DOE/EIA-0202(99/2Q)
Distribution Category UC-950

Short-Term Energy Outlook

April 1999

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

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Preface

The Energy Information Administration (EIA) prepares the *Short-Term Energy Outlook* (energy supply, demand, and price projections) monthly for distribution on the internet at: **www.eia.doe.gov/steo** In addition, printed versions of the report are available to subscribers in January, April, July and October.

The forecast period for this issue of the *Outlook* extends from April 1999 through December 2000. Data values for the first quarter 1999, however, are preliminary EIA estimates (for example, some monthly values for petroleum supply and disposition are derived in part from weekly data reported in EIA's *Weekly Petroleum Status Report*) or are calculated from model simulations that use the latest exogenous information available (for example, electricity sales and generation are simulated by using actual weather data). The historical energy data, compiled in the April 1999 version of the Short-Term Integrated Forecasting System (STIFS) database, are mostly EIA data regularly published in the *Monthly Energy Review*, *Petroleum Supply Monthly*, and other EIA publications. Minor discrepancies between the data in these publications and the historical data in this *Outlook* are due to independent rounding.

The STIFS model is driven principally by three sets of assumptions or inputs: estimates of key macroeconomic variables, world oil price assumptions, and assumptions about the severity of weather. Macroeconomic estimates are produced by DRI/McGraw-Hill but are adjusted by EIA to reflect EIA assumptions about the world price of crude oil, energy product prices, and other assumptions which may affect the macroeconomic outlook. By varying the assumptions, alternative cases are produced by using the STIFS model.

Contents

Figures

Highlights

World Oil Prices Rising as Oil Stocks Are Drawn Down

World oil prices are assumed to be about $15-$16 per barrel by the end of 1999, as the shifting balance between world oil production and demand begins to reverse the large accumulation of oil in storage. We expect prices to be near $17 per barrel by the end of 2000 as long as the recently announced cuts by OPEC (and others) actually do have significant impacts and as oil demand growth outside of the major industrialized countries begins to show some strength after this year. These cuts are likely to be only partially implemented, just as the previous two agreements were. However, enough oil should be removed from the market to draw down inventories.

Gasoline Prices Move Up with Crude Prices, Refinery Outages

Gasoline prices, having risen sharply since February, are projected to average $1.13 per gallon this summer, up about 9 to 10 cents from last summer. Refinery outages in California since February have caused spot and retail prices to soar there, adding to upward pressure on pump prices elsewhere. The refinery problems are expected to be largely resolved before the summer is over. Meanwhile, significant net cuts in world oil production are expected to keep crude oil prices on an upward track through 2000.

Phase 2 Reformulated Motor Gasoline to be at Gas Stations by January 1, 2000.

The reformulated motor gasoline provisions of the Clean Air Act Amendments of 1990 require reductions in automobile emissions of ozone-forming volatile organic compounds during the summer high-ozone season, and of toxic air pollutants and nitrogen oxides during the entire year in certain areas of the United States. Demand for Phase 2 reformulated gasoline is expected to represent about 34 percent of total motor gasoline demand in 2000

Natural Gas Wellhead Prices Seen at or Below $2.00 Until Next Heating Season

Natural gas spot prices are projected to remain at or below $2 per thousand cubic feet until the beginning of the next heating season, unless we have an unusually hot summer. Working gas in storage at the end of the past heating season (March 31) was at an estimated 1,354 billion cubic feet, which would be the highest end of March level since 1992. This implies a relatively weak injection season for 1999.

Electricity Demand Growth Modest in 1999

The outlook for electricity demand growth for the remainder of 1999 is expected to be modest at 1.1 percent. Cooling degree-days this summer are expected to be 15.7 percent lower than last summer, which was considerably warmer than normal.

Table HL1. U. S. Energy Supply and Demand

	Year				Annual Percentage Change		
	1997	1998	1999	2000	1997-1998	1998-1999	1999-2000
Real Gross Domestic Product (GDP)							
(billion chained 1992 dollars)	**7270**	**7552**	*7825*	*7960*	**3.9**	*3.6*	*1.7*
Imported Crude Oil Price [a]							
(nominal dollars per barrel)	**18.50**	**12.13**	*13.55*	*16.24*	**-34.4**	*11.7*	*19.9*
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	**6.45**	**6.24**	*5.84*	*5.69*	**-3.3**	*-6.4*	*-2.6*
Total Petroleum Net Imports							
(including SPR)	**9.16**	**9.69**	*10.21*	*10.56*	**5.8**	*5.4*	*3.4*
Energy Demand							
World Petroleum							
(million barrels per day)..................................	**73.0**	**73.8**	*75.1*	*76.7*	**1.1**	*1.8*	*2.1*
Petroleum							
(million barrels per day)..................................	**18.62**	**18.77**	*19.26*	*19.58*	**0.8**	*2.6*	*1.7*
Natural Gas							
(trillion cubic feet)	**21.97**	**21.32**	*21.92*	*22.47*	**-3.0**	*2.8*	*2.5*
Coal							
(million short tons)	**1029**	**1046**	*1075*	*1112*	**1.7**	*2.7*	*3.5*
Electricity (billion kilowatthours)							
Utility Sales [c]	**3140**	**3238**	*3282*	*3353*	**3.1**	*1.4*	*2.2*
Nonutility Own Use [d]	**161**	**164**	*166*	*168*	**1.9**	*1.2*	*1.2*
Total	**3301**	**3401**	*3447*	*3521*	**3.0**	*1.4*	*2.1*
Total Energy Demand [e]							
(quadrillion Btu)...	**94.3**	**94.4**	*96.4*	*98.4*	**0.1**	*2.1*	*2.1*
Total Energy Demand per Dollar of GDP							
(thousand Btu per 1992 Dollar)......................	**12.97**	**12.50**	*12.32*	*12.36*	**-3.6**	*-1.4*	*0.3*
Renewable Energy as Percent of Total [f]	**7.5**	**7.2**	*6.9*	*6.7*			

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

[b] Includes lease condensate.

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

[d] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1998 are estimates.

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

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

SPR: Strategic Petroleum Reserve.

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

Sources: Historical data: Latest data available from Bureau of Economic Analysis and Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-0520; *Weekly Petroleum Status Report,* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

1999 Summer Motor Gasoline Outlook

This year's base case outlook for summer (April-September) motor gasoline markets may be summarized as follows:

- **Pump Prices:** (average regular) projected to average about $1.13 per gallon this summer, up 9-10 cents from last year. The increase, while substantial, still leaves average prices low compared to pre-1998 history, especially in inflation-adjusted terms.

- **Supplies:** expected to be adequate, overall. Beginning-of-season inventories were even with the 1998 level, which was at the high end of the normal range. However, some refinery problems on the West Coast have tightened things up, at least temporarily.

- **Demand:** up 2.0 percent from last summer due to solid economic growth and low (albeit rising) fuel prices; highway travel may reach 1.4 trillion miles for the season, up about 2.1 percent from last year.

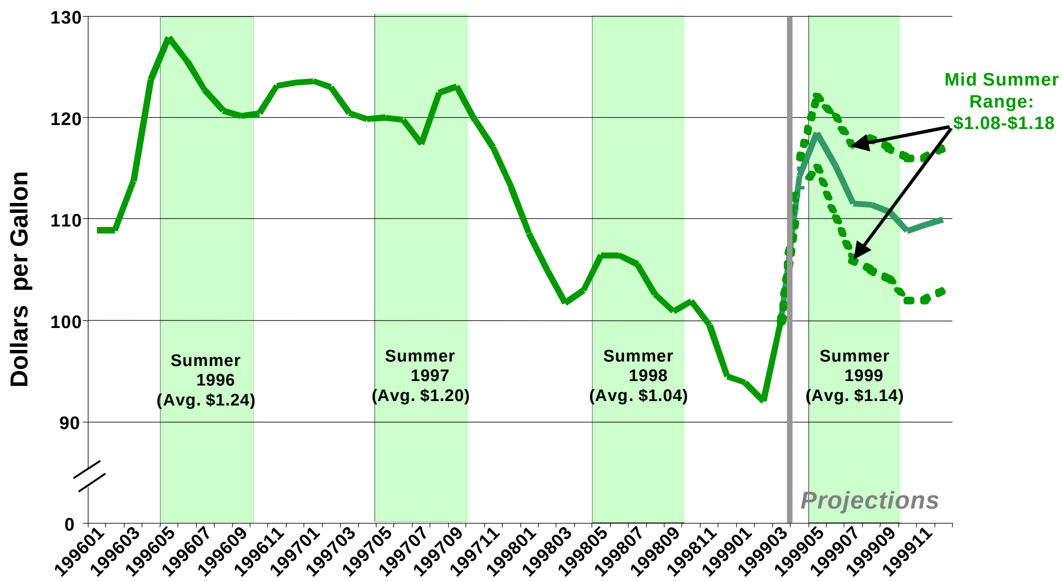
Table MG1. U.S. Motor Gasoline Summer Outlook: Mid World Oil Price Case

	1998			1999			Percent Change		
	Q2	Q3	Summer	Q2	Q3	Summer	Q2	Q3	Summer
Prices (cents per gallon)									
Imported Crude Oil Price [a]	**29.5**	**28.3**	**28.9**	*34.6*	*32.9*	*33.7*	*17.1%*	*16.5%*	*16.7%*
Wholesale Gasoline Price [b]	**56.1**	**52.0**	**54.0**	*65.8*	*59.3*	*62.5*	*17.2%*	*14.1%*	*15.7%*
Retail Gasoline Price [c]	**105.3**	**103.1**	**104.2**	*115.7*	*111.2*	*113.4*	*9.9%*	*7.9%*	*8.9%*
Stocks, Incl. Blending Components (million barrels)									
Beginning	**215.0**	**221.4**		*215.2*	*212.9*				
Ending	**221.4**	**207.4**		*212.9*	*208.1*				
Demand/Supply (million barrels per day)									
Total Demand	**8.324**	**8.509**	**8.417**	*8.524*	*8.654*	*8.589*	*2.4%*	*1.7%*	*2.0%*
Total Output [d]	**8.249**	**8.192**	**8.220**	*8.343*	*8.396*	*8.370*	*1.1%*	*2.5%*	*1.8%*
Net Finished Stock Withdrawal	**-0.124**	**0.141**	**0.009**	*-0.019*	*0.058*	*0.019*			
Net Imports	**0.199**	**0.177**	**0.188**	*0.200*	*0.200*	*0.200*	*0.6%*	*13.3%*	*6.6%*
Refinery Utilization (percent)	**97.5%**	**98.0%**	**97.8%**	*95.7%*	*97.8%*	*96.8%*			
Market Indicators									
Real GDP (billion 1992 dollars)	**7498.7**	**7566.4**	**7532.6**	*7808.7*	*7854.9*	*7831.8*	*4.1%*	*3.8%*	*4.0%*
Real Income (bill. 1992 dollars)	**5321.5**	**5364.1**	**5342.8**	*5516.5*	*5562.0*	*5539.3*	*3.7%*	*3.7%*	*3.7%*
Industrial Output (index, 1987=1.0)	**1.312**	**1.316**	**1.314**	*1.343*	*1.353*	*1.348*	*2.4%*	*2.8%*	*2.6%*
Miles Traveled (mill. miles per day)	**7424.5**	**7600.4**	**7512.9**	*7577.9*	*7758.6*	*7668.7*	*2.1%*	*2.1%*	*2.1%*
Average MPG (miles per gallon)	**21.24**	**21.27**	**21.25**	*21.17*	*21.35*	*21.26*	*-0.3%*	*0.4%*	*0.0%*

[a]Cost of imported crude oil to U.S.
[b]Price of gasoline sold by refiners to resellers.
[d]Average pump price for regular gasoline.
[d]Refinery output plus motor gasoline field production, including fuel ethanol blended into gasoline and new supply of oxygenates and other hydrocarbons for gasoline production.

Notes: Minor discrepancies with other EIA published historical data are due to rounding. Historical data are printed in bold, forecasts are in italic. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System. Sources: Historical data: latest data available from: Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109; *Monthly Energy Review*, DOE/EIA-0035; U.S. Department of Commerce, Bureau of Economic Analysis; Federal Reserve System; National Oceanic and Atmospheric Administration. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

Figure MG1. Retail Gasoline Price Cases* (Based on High, Base, and Low Oil Price Cases)



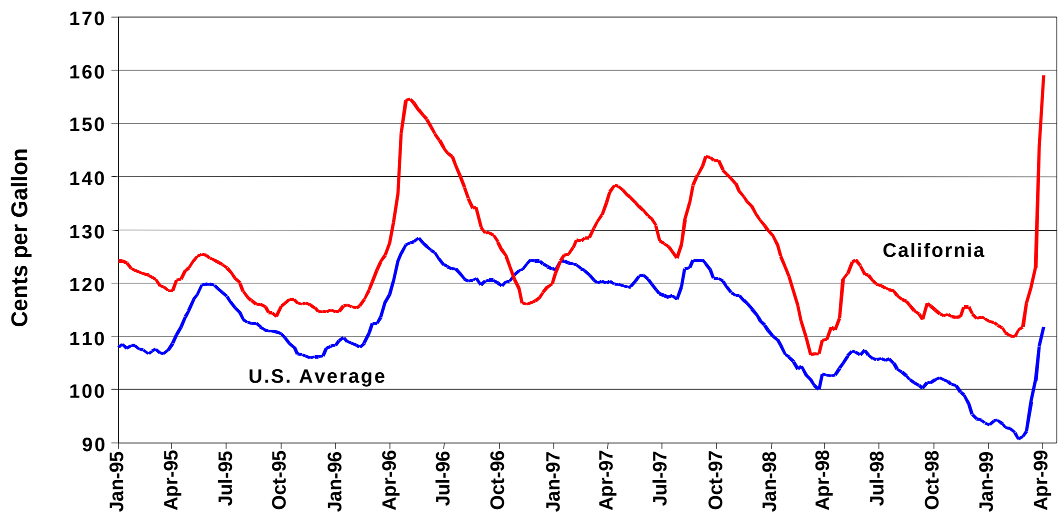
**Regular Unleaded; Self Service*

Due largely to the recent rise in crude costs and cost pressures associated with multiple refinery problems in California, the average U.S. regular unleaded self-service gasoline price is expected to post a very sharp increase in April over the February record-low (inflation-adjusted) price. We assume that the refinery problems will be largely resolved by mid-summer but that the impacts of these supply problems may keep prices higher than they otherwise would be for another month or two. The average price for the summer is expected to be about 9-10 cents above the year-ago level. Despite the increase, this average is still relatively low by historical standards.

To the extent that consumers are more concerned about how prices have changed recently rather than how they have changed since last year, it is of interest to note that our projected price for April would imply the largest month-to-month increase (14.2 cents per gallon) in the average regular gasoline price since April 1989. The projected April value would also imply the largest two-month increase in the U.S. average price (22.2 cents per gallon) since the two months immediately following Iraq's invasion of Kuwait in 1990.

The average regular self-service gasoline price is expected to peak this year in May at about $1.18 per gallon in the base case. Depending on crude oil market developments, prices at the pump may range between $1.00 and $1.22 per gallon during the driving season. Some additional uncertainty stems from the ever-present possibility that refinery problems could continue to be a factor late into the summer.

Figure MG2. U.S. and California Retail Regular Gasoline Prices

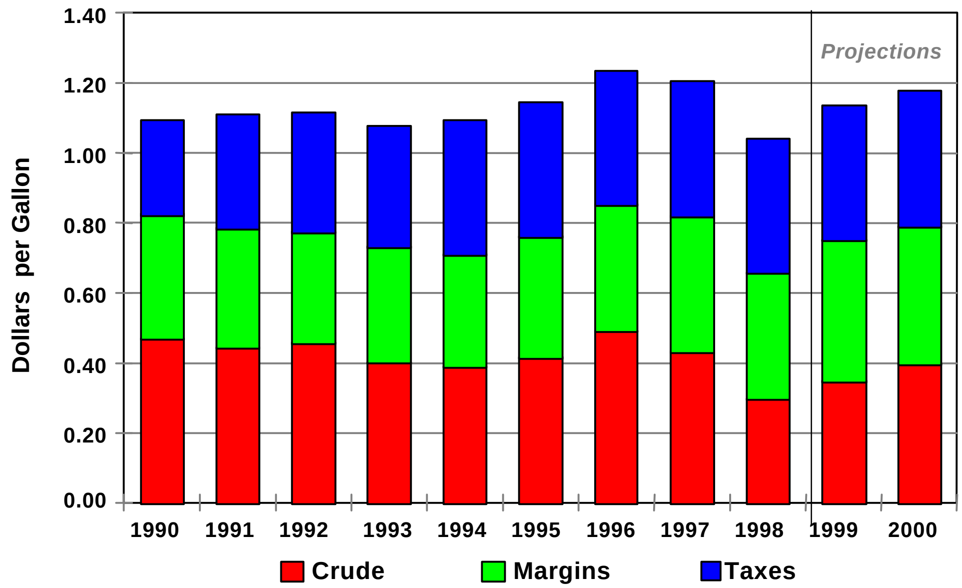


A rugged start to the 1999 driving season has emerged from the fragile gasoline market environment of California. A sequence of refinery problems there resulted in a very rapid escalation of both spot and retail gasoline prices since mid-February. Between February 18 and March 31, spot prices for reformulated gasoline in California rose by 60 cents per gallon or more compared with 24 cents at the Gulf. Meanwhile, average retail gasoline prices in California rose by 36 cents per gallon. The supply problems in California have had some spillover effects elsewhere as Gulf Coast, Caribbean and overseas suppliers have begun diverting some gasoline supply to the West Coast. Gulf Coast spot conventional regular gasoline prices rose 22 cents per gallon during the same period.

The California gasoline market problems stem from three separate refinery problems: 1) the February 23 fire at (and subsequent shutdown of) Tosco's Avon refinery; 2) the temporary shutdown in mid-March of a fluid catalytic cracking (FCC) unit at Exxon's Benicia refinery; and 3) the March 25 fire that shut down a hydrocracking unit at Chevron's Richmond refinery. We estimate that about 15 percent of California's gasoline-making capacity has been affected by the refinery shutdowns.

We assume that, one way or the other, the dislocations from refinery disruptions will be resolved by the end of April. It is unlikely that Tosco's refinery will be running by then, but, as other U.S. and foreign supplies come into California, the huge spike in spot prices should subside by May. However, some of the recent spot price runups will be working their way to the retail level for some weeks before subsiding. As a result, it is likely that June pump prices on the West Coast will move closer to a normal relationship with the rest of the country.

Figure MG3. Retail Gasoline Price* Components (Average Summer Price)



***Regular; Self Service**

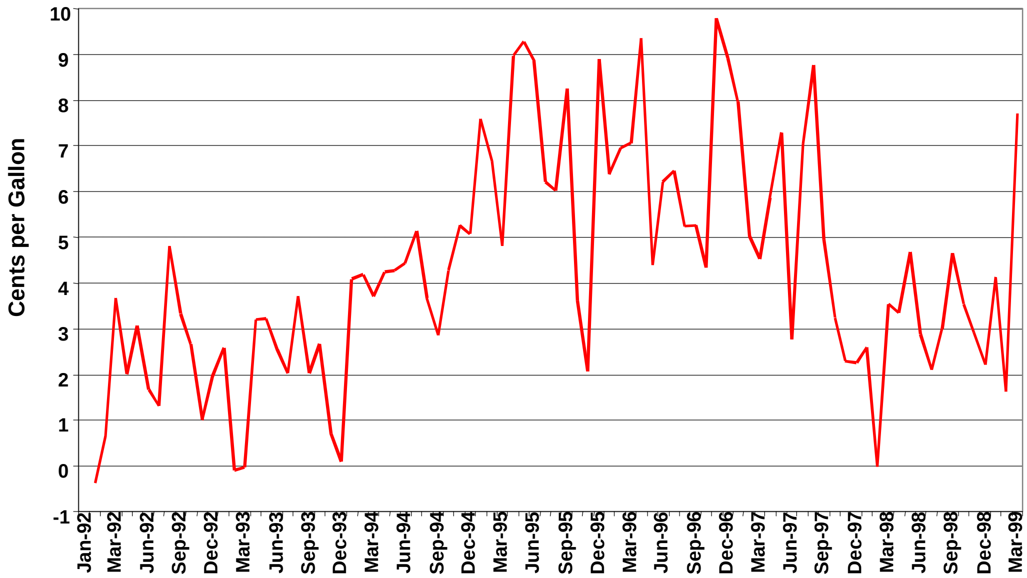
Some perspective on average summer gasoline prices is provided in Figure MG3. Even in nominal terms, last summer's average regular gasoline pump price was the lowest of the 1990's at $1.04 per gallon. Correcting for inflation it was the lowest ever. We expect average prices to be up noticeably (9-10 cents per gallon) this summer. This will put prices closer to the average levels seen prior to 1996.

It is apparent from Figure MG3 how crude oil cost changes have generally driven shifts in gasoline prices. The weakness in world oil markets last year and the collapse in crude oil prices drove summer pump prices to very low levels. (Even more dramatic declines were seen this past winter.)

The component of prices stemming from taxes (federal and state) is now higher than in 1990 by about 12 cents per gallon, underscoring the significance of the low prices last year.

The margin component (non-crude manufacturing costs plus profits) is expected to be somewhat above average this summer (40 cents per gallon versus a 35 cents-per-gallon average for 1990 to 1998). This expectation is based on the assumption that refiners and marketers will post profits that are much improved over the dismal results seen in the past winter. The higher margins are skewed by the 70- to 80-cent margins appearing now in California due to the tight supply situation there.

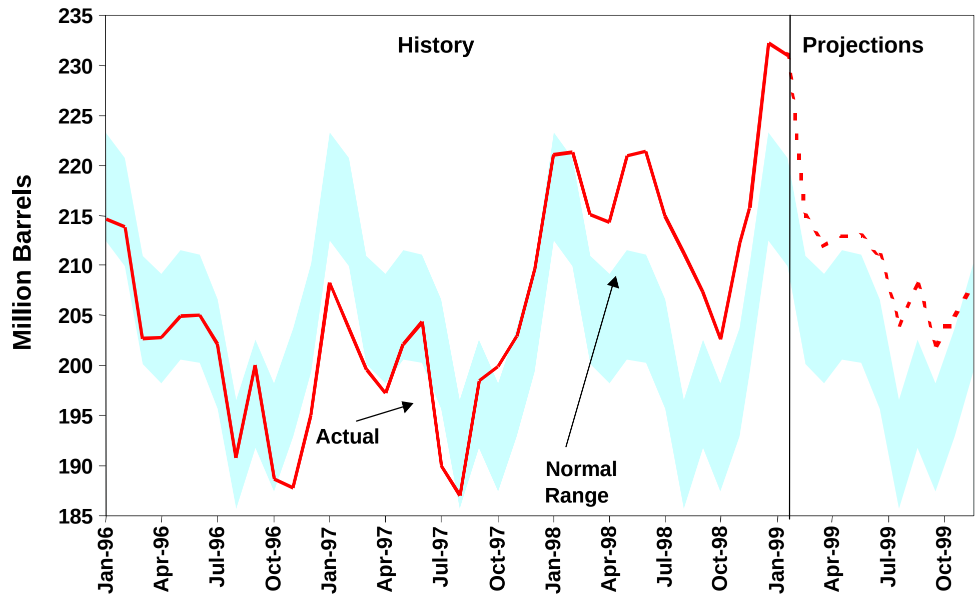
Figure MG4. Trans-Atlantic Gasoline Price Differentials (New York Harbor less Rotterdam)



Gasoline imports are an important source of supply for the East Coast, and Western Europe is an important source of incremental gasoline supply in the United States. Europe has an excess of gasoline production capability and has found the United States to be a good market for its product. Trans-Atlantic gasoline price differentials provide some indication of the attractiveness of the U.S. market to European refiners. When U.S. prices exceed European prices adequately to cover transportation cost, they favor moving product across the Atlantic. While transportation costs vary, they can be in the vicinity of 4 cents per gallon. The price differential increased after 1993 to average about 7 cents per gallon from 1995 through 1997, and, with the exception of 1995 when the transition to RFG initially may have discouraged foreign suppliers, imports from Europe were strong during this period.

During 1998, the differential fell back to levels similar to those in 1992 and 1993, yet imports were about the same as in 1997. The U.S. market apparently remained attractive to other regions even at the reduced differential level. As U.S. gasoline prices increased in late February and March of 1999, the differential rose sharply to levels more typical of 1996 and 1997, which may boost imports in the near term as gasoline's high-demand season gets underway.

Figure MG5. U.S. Total Motor Gasoline Stocks

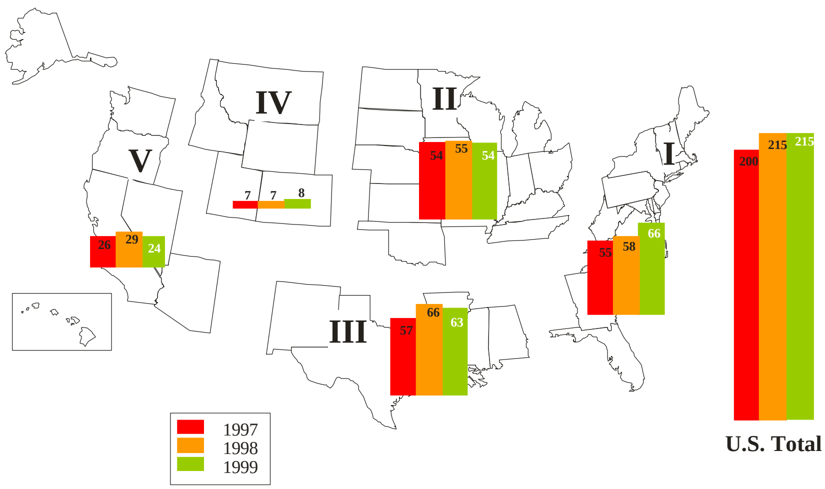


For 2 years through the spring of 1998, U.S. gasoline stocks increased from levels somewhat below those of recent historical averages to levels at the high end of or well above those averages. Stocks have remained high ever since. Total U.S. gasoline stocks at the beginning of the upcoming driving season (April 1) are estimated to be 215 million barrels, the same as last year.

Although gasoline stocks are now skirting the high end of the normal range, this is something of a change from earlier this year when the excess in inventory holdings was much more obvious. In January and February stocks were above 230 million barrels, meaning that a sharp decline occurred in March. Unexpectedly high gasoline demand in March is partly responsible for the sharp draw last month.

Still, it is generally the case that inventories are comparatively plentiful this year and should not, in and of themselves, contribute to any supply problems. It is possible that high inventories this winter will prove to have been a help in keeping the supply problems that have been plaguing California from transmitting a greater shock to the rest of the country than has apparently been the case.

Figure MG6. U.S. Regional Gasoline Stocks (Beginning of Season - March 31, 1999)(Million Barrels)

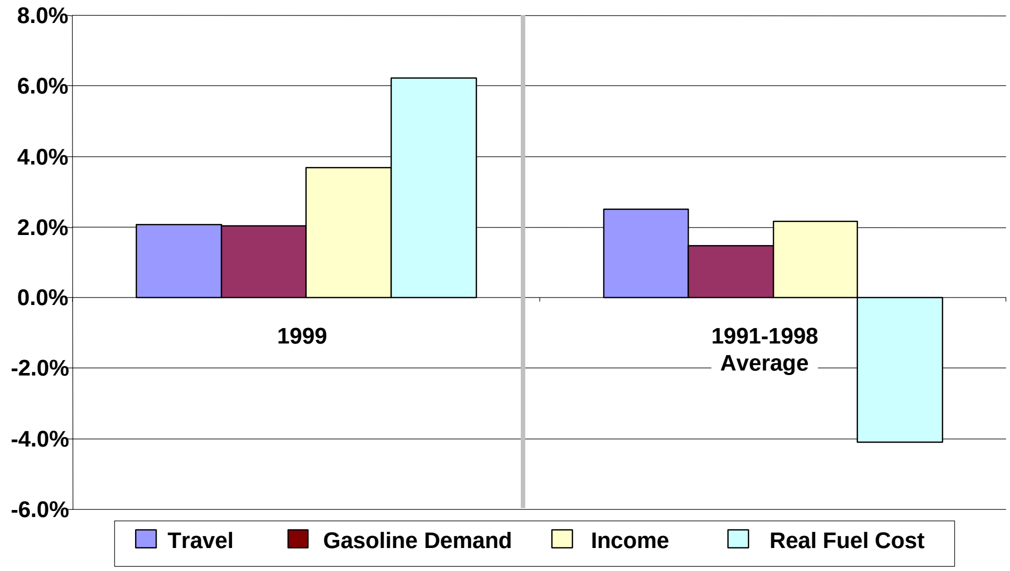


[1] Includes motor gasoline blending components.
Source: Energy Information Administration, Petroleum Supply Monthly, Table 51.

Total beginning-of-season stocks (including blending components) were estimated to be 215 million barrels, at the high end of the normal range for this time of year but almost exactly the amount in storage this time in 1998. Some regional differences are worth noting. The East Coast began the driving season with inventories well above last year's at this time, while other regions generally remained about flat or were down. The West Coast, in particular, showed a deficit compared to last year (down about 17 percent). This situation is partially reflective of the loss of gasoline capacity to refinery outages in California. In turn, the somewhat depleted stock situation in the West is likely to keep strong pressure on California spot prices until replacement supplies can arrive and the refinery outages are cleared up.

Nevertheless, the relatively high aggregate U.S. stock level, combined with a slow buildup of commercial stocks in Western Europe following several years of decline, should ensure ample availability of supplies during the summer season and help avoid any protracted market problems or shortage.

Figure MG7. Summer Motor Gasoline Market Indicators (Percent Change from Year Ago)



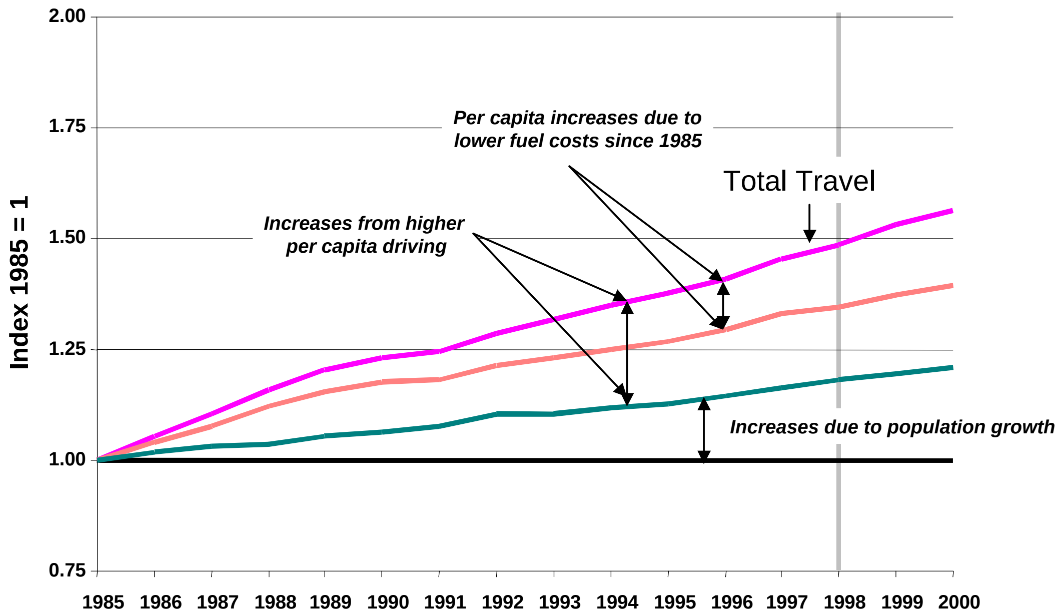
Despite the fact that the period of very low gasoline prices in the United States appears to be over, the prospects for another summer with solid growth in gasoline demand are very good.

The significant growth in real fuel costs evident in Figure MG7 (more than 6 percent above last summer) only fractionally reverses eight years (1991-1998) of real declines averaging 4 percent per year.

Furthermore, above-average growth in income expected this year contributes to continual momentum in highway travel.

Finally, we expect to see only marginal improvements (if any) to average vehicle efficiency this year. As a result of all this, summer gasoline demand is likely to expand at an above-average rate of 2 percent in 1999.

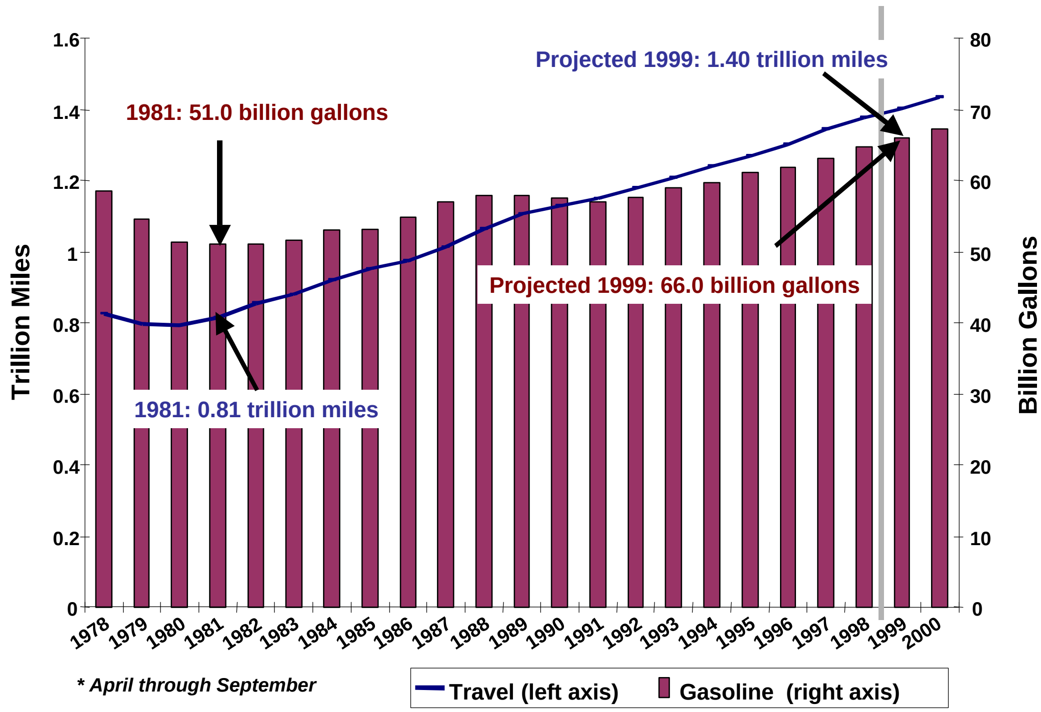
Figure MG8. Components of U.S. Highway Travel Growth



Travel has grown substantially since the early 1980's despite the Persian Gulf-related slowdown in 1990 and 1991. Almost half of the growth in per-capita travel since 1985 has resulted from the lagged effects of substantial price declines (see above). Growth in per-capita income has accounted for much of the other growth in per-capita travel since 1985. Recent trends suggest that, although real disposable income will continue to be a major factor in determining travel activity, continued increases in travel may not match that of income (see Table MG1).

Highway travel during the upcoming summer is projected to grow by 2.1 percent. Although that increase exceeds that of population (1.0 percent), it is substantially below that projected for real disposable income (3.7 percent). This is similar to the growth rate observed last summer (2.3 percent), during which disposable income growth averaged 3.2 percent. Nonetheless, per-capita travel can still be expected to increase during the forecast interval and in the long term.

