EIA Energy Information Administration
Short-Term Energy Outlook

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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/emeu/steo/pub/contents.html.** 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 October 1998 through December 1999. Values for third quarter of 1998 data, 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 October 1998 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.

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Introduction

Nearly two-thirds of all households in the United States rely upon natural gas, distillate fuel oil, or propane as their main heating fuel. In general, the status of these fuels as the winter heating season approaches is encouraging for consumers; supplies are ample, and prices are relatively low despite some upward pressure in September due in part to hurricane activity in the Gulf of Mexico and coastal areas. But this is not to say that the markets for these fuels are immune to atypical tightening during the coming winter, particularly if the back-to-back *El Niño/La Niña* weather patterns result in an unusually cold winter season. Alternatively, an unusually mild winter season would have the likely effect of driving down the already low prices of the winter fuels.

This article presents an analysis of demand, supply and prices of natural gas, heating oil and propane in the coming winter heating season (defined as October 1, 1998 through March 31, 1999). Primary emphasis is on the base case forecast, which assumes normal winter weather. Two alternative weather scenarios, reflecting a severe winter and a mild winter, are also addressed. Projections for the base case and the two alternative weather scenarios, along with historical data for last winter, are shown in Table WF01.

As of the beginning of the approaching winter season, the base case forecast shows that:

- Stocks of natural gas, distillate fuel oil and propane are unusually robust (Figure 1). Relative to the stock bands (3-year average inventory levels) of the Energy Information Administration's *Weekly Petroleum Status Report,*[1] natural gas and distillate fuel stocks on September 30, 1998 are 9 percent above average, and propane stocks are a surprising 30 percent above average. The high pre-season heating fuel inventories are in marked contrast to the relatively low pre-season inventory levels of the two prior years.

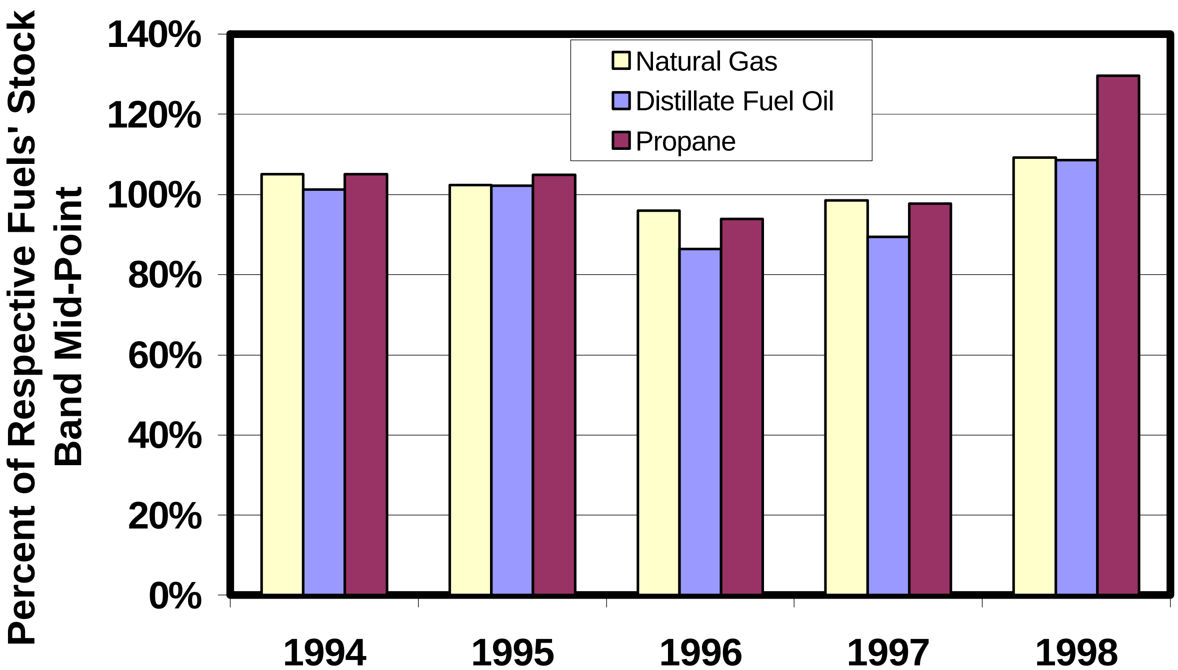
- Demand for all three winter heating fuels is expected to be generally higher than demand last winter, due to the assumption of normal weather relative to last year's milder weather.

- Prices for distillate and propane are expected to be lower than they were last winter, down by 5 and 3 percent, respectively. This is due to the lower world

[1] See *Weekly Petroleum Status Report* (DOE/EIA-0208), Appendix A, "Interpretation and Derivation of Average Inventory Levels".

oil prices, along with the high stock levels. Natural gas wellhead prices are expected to be lower in fourth quarter 1998 than they were in the fourth quarter of 1997. However, they are expected to be higher in the first quarter of 1999 than year-ago, due to the very substantial expected increase in demand associated with normal weather assumptions.

Figure 1. Heating Fuel Stocks at Beginning of Heating Season (Sept. 30)

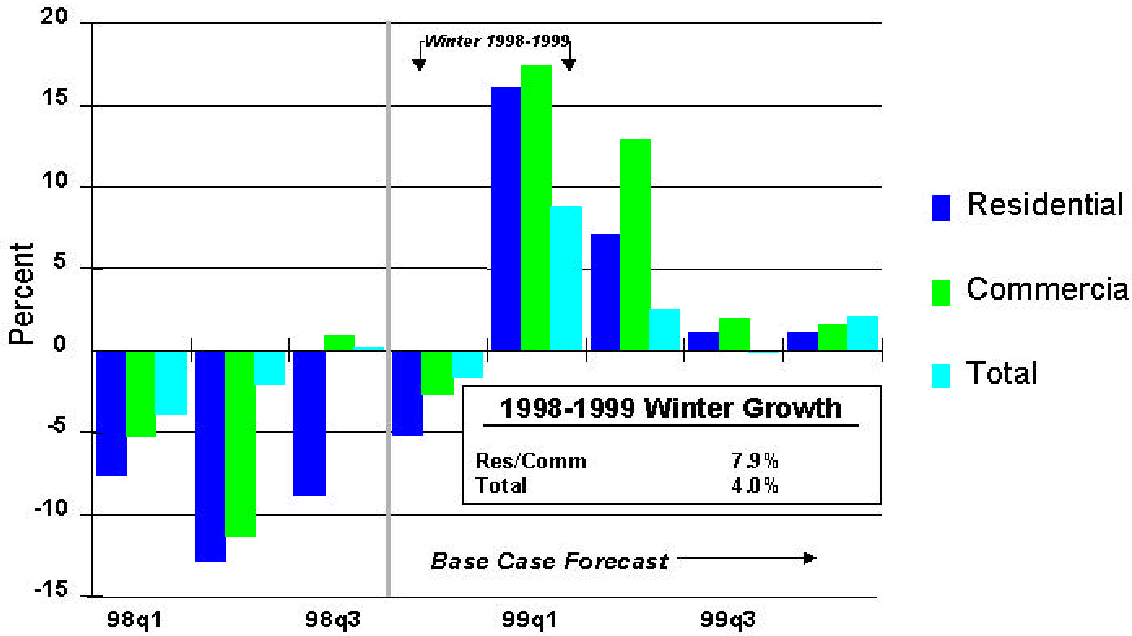


Natural Gas

Normal Winter Weather Brings Increased Demand

Total demand for natural gas is expected to be much higher this winter, averaging about 70.5 billion cubic feet (Bcf) per day. This would be an increase of about 4 percent compared to last year's daily average of 67.9 Bcf per day. Much of this increase is related to assumptions of a return to more normal weather patterns, as milder weather last year resulted in gas-weighted heating degree-days that were nearly 7-percent lower than normal. As a result, consumption in the seasonal markets, residential and commercial, is expected to increase more than 7 percent and 9 percent, respectively (Figure 2).

Figure 2. U. S. Natural Gas Demand (Percent Change from Year Ago)



Supplies Are Ample

With storage levels high and substantial wellhead productive capacity, natural gas supplies are anticipated to be adequate to meet demand under normal weather conditions. Domestic gas production is expected to average almost 52.8 Bcf per day during the heating season, up about 0.8 percent over last winter's production. Last year, during the unseasonably warm temperatures in January and February, when heating degree-days were more than 20 percent lower than normal, U.S. production still averaged above 52 Bcf per day. With more than 550 drilling rigs dedicated to gas exploration, the potential for an increase in U.S. production during the coming year is always present. This is the third consecutive year in which the majority of drilling rigs operating in the U.S. was dedicated to gas exploration. In August 1998, 70 percent of a total 792 drilling rigs in operation were in pursuit primarily of natural gas.

Underground natural gas storage plays a critical role in meeting increased demand during the winter months. In many areas of the country, storage provides the key resource that allows the local gas distributing company to increase supply in peak demand periods. Due to the past summer's ample supply situation and relatively soft prices, there has been a generally robust rate of storage refill leading up to the beginning of this winter. Overall underground storage levels are estimated to have been 7,282 Bcf at the end of September. (Gas storage doesn't actually peak until sometime in October.) Of this, 4,338 Bcf are needed to maintain reservoir pressure and are not available for withdrawal.

Thus, the remaining 2,944 Bcf of working gas storage are available to be drawn as needed (Figure 4). The lowest level that working gas has been drawn down to over the past two decades was 758 billion cubic feet in March 1996. The level of working gas on hand at the end of September was 272 Bcf greater than at the same time last year (2,944 Bcf versus 2,672) and is projected to be more than 3,100 Bcf at the end of October--the highest level since 1992. During this heating season, storage withdrawals are expected be significantly higher than last year's to meet the additional demand, averaging 10.6 Bcf per day compared to last year's average of 8.2 billion cubic feet per day. With the greater reliance on storage this winter, working gas on hand at the end of March is projected to be over 1,000 Bcf, noticeably below the 1,184 Bcf of working gas remaining at the end of the 1997/98 heating season, but still well above the observed minimum.

Figure 3. Components of Natural Gas Supply (Change from Year Ago)

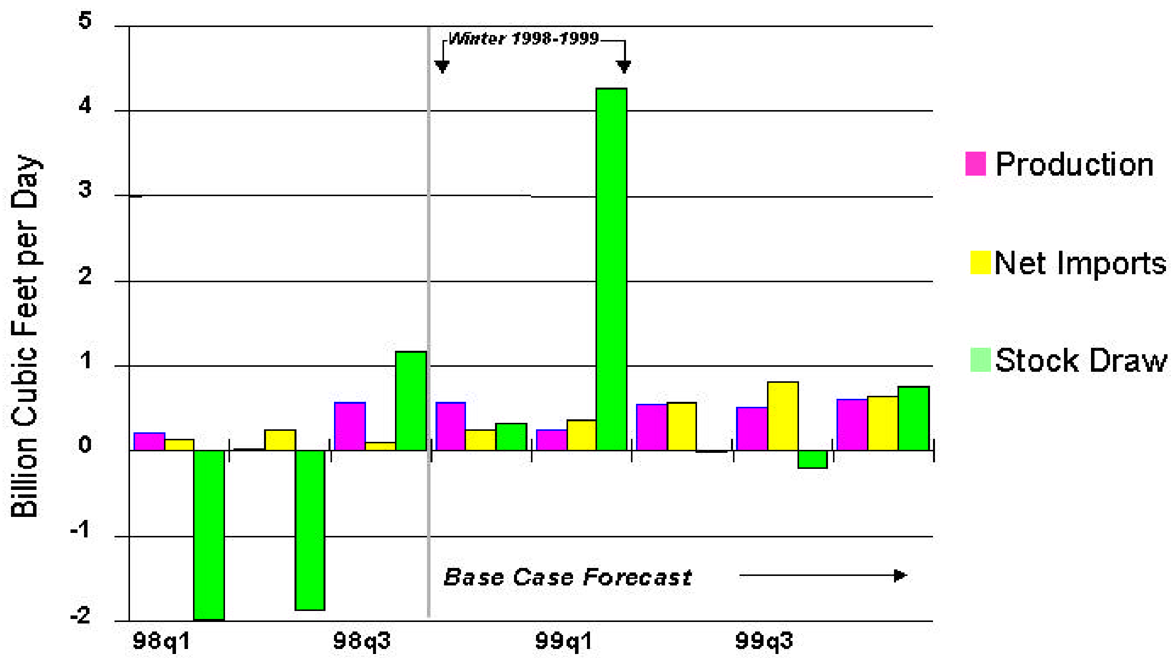
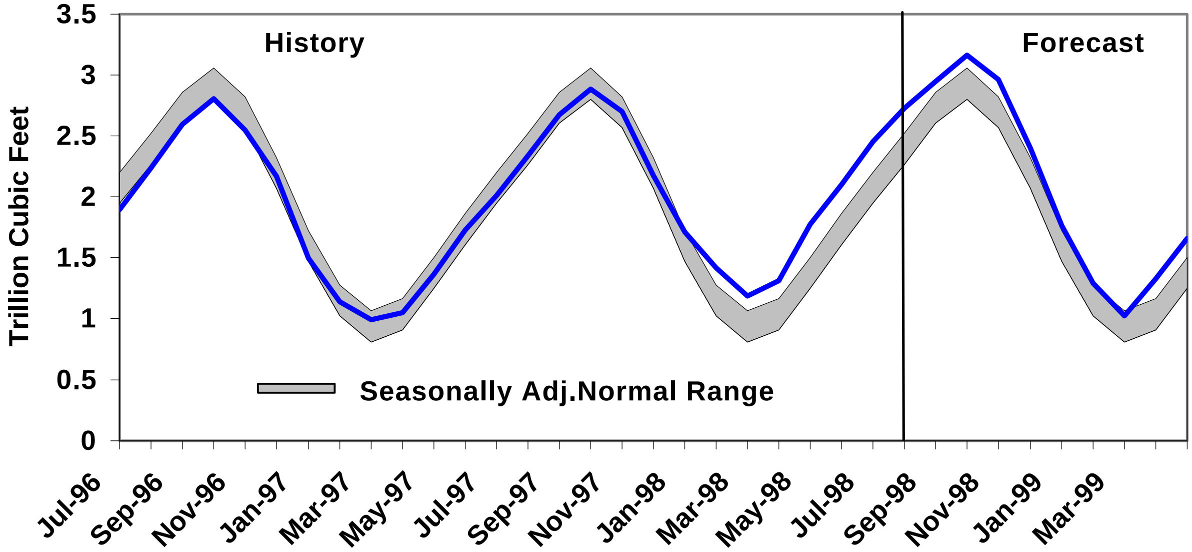


Figure 4. Working Gas in Storage



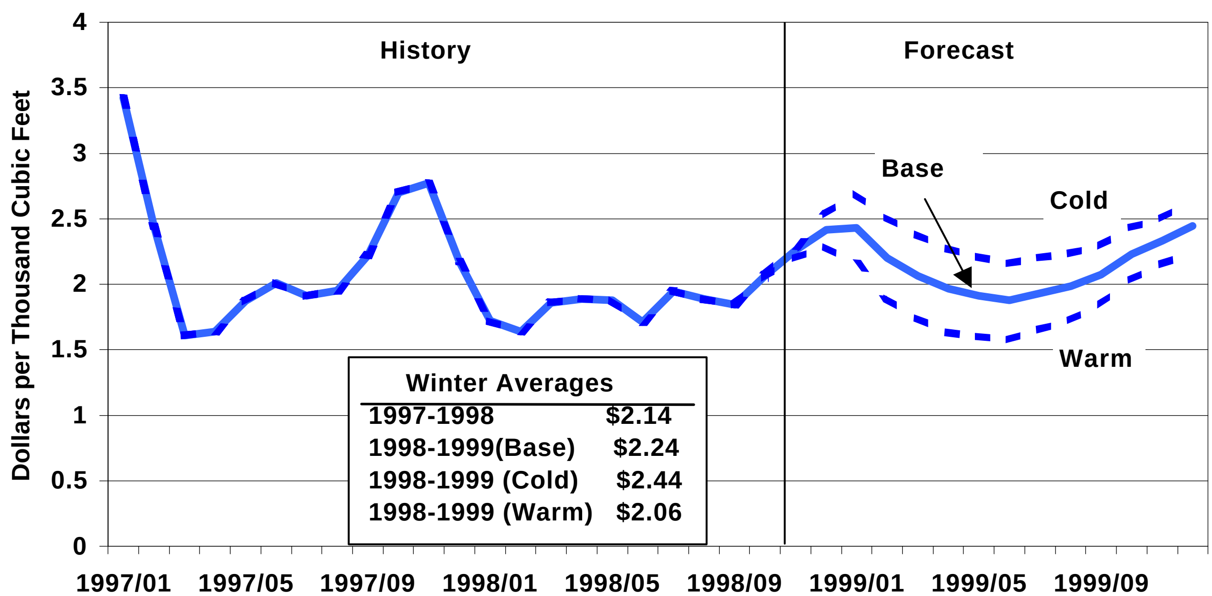
Natural gas imports from Canada, which supply more than 12 percent of total U.S. consumption, are expected to average 8.5 Bcf per day compared to last year's 8.2 Bcf per day. During the winter months, net imports usually increase to full pipeline capacity levels and are about 10 percent higher than flows during the rest of the year. Pipeline import capacity, which has been generally stable for the last few years, should increase at the end of this year as three construction projects are scheduled to be completed in November and December. These projects are designed to provide about 10 percent, or almost 1 Bcf per day, of additional pipeline import capacity from Canada. The largest of these projects is the expansion of the Northern Border pipeline system, which, when completed in December, will increase import capacity into Chicago and the Midwest by 650 million cubic feet (MMcf) per day.

Average Prices Slightly Higher Than Prices Last Heating Season

Natural gas wellhead prices are projected to average about $2.24 per thousand cubic feet (Mcf) this winter compared to the $2.14 per Mcf average price seen a year ago (Figure 5). Last winter, the average wellhead price was high going into the winter, reaching its monthly peak in November at $2.77 per Mcf. Contributing to this early price increase was concern about low stocks and reaction to the much colder-than-normal temperatures experienced early in the heating season in November. By late December, the weather began to moderate, storage levels improved, and prices retreated. By February, the wellhead price was at $1.64 per Mcf. For the first quarter of 1998, wellhead prices declined by more than 30 percent from prices during the previous quarter. This year's improved stock level has already had an impact on prices compared to last year's levels. In late September of this year, prices on the NYMEX natural gas commodities futures market for the early months of the upcoming winter season were 20 to 30 percent lower than last year at the same time. Thus, going into the winter, average wellhead prices for the fourth quarter ($2.25 per Mcf) are expected to be substantially below prices during the fourth quarter of 1997. They are projected to remain about steady, on average, at $2.23 in the first quarter 1999, an average which is substantially higher than the $1.74 per Mcf recorded in the first quarter 1998. Figure 5 illustrates how, as generally higher stocks and lower heating demand give way to stock reductions and high heating demand factors, we expect a higher gas price regime to emerge.

Prices paid by residential consumers are also expected to move up slightly, averaging $6.74 per Mcf, or 2.7 percent higher than last year's average. The largest differential compared to last year occurs in the first quarter of 1999. Last year, the moderate temperatures in January and February resulted in a 7-percent decline in the average residential price of gas between the last quarter of 1997 and the first quarter of 1998 ($6.83 per Mcf vs $6.38). This year, assuming normal weather, the average residential price in the first quarter of 1999 is projected to be close to $6.80 per Mcf, about 4 percent higher than in the last quarter of 1998. With projections of normal winter weather, residential consumption is projected to be about 3,840 Bcf and would result in total expenditures of $25.9 billion during the heating season. This is about $2.5 billion more than last year's expenditures, when residential consumption was significantly lower at about 3,580 Bcf.

Figure 5. Natural Gas Wellhead Prices



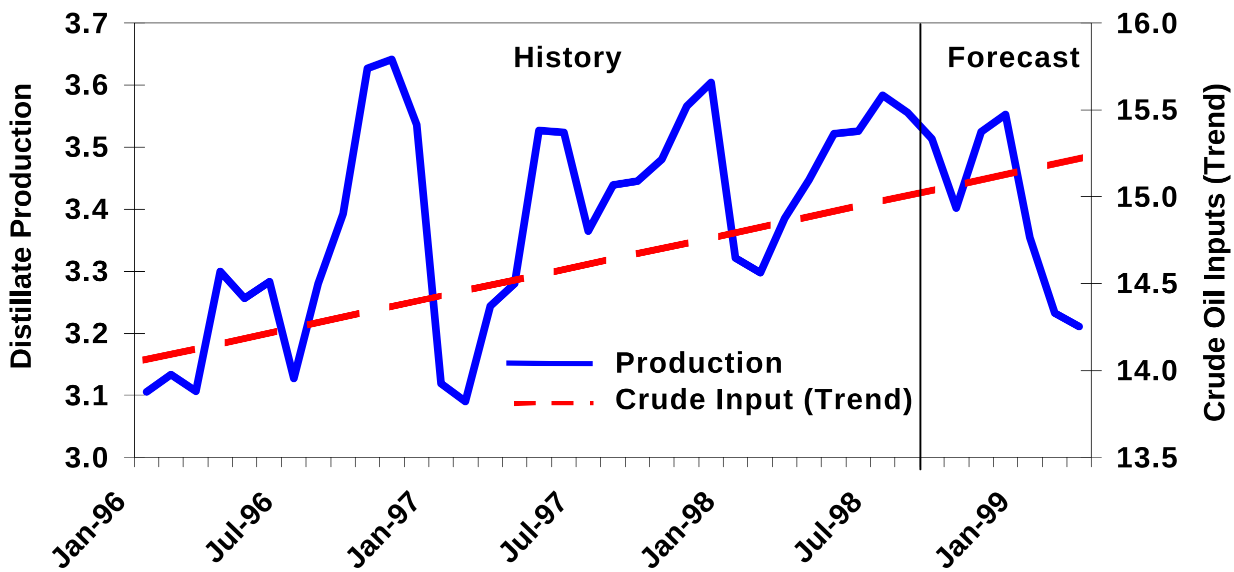
Heating Oil

While Demand Fell, Stocks Increased

The projection for U.S. demand for distillate this winter assumes normal weather, which, would result in a 3.3 percent increase in demand over last year. During the 1997-1998 heating season, weather in the Northeast was unusually warm, more than 10 percent below the normal pattern of heating degree-days (HDD), a trend repeated across the entire Northern Hemisphere. In spite of the higher U.S. demand projections for this winter, high pre-heating season distillate stocks and an outlook for continued low crude oil prices should keep distillate prices lower this year than last on average.

A major factor affecting the U.S. heating oil market this year is the shift in world petroleum markets that began in 1997. Most of 1996 was a time of tight supply-demand balances and rising prices. As 1997 began, crude oil prices fell with the return of Iraq to the crude oil market, but leveled out somewhat during the summer. However, prices resumed their decline in the fall of 1997 as continued strong crude oil production exceeded lower-than-expected demand brought about by the collapse of the Asian economies and a warmer-than-usual winter. Through the first half of 1998, world supply continued to exceed demand and the world crude prices continued to fall through late summer. Since the beginning of 1998, the world market has provided incentives to increase refinery crude runs to produce and store product for future delivery. The U.S. distillate market is no different. U.S. refinery crude runs since January 1998 have been higher than in similar months in 1997, and, as illustrated in Figure 6, production of distillate has increased through most of 1998.

