.8 Tcf from 1998 to 2000, 0.5 Tcf higher than projected in the NPC 1999 Study.

Faster economic growth, increased demand for natural gas-fired electricity, lower hydropower and a colder than normal winter account for the increased demand.

- *Is the higher-than-2.5% annual GDP growth (in '99 & '00) a longer term trend? How does this affect energy consumption?*
- *How much additional gas-fired electric power capacity will be installed in the next two years? How will this capacity be dispatched?*

Figure 1.
Factors Behind Increased Natural Gas Demand



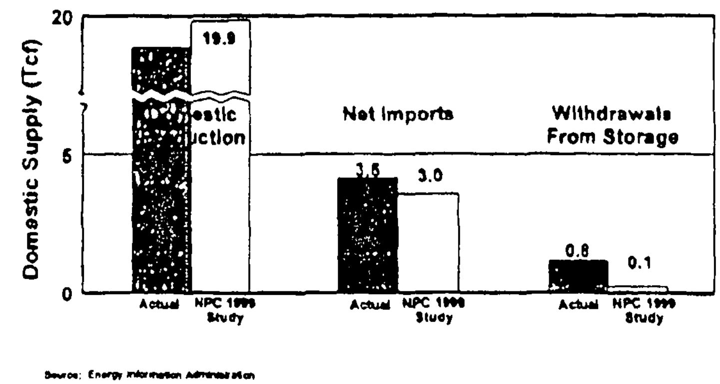
3. Domestic Gas Production Has Been Essentially Flat.

U.S. natural gas production has been relatively flat during the past two years, 800 Bcf less than expected in the NPC 1999 Study. Increased imports from Canada and gas storage were used to meet demand.

Adverse market conditions of 1998/99 seriously affected capital investment and well drilling.

- *With increases in drilling activity in 2000, is domestic productive capacity responding?*
- *How much additional Canadian productive capacity will be available in the next five years?*

Figure 2.
Actual vs. Expected Sources of Natural Gas Supply (2000)



4. Progress In Technology and Access To Resources Remain Major Issues

Technology Progress

Preliminary data for exploration success and rig efficiency show potential declines since the NPC 1999 Study's projected increases.

The NPC Study assumed expected "technological advances based on recent levels of R&D funding and the general effectiveness of those efforts". Actual data shows R&D funding by major energy producers to be declining, potentially impeding technology progress.

- *What will stimulate the industry to invest in new drilling systems?*
- *How might industry and government assure required R&D investments?*

4. Progress in Technology and Access To Resources Remain Major Issues (cont.)

Access

Forest Service Roadless Areas have decreased industry's access to Rocky Mountain resources.

Access to resources in the Eastern Gulf of Mexico and the Alaskan North Slope are topical issues.

- *Can the industry increase supply sufficiently without access to restricted areas?*
- *What technology advances would reduce impact in environmentally sensitive areas?*

5. Natural Gas Prices Have Been Higher Than Anticipated.

Domestic wellhead prices for natural gas averaged about $3.70 per Mcf in 2000, with a season spike of nearly $10 per Mcf in December, 2000 (Henry Hub). The NPC 1999 Study projected increased wellhead prices for 2000 and 2001, though not as high as actual.

- *How significantly will the changes in demand and supply influence future gas price?*
- *What actions might help provide a market-based ceiling on future gas prices?*

Summary

Differences exist between the NPC 1999 Study's anticipated and today's actual conditions in the natural gas industry. *Are these:*

- *Temporary Anomalies (eg. low hydropower)?*
- *Near-Term Constraints (eg. rigs and manpower)?*
- *Longer Term Trends (eg. higher GDP growth; slower technology progress)?*
- *How might the near-term constraints be mitigated?*
- *What are the implications of longer term trends for the natural gas industry?*

DOE Workshop: Surveying the Milestones

Demand Review

Harry Vidas
Energy and Environmental Analysis, Inc.

Outline of Presentation

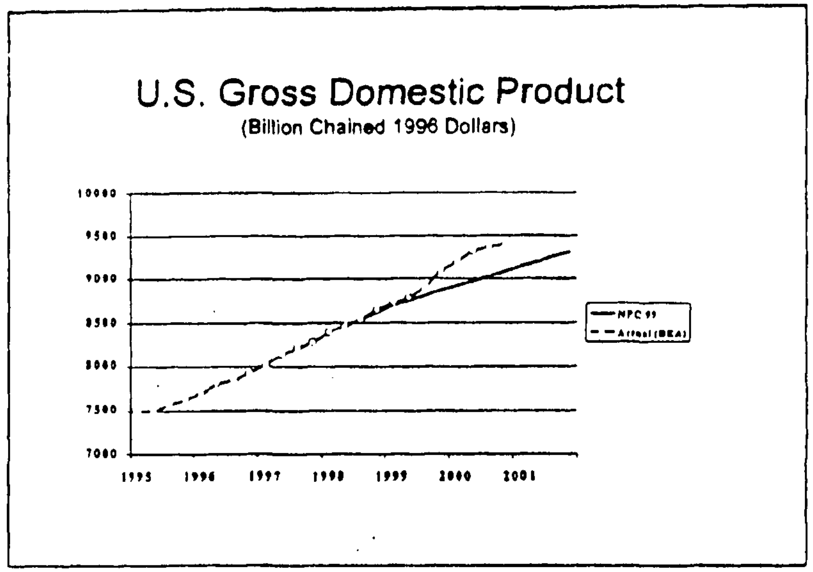
- Economic Activity
- Oil Prices
- Electricity Sales
- Electricity Generation by Fuel Type
- Generation Balance in 2000
- New Power Plants
- Natural Gas Balance
- Gas Demand by Sector
- Weather Effects
- Observations