Figure MG9. Summer* Travel and Fuel Demand



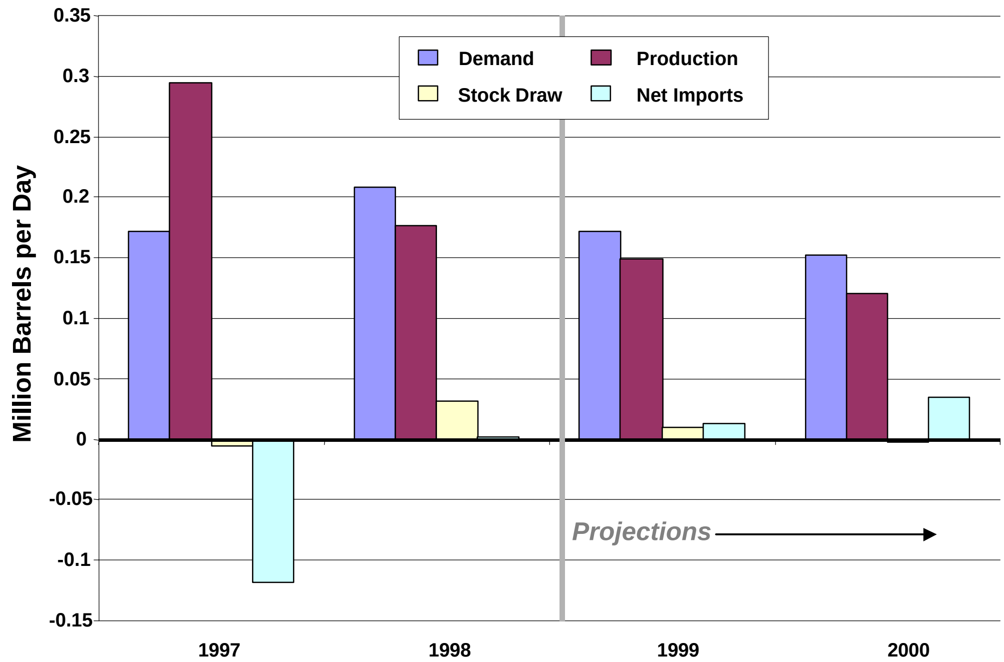
Summer highway travel in the United States (all vehicles) is expected to reach 1.40 trillion miles this year, up 2.1 percent, in 1998 (Figure MG9).

Vehicle miles traveled has increased since 1980, the turning point in U.S. travel following the 1970's oil price shocks. Since then, travel has grown rapidly as strong efficiency gains reduced the cost per mile of gasoline. Since 1985, high travel growth was also spurred by the collapse of prices to a new, lower regime, during which fuel efficiency continued to grow.

During the 1990's, travel has tended to grow at a slower rate than during the 1980's (note the inflection point in the travel line at 1989). The slowing is in part due to a decline (to well under 1 percent today) in the rate of growth of vehicle efficiency, which has reduced the decline in fuel costs on a cost per mile basis.

Summer gasoline demand, which has been increasing steadily since 1991, is expected to reach 66.0 billion gallons in 1999. That amount is almost 30 percent higher than it was in 1981, when the end of the downturn in domestic gasoline use, brought about by previous oil price shocks, occurred.

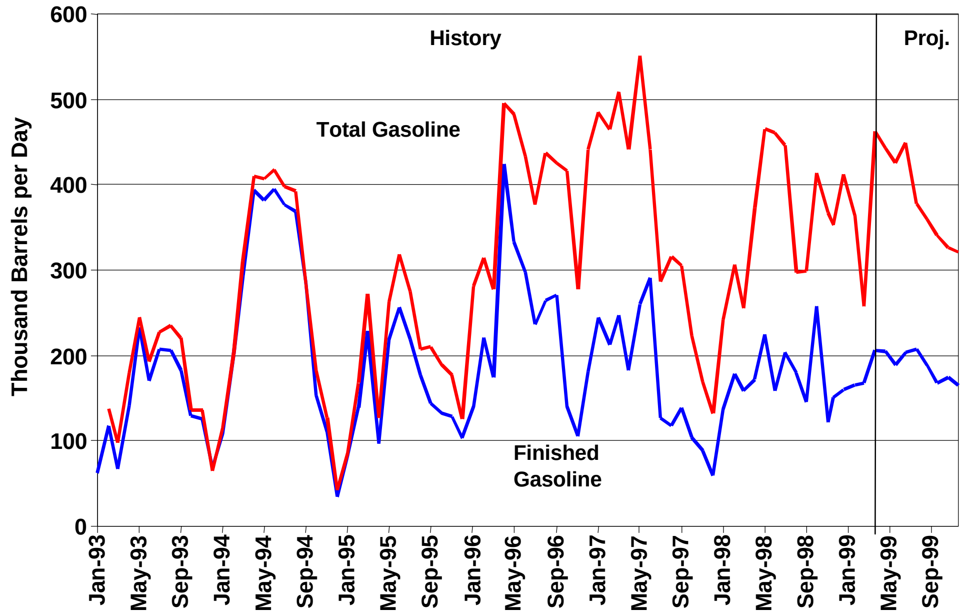
Figure MG10. Summer Gasoline Supply by Source (Change from Year Ago)



In recent years, the emphasis in domestic motor gasoline supply has been on domestic finished gasoline production, which has displaced some quantities of finished imports. This summer should not prove to be very different, as increased refining capacity should allow most of the expected growth in demand to be supplied without need for substantial increases in inventory drawdown or imports. But increases in projected refinery output are projected to be 20,000 barrels per day less than those of demand, implying a need to call upon imports and/or inventories. In any case, the ample supply of inventories and availability of imports is expected to preempt supply shortfalls.

As in recent years, changes in primary stocks are not expected to play a major role in supply/demand balances, even though *potential* stock drawdown brought by high inventory levels is substantial. Actual stock draw is projected to average 10,000 barrels per day. Net imports are expected to increase by 10,000 barrels per day this summer, reversing a pattern of declines observed in previous summers. These projections, however, assume no unanticipated disruptions in domestic refinery output or in foreign sources of supply.

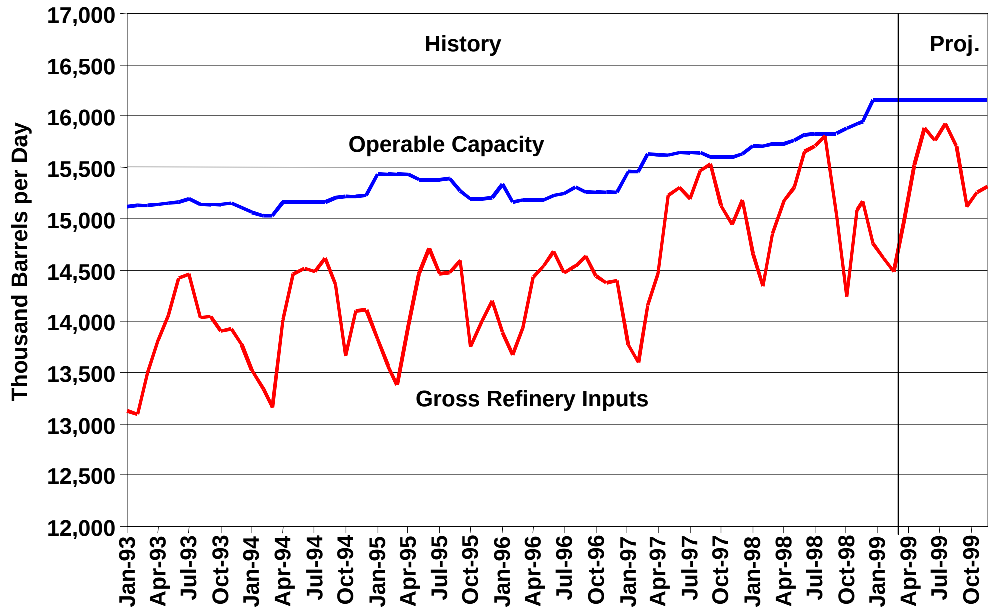
Figure MG11. Motor Gasoline Net Imports



Although imports of finished gasoline have declined in recent years, those of blending components required to meet environmental specifications increased from 1995, when the RFG program was implemented, to 1998. During that time net imports of blendstocks occasionally exceeded that of finished motor gasoline, boosting total net imports to as much as 500,000 barrels per day. Some of the increase in finished motor gasoline production in the United States was related to the additional quantities of imported blending components, especially during the summer months.

This summer, however, net imports of finished gasoline are projected to be only 10,000 barrels per day higher than the average net imports of the previous summer. This projection implies somewhat larger increases in imported quantities of blending components. But the continued increase in imports of the finished product, combined with 150,000 barrels-per-day increases of finished motor gasoline production (see Figure MG12), is expected to constrain inventory drawdowns to only 10,000 barrels per day.

Figure MG12. U.S. Refinery Capacity and Throughput



Refinery input has grown an average 300,000 barrels per day during the last 5 years, but refinery capacity has increased by less than half that amount. As a result, inputs approached rated capacity during periods of peak gasoline production during the 1997 and 1998 summer driving seasons (Figure MG12).

The upcoming summer, however, is expected to witness a reversal of those trends. Inputs are projected to increase by 180,000 per day, but capacity is expected to increase by almost twice that, lowering the average utilization rate. Nonetheless, increases in summer gasoline production are projected to average 150,000 barrels per day.

Demand and Price Outlook for Phase 2 Reformulated Gasoline, 2000

Tancred Lidderdale and Aileen Bohn [1]

Congress last enacted major amendments to the Clean Air Act in 1990 (CAA90). The CAA90 (Public Law 101-549) includes programs to control acid rain and reduce damage to the stratospheric ozone layer, new standards for emissions of hazardous air pollutants, and new requirements for motor vehicles and fuels. The amendments and earlier provisions of the Clean Air Act appear to have contributed to significant improvements in air quality nationwide. For example, peak ozone concentrations have declined 30 percent between 1978 and 1997; the 1997 average ambient concentration of carbon monoxide is 60 percent lower than it was in 1978; and annual mean nitrogen dioxide concentrations have decreased in urban areas by 25 percent since 1978.[2]

The reformulated motor gasoline (RFG) provisions of CAA90 require reductions in automobile emissions of ozone-forming volatile organic compounds during the summer high-ozone season, and of toxic air pollutants and nitrogen oxides during the entire year in certain areas of the United States. Phase 2 of the RFG program will begin at refineries on December 1, 1999, and at retail outlets beginning January 1, 2000.

This article presents projections of demand and the market price premium for Phase 2 RFG in the year 2000. The projections in this article are based on forecasts in the *Short-Term Energy Outlook*, which is published monthly by the Energy Information Administration.

Demand for Phase 2 RFG is expected to represent about 34 percent of total motor gasoline demand in 2000. Demand projections are based on estimated populations of the participating ozone nonattainment areas and per capita motor gasoline demand in each area.

Refineries will have to change operating procedures, make plant modifications, and obtain new process equipment in order to meet the new emissions reduction requirements for Phase 2 RFG. The higher costs of production are expected to

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[2] Environmental Protection Agency, *National Air Quality and Emissions Trends Report 1997*, 454/R-98-016 (Washington, DC, December 10, 1998).

yield the following wholesale price premiums (in cents per gallon of gasoline) for Phase 2 RFG above the price of conventional motor gasoline:

	Southern States (EPA region 1)	Northern States (EPA region 2)
Summer (May 1 - September 15)	3.5	4.0
Winter (September 16 - April 30)	2.5	2.5

These projected price premiums may fluctuate by as much as 1 cent per gallon depending on the market price of oxygenates (e.g., fuel ethanol and MTBE). Additional costs to store, transport, and distribute RFG are not expected as Phase 2 RFG works its way through the system replacing Phase 1 RFG. If the current trend requiring specific gasolines in limited areas continues, though, local spikes in retail prices could become more routine.

The use of oxygenates, which have a lower energy content than the motor gasoline components they displace, raises consumers' effective final costs by 0.5 to 1.5 percent as a result of reduced fuel economy (i.e., miles per gallon).

Introduction

The Clean Air Act requires that all areas of the country meet National Ambient Air Quality Standards (NAAQS), which are set by EPA at levels that are expected to be protective of human health and the environment. The Federal law requires that States do not exceed these standards. Areas that do exceed the NAAQS are required to develop and implement plans to attain them.

NAAQS have been established for 6 "criteria" air pollutants: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter, and lead. Air toxics (e.g., benzene, butadiene, formaldehyde, acetaldehyde, and polycyclic organic matter) is another set of pollutants regulated under the Clean Air Act. Ozone is the only air pollutant that is not directly emitted into the air but is the result of a reaction of volatile organic compounds and nitrogen oxides, which are both emitted by stationary and mobile sources.[3]

The U.S. petroleum refining industry has responded to 5 major new Federal rules on motor gasoline product quality in the last 11 years:

Environmental Regulations Affecting the Product Quality of U.S. Motor Gasoline

Phase 1 Summer Volatility (RVP) Regulation	June 1989
Phase 2 Summer Volatility (RVP) Regulation	May 1992
Oxygenated Gasoline	November 1992
Reformulated Gasoline Phase 1	December 1994
Reformulated Gasoline Phase 2	December 1999

[3] Ground-level ozone is the primary ingredient of smog and should not be confused with stratospheric ozone that is a natural layer some 6 to 20 miles above the earth and provides protection from harmful radiation.

The Phase 2 reformulated gasoline (RFG) standards consist of 2 fuel specifications (maximum benzene content and minimum oxygen content) and 3 performance standards applying to automobile emissions of volatile organic compounds (VOC) during the summer months and nitrogen oxides (NOx) and toxic air pollutants (TAP) year-round (Table RFG1). The emissions reduction performance standards are measured by use of a mathematical model that relates each type of emission to specific fuel components. The emissions reductions are measured relative to the average gasoline produced in 1990 (the "baseline gasoline"). The application of an emissions model provides refiners some flexibility in producing gasoline to meet the emissions reduction performance standards.

Phase 1 of the RFG program required refineries to begin production of RFG on December 1, 1994, using the *simple emissions model*, which judged emissions compliance by use of 4 gasoline variables (Reid vapor pressure, oxygen, benzene, and total aromatics). In January 1998, refiners were required to switch to the *Phase 1 complex emissions model,* which introduced 4 additional variables (sulfur, olefins, and 2 distillation limitations). Phase 2 of the RFG program begins at refineries on December 1, 1999, and at retail outlets beginning January 1, 2000. The *Phase 2 complex emissions model* uses the same variables as the Phase 1 complex emissions model. However, the estimated emissions using the Phase 2 model are different from those predicted by the Phase 1 model.

The VOC, NOx, and TAP emissions reduction performance standards under Phase 1 using the Phase 1 complex emissions model and under Phase 2 using the Phase 2 complex emissions model are not directly comparable because of the differences between the Phase 1 and Phase 2 complex emissions models. An approximate comparison is provided in Table RFG1, which estimates emissions of a fuel that complies with Phase 1 requirements but uses the Phase 2 complex emissions model. The comparison indicates that Phase 1 winter RFG comes very close to meeting the Phase 2 winter emissions reduction requirements for TAP and NOx. In fact, the average quality RFG produced during the 1997 - 1998 winter (December 1997 through February 1998) already met the Phase 2 RFG requirements (this is described in more detail later in this report). The difficult task facing refiners is meeting the required additional reductions in VOC and NOx during the summer months. The additional Phase 2 reduction in summer TAP emissions is small, and is also already being met by refiners.

Table RFG1. Reformulated Gasoline Averaging Standards

	RFG Phase 1 January 1995 - December 1999			RFG Phase 2 January 2000		
	Summer Region 1	Summer Region 2	Winter	Summer Region 1	Summer Region 2	Winter
Product Quality Standards:						
Oxygen, weight % min	2.1	2.1	2.1	2.1	2.1	2.1
Benzene, volume % max	0.95	0.95	0.95	0.95	0.95	0.95
Performance Standards (using Phase 2 complex emissions model), percent reduction required:						
Toxic Air Pollutants	18.5 %	17.8 %	17.3 %	21.5 %	21.5 %	21.5 %
Volatile Organic Compounds	20.8 %	10.5 %	n.a.	29.0 %	27.4 %	n.a.
Nitrogen Oxides	1.4 %	1.6 %	1.7 %	6.8 %	6.8 %	1.5 %

n.a. - not applicable

Notes: • Region 1 (southern States) - AL, AZ, AR, CA, CO, DC, FL, GA, KS, LA, MD, MS, MO, NV, NM, NC, OK, OR, SC, TN, TX, UT, and VA. • Region 2 (northern States) - CT, DE, ID, IL, IN, IA, KY, ME, MA, MI, MN, MT, NE, NH, NJ, NY, ND, OH, PA, RI, SD, VT, WA, WV, WI, and WY. • Summer - May 1 through September 15; Winter - September 16 through April 30. • Performance standards for Phase 1 RFG are calculated by using Phase 2 complex emissions model. Average levels for olefins, E200, E300, and summer aromatics are fixed at 1990 gasoline baseline. Summer RVP for region 1 (7.1 psi) and region 2 (8.0 psi) are fixed to meet Phase 1 complex emissions model VOC emissions reductions of 36.6 percent and 17.1 for regions 1 and 2, respectively. Sulfur (300 ppm) and winter aromatics (24.3 volume percent) are fixed to meet Phase 1 complex emissions model requirements for average 16.5 percent toxics and 1.5 percent nitrogen oxides emissions reductions. These levels are comparable to the EPA's estimate of Phase 1 fuel composition in the *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), Table V-6.

Source: Code of Federal Regulations, Title 40, Part 80, "Regulation of Fuels and Fuel Additives."

Reformulated Gasoline Demand

Forecasting reformulated gasoline demand in the year 2000 is not difficult because we have over 4 years of history of RFG sales on which to base our forecasts. What can change, however, is the number of areas participating in the program. For example, beginning June 1, 1999, St. Louis, Missouri, will join the list of control areas requiring RFG.[4] The purpose of this demand analysis is to evaluate the conventional method for estimating RFG demand in specific control areas.

Refer to the EIA analysis article, "Areas Participating in the Reformulated Gasoline Program," for a list of cities that participate in the reformulated gasoline program. This article is available online at:

http://www.eia.doe.gov/emeu/steo/pub/special/rfg2.html

This article includes:

- A list of all control areas, their populations, dates of opt-in or opt-out, and an Excel spreadsheet with control area populations at the county level.
- References to all opt-in and opt-out notices published by the Environmental Protection Agency in the Federal Register with pointers to their Internet addresses where available.
- History of Environmental Protection Agency opt-in and opt-out regulations.

[4] The St. Louis program will begin on May 1, 1999, for all persons other than retailers and wholesale purchaser-consumers (i.e., refiners, importers, and distributors). Environmental Protection Agency, *Federal Register*, Vol. 64 No. 41 (Washington, DC, March 3, 1999), pp. 10365-10371.

RFG market shares for each State (State RFG demand as a percentage of total State motor gasoline demand) are assumed to be equal to the proportion of a State's population that resides within an RFG control area.

State RFG Market Share = Each State's estimated control area population divided by the total State population

RFG demand forecasts are then based on the estimated State RFG market shares and the projected total State motor gasoline demands.

State RFG Demand = State's RFG market share multiplied by the State's total motor gasoline demand

RFG market shares are estimated at the State level because of significant differences in per capita demands across States. In general, States with a higher proportion of residents in metropolitan or urban areas have lower per capita gasoline demands.[5] For example, per capita demand in 1997 ranged from a low of 309 gallons per person per year in New York with 91.7 percent of its population living in metropolitan areas to 683 in Wyoming with a 29.8 percent metropolitan population.[6] Since RFG control areas are primarily metropolitan areas, estimating RFG demand at a more aggregate level will bias RFG demand estimates upwards.

In the tables that follow, the control area population of a region (2 or more States) may not equal that region's estimated RFG market share because of the differences in per capita demands across States. RFG market share for a region is based on the estimated RFG demand and total gasoline demand for each State within the region (Table RFG2).

Regional RFG Market Shares = The sum of RFG demand for each State in a region, divided by the sum of each State's total gasoline demand.

[5] A simple ordinary least squares regression analysis of State per capita motor gasoline demand (gallons per person per year) against the percentage of the State's population living in nonmetropolitan areas results in the following equation (t-statistics in parentheses):

$$\text{State per capita demand (1997)} = \underset{(7.57)}{428.8} + \underset{(6.04)}{2.22} * \text{State nonmetropolitan population share (July 1, 1996)}$$

[6] State demands from Federal Highway Administration, "Motor Gasoline Reported by States" *Highway Statistics 1997*, FHWA-PL-98-020 (Washington, DC, Nov. 1, 1998), Table MF-33GA. Estimated State population on July 1, 1996, from U.S. Census Bureau.

Table RFG2. Predicted Reformulated Gasoline Market Shares by Petroleum Administration for Defense District (PADD), Year 2000

Region	Control Area Population July 1, 1996 (thousands)	Region Population July 1, 1996 (thousands)	Predicted RFG Market Share from State Control Area Population Shares (percent)
PADD 1A - New England	11,051	13,351	79.2 %
PADD 1B - Central Atlantic	29,340	44,568	67.2 %
PADD 1C - Lower Atlantic	3,972	41,276	9.5 %
PADD 2 - Midwest	13,026	74,587	16.0 %
PADD 3 - Gulf Coast	8,280	34,691	23.0 %
PADD 4 - Rocky Mountain	0	8,373	0 %
PADD 5 - West Coast	34,490	48,437	67.1 %
Total U.S., 2000	**100,159**	**265,284**	**34.1 %**

Notes: • Includes St. Louis, Missouri, opt in, and Maine opt out, and State reformulated gasoline programs in northern California and Phoenix, AZ. • PADD and U.S. predicted RFG market shares do not correspond to control area population shares because of differences in per capita demands across States. Regional RFG market shares estimated from State control area population shares and State per capita gasoline demand based on 1997 State total motor gasoline demand.

Sources: State total motor gasoline demand: Federal Highway Administration, "Monthly Gasoline Reported by States" *Highway Statistics 1997*, FHWA-PL-98-020 (Washington, DC, Nov. 1, 1998), Table MF-33GA. Population: U.S. Census Bureau.

We can evaluate the accuracy of this RFG market share estimation methodology by comparing estimated with actual RFG market shares reported by EIA. Estimated State RFG market shares are calculated by using control area population shares and State total gasoline demand data reported by the Federal Highway Administration (FHWA), as described above. Although FHWA does not report gasoline sales by type, e.g., RFG versus conventional gasoline, State RFG market shares are available from EIA statistics. However, a State-by-State comparison is complicated because FHWA State gasoline demands do not necessarily correspond to EIA State demands.[7] Where differences do occur between FHWA and EIA State demand data, they are often offsetting between neighboring states. For example, EIA reports higher deliveries to Maine but lower sales in New Hampshire; higher in New Jersey and lower in New York; higher in California but lower in Arizona. Consequently, a comparison of estimated RFG market shares to actual market shares should be done on a regional level.

The comparison of estimated regional RFG market shares to actual RFG market shares reveals differences of less than 1.5 percent at the regional level and 0.2 percent at the national level (Table RFG3). Two significant corrections were made to the estimated RFG market shares in the analysis. The estimated RFG market shares for New York City and Chicago were multiplied by 0.85 to yield reasonable comparisons at the State and sub-PADD levels.

[7] EIA gasoline sales data are collected from a survey of about 200 "prime suppliers" -- firms that produce, import, or transport petroleum products across State boundaries and local marketing areas and sell the products to local distributors, local retailers, or end users. The Federal Highway Administration collects total gasoline sales data from State fuel taxation reports, which generally represent gasoline sales at the terminal or wholesale level.

Table RFG3. Comparison of Estimated RFG Market Shares With Actual RFG Market Shares by Petroleum Administration for Defense District (PADD), 1997

Region	Estimated 1997 RFG Market Share (percent of total gasoline demand)	Actual 1997 RFG Market Share (percent of total gasoline demand)
PADD 1A - New England	85.9 %	87.1 %
PADD 1B - Central Atlantic	64.2 %	62.6 %
PADD 1C - Lower Atlantic	9.5 %	9.3 %
PADD 2 - Midwest	11.8 %	11.3 %
PADD 3 - Gulf Coast	23.0 %	23.2 %
PADD 4 - Rocky Mountain	0 %	0 %
PADD 5 - West Coast	67.1 %	67.1 %
Total U.S., 1997	**32.8 %**	**32.6 %**

Notes: • Estimated RFG market shares for New York City and Chicago are corrected by multiplying control area population shares by 0.85. • Phoenix, Arizona, participation began in July 1997.

Sources: Estimated RFG market shares based on July 1, 1996, populations and total gasoline sales reported by Federal Highway Administration, "Monthly Gasoline Reported by States," *Highway Statistics 1997*, FHWA-PL-98-020 (Washington, DC, November 1, 998), Table MF-33GA. Actual 1997 RFG market share: Energy Information Administration, "Prime Supplier Sales Volume of Motor Gasoline," *Petroleum Marketing Annual 1997*, DOE/EIA-0487(97) (Washington, DC, December 1998), Table 48.

There are several possible explanations for these differences between estimated and actual State RFG market shares.

1997 estimated RFG market share larger than actual:

- RFG control areas are generally metropolitan areas, which have lower per capita gasoline demands than non-metropolitan areas.
- Delivery and sale of conventional gasoline within RFG control areas (i.e., noncompliance).
- Reported delivery of conventional gasoline in one State (region) was actually sold in another State (region).

1997 estimated RFG market share smaller than actual:

- A 1 to 2 percent reduction in fuel efficiency with RFG fuel means per capita demands in control areas may be larger than demands in non-control areas.
- Delivery of RFG to non-control areas (i.e., spillover).
- Reported delivery of RFG in one State (region) was actually sold in another State (region).

Oxygenate Demand

Oxygenates represent a key component of both Phase 1 and Phase 2 reformulated gasoline. The primary oxygenates include fuel ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), and tertiary amyl methyl ether (TAME). Reformulated gasoline requires a minimum 2.1 percent oxygen by weight when averaging, which corresponds to approximately 6.0

volume percent ethanol, 11.5 volume percent MTBE, and 13.4 volume percent ETBE or TAME.

While EIA reports monthly data on production, imports, and stocks of individual oxygenates, there is no comparable data on the disposition of oxygenates. However, an oxygenate demand balance can be derived from EPA estimates of the oxygenate content in reformulated and oxygenated gasoline by control area. MTBE is the dominant blendstock in reformulated gasoline, and ethanol is generally the oxygenate of choice in oxygenated gasoline (Table RFG4). Almost all MTBE supply is used for reformulated and oxygenated gasoline blending, while only about one-half of the total ethanol supply is. Demand for ethanol in gasohol blending and MTBE as a motor gasoline octane blendstock make up the balance of the oxygenate demand.

Table RFG4. Oxygenate Demand in Reformulated and Oxygenated Gasoline Control Areas, 1997 (thousands of barrels per day)

Region	Estimated 1997 Gasoline Demand in Control Areas	Estimated Oxygenate Volume in Control Area Gasoline		
		MTBE	ETBE or TAME	Ethanol
Reformulated Gasoline				
PADD 1 - East Coast................	1,054	128.2	9.1	1.0
PADD 2 - Midwest	270	4.0	0.0	21.8
PADD 3 - Gulf Coast	282	27.4	3.2	0.0
PADD 4 - Rocky Mountain	0	0.0	0.0	0.0
PADD 5 - West Coast...............	934	100.9	3.4	2.0
Subtotals.................................	**2,674**	**259.5**	**15.7**	**24.7**
Oxygenated Gasoline				
PADD 1 - East Coast................	0	0.0	0.0	0.0
PADD 2 - Midwest	79	0.0	0.0	6.7
PADD 3 - Gulf Coast	16	0.0	0.0	1.4
PADD 4 - Rocky Mountain	36	0.3	1.1	2.7
PADD 5 - West Coast...............	73	0.1	0.0	4.7
Subtotals.................................	**204**	**0.5**	**1.1**	**15.5**
Oxygenated-Reformulated Gasoline				
PADD 1 - East Coast................	137	4.8	0.0	0.4
PADD 5 - West Coast...............	10	0.1	0.0	0.7
Subtotals.................................	**147**	**4.9**	**0.0**	**1.1**
Average 1997 Oxygenate Demand for RFG and Oxygenated Gasoline Blending		**265**	**17**	**41**
Imputed Oxygenate Demand for Conventional Gasoline (e.g., octane and gasohol)		**4**	**n.a.**	**41**
Total 1997 Oxygenate Supply		**269**	**n.a.**	**82**

n.a. - not available

Notes: • Oxygenated gasoline includes year-round State mandated program in Minneapolis, MN. • Oxygenated gasoline assumed to contain 2.7 weight percent oxygen. • Oxygenate demand for New York City (PADD 1) and Phoenix, AZ (PADD 5) oxygenated-reformulated gasoline represents volume in excess of requirements for RFG. • Total oxygenate supply includes domestic production, net imports, and stock change. Imports of RFG (161,000 barrels per day) assumed to contain 11.0 percent MTBE by volume.

Sources: Oxygenate content in RFG control area gasoline: Environmental Protection Agency, "1997 RFG Surveys Oxygenate Information" (http://www.epa.gov/orcdizux/consumer/fuels/mtbe/oxy-type.pdf). Oxygenate market shares in oxygenated gasoline control areas: Environmental Protection Agency, "State Winter Oxygenated Fuel Programs, February 1, 1999" (http://www.epa.gov/oms/regs/fuels/oxy-area.pdf). Control area gasoline demand calculated from control area population as share of State population and 1997 State gasoline demand from Federal Highway Administration, "Monthly Gasoline Reported by States," *Highway Statistics 1997*, FHWA-PL-98-020 (Washington, DC, Nov. 1, 998), Table MF-33GA. Oxygenate supply: Energy Information Administration, *Petroleum Supply Annual 1997, Volume 1*, DOE/EIA-0340(97)/1 (Washington, DC, June 1998), Tables 3, 20, 27, 30; and *Petroleum Supply Monthly*, DOE/EIA-0109 (Washington, DC, various issues), Tables D2, and D3.

Logistics

Reformulated gasoline is required in Dallas, Houston, and some of the urban areas in the Northeast and Midwest while a more stringent RFG is called for in California and Phoenix (Figure RFG1). Oxygenated gasoline is required in other parts of the Midwest and West, generally from mid-October through the end of February. New York City gets a hybrid oxygenated RFG during the winter. Adding another layer of complexity is a lower RVP gasoline that is delivered to more than 30 Air Quality Control Regions in the South from June 1 to September 15.

The proliferation of clean fuel requirements over the last decade has complicated petroleum logistics. Though the transition from Phase 1 to Phase 2 reformulated gasoline in early 2000 should not have a profound effect, additional clean fuels programs could make the system more vulnerable to local outages and price spikes.

Interstate Movements and Storage

Some parts of the country are more dependent than others on external gasoline supply sources.[8] Refineries on the East Coast, for example, provided only 29 percent of gasoline demanded in that region in 1997. Over 60 percent came from U.S. Gulf Coast refiners and the balance was imported. U.S. Gulf Coast supplies face constraints at pipeline breakout storage tanks and distribution terminals during the heating season. In the Midwest, 79 percent of the gasoline demanded was produced locally; 15 percent came from the U.S. Gulf Coast. Product pipelines going into the Midwest have little surplus capacity to handle extra batches of clean fuels. The pipeline companies blame the lack of expansion on poor return on investment as inflation-adjusted pipeline tariffs have declined over the last few years. U.S. Gulf Coast refiners also supplied 3 percent of West Coast demand. More U.S. Gulf Coast supply is expected in the West as the Navajo Pipeline is completed, allowing flows to southern Arizona. Imports accounted for under a percent of West Coast demand due, in part, to the stringent gasoline requirements in California.

An increasing number of gasolines and distillates of different quality grades, referred to as "product proliferation", leads to a loss in flexibility. Clean gasolines can become tainted and deemed off-spec if commingled with conventional gasoline. Therefore, pipelines must configure batches so that progressively lower grades of RFG, for example, are transported before progressively lower grades of conventional gasoline. Product interface requires downgrading gasoline from premium to regular gasoline and from RFG to conventional, and so forth. The downgrading of RFG to conventional gasoline, caused by product proliferation and the necessity of carrying multiple types of

[8] Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(97/1) (Washington, DC, June 1998), Tables 4, 6, 8, 10, 12, and 32.

gasoline, reduces the amount of available RFG, thereby reducing the flexibility in supply.

Colonial Pipeline, operator of the U.S. Gulf Coast to New York trunk, has active product codes for 38 different grades of gasoline (including multiple vapor pressures for each grade), 7 grades of kerosene (including two for military), 16 grades of home heating oil and diesel fuel (including diesel fuel marine for the U.S. Navy and light cycle oil) and one grade of transmix (the gasoline/distillate interface that needs to be reprocessed). Of the 62 product codes, 29 are for fungible products and 33 are for products that must be shipped on a segregated basis.[9]

Furthermore, product proliferation has necessitated greater segregation at storage terminals, further complicating logistics. Terminaling facilities associated with pipelines are also faced with having to separate RFG, oxygenated and conventional stocks at different grades and RVP levels. Storage terminals need to maintain RFG or other program gasoline supplies for a metropolitan area and conventional gasoline supplies for the surrounding area, sometimes in the same facility. In the past two winters, Colonial Pipeline Company limited nominations for shipments on its Houston-to-New York pipeline due to a problem of customers not clearing storage space for receipt of a new shipment. Handling errors were up during the same time period.[10]

Local Distribution

Based on evidence during the Phase 1 RFG program, industry faces more problems related to delivery rather than production. During Phase 1, the only situations where EPA considered suspension of RFG requirements were for distribution emergencies. EPA emergency provisions provide for a specification waiver until alternative RFG supplies can be obtained. A pipeline rupture on Colonial Pipeline's gasoline trunk just prior to the start of the RFG program caused officials to consider the delay of the start-up of the program. Barging supplies to another Colonial input point in Louisiana proved to be a viable alternative. A review of the waiver applications indicates that alternative supplies were ultimately available:

- In March 1997, flooding in the Ohio Valley prompted Ashland Oil to call EPA about the possibility of a waiver of regulations requiring reformulated gasoline in the Louisville and Covington areas of Kentucky. With help from the BP refinery in Toledo, Ohio, and the Marathon refinery in Robinson, Illinois, Ashland was able to forego a request for a waiver. Trucking proved to be a viable alternative to river supplies, though not completely free of flooding-related problems.

[9] Colonial Pipeline Company (http://www.colpipe.com/ab_faq.asp), February 18, 1999.

[10] Discussion with Noel Giese, Colonial Pipeline Company, January 5, 1999.

- In advance of losing an MTBE unit in Texas for a couple of weeks at the peak of the gasoline season in July 1997, Sun Oil called EPA about the possibility of a waiver of regulations requiring reformulated gasoline in the noncompliance areas in the Mid-Atlantic States. Sun was able to forego a formal request for a waiver, after having found alternative supplies elsewhere in Texas that were barged to the Philadelphia facility.

- Facing the prospect of closing 11 gasoline stations in northern Kentucky in May 1998 due to a lack of reformulated gasoline (RFG) supplies, a jobber contacted EPA about the possibility of a waiver that would allow conventional gasoline to substitute for RFG. Ultimately, arrangements were made for the jobber to be resupplied out of a cargo received at a nearby terminal later in the day. The request for a waiver was withdrawn.

Price spikes were associated with each of these events and served as the basis for the first waiver application in March 1997. While the outage of the MTBE unit in Texas in July 1997 was resolved before local supplies and prices were impacted, the RFG cargo spot price in the New York Harbor went up, then receded by about a penny a gallon, as suppliers reacted to the worsening of an already tight MTBE situation.[11] An EIA survey picked up an 8-cent-per gallon week-to-week change in the average RFG retail price in Kentucky in connection with the May 1998 refinery problems.[12]

Phase 2 RFG Logistics

The conditions that existed for local distribution problems in Phase 1 will be carried forward into Phase 2. Other programs under consideration could effectively add more areas to the already hopscotched map of gasoline demand (Figure RFG1). Having to transport additional types of gasolines, interstate pipeline companies will be forced to generate more product codes and downgrade more gasoline tainted by contact with other gasoline types. Local distribution terminals may have to double the number of gasolines to segregate and, to accommodate this, will form more alliances with one type of gasoline stored at one facility and another type at a different facility. A summary of the future clean gasoline initiatives that could complicate the delivery of Phase 2 gasoline follows.

Possible Opt-Ins to the RFG Program

RFG is currently being suggested for four cities in addition to St. Louis, where RFG is set to start June 1, 1999. The combined demand for these four cities--Kansas City, New Orleans, Baton Rouge, and Lafayette--is about almost 200

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[11] Reuters News Service, July 7, 1997.

[12] Energy Information Administration, Form EIA-878, “Motor Gasoline Price Survey,” May 4 and May 11, 1998.

thousand barrels per day (Table RFG5). While EPA has yet to approve these programs, offered as part of the Kansas and Louisiana State implementation plans (SIPs), early assessments show that the industry has the capability to produce, move, and distribute the proposed volumes.[13] RFG could come to these four cities as early as 2000.