Figure 6. Distillate Refinery Production and Crude Oil Input (Million Barrels per Day)



The collapse of Asian demand is not only contributing to lower crude oil prices, it also may affect U.S. distillate imports and exports. Normally, Asian demand for distillate fuel (heating oil plus diesel fuel), collectively called gasoil on the world market) “tightens” the distillate import market, limiting available supply, and thereby bolstering prices during periods of peak demand. However, the rate of economic growth fueling Asia’s oil consumption has dropped since late 1997 as the financial markets unraveled. The base case projection for the 1998-1999 heating season assumes little change in distillate demand by the Asian economies but a return to normal weather in the Northeastern United States, Northern Europe, and Japan. This implies there will be less incentive to export distillate from the U.S., and more economic imports may be available to help meet any unanticipated U.S. demand.

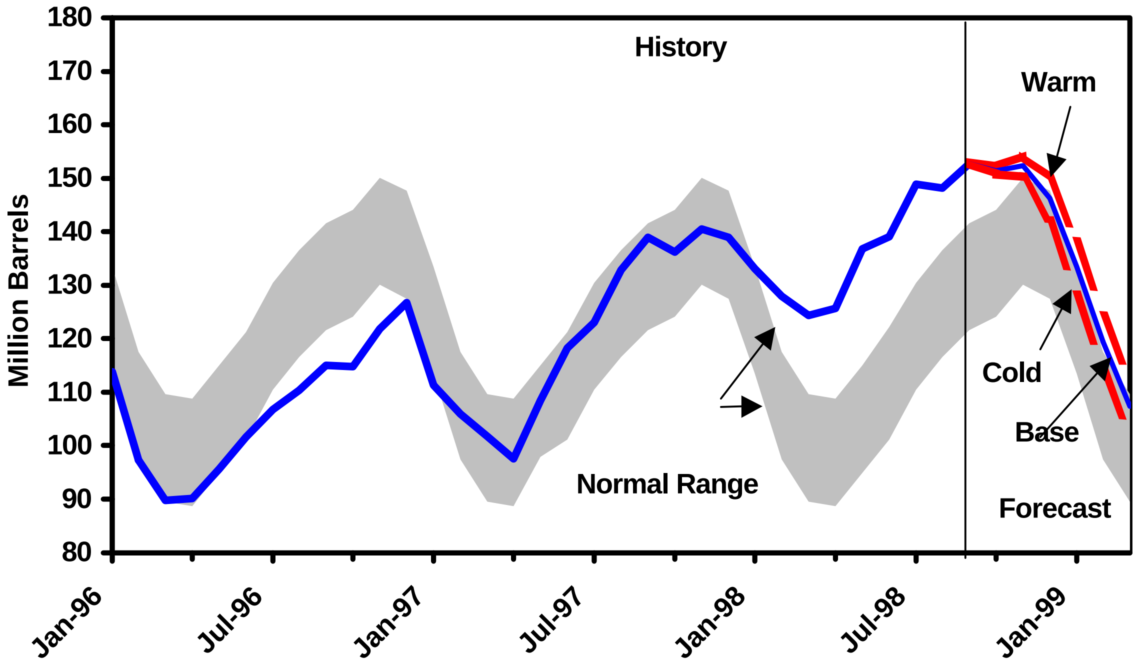
Results of High Stocks for this Winter? – Adequate Supply at Lower Prices

Because heating oil is often needed with short notice during cold spells, stocks play a very critical role -– in cold spikes, even more so. When cold spells persist or are drawn out over time, production and imports can supplement stocks in meeting winter demand. In normal years, changes in distillate stocks (and prices) reflect movements in the demand-supply balance tempered by expectations of uncertainties about the underlying fundamentals in the heating season months ahead. In preparation for a coming heating season in October, distillate stocks normally begin to be replenished in the spring. A large part of this rebuild in distillate stocks results from the co-production of distillate as demand for motor gasoline begins its seasonal rise.

How high the distillate stock build goes depends largely on expectations reflected in the futures market of the demand-supply balance for distillate once the coming heating season begins and peaks. In anticipation of the coming heating season, the futures market shifts into what is called "contango", when prices in succeeding delivery months are progressively higher than in the nearest delivery month. If the increase month-to-month exceeds the monthly cost of storage, there is a financial incentive to continue building stocks. This financial incentive stops when that month-to-month increase in delivery prices falls below the monthly cost of holding inventory. Although the market went into contango early in April 1998, there was little financial incentive to build distillate stocks until the middle of May. Over the next several months, this financial incentive coexisted with record high stock levels.

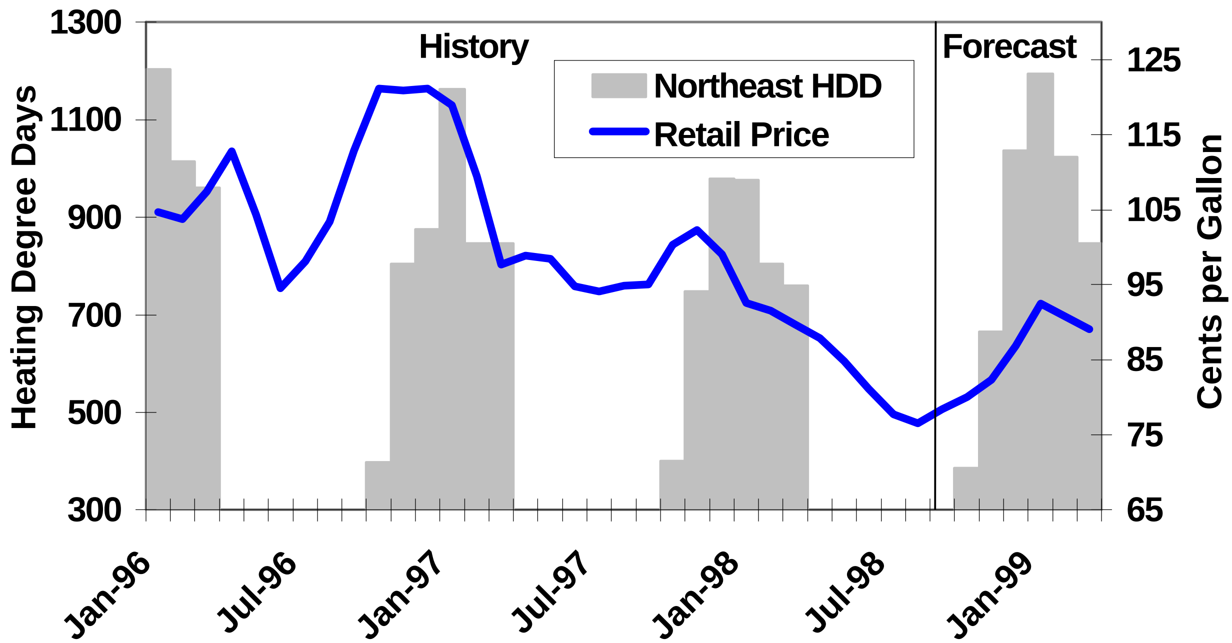
Figure 7 shows that the past 12 months in distillate markets leading up to the coming 1998-1999 heating season have departed from what had to date been called a normal pattern. By July 1998, distillate stocks exceeded 140 million barrels compared to slightly over 123 million barrels a year earlier. Distillate stocks began to exceed the previous 3-year average range in January 1998. The unexpected accumulation of this high level of distillate stocks by summer 1998 stems from the confluence of two factors: U.S. distillate inventories ended the prior heating season at high levels as a result of the warm winter; and the world petroleum market produced an incentive to continue to produce distillate and build stocks for future delivery of product. The base case projects that distillate stocks will remain over 140 million barrels through December 1998 and then drop sharply to meet the forecasted return to normal weather in the Northeast.

Figure 7. U.S. Distillate Stocks (Based on Normal, Severe, and Mild Winter Weather)



The path of total U.S. retail distillate prices is shown in Figure 8, in comparison to the HDD for the Northeast. Prices at both the wholesale and retail levels have been declining on average since the last half of 1996, largely as a result of crude oil price declines. While weather has been a factor for prices in the previous two heating seasons, the forecasted return to normal weather for the Northeast is projected to have some upward impact on prices, although this influence is tempered by the high stocks expected to be in place on October 1. The main factor expected to keep heating oil prices low this winter is low crude oil prices. In spite of the low prices, colder weather and higher usage this winter could boost consumers' bills up over last year's levels.

Figure 8. Retail Heating Oil Prices Showing Winter Weather in Northeast



Propane

Year-Over-Year Demand Flat

The primary factors that affect propane demand in the United States are propane prices, crude oil and natural gas prices, macroeconomic growth and weather. Because of the influence of the highly weather-dependent residential sector, total propane demand generally mirrors the same seasonal patterns as the residential sector, rising during winter months and falling during the spring and summer months.

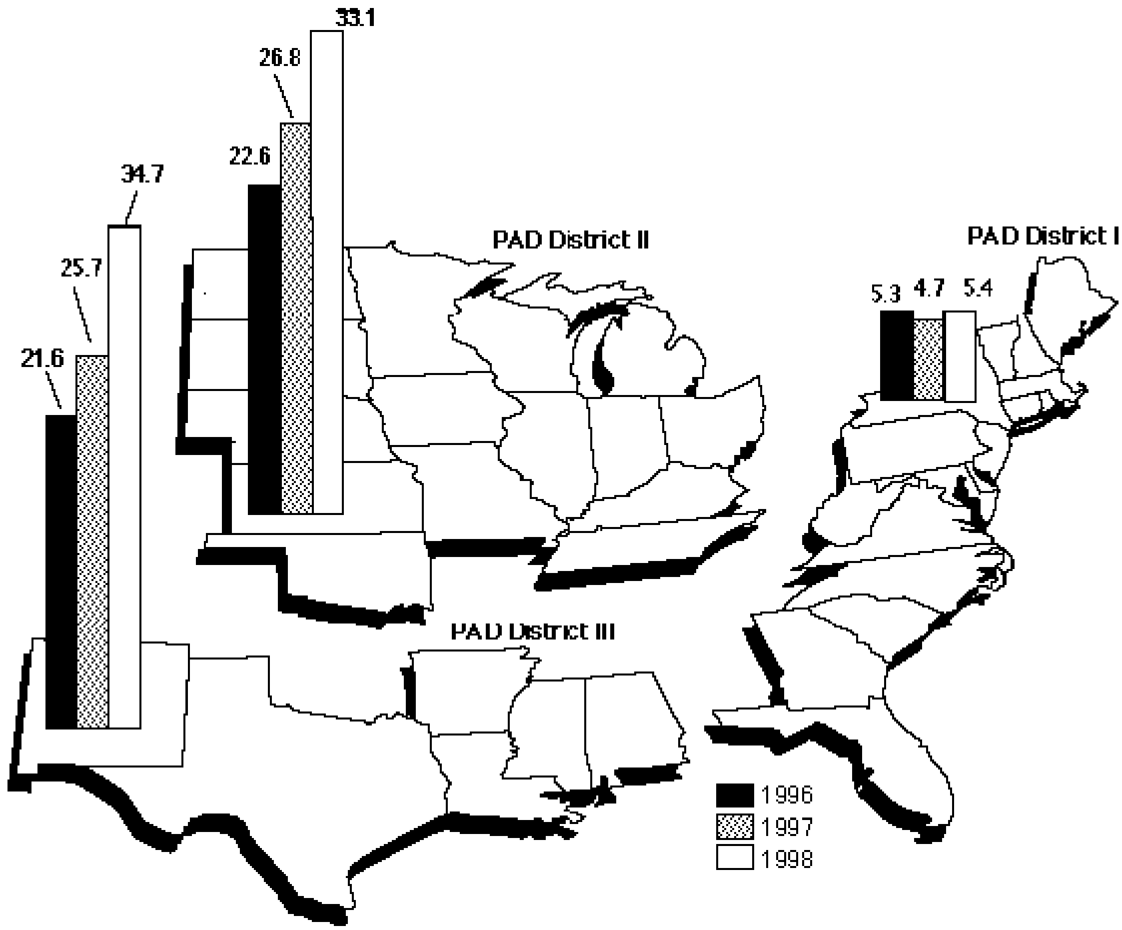
U.S. demand for propane averaged about 1.37 million barrels per day during the 1997-1998 winter heating season, up nearly 6 percent from the previous year's heating season despite mild winter weather. However, a comparison of demand for the first seven months of 1998 with demand during the same period last year shows demand relatively flat at 1.1 million barrels per day. Milder weather during the first quarter 1998, compared with first quarter 1997, contributed to lower residential heating demand, while slowing demand for petrochemical-based products pushed petrochemical feedstock demand for propane lower during the second quarter of 1998. Although industrial (including feedstock demand) for propane has appeared to be relatively weak since last winter, residential demand will most certainly be a strong positive factor this winter, if temperatures are near normal.

Record Stock Build Boosts Supply

Demand for propane is met by domestic production at gas processing plants and at refineries, inventory withdrawals, and net imports. Domestic production accounts for the largest share of winter supply, followed, in turn, by inventory withdrawals and imports. Total propane production through July 1998 averaged nearly 1.1 million barrels per day, relatively unchanged from last year's level during this same period. Production at gas processing plants dipped slightly from year-ago levels through July, while production at refineries remained nearly flat compared with year-ago levels. Refineries have accounted for most of the annual growth in propane production over the past several years due to high refinery runs from strong gasoline production. However, the sluggishness from gas plant production was due partly to higher natural gas prices compared with relatively low natural gas liquid prices that have discouraged higher extraction rates from gas processing plants.

Primary inventory withdrawals provide the second largest source of propane during the winter heating season. Inventories are built up during the spring and summer months and typically peak by the end of September. The buildup of U.S. inventories through September 1998 was one of the largest ever, measuring over 46 million barrels. As of September 30, U.S. inventories of propane stood at 75.9 million barrels, the highest level for this month since 1986. One of the factors for the high level of inventories this year was the relatively mild winter that left U.S. inventories at nearly 30 million barrels by the end of March, their highest level for this month in 6 years. Regional inventories remain above prior year levels and are well above the normal range in the Midwest and the Gulf Coast areas. Inventories in the East Coast remain slightly above the normal range for this time of year (Figure 9).

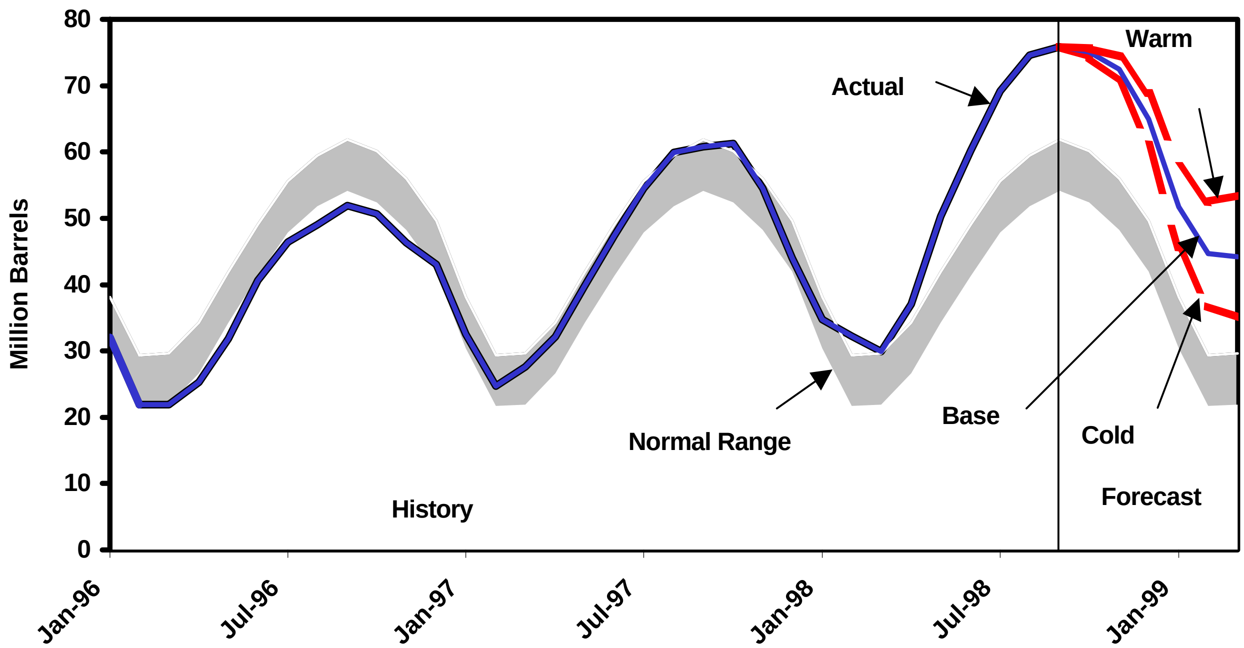
Figure 9. Propane Stocks of Beginning of Heating Season (September 30[1])



[1]Ending Stocks by PAD Districts I, II, and III for September 30, 1998, were imputed based on August 31, 1998 data reported on Form EIA-807, "Propane Telephone Survey," and September 30, 1998 data developed from the Propane Market Model," (DOE/EIA-M055).

On the basis of current inventory levels and projected supply and demand, the expectation for the 1998-1999 winter heating season is for adequate supplies and moderate prices, given normal weather and the absence of any major supply problem. Under a base case scenario, stocks are projected to gradually decline over the course of the season, reaching a level of 44 million barrels by the end of March 1999 (Figure 10).

Figure 10. U.S. Propane Stocks (Based on Normal, Cold, and Warm Winter Weather)

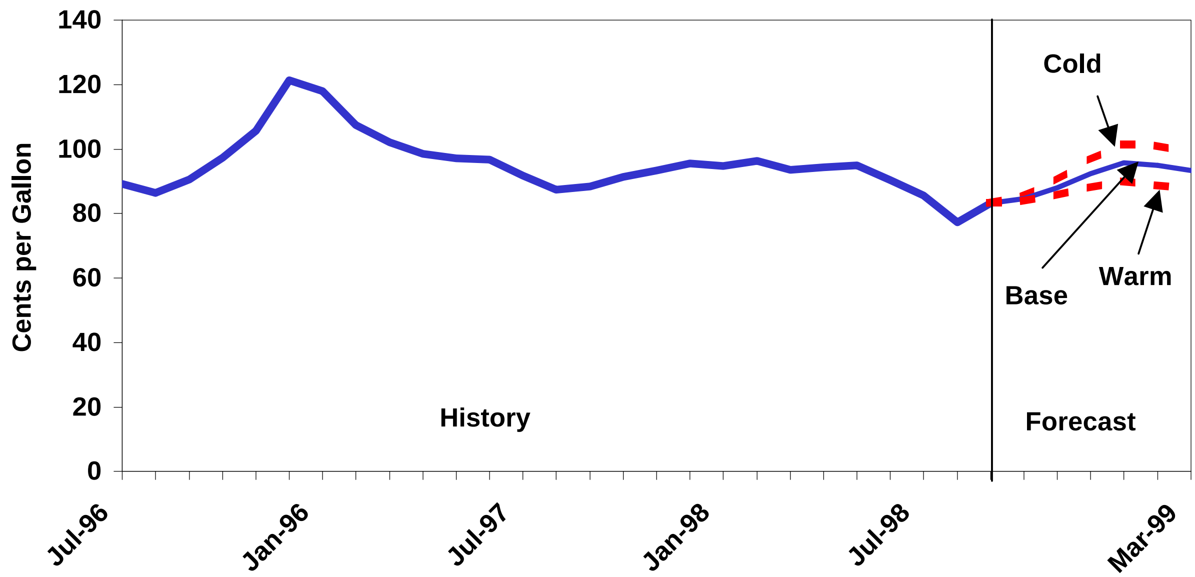


Prices Remain Low

Propane prices at all levels of the distribution chain are subject to a number of influences. The primary determinant of spot propane prices, as with most commodities, is the balance of demand and available supply, often on a regional basis. Additionally, propane prices are influenced by crude oil and natural gas prices, competition with other commodities used as fuel or feedstock, and intangible factors, such as uncertainty about future supply or demand.

Both wholesale and residential propane prices have tracked below prior year levels through July 1998, primarily the result of abundant supplies of propane in the face of weakening demand. Under the base case scenario, average residential prices would be expected to increase seasonally from about 83 cents per gallon in September to a winter peak of 96 cents per gallon in January. Prices would gradually fall and end the season at 93 cents per gallon (Figure 11).

Figure 11. Residential Propane Prices (Based on Normal, Severe, and Mild Winter Weather)



Cold Weather Scenario

This scenario assumes that weather, in terms of heating degree-days, will be 10 percent colder than normal for the entire heating season (October 1998 through March 1999). Such a heating season would be substantially colder than last winter's relatively mild weather.

Under this cold weather pattern, natural gas consumption could increase by 5 percent above consumption generated under normal weather conditions, to about 73.9 Bcf per day. Reliance on increased withdrawals from storage is expected to meet much of the incremental demand increase. The rate of storage withdrawal would rise to about 12.3 Bcf per day, up from 10.6 Bcf in the normal weather scenario. Production would increase to 53.8 Bcf per day. Assuming that the planned additional pipeline import capacity becomes available, imports from Canada are expected to increase about 0.5 Bcf per day, mostly in the first quarter of 1999 as much of the capacity will not be on line until then. With the increased demand, wellhead prices would move up about $0.20 per Mcf to average $2.44 and residential prices would increase by $.08 to average $6.82 per Mcf. This would mean an additional cost to residential consumers of about $2.6 billion under these more severe winter conditions.

In heating oil markets, the severe winter case implies an increase in distillate demand of about 2.7 percent above demand in the normal weather case, or 6.0 percent above last winter's. Even with colder weather, the average winter retail price for heating oil would be expected to be about even with last winter's (93 cents per gallon) even if higher crude oil prices occurred as well.

In this scenario, propane supplies are projected to end the heating season at 35 million barrels, 9 million barrels lower than in the base case scenario. The impact of this scenario on residential prices would be significant. With cold weather concentrated in the second half of the season, a shorter period would exist for incremental supplies of propane from production and imports to respond to the higher demand during the peak winter months. The projected result would be residential propane prices reaching a maximum price in January of 102 cents per gallon, then declining to 99 cents per gallon by March 1999, 6 cents over the base case price.

Warm Weather Scenario

This scenario assumes that weather, in terms of heating degree-days, will be 10 percent warmer than normal throughout the coming heating season. Assuming this warmer-than-normal case, natural gas consumption is projected to be about 67.2 Bcf per day, nearly 5 percent lower than consumption under normal weather and slightly below last year's consumption levels. This would likely result in lower withdrawals from storage, and end of season working gas storage levels could be nearly 1,400 billion cubic feet, which would be the highest in 7 years. This would apply downward pressure on prices and lessen the need for a typical storage refill season. Prices are projected under this scenario to average $2.06 per Mcf at the wellhead, $0.18 lower than prices under normal weather conditions. Residential consumers would see slightly lower prices, averaging $6.68 per Mcf, with expenditures of $23.9 billion, $2.0 billion lower than expenditures under normal winter conditions.

In the warm weather scenario, refinery output of distillate recedes from the high usage levels of distillate units in 1998, making it possible to conduct needed maintenance in preparation for the next stock building cycle in spring 1999. The expected retail price of heating oil for the coming winter season under the mild weather scenario is 82.6 cents per gallon.