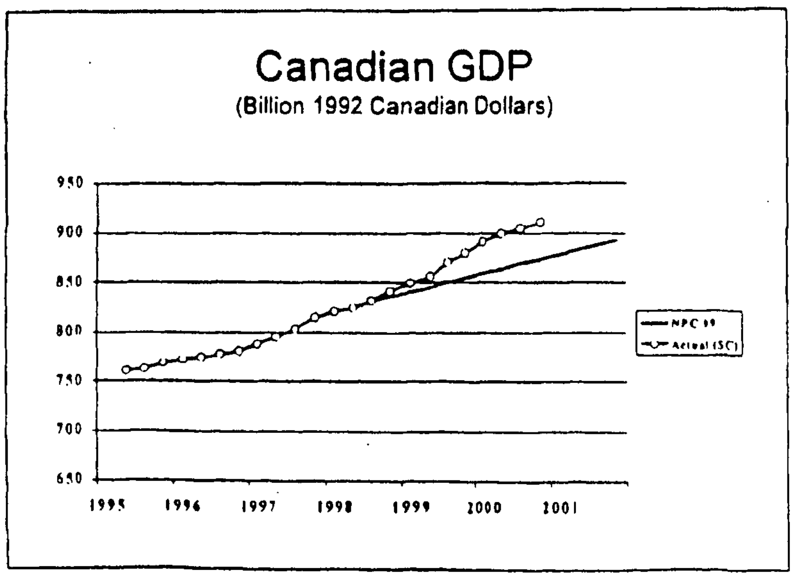
Economic Activity

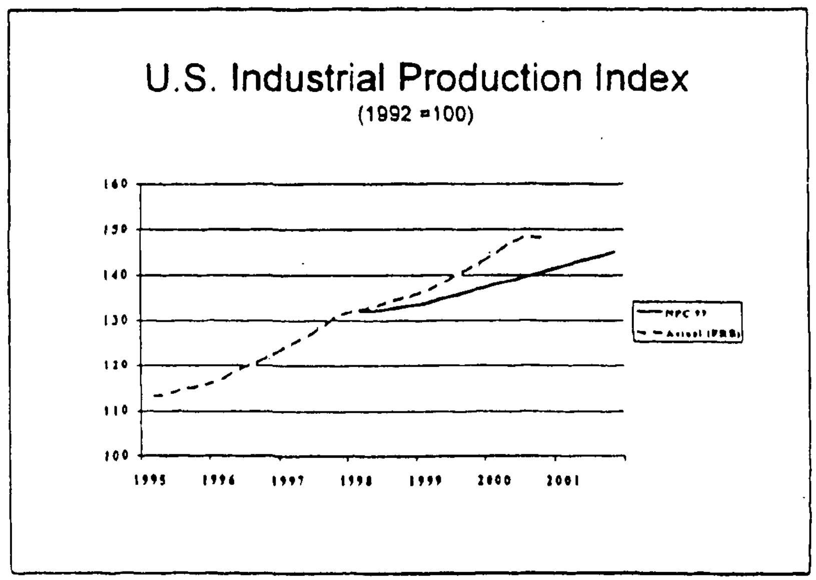
National Petroleum Council Assumption: The NPC Reference Case assumed that U.S. Gross Domestic Product (GDP) would grow at 3.3% in 1999 (full year over full year) and an average of 2.5% each year thereafter. Sensitivity cases were run with 3.0% and 2.0% long-run GDP growth.

Market or Public Policy Change Since 1999 Study: Actual GDP grew 4.2% in 1999 and 5.0% in 2000. However, the last quarter of 2000 showed growth of only 1.0% on an annual basis.

Magnitude of Change: By 2000, actual GDP was 9.402 trillion in 1992 dollars versus an anticipated GDP of 9.087 trillion dollars. This is a difference of 3.5%.







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Oil Prices

National Petroleum Council Assumption: The Reference Case oil price assumption was $18.50/bbl WTI in real 1999 dollars and $16.50 for refiners average cost of crude (RACC). These prices were chosen because they are the actual long-run average over several decades. Sensitivity Cases assuming WTI oil prices of plus or minus $3.50/bbl were also run.

Market or Public Policy Change Since 1999 Study: Actual prices were much higher starting in the second half of 1999. Through most of 2000, oil prices were about $2.00/MMBtu higher than expected.

Observations: The high oil prices stimulated upstream activity and led indirectly to higher gas prices through much of 2000 when gas competed with fuel oils at the burner tip.