Las Vegas is reviewing the possibility of using a special clean gasoline with specifications more in line with California's. The proposal also calls for an ethanol-only 3.5 weight percent oxygenate level that could arrive as early as November 1999, potentially adding another 57 thousand barrels per day to new RFG demand.

At the same time that some areas are opting into the RFG program, a controversy over MTBE is causing areas to consider opting out. MTBE, a suspected carcinogen, is appearing in ground water supplies. Maine opted out of the RFG program in March 1999. California is planning to phase out the use of MTBE by 2002.[14] A panel of experts has been established to advise EPA on how to address concerns about the use of MTBE and other oxygenates. The panel is scheduled to report to EPA its findings by summer 1999. The recommendations will address how to ensure public health protection for both air and water.

State Low Sulfur, Low RVP Gasoline Initiatives

Lowering RVP and sulfur circumvents the comparatively more expensive requirement for oxygenates in RFG while still reducing VOC emissions. Atlanta and Birmingham have plans for a low sulfur, low RVP gasoline. As with the RFG proposals, EPA has yet to approve 160 thousand barrels per day in total low sulfur, low RVP gasoline for these cities (Table RFG5). In addition, the regulations requiring RFG, complete with oxygenates, in ozone noncompliance areas may have to be repealed. The proposed gasoline has a summertime 7.0 psi RVP content and 150 ppm sulfur.

Some companies have offered to supply a low sulfur gasoline to service territories in the Eastern half of Texas while the State considers altering their SIP to require a low sulfur, low RVP fuel. Proximity to the Gulf Coast refining center and ample pipeline and storage capacity facilitates this discretionary, early move to a clean fuel. The demand for low sulfur, low RVP gasoline would start at almost 610 thousand barrels per day.

[13] Energy Information Administration, "Availability of RFG Supplies," unpublished paper provided to the U.S. Environmental Protection Agency, April 10, 1998.

[14] For further information, see California Energy Commission, *Supply and Cost of Alternatives to MTBE in Gasoline*, P300-98-013 (Sacramento, CA, October 1998).

Table RFG5. Potential Total U.S. Requirement for Gasoline by Type (thousand barrels per day)

Program	1997	2000	2004	2010
Conventional	5,301	5,063	2,847	N/A
Oxygenated	233	271	297	330
Phase 1 RFG	2,674	N/A	N/A	N/A
Phase 2 RFG	N/A	2,857	3,056	3,313
Potential RFG Opt-In Areas *	N/A	257	258	259
Low Sulfur, Low RVP	N/A	160	770	771
Tier 2	N/A	N/A	1,997	4,368
1997 NAAQS **	N/A	N/A	N/A	975
Total Gasoline Consumption	**8,220**	**8,590**	**9,220**	**10,010**

* As of March 31, 1999.
** Motor gasoline product quality requirements may not be substantially different from those of Phase 2 RFG.
N / A = not applicable.

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

Source: Estimated from the Federal Highway Administration, "Monthly Gasoline Reported by States," FHWA-PL-98-020 (Washington, DC, Nov. 1, 1998); Energy Information Administration, *Annual Energy Outlook*, DOE / EIA-0383(99) (Washington, DC, December 1998), Table A11; Energy Information Administration, *Petroleum Marketing Annual*, DOE / EIA-0487(98) (Washington, DC, June 1998), Table 50; U.S. Census Bureau.

NAAQS

In July 1997, EPA finalized new attainment standards for ground-level ozone.[15] EPA is replacing the previous 1-hour ozone standard with a new 8-hour standard.[16] The new standards will have no immediate impact on energy markets; however, some impacts may be seen after 2004, when noncompliance areas are identified and control strategies are developed. Although SIPs will be unique to each State, all are likely to include strategies to reduce NOx and VOC emissions from such key sources as electric utilities, industries, and motor fuels consumption to address the tighter ozone standard.

RFG use has led to a considerable reduction in VOC and NOx emissions, which are precursors to the formation of ozone. Therefore, RFG is likely to be included in SIPs. Examination on a county-by-county basis for large, noncomplying areas that have few other ozone-reducing alternatives results in a demand estimate for 2010 of almost a million barrels per day (Table RFG5) when fully implemented. This further complicates logistics by possibly adding counties in 10 States, mainly those in the Midwest and the South, to the RFG program (Figure RFG1).

[15] Much of the following discussion is taken from Energy Information Administration, *Annual Energy Outlook 1998*, DOE / EIA-0383(98) (Washington DC, December 1997), pp. 12-15.

[16] A National Ambient Air Quality Standard (NAAQS) for ground-level ozone has three parts: the concentration or level, the measurement period, and the "form" of the standard. The new ozone standard is set at a concentration of 0.08 ppm and the measurement period is 8 hours. Under the form adopted by EPA, areas are allowed to disregard their three worst measurements every year and average performance over three years to determine if they meet the standard.

Tier 2 Gasoline

EPA is considering a proposal to lower the sulfur content of gasoline from an average 340 ppm to as low as 30 ppm, approximating the California limit. The purpose of this move is to meet Tier 2 requirements to further reduce tailpipe emissions. Both the Tier 1 and 2 designations come from the 1990 Clean Air Act Amendments.[17] The low sulfur proposal would apply to all gasoline sold in the United States and, therefore, would be more a refining than a logistics issue. The industry is countering with proposals for a slower phase-in of the standard and more regionalization, a position that complicates delivery. If enacted in stages, terminals with service areas that straddle the Mississippi River could be looking at adding Tier 2 gasoline to their product slate and would need to segregate the various grades until the remaining States were phased in. EPA is currently developing a proposal for a trading program and a phase-in for small refiners, thereby requiring the segregation of Tier 2 gasoline through to any one of a number of destinations receiving conventional gasoline. While these proposals complicate logistics in many respects, Tier 2 could make the delivery of RFG in additional counties in 10 States, a possibility under the proposed NAAQS, unnecessary.

The demand for this gasoline effectively supplants conventional gasoline demand and carries with it the requirement for low summertime RVP in southern States. If enacted in stages, Tier 2 demand could start at 2.0 million barrels per day for 2004 (at a higher 150 ppm sulfur level) and be as much as 4.4 million barrels a day by 2010 (at the lower sulfur level, Table RFG5).

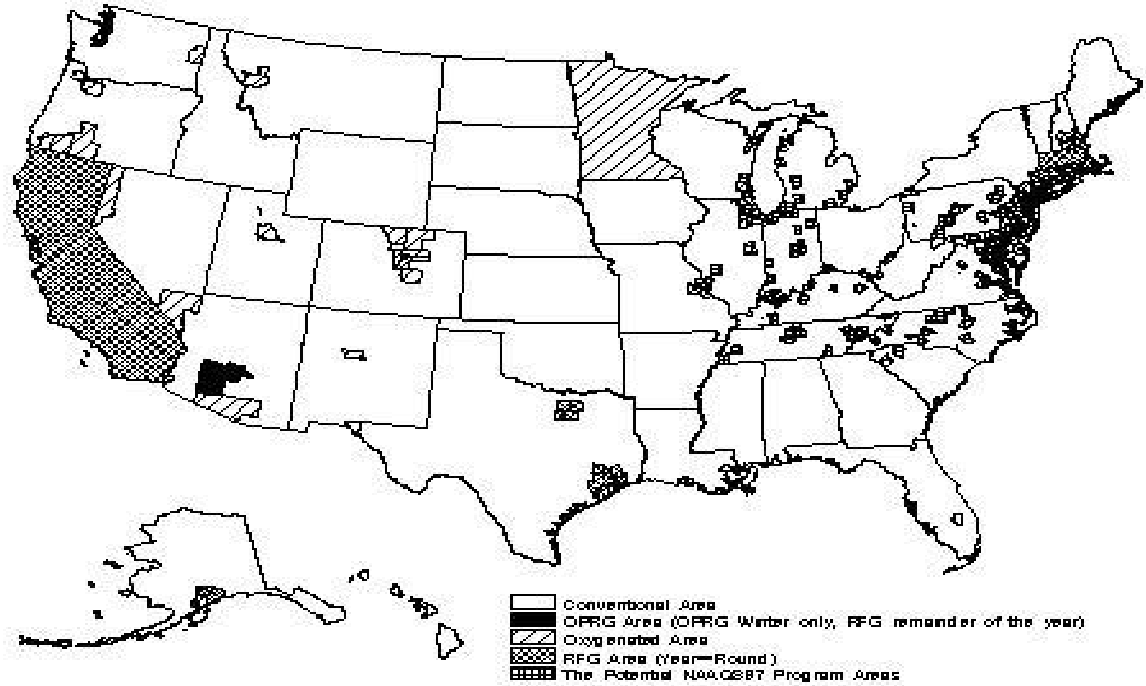
RFG Production Options

The application of the Phase 2 complex emissions model provides refiners some flexibility to meet the emissions reduction performance standards. The estimation of the Phase 2 RFG price premium depends on what fuel components will provide the most cost-effective means for reducing emissions.

Although the emissions reduction performance standards for Phase 2 RFG are based on comparison with emissions from the 1990 baseline gasoline fuel, the required emissions reductions and cost of Phase 2 RFG in this analysis are based on the emission reductions and costs incremental to those already realized in meeting the Phase 1 RFG standard.

[17] An analysis of Tier 2 supply and costs is contained in: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington DC, December 1998), pp. 29-30.

Figure RFG1. Gasoline Formulations (Clean Air Act Amendments 1990 and National Ambient Air Quality Standards 1997)



Note: Does not include low RVP gasoline required in over 30 Air Quality Control Regions in OR, NV, UT, CO, KS, MO, TN, MD, and DE and States south.
Source: U.S. Environmental Protection Agency, State Environmental Offices, and Energy Information Administration estimates.

The minimum emission reduction requirements for Phase 1 RFG were established in the Introduction of this article (Table RFG1). MTBE is assumed to be the blended oxygenate because it is the most commonly used and most likely represents the oxygenate used at the margin. All emissions reduction performance standards are based on averaging, i.e., refiners will choose to achieve emissions reduction targets on average rather than on each gallon of gasoline produced.

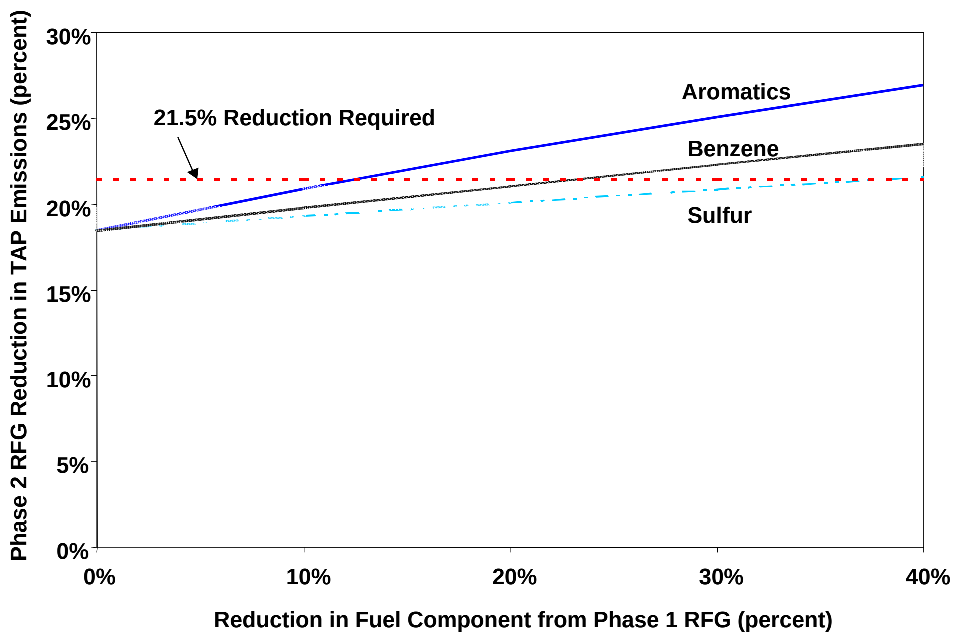
The impact of changes in the individual fuel components on TAP, NOx, and VOC emissions beyond the minimum requirements of Phase 1 are presented in graphs. This analysis indicates that RVP, sulfur, and aromatics are the fuel components that have the greatest impact on TAP, NOx, and VOC emissions and should be the primary targets of refiner Phase 2 RFG quality control.

Toxic Air Pollutants (TAP) Reduction

Phase 2 RFG requires a year-round 21.5 percent reduction in TAP emissions from the 1990 baseline gasoline. Phase 1 RFG already produces an average 18 percent reduction and only a small improvement is required to achieve the Phase 2 target (Table RFG1).

The three dominant variables in TAP emissions reduction are aromatics, benzene, and sulfur (Figure RFG2). Changes in RVP, olefins, E200 and E300 (not shown in graph) have only small effects on TAP. Replacing MTBE with ethanol increases TAP emissions because of the higher production of formaldehyde and acetaldehyde. The additional 3.5 percent reduction in TAP emissions (over current Phase 1 requirements) can be accomplished either by a 13 percent reduction in aromatics (from 32 to 28 volume percent), by a 24 percent reduction in benzene (from 0.95 to 0.72 volume percent), or by a 39 percent reduction in sulfur (from 312 to 190 ppm).

Figure RFG2. RFG Phase 2 TAP Reduction by Gasoline Component (Summer Region 1)



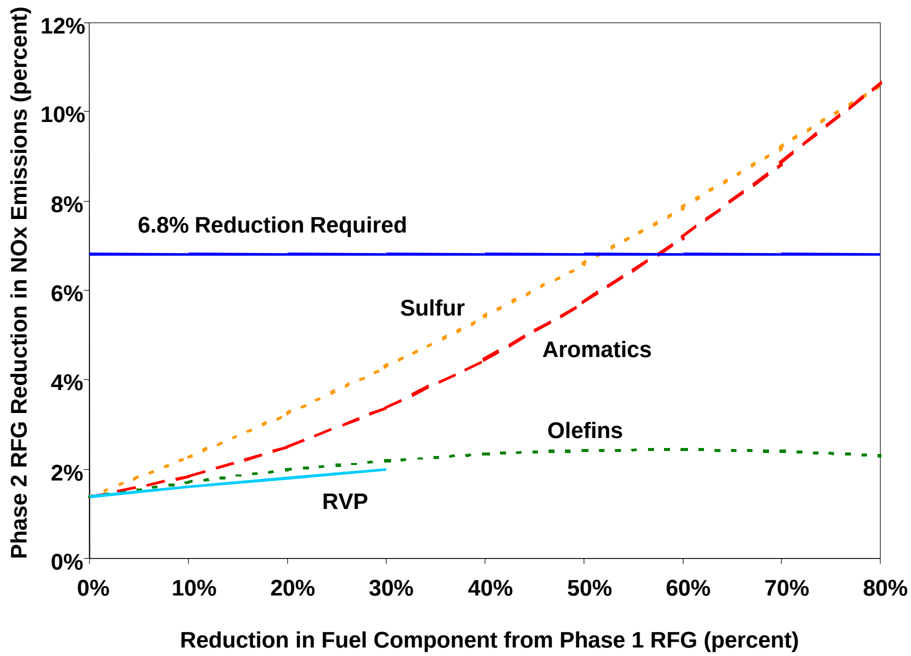
Nitrogen Oxides (NOx) Reduction

Phase 2 RFG requires a 6.8 percent reduction in NOx during the summer months and a winter reduction of 1.5 percent. Phase 1 RFG already produces an average 1.5 percent reduction in NOx year-round. Thus, the required summer NOx emission reduction is the performance standard of interest.

Sulfur and aromatics dominate the NOx emissions equation (Figure RFG3). Olefins, RVP, E200, and E300 have only small effects, and benzene has no effect on NOx emissions. The additional 5.3 percent reduction in NOx emissions (over current Phase 1 requirements) during the summer months can be accomplished either by a 52 percent reduction in sulfur (from 312 to 150 ppm) or by a 58 percent reduction in aromatics (from 32 to 13.6 volume percent).[18]

[18] The EPA originally established the NOx standard on the basis of the level of NOx control that can be cost-effectively achieved through sulfur reduction down to 138 ppm: Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 396

Figure RFG3. RFG Phase 2 NOx Reduction by Gasoline Component (Summer Region 1)



Volatile Organic Compounds (VOC) Reduction

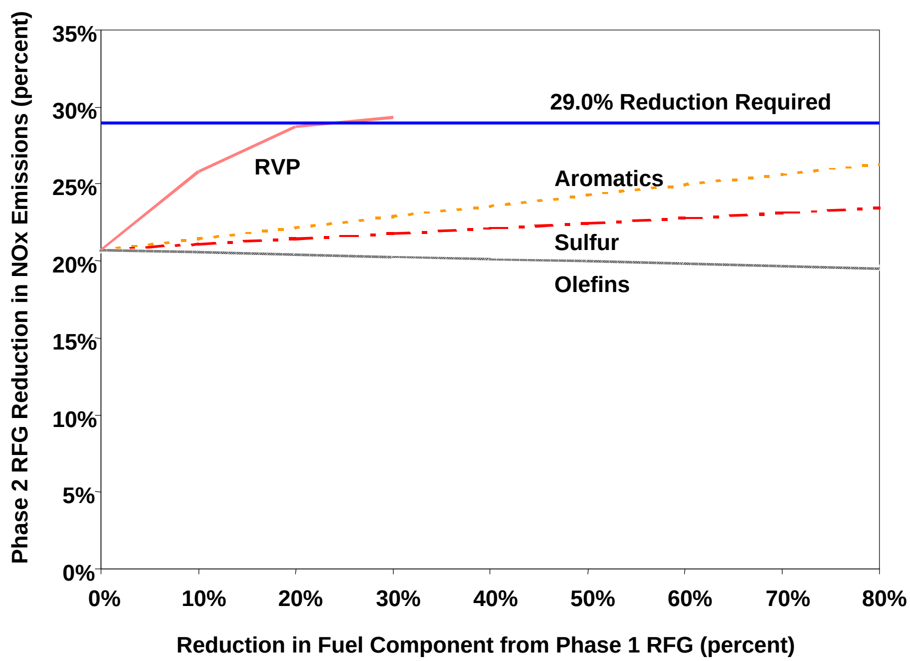
The Phase 2 VOC emissions reduction performance standards for southern States (region 1) and northern States (region 2) are almost identical. However, the required incremental VOC emissions reduction beyond Phase 1 RFG is much greater in region 2 because Phase 1 RFG requires a much smaller reduction in VOC emissions in region 2 (Table RFG1).

RVP dominates the VOC emissions calculation (Figure RFG4). Reductions in aromatics and sulfur make small contributions to lower VOC emissions. However, reductions in RVP alone will not be enough to achieve the required Phase 2 VOC reduction.[19] A reduction in RVP to 6.7 psi will reduce VOC

[19] The EPA established the VOC standard based on the level of VOC control that can be cost-effectively achieved through RVP reduction down to 6.7 psi, in addition to VOC reduction achieved by reducing sulfur to meet the NOx standard: Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 396.

emissions by about 24 percent in region 1, and 22 percent in region 2, well below the 29 percent and 27.4 percent required in regions 1 and 2, respectively. Reducing sulfur from 300 to 140 ppm will yield an additional reduction of 1.9 percent. Lowering aromatics from 32 to 26 volume percent adds another 1.5 percent VOC reduction. Still, this is not enough. The final necessary emissions reductions must come from increasing E200, E300, and olefins, without violating the NOx emissions reduction requirement (the TAP emissions requirement is not binding).

Figure RFG4. RFG Phase 2 VOC Reduction by Gasoline Component (Summer Region 1)



Summary of RFG Production Options

Sulfur, RVP, and total aromatics are the fuel components that have the greatest impact on TAP, NOx, and VOC emissions, and should be the primary targets of refiner Phase 2 RFG quality control.

Because of the required addition of oxygenates, the level of aromatics has already been reduced significantly below the 1990 baseline gasoline composition. In fact, Phase 1 RFG that is currently being produced should already meet the Phase 2 TAP emissions reduction performance standard. The addition of 11 volume percent MTBE (or 6 volume percent fuel ethanol) contributes to a reduction in aromatics in two ways. First, there is a simple dilution effect. For example, adding 11 gallons of MTBE to 89 gallons of conventional gasoline with 32 volume percent aromatics will result in a blend with 28.5 volume percent aromatics (or 30 volume percent aromatics when diluted with 6 volume percent fuel ethanol). Second, the addition of oxygenates, which are high in octane, allows refiners to reduce the conversion of low octane gasoline components to high octane aromatics in Reformers.[20] This oxygenate blending effect can be seen in Phase 1 RFG that was produced during the winter 1997-1998 (Table RFG6). The addition of oxygenates also increases the percentage of gasoline that boils off at temperatures below 200 and 300 degrees Fahrenheit (i.e., E200 and E300).

Table RFG6. Reformulated Gasoline Quality Survey Results, Winter 1997-1998

	1990 Winter Baseline	Reformulated Gasoline, Winter 1997 - 1998		RFG Phase 2 Winter Requirements
		With Ethers	With Ethanol	
Product Quality:				
Oxygenate (weight %)				2.1 % min
MTBE	0	1.98	0.05	
TAME	0	0.09	0.00	
Ethanol	0	0.00	3.52	
Sulfur (ppm by weight)	338	144	193	
Aromatics (volume %)	26.4	20.1	22.4	
Benzene (volume %)	1.64	0.68	0.76	0.95 % max
Olefins (volume %)	11.9	6.6	10.2	
E200 (volume %)	50	56	n.a.	
E300 (volume %)	83	86	n.a.	
Emissions Reduction from Baseline (percent):				
TAP	0	27.7 %		21.5 % min
NOx	0	9.9 %		1.5 % min

n.a. - not available

Notes: • Winter 1997 - 1998 corresponds to December 1997 through February 1998. • Emissions reduction from baseline is calculated by using RFG Phase 2 complex emissions model

Sources: 1990 Winter Baseline and RFG Phase 2 Winter Requirements: Code of Federal Regulations, Title 40, Part 80, "Regulation of Fuels and Fuel Additives." Reformulated Gasoline, Winter 1997 - 1998: National Institute for Petroleum and Energy Research, *Motor Gasolines, Winter 1997-98* (Bartlesville, OK, August 1998), Table 5.

Costs of Reformulated Gasoline

The clean air benefits of reformulated gasoline do not come freely. Consumers are faced with two costs of reformulated gasoline. First, the price of Phase 2 reformulated gasoline at the pump is expected to be 2.5 to 4.0 cents per gallon higher than conventional (non-reformulated) gasoline, depending on the region on the country and the time of year. Compared with the cost of Phase 1 RFG, no increase is expected during the winter months and a 1.0 to 1.5 cent per gallon increase is expected during the summer months in southern and northern States, respectively.

[20] Reformer product (reformate) contains about 66 percent aromatics and makes up about 27 percent of the total motor gasoline pool: National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), pp. N242-N244. The road octane (R+M/2) of MTBE is 109, compared with an average 104.1 road octane for aromatics: Robert E. Maples, *Petroleum Refinery Process Economics* (PennWell Books: Tulsa, OK, 1993), Table 5-1.

Second, the fuel economy (miles per gallon) of Phase 2 RFG is about 1.5 to 2 percent lower than conventional gasoline because the energy (Btu) content of RFG is lower than that of conventional gasoline. This fuel economy penalty is unchanged from the fuel economy penalty realized with the use of Phase 1 RFG.

Two sources of data are available to bracket the expected wholesale market price premium for Phase 2 reformulated gasoline over conventional gasoline. First, the historical price premium for Phase 1 RFG provides a lower bound for the estimate (2.3 cents per gallon). Second, the historical price premium for California clean gasoline, which has stricter requirements for emissions reductions, should provide an upper bound for the expected price premium (4.3 cents per gallon).

Phase 1 RFG Price Premium

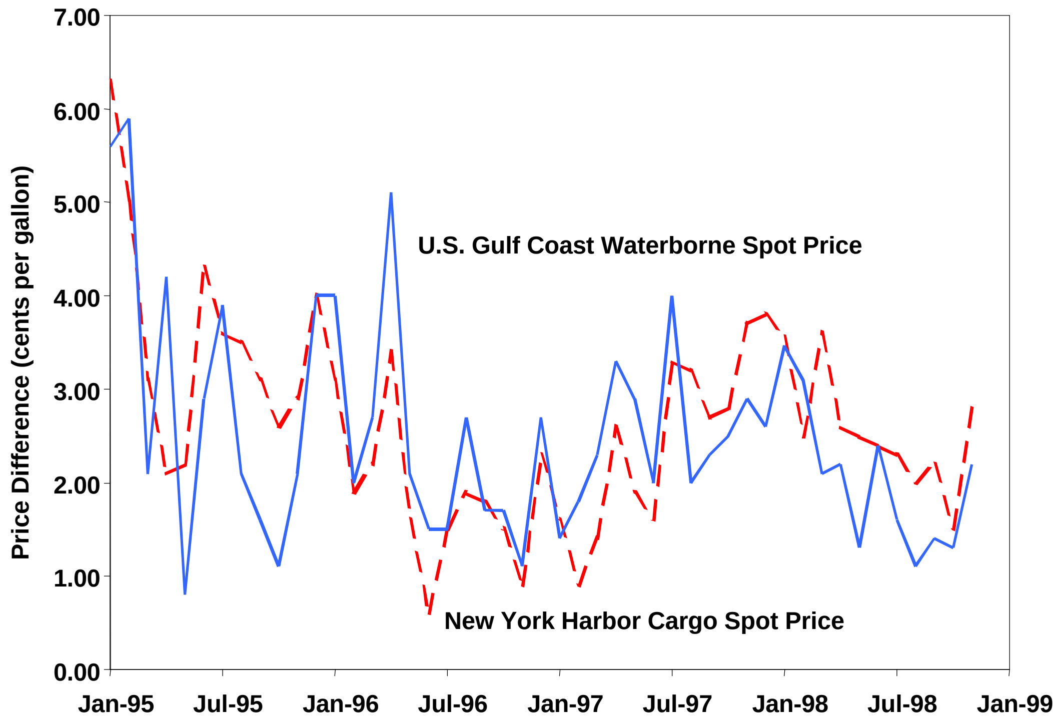
Before the start of the reformulated gasoline program in 1995, EIA originally projected a Phase 1 RFG price premium of 3.5 to 4 cents per gallon over conventional gasoline.[21] The price premium is due primarily to the required 2.1 percent by weight of oxygenates (equivalent to about 11.5 percent MTBE, or 6.0 percent fuel ethanol by volume), which made up 3.0 cents of the projected Phase 1 RFG price premium. The additional requirements for RVP reduction in the summer and reducing the levels of benzene and other aromatics were projected to add 0.4 cents per gallon and 0.5 cents per gallon, respectively, to the cost of reformulated gasoline.

The actual wholesale price premium for Phase 1 RFG has generally fallen in the range of 2 to 4 cents per gallon (Figure RFG5). The variability in the Phase 1 RFG price premium has been due to changes in the cost of oxygenates, particularly MTBE, relative to the cost of gasoline.[22] The wholesale price difference between Phase 1 RFG and conventional gasoline has averaged 2.3 cents per gallon for both U.S. Gulf Coast and New York Harbor waterborne cargoes (from January 1996 to December 1998).

Figure RFG5. Price Difference: Reformulated - Conventional Regular Gasoline (cents per gallon)

[21] Tancred Lidderdale, "Demand, Supply, and Price Outlook for Reformulated Motor Gasoline, 1995," *Monthly Energy Review*, DOE/EIA-0035 (94/07) (Washington, DC, July 1994), pp.1-10. Using a more rigorous refinery model, EPA estimated the national average Phase 1 RFG cost would range from 1.6 to 3.5 cents per gallon (excluding the cost of oxygenates already required in oxygenated gasoline control areas during the winter), depending on the price of oxygenates: Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 303.

[22] The strong relationship between the cost of MTBE and the price premium for Phase 1 RFG is evident from the comparison of the price difference between MTBE and conventional gasoline with the price difference between RFG and conventional gasoline. This was illustrated in an earlier EIA analysis article: "Environmental Regulations and Changes in Petroleum Refining Operations" (June 1998) http://www.eia.doe.gov/emeu/steo/pub/special/enviro.html.



Source: DRI/McGraw-Hill, *Platt's Oilgram Price Report, Price Average Supplement* (New York, NY), various issues 1995 - 1998.

California Clean Gasoline Price Premium

California began its own clean gasoline program in early 1996. The California clean gasoline (referred to as "CARB" gasoline because the program is administered by the California Air Resources Board) has stricter gasoline quality and emissions reduction performance standards than EPA Phase 2 RFG (Table RFG7).

The wholesale (pipeline) price difference between CARB clean gasoline and conventional gasoline has averaged 4.2 cents per gallon in Los Angeles and 4.3 cents per gallon in San Francisco (from January 1997 to December 1998) (Figure RFG6).

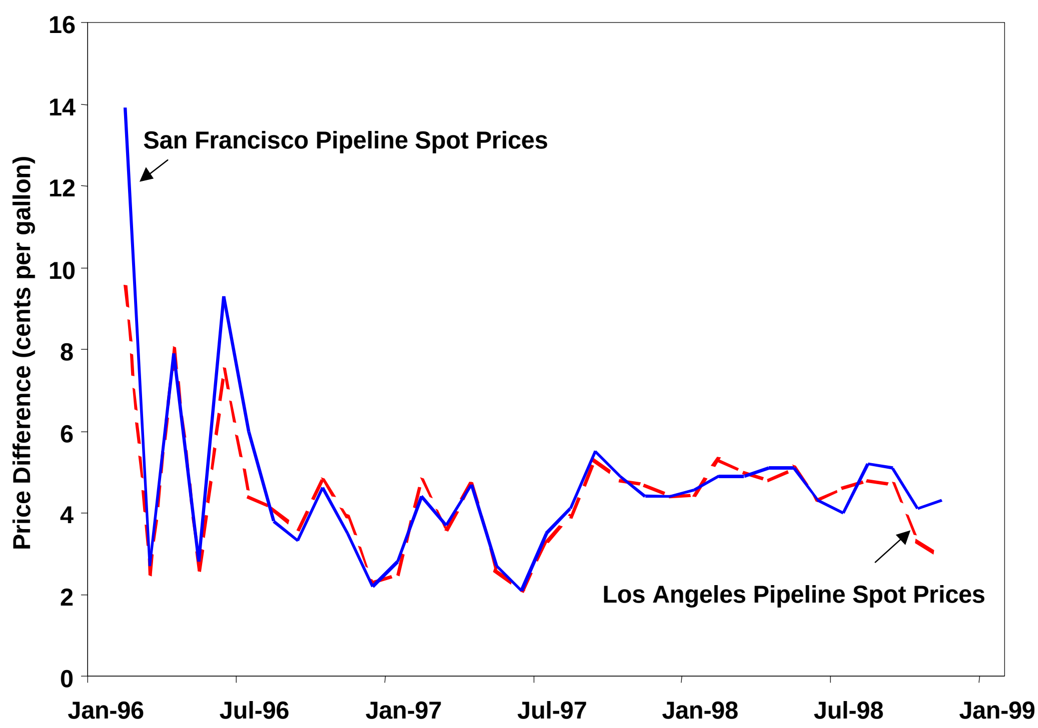
Table RFG7. Reformulated Gasoline Averaging Standards

	CARB Gasoline	RFG Phase 2, January 2000 Summer Region 1	Summer Region 2	Winter
Product Quality Standards:				
RVP, psi max	7.0			
Oxygen, wt % min	2.0	2.1	2.1	2.1
Benzene, vol % max	0.8	0.95	0.95	0.95
Aromatics, vol % max	22.0			
Olefins, vol % max	4.0			
Sulfur, ppm	30.0			
Distillation temperatures:				
50% Distilled, degrees F max	200			
90% Distilled, degrees F max	290			
Performance Standards, percent reduction required:				
Toxic Air Pollutants	34.4 %	21.5 %	21.5 %	21.5 %
Volatile Organic Compounds	27.9 %	29.0 %	27.4 %	n.a.
Nitrogen Oxides	14.6 %	6.8 %	6.8 %	1.5 %

Notes: Performance standards for CARB gasoline are calculated by using EPA Phase 2 complex emissions model.

Sources: RFG specifications: Environmental Protection Agency, "Regulation of Fuel and Fuel Additives," Code of Federal Regulations, Title 40, Part 80. California specifications: California Air Resources Board, "The California Reformulated Gasoline Regulations," Title 13, California Code of Regulations, Sections 2250-2272 (as last amended July 2, 1996).

Figure RFG6. Price Difference: California (CARB) Clean Gasoline - Conventional Gasoline



Source: DRI/McGraw-Hill, *Platt's Oilgram Price Report, Price Average Supplement* (New York, NY), various issues 1996 - 1998.

Phase 2 RFG Price Premium

Phase 1 RFG should already meet the year-round TAP and winter NOx emissions reduction performance standards. Thus, there should be no additional price premium for Phase 2 RFG over Phase 1 RFG during the winter months. The summer VOC and NOx emissions reduction performance standards will require reductions in total aromatics, RVP, and sulfur.

Aromatics Reduction. Although reducing the level of aromatics in motor gasoline significantly reduces NOx emissions, this is generally not considered a cost-effective method of control (beyond the level already achieved with the addition of oxygenates).

RVP Reduction. Lowering RVP increases the refiner's cost of producing gasoline because low-cost normal butane (C4s) must be removed from the gasoline pool. Since the start of the RFG program in 1995, the price of normal butane (at Mont Belvieu, Texas) has averaged 17 cents per gallon below the price of conventional regular gasoline (U.S. Gulf Coast waterborne cargoes) during the summer months (May through August).[23] A 1 psi reduction in RVP requires about a 2 volume percent reduction in the concentration of normal butane in gasoline.[24] Based on a simple linear blend calculation, the removal of 2 volume percent normal butane from gasoline would increase the price of gasoline by about 0.34 cents per gallon. There is an additional cost of about 0.1 cents per gallon per psi reduction for the loss of octane that butane provides the gasoline pool.[25] Thus, the cost of removing butane on the basis of a simple blending economics is about 0.44 cents per gallon per psi reduction.

A comparable estimate of the cost of RVP reduction can be obtained from the market price differential between 7.8 and 9.0 RVP gasoline. The wholesale market price premium for 7.8 RVP gasoline relative to 9.0 RVP gasoline on the U.S. Gulf Coast during the summers of 1993 through 1998 (May through August) averaged 0.52 cents per gallon, which is equivalent to a price premium of about 0.43 cents per gallon per 1 psi reduction. EPA estimated RVP reduction costs to average 0.42 cents per gallon per 1 psi.

Phase 2 RFG will require approximately a 1.3 psi reduction in RVP (from 8.0 to 6.7 psi) in northern control areas (region 2) and a 0.4 psi reduction (from 7.1 to 6.7 psi) in southern areas (region 1) from current Phase 1 RFG levels during the summer months. EIA estimates the average cost for reducing RVP from Phase 1 to Phase 2 RFG levels during the summer months to be about 0.6 cent per gallon

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[23] McGraw-Hill, Inc., *Platt's Oilgram Price Report, Price Average Supplement* (New York, NY), various issues 1995 - 1998.

[24] Based on a normal butane blending RVP of 60 psi.

[25] Based on the octane contribution to regular gasoline from normal butane with a road octane (R+M/2) of 92.1, being replaced with MTBE and a road octane of 110. Octanes from Robert E. Maples, *Petroleum Refinery Process Economics* (PennWell Books: Tulsa, OK, 1993), Table 5-1.

(1.3 psi multiplied by 0.45 cent/gallon/psi reduction) in northern control areas and 0.2 cent per gallon in the southern control areas.

Sulfur Reduction. Sulfur occurs naturally in crude oil. As crude oil is refined, some of the sulfur ends up in motor gasoline. The sulfur in crude oil is generally concentrated in the heavier components such as distillate and residual fuel oils. Most sulfur in motor gasoline (80 to 90 percent) comes from the conversion of the heavier components to gasoline in fluid catalytic cracking (FCC) units, which produce about one-third of the U.S. motor gasoline pool.[26] The sulfur in untreated FCC gasoline product ranges as high as 1,000 to 2,000 ppm. There are two general process options for reducing sulfur. The first option involves diversion of the heavy FCC product that is highest in sulfur to the distillate fuel oil pool. This is the lowest capital and operating cost option, but results in the downgrade of gasoline product to lower-valued fuel oil and reduces the volume of motor gasoline produced. The second option involves hydrotreating either the feed to or the product from the FCC unit. Hydrotreating to remove sulfur may have high capital and operating costs but maintains the volume of the gasoline pool.