Under this scenario, U.S. propane stocks would be projected to end the heating season at 53 million barrels. This level would be 9 million barrels above the base case scenario and 18 million barrels above the severe case scenario. The impact on residential prices would be similar in magnitude but opposite that of prices in the severe case, moving average residential prices to about 87.4 cents per gallon, or about 4 cents per gallon below the base case price and 7 cents below the average for last winter.

Table WF01. U.S. Winter Fuels Outlook: Base Case and Weather Cases

	History			Base Case							
	1997-1998			1998-1999			Percent Change			Cold	Warm
	Q4	Q1	Winter	Q4	Q1	Winter	Q4	Q1	Winter	Weather	Weather
Demand/Supply											
Distillate Fuel (mill. barrels per day)											
Total Demand	**3.60**	**3.58**	**3.59**	**3.57**	**3.85**	*3.71*	*-0.9%*	*7.6%*	*3.3%*	*3.81*	*3.61*
Refinery Output	**3.55**	**3.34**	**3.44**	**3.49**	**3.27**	*3.38*	*-1.6%*	*-2.1%*	*-1.8%*	*3.42*	*3.3*
Net Stock Withdrawal	**0.00**	**0.16**	**0.08**	**0.07**	**0.43**	*0.25*	*NM*	*177.9%*	*218.6%*	*0.29*	*0.23*
Net Imports	**0.05**	**0.08**	**0.07**	**0.01**	**0.15**	*0.08*	*NM*	*86.2%*	*21.3%*	*0.1*	*0.07*
Refinery Utilization (percent)	**96.6%**	**93.1%**	**94.9%**	**93.9%**	**91.5%**	*92.7%*				*92.8*	*91.8*
Natural Gas (bill. cubic feet per day)											
Total Demand	**62.32**	**73.53**	**67.86**	**61.28**	**79.97**	*70.52*	*-1.7%*	*8.8%*	*3.9%*	*73.85*	*67.22*
Production	**51.99**	**52.73**	**52.36**	**52.55**	**52.98**	*52.76*	*1.1%*	*0.5%*	*0.8%*	*53.78*	*51.77*
Net Stock Withdrawal	**5.46**	**10.96**	**8.18**	**5.89**	**15.36**	*10.57*	*8.0%*	*40.2%*	*29.3%*	*12.31*	*8.74*
Net Imports	**8.09**	**8.30**	**8.20**	**8.34**	**8.67**	*8.51*	*3.1%*	*4.4%*	*3.8%*	*9.02*	*8.05*
Propane (mill. barrels per day)											
Total Demand	**1.38**	**1.36**	**1.37**	**1.26**	**1.36**	*1.31*	*-8.7%*	*0.0%*	*-4.4%*	*1.36*	*1.26*
Net Stock Withdrawal	**0.18**	**0.16**	**0.17**	**0.12**	**0.23**	*0.17*	*-34.1%*	*45.9%*	*2.6%*	*0.22*	*0.12*
Stocks (ending period)											
Distillate Fuel (MMB)- Beg. [a]	**139**	**138**	**139**	**153**	**146**	*153*	*10.1%*	*5.6%*	*10.1%*	*153*	*153*
- End. [a]	**138**	**124**	**124**	**146**	**107**	*107*	*5.6%*	*-13.8%*	*-13.8%*	*102*	*112*
Working Gas (BCF) - Beg. [b]	**2672**	**2170**	**2672**	**2944**	**2402**	*2944*	*10.2%*	*10.7%*	*10.2%*	*2944*	*2944*
- End. [b]	**2170**	**1184**	**1184**	**2402**	**1020**	*1020*	*10.7%*	*-13.9%*	*-13.9%*	*704*	*1354*
Propane (MMB) - Beg. [a]	**61**	**44**	**61**	**76**	**65**	*76*	*25.0%*	*47.6%*	*25.0%*	*76*	*76*
- End. [a]	**44**	**30**	**30**	**65**	**44**	*44*	*47.6%*	*47.4%*	*47.4%*	*35*	*53*
Prices											
Imported Crude Oil (c/g) c	**42.3**	**32.0**	**37.4**	**30.3**	**31.2**	*30.7*	*-28.3%*	*-2.7%*	*-17.7%*	*34.4*	*27.1*
Retail Heating Oil (c/g)	**93.4**	**91.5**	**92.5**	**84.3**	**91.0**	*87.7*	*-9.8%*	*-0.6%*	*-5.1%*	*93.4*	*82.6*
Wellhead Gas ($/mcf)	**2.54**	**1.74**	**2.14**	**2.25**	**2.23**	*2.24*	*-11.7%*	*28.0%*	*4.4%*	*2.44*	*2.06*
Resid. Gas ($/mcf)	**6.83**	**6.38**	**6.56**	**6.58**	**6.83**	*6.74*	*-3.6%*	*7.1%*	*2.7%*	*6.82*	*6.68*
Resid. Propane (c/g)	**93.4**	**94.8**	**94.1**	**88.3**	**94.7**	*91.5*	*-5.5%*	*-0.1%*	*-2.8%*	*95.6*	*87.4*
Market Indicators											
Manuf. Output (index, 1992=1.0)	**1.301**	**1.309**	**1.305**	**1.332**	**1.342**	*1.337*	*2.4%*	*2.6%*	*2.5%*	*1337*	*1337*
Northeast HDDs	**2120**	**2540**	**4661**	**2089**	**3064**	*5153*	*-1.5%*	*20.6%*	*10.6%*	*5668*	*4638*
Gas-Weighted HDDs	**1773**	**2078**	**3851**	**1686**	**2426**	*4112*	*-4.9%*	*16.7%*	*6.8%*	*4524*	*3700*

[a]mmb = million barrels.
[b]bcf = billion cubic feet
[c]Refiners' acquisition cost for imported crude oil.
[d]Percent changes have been adjusted for leap-year effects.
Notes: NM = percentage changes not particularly informative. 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: Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109; *Monthly Energy Review*, DOE/EIA-0035. Macroeconomic projections are based on DRI/McGraw-Hill Forecast CONTROL0897.

Highlights

Anticipated Demand Increases Promise Higher Heating Bills: Supply Plentiful

Assuming normal weather for this winter, a sharp increase in demand for heating fuels is expected compared to demand during the 1997-1998 season. Most if not all of the increase is expected to fall in the first quarter of 1999. For the winter, normal temperatures would imply an 8-percent year-to-year increase in heating degree-days nationally, with much higher increases in key heating regions. However, high stocks for all major heating fuels will tend to minimize the price effects of the expected higher demand. Furthermore, with an outlook of relatively low crude oil prices, heating fuel prices are likely to be lower this winter than they were last winter. Average winter retail heating oil prices are expected to average 3 to 5 cents below last season's prices. Natural gas wellhead prices should be well below last winter's level for the fourth quarter but well above last winter's level for the first quarter. Because of expected higher demand, households can expect to pay more for heat this winter despite the price outlook.

Cumulative Stock Builds Deflect Chances for Rapid Crude Oil Price Recovery

By the end of 1998 we will have completed a two-year period during which world petroleum inventories have increased a cumulative 550 million barrels (about 7 days of world supply). The main cause of this development has been weak worldwide demand generated by mild winter weather and the economic crises in East Asian countries. So far, production cutbacks by major producing countries have proved to be inadequate to move oil prices upward significantly. Despite the expectation of substantial increases in worldwide heating-related petroleum demand this coming winter, excess inventories may be trimmed only marginally next year. This is largely because U.S. and world economic growth is expected to slow in 1999. Thus, following an expected decline of about $6 per barrel in 1998, we see an increase of perhaps a $1 per barrel likely in 1999. Mild weather this winter could sustain low oil prices for many additional months.

U.S. Oil Demand: Despite Slower Economy, 1999 Likely to Yield Higher Growth

With the assumption that weather will be normal in the forecast, the chances are high that U.S. petroleum demand will grow more rapidly in 1999 than in 1998. Currently, we project that U.S demand will show an increase of about 0.8 percent in 1998 but a more robust 1.7 percent in 1999. Much of this additional growth would evaporate if the assumed increases in heating demand do not materialize this winter.

Natural Gas Demand: Probability of Sharp Increases Unusually High

While natural gas demand has generally been weak this year, it is evident that market participants appreciate the magnitude of likely average increases this coming winter. Despite very high stocks, price volatility remains high, with spot and futures prices reacting sharply to any threat to continued supply stability (such as hurricanes). We see the potential for some seasonal increases in gas prices between now and mid winter as well justified by potential demand increases. Base case demand is 9 percent (6.4 billion cubic feet per day) above year-ago levels in the first quarter of 1999.

Table HL1. U. S. Energy Supply and Demand

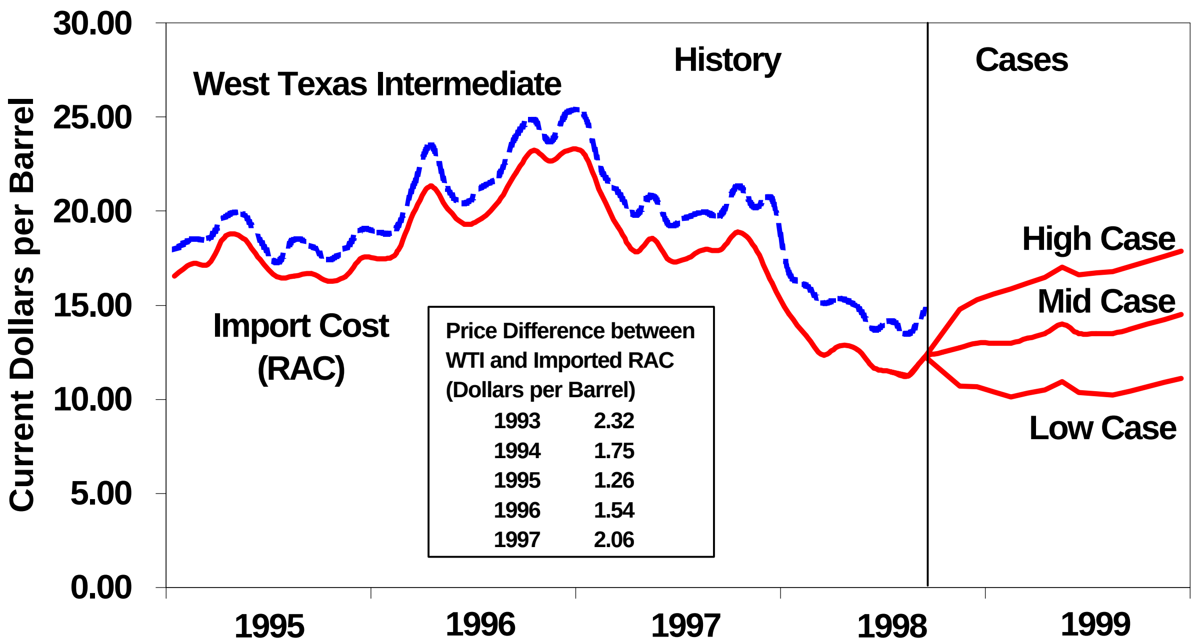
	Year				Annual Percentage Change		
	1996	1997	1998	1999	1996-1997	1997-1998	1998-1999
Real Gross Domestic Product (GDP)							
(billion chained 1992 dollars)	**6995**	**7270**	*7517*	*7639*	**3.9**	*3.4*	*1.6*
Imported Crude Oil Price [a]							
(nominal dollars per barrel)	**20.61**	**18.57**	*12.52*	*13.65*	**-9.9**	*-32.6*	*9.0*
Petroleum Supply (million barrels per day)							
Crude Oil Production [b]	**6.46**	**6.45**	*6.41*	*6.38*	**-0.2**	*-0.6*	*-0.5*
Total Petroleum Net Imports							
(including SPR)	**8.50**	**9.16**	*9.31*	*9.39*	**7.8**	*1.6*	*0.9*
Energy Demand							
World Petroleum							
(million barrels per day)..................................	**71.5**	**73.2**	*74.2*	*75.9*	**2.4**	*1.4*	*2.3*
Petroleum							
(million barrels per day)..................................	**18.31**	**18.62**	*18.76*	*19.09*	**1.7**	*0.8*	*1.8*
Natural Gas							
(trillion cubic feet)	**21.96**	**21.98**	*21.53*	*22.35*	**0.1**	*-2.0*	*3.8*
Coal							
(million short tons)	**1006**	**1030**	*1046*	*1072*	**2.4**	*1.6*	*2.5*
Electricity (billion kilowatthours)							
Utility Sales [c]	**3098**	**3115**	*3221*	*3249*	**0.5**	*3.4*	*0.9*
Nonutility Own Use [d]	**164**	**169**	*173*	*178*	**3.0**	*2.4*	*2.9*
Total	**3262**	**3283**	*3394*	*3427*	**0.6**	*3.4*	*1.0*
Total Energy Demand [e]							
(quadrillion Btu)...	**93.9**	**94.4**	*94.8*	*96.9*	**0.5**	*0.4*	*2.2*
Total Energy Demand per Dollar of GDP							
(thousand Btu per 1992 Dollar)......................	**13.43**	**12.99**	*12.61*	*12.68*	**-3.3**	*-2.9*	*0.6*
Renewable Energy as Percent of Total..........	**7.8**	**7.6**	*7.4*	*6.9*			

[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 1997 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)*.
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 CONTROL0898.

The Outlook

Outlook Assumptions

Figure 12. U.S. Monthly Crude Oil Prices



World Oil Prices

Crude oil prices, in terms of the average cost of imported oil to U.S. refiners, are assumed to climb gradually from the estimated September level of about $12.50 per barrel, after falling to an estimated low of just under $12 in June. Efforts by OPEC members to reduce current supply, including planned cuts announced on June 24, are seen as having stemmed the oil price free-fall but are not expected to return prices to anywhere near 1997 levels during our forecast period. Greater-than-expected success in holding down production levels or the occurrence of significant demand shocks could alter this result and move prices closer to the high range shown in Figure 12. Risks are probably equivalent on the down side, however, especially because of the fragility of the economic situation in Asia and the possibility that weather patterns could conceivably work against increased demand.

Economic Outlook

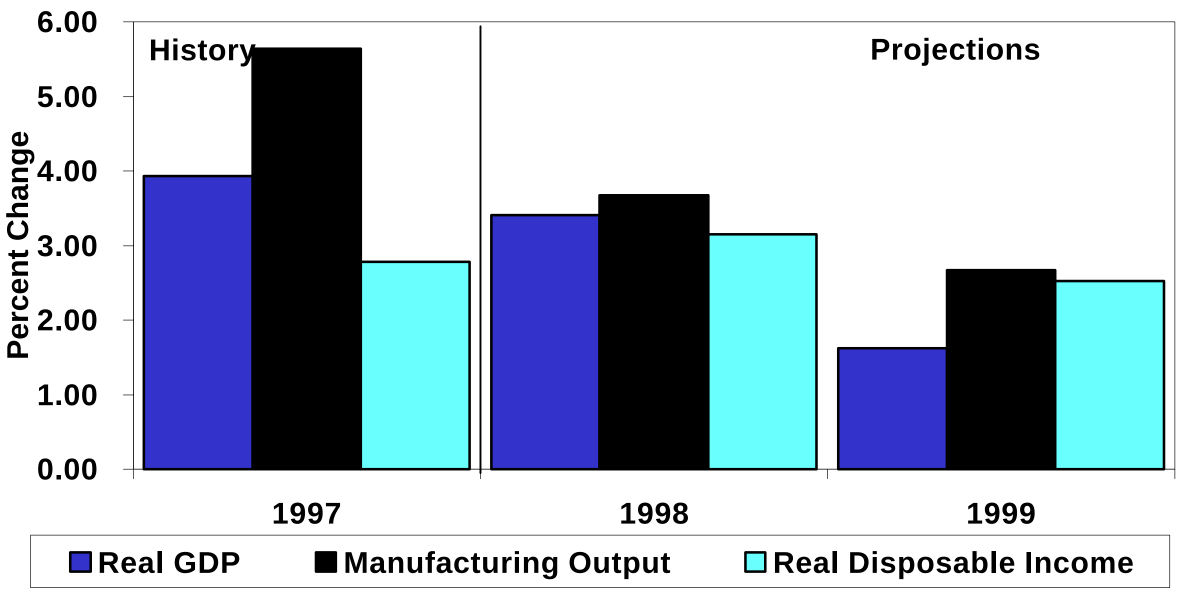
In 1998 and 1999, GDP is expected to continue to grow at rates of 3.4 percent and 1.6 percent, respectively. Growth in disposable income is assumed to be 3.1 percent in 1998 and 2.5 percent in 1999 (Figure 13 and Table 1).

Inflation (consumer price index: see Table 2) should remain moderate over the next few years. Consumer price inflation is expected to be 1.1 percent in 1998 and 1.8 percent in 1999 (Table 1). Manufacturing production growth is expected to be 3.7 percent in 1998. In 1999, manufacturing production growth slows to 2.7 percent as investment growth decelerates. Total employment will increase slowly over the forecast period.

Weather Assumptions

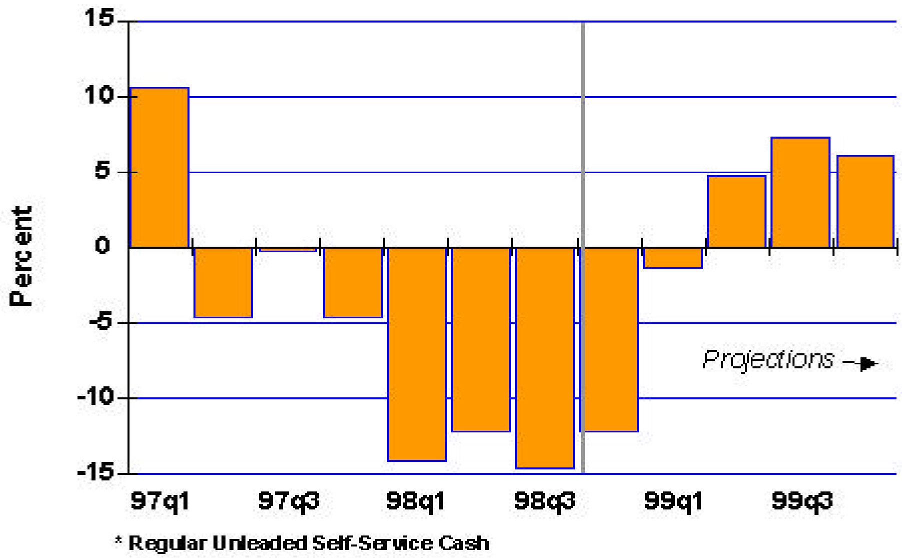
Weather patterns (expressed as heating and cooling degree-days in Table 1) are assumed to follow historical norms in the remaining 5 quarters of the forecast period. Winter heating degree-days in fourth quarter 1998 are expected to be slightly lower than heating degree-days during the same period last year. Normal temperatures would push winter heating degree-days 8 percent above first quarter 1998 levels.

Figure 13. U.S. Macroeconomic Indicators



U.S. Energy Prices

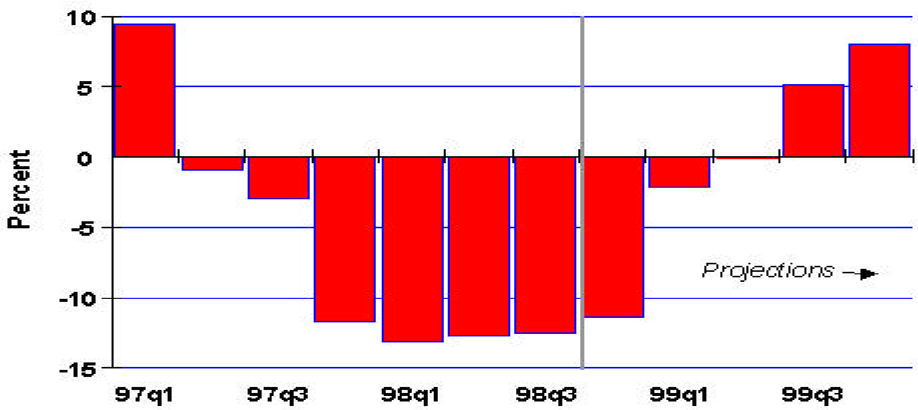
Figure 14. Quarterly Retail Motor Gasoline Prices (Percent Change from Year Ago)



U.S. retail motor gasoline prices may have hit bottom for the year in September due to the low world oil prices in the prior month as well as ample inventories available as the summer driving season ended. In real (inflation-adjusted) terms this price --$1.01 per gallon for unleaded regular self-service--is the lowest U.S. monthly price on record. Prices in the third quarter were 18 cents per gallon, or 15 percent, lower than they were one year ago (Figure 14). The average price for 1998 for this grade of gasoline is projected to be $1.04 per gallon, keeping alive our recent previous projection for the lowest (real) annual price in U.S history.

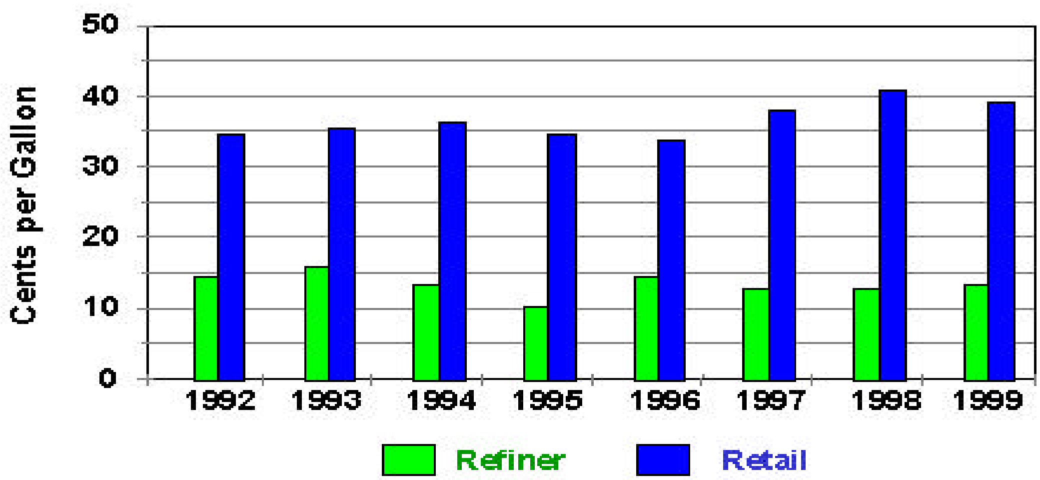
Residential heating oil prices for the fourth quarter of this year are projected to average about 9 cents per gallon (10 percent) less than in the same period last winter (Figure 15). Not only are crude oil prices expected to be about $5.00 per barrel lower, but stocks of distillate fuel at the end of September were about 14 million barrels above last year's levels. However, the price difference for the second half of the heating season (first quarter 1998 compared to first quarter 1999) is expected to be only 1 cent per gallon lower (1 percent), as the crude oil price difference between those two quarters narrows considerably. Most of the heating oil demand in the U.S. is consumed in the Northeast (Mid-Atlantic region and New England). Thus the weather in that region over the next several months will influence heating oil prices, although the extent of this influence also depends on other factors. These include not only inventories of distillate and crude oil and the world oil price, but they may also include the weather in Western Europe, which is the other large heating oil-consuming region in the world. These heating oil price projections assume "normal" weather, that is a 30-year monthly average. (For a discussion on colder or warmer than normal weather, see the Winter Outlook section). For the year 1998, residential heating oil prices are projected to average about 13 cents per gallon less than last year's average price. Next year, the average price should pick up about 3 cents per gallon in keeping with the assumed crude oil price rise.

Figure 15. Quarterly Retail Heating Oil Prices (Percent Change from Year Ago)



It is interesting to note that retail margins for heating oil climbed by more than five cents per gallon from 1996 through 1998--increases which occurred during periods of warm winter weather (Figure 16). Conversely, retail margins fell from 1995 to 1996, when the winter was quite cold.

Figure 16. Heating Oil Margins



The biggest single variable affecting petroleum product prices over the next several months is crude oil prices. With plentiful supplies and a slowdown in much of the world economy, crude oil prices have been low, much to the concern of oil-exporting nations. The question still remains whether the oil-exporting nations can maintain the discipline needed to raise prices. An attempt last spring to cut production failed to rally prices for more than about one month (See Outlook Assumptions for more analysis of the world oil situation.)

With the lower crude oil prices, all petroleum product prices have exhibited significant declines in 1998. With crude oil prices about $6 per barrel lower in 1998, petroleum product prices will probably average 13-16 cents per gallon less than in they were in 1997. In 1999, with slightly rising crude oil costs projected, petroleum product prices can be expected to creep upward about 2-4 cents per gallon over 1998 prices.

Natural gas composite wellhead prices started the year considerably under $2.00 per thousand cubic feet as the very mild winter weather left underground storage levels much above the levels of the previous year (Figure 17). These prices stayed under $2.00 through the summer. Spot wellhead prices, on the other hand, never dipped below $2.00 this year until August as unseasonably hot weather starting last June had increased air conditioning demand for electricity in much of the nation.

At the end of the cooling season, underground storage levels were notably above last year's levels, forcing the spot price down. However, there were brief periods in late August (Tropical Storm Charley) and in early September (Hurricane Earl) when severe storms curtailed gas production in the Gulf of Mexico, which reduced excess supplies to some extent. The result was that spot and futures prices jumped up by nearly 40 cents per thousand cubic feet in a few days. However, once the storms passed, production resumed and prices retreated. Hurricane Georges, which hit the Gulf Coast in late September, again pushed up spot and futures prices. Once the hurricane season passes (usually by the end of October or middle of November) that one factor causing price skittishness will have disappeared. The current storage situation, as stated before, shows levels well above last year's levels even with the storm-related production shutdowns. Thus, wellhead prices for the fourth quarter, assuming normal weather, are projected to be almost 13 percent less than prices for the same period last year (Figure 18). On the other hand, prices for the first quarter of 1999 are projected to average 50 cents higher than the prices in the first quarter of 1998, which were depressed because of the unusually warm first quarter of this year.

Figure 17. Natural Gas Wellhead Prices: Composite and Spot

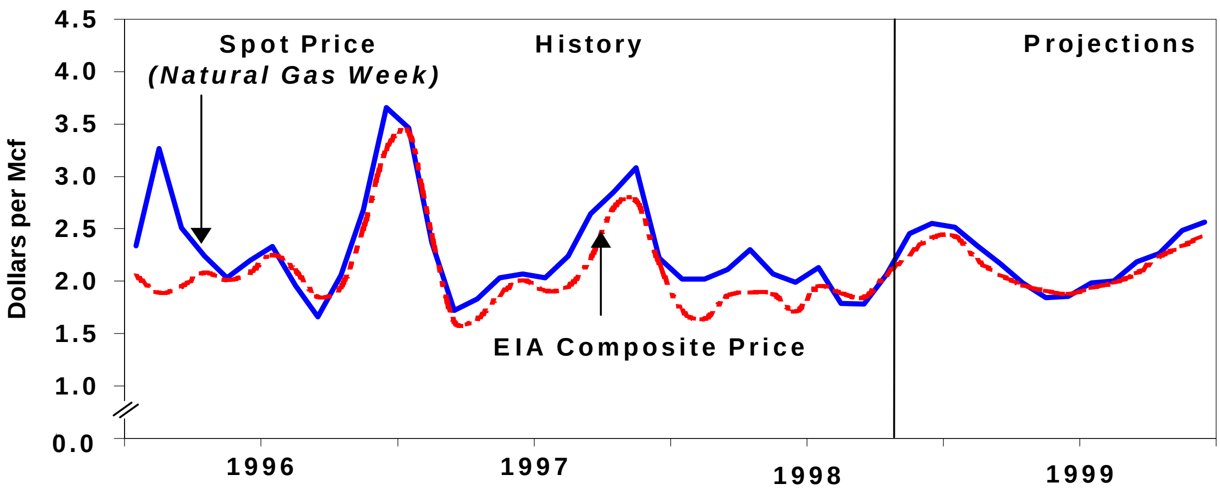
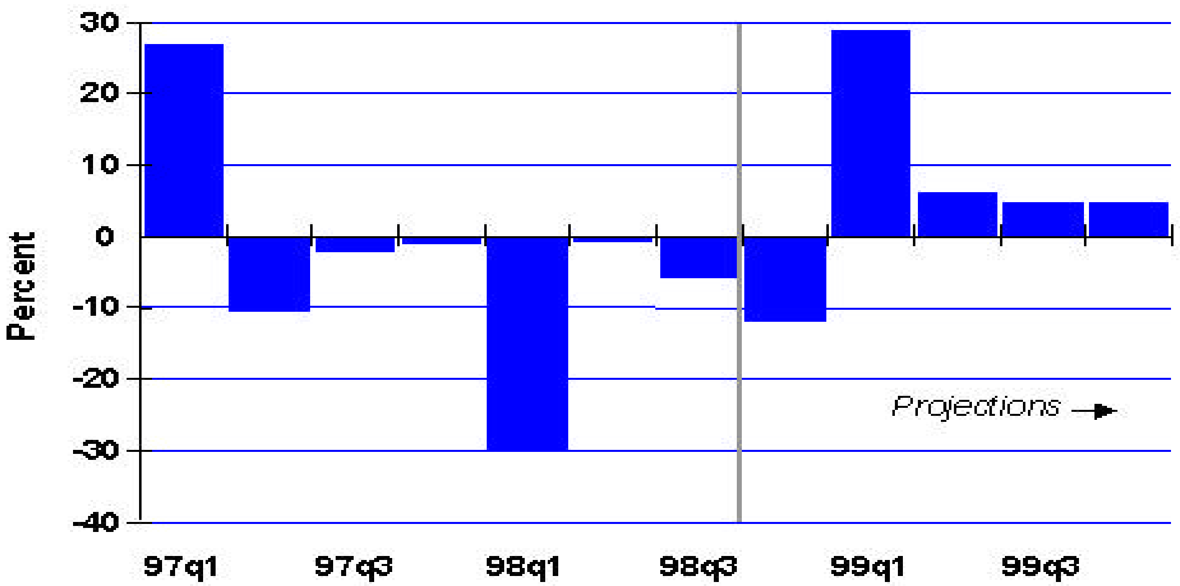


Figure 18. Quarterly Natural Gas Wellhead Prices (Percent Change from Year Ago)

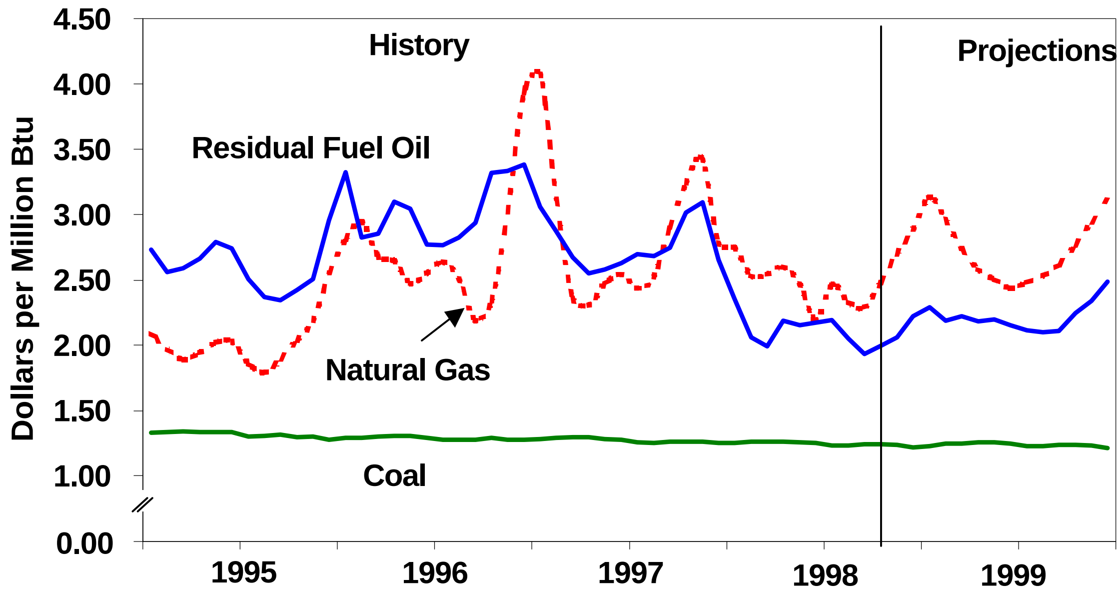


Where natural gas prices go this winter will depend heavily on the weather in the fall. A cold October in the East could once again send spot and futures prices upward, as they did last year, although there is a much larger cushion, in terms of working gas storage, this time around. Assuming normal weather for the remainder of the year, the annual average wellhead price is projected be about 13 percent lower in 1998 than in 1997 (Figure 18), with over half of the decrease resulting from the low first quarter prices of this year.

In 1999, again assuming normal weather, a return to normal seasonal price patterns for natural gas at the wellhead is projected, with prices once again peaking in the winter quarters. Mainly due to anticipated strength of demand during the heating season, the average annual price is projected to increase by about 10 percent next year.

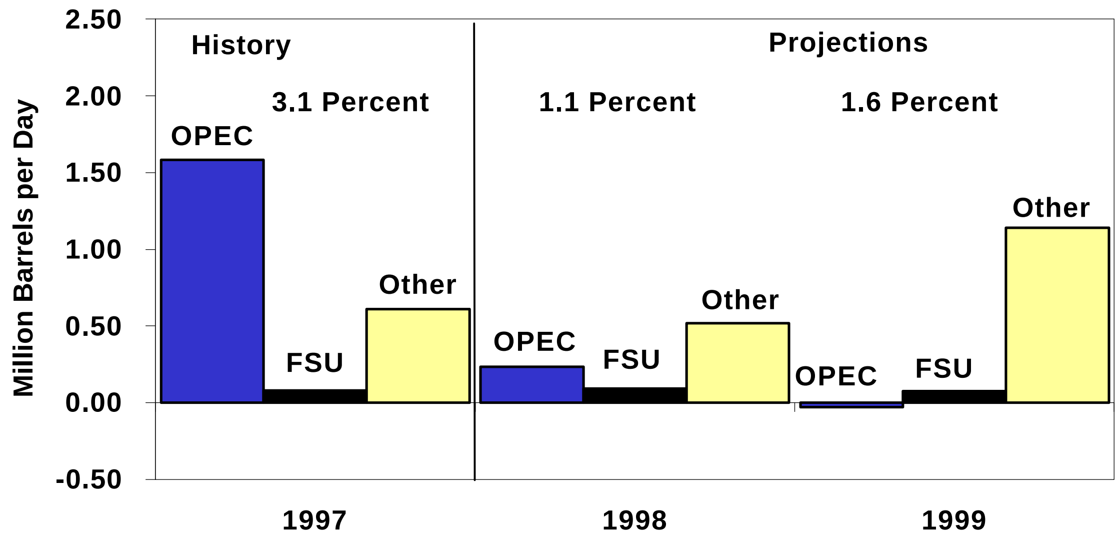
The price changes at the wellhead should be passed on to the end-users, resulting in lower residential gas prices for the fourth quarter 1998 compared to last year's prices, then followed by higher prices in the first quarter of 1999. The price of gas to electric utilities should exhibit a decline of about 10.5 percent in 1998, then rise by about 10 percent next year. Assuming moderate crude oil prices, residual fuel oil will remain the cheaper of the two fossil fuels burned at electric utilities throughout the forecast period. Coal remains by far the least expensive fossil fuel for electric utilities (Table 4 and Figure 19). Coal prices are expected to decline through 1999 even after costs associated with compliance with the Clean Air Act Amendments of 1990 are accounted for. Continued increases in mining productivity, including longwall mining , as well as the closing of costly marginal mines, more than offset increases in costs associated with rail transportation.

Figure 19. Fossil Fuel Prices to Electric Utilities



International Oil Supply

Figure 20. World Oil Supply (Changes from Previous Year)



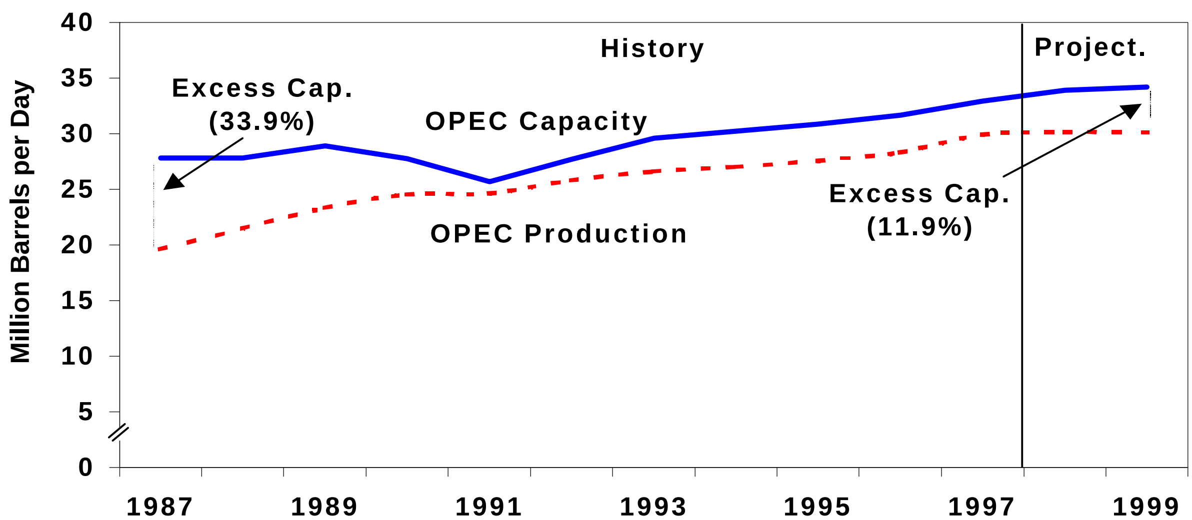
In late June, OPEC and some major non-OPEC countries announced cuts in production that, in combination with earlier pledged cutbacks this year, would reduce output by 3.1 million barrels per day from February 1998, with 2.6 million barrels per day of production cuts coming from OPEC. But even with an assumed 85% compliance rate in the production cuts for the 3rd quarter of 1998 (72% in the fourth quarter of 1998 and even lower in subsequent quarters), EIA is still forecasting world oil supply to exceed world oil demand by over 700 thousand barrels per day (over 250 million barrels) in 1998. And this follows 1997, a year in which EIA estimates world oil supply exceeded world oil demand by over 800 thousand barrels per day (300 million barrels over the course of the year)! This has returned inventories to historically high levels and has helped keep prices from rising substantially following the latest announced cuts in production by OPEC and some non-OPEC producers.

Beginning in early June 1998, Iraq began exporting under the latest United Nations Security Council (UNSC) resolution limiting Iraqi oil exports. Under this agreement, Iraq will be allowed to export over $5.2 billion worth of oil exports over the next 180 days, although limitations on Iraq's ability to produce and export oil will likely limit the total amount to something around $4 billion. On June 20, Iraq came to terms with the United Nations on allowing Iraq to import $300 million worth of spare parts in order to boost production and export levels. For the purposes of this forecast we have assumed Iraqi oil exports to average about 1.6 to 1.7 million barrels per day for the second half of 1998 and all of 1999. 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. Any increase in Iraqi oil beyond this will lessen the impact on prices from the oil supply cutback agreements in 1998.

For this forecast we have assumed that OPEC oil production will increase by about 200,000 barrels per day in 1998 (Figures 20 and 21) before stabilizing in 1999, after increasing almost 1.6 million barrels per day in 1997. This is because some OPEC countries are cutting back oil production at the same time Iraq, a member of OPEC, is increasing oil production. This forecast of OPEC production represents a loss of $48 billion (32%) from OPEC's crude oil export revenue in 1998 relative to production in 1997, due mainly to projected world oil price drops in 1998. (See EIA's analysis of OPEC oil revenues on Internet at http://www.eia.doe.gov/emeu/cabs/opecrev.html). With many OPEC countries highly dependent on oil export revenues as their main source of government revenues, a decline of this magnitude is extremely significant.

Sustained growth of non-OPEC supply is expected to continue for the foreseeable future, both inside and outside of the OECD.

Figure 21. OPEC Oil Production and Capacity



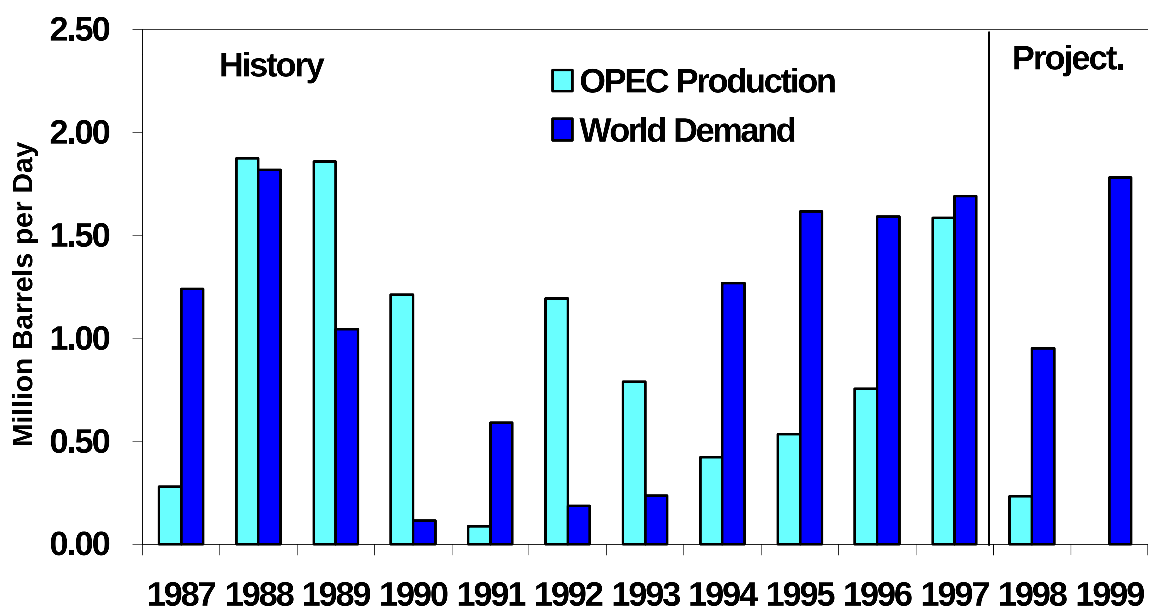
The major growth story within the Organization of Economic Cooperation and Development (OECD) region is North Sea production, which grew by about 2.2 million barrels per day between 1991 and 1996. North Sea production actually decreased in 1997, as several oil development projects were delayed. However, this forecast assumes a return to growth in North Sea oil production, with an increase of about 100,000 barrels per day expected in 1998 and about 500,000 barrels per day 1999 (Table 3).

Outside the OECD, the non-OPEC growth story is depicted by the "Other" group (Figure 19). Increments from this group are accelerating due to increases from Latin America, Africa, Other Asia, and some slight increases from the Middle East. Privatization efforts are beginning to accelerate growth, particularly in Latin America. Together, the non-OECD, non-OPEC countries, excluding the Former Soviet Union republics (FSU), are expected to increase production by 900,000 barrels per day between 1997 and 1999 (Table 3).

Joint ventures in the FSU, although growing slowly due to legal problems and export pipeline constraints, are beginning to foster positive supply prospects. Significant near-term increases are most likely to come from Kazakhstan, Russia, and Azerbaijan, rather than from any of the other former republics. This forecast assumes oil supply from the Former Soviet Union will increase by about 100,000 barrels per day in both 1998 and 1999.

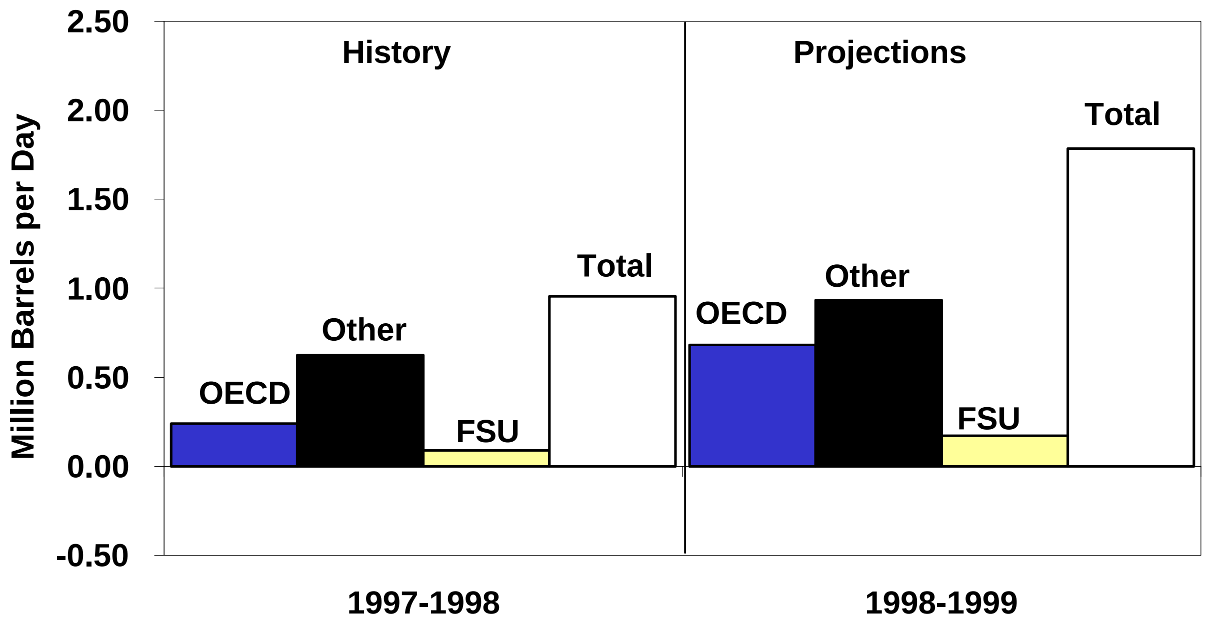
Non-OPEC supply has become a significant source of oil production during the last few years. Since 1994, OPEC production has increased less than world oil demand in every year, although in 1997 the increase in OPEC oil production nearly equaled the increase in world oil demand (Figure 22).