The expected cost for removing sulfur is highly dependent on a refiner's available hydrotreating capacity and the share of total gasoline production that must be reformulated. EPA originally estimated the cost of reducing sulfur from 340 ppm down to 250 ppm to be 0.18 cent per gallon and the cost of going from 250 ppm down to 160 ppm to be 0.56 cent per gallon.[27] More recently, EPA estimated the cost for all PADD 1 and 3 refiners to reduce sulfur from 340 ppm down to 150 ppm to range from 1.1 to 1.8 cent per gallon.[28] We expect that sulfur reduction for Phase 2 RFG will cost on average 0.8 cent per gallon.

Total Incremental Phase 2 Summer RFG Production Cost. Refiners will take different paths to produce Phase 2 RFG. On average, we expect Phase 2 RFG during the summer months to be low in RVP (6.7 psi) and low in sulfur (140 ppm). In addition, the blending of oxygenates will contribute to lower aromatics (26 volume percent or less) and raise E200 (to 50 volume percent). The costs of reducing RVP and sulfur during the summer months are expected to add about 1.5 and 1.0 cents per gallon to the cost of supplying Phase 1 RFG to the northern (region 2) and southern (region 1) States, respectively. The cost to produce Phase 2 RFG during the winter months should be no greater than the current cost to produce Phase 1 RFG.

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[26] "Pipeline Hydrogen Supply Provides Flexibility and Alternative Solutions to Improve Returns on Refinery Assets," *Hart's Fuel Technology and Management's Sulfur 2000* (Summer 1998), pp. 26-28; and "Low-Sulfur Specifications Cause Refiners to Look at Hydrotreating Options," *Oil & Gas Journal* (December 8, 1997), pp. 47-51.

[27] Environmental Protection Agency, *Final Regulatory Impact Analysis* (Washington, DC, December 13, 1993), Table VI-6.

[28] Environmental Protection Agency, *EPA Staff Paper on Gasoline Sulfur Issues* (Washington, DC, May 1, 1998), p. 32.

Since the wholesale price difference between Phase 1 RFG and conventional gasoline has averaged close to 2.5 cents per gallon throughout the year, we expect the wholesale price of Phase 2 RFG to average about 2.5 cents per gallon above the price of conventional gasoline during the winter. During the summer months, Phase 2 RFG is expected to average 4.0 cents per gallon above the price of conventional gasoline in northern States, and 3.5 cents per gallon above the price of conventional gasoline in southern States. This expected price premium is lower than the wholesale price difference between CARB clean gasoline and conventional gasoline in California.

Reduced Fuel Economy

The fuel economy (miles per gallon) of Phase 1 and Phase 2 RFG is about 1.5 per cent lower during the summer and 2 percent lower during the winter because the energy (Btu) content of RFG is lower than that of conventional gasoline. This corresponds to about 0.4 to 0.6 miles per gallon for a car that averages 27 miles per gallon. The decline in fuel economy is due primarily to the required use of oxygenates, which have a lower energy content than that of the conventional motor gasoline or octane blendstocks (e.g., aromatics) that the oxygenates displace. This loss is offset partially by the lower summer RVP requirement, which will reduce both evaporative emissions and the volume of butane, which is low in energy content, in motor gasoline.

Reformulated gasoline with 11.5 volume percent MTBE has a Btu value that is about 2.1 percent lower than that of conventional motor gasoline, while motor gasoline reformulated with 6 volume percent ethanol has a Btu content that is about 2.0 percent lower than that of conventional gasoline (Table RFG8).

Table RFG8. Fuel Economy Loss With Oxygenate Blending

Oxygenate	Energy Content of Oxygenate (Btu/gallon)	Volume Percent Oxygenate	Volume Percent Gasoline	Energy Content of 1 Gallon of Blend	Percent Reduction Compared to Gasoline
MTBE	93,500	11.5	88.5	111,642	2.1
Ethanol at 6 vol. %	76,000	6.0	94.0	111,720	2.0
Ethanol at 10 vol. %	76,000	10.0	90.0	110,200	3.3
TAME	100,600	13.4	86.6	112,204	1.6
ETBE	97,700	13.4	86.6	111,816	1.9

Notes: Energy content of gasoline is 114,000 Btu / gallon.

Source: Energy contents of oxygenates and gasoline are from American Petroleum Institute, *Alcohols and Ethers: A Technical Assessment of Their Applications as Fuel and Fuel Components*, Publication 4261, Second Edition (Washington, DC, December 13, 1993), p. 334.

The required reduction of RVP during the summer months partially offsets the decline in fuel economy due to the addition of oxygenates. Refiners reduce RVP by removing light hydrocarbons like normal butane. A 2 volume percent reduction in normal butane results in an approximately 1 psi reduction in RVP, and a 0.3 percent increase in energy content and fuel economy.[29] Some additional (unestimated) benefit is realized due to reduced fuel losses through evaporation from the gas tank and while fueling a car.

A number of on-road studies of the fuel economy effects of reformulated gasoline have been conducted that confirm the theoretical estimates of fuel economy loss based on energy content: fuel economy is reduced by 2 to 3 percent during the winter season and 1 to 2 percent during the summer season.[30]

Conclusion

As the Phase 2 RFG program goes into effect, the estimated market share for RFG should continue to represent about one-third of total U.S. gasoline demand. Refiners are expected to lower the RVP, sulfur, and aromatics content of RFG in order to meet the summer VOC and NOx reductions required under the Phase 2 RFG program. The cost of producing Phase 2 RFG is expected to represent a price premium of 2.5 to 4.0 cents per gallon over the cost of producing conventional motor gasoline, depending on the region on the country and the time of year. The price of MTBE, ethanol, and other oxygenates could change the cost estimate by a penny either direction.

No changes are required to transport and distribute Phase 2 RFG, compared with Phase 1 RFG. However, the delivery of a number of different grades of gasoline to specific areas at certain times of the year has led to local supply problems and limited price spikes. Future regulations requiring the phase-in of additional localized clean fuel requirements are expected to add to the potential for localized supply disruptions.

[29] Based on a normal butane blending RVP of 60 psi and a heat content of 95,040 Btu per gallon.

[30] White House Office of Science and Technology Policy, "Fuel Economy and Engine Performance Issues," *Interagency Assessment of Oxygenated Fuels* (Washington, DC, June 1997), Chapter 3; Lawrence Livermore National Laboratory, *Assessment of California Reformulated Gasoline Impact on Vehicle Fuel Economy*, UCRL-ID-126551 (Livermore, CA, January 1997).

Guide to Abbreviations and Acronyms

Btu - British thermal unit

CAA90 - Clean Air Act Amendments of 1990 (Public Law 101-549)

CARB - California Air Resources Board

E200 - Percent of fuel evaporated at 200 degrees Fahrenheit

E300 - Percent of fuel evaporated at 300 degrees Fahrenheit

EIA - Energy Information Administration, U.S. Department of Energy

EPA - U.S. Environmental Protection Agency

ETBE - Ethyl tertiary butyl ether

FCC - Fluid catalytic cracking unit

FHWA - Federal Highway Administration

MTBE - Methyl tertiary butyl ether

NAAQS - National ambient air quality standard

NOx - Nitrogen oxide

PADD - Petroleum Administration for Defense District

ppm - Parts per million

psi - Pounds per square inch

RFG - Reformulated gasoline

RVP - Reid vapor pressure

SIP - State implementation plan

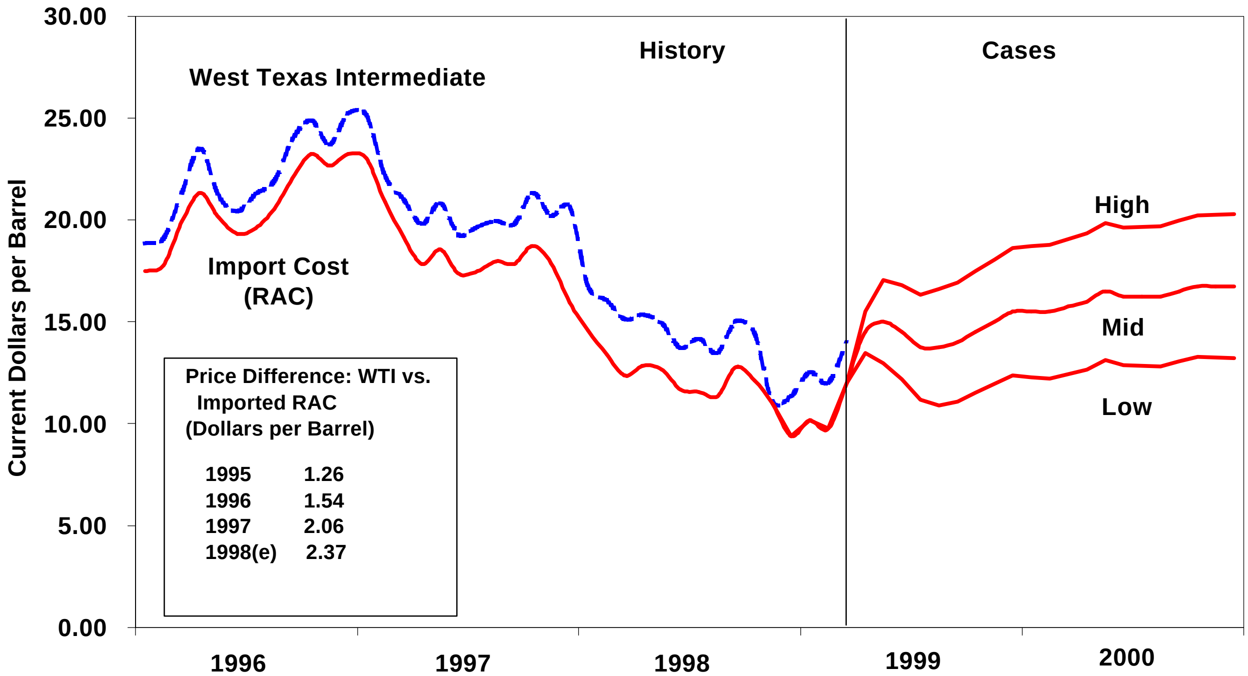
TAME - Tertiary amyl methyl ether

TAP - Toxic air pollutants

VOC - Volatile organic compound

The Outlook

Figure 1. U.S. Monthly Crude Oil Prices



World Oil Prices

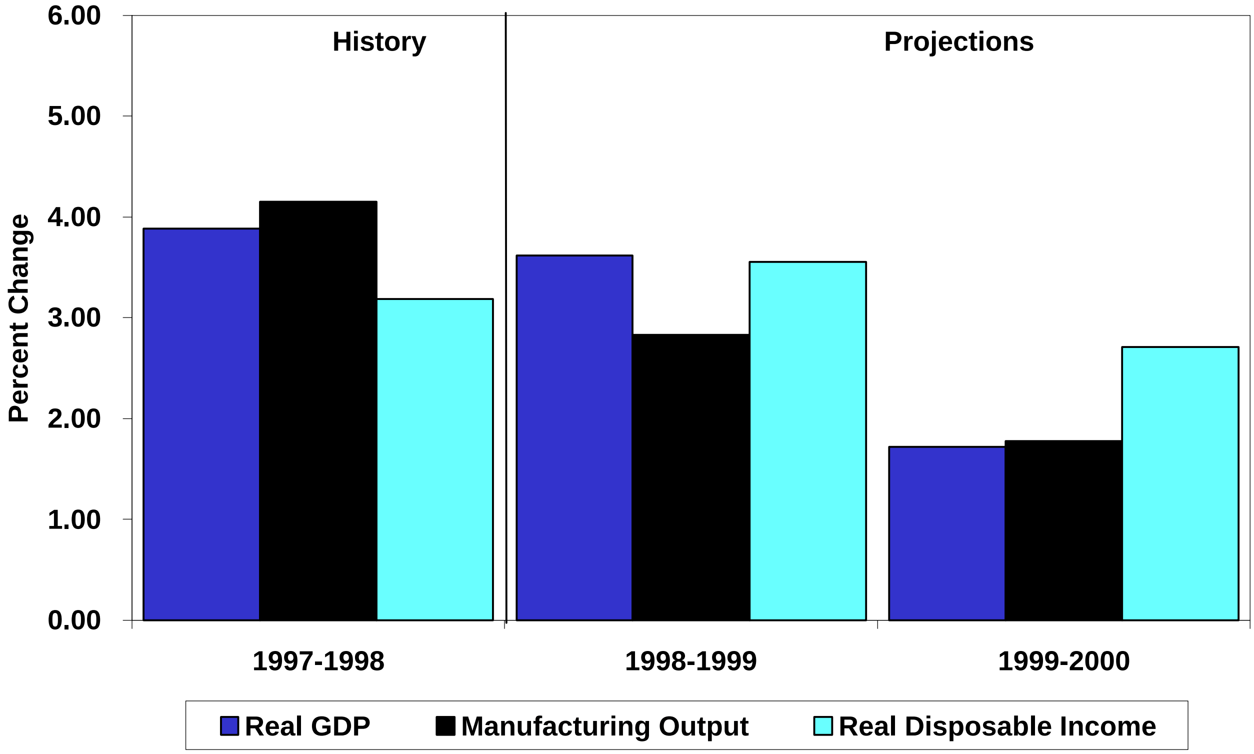
The average cost of imported oil to U.S. refiners, an indicator of world oil prices, is assumed to climb gradually from the estimated March level of about $12 per barrel, which was $2-$3 above the low point (on a monthly average basis) of $9.25 reached in December 1997. Monthly prices are assumed to be about $14.50-$15.50 per barrel by the end of 1999, as the shifting balance between world oil production and demand begins to reverse the large accumulation of oil in storage. We expect prices to move towards $17 per barrel by the end of 2000 as long as the recently announced cuts by OPEC (and others) actually do have significant impact and as long as oil demand growth outside of the major industrialized countries begins to show some strength after this year (Figure 1).

Economic Outlook

In 1999, GDP is expected to continue to grow at the rate of 3.6 percent, close to the 3.9 percent growth seen in 1998. In 2000, GDP is projected to continue to grow but at the slower pace of 1.7 percent. Personal disposable income is assumed to be up by 3.6 percent in 1999 from its 1998 level, and up by another 2.7 percent in 2000. This is somewhat below the 3.2 percent growth seen in 1998 (Figure 2 and Table 1).

Inflation (consumer price index: see Table 2) should rise somewhat over the next two years. Consumer price inflation is expected to be 1.8 percent in 1999, up only slightly from the 1.6 percent in 1998 (Table 1) and 2.4 percent in 2000. Manufacturing production is expected to grow by 2.8 percent in 1999 and by 1.8 percent in 2000, compared with 4.1 percent in 1998, as investment growth decelerates and exports decline. Total employment will increase slowly over the forecast period.

Figure 2. U.S. Macroeconomic Indicators

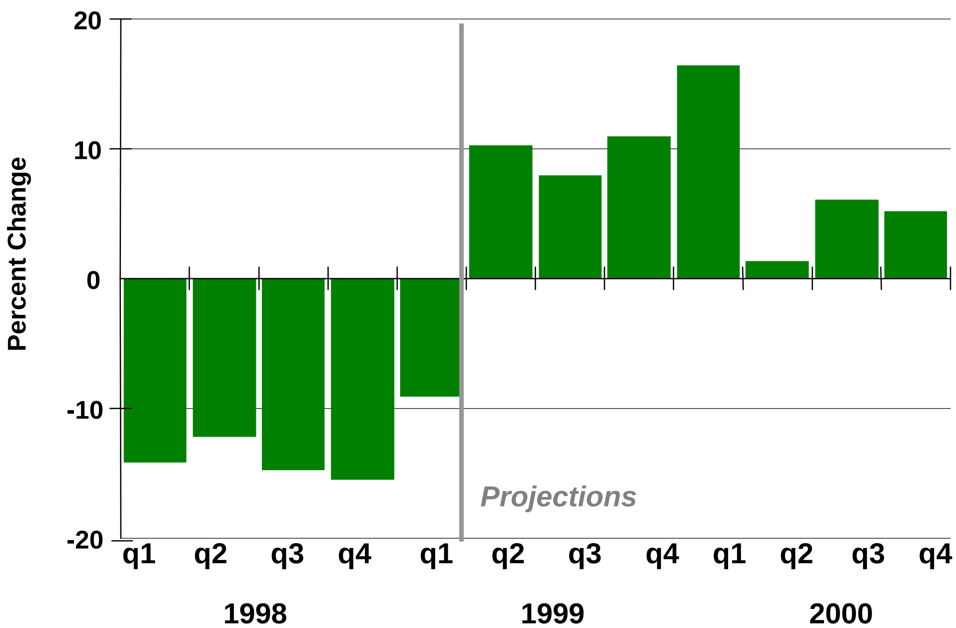


Weather Assumptions

Weather patterns (expressed as heating and cooling degree-days in Table 1) are assumed to follow historical norms during the remainder of 1999 and in 2000. This would imply that, for 1999, heating degree-days would to be 9.4 percent above 1998 levels. Meanwhile, summer cooling degree-days would be 15.7 percent lower than 1998 levels, using our normal assumptions.

U. S. Energy Prices

Figure 3. Quarterly Retail Motor Gasoline Prices* (Percent Change from Year Ago)

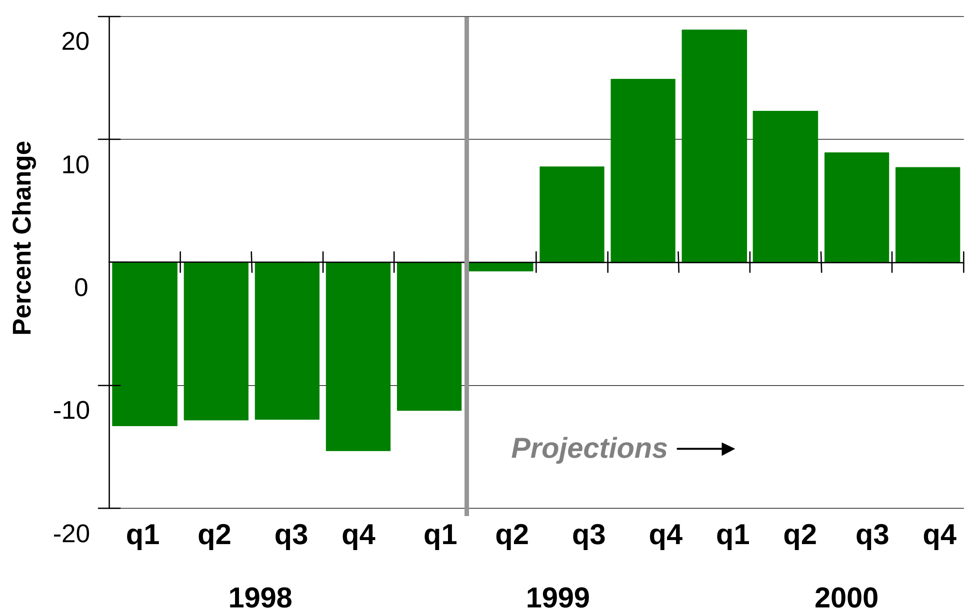


Regular Unleaded, Self-Service Cash

The biggest single factor influencing petroleum product prices over the next two years will be crude oil prices. Crude oil prices collapsed in 1998 and as a result, all petroleum product prices fell sharply last year. In 1999, average annual crude oil costs are expected to increase by about $1.50 per barrel, thus allowing some petroleum product prices to gain. In 2000, crude oil prices are projected to recover considerably more, resulting in petroleum product price increases of 7-11 cents per gallon.

U.S. retail motor gasoline prices--unleaded regular, self-service, cash--hit rock bottom--a historical low adjusted for inflation--in February, due largely to the low world oil prices at the time (Figure 3). Due partly to the recent rise in crude costs, regular unleaded self-service gasoline prices are expected to jump by about 22 cents per gallon by April from the February record low U.S. monthly price. Pump prices are projected to peak in May at an average of $1.18 per gallon for unleaded regular. In addition to the crude price jump, which is expected to account for over one half of the gasoline price increase, other factors will push up prices this driving season. The spring runup that normally occurs this time of the year should easily add 5-8 cents per gallon onto the low prices of winter. In addition, refiner margins have begun to recover from the near ten-year lows that were evident in the first two months of this year. Finally, refinery shutdowns in February and March of this year, particularly on the West Coast, but also elsewhere, led to reduced production of gasoline which in turn moved prices upward. The average regular unleaded self-service gasoline price is expected to peak this summer at $1.14. Pump prices this summer (April-September) are projected to average about 10 cents per gallon more than last summer's price (Figure 4). However, pump prices are projected to average 6 cents per gallon less than the summer 1997 average and about 10 cents less than the summer 1996 average. Given the projected crude oil price increase for 2000, annual average pump prices are expected to gain about 7 cents per gallon next year (Table 4). A recent executive order by California Governor Gray Davis calling for the phase-out of methyl tertiary butyl ether (MTBE), which is blended in gasoline to boost oxygen content and octane, adds a level of uncertainty to West Coast prices for 2000.

Figure 4. Quarterly Retail Heating Oil Prices (Percent Change from Year Ago)



Residential heating oil prices are projected to dip slightly in 1999, by about a penny per gallon from the 1998 annual average, even though annual crude oil prices are assumed to rise. (Table 4). This phenomenon is the result of the low crude oil prices and the warm-than-normal occurred during the first quarter of this year-- the quarter with the highest consumption. Next winter these prices are projected to rebound by about 11 cents per gallon as world crude oil prices recover and as winter weather is assumed to be normal (Figure 4).

The below-normal heating demand this past winter and the resulting high levels of underground storage have kept a lid on natural gas wellhead prices in the last quarter (Figure 5 and Table 4). With current storage levels above those of last year's levels and with the cooling season assumed to be "normal" (14 percent cooler than last summer), we project natural gas prices to stay relatively moderate, peaking for the year at $2.35 per thousand cubic feet in December. Next year, with the assumption of "normal" winter weather (which would imply 8-9 percent higher heating degree-days for the heating season), natural gas prices at the wellhead are projected to grow by about 15 percent (Figure 6). Underlying this forecast are first quarter 2000 underground natural gas storage level projections that are 6 percent below year-earlier levels, while at the same time, total gas demand is expected to be about 7 percent greater.

Figure 5. Natural Gas Wellhead Prices (Composite and Spot)

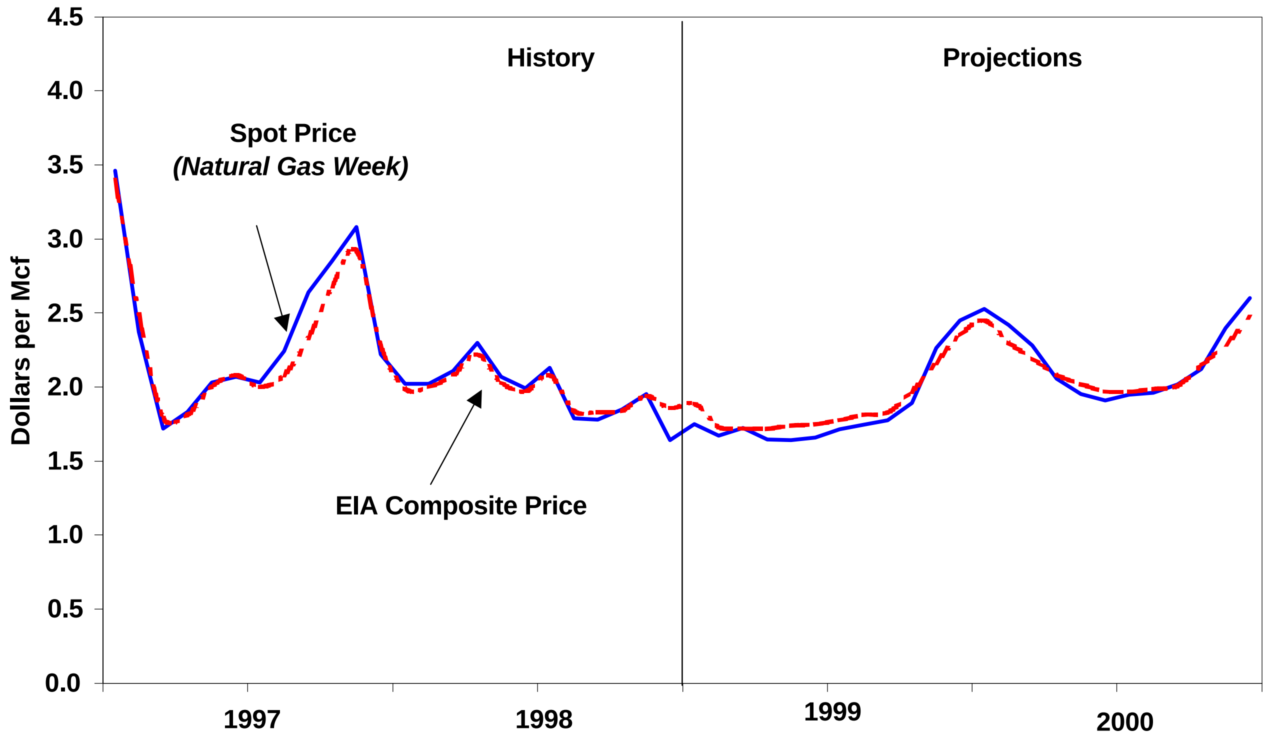
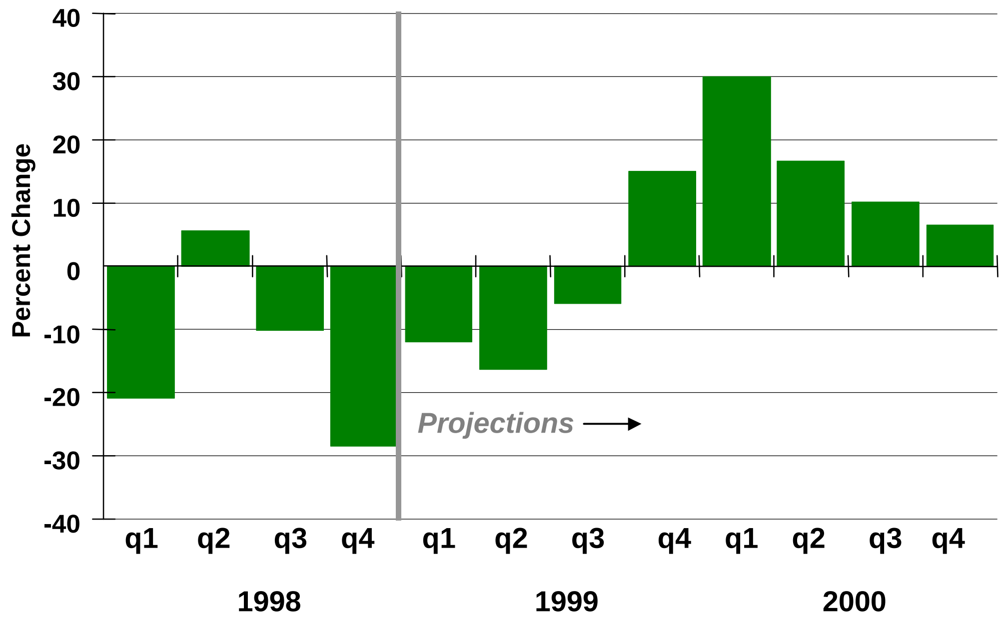
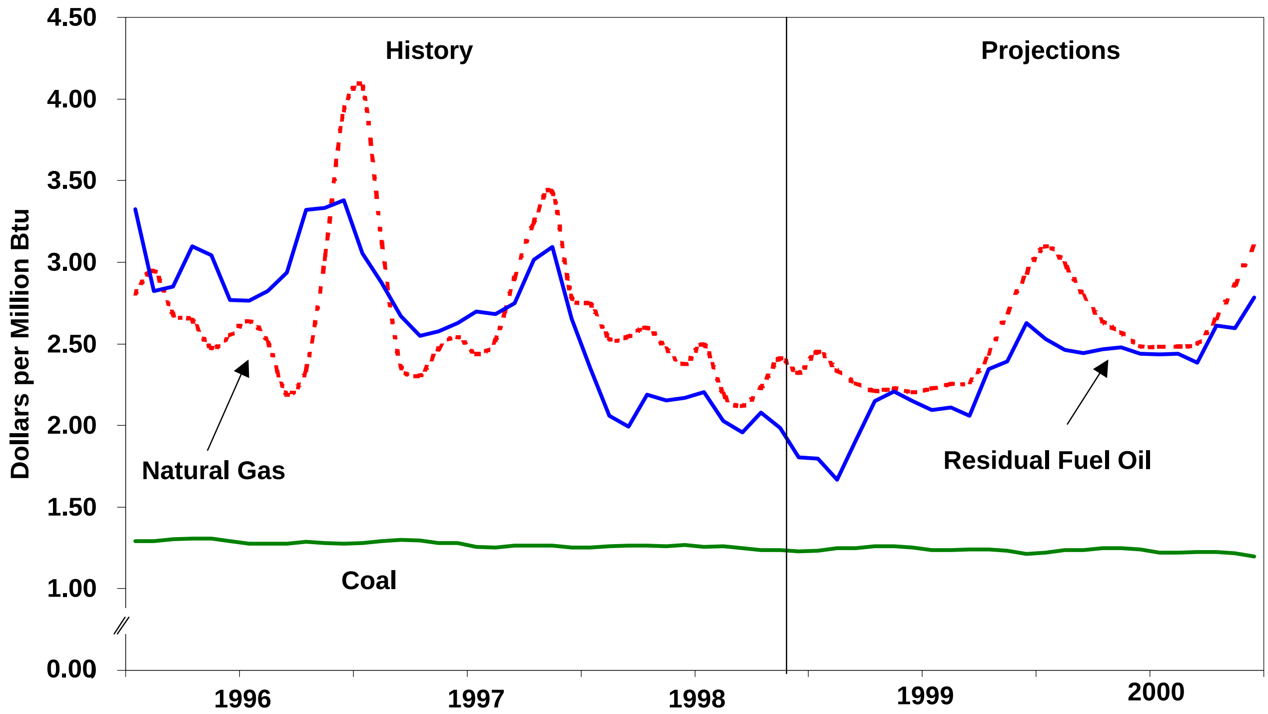


Figure 6. Quarterly Natural Gas Wellhead Prices (Percent Change from Year-Ago)



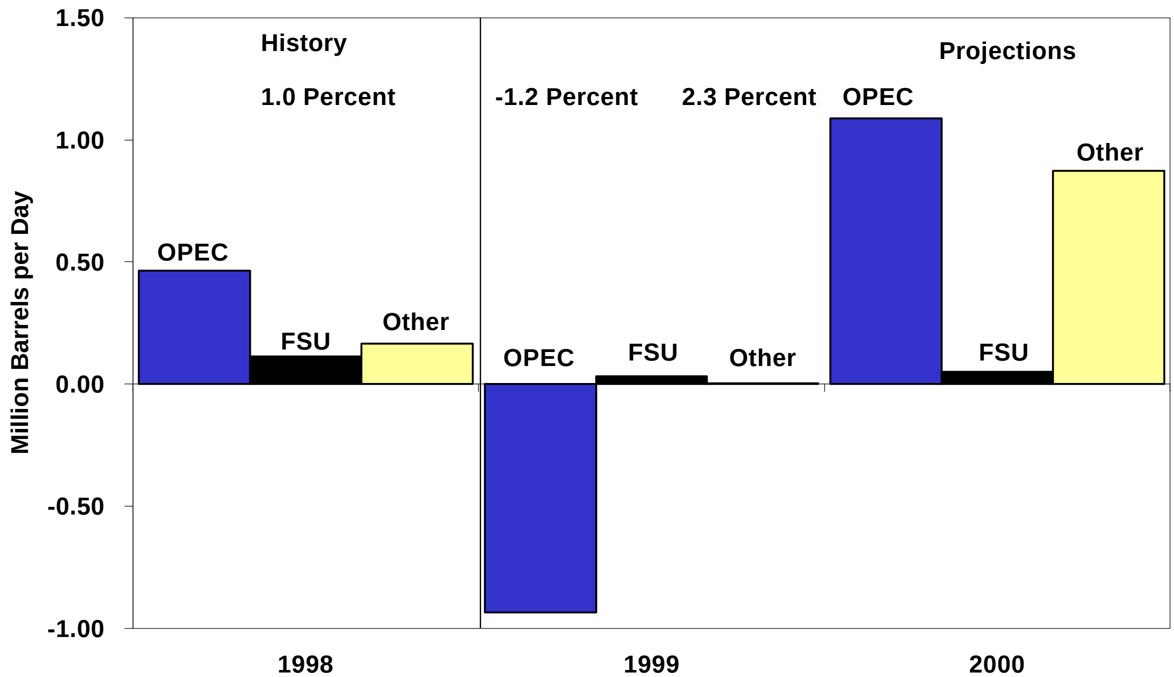
In 1998, the average annual residual fuel oil price to electric utilities fell below the natural gas price (to electric utilities) for the first time since 1993, giving heavy oil the price advantage for electricity generation (Table A4). This price advantage is expected to continue, but to narrow through the forecast period. The price of both fuels are projected to increase in the year 2000, with the residual fuel oil price increasing faster, assuming our base crude oil price path holds. Coal remains by far the least expensive fossil fuel for electric utilities (Table 4 and Figure 7). Coal prices are expected to decline through 2000 even after including costs associated with compliance with the Clean Air Act Amendments of 1990. Continued increases in mining productivity, including longwall mining, as well as the closing of costly marginal mines, particularly East of the Mississippi, have kept coal supply costs on a gradually declining trend for many years.

Figure 7. Fossil Fuel Prices to Electric Utilities



International Oil Supply

Figure 8. World Oil Supply (Changes from Previous Year)

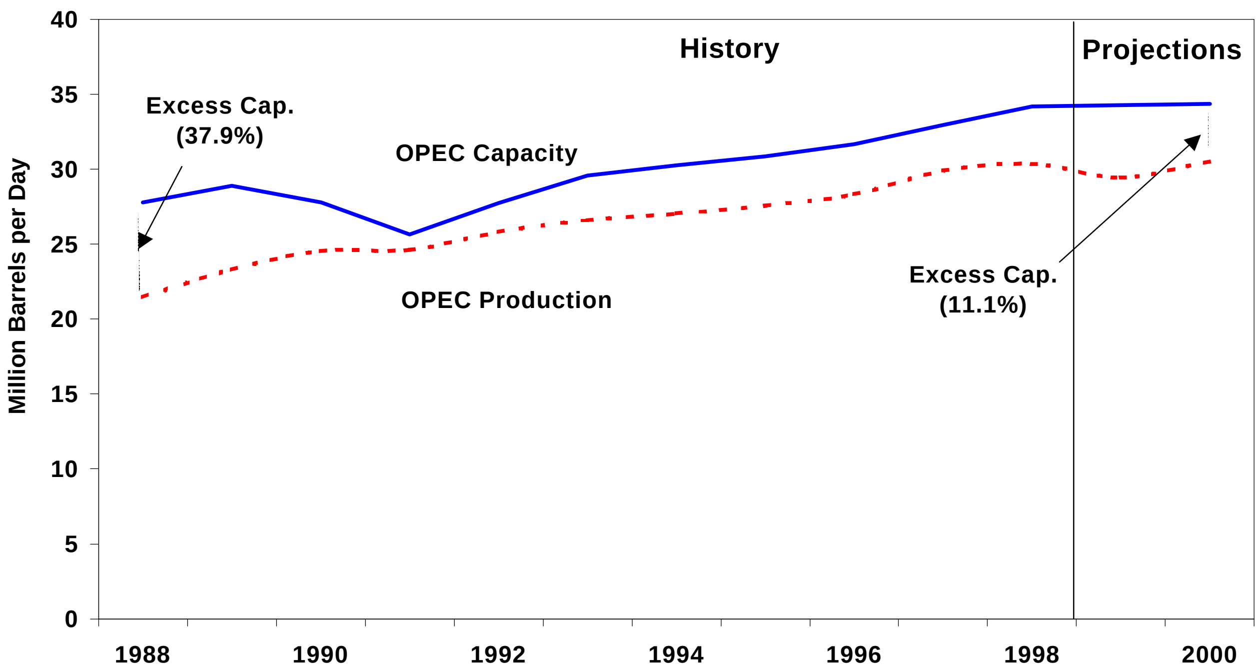


For the third time since March 1998, OPEC, along with some non-OPEC oil producing countries, agreed to cut production in attempt to raise prices. On March 23, 1999, OPEC (excluding Iraq) agreed to cut an additional 1.7 million barrels per day on top of the cuts made in two agreements last year. Four non-OPEC countries (Mexico, Norway, Russia, and Oman) pledged to cut nearly an additional 0.4 million barrels per day, bringing the total pledged cuts to just over 2.1 million barrels per day. Although EIA is not estimating full implementation of these additional production cuts, it is expected that this time, unlike the previous agreements to cut oil production in 1998, prices should increase. In fact, prices began increasing in mid-February even before Saudi Arabia, Iran, Algeria, Venezuela, and Mexico forged the basis of the most recent cuts at a meeting in Amsterdam. Prior to this, the world oil price, defined as the average price U.S. refiners pay for imported crude oil, averaged less than $10 per barrel in the 3 month period from December 1998 through February 1999. However, as a result of these most recent cuts, the world oil price in March is estimated to be $12.00 per barrel, while the forecast for April is $14.50 per barrel. If the world oil price for April averages above $12.85 per barrel, it will be the first time since February 1997 that the monthly world oil price was higher than year-earlier levels.