Figure 22. Annual Increases in OPEC Production and World Demand Changes, 1986-1998



International Oil Demand

Figure 23. World Oil Demand (Changes from Previous Year)



World oil demand is expected to continue to increase through 1999 (Figure 23), by which time total world oil demand may average 75.9 million barrels per day (Table 3). Problems in several Southeast Asian economies are expected to soften the increase in world oil demand, particularly in 1998. Following an annual world oil demand increment of 1.7 million barrels per day worldwide in 1997, world oil demand is expected to increase by only 1.0 million barrels per day in 1998, before rebounding with a 1.8 million barrels per day increase in 1999. Excluding demand in the Former Soviet Union, oil demand in 1998 is expected to increase by less than 1 million barrels per day, the first time this will have happened since 1990. But, even with less demand in Southeast Asia than originally expected, world oil demand under these assumptions will be growing at an average annual rate of 1.9 percent between 1997-1999 after growing at an average annual rate of only 1.7 percent between 1992-1996.

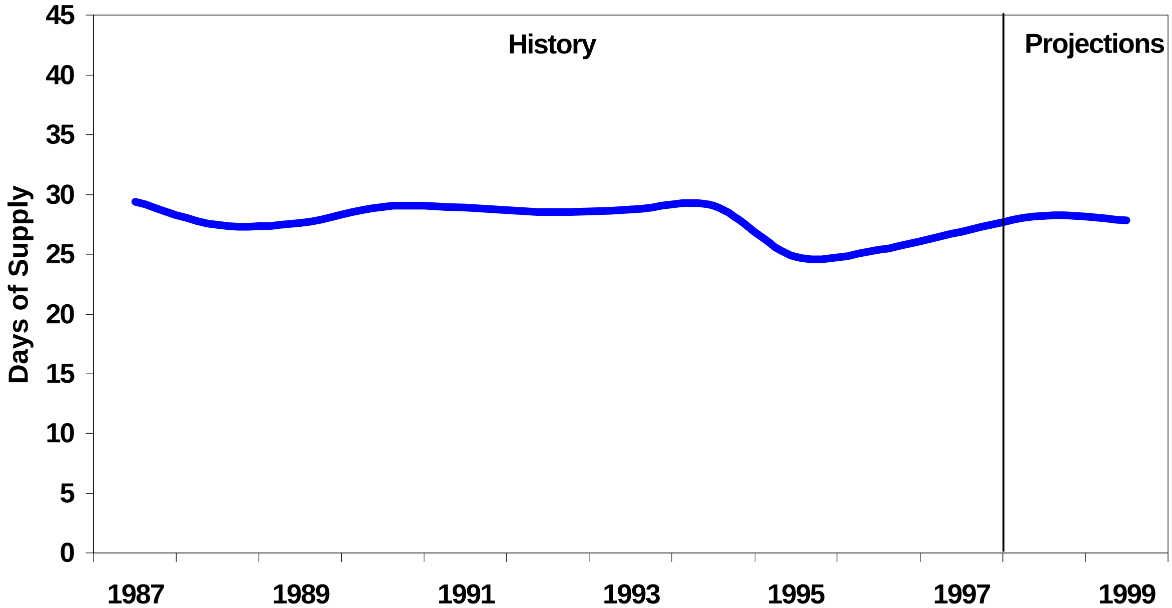
Oil demand in countries of the OECD is expected to increase by about 200,000 barrels per day in 1998 and another 700,000 barrels per day in 1999, an average annual rate of 1.1 percent (Figure 23 and Table 3). (Our OECD estimates do not yet include those of the Czech Republic, Hungary, Mexico, Poland, and South Korea). Japan's current recession is expected to be the main reason for a decline in Japanese oil demand in 1998 while remaining relatively flat in 1999. Partly because of this, the United States' oil demand growth represents nearly two-thirds of OECD oil demand growth in 1998 and nearly half of OECD oil demand growth in 1999.

A major story of this forecast is 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 7.6 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 6.4 percent for China and a barely noticeable growth of 0.3 percent for Other Asian oil demand between 1997 and 1999. At the same time, however, Latin American oil demand is expected to grow at an annual rate of 4.5 percent between 1997 and 1999. Continued strength in world oil demand is partly due to significant increases in U.S. and Latin American oil demand growth. Of course, this assumes that the economic slowdown in Asia does not impact Latin America at nearly the same degree.

After showing some growth in oil demand in 1997 for the first time since the collapse of the Soviet Union, oil demand in the former Soviet Union (FSU) is projected to increase even further in 1998 and 1999. This occurs even though the growth has been revised downward due to the recent economic problems in Russia. Oil demand in the FSU stood at 8.9 million barrels per day just 10 years ago, reached a low of 4.4 million barrels per day in 1996, and is forecast to increase to 4.7 million barrels per day by 1999 (Table 3).

World Oil Stocks, Capacity and Net Trade

Figure 24. OECD Commercial Oil Stocks

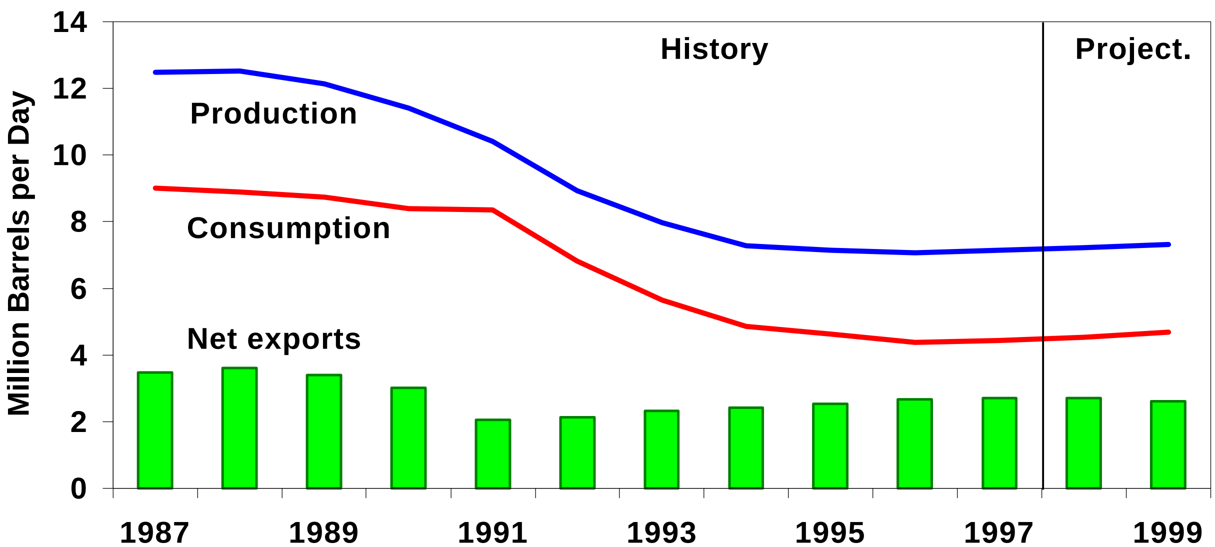


Commercial oil inventories (measured in days of supply) in OECD countries increased nearly 1.5 days worth of supply in 1997, the largest such increase since 1990. OECD commercial oil inventories are expected to increase even more in 1998 (1.3 days of supply) before declining in 1999 (Figure 24). The increase in 1997 and 1998 is in large part due to the currently oversupplied market, but by 1999 our forecast shows a more balanced world oil market in terms of supply and demand, thus reducing the days of supply level for OECD commercial oil inventories.

Outside Iraq, OPEC oil production capacity is expected to increase by nearly 800,000 barrels per day in 1998 and an additional 250,000 barrels per day in 1999. This is due to OPEC oil production increases lagging behind planned capacity increases, which is in large part due to the cutbacks in production announced in 1998. Overall, OPEC excess oil production capacity is expected to increase from about 3.1 million barrels per day in 1997 to about 4.1 million barrels per day in 1999, the most since 1989. Saudi Arabia is still expected to control over half of OPEC excess production capacity and, along with Kuwait and the United Arab Emirates, controls the vast majority of excess world oil production capacity.

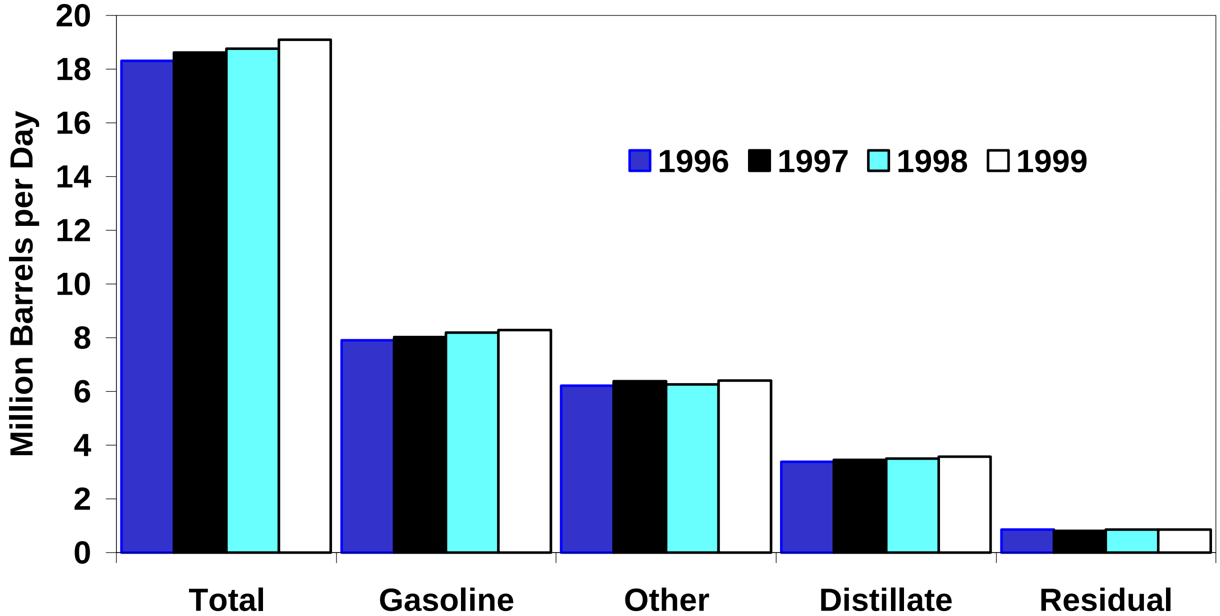
Current exports of crude oil worldwide are averaging about 35 million barrels per day, with about 60 percent originating from OPEC countries. Saudi Arabia is by far the world's largest exporter, with over 7 million barrels per day of crude exports. Net exports from the FSU are expected to decrease slightly during the forecast period, from 2.7 million barrels per day in 1997 to about 2.6 million barrels per day in 1999. This is because increases in oil demand are expected to be slightly more than anticipated increases in oil production (Figure 25 and Table 3). Most of the increase in oil production in FSU countries is still expected to come after 1999. However, FSU exports are still significantly higher than they were immediately following the collapse of the FSU (2.1 million barrels per day in 1991 and 1992) and are now closer to levels seen just prior to the collapse of the FSU (3.0 million barrels per day).

Figure 25. FSU Oil Output, Demand and Net Exports



U.S. Oil Demand

Figure 26. Petroleum Demand Change



For the year as a whole, U.S. oil demand growth in 1998 is projected to be 140,000 barrels per day, or only 0.8 percent above the 1997 level. Slow motor gasoline growth during the first half of the year, warm weather during the first quarter and--most notably--an apparent slump in jet fuel markets since the beginning of the year have contributed to the tepid growth. The weakness in reported jet fuel deliveries, however, does not appear to be consistent with other jet-fuel market indicators, such as air traffic activity and fuel purchases by commercial carriers, and may more realistically be attributed to jet-kerosene volumes being misclassified in other categories such as distillate fuel.

Following an apparent lull in petroleum markets, available data point to renewed strength for the third quarter. Buoyed by strength in motor gasoline, distillate fuel oil, and residual fuel oil markets, year-to-year demand growth for that period is currently estimated to be 2.1 percent, the peak quarterly growth rate for 1998. Demand growth for the rest of the year, however, is likely to be subdued, resulting in slow growth for the year as a whole (Figure 26).

Despite a slowing economy, U.S. petroleum demand growth is expected to increase in 1999 by about 1.8 percent. Much of this incremental growth is attributed to expected gains in heating fuel and other weather-sensitive products.

Available data for the summer indicate a 1.8-percent average increase in motor gasoline demand for the second and third quarters. This reflected an estimated 2.7-percent increase in highway travel during that period. Stimulated by year-over-year price declines of almost 15 percent to new (inflation-adjusted) lows, third-quarter demand rose an estimated 3.0 percent. That demand growth contrasts sharply with the 0.6-percent demand growth recorded in the second quarter. For the year as a whole, 1998 motor gasoline demand is projected to climb by a moderate 2.0 percent growth rate, reflecting a 2.6-percent increase in highway travel. Real disposable income, however, is projected to climb 3.1 percent, and real fuel costs per mile are expected to decline an average of 14.8 percent, reaching new lows. But the combination of robust economic growth, sharply declining fuel prices and high consumer confidence levels did not bring about the same growth in gasoline demand as previously observed under similar conditions during the mid-to-late eighties. These projections (as well as recent history) therefore suggest an apparent shift in travel patterns: highway travel can be expected to grow, but at rates somewhat less than experienced in the past. In 1999, vehicle miles traveled are projected to climb a further 2.1 percent, while motor gasoline demand is projected to climb 1.3 percent, reflecting small but continued growth in fuel efficiencies.

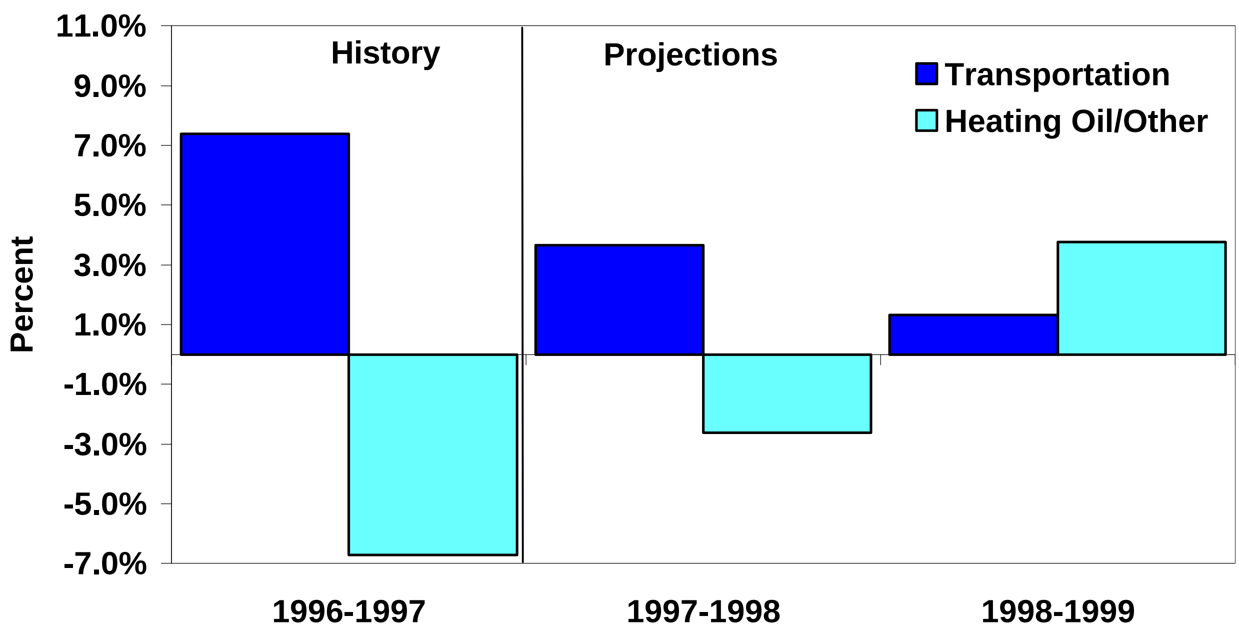
Data since the beginning of the year have indicated apparent weakness in total jet fuel demand. “Total” demand comprises not only commercial air carrier demand but also military purchases and quantities used by downstream blenders as additives to heating oil and distillate fuel to prevent freezing during periods of cold weather. The latter two components have contributed to the weakness in demand: the very mild first quarter and reductions in military purchases have contributed to the year-to-year decline thus far. Purchases by air carriers, however, have continued to increase steadily despite a slowdown in the growth of revenue ton-miles and available capacity since the beginning of the year. Growth in airline capacity (available passenger and cargo space in the air) is projected to increase 4.9 percent, slightly below last year's rate. But growth in air travel (utilization of the available capacity) is projected to be 3.8 percent, down substantially from last year's robust 6.9 percent growth rate, resulting in a decline in average load factors. Although Asia clearly accounts for part of that slowdown, domestic air travel growth has also slowed somewhat. In an apparent attempt to enhance revenue and profitability, several airlines have become more selective in offering discounts in discretionary travel markets. Despite these developments, market indicators would suggest that jet fuel demand should be showing some net increases this year.

In 1999, capacity is projected to grow by a relatively modest 3.4 percent in response to the slowdown in air travel of the previous year as well as a slowing domestic economy. Air travel is projected to climb 3.4 percent in 1999, resulting in a stabilization of average load factors at the previous year's averages. Having contracted for several years, military purchases of jet fuel are not expected to decline from present levels. Under assumptions of normal weather, demand for jet fuel as a blending component is expected to increase noticeably. If much of the expected "growth" in jet fuel in 1999 is a function of the rather peculiar weakness seen in 1998, it is our judgement that this does not imply an upward bias in total petroleum demand growth shown for next year.

Distillate demand growth for 1998 is expected to be relatively weak at 1.5 percent, down from last year's growth of 2.1 percent. (Figure 27). Much of that slowdown brought about two factors: a moderation in manufacturing output growth from last year's 5.6 percent to this year's projected 3.7 percent, and the combined effects of warmer weather in the first and fourth quarters compared with conditions in 1997.

Despite the economically-driven slowdown in transportation demand growth to only 1.3 percent, total distillate demand is projected to increase by 2.0 percent in

Figure 27. Distillate Demand Growth



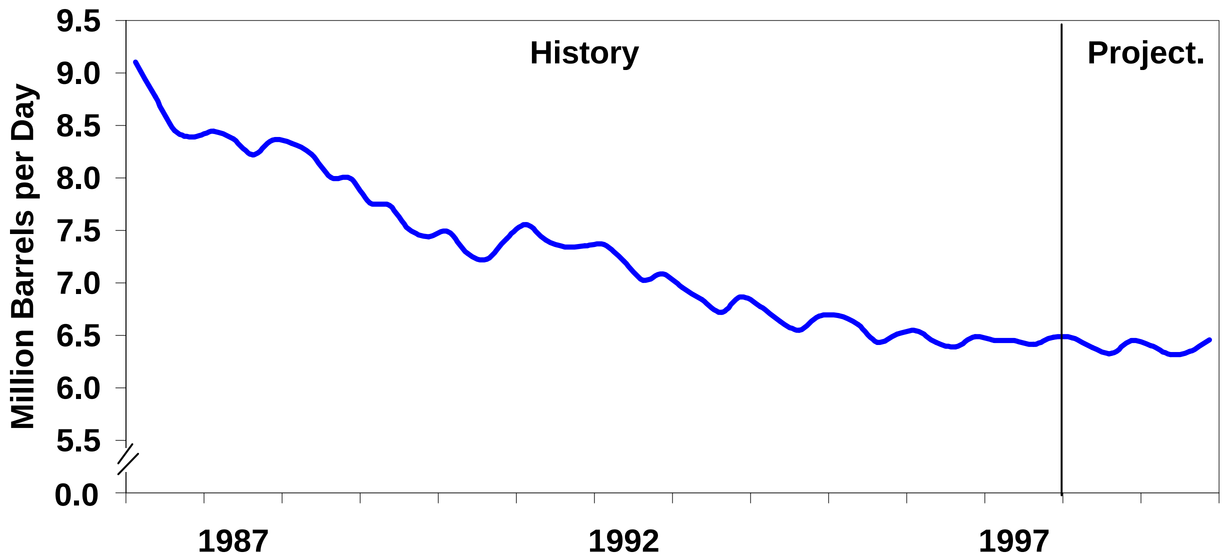
1999. That growth results largely from the return to normal weather patterns.

Recovering from all-time lows, residual fuel oil demand in 1998 is projected to post an increase of about 5 percent, boosted by declines in residual fuel prices of between 20 and 30 percent in both the electric utility and industrial sectors.

Electric utility use of heavy fuel oil has been strong almost every month this year, with year-over-year growth rates ranging as high as 100 percent or more. In 1999, residual fuel oil demand is projected to remain unchanged. Increases in non-utility demand are expected to be offset by declines in electric utilities demand under assumptions of normal summer weather.

U.S. Oil Supply

Figure 28. U.S. Crude Oil Production

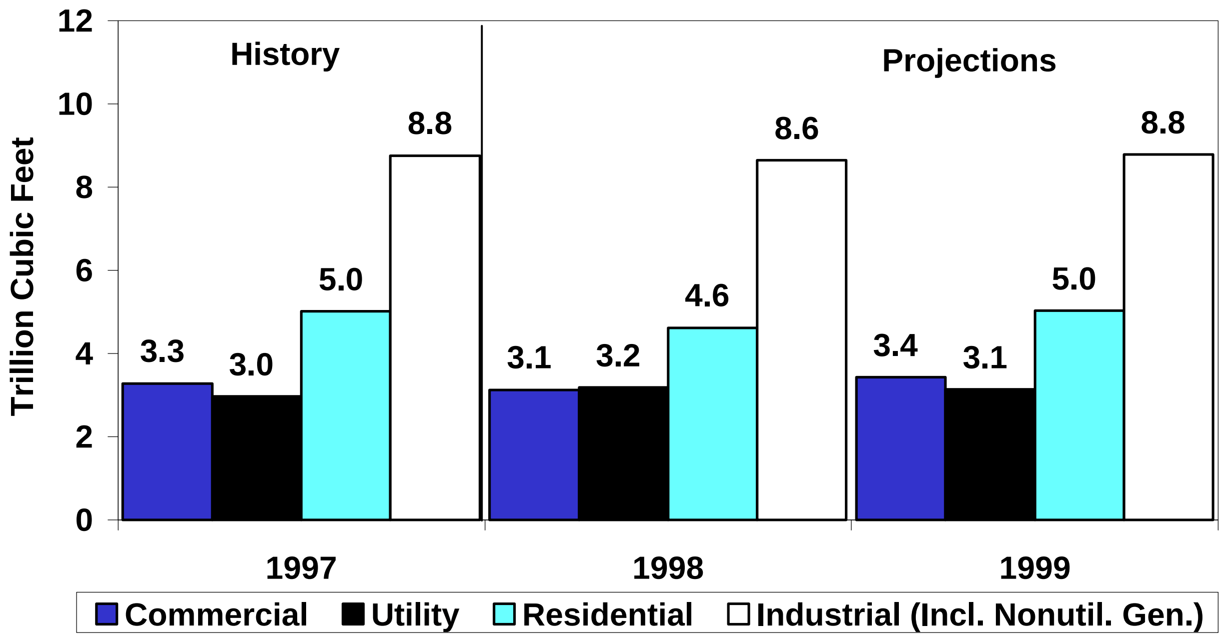


New production from Federal offshore oil slowed the steady decline of domestic crude oil supply in 1998. Average domestic oil production in 1998 is expected to decline by about 40,000 barrels per day from the 1997 level of 6.45 million barrels per day (Figure 28). This rate of decline is expected to continue in 1999.