Just as the previous two agreements were only partially implemented (between 65% and 78% from August 1998 through January 1999), these cuts are also likely to be only partially implemented. However, enough oil should be removed from the market to draw down inventories that were built substantially in 1997 and 1998. This drawdown of oil should allow prices to increase to $15.50 per barrel by the end of 1999 (add $2.00-$2.25 to get a spot price for West Texas Intermediate crude oil), and average $16.24 per barrel in 2000.

Mostly as a result of the two agreements last year and the one announced recently, OPEC oil production is expected to fall by more than 900,000 barrels per day in 1999, before increasing by 1.1 million barrels per day in 2000 (see Figure 8). This assumes that OPEC (excluding Iraq, which is not part of the agreements) crude oil production drops by about 1.2 million barrels per day in the second quarter of 1999, and 1.1 million barrels per day in the third quarter of 1999 from the average first quarter crude oil production. Although this is less than OPEC agreed to cut, it is still a substantial amount of oil that will not be available. Beginning in the fourth quarter of 1999, our forecast assumes that OPEC production will begin to increase more significantly as rising prices provide incentive to add supply to the market (Figure 9).

Figure 9. OPEC Oil Production and Capacity

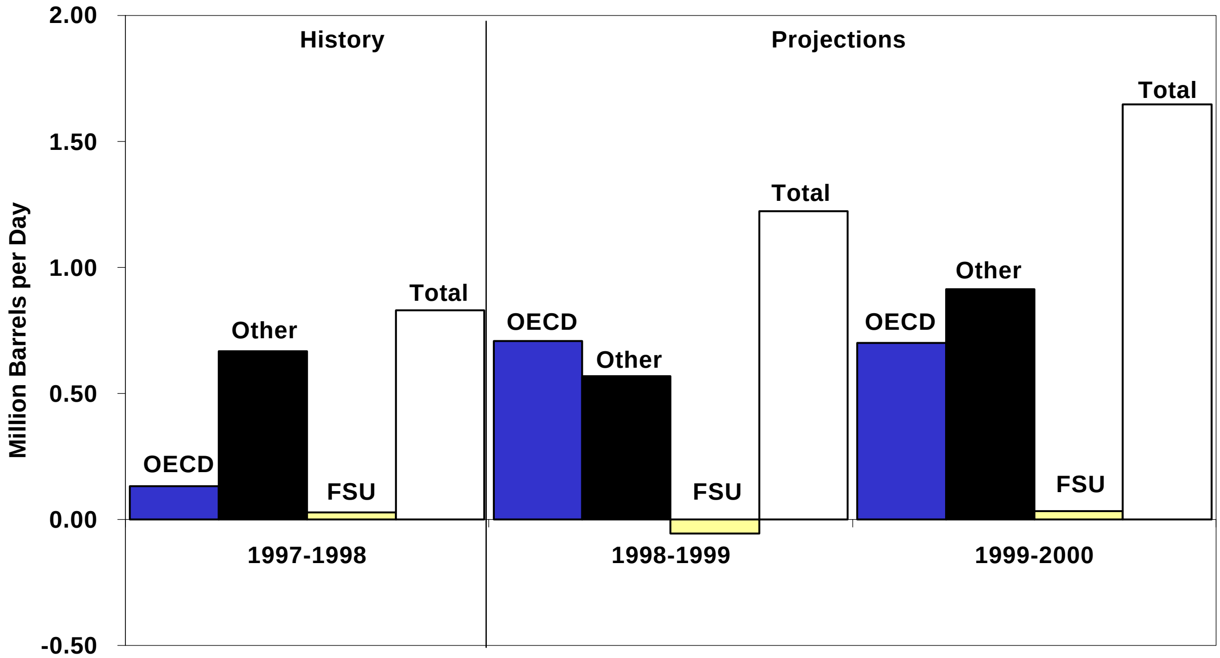


For the purposes of this forecast we have assumed Iraqi oil production to average about 2.6 million barrels per day in 1999, and about 2.7-2.8 million barrels per day in 2000. This is merely an assumption for this forecast and does not reflect any official U.S. government view on the future of Iraqi oil exports.

After growing on average by 1 million barrels per day in 1995, 1996, and 1997; non-OPEC oil supply increased by only 300,000 barrels per day in 1998 and is forecasted to increase by less than 50,000 barrels per day in 1999. Low oil prices, both in terms of how much they fell and how long they persisted, have caused production in some parts of the world to decline. In the United States for example, crude oil production in 1999 is expected to average about 400,000 barrels per day less than 1998. Smaller declines are expected in Australia and Mexico. The North Sea, however, is estimated to increase by less than 200,000 barrels per day, almost all of which is expected to come from the United Kingdom (some other increases are expected in Denmark, while Norway oil production is estimated to show a slight decrease from 1998 production levels). In 2000, non-OPEC oil production is expected to increase by about 900,000 barrels per day as higher prices enable more oil production to come back into the market. This occurs despite an additional decline of about 100,000 barrels per day in U.S. oil supply. However, other areas are expected to increase from 1999 levels. For instance, our forecast assumes nearly 400,000 barrel-per-day growth in North Sea oil supply next year, as well as increases in most regions as higher oil prices in 2000 encourage production.

International Oil Demand

Figure 10. World Oil Demand (Changes from Previous Year)



World oil demand is expected to continue to increase through 2000 (Figure 10), by which time total world oil demand may average nearly 77 million barrels per day (Table 3). With problems in several Southeast Asian countries softening the increase in world oil demand in 1998, world oil demand increases in 1999 and 2000, while larger than in 1998, are forecasted to be less than the increases seen before the Asian economic problems began. Following an annual world oil demand increment of 1.7 million barrels per day worldwide in 1997, world oil demand is estimated to have increased by only 0.7 million barrels per day in 1998, and 1999 world oil demand is expected to increase by only 1.2 million barrels per day. In 2000, world oil demand is forecasted to increase by about 1.6 million barrels per day, as Asian oil demand is expected to recover somewhat. But, with less demand in Southeast Asia than originally expected, world oil demand under these assumptions will be growing at an average annual rate of 1.7 percent between 1997-2000 after growing at an average annual rate of 2.2 percent between 1994-1997.

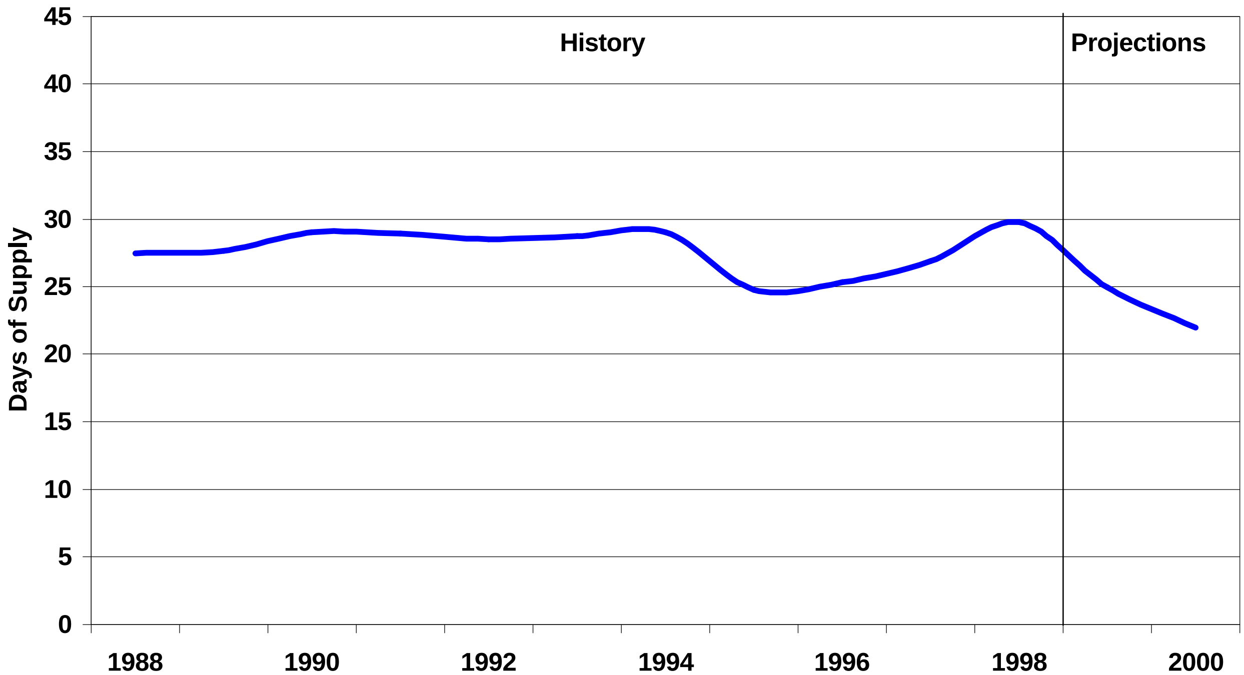
After increasing by less than 200,000 barrels per day in 1998, oil demand in countries of the OECD is expected to increase by about 700,000 barrels per day in both 1999 and 2000, an average annual rate of 1.6 percent (Figure 10 and Table 3). (Our OECD estimates do not yet include those of the Czech Republic, Hungary, Mexico, Poland, and South Korea). Japan's current recession is the main reason for a decline in Japanese oil demand in 1998 and oil demand in Japan should remain relatively flat in 1999. An increase of 100,000 barrels per day in Japanese oil demand is expected in 2000. Partly because of the general weakness expected for Japanese demand, the United States' oil demand growth represents about 69 percent of OECD oil demand growth in 1999 and about 46 percent of OECD oil demand growth in 2000.

A major story regarding world oil demand continues to be the effect the economic problems in Southeast Asia are expected to have on oil demand growth in the region. Prior to this recent economic slowdown, non-OECD countries exhibited strong growth in oil demand. This was especially true in Asian countries. For example, oil demand in China and in Other Asia (see Summary of Important Terms for definition) grew by 7.5 percent per year between 1991-1997. However, due to the recent economic slowdown in several Asian countries, this forecast has an average annual oil demand growth rate of 5.1 percent for China and a growth of only 2.0 percent for Other Asian oil demand between 1998 and 2000. At the same time, Latin American oil demand is expected to grow at an annual rate of 2.2 percent between 1998 and 2000.

After showing some growth in 1997 for the first time since the collapse of the Soviet Union, oil demand in the former Soviet Union (FSU) is estimated to have increased slightly again in 1998. However, as economic problems in Russia continue to mount, oil demand in the FSU is expected to decline in 1999, before increasing slightly in 2000. Oil demand in the FSU, which was 8.7 million barrels per day just 10 years ago, is forecasted to be less than 4.3 million barrels per day in 2000 (Table 3).

World Oil Stocks, Capacity and Net Trade

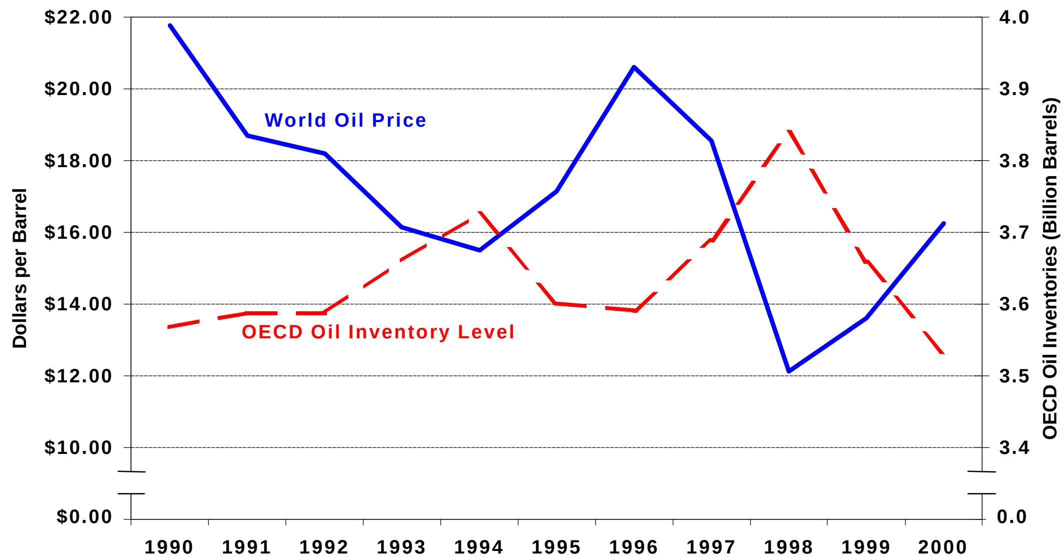
Figure 11. OECD Commercial Oil Stocks



Commercial oil inventories (measured in days of supply) in OECD countries increased by nearly 2.9 days worth in 1998, the largest such increase since at least 1982. OECD commercial oil inventories are expected to decrease in 1999 by nearly 5 days of supply and in 2000 by nearly 3 days of supply next year to end 2000 at levels not seen in recent years (Figure 11). The decrease in 1999 and 2000 is in large part due to recently announced OPEC and non-OPEC cuts in oil production. The inverse relationship between stock levels and the direction in prices continue as prices are projected to rise while inventories fall (Figure 12).

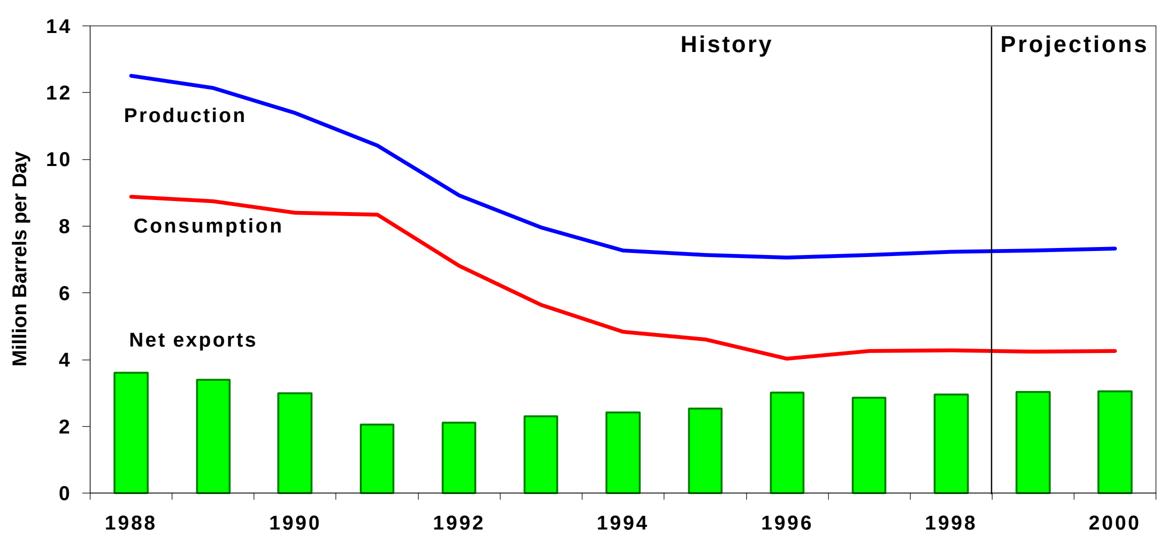
OPEC oil production capacity is expected to increase by less than 500,000 barrels per day between 1998 and 2000. This is due to the market being oversupplied in 1997 and 1998, thus limiting the incentive to build productive capacity over the next 2 years. Overall, OPEC excess oil production capacity is expected to increase from about 3.1 million barrels per day in 1997 to about 4.9 million barrels per day in 1999 (as cuts in OPEC production are not matched by cuts in capacity). This level would be the highest since 1989. A resumption of production increases next year should reduce excess capacity to 3.8 million barrels per day in 2000. Saudi Arabia is still expected to control over half of OPEC excess production capacity and, along with Kuwait and the United Arab Emirates, control the vast majority of excess capacity in the world.

Figure 12. OECD Oil Stocks vs World Oil Price, 1990-2000



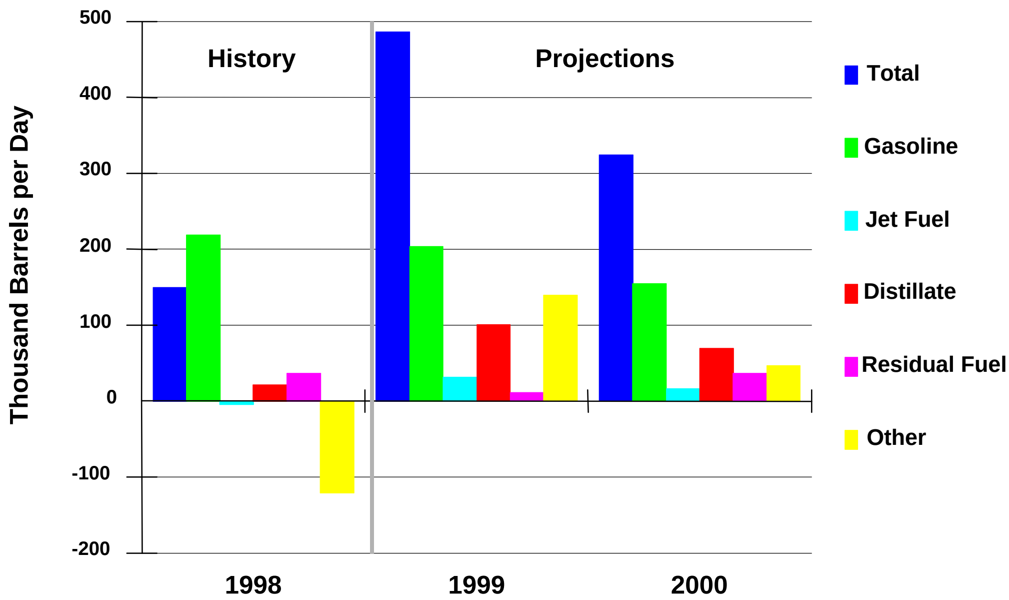
Net exports from the FSU are expected to increase slightly during the forecast period, from 2.9 million barrels per day in 1997 to about 3.1 million barrels per day in 2000 (Figure 13). Exports are significantly higher than they were immediately following the collapse of the FSU (2.1 million barrels per day in 1991 and 1992) and by 2000 could be at levels not seen since before the collapse (3.0 million barrels per day in 1990).

Figure 13. FSU Oil Production, Consumption and Net Exports



U.S. Oil Demand

Figure 14. Petroleum Demand Growth (Change from Year Ago)



Taking advantage of known revisions to 1998 U.S. petroleum data (reported in Table C1 of EIA's *Petroleum Supply Monthly*), we have recast the 1998 U.S. petroleum demand and supply balance to more closely reflect the expected annual results expected later this spring. For details of key revisions, see *Interim Petroleum Data Revisions for the Short-Term Energy* Outlook at the end of this report. These revisions result in a 100,000-barrels-per-day upward adjustment to domestic petroleum demand in 1998. Thus, growth in 1998 was evidently closer to 0.8 percent than the 0.3 percent previously reported (without incorporation of the revisions).

Petroleum demand this year is still expected to exhibit a much higher growth rate than last year, although the 1998 revisions we are employing here reduce the stated growth rate to about 2.6 percent from the 2.9 percent reported previously. Total petroleum demand in 1998 increased by an estimated 150,000 barrels per day, or 0.8 percent, from that of 1997 (Figure 14). This compares to the 1.7-percent growth recorded for 1997. The continued robust growth in most economic indicators--combined with substantial declines in product prices--would have been expected to stimulate demand for oil products. Several factors, however, helped constrain demand last year. The first was warm weather during the first and fourth quarters. In terms of heating degree-days, weather was 13 percent warmer than in 1997 (considered to be a nearly “normal” weather year) in both the Northeast and in the U.S. as a whole. The second factor was a marked reduction in residual fuel oil shipments to users other than electric utilities. A continuation of the shrinkage in the U.S. market for heavy oil in the industrial and commercial sectors as well as the further diminution in the U.S. role as a supply source for bunker fuel are suspected causes. As indicated in EIA's *Fuel Oil and Kerosene Report, 1997*, residual fuel oil sales to these three sectors fell by about 150,000 barrels per day (24 percent) between 1995 and 1997. Also, 1998 saw an apparent flattening in total jet fuel demand. It should be noted that kero-jet fuel actually used in commercial aviation did increase in 1998, perhaps by as much as 2 percent based on data from the Federal Aviation Administration (FAA Form P-12). Thus, changes in the somewhat broader jet-quality fuel discussed here (reported monthly in EIA's *Petroleum Supply Monthly*) were not indicative of changes in airline activity. Based on FAA data, we estimate that air traffic (available ton-miles) increased by about 3.5 percent in 1998.

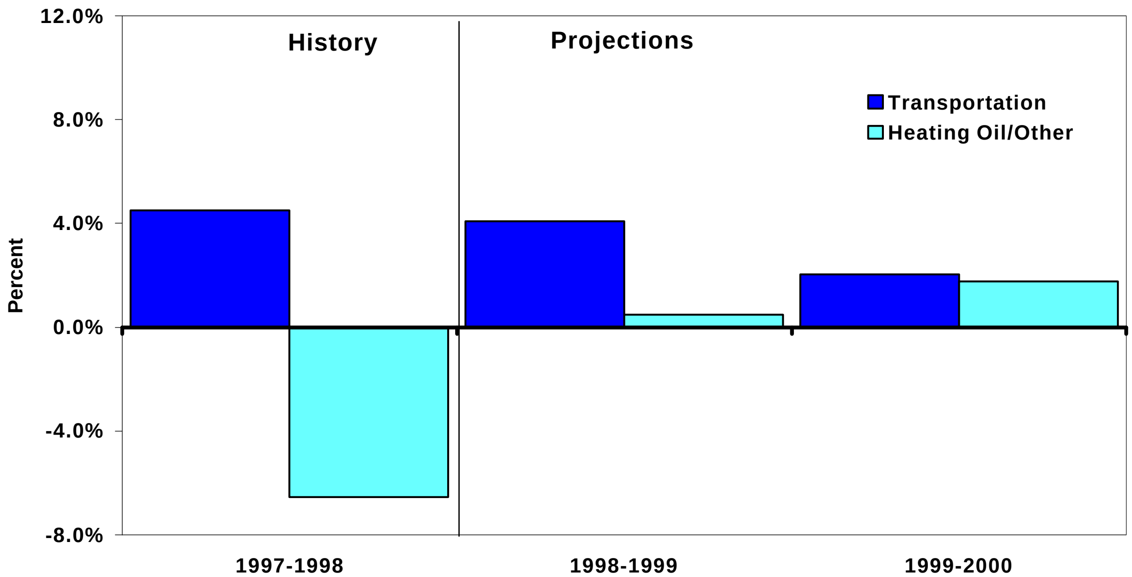
In 1998, following a first-half lull in petroleum markets, modest strength returned briefly for the third quarter, primarily in motor gasoline, distillate fuel oil, and residual fuel oil, resulting in a 2.1-percent growth in year-to-year total demand growth for that period. Dampened by warmer-than-normal weather and strike-related weakness in commercial jet-fuel markets, demand for the fourth quarter actually declined slightly, contributing to the slow growth for the year as a whole (Figure 32).

With continued strength in the economy, U.S. petroleum demand growth is expected to increase in 1999 by 480,000 barrels per day, or 2.6 percent. Much of this growth is attributed to 1) increased demand for heating fuel and other weather-sensitive products resulting from higher heating degree-days and 2) continued growth in transportation demand. In 2000, total demand is projected to increase an additional 320,000 barrels per day, or 1.7 percent. That moderation in growth assumes normal weather patterns in 2000 and a moderation in overall economic growth.

Motor gasoline demand in 1998 grew by an estimated 2.7 percent, reflecting mostly a 2.4-percent increase in highway travel. That moderate growth in highway travel was obtained despite a 3.2-percent increase in real disposable income and a 15-percent decline in inflation-adjusted fuel costs per mile to a record low. Gasoline demand is expected to post similar growth (2.5 percent) in 1999 as continued growth in the economy and relatively low real fuel costs keep highway travel growing steadily. For the 1999-2000 period, growth in motor gasoline is expected to average 1.8 percent. That reflects growth in vehicle miles traveled averaging 2.2 percent.

Distillate demand growth for 1998 was very weak, estimated to be 0.6 percent, compared to growth of 2.1 percent in 1997 (Figure 15). Much of that slowdown was brought about two factors: a moderation in manufacturing output growth from 5.6 percent in 1997 to 4.1 percent estimated for 1998 and (most importantly) the combined effects of warmer weather in the first and fourth quarters. Total distillate demand is projected to increase by 2.9 percent in 1999 and a further 2.0 percent in 2000. This growth results largely from both an assumed return to normal weather patterns in 1998 and continued growth in transportation (diesel) demand in both years.

Figure 15. Distillate Demand Growth (Percent Change from Year Ago)

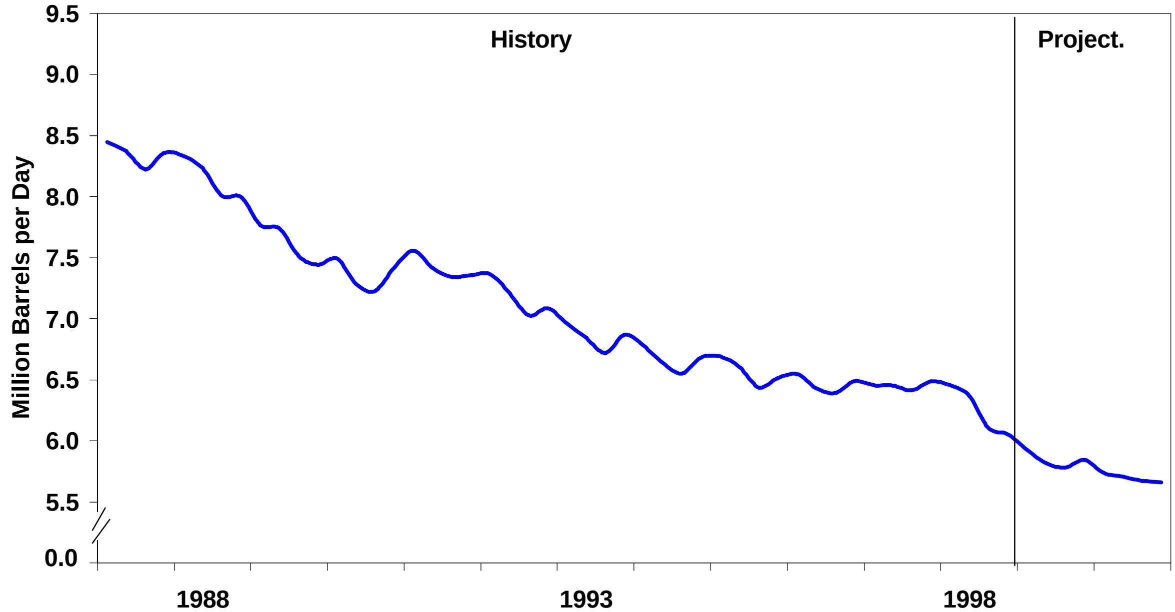


Residual fuel oil demand in 1998 staged a recovery from all-time lows, increasing by almost 5 percent. That increase was brought about by declines in residual fuel prices of between 20 and 30 percent in the price-sensitive electricity generation sector. Electric utility consumption of heavy fuel oil increased by an estimated 130,000 barrels per day, or 42 percent, with year-over-year growth rates ranging as high as 100 percent or more for some months. Other sectors, however, experienced demand weakness in 1998. Transportation deliveries of residual fuel oil (bunker fuel) shrank as refinery upgrades reduced the availability of the fuel. Abnormally warm weather during the first and fourth quarters resulted in a decline in deliveries to weather-sensitive sectors.

In 1999, total residual fuel oil demand is projected to rise a further 1.3 percent, most of which can be accounted for by continued growth in electric utility consumption. Boosted by continued low prices and a return to normal weather patterns, utilities are expected to maintain relatively high use of the fuel. The overall impact of increased utility purchases would be greater in 1999, if, as we assume, non-utility markets stabilize or are positively affected by normal weather.

U.S. Oil Supply

Figure 16. U.S. Crude Oil Production



The sharp decline in oil prices that began in 1997 and (apparently) ended this past winter has taken its toll on U.S. oil production. While domestic oil production during the first quarter of 1998 was unchanged from the same period in 1997, fourth quarter 1998 production was almost 7 percent below the fourth quarter of 1997. The rapid decline in production lowered estimated 1998 average domestic crude oil production to 6.24 million barrels per day, a decline of 3.2 percent from 1997 (Figure 16). A sharper rate of decline (6.4 percent) is expected in 1999, followed by a slowdown in the decline rate to 2.5 percent in 2000.

Lower-48 States oil production is expected to decrease by 330,000 barrels per day in 1999, followed by a decrease of 58,000 barrels per day in 2000. Oil production from the Ram-Powell, Auger, Ursa, Mars, Troika, Baldpate, and Diana-Hoover Federal Offshore fields is expected to account for about 12.3 percent of the lower-48 oil production by the 4th quarter of 2000. The Ram-Powell production began in the third quarter of 1997, attaining production of 60,000 barrels per day in early 1998. Shell Oil Co. estimates that Ram-Powell production will increase another 5,000 barrels per day in 1999. Production from Shell's Auger platform was cut back to 70,000 barrels per day in the fourth quarter of 1998, and is expected to return to output of 100,000 barrels per day in the third quarter of 1999. Shell will start production in 1999 in their Ursa field, which will peak in production in the year 2000 at 150,000 barrels per day of condensate. Shell also estimates that production from the Mars platform will increase by another 40,000 barrels per day in 1999. The Baldpate platform started producing in August and

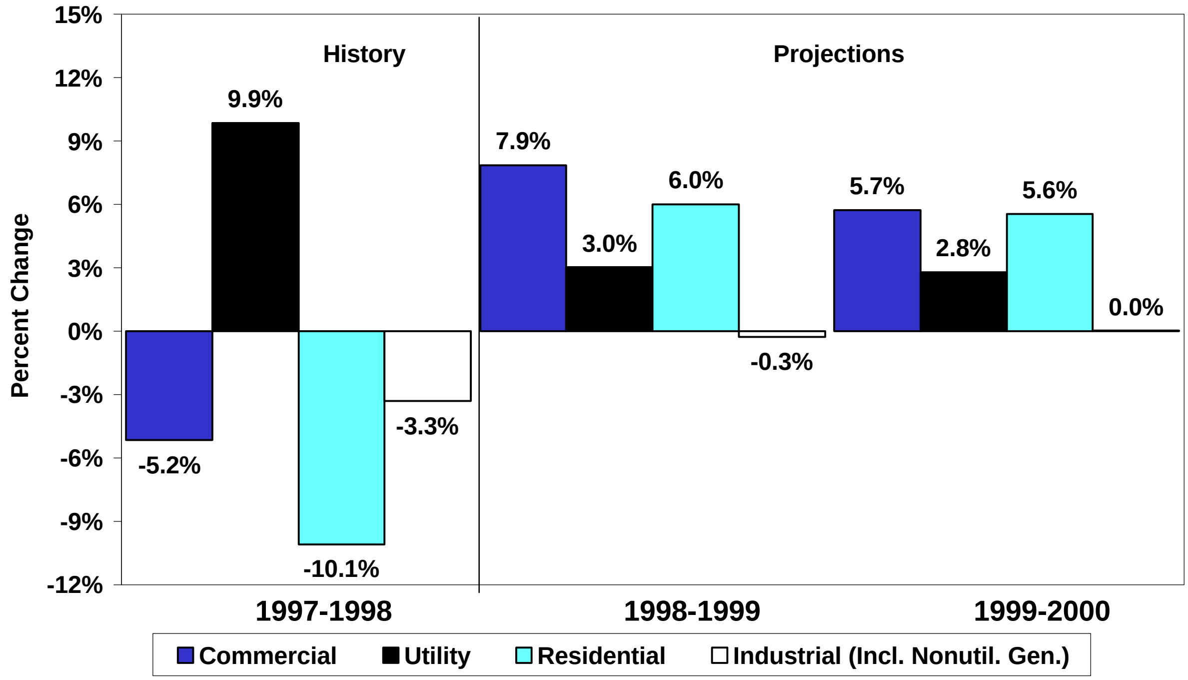
Amerada Hess estimates a production rate of 50,000 barrels per day in the first quarter of 1999. Exxon's Diana-Hoover fields will start production in mid-2000 at a rate of 30,000 barrels per day, increasing to 100,000 barrels per day in early 2001.

Alaska is expected to account for about 18 percent of the total U.S. oil production in 2000. Production there is expected to decrease by 70,000 barrels per day (6.1 percent) in 1999, followed by an decline of 90,000 barrels per day in 2000 (8.1 percent).

Almost 52 percent of total U.S. petroleum demand was met by net imports of crude oil and finished petroleum products in 1998. That percentage is expected to continue to grow in 1999 and 2000 despite the drawdown of domestic inventories. Import dependence may reach 54 percent in 2000 if the expected continued decline in domestic oil production occurs, if weather conditions are normal and modest economic growth continues.

U.S. Natural Gas Demand

Figure 17. Natural Gas Demand by Sector

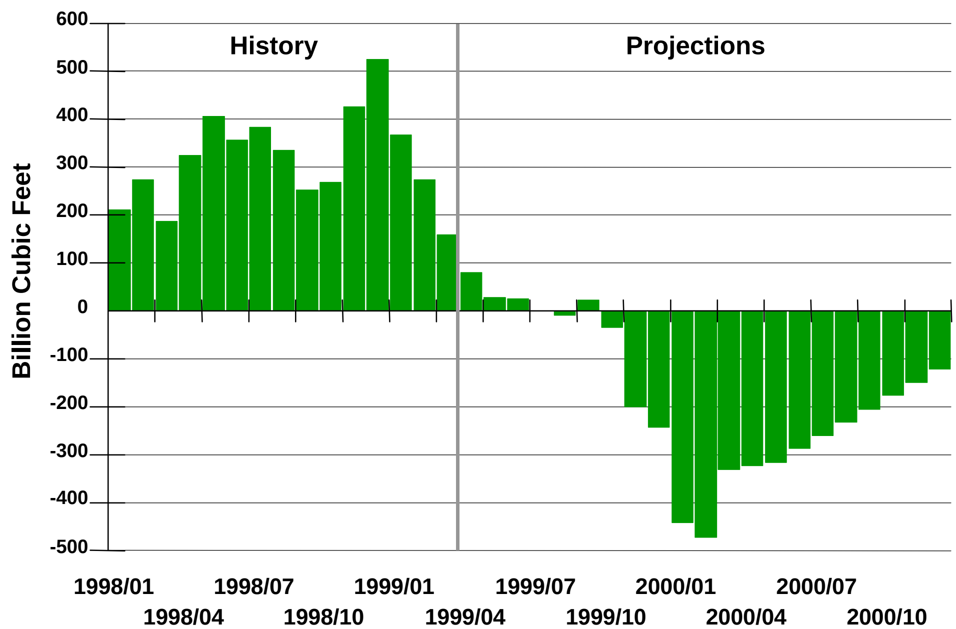


On the assumption that weather conditions will be normal through the remainder of the forecast period, we are projecting that total natural gas demand will grow at annual rates of 2.8 percent in 1999 and 2.5 percent in 2000 (Figure 17). In first quarter 1999, heating degree-days were 11.3 percent lower than normal. However, this was 7.2 percent higher than they were in the first quarter of 1998, which was an exceptionally warm quarter.

Except for industrial gas demand, which is projected to be flat, gas demand is expected to grow across all sectors in 1999 and 2000 under the assumptions of normal weather conditions and continued, although slowing, economic growth. Residential and commercial demand for natural gas in 1999 is projected to rebound from the decrease seen in 1998, when the weather during the heating season was relatively mild. Electricity demand for natural gas is also expected to continue to grow, but at a somewhat slower pace than the high rate of 9.9 percent seen in 1998.

U.S. Natural Gas Supply

Figure 18. Working Gas in Storage (From Year Ago)



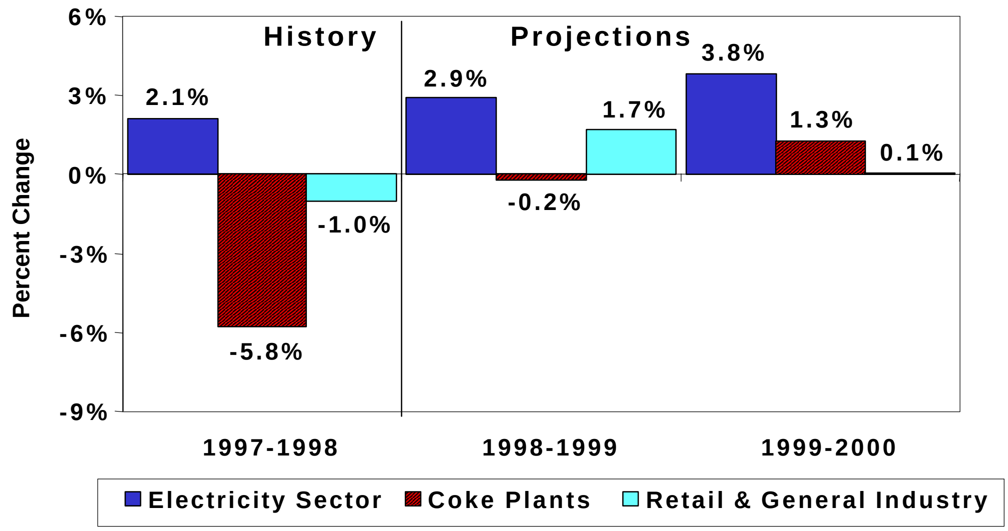
After showing little or no growth in 1998, U.S. natural gas production is expected to decline by about 0.5 percent in 1999. Low oil prices, as well as a decrease in natural gas demand in 1998, have affected natural gas production. This is because of the drop off in drilling and consequent falloff in gas produced in association with oil due to low prices, in addition to high levels of natural gas in storage. Exploration and production budgets have been slashed for 1999.

Natural gas storage at the end of the first quarter of 1999 is estimated to be 160 billion cubic feet higher than it was a year ago (Figure 18). Working gas in storage at the end of the heating season (March 31) was at an estimated 1,354 billion cubic feet, the highest end-March level since 1992. The still high levels of surplus gas in storage are expected to put a damper on gas prices until the arrival of heating demand in the fourth quarter. But by the fourth quarter of 1999, gas storage is expected to finally fall below the extremely high levels of the same period in 1998, under normal winter weather assumptions.

Natural gas net imports to are expected to increase by 1.2 percent in 1999 compared to import growth of 4.5 percent in 1998. Imports are forecast to increase by another 8.7 percent in 2000. The expansion of the Transcanada pipeline in November of 1999 will add another 450 million cubic feet per day, while the new Alliance pipeline to the U.S. Midwest is expected to add an additional 1.3 billion cubic feet per day in November of 2000.

U.S. Coal Demand and Supply

Figure 19. Annual Change in U.S. Coal Demand



Total coal demand is expected to increase 2.7 percent in 1999 and 3.5 percent in 2000, compared to 1.7 percent growth in 1998 (Table 9 and Figure 19). Coal demand by the electricity sector (including independent power producers) grew 2.1 percent (to 942 million short tons) in 1998, largely due to the very hot summer. Growth in electricity demand (1.4 percent in 1999 and 2.2 percent in 2000), combined with a return to normal levels of hydroelectric generation, will provide the impetus for continued growth in coal demand by the electricity sector. This sector currently consumes 90 percent of all coal used in the United States.

Coal carbonized (consumed) by coke plants fell 5.8 percent in 1998 to 28.5 million short tons. Demand for coal at coke plants is expected to remain below 29 million short tons throughout the forecast period, primarily as a result of coking plant capacity constraints. There are currently 26 coke plants operating in the United States, compared with 34 operating units at the end of 1990 and 65 at the end of 1970. While two coke plants closed in 1998, a new coke plant (Indiana Harbor) opened during the year, the first new domestic coke plant in 16 years. Growth in coke plant coal consumption is obviated by the use of non-coke methods of steel production (steel recycling and electric arc furnaces) by the iron and steel industry. Electric-arc production grew 4.3 percent in 1998, and it accounted for 44 percent of all raw steel produced in the United States. Coal-based raw steel production declined 2.1 percent in 1998 and it is expected to average only 0.7 percent growth over the forecast period.

Demand for coal by the retail and general industry sectors is projected at 77.6 million short tons in 1999, a 1.7 percent increase over 1998 demand. In 2000, demand is expected to remain flat from the 1999 level.

U.S. coal exports are expected to continue to weaken as the lower-priced coals from Australia and South Africa, as well as the growing coal export industries of Indonesia, Venezuela, and Colombia, grab a larger share of the market. Steam coal exports will bear the brunt of the export decline, while metallurgical exports will be buoyed somewhat by the demand for the higher quality U.S. coals. Exports are projected to be 73.4 million short tons in 1999 (a 4.9 percent decrease) and 72.5 million short tons in 2000 (Table 9).

Coal imports grew 16.5 percent in 1998, but they represent less than 1 percent of total U.S. consumption. The continued strength of the dollar, coupled with increased demands for low sulfur compliance coal, and the impending CAAA (Clean Air Act Amendments) Phase II emission requirements will provide the impetus for continued growth of coal imports. Imports are forecast to be to 8.9 million short tons, in 1999 (a 1.6 percent increase), and grow 1.7 percent to 9.0 million short tons in 2000.

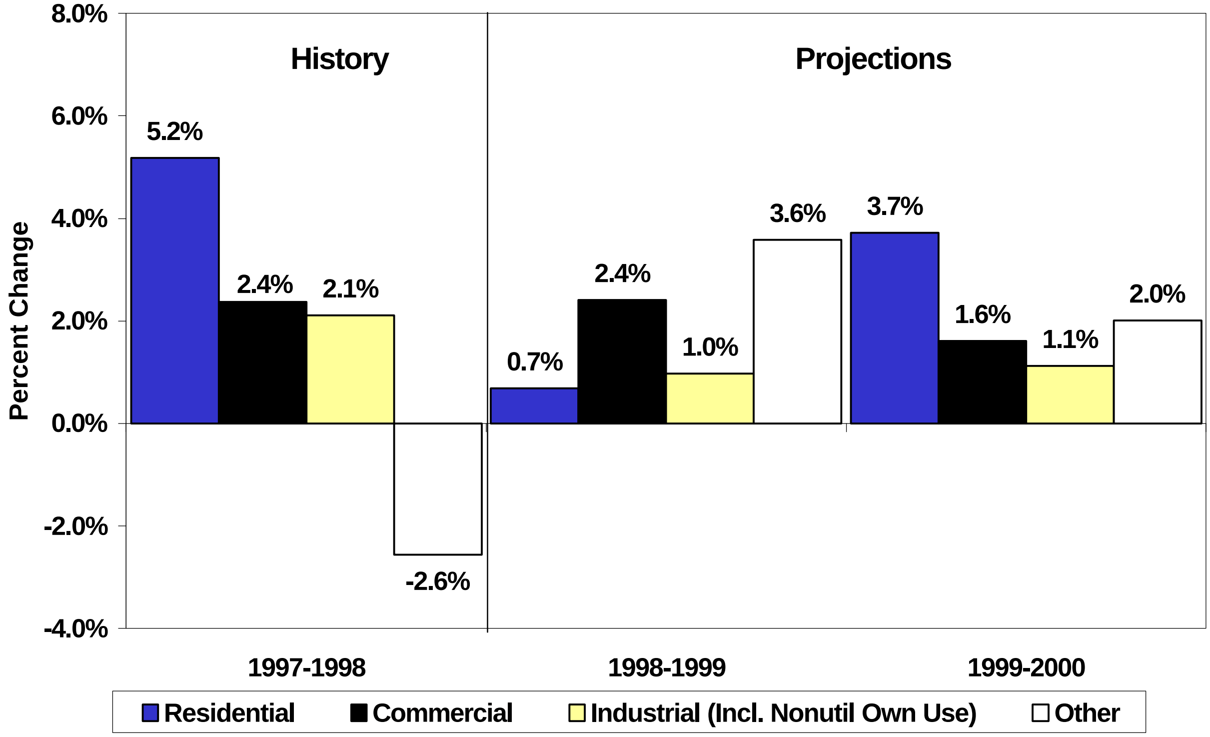
A record 1,118.7 million short tons of coal was produced in 1998. Production is expected to remain nearly flat in 1999. Mild weather over much of the country during the fall and winter reduced coal use at electric utilities and led to a large buildup in coal stocks. A large portion of the increase in electric utility coal requirements for 1999 will be met by drawing down these stockpiles. As a result, the need for growth in coal production will be weak. Annual output is expected to reach 1,123.6 million short tons in 1999. Production will grow 2.6 percent in 2000, as stock levels return to normal levels, and production is projected to be 1152.7 million short tons. Production in the Western region should continue to rise significantly over the forecast period (2.3 percent in 1999 and 5.6 percent in 2000). The Western region became the nation’s largest coal producer in 1998, surpassing the Appalachian region. Production in the Appalachian region is expected to grow slowly in the forecast period (0.6 percent in 1999 and 0.9 percent in 2000). Interior region production is projected to exhibit an average decline of nearly 4 percent over the forecast period.

Total coal stocks (producers and consumers) were 163.1 million short tons at the end of 1998, a 20.5 percent increase from the previous year. Producer stocks remained virtually unchanged in 1998, and they are expected to increase by 7.2 percent in 1999, as consumer stocks will be used to meet growth in demand. Increased demand will see producer stocks fall by 4 million short tons in 2000.

Consumer stocks increased by 22.6 million short tons in 1998, primarily in the electric utility sector. Consumer stocks will be drawn down significantly in the forecast period. To meet the increases in electricity demand, 8.3 million short tons will be drawn down in 1999, and an additional 8.2 million short tons will be withdrawn in 2000.

U.S. Electricity Demand and Supply

Figure 20. U. S. Electricity Demand

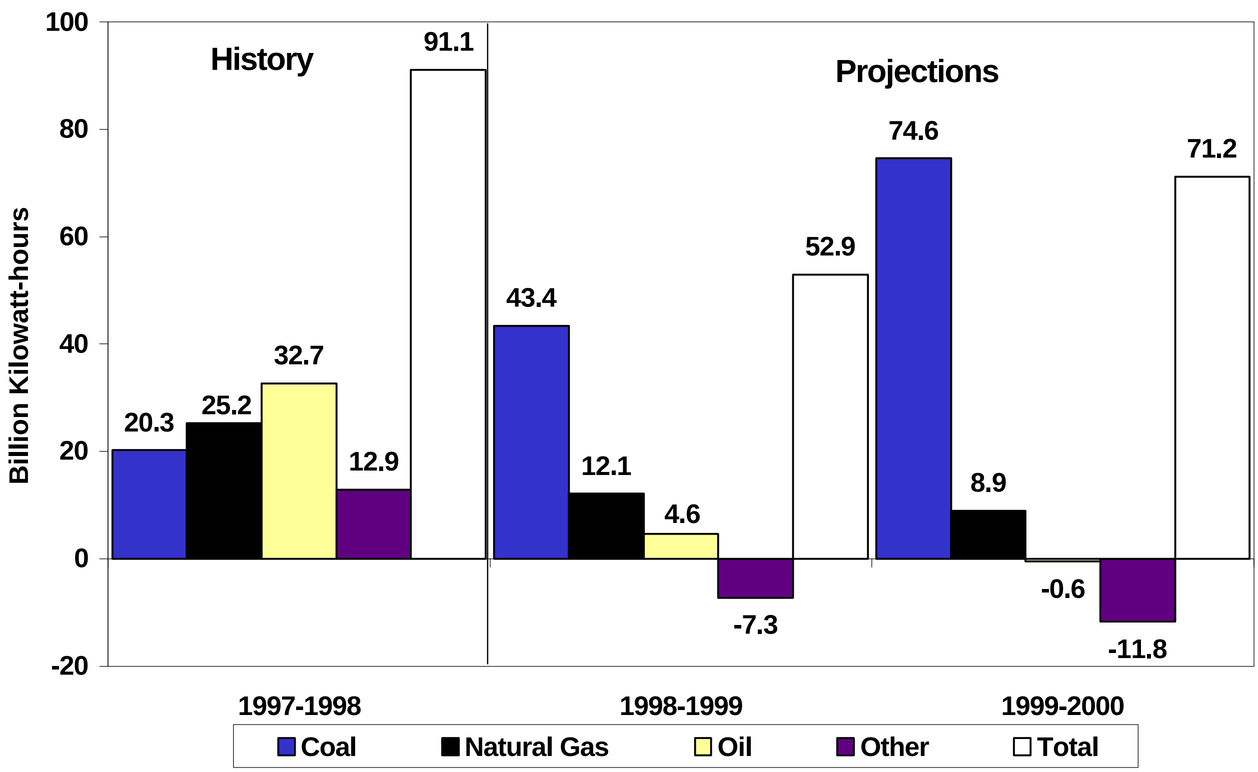


Assuming normal weather for the remainder of the year, the outlook for electricity in 1999 is modest growth of 1.4 percent. Cooling degree-days this summer are expected to be 15.7 percent lower than last summer, which was quite hot. Thus, lower electricity demand is indicated for this summer compared to last summer. In 2000, electricity demand is expected to grow by 2.1 percent due to assumed normal weather conditions, but somewhat below trend as the economy continues to slow. Average electricity growth between 1990 and 1998 was about 2.4 percent per year.

A boost to electricity demand in the first quarter of 1999 arose from higher heating demand, particularly in the residential and commercial sectors (Figure 20). Also, net imports of electricity jumped by 17 percent in first quarter 1999, after having fallen through most of 1998, and are expected to show that same percent increase (17 percent) on an annual basis for 1999. In 2000, electricity demand is expected to grow across all sectors.

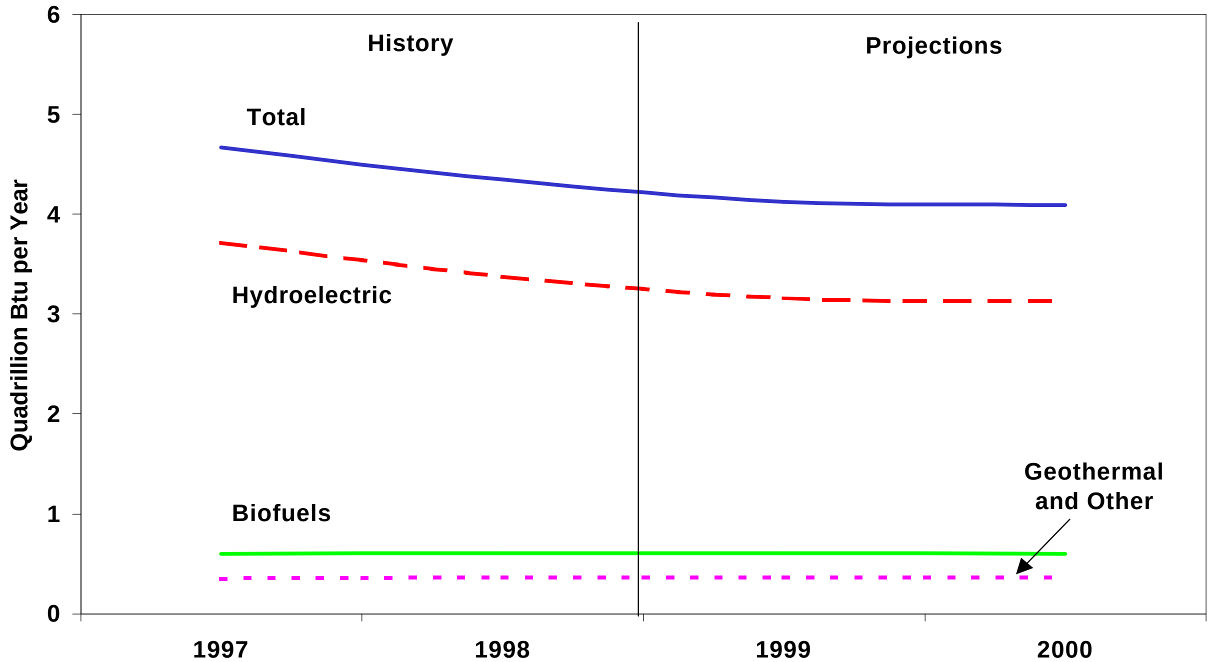
Significant differences in the electricity supply profile in 1999 are expected (Figure 21). Because much of the electricity demand growth in 1998 occurred during the spring and summer months, and because of the decline in availability of hydroelectric power, natural gas and oil played relatively large roles in meeting incremental demand in 1998. In 1999, with most of the electricity demand growth expected to take place in the winter (first and fourth quarters), we expect to see coal play a larger role in meeting incremental demand. Nuclear power generation is expected to rise somewhat, as some plants that were down have come back online. Oil price increases this year are expected to reduce the competitive advantage of oil in power generation, diminishing the role of oil in meeting incremental demand this year.

Figure 21. Electricity Generation by Fuel (Change From Year Ago)



U.S. Renewable Energy Demand

Figure 22. Renewable Energy Use for Electricity



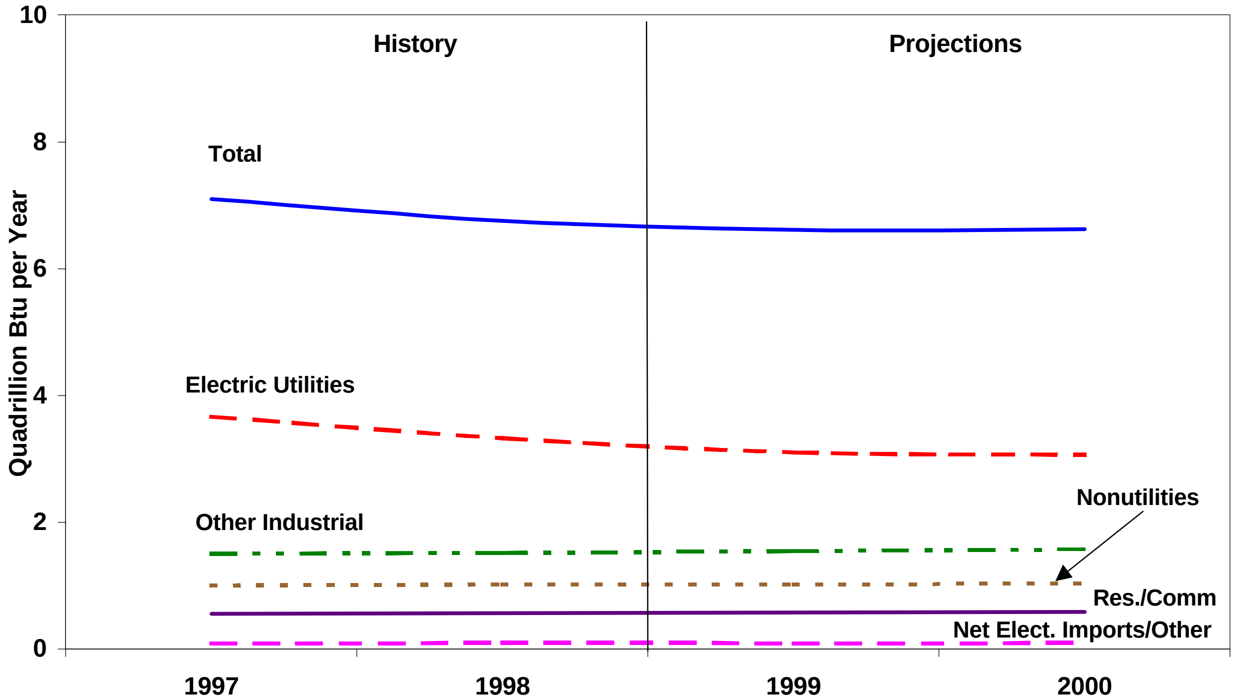
Total renewable energy demand, as defined here, includes minor non-marketed components (that is, amounts which are neither bought nor sold, either directly or indirectly as inputs to marketed energy). The Energy Information Administration does not estimate or project total consumption of non-marketed renewable energy.

Renewable energy use in the United States in 1998 amounted to about 6.7 quadrillion Btu (quads), or about 7.2 percent of total domestic gross energy demand (Tables HL1 and 11). In 1998, use of renewables is estimated to have decreased by about 4.8 percent due to a decline in hydroelectric generation. In 1999, renewables use is expected to decrease by another 2.2 percent, as hydroelectric availability continues to decline to more normal levels due to the assumption of normal rain and snowfall for the remainder of the forecast period (Figure 22). In 2000, renewables use is expected to increase slightly.

More than half of all renewable energy use measured by EIA is associated with the production of electricity. While the biggest component of electricity producers' use of renewables is hydroelectric power generated by electric utilities (Figure 23), a significant and growing portion of renewables use occurs at nonutility generating facilities.

Most of the nonutility use of renewables involves biofuels, principally wood and wood by-products.

Figure 23. Renewable Energy Use by Sector

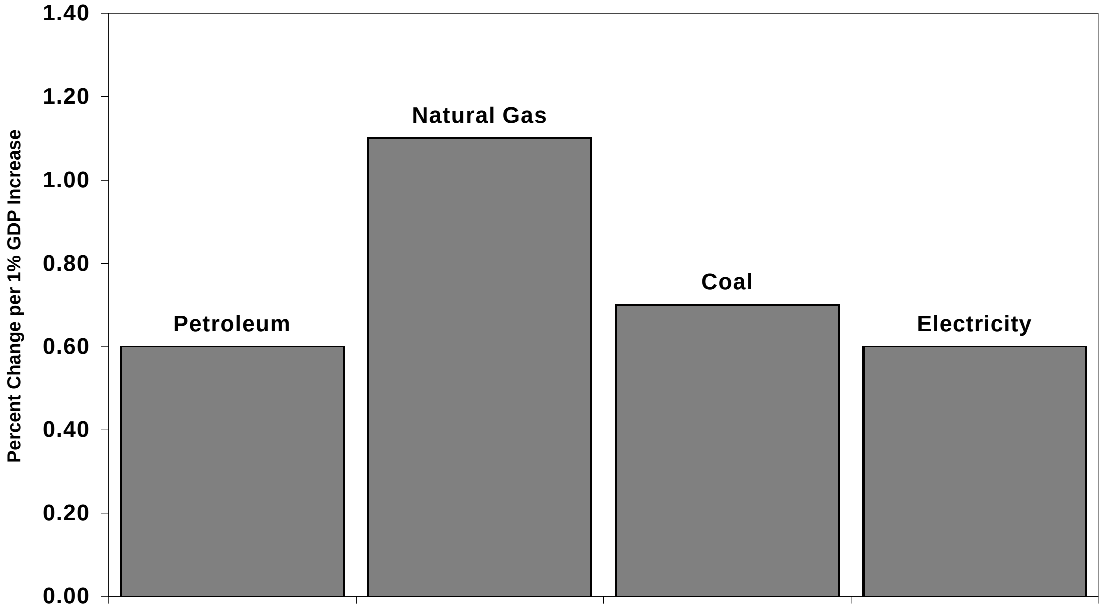


Currently, aside from power generation, the most significant area of renewables use is in the industrial sector, accounting for 22 percent of the total in 1998. This component is principally biofuels.

Renewables use in the combined residential and commercial sector, at about 0.6 quadrillion Btu in 1998, generally accounts for about 8 percent of total domestic renewables demand (Table 11). Most of this energy is wood used for home heating, with only a very small amount having to do with solar hot water heating.

U.S. Energy Demand and Supply Sensitivities

Figure 24. Macro Sensitivities



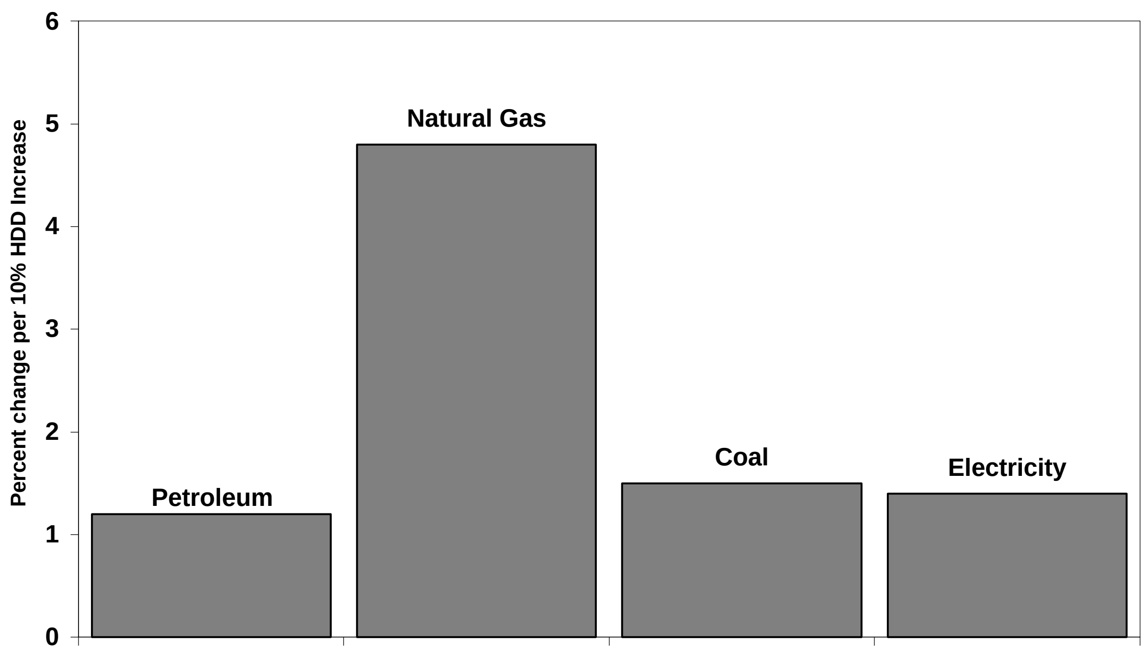
The petroleum demand and supply outlook for the mid-price case is based on assumed normal temperatures and GDP growth of 3.6 percent per year in 1999 and 1.7 percent in 2000. To enhance the usefulness of the mid-case forecasts, sensitivities of energy demand and supply are also derived, using alternative macroeconomic, price, and weather assumptions. Plausible macroeconomic and weather-related petroleum demand sensitivities are illustrated in Figures 24 and 25 and Table 6.

A 1 percent increase in real GDP raises petroleum demand by about 0.6 percent; natural gas demand by 1.1 percent; coal demand by 0.7 percent; and electricity demand by 0.6 percent (Figure 24). The impact of shifts in economic growth varies, depending upon distribution of incremental growth across energy-intensive and non-energy-intensive sectors.

A 10 percent increase in crude oil prices, assuming no price response from non-petroleum energy sources, reduces petroleum demand by 0.3 percent. A 10 percent increase in gas prices at the wellhead, assuming no price response for other fuels, reduces natural gas demand by 0.4 percent.

A 10 percent increase in heating degree-days increases winter petroleum demand by 1.1 percent; natural gas demand by 4.4 percent; coal demand by 1.7 percent; and electricity demand by 1.5 percent (Figure 25). The impact of heating degree-day deviations from normal may not be symmetrical. Extremely cold weather could result in indirect effects on fuel oil markets due to potential natural gas supply constraints.

Figure 25. Weather Sensitivities



A 10 percent increase in cooling degree-days increases summer petroleum demand by about 0.1 percent, natural gas by 1.0 percent, coal by 1.7 percent and electricity demand by 1.7 percent.

A $1-per-barrel increase in crude oil prices boosts domestic oil supply (crude oil and natural gas liquids production) by about 109,000 barrels per day.

Interim Petroleum Data Revisions for the Short-Term Energy Outlook

This issue of the STEO includes revisions to certain 1998 U.S. petroleum product supply and demand statistics caused by resubmission of respondent survey forms. Cumulative revisions to published 1998 data are reported in the *Petroleum Supply Monthly (PSM)* in Table C1. The official published petroleum supply statistics are not changed to reflect revisions until publication of the *Petroleum Supply Annual (PSA).*

The following average annual revisions were made to official published 1998 petroleum supply statistics in the *STEO*, in thousands of barrels per day:

	Finished Motor Gasoline	Distillate Fuel	Jet Fuel	Residual Fuel
Field Production	+ 2	0	0	0
Refinery Production	+ 31	+ 7	+ 6	0
Net Imports	+ 3	+ 6	+ 16	+ 16
Product Supplied	+ 36	+ 13	+ 21	+ 16

Source: Petroleum Supply Monthly, DOE/EIA-0109 (Washington, DC, various issues), Table C1.

	Crude Oil	Motor Gasoline Blending Components
Field Production	0	- 2
Net Imports	+ 3	+ 10
Refinery Inputs	+ 36	+ 8
Unaccounted for Crude Oil	+ 33	0

Source: Petroleum Supply Monthly, DOE/EIA-0109 (Washington, DC, various issues), Table C1.

Summary of Important Terms

PETROLEUM PRICES

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

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

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

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

PETROLEUM DEMAND and SUPPLY

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

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

NATURAL GAS

Natural gas wellhead price: The wellhead price of natural gas, which is calculated by dividing the total reported value at the wellhead by the total quantity produced as reported by the appropriate agencies of individual producing States and the U.S. Minerals Management Service, Department of the Interior. The price includes all costs prior to shipment from the lease, including gathering and compression costs, in addition to State production, severance, and similar charges.

Natural gas spot price: A transaction price for natural gas concluded "on the spot," that is, on a one-time prompt (immediate) basis, as opposed to a longer-term contract price obligating the seller to deliver the product at an agreed price over an extended period of time.

MACROECONOMIC

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

GDP Implicit Price Deflator: A byproduct of the price deflation of gross domestic product (GDP). It is derived as the ratio of current- to constant-dollar GDP. It is a weighted average of the detailed price indexes used in the deflation of GDP, but these indexes are combined, using weights that reflect the composition of GDP in each period. Thus, changes in the implicit price deflator reflect not only changes in prices but also changes in the composition of GDP. Corresponding current- and constant-dollar series are published by the U.S. Bureau of Economic Analysis, National Income and Product Accounts. The current base year for the deflator is 1992.

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

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

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

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

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

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

TOTAL ENERGY

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

GEOGRAPHICAL

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

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

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

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

Table 1. U.S. Macroeconomic and Weather Assumptions

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Macroeconomic [a]															
Real Gross Domestic Product (billion chained 1992 dollars - SAAR)............	7465	7499	7566	7679	7755	7809	7855	7883	7895	7933	7982	8028	7552	7825	7960
Percentage Change from Prior Year.............	4.2	3.6	3.5	4.3	3.9	4.1	3.8	2.7	1.8	1.6	1.6	1.8	3.9	3.6	1.7
Annualized Percent Change from Prior Quarter...	5.4	1.8	3.6	5.9	4.0	2.8	2.4	1.4	0.6	1.9	2.5	2.3			
GDP Implicit Price Deflator (Index, 1992=1.000)	1.123	1.126	1.129	1.131	1.134	1.137	1.140	1.143	1.148	1.151	1.155	1.159	1.127	1.139	1.153
Percentage Change from Prior Year.............	1.2	1.0	1.0	0.9	0.9	1.0	1.0	1.1	1.2	1.3	1.3	1.4	1.0	1.0	1.3
Real Disposable Personal Income (billion chained 1992 Dollars - SAAR)	5287	5322	5364	5420	5478	5517	5562	5596	5637	5677	5710	5728	5348	5538	5688
Percentage Change from Prior Year.............	3.0	3.0	3.2	3.5	3.6	3.7	3.7	3.3	2.9	2.9	2.7	2.4	3.2	3.6	2.7
Manufacturing Production (Index, 1992=1.000)	1.338	1.347	1.348	1.364	1.369	1.385	1.396	1.400	1.398	1.404	1.417	1.429	1.349	1.387	1.412
Percentage Change from Prior Year.............	6.0	5.0	3.1	2.5	2.3	2.8	3.5	2.6	2.1	1.4	1.5	2.1	4.1	2.8	1.8
OECD Economic Growth (percent) [b]													3.0	2.6	2.4
Weather [c]															
Heating Degree-Days															
U.S.	1972	480	68	1468	2114	524	89	1636	2354	524	89	1636	3988	4363	4603
New England	2766	769	203	2109	3103	915	171	2269	3306	915	171	2269	5847	6457	6660
Middle Atlantic	2461	570	106	1779	2801	716	105	2026	3028	716	105	2026	4916	5648	5875
U.S. Gas-Weighted	2078	548	66	1555	2246	539	81	1686	2454	539	81	1686	4247	4552	4760
Cooling Degree-Days (U.S.)	25	399	865	69	28	334	758	72	30	334	758	72	1358	1191	1193

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

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

[c] Population-weighted degree days. A degree day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population. Normal is used for the forecast period and is defined as the average number of degree days between 1961 and 1990 for a given period.

SAAR: Seasonally-adjusted annualized rate.