Lower-48 States oil production is actually expected to increase by about 70,000 barrels per day to about 5.23 million barrels per day in 1998. This is followed by a further increase of 50,000 barrels per day in 1999. New to this forecast is the addition of the Baldplate deepwater field with production of 50,000 barrels per day beginning in 1999. Shell reported production increases of 40,000 barrels per day in the Mars platform production in 1998. Shell will also 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. Oil production from the Mars, Ram-Powell, Auger, Troika, Ursa, and Santa Ynez Federal Offshore fields is expected to account for about 10.8 per cent of the lower-48 oil production by the 4th quarter of 1999. Alaska is expected to account for about 17.3 percent of the total U.S. oil production in 1999. Production there is expected to decrease by 8.6 percent in 1998, followed by a slight decline of 6.9 percent in 1999.

U.S. Natural Gas Demand

Figure 29. Natural Gas Demand by Sector



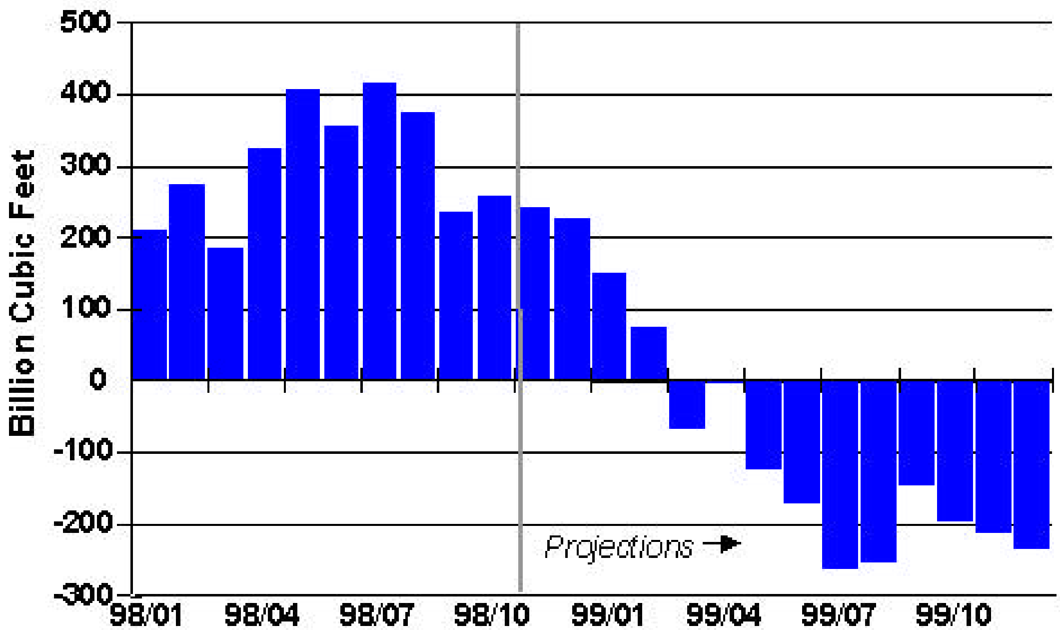
Demand growth for natural gas in 1998 reflects the weather-related weakness in residential and commercial sector demand for gas. Natural gas demand in 1998 is expected to be below the estimated 1997 level of 21.98 trillion cubic feet by 2.0 percent. The only strength in gas demand this year has been due to growth in electricity generation, boosted largely by the substantial increase in cooling demand this year. The industrial sector did not generally provide any strength to the market in the first half of this year, although industrial demand is expected to show a positive year-to-year change in the fourth quarter. Industrials are using less energy to produce more output while gas is losing share to other fuels in this shrinking market, due to some extent to interfuel competition.

Despite high gas stocks, price volatility remains high, with spot and futures prices reacting sharply to any threat to continued supply stability. Production cuts and consequent use of some storage as a result of recent stormy weather in the Gulf could lead to a higher prices moving into winter. However, assuming normal weather, we expect fourth quarter 1998 heating demand to be slightly below the year-ago level.

Next year, a much broader natural gas demand growth profile is likely, particularly if a normal or colder-than-normal winter occurs. Base case demand is expected to be almost 9 percent above year-ago levels in first quarter 1999. Gas demand is expected to grow across all sectors in 1999 under the assumptions of normal weather conditions and continued economic growth. Gas demand is projected to rise by 3.8 percent in 1999 (Figure 29).

U.S. Natural Gas Supply

Figure 30. Changes in Total Gas Underground Storage (From Year Ago)



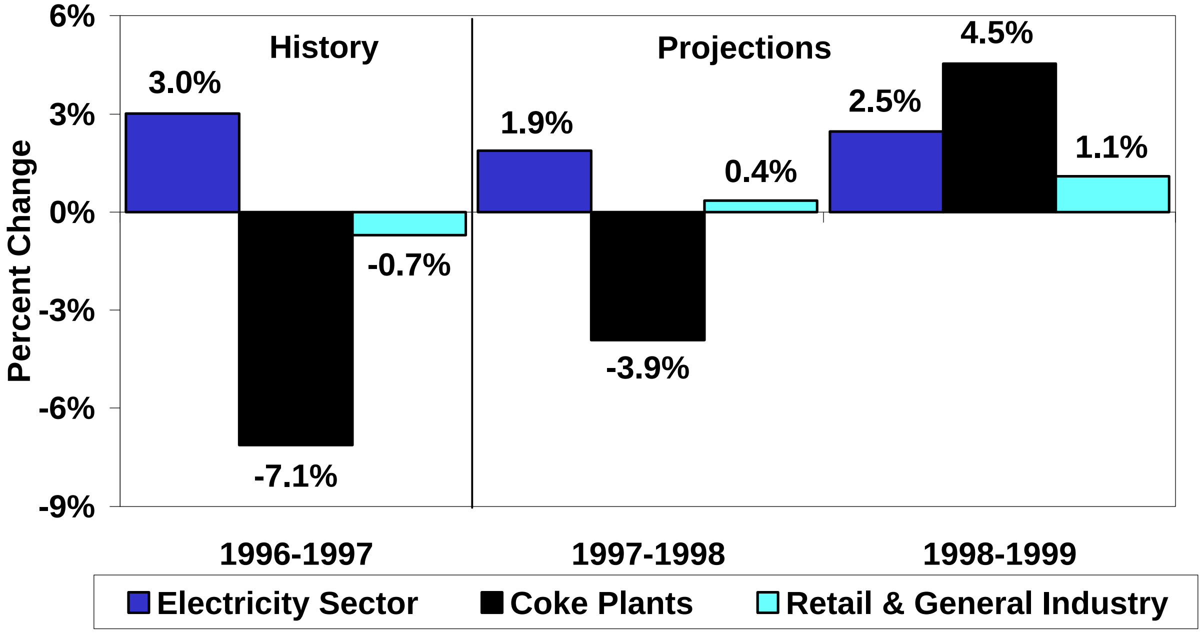
Total natural gas in underground storage enters the heating season well ahead of last year's level and is expected to remain ahead through the end of 1998. Gas storage levels are estimated to have been over 400 billion cubic feet higher at the end of July than they were a year ago (Figure 30), with each of the three gas-consuming and gas-producing regions holding more gas in storage than they did a year ago. Gas storage at the beginning of the heating season is expected to maintain that edge over year-ago.

Despite the large increase in drilling activity in 1997 to the highest levels since 1990 and relatively higher wellhead prices, U.S. gas production is expected to rise by only 0.6 percent in 1998 from 1997 levels, reflecting both the demand limitations and the greater use of storage. High decline rates for some recent wells, particularly in the Outer Continental Shelf of the Gulf of Mexico, indicate a need for continued high levels of drilling to maintain current levels of production. On the other hand, given the current demand outlook and the high levels of gas in storage, little need for additional production is seen, at least for this year. Dry gas production growth in 1999 is expected to be only slightly higher than the 1998 rate.

Natural gas net imports are expected to increase by 2.1 percent this year compared to imports last year, and by another 7.6 percent in 1999. By the end of this year, a total of more than 1.1 billion cubic feet per day of new Canadian export capacity is expected due to expansion of the Transcanada and Northern Border pipelines. Additional expansion of the Transcanada pipeline in 1999 will add another 450 million cubic feet per day in November of that year. The ability of Canadian producers to fill the new pipelines will depend on storage and drilling levels in Canada.

U.S. Coal Demand and Supply

Figure 31. Annual Change in U.S. Coal Demand



Total coal demand is expected to increase by 1.6 percent in 1998 and by 2.4 percent in 1999, compared to 2.4 percent growth in 1997 (Table 9 and Figure 31). Coal demand by the electricity sector (including independent power producers) grew by 3.0 percent to a record 924 million short tons in 1997, despite weak electricity demand growth of about 0.6 percent. Declines in nuclear generation (6.8 percent) were largely responsible for the rise in coal consumed for power generation in 1997. Growth in electricity demand (3.4 percent in 1998 and 1.0 percent in 1999), combined with a return to normal levels of hydroelectric generation, will provide the impetus for continued growth in coal demand by the electricity sector. The electric sector currently consumes nearly 90 percent (89.7 percent in 1997) of all coal used in the United States.

Coal carbonized (consumed) by coke plants fell 7.1 percent in 1997 to 29.4 million short tons. Demand for coal at coke plants is expected to remain below 30 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. The growth of coke plant coal consumption is also hindered 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 by 4.6 percent in 1997, and it is expected to grow by an average of 4.7 percent over the forecast period. Electric-arc production accounted for 43 percent of all raw steel produced in the United States. Coal-based raw steel production grew by only 1.2 percent in 1997, and it is expected to average 1.3 percent growth over the forecast period.

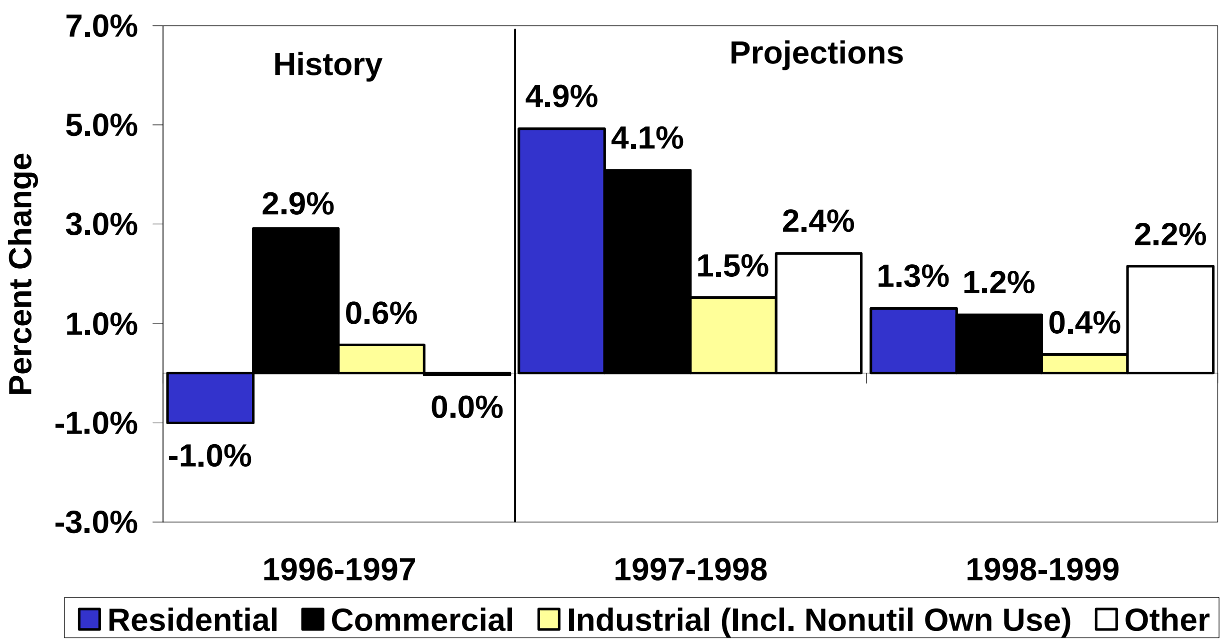
Demand for coal by the retail and general industry sectors is projected at 76.7 million short tons in 1998, a 0.4 percent increase from 1997 demand. In 1999, demand is expected to be 77.5 million short tons.

U.S. coal exports are expected to decline for a second straight year in 1998, but exports will rebound in 1999. Exports are projected to be 79.0 million short tons in 1998 (a 5.4 percent decrease) and 79.8 million short tons in 1999 (Table 9).

A record 1,089.9 million short tons of coal was produced in 1997. Production is expected to grow by 1.9 percent in 1998 and 1999, with annual output exceeding 1,110 million short tons in 1998. Production is projected to be 1130.9 million short tons in 1999. Production in the Western region should continue to rise significantly over the forecast period (6.4 percent in 1998 and 4.6 percent in 1999). The Western region is expected to become the nation's largest coal producer in 1998 surpassing the Appalachian region. Production in the Appalachian region will decline in 1998 (by 1.3 percent), and increase by a modest 1.0 percent in 1999. Interior region production is projected to average a decline of 2.5 percent over the forecast period.

U.S. Electricity Demand and Supply

Figure 32. U. S. Electricity Demand



Total electricity demand growth for 1998 is now expected to be 3.4 percent above the 1997 level, an upward revision from the 2.5 percent growth projected last month. This is due mainly to upward revisions to both residential and commercial demand for electricity (Figure 32 and Table 10), due mainly to the record high temperatures in second and third quarters. Industrial output growth is also expected to be slightly higher than previously predicted this year, although 1999 growth is expected to be relatively flat.

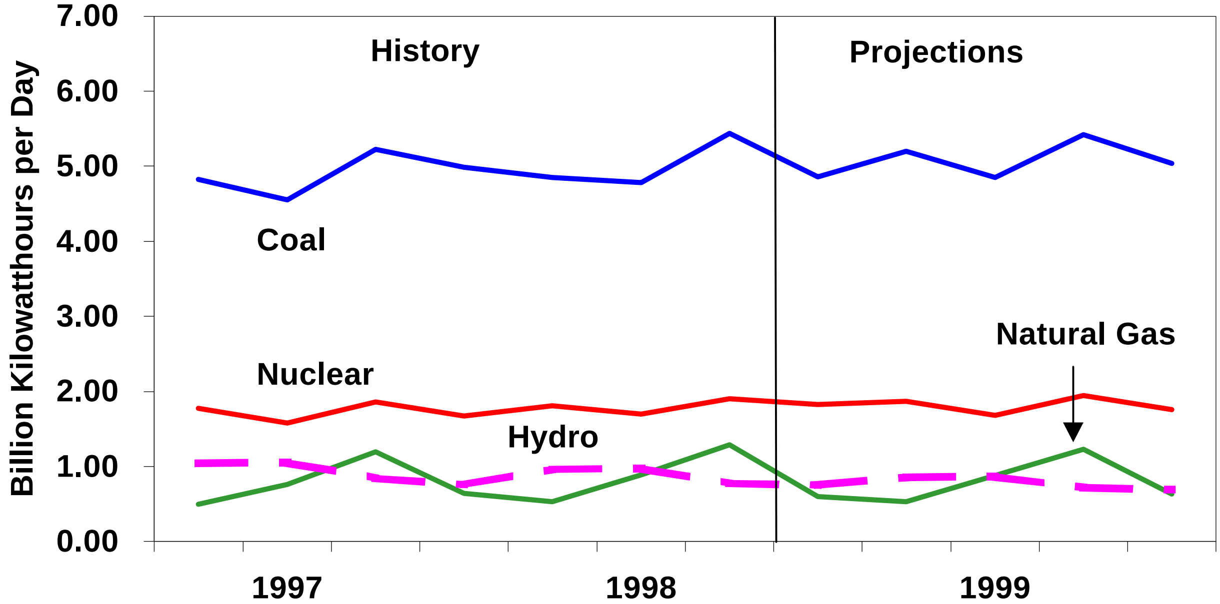
Demand growth should slow down to 1.0 percent in 1999 since cooling demand would not be expected to rise from the high 1998 levels and since the economy is assumed to grow at a slower pace next year. As in the case of natural gas and heating oil, a boost to demand in first quarter 1999 is expected to arise from higher heating demand, especially in the residential and commercial sectors. However, the industrial sales growth rate is likely to tail off through the next year (Figure 31).

In addition to expecting significantly lower electricity demand growth next year, we also expect to see some significant differences in the electricity supply profiles. Because much of the electricity demand growth this year occurred during the spring and summer months, and because most of the decline in availability of hydroelectric power this year occurred in the Pacific region, natural gas has played a relatively large role in meeting incremental demand in 1998. Next year, with most of the electricity demand growth expected to take place in the winter, we expect to see a much smaller role (if any) for natural gas and a much larger incremental role for coal. It seems unlikely that oil will continue to gain share as a fuel source in electric power generation beyond the gains made in 1998. While hydroelectric power is expected to continue to decline as a fuel source in 1999, much more of next year's reductions in electricity demand are likely to be outside the Pacific region, which generally implies a smaller impact on natural gas.

Much of what has happened with regard to cooling demand this year and most of the consequent impacts on natural gas demand were concentrated in the West South Central (WSC) region (Texas, Louisiana Oklahoma and Arkansas). That it has been sweltering in the South also is evident by the huge increases in heating degree-days relative to 1997.

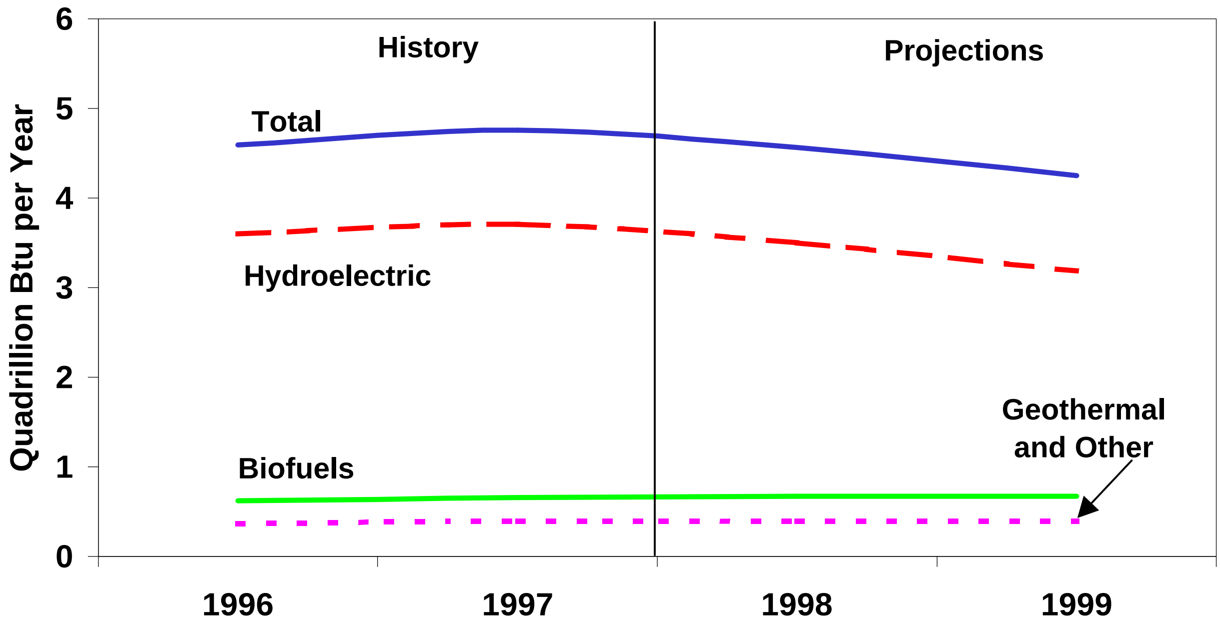
In 1998 and 1999, nuclear generation is forecast to recover from its decline in 1997, as many of the downed nuclear plants go back on line.

Figure 33. Electricity Generation by Fuel



U.S. Renewable Energy Demand

Figure 34. Renewable Energy Use for Electricity



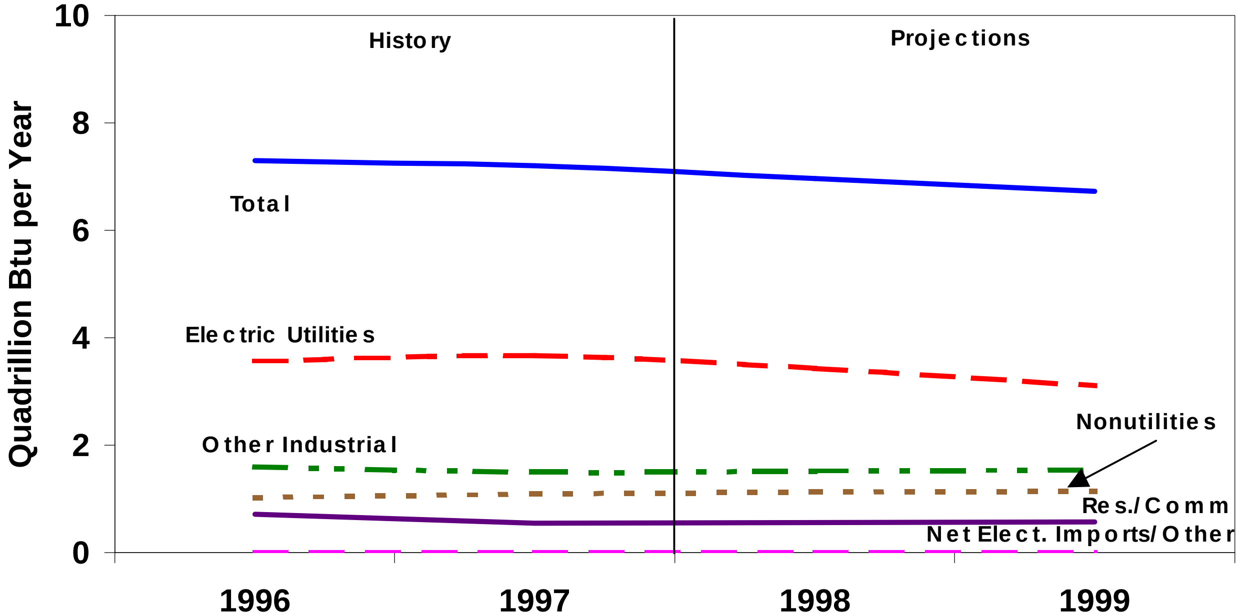
Renewable energy use in the United States amounted to about 7.2 quadrillion Btu (quads), or about 7.8 percent of total domestic gross energy demand, in 1997 (Tables HL1 and 11). In 1998, use of renewables is expected to decrease by about 3.2 percent due to a decline in hydroelectric generation. In 1999, renewables use is expected to decrease further by an annual average of 3.5 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 34).

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 34), 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.

Currently, aside from power generation, the most significant area of renewables use is in the industrial sector, accounting for 21 percent of the total in 1997. This component is principally biofuels.

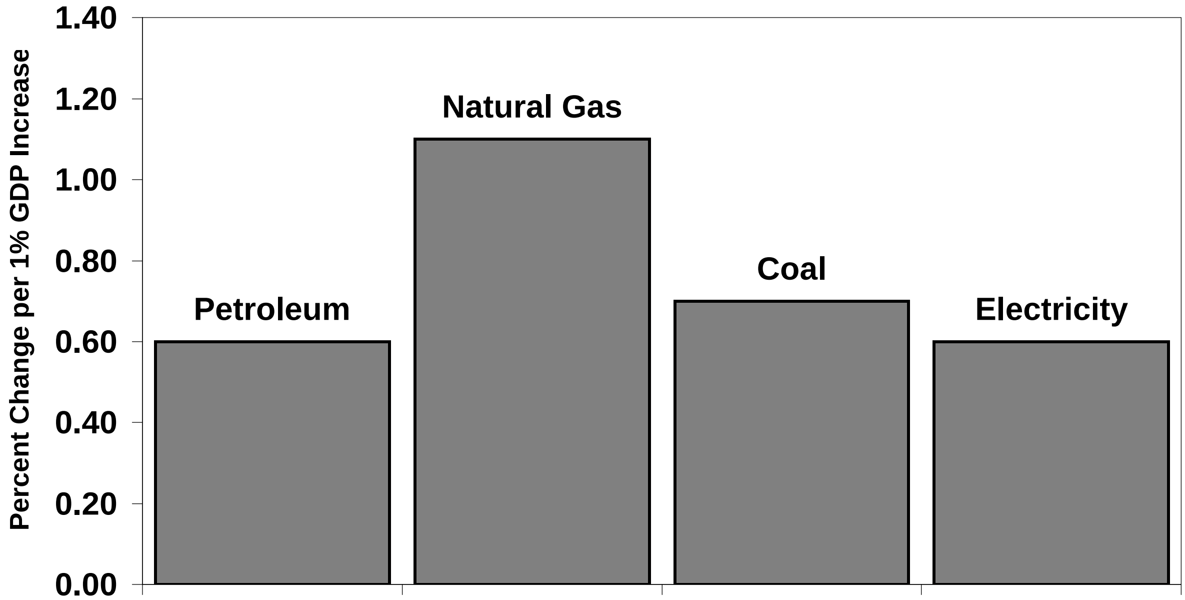
Figure 35. Renewable Energy Use by Sector



Renewables use in the combined residential and commercial sector, at about 0.6 quad in 1997 (Figure 35), 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 36. Macro Sensitivities



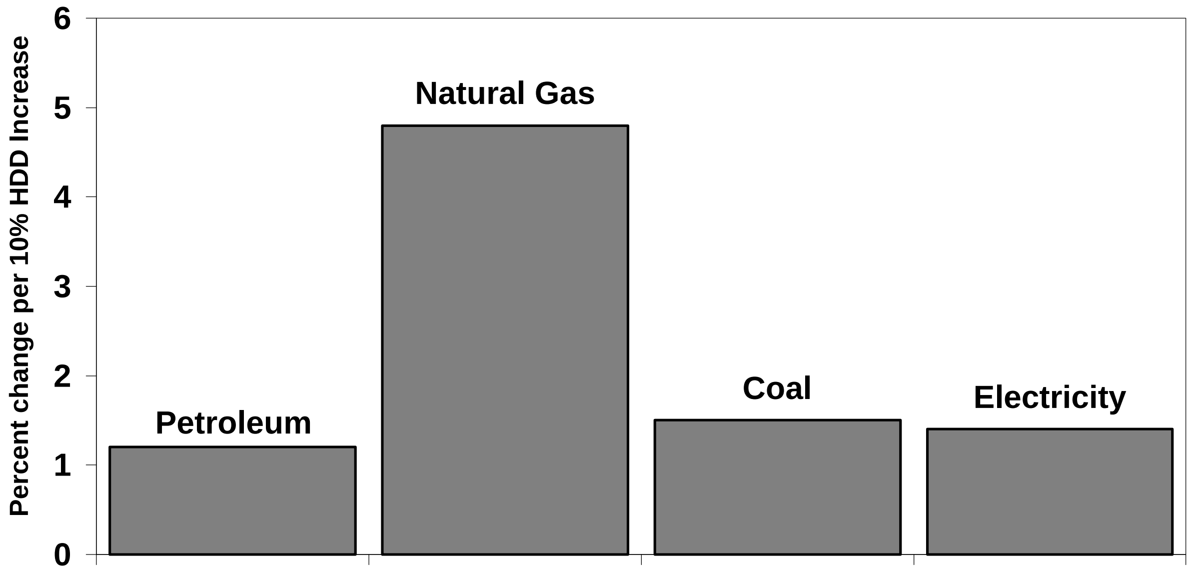
The petroleum demand and supply outlook for the mid-price case is based on assumed normal temperatures and GDP growth of 3.3 percent per year in 1998 and 2.1 percent in 1999. To enhance the usefulness of the mid-case forecasts, sensitivities of energy demand and supply are also derived, using alternative macroeconomic, price and weather assumptions. Plausible macroeconomic and weather-related petroleum demand sensitivities are illustrated in Figures 36 and 37 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 36). 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 1.2 percent; natural gas demand by 4.8 percent; coal demand by 1.5 percent; and electricity demand by 1.4 percent (Figure 37). 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 37. Weather Sensitivities



A 10 percent increase in cooling degree-days increases summer petroleum demand by about 0.1 percent, other fuels by 1.4 percent.

A $1-per-barrel increase in crude oil prices boosts domestic oil supply (crude oil and natural gas liquids production) by about 129,000 barrels per day.

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 unleaded 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 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 transition 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 which obligates 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, which includes 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.

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

Table 1. U.S. Macroeconomic and Weather Assumptions

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Macroeconomic [a]															
Real Gross Domestic Product (billion chained 1992 dollars - SAAR)	**7167**	**7237**	**7311**	**7365**	**7465**	**7491**	*7529*	*7585*	*7598*	*7617*	*7645*	*7696*	**7270**	*7517*	*7639*
Percentage Change from Prior Year	**4.1**	**3.6**	**4.1**	**3.8**	**4.2**	**3.5**	*3.0*	*3.0*	*1.8*	*1.7*	*1.5*	*1.5*	**3.9**	*3.4*	*1.6*
Annualized Percent Change from Prior Quarter..	**4.1**	**3.9**	**4.1**	**2.9**	**5.4**	**1.4**	*2.0*	*3.0*	*0.7*	*1.0*	*1.5*	*2.6*			
GDP Implicit Price Deflator (Index, 1992=1.000).......................................	**1.110**	**1.115**	**1.118**	**1.121**	**1.123**	**1.126**	*1.130*	*1.134*	*1.140*	*1.146*	*1.151*	*1.157*	**1.116**	*1.128*	*1.148*
Percentage Change from Prior Year	**1.9**	**2.0**	**1.9**	**1.7**	**1.2**	**1.0**	*1.0*	*1.2*	*1.5*	*1.8*	*1.9*	*2.0*	**1.9**	*1.1*	*1.8*
Real Disposable Personal Income (billion chained 1992 Dollars - SAAR)............	**5131**	**5168**	**5198**	**5236**	**5287**	**5325**	*5370*	*5404*	*5438*	*5465*	*5493*	*5529*	**5183**	*5346*	*5481*
Percentage Change from Prior Year	**2.8**	**3.0**	**2.5**	**2.9**	**3.0**	**3.0**	*3.3*	*3.2*	*2.8*	*2.6*	*2.3*	*2.3*	**2.8**	*3.1*	*2.5*
Manufacturing Production (Index, 1992=1.000).......................................	**1.243**	**1.257**	**1.276**	**1.301**	**1.309**	**1.314**	*1.309*	*1.332*	*1.342*	*1.350*	*1.352*	*1.360*	**1.269**	*1.316*	*1.351*
Percentage Change from Prior Year	**5.8**	**5.0**	**5.3**	**6.3**	**5.3**	**4.5**	*2.6*	*2.4*	*2.6*	*2.7*	*3.3*	*2.1*	**5.6**	*3.7*	*2.7*
OECD Economic Growth (percent) [b]													**3.1**	*2.7*	*2.4*
Weather [c]															
Heating Degree-Days															
U.S.	**2156**	**635**	**86**	**1665**	**1972**	**515**	*89*	*1636*	*2327*	*524*	*89*	*1636*	**4542**	*4212*	*4576*
New England...	**3108**	**1047**	**172**	**2335**	**2766**	**870**	*213*	*2269*	*3267*	*915*	*171*	*2269*	**6662**	*6118*	*6621*
Middle Atlantic...	**2777**	**866**	**121**	**2045**	**2461**	**656**	*115*	*2026*	*2993*	*716*	*105*	*2026*	**5809**	*5258*	*5839*
U.S. Gas-Weighted....................................	**2275**	**711**	**127**	**1773**	**2078**	**548**	*70*	*1686*	*2426*	*539*	*81*	*1686*	**4886**	*4382*	*4732*
Cooling Degree-Days (U.S.)	**50**	**289**	**754**	**63**	**25**	**376**	*855*	*72*	*30*	*334*	*758*	*72*	**1156**	*1328*	*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 CONTROL0898.

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

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Macroeconomic [a]															
Real Fixed Investment (billion chained 1992 dollars-SAAR)	**1096**	**1127**	**1159**	**1170**	**1225**	**1260**	*1270*	*1284*	*1294*	*1297*	*1302*	*1310*	**1138**	*1260*	*1301*
Real Exchange Rate (index)	**1.086**	**1.098**	**1.108**	**1.117**	**1.140**	**1.158**	*1.172*	*1.164*	*1.148*	*1.128*	*1.113*	*1.108*	**1.102**	*1.159*	*1.124*
Business Inventory Change (billion chained 1992 dollars-SAAR)	**20.0**	**26.7**	**15.8**	**17.7**	**30.2**	**26.2**	*14.3*	*3.2*	*-1.2*	*-7.1*	*-6.8*	*-6.9*	**20.1**	*18.5*	*-5.5*
Producer Price Index (index, 1982=1.000)	**1.286**	**1.271**	**1.272**	**1.275**	**1.251**	**1.247**	*1.244*	*1.247*	*1.256*	*1.262*	*1.266*	*1.269*	**1.276**	*1.247*	*1.263*
Consumer Price Index (index, 1982-1984=1.000)	**1.596**	**1.602**	**1.609**	**1.618**	**1.620**	**1.628**	*1.633*	*1.643*	*1.656*	*1.666*	*1.676*	*1.688*	**1.606**	*1.631*	*1.671*
Petroleum Product Price Index (index, 1982=1.000)	**0.722**	**0.675**	**0.669**	**0.654**	**0.542**	**0.524**	*0.511*	*0.527*	*0.528*	*0.542*	*0.545*	*0.548*	**0.680**	*0.526*	*0.540*
Non-Farm Employment (millions)	**121.5**	**122.3**	**123.0**	**123.9**	**124.8**	**125.5**	*126.3*	*126.8*	*127.3*	*127.6*	*127.9*	*128.2*	**122.7**	*125.9*	*127.8*
Commercial Employment (millions)	**82.8**	**83.6**	**84.1**	**84.9**	**85.7**	**86.3**	*87.2*	*87.9*	*88.4*	*88.7*	*88.9*	*89.3*	**83.9**	*86.8*	*88.8*
Total Industrial Production (index, 1992=1.000)	**1.219**	**1.233**	**1.251**	**1.273**	**1.277**	**1.285**	*1.280*	*1.299*	*1.308*	*1.315*	*1.317*	*1.325*	**1.244**	*1.285*	*1.316*
Housing Stock (millions)	**112.0**	**112.3**	**112.5**	**113.1**	**113.8**	**114.2**	*114.5*	*114.8*	*115.1*	*115.5*	*115.8*	*116.1*	**112.5**	*114.3*	*115.6*
Miscellaneous															
Gas Weighted Industrial Production (index, 1992=1.000)	**1.140**	**1.152**	**1.155**	**1.170**	**1.180**	**1.176**	*1.168*	*1.178*	*1.181*	*1.186*	*1.194*	*1.203*	**1.154**	*1.175*	*1.191*
Vehicle Miles Traveled [b] (million miles/day)	**6463**	**7138**	**7310**	**6824**	**6579**	**7315**	*7555*	*7019*	*6756*	*7448*	*7699*	*7156*	**6936**	*7119*	*7267*
Vehicle Fuel Efficiency (index, 1996=1.000)	**1.038**	**0.997**	**0.993**	**1.002**	**1.032**	**1.015**	*0.996*	*1.010*	*1.044*	*1.013*	*1.009*	*1.016*	**1.007**	*1.013*	*1.020*
Real Vehicle Fuel Cost (cents per mile)	**3.94**	**3.73**	**3.70**	**3.72**	**3.36**	**3.17**	*3.10*	*3.24*	*3.22*	*3.24*	*3.18*	*3.26*	**3.77**	*3.22*	*3.22*
Air Travel Capacity (mill. available ton-miles/day)	**402.1**	**417.2**	**434.3**	**427.7**	**422.3**	**438.1**	*455.6*	*446.7*	*438.2*	*453.4*	*471.6*	*459.2*	**420.4**	*440.8*	*455.7*
Aircraft Utilization (mill. revenue ton-miles/day)	**230.5**	**248.0**	**260.8**	**247.2**	**237.1**	**258.5**	*271.9*	*256.2*	*244.1*	*268.0*	*281.5*	*265.3*	**246.7**	*256.0*	*264.8*
Airline Ticket Price Index (index, 1982-1984=1.000)	**1.975**	**2.016**	**1.985**	**1.993**	**2.058**	**2.053**	*2.069*	*2.101*	*2.139*	*2.150*	*2.160*	*2.193*	**1.992**	*2.070*	*2.161*
Raw Steel Production (millions tons)	**26.47**	**26.59**	**26.52**	**27.31**	**28.44**	**27.87**	*26.50*	*27.06*	*28.33*	*28.09*	*27.71*	*28.31*	**106.60**	*109.86*	*112.44*

[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 CONTROL0898.

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

(Million Barrels per Day, Except OECD Commercial Stocks)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Demand [a]															
OECD															
U.S. (50 States)	18.3	18.5	18.7	19.0	18.3	18.4	19.2	19.1	19.0	18.8	19.2	19.4	18.6	18.8	19.1
U.S. Territories	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Canada	1.8	1.8	1.9	1.9	1.9	1.8	2.0	2.0	1.9	1.9	2.1	2.0	1.9	1.9	2.0
Europe	14.3	14.2	14.4	14.8	14.9	14.1	14.6	15.0	15.1	14.3	14.8	15.2	14.4	14.6	14.9
Japan	6.4	5.2	5.4	5.9	6.2	5.0	5.3	5.8	6.2	5.0	5.3	5.9	5.7	5.6	5.6
Australia and New Zealand	0.9	0.9	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0
Total OECD	41.9	40.8	41.7	42.7	42.3	40.4	42.3	43.0	43.3	41.1	42.6	43.7	41.8	42.0	42.7
Non-OECD															
Former Soviet Union	4.7	4.2	4.2	4.6	4.8	4.3	4.3	4.7	5.0	4.5	4.4	4.9	4.4	4.5	4.7
Europe	1.5	1.3	1.3	1.4	1.6	1.4	1.4	1.5	1.7	1.4	1.4	1.6	1.4	1.5	1.5
China	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.3	4.4	4.4	4.5	3.9	4.1	4.4
Other Asia	8.8	8.6	8.3	9.5	8.5	8.4	8.3	9.5	8.6	8.6	8.4	9.8	8.8	8.7	8.8
Other Non-OECD	12.8	13.1	12.8	13.1	13.2	13.6	13.2	13.5	13.6	14.0	13.7	13.9	13.0	13.4	13.8
Total Non-OECD	31.6	31.1	30.6	32.6	32.2	31.8	31.3	33.4	33.1	32.8	32.4	34.7	31.4	32.2	33.3
Total World Demand	73.5	71.9	72.2	75.3	74.5	72.2	73.5	76.5	76.5	73.9	75.1	78.3	73.2	74.2	75.9
Supply [b]															
OECD															
U.S. (50 States)	9.4	9.5	9.5	9.5	9.5	9.4	9.3	9.4	9.3	9.3	9.3	9.4	9.5	9.4	9.3
Canada	2.6	2.5	2.6	2.7	2.7	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.6	2.7	2.8
North Sea [c]	6.5	6.1	6.0	6.5	6.4	6.2	6.3	6.6	6.8	6.6	6.9	7.2	6.2	6.4	6.9
Other OECD	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.7
Total OECD	20.1	19.6	19.7	20.3	20.2	19.8	19.9	20.4	20.5	20.3	20.7	21.1	19.9	20.1	20.6
Non-OECD															
OPEC	29.5	29.7	30.1	30.3	30.8	30.6	29.4	29.8	29.9	29.9	30.2	30.5	29.9	30.1	30.1
Former Soviet Union	7.0	7.1	7.2	7.2	7.3	7.2	7.2	7.3	7.3	7.3	7.3	7.4	7.1	7.2	7.3
China	3.2	3.2	3.2	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.2	3.2	3.3
Mexico	3.4	3.4	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.4	3.6	3.6
Other Non-OECD	10.4	10.5	10.4	10.5	10.6	10.6	10.7	10.8	10.9	11.1	11.2	11.4	10.4	10.7	11.2
Total Non-OECD	53.5	53.9	54.3	54.7	55.4	55.1	54.0	54.7	54.9	55.2	55.6	56.1	54.1	54.8	55.4
Total World Supply	73.6	73.5	74.0	75.0	75.6	75.0	74.0	75.0	75.4	75.4	76.2	77.2	74.0	74.9	76.1
Stock Changes															
Net Stock Withdrawals or Additions (-)															
U.S. (50 States including SPR)	0.0	-0.7	-0.2	0.4	-0.3	-0.7	0.1	0.5	0.5	-0.5	-0.2	0.5	-0.1	-0.1	0.1
Other	-0.1	-1.0	-1.6	-0.1	-0.8	-2.1	-0.5	1.0	0.6	-1.1	-0.9	0.6	-0.7	-0.6	-0.2
Total Stock Withdrawals	-0.1	-1.7	-1.8	0.3	-1.1	-2.8	-0.4	1.4	1.1	-1.5	-1.2	1.1	-0.8	-0.7	-0.1
OECD Comm. Stocks, End (bill. bbls.)	2.7	2.7	2.7	2.7	2.7	2.9	2.9	2.8	2.7	2.8	2.9	2.8	2.7	2.8	2.8
Non-OPEC Supply	44.1	43.9	43.9	44.7	44.8	44.3	44.6	45.3	45.5	45.5	46.1	46.7	44.1	44.7	46.0
Net Exports from Former Soviet Union	2.3	2.9	3.0	2.6	2.5	2.9	2.9	2.6	2.3	2.8	2.9	2.5	2.7	2.7	2.6

[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)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Imported Crude Oil [a]															
(dollars per barrel)	21.04	17.93	17.81	17.78	13.44	12.39	11.64	12.74	13.08	13.67	13.58	14.25	18.57	12.52	13.65
Natural Gas Wellhead															
(dollars per thousand cubic feet)	2.49	1.84	2.02	2.54	1.74	1.83	1.89	2.25	2.23	1.92	2.00	2.34	2.23	1.93	2.12
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	1.27	1.24	1.25	1.21	1.10	1.10	1.07	1.08	1.09	1.14	1.14	1.12	1.24	1.09	1.12
Regular Unleaded	1.22	1.20	1.21	1.17	1.05	1.05	1.03	1.04	1.04	1.10	1.11	1.08	1.20	1.04	1.08
No. 2 Diesel Oil, Retail															
(dollars per gallon)	1.25	1.18	1.15	1.17	1.08	1.05	1.02	1.07	1.06	1.07	1.06	1.11	1.19	1.06	1.08
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	0.65	0.57	0.54	0.57	0.47	0.43	0.39	0.45	0.47	0.46	0.46	0.52	0.59	0.44	0.48
No. 2 Heating Oil, Retail															
(dollars per gallon)	1.05	0.98	0.88	0.93	0.92	0.85	0.78	0.84	0.91	0.87	0.82	0.90	0.99	0.86	0.89
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	19.00	16.84	17.04	18.16	13.56	13.22	12.51	12.71	14.16	13.27	12.79	14.35	17.80	12.98	13.68
Electric Utility Fuels															
Coal															
(dollars per million Btu)	1.29	1.28	1.26	1.26	1.26	1.26	1.24	1.23	1.24	1.25	1.23	1.23	1.27	1.25	1.24
Heavy Fuel Oil [d]															
(dollars per million Btu)	2.91	2.59	2.71	2.92	2.12	2.17	2.07	2.10	2.23	2.18	2.11	2.37	2.79	2.11	2.21
Natural Gas															
(dollars per million Btu)	3.10	2.46	2.60	3.15	2.61	2.38	2.37	2.66	2.93	2.50	2.54	2.92	2.76	2.46	2.66
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	6.70	6.97	8.80	6.83	6.38	7.31	8.45	6.58	6.83	7.56	8.57	6.81	6.94	6.75	7.07
Electricity															
(cents per kilowatthour)	8.04	8.69	8.79	8.31	7.93	8.42	8.58	8.07	7.73	8.37	8.63	8.15	8.46	8.27	8.22

[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 third quarter of 1998. 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)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Supply															
Crude Oil Supply															
Domestic Production [a]	6.45	6.45	6.41	6.49	6.48	6.39	6.33	6.45	6.41	6.32	6.35	6.46	6.45	6.41	6.38
Alaska	1.36	1.30	1.24	1.28	1.23	1.17	1.12	1.22	1.16	1.08	1.06	1.10	1.30	1.19	1.10
Lower 48	5.09	5.15	5.18	5.20	5.25	5.22	5.21	5.23	5.24	5.24	5.29	5.36	5.16	5.23	5.28
Net Imports (including SPR) [b]	7.40	8.41	8.44	8.21	7.81	8.61	8.90	8.13	7.73	8.56	8.77	8.21	8.12	8.37	8.32
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	0.00	0.00
SPR Stock Withdrawn or Added (-)	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Other Stock Withdrawn or Added (-)	-0.33	-0.08	0.18	-0.01	-0.35	0.04	0.19	-0.11	-0.04	-0.01	0.07	0.01	-0.06	-0.06	0.01
Product Supplied and Losses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.00	-0.01
Unaccounted-for Crude Oil	0.19	0.09	0.15	0.15	0.38	0.11	0.04	0.24	0.23	0.24	0.25	0.24	0.14	0.19	0.24
Total Crude Oil Supply	13.74	14.87	15.19	14.83	14.32	15.14	15.45	14.70	14.32	15.11	15.42	14.91	14.66	14.91	14.94
Other Supply															
NGL Production	1.84	1.82	1.83	1.77	1.85	1.80	1.69	1.77	1.80	1.80	1.80	1.81	1.82	1.78	1.80
Other Hydrocarbon and Alcohol Inputs	0.31	0.34	0.36	0.36	0.34	0.36	0.36	0.35	0.35	0.34	0.35	0.36	0.34	0.35	0.35
Crude Oil Product Supplied	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01
Processing Gain	0.79	0.84	0.87	0.90	0.83	0.84	0.87	0.84	0.80	0.86	0.88	0.84	0.85	0.85	0.85
Net Product Imports [c]	1.33	1.23	0.86	0.75	0.93	1.04	0.93	0.88	1.14	1.16	1.03	0.95	1.04	0.94	1.07
Product Stock Withdrawn or Added (-) [d]	0.25	-0.62	-0.37	0.36	0.03	-0.75	-0.16	0.59	0.57	-0.47	-0.30	0.49	-0.09	-0.07	0.07
Total Supply	18.27	18.49	18.75	18.97	18.30	18.43	19.14	19.14	18.98	18.80	19.19	19.37	18.62	18.76	19.09
Demand															
Motor Gasoline	7.59	8.16	8.25	8.06	7.77	8.21	8.50	8.22	7.88	8.38	8.55	8.34	8.02	8.18	8.29
Jet Fuel	1.57	1.56	1.64	1.62	1.55	1.55	1.56	1.61	1.56	1.59	1.67	1.65	1.60	1.56	1.62
Distillate Fuel Oil	3.58	3.33	3.24	3.60	3.58	3.37	3.43	3.57	3.85	3.43	3.35	3.62	3.44	3.49	3.56
Residual Fuel Oil	0.89	0.76	0.77	0.77	0.81	0.81	0.90	0.85	0.99	0.78	0.77	0.82	0.80	0.84	0.84
Other Oils [e]	4.64	4.67	4.85	4.93	4.62	4.49	4.75	4.89	4.70	4.61	4.85	4.95	4.77	4.69	4.78
Total Demand	18.27	18.49	18.75	18.97	18.32	18.43	19.14	19.14	18.98	18.80	19.19	19.37	18.62	18.76	19.09
Total Petroleum Net Imports	8.73	9.64	9.31	8.96	8.74	9.66	9.82	9.01	8.87	9.72	9.79	9.16	9.16	9.31	9.39
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	313	320	304	305	336	333	316	326	330	331	325	324	305	326	324
Total Motor Gasoline	200	204	198	210	215	221	212	210	213	207	203	204	210	210	204
Finished Motor Gasoline	154	164	158	166	166	178	167	166	169	167	161	162	166	166	162
Blending Components	46	41	41	43	49	44	45	43	44	41	42	41	43	43	41
Jet Fuel	39	43	46	44	43	44	46	46	49	47	47	45	44	46	45
Distillate Fuel Oil	101	118	139	138	124	139	153	146	107	118	135	138	138	146	138
Residual Fuel Oil	41	39	35	40	41	40	39	43	34	38	39	42	40	43	42
Other Oils [e]	253	286	308	259	265	313	322	273	264	298	313	262	259	273	262
Total Stocks (excluding SPR)	948	1011	1029	996	1025	1090	1088	1044	997	1040	1061	1015	996	1044	1015
Crude Oil in SPR	563	563	563	563	563	563	563	563	563	563	563	563	563	563	563
Total Stocks (including SPR)	1512	1575	1592	1560	1588	1654	1651	1608	1560	1603	1624	1578	1560	1608	1578