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

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release G.17(419)*. Projections of OECD growth are based on WEFA Group, "World Economic Outlook," Volume 1. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

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

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Macroeconomic [a]															
Real Fixed Investment (billion chained 1992 dollars-SAAR)	1225	1264	1271	1314	1348	1362	1368	1372	1375	1376	1379	1387	1269	1362	1379
Real Exchange Rate (index)	1.142	1.161	1.182	1.118	1.123	1.129	1.138	1.130	1.121	1.112	1.104	1.096	1.151	1.130	1.108
Business Inventory Change (billion chained 1992 dollars-SAAR)	30.1	23.9	19.2	6.8	10.9	13.1	13.7	12.8	-4.0	-7.0	-3.3	-0.9	20.0	12.6	-3.8
Producer Price Index (index, 1982=1.000)	1.251	1.249	1.243	1.234	1.234	1.238	1.241	1.247	1.254	1.258	1.261	1.267	1.244	1.240	1.260
Consumer Price Index (index, 1982-1984=1.000)	1.621	1.628	1.635	1.642	1.648	1.657	1.666	1.675	1.687	1.696	1.705	1.716	1.631	1.662	1.701
Petroleum Product Price Index (index, 1982=1.000)	0.541	0.536	0.503	0.477	0.473	0.576	0.557	0.556	0.590	0.610	0.612	0.599	0.515	0.541	0.603
Non-Farm Employment (millions)	124.8	125.5	126.1	126.8	127.6	128.7	129.2	129.5	129.6	129.8	130.0	130.4	125.8	128.7	130.0
Commercial Employment (millions)	85.7	86.3	87.0	87.7	88.5	89.5	90.1	90.4	90.5	90.7	91.0	91.5	86.7	89.6	90.9
Total Industrial Production (index, 1992=1.000)	1.303	1.312	1.316	1.324	1.329	1.343	1.353	1.358	1.357	1.363	1.375	1.386	1.314	1.346	1.370
Housing Stock (millions)	113.7	114.0	114.4	114.8	115.2	115.5	115.9	116.2	116.5	116.8	117.1	117.4	114.2	115.7	117.0
Miscellaneous															
Gas Weighted Industrial Production (index, 1992=1.000)	1.175	1.171	1.158	1.155	1.164	1.163	1.170	1.171	1.166	1.171	1.181	1.189	1.165	1.167	1.177
Vehicle Miles Traveled [b] (million miles/day)	6629	7424	7600	7056	6889	7578	7759	7283	7049	7742	7923	7436	7180	7379	7538
Vehicle Fuel Efficiency (index, 1996=1.000)	0.992	1.004	0.992	0.997	0.997	1.001	0.996	1.005	0.998	1.004	1.000	1.009	0.997	0.999	1.003
Real Vehicle Fuel Cost (cents per mile)	3.34	3.17	3.08	3.10	2.96	3.40	3.23	3.32	3.35	3.36	3.32	3.39	3.17	3.23	3.36
Air Travel Capacity (mill. available ton-miles/day)	423.2	438.8	441.8	436.2	433.6	452.2	466.2	458.3	452.4	470.4	487.3	476.0	435.1	452.7	471.6
Aircraft Utilization (mill. revenue ton-miles/day)	237.5	258.9	261.4	254.4	249.6	267.7	282.4	266.1	260.1	277.1	292.4	277.5	253.1	266.5	276.9
Airline Ticket Price Index (index, 1982-1984=1.000)	2.058	2.053	2.070	2.029	2.071	2.102	2.129	2.171	2.217	2.233	2.248	2.281	2.053	2.118	2.245
Raw Steel Production (millions tons)	28.75	27.87	26.57	24.40	27.08	26.87	26.56	27.53	27.36	27.21	26.91	27.55	107.28	108.05	109.03

[a]Macroeconomic projections from DRI/McGraw-Hill model forecasts are seasonally adjusted at annual rates and modified as appropriate to the mid world oil price case.
[b]Includes all highway travel.
SAAR: Seasonally-adjusted annualized rate.
Note: Historical data are printed in bold; forecasts are in italics.
Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

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

(Million Barrels per Day, Except OECD Commercial Stocks)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Demand [a]															
OECD															
U.S. (50 States)	18.4	18.6	19.1	18.9	19.1	18.9	19.4	19.6	19.5	19.3	19.7	19.9	18.8	19.3	19.6
U.S. Territories	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Canada	1.9	1.8	1.9	1.9	1.9	1.9	2.0	2.0	2.0	1.9	2.0	2.0	1.9	1.9	2.0
Europe	14.9	14.1	14.6	14.9	15.0	14.3	14.7	15.0	15.1	14.3	15.0	15.3	14.6	14.7	14.9
Japan	6.2	5.0	5.2	5.6	6.2	5.0	5.3	5.6	6.2	5.1	5.2	5.8	5.5	5.5	5.6
Australia and New Zealand	0.9	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0
Total OECD	42.5	40.8	42.1	42.5	43.4	41.3	42.6	43.4	44.2	41.9	43.1	44.4	42.0	42.7	43.4
Non-OECD															
Former Soviet Union	4.5	4.1	4.1	4.5	4.5	4.0	4.0	4.4	4.5	4.1	4.1	4.4	4.3	4.2	4.3
Europe	1.6	1.4	1.4	1.5	1.7	1.5	1.5	1.6	1.8	1.5	1.5	1.7	1.5	1.6	1.6
China	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.0	4.2	4.4
Other Asia	8.9	8.6	8.4	9.6	9.0	8.8	8.5	9.7	9.4	9.1	8.9	10.0	8.9	9.0	9.4
Other Non-OECD	13.0	13.3	13.1	13.4	13.2	13.5	13.3	13.5	13.5	13.8	13.6	13.8	13.2	13.4	13.7
Total Non-OECD	32.0	31.4	31.0	33.0	32.5	31.9	31.5	33.5	33.4	32.9	32.5	34.5	31.9	32.4	33.3
Total World Demand	74.4	72.2	73.1	75.6	75.9	73.2	74.1	77.0	77.6	74.8	75.6	78.8	73.8	75.1	76.7
Supply [b]															
OECD															
U.S. (50 States)	9.5	9.4	9.0	9.1	8.9	8.8	8.8	8.8	8.7	8.7	8.7	8.7	9.2	8.8	8.7
Canada	2.7	2.6	2.8	2.7	2.8	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.7	2.8	2.8
North Sea [c]	6.4	6.2	5.9	6.3	6.3	6.1	6.2	6.7	6.8	6.5	6.7	7.0	6.2	6.3	6.7
Other OECD	1.6	1.6	1.6	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.6	1.6	1.6
Total OECD	20.1	19.8	19.3	19.5	19.4	19.1	19.3	19.9	19.9	19.7	19.8	20.2	19.7	19.5	19.9
Non-OECD															
OPEC	30.9	30.7	30.0	29.9	30.2	28.9	29.1	29.5	29.9	30.3	30.7	31.1	30.4	29.4	30.5
Former Soviet Union	7.3	7.2	7.2	7.3	7.3	7.2	7.3	7.4	7.4	7.3	7.3	7.4	7.2	7.3	7.3
China	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.3
Mexico	3.6	3.6	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.6
Other Non-OECD	10.7	10.8	10.8	11.0	10.9	11.0	11.1	11.3	11.3	11.3	11.4	11.4	10.8	11.1	11.4
Total Non-OECD	55.7	55.4	54.7	54.8	55.1	53.7	54.2	54.9	55.4	55.7	56.2	56.9	55.1	54.5	56.0
Total World Supply	75.8	75.2	74.0	74.4	74.5	72.9	73.5	74.8	75.3	75.3	76.0	77.0	74.8	73.9	75.9
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	-0.3	-0.7	0.0	0.1	0.4	-0.4	-0.3	0.5	0.7	-0.5	-0.3	0.5	-0.2	0.1	0.1
Other	-1.0	-2.2	-0.9	1.1	1.0	0.8	0.9	1.6	1.6	0.0	-0.2	1.3	-0.7	1.1	0.7
Total Stock Withdrawals	-1.4	-3.0	-0.8	1.2	1.4	0.4	0.6	2.2	2.3	-0.5	-0.5	1.8	-1.0	1.1	0.8
OECD Comm. Stocks, End (bill. bbls.)	2.7	2.9	2.9	2.9	2.8	2.8	2.8	2.7	2.6	2.6	2.7	2.6	2.9	2.7	2.6
Non-OPEC Supply	44.9	44.5	44.0	44.5	44.3	43.9	44.4	45.3	45.4	45.0	45.4	45.9	44.5	44.5	45.4
Net Exports from Former Soviet Union	2.7	3.1	3.1	2.8	2.8	3.2	3.2	3.0	2.8	3.2	3.2	3.0	3.0	3.0	3.1

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

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

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

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

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

SPR: Strategic Petroleum Reserve

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

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

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

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

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Imported Crude Oil [a]															
(dollars per barrel)	13.45	12.40	11.87	10.86	10.64	14.51	13.83	14.99	15.58	16.25	16.33	16.75	12.13	13.55	16.24
Natural Gas Wellhead															
(dollars per thousand cubic feet)	2.02	2.07	1.92	1.88	1.78	1.74	1.80	2.16	2.31	2.02	1.99	2.30	1.97	1.87	2.16
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	1.10	1.10	1.07	1.03	1.00	1.19	1.15	1.13	1.15	1.21	1.21	1.19	1.07	1.12	1.19
Regular Unleaded	1.05	1.05	1.03	0.99	0.95	1.16	1.11	1.09	1.11	1.18	1.18	1.15	1.03	1.08	1.15
No. 2 Diesel Oil, Retail															
(dollars per gallon)	1.08	1.05	1.02	1.00	0.97	1.06	1.05	1.11	1.12	1.13	1.13	1.17	1.04	1.05	1.14
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	0.47	0.43	0.39	0.38	0.36	0.46	0.46	0.52	0.54	0.55	0.55	0.59	0.42	0.45	0.56
No. 2 Heating Oil, Retail															
(dollars per gallon)	0.91	0.85	0.77	0.79	0.80	0.84	0.83	0.91	0.96	0.95	0.90	0.98	0.85	0.84	0.96
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	13.58	13.27	12.32	11.78	11.39	13.27	12.73	14.77	15.90	15.12	14.81	16.04	12.74	13.04	15.49
Electric Utility Fuels															
Coal															
(dollars per million Btu)	1.26	1.26	1.25	1.23	1.24	1.26	1.24	1.23	1.23	1.25	1.22	1.21	1.25	1.24	1.23
Heavy Fuel Oil [d]															
(dollars per million Btu)	2.12	2.17	2.07	1.95	1.78	2.17	2.09	2.46	2.48	2.46	2.42	2.67	2.08	2.10	2.50
Natural Gas															
(dollars per million Btu)	2.61	2.46	2.28	2.31	2.35	2.21	2.25	2.67	2.95	2.55	2.49	2.85	2.38	2.34	2.65
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	6.39	7.33	8.90	6.67	6.67	7.07	8.67	6.64	6.85	7.63	8.97	7.28	6.83	6.86	7.23
Electricity															
(cents per kilowatthour)	7.93	8.42	8.54	8.09	7.68	8.25	8.51	8.03	7.47	8.08	8.34	7.86	8.26	8.13	7.94

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] Average self-service cash prices.

[c] Average for all sulfur contents.

[d] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the first quarter of 1999. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

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

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

(Million Barrels per Day, Except Closing Stocks)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Crude Oil Supply															
Domestic Production [a]	6.45	6.37	6.10	6.05	5.93	5.81	5.78	5.84	5.74	5.71	5.67	5.66	6.24	5.84	5.69
Alaska	1.23	1.17	1.13	1.18	1.16	1.10	1.06	1.10	1.02	1.02	1.01	1.01	1.17	1.10	1.01
Lower 48	5.23	5.20	4.98	4.88	4.77	4.71	4.72	4.75	4.72	4.69	4.66	4.65	5.07	4.74	4.68
Net Imports (including SPR) [b]	8.12	8.89	9.05	8.43	8.39	9.26	9.71	9.13	8.71	9.58	9.83	9.22	8.63	9.12	9.33
Other SPR Supply	0.00	0.00	0.00	0.00	0.00	0.03	0.08	0.10	0.00	0.00	0.00	0.00	0.00	0.05	0.00
SPR Stock Withdrawn or Added (-)	0.00	0.00	0.00	-0.09	-0.01	-0.05	-0.16	-0.08	0.00	0.00	0.00	0.00	-0.02	-0.07	0.00
Other Stock Withdrawn or Added (-)	-0.35	0.04	0.25	-0.15	-0.23	0.06	0.13	0.03	0.06	-0.04	0.05	0.02	-0.05	0.00	0.02
Product Supplied and Losses	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	-0.01	-0.01
Unaccounted-for Crude Oil	0.10	-0.15	-0.06	0.28	0.36	0.23	0.23	0.23	0.22	0.23	0.24	0.23	0.04	0.26	0.23
Total Crude Oil Supply	14.33	15.24	15.38	14.53	14.43	15.28	15.61	15.04	14.72	15.47	15.78	15.12	14.87	15.09	15.27
Other Supply															
NGL Production	1.85	1.80	1.67	1.70	1.70	1.75	1.75	1.76	1.77	1.77	1.77	1.77	1.75	1.74	1.77
Other Hydrocarbon and Alcohol Inputs	0.34	0.36	0.38	0.39	0.36	0.34	0.34	0.37	0.36	0.35	0.36	0.38	0.37	0.35	0.36
Crude Oil Product Supplied	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01
Processing Gain	0.83	0.84	0.89	0.94	0.86	0.87	0.90	0.87	0.86	0.89	0.91	0.87	0.88	0.88	0.88
Net Product Imports [c]	0.97	1.13	1.06	1.09	1.06	1.08	1.11	1.09	1.16	1.26	1.22	1.28	1.06	1.09	1.23
Product Stock Withdrawn or Added (-) [d]	0.03	-0.75	-0.24	0.29	0.65	-0.40	-0.31	0.48	0.64	-0.49	-0.37	0.46	-0.17	0.10	0.06
Total Supply	18.36	18.62	19.13	18.94	19.09	18.91	19.41	19.62	19.51	19.26	19.66	19.89	18.77	19.26	19.58
Demand															
Motor Gasoline	7.78	8.32	8.51	8.32	8.05	8.52	8.65	8.52	8.23	8.69	8.79	8.66	8.24	8.44	8.59
Jet Fuel	1.57	1.57	1.58	1.65	1.67	1.57	1.62	1.65	1.64	1.59	1.65	1.68	1.59	1.63	1.64
Distillate Fuel Oil	3.59	3.40	3.41	3.43	3.71	3.47	3.41	3.65	3.89	3.49	3.44	3.69	3.46	3.56	3.63
Residual Fuel Oil	0.82	0.83	0.92	0.76	0.88	0.77	0.86	0.87	1.01	0.82	0.84	0.86	0.83	0.85	0.88
Other Oils [e]	4.62	4.49	4.71	4.78	4.77	4.58	4.87	4.94	4.74	4.67	4.93	5.01	4.65	4.79	4.84
Total Demand	18.38	18.62	19.13	18.94	19.08	18.91	19.41	19.62	19.51	19.26	19.66	19.89	18.77	19.26	19.58
Total Petroleum Net Imports	9.10	10.02	10.11	9.52	9.46	10.34	10.82	10.22	9.86	10.85	11.04	10.50	9.69	10.21	10.56
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	336	333	310	323	344	339	327	324	319	323	318	316	323	324	316
Total Motor Gasoline	215	221	207	216	215	213	208	208	210	207	204	203	216	208	203
Finished Motor Gasoline	166	178	165	172	168	169	164	165	166	165	162	162	172	165	162
Blending Components	49	44	43	44	48	44	44	44	44	41	42	41	44	44	41
Jet Fuel	43	44	46	45	43	44	47	46	42	44	46	46	45	46	46
Distillate Fuel Oil	124	139	153	156	122	126	142	145	105	115	134	140	156	145	140
Residual Fuel Oil	41	40	40	44	38	40	39	42	33	37	38	42	44	42	42
Other Oils [e]	265	313	334	292	275	308	323	274	266	298	313	262	292	274	262
Total Stocks (excluding SPR)	1025	1090	1089	1076	1038	1069	1085	1038	975	1024	1054	1009	1076	1038	1009
Crude Oil in SPR	563	563	563	571	572	577	591	599	599	599	599	599	571	599	599
Total Stocks (including SPR)	1588	1654	1653	1647	1610	1645	1676	1637	1574	1622	1652	1608	1647	1637	1608

[a] Includes lease condensate.

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

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

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

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

SPR: Strategic Petroleum Reserve

NGL: Natural Gas Liquids

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

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

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

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

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

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

	High Price Case	Low Price Case	Difference		
			Total	Uncertainty	Price Impact
United States	*6.11*	*5.37*	*0.74*	*0.09*	*0.66*
Lower 48 States	*5.09*	*4.37*	*0.72*	*0.07*	*0.64*
Alaska	*1.02*	*1.00*	*0.03*	*0.01*	*0.01*

Note: Components provided are for the fourth quarter 2000. Totals may not add to sum of components due to independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, Reserves and Natural Gas Division.

Table 8. U.S. Natural Gas Supply and Demand: Mid world Oil Price Case

(Trillion cubic Feet)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Total Dry Gas Production	**4.72**	**4.72**	**4.74**	**4.76**	*4.69*	*4.69*	*4.71*	*4.73*	*4.76*	*4.71*	*4.73*	*4.75*	**18.93**	*18.83*	*18.95*
Net Imports	**0.75**	**0.71**	**0.75**	**0.76**	*0.74*	*0.72*	*0.74*	*0.80*	*0.82*	*0.79*	*0.79*	*0.86*	**2.97**	*3.00*	*3.26*
Supplemental Gaseous Fuels	**0.03**	**0.02**	**0.03**	**0.03**	*0.04*	*0.03*	*0.03*	*0.03*	*0.04*	*0.03*	*0.03*	*0.03*	**0.12**	*0.13*	*0.13*
Total New Supply	**5.50**	**5.45**	**5.51**	**5.55**	*5.47*	*5.44*	*5.48*	*5.57*	*5.62*	*5.52*	*5.55*	*5.64*	**22.01**	*21.96*	*22.33*
Underground Working Gas Storage															
Opening	**6.52**	**5.52**	**6.44**	**7.28**	*7.04*	*5.68*	*6.47*	*7.31*	*6.80*	*5.35*	*6.18*	*7.10*	**6.52**	*7.04*	*6.80*
Closing	**5.52**	**6.44**	**7.28**	**7.04**	*5.68*	*6.47*	*7.31*	*6.80*	*5.35*	*6.18*	*7.10*	*6.68*	**7.04**	*6.80*	*6.68*
Net Withdrawals	**1.00**	**-0.92**	**-0.84**	**0.24**	*1.36*	*-0.79*	*-0.84*	*0.50*	*1.45*	*-0.83*	*-0.92*	*0.42*	**-0.52**	*0.24*	*0.12*
Total Supply	**6.49**	**4.53**	**4.67**	**5.79**	*6.83*	*4.65*	*4.64*	*6.07*	*7.07*	*4.69*	*4.63*	*6.06*	**21.49**	*22.20*	*22.46*
Balancing Item [a]	**0.16**	**0.18**	**-0.06**	**-0.45**	*0.02*	*0.22*	*-0.12*	*-0.40*	*0.29*	*0.22*	*-0.10*	*-0.39*	**-0.17**	*-0.28*	*0.01*
Total Primary Supply	**6.65**	**4.71**	**4.62**	**5.34**	*6.85*	*4.87*	*4.52*	*5.67*	*7.36*	*4.91*	*4.53*	*5.67*	**21.32**	*21.92*	*22.47*
Demand															
Lease and Plant Fuel	**0.31**	**0.31**	**0.31**	**0.31**	*0.31*	*0.31*	*0.31*	*0.32*	*0.31*	*0.31*	*0.31*	*0.32*	**1.25**	*1.25*	*1.25*
Pipeline Use	**0.23**	**0.16**	**0.16**	**0.18**	*0.23*	*0.16*	*0.15*	*0.19*	*0.23*	*0.16*	*0.15*	*0.19*	**0.73**	*0.73*	*0.74*
Residential	**2.13**	**0.78**	**0.37**	**1.20**	*2.25*	*0.80*	*0.32*	*1.38*	*2.48*	*0.81*	*0.32*	*1.40*	**4.48**	*4.75*	*5.01*
Commercial	**1.21**	**0.58**	**0.45**	**0.81**	*1.28*	*0.64*	*0.46*	*0.91*	*1.45*	*0.65*	*0.46*	*0.92*	**3.05**	*3.29*	*3.48*
Industrial (Incl. Cogenerators)	**2.23**	**1.98**	**2.00**	**2.16**	*2.21*	*2.00*	*1.97*	*2.16*	*2.27*	*2.00*	*1.95*	*2.13*	**8.37**	*8.34*	*8.34*
Cogenerators	**0.51**	**0.49**	**0.54**	**0.60**	*0.53*	*0.50*	*0.55*	*0.61*	*0.54*	*0.51*	*0.56*	*0.63*	**2.14**	*2.19*	*2.23*
Electricity Production															
Electric Utilities	**0.50**	**0.86**	**1.29**	**0.61**	*0.53*	*0.91*	*1.26*	*0.66*	*0.57*	*0.93*	*1.29*	*0.66*	**3.26**	*3.36*	*3.45*
Nonutilities (Excl. Cogen.) [b]	**0.04**	**0.04**	**0.05**	**0.05**	*0.04*	*0.04*	*0.05*	*0.05*	*0.05*	*0.04*	*0.05*	*0.05*	**0.18**	*0.18*	*0.19*
Total Demand	**6.65**	**4.71**	**4.62**	**5.34**	*6.85*	*4.87*	*4.52*	*5.67*	*7.36*	*4.91*	*4.53*	*5.67*	**21.32**	*21.92*	*22.47*

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

[b]Quarterly estimates and projections for gas consumption by nonutility generators are based on estimates for quarterly gas-fired generation at nonutilities, supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867 (Annual Nonutility Power Producer Report). Annual projections for nonutility gas consumption, as well as the detail on independent power producers' share of gas consumption, are provided by CNEAF.

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

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

Table 9. U.S. Coal Supply and Demand: Mid World Oil Price Case

(Million Short Tons)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Production	281.6	275.4	279.1	282.6	272.4	279.5	285.0	286.6	299.9	280.4	280.9	291.4	1118.7	1123.6	1152.7
Appalachia	119.5	114.0	113.2	113.6	114.5	118.8	111.5	118.1	124.4	117.0	107.7	118.1	460.4	463.0	467.2
Interior	43.1	42.4	41.5	41.4	38.3	39.0	40.7	41.5	40.4	37.4	38.2	40.3	168.4	159.5	156.2
Western	119.0	119.0	124.4	127.6	119.6	121.7	132.8	127.1	135.2	126.0	135.0	133.0	489.9	501.2	529.2
Primary Stock Levels [a]															
Opening	34.0	41.0	38.3	34.2	34.1	42.4	41.4	39.0	36.6	42.7	43.0	32.9	34.0	34.1	36.6
Closing	41.0	38.3	34.2	34.1	42.4	41.4	39.0	36.6	42.7	43.0	32.9	32.6	34.1	36.6	32.6
Net Withdrawals	-7.0	2.7	4.2	(S)	-8.2	1.0	2.4	2.4	-6.0	-0.3	10.1	0.3	-0.2	-2.5	4.1
Imports	1.8	2.2	2.1	2.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	8.7	8.9	9.0
Exports	18.3	20.5	19.7	18.6	16.7	18.8	19.0	19.0	17.8	18.1	18.3	18.2	77.2	73.4	72.5
Total Net Domestic Supply	258.1	259.8	265.7	266.5	249.7	263.9	270.6	272.2	278.3	264.2	274.9	275.8	1050.0	1056.6	1093.3
Secondary Stock Levels [b]															
Opening	101.4	114.1	124.7	111.5	129.0	119.3	132.9	119.1	120.7	120.5	125.5	111.4	101.4	129.0	120.7
Closing	114.1	124.7	111.5	129.0	119.3	132.9	119.1	120.7	120.5	125.5	111.4	112.5	129.0	120.7	112.5
Net Withdrawals	-12.7	-10.6	13.3	-17.5	9.7	-13.7	13.8	-1.6	0.2	-5.1	14.1	-1.0	-27.6	8.3	8.2
Waste Coal Supplied to IPPs [c]	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	9.6	10.1	10.6
Total Supply	247.8	251.5	281.4	251.4	261.9	252.8	287.0	273.2	281.1	261.8	291.7	277.4	1032.1	1074.9	1112.1
Demand															
Coke Plants	7.3	7.2	7.3	6.7	7.3	6.9	6.9	7.3	7.3	7.1	7.0	7.3	28.5	28.4	28.8
Electricity Production															
Electric Utilities	220.5	218.7	252.8	220.0	225.0	218.5	252.3	235.4	243.3	227.0	256.6	239.3	912.1	931.1	966.1
Nonutilities (Excl. Cogen.) [d]	6.4	6.5	7.8	8.8	9.4	9.2	9.6	9.7	9.8	9.7	10.0	10.1	29.5	37.9	39.6
Retail and General Industry [e]	20.1	18.3	18.1	19.8	20.3	18.2	18.2	20.9	20.7	18.1	18.1	20.8	76.3	77.6	77.6
Total Demand	254.3	250.8	285.9	255.3	261.9	252.8	287.0	273.2	281.1	261.8	291.7	277.4	1046.3	1074.9	1112.1
Discrepancy [f]	-6.5	0.8	-4.6	-3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-14.2	0.0	0.0

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

[b] Secondary stocks are held by users.

[c] Estimated independent power producers (IPPs) consumption of waste coal for 1994 is 7.9 million tons, 8.5 million tons in 1995, and 8.8 million tons in 1996.

[d] Consumption of coal by IPPs. In 1995, IPP consumption was estimated to be 5.290 million tons per quarter. Quarterly estimates and projections for coal consumption by nonutility generators are based on estimates for annual coal-fired generation at nonutilities, supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867 (Annual Nonutility Power Producer Report). Data for first quarter 1999 are estimates.

[e] Synfuels plant demand in 1993 was 1.7 million tons per quarter and is assumed to remain at that level in 1994, 1995, 1996, 1997 and 1998.

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

(S) indicates amounts of less than 50,000 tons in absolute value.

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

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

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

(Billion Kilowatthours)

	1998				1999				2000				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1998	1999	2000
Supply															
Net Utility Generation															
Coal	**437.0**	**434.9**	**501.3**	**434.9**	*447.3*	*435.5*	*500.8*	*467.8*	*487.3*	*453.9*	*509.4*	*475.6*	**1808.1**	*1851.5*	*1926.1*
Petroleum	**20.9**	**28.5**	**37.3**	**23.8**	*31.5*	*23.9*	*33.6*	*26.0*	*31.4*	*26.0*	*31.7*	*25.5*	**110.5**	*115.1*	*114.6*
Natural Gas	**47.9**	**80.7**	**120.8**	**59.4**	*50.6*	*86.8*	*120.8*	*62.9*	*54.3*	*88.8*	*123.7*	*63.2*	**308.9**	*321.0*	*329.9*
Nuclear	**162.6**	**154.7**	**179.1**	**177.3**	*174.8*	*168.3*	*181.2*	*163.4*	*172.9*	*157.0*	*184.3*	*165.5*	**673.7**	*687.7*	*679.7*
Hydroelectric	**86.7**	**88.6**	**69.7**	**60.3**	*76.5*	*77.9*	*65.6*	*64.0*	*74.9*	*77.2*	*64.5*	*63.7*	**305.3**	*284.0*	*280.3*
Geothermal and Other [a]	**1.9**	**1.4**	**1.9**	**2.0**	*1.6*	*1.5*	*2.0*	*2.1*	*1.7*	*1.5*	*2.0*	*2.1*	**7.2**	*7.2*	*7.2*
Subtotal	**757.0**	**789.0**	**910.0**	**757.6**	*782.3*	*794.0*	*904.0*	*786.2*	*822.5*	*804.2*	*915.5*	*795.6*	**3213.6**	*3266.6*	*3337.8*
Nonutility Generation [b]															
Coal	**14.9**	**14.3**	**15.5**	**17.4**	*15.1*	*14.4*	*15.7*	*17.6*	*15.3*	*14.6*	*15.9*	*17.8*	**62.0**	*62.8*	*63.7*
Petroleum	**3.9**	**3.8**	**4.1**	**4.6**	*4.0*	*3.9*	*4.2*	*4.7*	*4.1*	*4.0*	*4.3*	*4.8*	**16.4**	*16.8*	*17.2*
Natural Gas	**49.8**	**47.7**	**51.9**	**58.1**	*50.9*	*48.7*	*53.0*	*59.4*	*51.9*	*49.8*	*54.1*	*60.6*	**207.6**	*212.0*	*216.5*
Other Gaseous Fuels [c]	**3.0**	**2.9**	**3.1**	**3.5**	*2.9*	*2.8*	*3.1*	*3.4*	*2.9*	*2.7*	*3.0*	*3.3*	**12.5**	*12.2*	*11.9*
Hydroelectric	**4.2**	**4.0**	**4.3**	**4.9**	*4.3*	*4.1*	*4.5*	*5.0*	*4.5*	*4.3*	*4.7*	*5.2*	**17.4**	*18.0*	*18.7*
Geothermal and Other [d]	**17.9**	**17.1**	**18.6**	**20.8**	*17.8*	*17.0*	*18.5*	*20.8*	*17.7*	*17.0*	*18.5*	*20.7*	**74.4**	*74.1*	*73.9*
Subtotal	**93.6**	**89.7**	**97.6**	**109.3**	*95.0*	*91.0*	*99.1*	*110.9*	*96.4*	*92.4*	*100.5*	*112.6*	**390.3**	*396.0*	*401.9*
Total Generation	**850.6**	**878.7**	**1007.7**	**866.9**	*877.3*	*885.0*	*1003.1*	*897.1*	*918.9*	*896.6*	*1016.1*	*908.1*	**3604.0**	*3662.6*	*3739.7*
Net Imports [e]	**5.8**	**6.9**	**10.9**	**5.2**	*6.8*	*7.9*	*11.2*	*7.8*	*7.1*	*8.4*	*11.3*	*8.1*	**28.8**	*33.7*	*34.8*
Total Supply	**856.4**	**885.6**	**1018.6**	**872.1**	*884.1*	*892.9*	*1014.3*	*904.9*	*926.0*	*905.0*	*1027.4*	*916.2*	**3632.7**	*3696.2*	*3774.5*
Losses and Unaccounted for [f]	**48.1**	**75.7**	**57.2**	**50.4**	*46.4*	*73.5*	*64.1*	*64.9*	*48.0*	*74.5*	*65.0*	*65.7*	**231.4**	*248.8*	*253.2*
Demand															
Electric Utility Sales															
Residential	**275.8**	**250.7**	**347.9**	**257.2**	*289.2*	*254.0*	*330.5*	*265.6*	*311.5*	*260.6*	*338.3*	*271.1*	**1131.5**	*1139.3*	*1181.7*
Commercial	**217.4**	**230.9**	**271.7**	**230.5**	*228.7*	*235.5*	*273.2*	*236.1*	*239.0*	*237.5*	*274.9*	*237.6*	**950.5**	*973.4*	*989.1*
Industrial	**252.2**	**266.3**	**273.8**	**263.1**	*254.6*	*266.8*	*277.3*	*266.2*	*260.7*	*268.2*	*279.0*	*268.4*	**1055.5**	*1064.9*	*1076.3*
Other	**23.7**	**24.3**	**27.1**	**25.2**	*25.5*	*25.0*	*27.6*	*25.7*	*26.3*	*25.4*	*28.1*	*26.2*	**100.3**	*103.9*	*105.9*
Subtotal	**769.1**	**772.3**	**920.5**	**775.9**	*798.0*	*781.3*	*908.7*	*793.6*	*837.5*	*791.8*	*920.3*	*803.3*	**3237.7**	*3281.5*	*3352.9*
Nonutility Gener. for Own Use [b]	**39.2**	**37.6**	**40.9**	**45.8**	*39.8*	*38.1*	*41.5*	*46.5*	*40.4*	*38.7*	*42.1*	*47.2*	**163.6**	*166.0*	*168.5*
Total Demand	**808.3**	**809.9**	**961.4**	**821.7**	*837.8*	*819.5*	*950.2*	*840.1*	*878.0*	*830.5*	*962.4*	*850.5*	**3401.3**	*3447.5*	*3521.4*
Memo:															
Nonutility Sales to Electric Utilities [b]	**54.4**	**52.1**	**56.7**	**63.5**	*55.2*	*52.9*	*57.5*	*64.4*	*56.0*	*53.7*	*58.4*	*65.4*	**226.7**	*230.1*	*233.4*

[a] "Other" includes generation from wind, wood, waste, and solar sources.

[b] Electricity from nonutility sources, including cogenerators and small power producers. Quarterly estimates and projections for nonutility net sales, own use, and generation by fuel source supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867, "Annual Nonutility Power Producer Report."

[c] Includes refinery still gas and other process or waste gases, and liquefied petroleum gases.

[d] Includes geothermal, solar, wind, wood, waste, nuclear, hydrogen, sulfur, batteries, chemicals and spent sulfite liquor.

[e] Data for 1998 are estimates.

[f] Balancing item, mainly transmission and distribution losses.

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

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

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

	Year				Annual Percentage Change		
	1997	1998	1999	2000	1997-1998	1998-1999	1999-2000
Electric Utilities							
Hydroelectric Power [a]	**3.530**	**3.196**	*2.973*	*2.934*	**-9.5**	*-7.0*	*-1.3*
Geothermal, Solar and Wind Energy [b]	**0.115**	**0.109**	*0.109*	*0.109*	**-5.2**	*0.0*	*0.0*
Biofuels [c]	**0.021**	**0.021**	*0.021*	*0.021*	**0.0**	*0.0*	*0.0*
Total	**3.665**	**3.325**	*3.103*	*3.063*	**-9.3**	*-6.7*	*-1.3*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.185**	**0.179**	*0.186*	*0.193*	**-3.2**	*3.9*	*3.8*
Geothermal, Solar and Wind Energy [b]	**0.235**	**0.253**	*0.254*	*0.255*	**7.7**	*0.4*	*0.4*
Biofuels [c]	**0.578**	**0.585**	*0.582*	*0.579*	**1.2**	*-0.5*	*-0.5*
Total	**0.998**	**1.018**	*1.022*	*1.027*	**2.0**	*0.4*	*0.5*
Total Power Generation	**4.663**	**4.343**	*4.125*	*4.091*	**-6.9**	*-5.0*	*-0.8*
Other Sectors [d]							
Residential and Commercial [e]	**0.553**	**0.568**	*0.574*	*0.583*	**2.7**	*1.1*	*1.6*
Industrial [f]	**1.498**	**1.515**	*1.542*	*1.569*	**1.1**	*1.8*	*1.8*
Transportation [g]	**0.087**	**0.094**	*0.093*	*0.094*	**8.0**	*-1.1*	*1.1*
Total	**2.138**	**2.178**	*2.209*	*2.246*	**1.9**	*1.4*	*1.7*
Net Imported Electricity [h]	**0.297**	**0.234**	*0.274*	*0.283*	**-21.2**	*17.1*	*3.3*
Total Renewable Energy Demand	**7.098**	**6.755**	*6.608*	*6.620*	**-4.8**	*-2.2*	*0.2*

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

[b] Also includes photovoltaic and solar thermal energy.

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

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

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

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

[g] Ethanol blended into gasoline.

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

(S) Less than 500 billion Btu.

NM indicates percent change calculations are not meaningful or undefined at the precision level of this table.

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

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

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Real Gross Domestic Product (GDP)															
(billion chained 1992 dollars).........................	5488	5649	5865	6062	6136	6079	6244	6390	6611	6762	6995	7270	7552	*7825*	*7960*
Imported Crude Oil Price [a]															
(nominal dollars per barrel)............................	14.00	18.13	14.57	18.08	21.75	18.70	18.20	16.14	15.52	17.14	20.61	18.50	12.13	*13.55*	*16.24*
Petroleum Supply															
Crude Oil Production [b]															
(million barrels per day).................................	8.68	8.35	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.45	6.24	*5.84*	*5.69*
Total Petroleum Net Imports (including SPR)															
(million barrels per day).................................	5.44	5.91	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	9.16	9.69	*10.21*	*10.56*
Energy Demand															
World Petroleum															
(million barrels per day).................................	61.8	63.1	64.9	65.9	66.0	66.6	66.8	67.0	68.3	69.9	71.3	73.0	73.8	75.1	76.7
U.S. Petroleum															
(million barrels per day).................................	16.33	16.72	17.34	17.37	17.04	16.77	17.10	17.24	17.72	17.72	18.31	18.62	18.77	*19.26*	*19.58*
Natural Gas															
(trillion cubic feet)..	16.22	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.97	21.32	*21.92*	*22.47*
Coal															
(million short tons)..	797	830	877	891	897	898	907	944	951	962	1006	1029	1046	*1068*	*1105*
Electricity (billion kilowatthours)															
Utility Sales [c]	2369	2457	2578	2647	2713	2762	2763	2861	2935	3013	3098	3140	3238	*3282*	*3353*
Nonutility Own Use [d]	NA	NA	NA	97	113	122	137	138	150	158	158	161	164	*166*	*168*
Total...	2369	2457	2578	2744	2826	2884	2901	2999	3085	3171	3256	3301	3401	*3447*	*3521*
Total Energy Demand [e]															
(quadrillion Btu)	NA	NA	NA	NA	84.2	84.3	85.6	87.4	89.3	90.9	93.9	94.3	94.4	*96.4*	*98.4*
Total Energy Demand per Dollar of GDP															
(thousand Btu per 1992 Dollar).....................	NA	NA	NA	NA	13.72	13.86	13.71	13.68	13.50	13.45	13.43	12.97	12.50	*12.32*	*12.36*

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

[b] Includes lease condensate.

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

[d] Defined as the difference between total nonutility electricity generation and sales to electric utilities by nonutility generators, reported on Form EIA-867, "Annual Nonutility Power Producer Report." Data for 1998 are estimates.

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

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

Sources: Historical data: Latest data available from Bureau of Economic Analysis; Energy Information Administration; latest data available from EIA databases supporting the following reports: *Petroleum Supply Monthly*, DOE/EIA-0109; *Petroleum Supply Annual*, DOE/EIA-0340/2; *Natural Gas Monthly*, DOE/EIA-0130; *Electric Power Monthly*, DOE/EIA-0226; and *Quarterly Coal Report*, DOE/EIA-0121; *International Petroleum Statistics Report* DOE/EIA-520; Weekly Petroleum *Status Report* DOE/EIA-0208. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

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

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Macroeconomic															
Real Gross Domestic Product (billion chained 1992 dollars)	**5488**	**5649**	**5865**	**6062**	**6136**	**6079**	**6244**	**6390**	**6611**	**6762**	**6995**	**7270**	**7552**	*7825*	*7960*
GDP Implicit Price Deflator (Index, 1992=1.000)	**0.806**	**0.831**	**0.861**	**0.897**	**0.936**	**0.973**	**1.000**	**1.026**	**1.051**	**1.075**	**1.095**	**1.116**	**1.127**	*1.139*	*1.153*
Real Disposable Personal Income (billion chained 1992 Dollars)	**4077**	**4155**	**4325**	**4412**	**4490**	**4484**	**4605**	**4667**	**4773**	**4906**	**5043**	**5183**	**5348**	*5538*	*5688*
Manufacturing Production (Index, 1987=1.000)	**0.881**	**0.928**	**0.971**	**0.990**	**0.985**	**0.962**	**1.000**	**1.037**	**1.099**	**1.159**	**1.214**	**1.296**	**1.349**	*1.387*	*1.412*
Real Fixed Investment (billion chained 1992 dollars)	**805**	**799**	**818**	**832**	**806**	**741**	**783**	**843**	**916**	**966**	**1051**	**1138**	**1269**	*1362*	*1379*
Real Exchange Rate (Index, 1990=1.000)	**NA**	**NA**	**NA**	**NA**	**0.999**	**1.007**	**1.013**	**1.057**	**1.033**	**0.961**	**1.017**	**1.104**	**1.151**	*1.130*	*1.108*
Business Inventory Change (billion chained 1992 dollars)	**-4.2**	**5.1**	**9.5**	**19.2**	**6.6**	**-6.1**	**-9.2**	**6.1**	**11.1**	**11.2**	**12.0**	**20.1**	**20.0**	*12.6*	*-3.8*
Producer Price Index (index, 1982=1.000)	**1.002**	**1.028**	**1.069**	**1.122**	**1.163**	**1.165**	**1.172**	**1.189**	**1.205**	**1.248**	**1.277**	**1.276**	**1.244**	*1.240*	*1.260*
Consumer Price Index (index, 1982-1984=1.000)	**1.097**	**1.137**	**1.184**	**1.240**	**1.308**	**1.363**	**1.404**	**1.446**	**1.483**	**1.525**	**1.570**	**1.606**	**1.631**	*1.662*	*1.701*
Petroleum Product Price Index (index, 1982=1.000)	**0.532**	**0.568**	**0.539**	**0.612**	**0.748**	**0.671**	**0.647**	**0.620**	**0.591**	**0.608**	**0.701**	**0.680**	**0.515**	*0.541*	*0.603*
Non-Farm Employment (millions)	**99.3**	**102.0**	**105.2**	**107.9**	**109.4**	**108.3**	**108.6**	**110.7**	**114.1**	**117.2**	**119.6**	**122.7**	**125.8**	*128.7*	*130.0*
Commercial Employment (millions)	**62.9**	**65.2**	**67.8**	**70.0**	**71.3**	**70.8**	**71.2**	**73.2**	**76.1**	**78.8**	**81.1**	**83.9**	**86.7**	*89.6*	*90.9*
Total Industrial Production (index, 1987=1.000)	**0.890**	**0.931**	**0.974**	**0.991**	**0.990**	**0.970**	**1.000**	**1.034**	**1.091**	**1.144**	**1.196**	**1.267**	**1.314**	*1.346*	*1.370*
Housing Stock (millions)	**98.0**	**99.8**	**101.6**	**102.9**	**103.5**	**104.5**	**105.5**	**106.8**	**108.2**	**109.6**	**111.0**	**112.5**	**114.2**	*115.7*	*117.0*
Weather [a]															
Heating Degree-Days															
U.S.	**4295**	**4334**	**4653**	**4726**	**4016**	**4200**	**4441**	**4700**	**4483**	**4531**	**4713**	**4542**	**3988**	*4363*	*4603*
New England	**6517**	**6546**	**6715**	**6887**	**5848**	**5960**	**6844**	**6728**	**6672**	**6559**	**6679**	**6662**	**5847**	*6457*	*6660*
Middle Atlantic	**5665**	**5699**	**6088**	**6134**	**4998**	**5177**	**5964**	**5948**	**5934**	**5831**	**5986**	**5809**	**4916**	*5648*	*5875*
U.S. Gas-Weighted	**4442**	**4391**	**4804**	**4856**	**4139**	**4337**	**4458**	**4754**	**4659**	**4707**	**5040**	**4886**	**4247**	*4552*	*4760*
Cooling Degree-Days (U.S.)	**1249**	**1269**	**1283**	**1156**	**1260**	**1331**	**1040**	**1218**	**1220**	**1293**	**1180**	**1156**	**1358**	*1191*	*1193*

[a] Population-weighted degree days. A degree day indicates the temperature variation from 65 degrees Fahrenheit (calculated as the simple average of the daily minimum and maximum temperatures) weighted by 1990 population. Normal is used for the forecast period and is defined as the average number of degree days between 1961 and 1990 for a given period.

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

Sources: Historical data: latest data available from: U.S. Department of Commerce, Bureau of Economic Analysis; U.S. Department of Commerce, National Oceanic and Atmospheric Administration; Federal Reserve System, *Statistical Release* G.17(419); U.S. Department of Transportation; American Iron and Steel Institute. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0299.

Table A3. Annual International Petroleum Supply and Demand Balance

(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Demand [a]															
OECD															
U.S. (50 States)	**16.3**	**16.7**	**17.3**	**17.4**	**17.0**	**16.8**	**17.1**	**17.2**	**17.7**	**17.7**	**18.3**	**18.6**	**18.8**	*19.3*	*19.6*
Europe [b]	**12.1**	**12.3**	**12.4**	**12.5**	**12.6**	**13.4**	**13.6**	**13.5**	**13.6**	**14.1**	**14.3**	**14.4**	**14.6**	*14.7*	*14.9*
Japan	**4.4**	**4.5**	**4.8**	**5.0**	**5.1**	**5.3**	**5.4**	**5.4**	**5.7**	**5.7**	**5.9**	**5.7**	**5.5**	*5.5*	*5.6*
Other OECD	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**	**2.7**	**2.7**	**2.8**	**2.9**	**3.0**	**3.0**	**3.1**	**3.1**	*3.2*	*3.3*
Total OECD	**35.3**	**36.0**	**37.1**	**37.6**	**37.5**	**38.1**	**38.8**	**39.0**	**39.9**	**40.6**	**41.4**	**41.8**	**42.0**	*42.7*	*43.4*
Non-OECD															
Former Soviet Union	**9.0**	**9.0**	**8.9**	**8.7**	**8.4**	**8.3**	**6.8**	**5.6**	**4.8**	**4.6**	**4.0**	**4.3**	**4.3**	*4.2*	*4.3*
Europe	**2.2**	**2.2**	**2.2**	**2.1**	**1.9**	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	*1.6*	*1.6*
China	**2.0**	**2.1**	**2.3**	**2.4**	**2.3**	**2.5**	**2.7**	**3.0**	**3.1**	**3.3**	**3.5**	**3.8**	**4.0**	*4.2*	*4.4*
Other Asia	**3.8**	**4.1**	**4.4**	**4.9**	**5.3**	**5.7**	**6.2**	**6.8**	**7.3**	**7.9**	**8.5**	**8.8**	**8.9**	*9.0*	*9.4*
Other Non-OECD	**9.5**	**9.7**	**10.0**	**10.3**	**10.5**	**10.6**	**11.0**	**11.4**	**11.8**	**12.1**	**12.4**	**12.8**	**13.2**	*13.4*	*13.7*
Total Non-OECD	**26.5**	**27.1**	**27.7**	**28.3**	**28.5**	**28.5**	**28.0**	**28.1**	**28.4**	**29.3**	**29.9**	**31.2**	**31.9**	*32.4*	*33.3*
Total World Demand	**61.8**	**63.1**	**64.9**	**66.0**	**66.0**	**66.6**	**66.8**	**67.0**	**68.3**	**69.9**	**71.3**	**73.0**	**73.8**	*75.1*	*76.7*
Supply [c]															
OECD															
U.S. (50 States)	**11.0**	**10.7**	**10.5**	**9.9**	**9.7**	**9.9**	**9.8**	**9.6**	**9.4**	**9.4**	**9.4**	**9.5**	**9.2**	*8.8*	*8.7*
Canada	**1.8**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.1**	**2.2**	**2.3**	**2.4**	**2.5**	**2.6**	**2.7**	*2.8*	*2.8*
North Sea [d]	**3.8**	**3.8**	**3.8**	**3.7**	**3.9**	**4.1**	**4.5**	**4.8**	**5.5**	**5.9**	**6.3**	**6.2**	**6.2**	*6.3*	*6.7*
Other OECD	**1.4**	**1.4**	**1.5**	**1.4**	**1.5**	**1.5**	**1.4**	**1.4**	**1.5**	**1.5**	**1.5**	**1.6**	**1.6**	*1.6*	*1.6*
Total OECD	**17.9**	**17.9**	**17.8**	**17.1**	**17.1**	**17.5**	**17.9**	**18.0**	**18.7**	**19.2**	**19.7**	**19.9**	**19.7**	*19.5*	*19.9*
Non-OECD															
OPEC	**19.3**	**19.6**	**21.5**	**23.3**	**24.5**	**24.6**	**25.8**	**26.6**	**27.0**	**27.6**	**28.3**	**29.9**	**30.4**	*29.4*	*30.5*
Former Soviet Union	**12.3**	**12.5**	**12.5**	**12.1**	**11.4**	**10.4**	**8.9**	**8.0**	**7.3**	**7.1**	**7.1**	**7.1**	**7.2**	*7.3*	*7.3*
China	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.1**	**3.2**	**3.2**	*3.2*	*3.3*
Mexico	**2.8**	**2.9**	**2.9**	**2.9**	**3.0**	**3.2**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.4**	**3.5**	*3.5*	*3.6*
Other Non-OECD	**6.8**	**11.3**	**7.3**	**7.7**	**8.0**	**8.1**	**8.4**	**8.7**	**9.2**	**9.9**	**10.2**	**10.5**	**10.8**	*11.1*	*11.4*
Total Non-OECD	**43.9**	**44.6**	**47.0**	**48.9**	**49.7**	**49.1**	**49.1**	**49.4**	**49.6**	**50.7**	**52.0**	**54.2**	**55.1**	*54.5*	*56.0*
Total World Supply	**61.8**	**62.5**	**64.8**	**65.9**	**66.8**	**66.7**	**67.0**	**67.4**	**68.3**	**69.9**	**71.8**	**74.1**	**74.8**	*73.9*	*75.9*
Total Stock Withdrawals	**0.0**	**0.6**	**0.1**	**0.0**	**-0.8**	**-0.1**	**-0.2**	**-0.3**	**0.1**	**0.0**	**-0.4**	**-1.1**	**-1.0**	*1.1*	*0.8*
OECD Comm. Stocks, End (bill. bbls.)	**2.7**	**2.7**	**2.6**	**2.6**	**2.7**	**2.7**	**2.7**	**2.8**	**2.8**	**2.7**	**2.7**	**2.7**	**2.9**	*2.7*	*2.6*
Net Exports from Former Soviet Union	**3.4**	**3.5**	**3.6**	**3.4**	**3.0**	**2.1**	**2.1**	**2.3**	**2.4**	**2.5**	**3.0**	**2.9**	**3.0**	*3.0*	*3.1*

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

[b] OECD Europe includes the former East Germany.

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

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

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

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

SPR: Strategic Petroleum Reserve

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

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

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

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

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Imported Crude Oil [a]															
(dollars per barrel)	**14.00**	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.50**	**12.13**	*13.55*	*16.24*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**1.94**	**1.66**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.16**	**2.32**	**1.97**	*1.87*	*2.16*
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	**0.88**	**0.91**	**0.92**	**1.02**	**1.17**	**1.15**	**1.14**	**1.13**	**1.13**	**1.16**	**1.25**	**1.24**	**1.07**	*1.12*	*1.19*
Regular Unleaded	**0.88**	**0.91**	**0.91**	**0.99**	**1.13**	**1.10**	**1.09**	**1.07**	**1.08**	**1.11**	**1.20**	**1.20**	**1.03**	*1.08*	*1.15*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	**0.88**	**0.93**	**0.91**	**0.99**	**1.16**	**1.12**	**1.10**	**1.11**	**1.11**	**1.11**	**1.23**	**1.19**	**1.04**	*1.05*	*1.14*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	**0.49**	**0.53**	**0.47**	**0.56**	**0.70**	**0.62**	**0.58**	**0.54**	**0.51**	**0.51**	**0.64**	**0.59**	**0.42**	*0.45*	*0.56*
No. 2 Heating Oil, Retail															
(dollars per gallon)	**0.84**	**0.80**	**0.81**	**0.90**	**1.06**	**1.02**	**0.93**	**0.91**	**0.89**	**0.87**	**0.99**	**0.99**	**0.85**	*0.84*	*0.96*
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	**14.46**	**17.76**	**14.04**	**16.20**	**18.66**	**14.32**	**14.21**	**14.00**	**14.79**	**16.49**	**19.01**	**17.82**	**12.74**	*13.04*	*15.49*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	**1.58**	**1.51**	**1.47**	**1.44**	**1.45**	**1.45**	**1.41**	**1.38**	**1.36**	**1.32**	**1.29**	**1.27**	**1.25**	*1.24*	*1.23*
Heavy Fuel Oil [d]															
(dollars per million Btu)	**2.40**	**2.98**	**2.41**	**2.85**	**3.22**	**2.49**	**2.46**	**2.36**	**2.40**	**2.60**	**3.01**	**2.79**	**2.08**	*2.10*	*2.50*
Natural Gas															
(dollars per million Btu)	**2.35**	**2.24**	**2.26**	**2.36**	**2.32**	**2.15**	**2.33**	**2.56**	**2.23**	**1.98**	**2.64**	**2.76**	**2.38**	*2.34*	*2.65*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	**5.83**	**5.55**	**5.47**	**5.64**	**5.80**	**5.82**	**5.89**	**6.17**	**6.41**	**6.06**	**6.35**	**6.95**	**6.83**	*6.86*	*7.23*
Electricity															
(cents per kilowatthour)	**7.4**	**7.4**	**7.5**	**7.6**	**7.8**	**8.1**	**8.2**	**8.3**	**8.4**	**8.4**	**8.4**	**8.4**	**8.3**	*8.1*	*7.9*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] Average self-service cash prices.

[c] Average for all sulfur contents.

[d] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

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

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

Table A5. Annual U.S. Petroleum Supply and Demand

(Million Barrels per Day, Except Closing Stocks)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Crude Oil Supply															
Domestic Production [a]	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.24**	*5.84*	*5.69*
Alaska	**1.87**	**1.96**	**2.02**	**1.87**	**1.77**	**1.80**	**1.71**	**1.58**	**1.56**	**1.48**	**1.39**	**1.30**	**1.17**	*1.10*	*1.01*
Lower 48	**6.81**	**6.39**	**6.12**	**5.74**	**5.58**	**5.62**	**5.46**	**5.26**	**5.10**	**5.08**	**5.07**	**5.16**	**5.07**	*4.74*	*4.68*
Net Imports (including SPR) [b]	**4.02**	**4.52**	**4.95**	**5.70**	**5.79**	**5.67**	**5.99**	**6.69**	**6.96**	**7.14**	**7.40**	**8.12**	**8.63**	*9.12*	*9.33*
Other SPR Supply	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	*0.05*	*0.00*
Stock Draw (Including SPR)	**-0.08**	**-0.12**	**0.00**	**-0.09**	**0.02**	**-0.01**	**0.01**	**-0.06**	**-0.02**	**0.09**	**0.05**	**-0.06**	**-0.05**	*-0.05*	*0.02*
Product Supplied and Losses	**-0.05**	**-0.03**	**-0.04**	**-0.03**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**0.00**	**0.00**	*-0.01*	*-0.01*
Unaccounted-for Crude Oil	**0.14**	**0.14**	**0.20**	**0.20**	**0.26**	**0.20**	**0.26**	**0.17**	**0.27**	**0.19**	**0.22**	**0.14**	**0.04**	*0.26*	*0.23*
Total Crude Oil Supply	**12.72**	**12.85**	**13.25**	**13.40**	**13.41**	**13.30**	**13.41**	**13.61**	**13.87**	**13.97**	**14.19**	**14.66**	**14.87**	*15.09*	*15.27*
Other Supply															
NGL Production	**1.55**	**1.59**	**1.62**	**1.55**	**1.56**	**1.66**	**1.70**	**1.74**	**1.73**	**1.76**	**1.83**	**1.82**	**1.75**	*1.74*	*1.77*
Other Hydrocarbon and Alcohol Inputs	**0.11**	**0.12**	**0.11**	**0.11**	**0.13**	**0.15**	**0.20**	**0.25**	**0.26**	**0.30**	**0.31**	**0.34**	**0.37**	*0.35*	*0.36*
Crude Oil Product Supplied	**0.05**	**0.03**	**0.04**	**0.03**	**0.02**	**0.02**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.00**	**0.00**	*0.01*	*0.01*
Processing Gain	**0.62**	**0.64**	**0.66**	**0.66**	**0.70**	**0.71**	**0.77**	**0.76**	**0.77**	**0.77**	**0.84**	**0.85**	**0.88**	*0.88*	*0.88*
Net Product Imports [c]	**1.41**	**1.39**	**1.63**	**1.50**	**1.38**	**0.96**	**0.94**	**0.93**	**1.09**	**0.75**	**1.10**	**1.04**	**1.06**	*1.09*	*1.23*
Product Stock Withdrawn	**-0.12**	**0.09**	**0.03**	**0.13**	**-0.14**	**-0.04**	**0.06**	**-0.05**	**0.00**	**0.15**	**0.03**	**-0.09**	**-0.17**	*0.10*	*0.06*
Total Supply	**16.33**	**16.72**	**17.33**	**17.37**	**17.05**	**16.76**	**17.10**	**17.25**	**17.72**	**17.72**	**18.31**	**18.62**	**18.77**	*19.26*	*19.58*
Demand															
Motor Gasoline [d]	**6.94**	**7.19**	**7.36**	**7.40**	**7.31**	**7.23**	**7.38**	**7.48**	**7.60**	**7.79**	**7.89**	**8.02**	**8.24**	*8.44*	*8.59*
Jet Fuel	**1.31**	**1.38**	**1.45**	**1.49**	**1.52**	**1.47**	**1.45**	**1.47**	**1.53**	**1.51**	**1.58**	**1.60**	**1.59**	*1.63*	*1.64*
Distillate Fuel Oil	**2.91**	**2.98**	**3.12**	**3.16**	**3.02**	**2.92**	**2.98**	**3.04**	**3.16**	**3.21**	**3.37**	**3.44**	**3.46**	*3.56*	*3.63*
Residual Fuel Oil	**1.42**	**1.26**	**1.38**	**1.37**	**1.23**	**1.16**	**1.09**	**1.08**	**1.02**	**0.85**	**0.85**	**0.80**	**0.83**	*0.85*	*0.88*
Other Oils [e]	**3.75**	**3.90**	**4.03**	**3.95**	**3.95**	**3.99**	**4.20**	**4.17**	**4.41**	**4.36**	**4.63**	**4.77**	**4.65**	*4.79*	*4.84*
Total Demand	**16.33**	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.77**	*19.26*	*19.58*
Total Petroleum Net Imports	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.69**	*10.21*	*10.56*
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	**331**	**349**	**330**	**341**	**323**	**325**	**318**	**335**	**337**	**303**	**284**	**305**	**323**	*324*	*316*
Total Motor Gasoline	**233**	**226**	**228**	**213**	**220**	**219**	**216**	**226**	**215**	**202**	**195**	**210**	**216**	*208*	*203*
Jet Fuel	**50**	**50**	**44**	**41**	**52**	**49**	**43**	**40**	**47**	**40**	**40**	**44**	**45**	*46*	*46*
Distillate Fuel Oil	**155**	**134**	**124**	**106**	**132**	**144**	**141**	**141**	**145**	**130**	**127**	**138**	**156**	*145*	*140*
Residual Fuel Oil	**47**	**47**	**45**	**44**	**49**	**50**	**43**	**44**	**42**	**37**	**46**	**40**	**44**	*42*	*42*
Other Oils [f]	**265**	**260**	**267**	**257**	**261**	**267**	**263**	**273**	**275**	**258**	**250**	**259**	**292**	*274*	*262*

[a] Includes lease condensate.
[b] Net imports equals gross imports plus SPR imports minus exports.
[c] Includes finished petroleum products, unfinished oils, gasoline blending components, and natural gas plant liquids for processing.
[d] For years prior to 1993, motor gasoline includes an estimate of fuel ethanol blended into gasoline and certain product reclassifications, not reported elsewhere in EIA. See Appendix B in Energy Information Administration, *Short-Term Energy Outlook*, EIA/DOE-0202(93/3Q), for details on this adjustment.
[e] Includes crude oil product supplied, natural gas liquids, liquefied refinery gas, other liquids, and all finished petroleum products except motor gasoline, jet fuel, distillate, and residual fuel oil.
[f] Includes stocks of all other oils, such as aviation gasoline, kerosene, natural gas liquids (including ethane), aviation gasoline blending components, naphtha and other oils for petrochemical feedstock use, special naphthas, lube oils, wax, coke, asphalt, road oil, and miscellaneous oils.

SPR: Strategic Petroleum Reserve. NGL: Natural Gas Liquids

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

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

Table A6. Annual U.S. Natural Gas Supply and Demand

(Trillion Cubic Feet)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Total Dry Gas Production	**16.06**	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.79**	**18.90**	**18.93**	*18.83*	*18.95*
Net Imports	**0.69**	**0.94**	**1.22**	**1.27**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.78**	**2.84**	**2.97**	*3.00*	*3.26*
Supplemental Gaseous Fuels	**0.11**	**0.10**	**0.10**	**0.11**	**0.12**	**0.11**	**0.12**	**0.12**	**0.11**	**0.11**	**0.11**	**0.10**	**0.12**	*0.13*	*0.13*
Total New Supply	**16.86**	**17.66**	**18.42**	**18.69**	**19.38**	**19.45**	**19.88**	**20.42**	**21.39**	**21.40**	**21.69**	**21.84**	**22.01**	*21.96*	*22.33*
Total Underground Storage															
Opening	**6.45**	**6.57**	**6.55**	**6.65**	**6.33**	**6.94**	**6.78**	**6.64**	**6.65**	**6.97**	**6.50**	**6.51**	**6.52**	*7.04*	*6.80*
Closing	**6.57**	**6.55**	**6.65**	**6.33**	**6.94**	**6.78**	**6.64**	**6.65**	**6.97**	**6.50**	**6.51**	**6.52**	**7.04**	*6.80*	*6.68*
Net Withdrawals	**-0.12**	**0.02**	**-0.10**	**0.33**	**-0.61**	**0.16**	**0.14**	**-0.01**	**-0.32**	**0.46**	**-0.01**	**-0.01**	**-0.52**	*0.24*	*0.12*
Total Supply	**16.74**	**17.68**	**18.32**	**19.02**	**18.77**	**19.61**	**20.02**	**20.42**	**21.08**	**21.86**	**21.68**	**21.84**	**21.49**	*22.20*	*22.46*
Balancing Item [a]	**-0.52**	**-0.47**	**-0.29**	**-0.22**	**-0.05**	**-0.58**	**-0.47**	**-0.14**	**-0.37**	**-0.28**	**0.29**	**0.13**	**-0.17**	*-0.28*	*0.01*
Total Primary Supply	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.97**	**21.32**	*21.92*	*22.47*
Demand															
Lease and Plant Fuel	**0.92**	**1.15**	**1.10**	**1.07**	**1.24**	**1.13**	**1.17**	**1.17**	**1.12**	**1.22**	**1.25**	**1.20**	**1.25**	*1.25*	*1.25*
Pipeline Use	**0.49**	**0.52**	**0.61**	**0.63**	**0.66**	**0.60**	**0.59**	**0.62**	**0.69**	**0.70**	**0.71**	**0.75**	**0.73**	*0.73*	*0.74*
Residential	**4.31**	**4.31**	**4.63**	**4.78**	**4.39**	**4.56**	**4.69**	**4.96**	**4.85**	**4.85**	**5.24**	**4.98**	**4.48**	*4.75*	*5.01*
Commercial	**2.32**	**2.43**	**2.67**	**2.72**	**2.62**	**2.73**	**2.80**	**2.86**	**2.90**	**3.03**	**3.16**	**3.22**	**3.05**	*3.29*	*3.48*
Industrial (Incl. Nonutilities)	**5.58**	**5.95**	**6.38**	**6.82**	**7.02**	**7.23**	**7.53**	**7.98**	**8.17**	**8.58**	**8.87**	**8.84**	**8.55**	*8.53*	*8.53*
Cogenerators [b]	**NA**	**NA**	**NA**	**NA**	**1.30**	**1.41**	**1.70**	**1.80**	**1.98**	**2.18**	**2.30**	**2.16**	**2.14**	*2.19*	*2.23*
Other Nonutil. Gen. [b]	**NA**	**NA**	**NA**	**NA**	**0.09**	**0.16**	**0.18**	**0.22**	**0.16**	**0.17**	**0.16**	**0.18**	**0.18**	*0.18*	*0.19*
Electric Utilities	**2.60**	**2.84**	**2.64**	**2.79**	**2.79**	**2.79**	**2.77**	**2.68**	**2.99**	**3.20**	**2.73**	**2.97**	**3.26**	*3.36*	*3.45*
Total Demand	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.97**	**21.32**	*21.92*	*22.47*

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

[b] Annual projections for nonutility gas consumption, as well as the detail on independent power producers' share of gas consumption, are provided by the office of Coal, Nuclear, Electric and Alternative Fuels, Energy Information Administration.

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

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

Table A7. Annual U.S. Coal Supply and Demand

(Million Short Tons)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Production	890.3	918.8	950.3	980.7	1029.1	996.0	997.5	945.4	1033.5	1033.0	1063.9	1089.9	1118.7	1123.6	1152.7
Appalachia	NA	NA	NA	464.8	489.0	457.8	456.6	409.7	445.4	434.9	451.9	467.8	460.4	463.0	467.2
Interior	NA	NA	NA	198.1	205.8	195.4	195.7	167.2	179.9	168.5	172.8	170.9	168.4	159.5	156.2
Western	NA	NA	NA	317.9	334.3	342.8	345.3	368.5	408.3	429.6	439.1	451.3	489.9	501.2	529.2
Primary Stock Levels [a]															
Opening	33.1	32.1	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	34.1	36.6
Closing	32.1	28.3	30.4	29.0	33.4	33.0	34.0	25.3	33.2	34.4	28.6	34.0	34.1	36.6	32.6
Net Withdrawals	1.0	3.8	-2.1	1.4	-4.4	0.4	-1.0	8.7	-7.9	-1.2	5.8	-5.3	-0.2	-2.5	4.1
Imports	2.2	1.7	2.1	2.9	2.7	3.4	3.8	7.3	7.6	7.2	7.1	7.5	8.7	8.9	9.0
Exports	85.5	79.6	95.0	100.8	105.8	109.0	102.5	74.5	71.4	88.5	90.5	83.5	77.2	73.4	72.5
Total Net Domestic Supply	808.0	844.7	855.3	884.2	921.6	890.9	897.8	886.9	961.8	950.4	986.3	1008.5	1050.0	1056.6	1093.3
Secondary Stock Levels [b]															
Opening	170.2	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	101.4	129.0	120.7
Closing	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.4	129.0	120.7	112.5
Net Withdrawals	-5.0	-10.2	27.0	12.3	-22.1	0.5	4.0	43.2	-15.7	1.5	11.7	16.6	-27.6	8.3	8.2
Waste Coal Supplied to IPPs [c]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	8.5	8.8	8.1	9.6	10.1	10.6
Total Supply	803.1	834.4	882.3	896.5	899.4	891.4	901.8	930.2	954.0	960.4	1006.7	1033.2	1032.1	1074.9	1112.1
Demand															
Coke Plants	35.9	37.0	41.9	40.5	38.9	33.9	32.4	31.3	31.7	33.0	31.7	30.2	28.5	28.4	28.8
Electricity Production															
Electric Utilities	685.1	717.9	758.4	766.9	773.5	772.3	779.9	813.5	817.3	829.0	874.7	900.4	912.1	931.1	966.1
Nonutilities (Excl. Cogen.) [d]	NA	NA	NA	0.9	1.6	10.2	14.8	17.8	20.9	21.2	22.2	21.6	29.5	37.9	39.6
Retail and General Industry [e]	75.6	75.2	76.3	82.3	83.1	81.5	80.2	81.1	81.2	78.9	76.9	77.1	76.3	77.6	77.6
Total Demand	796.6	830.0	876.5	890.6	897.1	897.8	907.3	943.7	951.1	962.0	1005.6	1029.2	1046.3	1074.9	1112.1
Discrepancy [f]	6.5	4.4	5.8	5.9	2.4	-6.4	-5.4	-13.5	2.9	-1.6	1.2	4.0	-14.2	0.0	0.0

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

[b] Secondary stocks are held by users.

[c] Estimated independent power producers (IPPs) consumption of waste coal for 1994 is 7.9 million tons, 8.5 million tons in 1995, and 8.8 million tons in 1996.

[d] Consumption of coal by IPPs. In 1995, IPP consumption was estimated to be 5.290 million tons per quarter. Quarterly estimates and projections for coal consumption by nonutility generators are based on estimates for annual coal-fired generation at nonutilities, supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration (EIA), based on annual data reported to EIA on Form EIA-867 (Annual Nonutility Power Producer Report). Data for third quarter 1998 are estimates.

[e] Synfuels plant demand in 1993 was 1.7 million tons per quarter and is assumed to remain at that level in 1994, 1995, 1996, 1997 and 1998.

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

(S) indicates amounts of less than 50,000 tons in absolute value.

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

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

Table A8. Annual U.S. Electricity Supply and Demand

(Billion Kilowatthours)

	Year														
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Supply															
Net Utility Generation															
Coal	**1385.8**	**1463.8**	**1540.7**	**1553.7**	**1559.6**	**1551.2**	**1575.9**	**1639.2**	**1635.5**	**1652.9**	**1737.5**	**1787.8**	**1808.1**	*1851.5*	*1926.1*
Petroleum	**136.6**	**118.5**	**148.9**	**158.3**	**117.0**	**111.5**	**88.9**	**99.5**	**91.0**	**60.8**	**67.3**	**77.8**	**110.5**	*115.1*	*114.6*
Natural Gas	**248.5**	**272.6**	**252.8**	**266.6**	**264.1**	**264.2**	**263.9**	**258.9**	**291.1**	**307.3**	**262.7**	**283.6**	**308.9**	*321.0*	*329.9*
Nuclear	**414.0**	**455.3**	**527.0**	**529.4**	**576.9**	**612.6**	**618.8**	**610.3**	**640.4**	**673.4**	**674.7**	**628.6**	**673.7**	*687.7*	*679.7*
Hydroelectric	**290.8**	**249.7**	**222.9**	**265.1**	**279.9**	**275.5**	**239.6**	**265.1**	**243.7**	**293.7**	**328.0**	**337.2**	**305.3**	*284.0*	*280.3*
Geothermal and Other [a]	**11.5**	**12.3**	**12.0**	**11.3**	**10.7**	**10.1**	**10.2**	**9.6**	**8.9**	**6.4**	**7.2**	**7.5**	**7.2**	*7.2*	*7.2*
Subtotal	**2487.3**	**2572.1**	**2704.3**	**2784.3**	**2808.2**	**2825.0**	**2797.2**	**2882.5**	**2910.7**	**2994.5**	**3077.4**	**3122.5**	**3213.6**	*3266.6*	*3337.8*
Nonutility Generation [b]	**NA**	**NA**	**NA**	**187.0**	**221.5**	**253.3**	**301.8**	**325.2**	**354.9**	**375.9**	**382.4**	**384.7**	**390.3**	*396.0*	*401.9*
Total Generation	**NA**	**NA**	**NA**	**2971.3**	**3029.6**	**3078.3**	**3099.0**	**3207.8**	**3265.6**	**3370.4**	**3459.9**	**3507.2**	**3604.0**	*3662.6*	*3739.7*
Net Imports	**35.9**	**46.3**	**31.8**	**11.0**	**2.0**	**22.3**	**28.3**	**28.4**	**44.6**	**37.6**	**38.0**	**36.6**	**28.8**	*33.7*	*34.8*
Total Supply	**NA**	**NA**	**NA**	**2982.3**	**3031.6**	**3100.6**	**3127.3**	**3236.2**	**3310.3**	**3408.0**	**3497.9**	**3543.8**	**3632.7**	*3696.2*	*3774.5*
Losses and Unaccounted for [c]	**NA**	**NA**	**NA**	**238.3**	**205.8**	**216.9**	**226.6**	**237.0**	**225.5**	**236.8**	**242.3**	**242.8**	**231.4**	*248.8*	*253.2*
Demand															
Electric Utility Sales															
Residential	**819.1**	**850.4**	**892.9**	**905.5**	**924.0**	**955.4**	**935.9**	**994.8**	**1008.5**	**1042.5**	**1082.5**	**1075.8**	**1131.5**	*1139.3*	*1181.7*
Commercial	**630.5**	**660.4**	**699.1**	**725.9**	**751.0**	**765.7**	**761.3**	**794.6**	**820.3**	**862.7**	**887.4**	**928.4**	**950.5**	*973.4*	*989.1*
Industrial	**830.5**	**858.2**	**896.5**	**925.7**	**945.5**	**946.6**	**972.7**	**977.2**	**1008.0**	**1012.7**	**1030.4**	**1032.7**	**1055.5**	*1064.9*	*1076.3*
Other	**88.6**	**88.2**	**89.6**	**89.8**	**92.0**	**94.3**	**93.4**	**94.9**	**97.8**	**95.4**	**97.5**	**102.9**	**100.3**	*103.9*	*105.9*
Subtotal	**2368.8**	**2457.3**	**2578.1**	**2646.8**	**2712.6**	**2762.0**	**2763.4**	**2861.5**	**2934.6**	**3013.3**	**3097.8**	**3139.8**	**3237.7**	*3281.5*	*3352.9*
Nonutility Own Use [b]	**NA**	**NA**	**NA**	**97.2**	**113.2**	**121.7**	**137.3**	**137.8**	**150.2**	**158.0**	**157.8**	**161.2**	**163.6**	*166.0*	*168.5*
Total Demand	**NA**	**NA**	**NA**	**2744.0**	**2825.8**	**2883.7**	**2900.7**	**2999.2**	**3084.8**	**3171.3**	**3255.6**	**3301.0**	**3401.3**	*3447.5*	*3521.4*
Memo:															
Nonutility Sales to Electric Utilities [d]	**39.9**	**50.0**	**68.0**	**89.8**	**108.2**	**131.6**	**164.4**	**187.5**	**204.7**	**217.9**	**224.6**	**223.5**	**226.7**	*230.1*	*233.4*

[a] Other includes generation from wind, wood, waste, and solar sources.

[b] For 1989 to 1991, estimates for nonutility generation are estimates made by the Energy Markets and Contingency Information Division, based on Form EIA-867 (Annual Nonutility Power Producer Report) data. Historical data and Projections for the same items are from the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration, based on Form EIA-867.

[c] Balancing item, mainly transmission and distribution losses.

[d] Historical data for nonutility sales to electric utilities are from the Energy Information Administration, *Annual Energy Review*, DOE/EIA-0389, Table 8.1, for 1982 to 1988; from Form EIA-867 (Annual Nonutility Power Producer Report) for 1989 to 1996.

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

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