[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

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

Demand Sector	+1% GDP	+ 10% Prices: Crude Oil [c]	+ 10% Prices: N.Gas Wellhead [d]	+ 10% Weather [e]: Fall/Winter [f]	+ 10% Weather [e]: 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	Difference: Uncertainty	Difference: Price Impact
United States	*6.75*	*6.00*	*0.75*	*0.11*	*0.64*
Lower 48 States	*5.61*	*4.92*	*0.69*	*0.08*	*0.61*
Alaska	*1.13*	*1.08*	*0.06*	*0.03*	*0.03*

Note: Components provided are for the fourth quarter 1999. 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)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Supply															
Total Dry Gas Production	**4.73**	**4.70**	**4.72**	**4.78**	**4.75**	**4.70**	*4.77*	*4.83*	*4.77*	*4.75*	*4.82*	*4.89*	**18.93**	*19.05*	*19.23*
Net Imports	**0.74**	**0.68**	**0.68**	**0.74**	**0.75**	**0.70**	*0.69*	*0.77*	*0.78*	*0.75*	*0.76*	*0.83*	**2.84**	*2.90*	*3.12*
Supplemental Gaseous Fuels	**0.03**	**0.03**	**0.02**	**0.03**	**0.03**	**0.02**	*0.03*	*0.03*	*0.04*	*0.03*	*0.03*	*0.03*	**0.12**	*0.12*	*0.13*
Total New Supply	**5.50**	**5.40**	**5.42**	**5.56**	**5.53**	**5.43**	*5.49*	*5.64*	*5.59*	*5.53*	*5.61*	*5.75*	**21.88**	*22.08*	*22.48*
Underground Working Gas Storage															
Opening	**6.51**	**5.34**	**6.09**	**7.03**	**6.52**	**5.52**	*6.44*	*7.28*	*6.74*	*5.36*	*6.28*	*7.14*	**6.51**	*6.52*	*6.74*
Closing	**5.34**	**6.09**	**7.03**	**6.52**	**5.52**	**6.44**	*7.28*	*6.74*	*5.36*	*6.28*	*7.14*	*6.53*	**6.52**	*6.74*	*6.53*
Net Withdrawals	**1.18**	**-0.75**	**-0.95**	**0.51**	**1.00**	**-0.92**	*-0.84*	*0.54*	*1.38*	*-0.92*	*-0.86*	*0.61*	**-0.01**	*-0.22*	*0.21*
Total Supply	**6.67**	**4.65**	**4.48**	**6.07**	**6.52**	**4.51**	*4.65*	*6.18*	*6.97*	*4.61*	*4.76*	*6.36*	**21.88**	*21.86*	*22.70*
Balancing Item [a]	**0.21**	**0.20**	**0.03**	**-0.34**	**0.10**	**0.25**	*-0.13*	*-0.54*	*0.23*	*0.26*	*-0.24*	*-0.61*	**0.10**	*-0.33*	*-0.35*
Total Primary Supply	**6.88**	**4.85**	**4.51**	**5.73**	**6.62**	**4.75**	*4.52*	*5.64*	*7.20*	*4.87*	*4.52*	*5.76*	**21.98**	*21.53*	*22.35*
Demand															
Lease and Plant Fuel	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**	*0.32*	*0.32*	*0.32*	*0.31*	*0.31*	*0.32*	**1.25**	*1.26*	*1.27*
Pipeline Use	**0.22**	**0.16**	**0.15**	**0.19**	**0.21**	**0.15**	*0.14*	*0.18*	*0.22*	*0.15*	*0.14*	*0.18*	**0.71**	*0.70*	*0.70*
Residential	**2.28**	**0.89**	**0.38**	**1.47**	**2.11**	**0.78**	*0.34*	*1.39*	*2.45*	*0.83*	*0.35*	*1.41*	**5.01**	*4.62*	*5.03*
Commercial	**1.27**	**0.65**	**0.44**	**0.93**	**1.20**	**0.57**	*0.45*	*0.90*	*1.41*	*0.65*	*0.46*	*0.92*	**3.29**	*3.13*	*3.43*
Industrial (Incl. Cogenerators)	**2.28**	**2.09**	**2.04**	**2.17**	**2.23**	**2.03**	*1.98*	*2.21*	*2.25*	*2.04*	*2.02*	*2.26*	**8.57**	*8.45*	*8.58*
Cogenerators	**0.53**	**0.57**	**0.57**	**0.64**	**0.58**	**0.55**	*0.60*	*0.68*	*0.60*	*0.57*	*0.62*	*0.70*	**2.31**	*2.41*	*2.49*
Electricity Production															
Electric Utilities	***0.47***	***0.72***	***1.15***	**0.62**	**0.50**	**0.86**	*1.24*	*0.58*	*0.50*	*0.84*	*1.19*	*0.61*	**2.97**	*3.18*	*3.14*
Nonutilities (Excl. Cogen.)[b]	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.04**	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.06*	**0.18**	*0.19*	*0.20*
Total Demand	**6.88**	**4.85**	**4.51**	**5.73**	**6.62**	**4.75**	*4.52*	*5.64*	*7.20*	*4.87*	*4.52*	*5.76*	**21.98**	*21.53*	*22.35*

[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)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Supply															
Production	274.1	270.1	271.6	274.1	279.2	271.6	283.5	275.8	292.2	274.0	278.3	286.3	1089.9	1110.1	1130.9
Appalachia	119.7	118.7	112.7	116.7	119.1	111.6	115.2	115.6	122.9	114.2	110.9	118.1	467.8	461.5	466.1
Interior	42.5	41.1	44.1	43.3	41.0	41.5	44.1	41.7	41.1	38.3	41.5	41.4	170.9	168.3	162.4
Western	111.9	110.4	114.8	114.1	119.1	118.5	124.2	118.5	128.2	121.5	126.0	126.8	451.3	480.3	502.4
Primary Stock Levels [a]															
Opening	28.6	37.5	42.5	39.1	34.0	37.5	37.2	34.2	32.9	39.9	40.3	34.1	28.6	34.0	32.9
Closing	37.5	42.5	39.1	34.0	37.5	37.2	34.2	32.9	39.9	40.3	34.1	33.0	34.0	32.9	33.0
Net Withdrawals	-8.9	-5.0	3.4	5.1	-3.6	0.3	3.0	1.2	-6.9	-0.4	6.2	1.1	-5.3	1.0	(S)
Imports	1.3	1.7	2.2	2.2	1.8	2.2	2.0	1.8	1.8	1.8	1.8	1.8	7.5	7.8	7.3
Exports	20.0	20.6	22.4	20.6	18.3	20.5	19.9	20.3	19.4	20.0	20.2	20.2	83.5	79.0	79.8
Total Net Domestic Supply	246.5	246.3	254.9	260.9	259.2	253.6	268.6	258.5	267.7	255.4	266.1	269.1	1008.5	1040.0	1058.4
Secondary Stock Levels [b]															
Opening	123.0	120.7	127.6	109.8	106.8	114.1	124.7	112.5	114.4	116.0	121.4	107.6	123.0	106.8	114.4
Closing	120.7	127.6	109.8	106.8	114.1	124.7	112.5	114.4	116.0	121.4	107.6	111.8	106.8	114.4	111.8
Net Withdrawals	2.3	-6.9	17.8	3.0	-7.3	-10.6	12.2	-1.9	-1.6	-5.4	13.9	-4.3	16.1	-7.6	2.6
Waste Coal Supplied to IPPs [c]	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	9.4	10.0	10.6
Total Supply	251.2	241.7	275.0	266.2	254.4	245.5	283.4	259.1	268.8	252.6	282.6	267.5	1034.1	1042.4	1071.6
Demand															
Coke Plants	7.6	7.4	7.9	6.6	6.9	6.8	7.2	7.4	7.6	7.3	7.2	7.5	29.4	28.3	29.6
Electricity Production															
Electric Utilities	218.8	207.7	243.7	230.3	220.5	218.7	252.0	225.1	234.0	220.7	250.8	232.5	900.4	916.2	938.0
Nonutilities (Excl. Cogen.) [d]	5.9	5.9	5.9	5.9	6.3	6.2	6.3	6.3	6.6	6.6	6.6	6.6	23.5	25.0	26.5
Retail and General Industry [e]	20.0	18.2	17.9	20.2	20.0	18.3	18.0	20.4	20.6	18.1	18.1	20.8	76.4	76.7	77.5
Total Demand	252.3	239.1	275.4	262.9	253.7	250.1	283.4	259.1	268.8	252.6	282.6	267.5	1029.7	1046.2	1071.5
Discrepancy [f]	-1.1	2.6	-0.4	3.3	0.7	-4.5	0.0	0.0	0.0	0.0	0.0	0.0	4.4	-3.8	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 8.9 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.

(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)

	1997				1998				1999				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1997	1998	1999
Supply															
Net Utility Generation															
Coal	434.1	413.9	480.9	458.9	437.0	434.9	500.1	447.4	468.4	441.5	499.2	463.5	1787.8	1819.4	1872.6
Petroleum	17.0	15.1	24.5	21.1	20.9	28.5	36.1	23.1	27.3	22.5	26.8	20.5	77.8	108.5	97.1
Natural Gas	45.0	69.5	109.9	59.2	47.9	80.7	118.8	55.1	47.6	80.5	113.6	58.3	283.6	302.5	300.0
Nuclear	160.0	144.0	171.0	153.6	162.6	154.7	175.4	168.4	168.5	152.9	179.5	161.8	628.6	661.1	662.8
Hydroelectric	94.2	95.9	77.5	69.6	86.7	88.6	71.4	69.6	77.3	78.3	66.1	63.7	337.2	316.4	285.5
Geothermal and Other [a]	1.6	1.8	2.0	2.0	1.9	1.4	1.8	1.8	1.7	1.7	1.7	1.7	7.5	6.9	6.8
Subtotal	752.0	740.2	865.8	764.5	757.0	789.0	903.5	765.2	790.8	777.4	887.0	769.5	3122.5	3214.7	3224.7
Nonutility Generation [b]															
Coal	15.3	16.3	16.4	18.4	16.6	15.9	17.3	19.3	17.0	16.3	17.7	19.8	66.4	69.1	70.8
Petroleum	4.0	4.2	4.2	4.7	4.4	4.2	4.6	5.1	4.7	4.5	4.9	5.5	17.1	18.4	19.6
Natural Gas	49.2	52.5	52.8	59.1	53.7	51.4	55.9	62.6	55.2	52.9	57.6	64.5	213.7	223.7	230.2
Other Gaseous Fuels [c]	2.9	3.1	3.1	3.5	3.0	2.9	3.1	3.5	3.0	2.9	3.1	3.5	12.5	12.5	12.6
Hydroelectric	3.9	4.2	4.2	4.7	4.4	4.2	4.5	5.1	4.6	4.4	4.7	5.3	17.1	18.2	19.0
Geothermal and Other [d]	19.0	20.3	20.4	22.9	20.3	19.4	21.2	23.7	20.5	19.6	21.3	23.9	82.6	84.6	85.3
Subtotal	94.3	100.6	101.2	113.3	102.3	98.0	106.7	119.4	104.9	100.5	109.4	122.5	409.4	426.4	437.4
Total Generation	846.3	840.8	967.0	877.7	859.3	887.0	1010.2	884.6	895.7	877.9	996.4	892.0	3531.9	3641.1	3662.1
Net Imports [e]	7.5	8.9	11.8	8.3	5.8	6.9	9.2	6.5	6.8	7.9	10.4	7.6	36.6	28.5	32.7
Total Supply	853.8	849.8	978.8	886.1	865.1	893.9	1019.4	891.1	902.5	885.8	1006.8	899.7	3568.5	3669.5	3694.8
Losses and Unaccounted for [f]	52.8	82.7	76.3	73.3	54.5	81.8	70.6	68.4	53.0	76.1	69.9	69.0	285.0	275.3	268.0
Demand															
Electric Utility Sales															
Residential	276.7	226.2	309.9	258.8	275.8	250.7	337.2	260.7	299.7	250.6	325.6	263.2	1071.6	1124.4	1139.1
Commercial	214.5	217.6	256.0	225.3	217.4	230.9	272.3	230.1	230.6	232.0	268.0	231.4	913.3	950.7	961.9
Industrial	247.6	258.7	268.9	257.4	252.2	266.3	269.2	258.4	251.5	261.7	271.8	261.1	1032.5	1046.2	1046.1
Other	23.5	23.2	26.2	24.6	23.7	24.3	26.9	25.0	25.2	24.6	27.1	25.2	97.5	99.9	102.0
Subtotal	762.2	725.7	860.9	766.1	769.1	772.3	905.5	774.2	806.9	768.8	892.5	780.9	3114.9	3221.1	3249.1
Nonutility Gener. for Own Use [b]	38.8	41.4	41.7	46.6	41.5	39.8	43.3	48.5	42.6	40.9	44.5	49.8	168.6	173.1	177.7
Total Demand	801.0	767.1	902.6	812.7	810.6	812.1	948.8	822.7	849.5	809.7	936.9	830.7	3283.5	3394.2	3426.8
Memo:															
Nonutility Sales to Electric Utilities [b]	55.5	59.2	59.5	66.6	60.7	58.2	63.3	70.9	62.3	59.7	65.0	72.7	240.8	253.2	259.7

[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 1997 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		
	1996	1997	1998	1999	1996-1997	1997-1998	1998-1999
Electric Utilities							
Hydroelectric Power [a]	**3.433**	**3.530**	*3.311*	*2.988*	**2.8**	*-6.2*	*-9.8*
Geothermal, Solar and Wind Energy [b]	**0.110**	**0.115**	*0.103*	*0.100*	**4.5**	*-10.4*	*-2.9*
Biofuels [c]	**0.020**	**0.021**	*0.021*	*0.021*	**5.0**	*0.0*	*0.0*
Total	**3.563**	**3.665**	*3.435*	*3.108*	**2.9**	*-6.3*	*-9.5*
Nonutility Power Generators							
Hydroelectric Power [a]	**0.171**	**0.177**	*0.188*	*0.196*	**3.5**	*6.2*	*4.3*
Geothermal, Solar and Wind Energy [b]	**0.258**	**0.280**	*0.289*	*0.294*	**8.5**	*3.2*	*1.7*
Biofuels [c]	**0.601**	**0.638**	*0.651*	*0.655*	**6.2**	*2.0*	*0.6*
Total	**1.030**	**1.095**	*1.128*	*1.145*	**6.3**	*3.0*	*1.5*
Total Power Generation	**4.593**	**4.760**	*4.563*	*4.253*	**3.6**	*-4.1*	*-6.8*
Other Sectors							
Residential and Commercial [d]	**0.722**	**0.553**	*0.568*	*0.574*	**-23.4**	*2.7*	*1.1*
Industrial [e]	**1.603**	**1.498**	*1.515*	*1.542*	**-6.6**	*1.1*	*1.8*
Transportation [f]	**0.074**	**0.097**	*0.094*	*0.095*	**31.1**	*-3.1*	*1.1*
Total	**2.399**	**2.148**	*2.177*	*2.211*	**-10.5**	*1.4*	*1.6*
Net Imported Electricity [g]	**0.305**	**0.297**	*0.231*	*0.266*	**-2.6**	*-22.2*	*15.2*
Total Renewable Energy Demand	**7.297**	**7.205**	*6.971*	*6.730*	**-1.3**	*-3.2*	*-3.5*

[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]Includes biofuels and solar energy consumed in the residential and commercial sectors.
[e]Consists primarily of biofuels for use other than in electricity cogeneration.
[f]Ethanol blended into gasoline.
[g]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														
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Real Gross Domestic Product (GDP)															
(billion chained 1992 dollars)..........................	**5324**	**5488**	**5649**	**5865**	**6062**	**6136**	**6079**	**6244**	**6390**	**6611**	**6762**	**6995**	**7270**	*7517*	*7639*
Imported Crude Oil Price [a]															
(nominal dollars per barrel)............................	**26.99**	**14.00**	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.57**	*12.52*	*13.65*
Petroleum Supply															
Crude Oil Production [b]															
(million barrels per day).................................	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	*6.41*	*6.38*
Total Petroleum Net Imports (including SPR)															
(million barrels per day).................................	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	*9.31*	*9.39*
Energy Demand															
World Petroleum															
(million barrels per day).................................	**60.1**	**61.8**	**63.1**	**64.9**	**65.9**	**66.0**	**66.6**	**66.8**	**67.0**	**68.3**	**69.9**	**71.5**	**73.2**	*74.2*	*75.9*
U.S. Petroleum															
(million barrels per day).................................	**15.78**	**16.33**	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	*18.76*	*19.09*
Natural Gas															
(trillion cubic feet)..	**17.28**	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.03**	**19.54**	**20.28**	**20.71**	**21.58**	**21.96**	**21.98**	*21.53*	*22.35*
Coal															
(million short tons)..	**810**	**797**	**830**	**877**	**891**	**897**	**898**	**907**	**944**	**951**	**962**	**1006**	**1030**	*1046*	*1072*
Electricity (billion kilowatthours)															
Utility Sales [c]	**2324**	**2369**	**2457**	**2578**	**2647**	**2713**	**2762**	**2763**	**2861**	**2935**	**3013**	**3098**	**3115**	*3221*	*3249*
Nonutility Own Use [d]	**NA**	**NA**	**NA**	**NA**	**108**	**113**	**122**	**132**	**138**	**150**	**158**	**164**	**169**	*173*	*178*
Total...	**2324**	**2369**	**2457**	**2578**	**2755**	**2826**	**2884**	**2895**	**3000**	**3085**	**3171**	**3262**	**3283**	*3394*	*3427*
Total Energy Demand [e]															
(quadrillion Btu)	**NA**	**NA**	**NA**	**NA**	**NA**	**84.1**	**84.0**	**85.6**	**87.4**	**89.3**	**90.9**	**93.9**	**94.4**	*94.6*	*96.4*
Total Energy Demand per Dollar of GDP															
(thousand Btu per 1992 Dollar).....................	**NA**	**NA**	**NA**	**NA**	**NA**	**13.71**	**13.82**	**13.70**	**13.67**	**13.50**	**13.45**	**13.43**	**12.99**	*12.58*	*12.62*

[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 1997 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 CONTROL0898.

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

	Year														
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Macroeconomic															
Real Gross Domestic Product (billion chained 1992 dollars)	**5324**	**5488**	**5649**	**5865**	**6062**	**6136**	**6079**	**6244**	**6390**	**6611**	**6762**	**6995**	**7270**	*7517*	*7639*
GDP Implicit Price Deflator (Index, 1992=1.000)	**0.786**	**0.806**	**0.831**	**0.861**	**0.897**	**0.936**	**0.973**	**1.000**	**1.026**	**1.051**	**1.075**	**1.095**	**1.116**	*1.128*	*1.148*
Real Disposable Personal Income (billion chained 1992 Dollars)	**3960**	**4077**	**4155**	**4325**	**4412**	**4490**	**4484**	**4605**	**4667**	**4773**	**4906**	**5043**	**5183**	*5346*	*5481*
Manufacturing Production (Index, 1987=1.000)	**0.857**	**0.881**	**0.928**	**0.971**	**0.990**	**0.985**	**0.962**	**1.000**	**1.038**	**1.100**	**1.160**	**1.202**	**1.269**	*1.316*	*1.351*
Real Fixed Investment (billion chained 1992 dollars)	**799**	**805**	**799**	**818**	**832**	**806**	**741**	**783**	**843**	**916**	**966**	**1051**	**1138**	*1260*	*1301*
Real Exchange Rate (Index, 1990=1.000)	**NA**	**NA**	**NA**	**NA**	**NA**	**1.000**	**1.006**	**1.012**	**1.055**	**1.032**	**0.959**	**1.015**	**1.102**	*1.159*	*1.124*
Business Inventory Change (billion chained 1992 dollars)	**-4.5**	**-4.2**	**5.1**	**9.5**	**19.2**	**6.6**	**-6.1**	**-9.2**	**6.1**	**11.1**	**11.2**	**12.0**	**20.1**	*18.5*	*-5.5*
Producer Price Index (index, 1982=1.000)	**1.032**	**1.002**	**1.028**	**1.069**	**1.122**	**1.163**	**1.165**	**1.172**	**1.189**	**1.205**	**1.248**	**1.277**	**1.276**	*1.247*	*1.263*
Consumer Price Index (index, 1982-1984=1.000)	**1.076**	**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*	*1.671*
Petroleum Product Price Index (index, 1982=1.000)	**0.832**	**0.532**	**0.568**	**0.539**	**0.612**	**0.748**	**0.671**	**0.647**	**0.620**	**0.591**	**0.608**	**0.701**	**0.680**	*0.526*	*0.540*
Non-Farm Employment (millions)	**97.4**	**99.3**	**102.0**	**105.2**	**107.9**	**109.4**	**108.3**	**108.6**	**110.7**	**114.1**	**117.2**	**119.6**	**122.7**	*125.9*	*127.8*
Commercial Employment (millions)	**60.8**	**62.9**	**65.2**	**67.8**	**70.0**	**71.3**	**70.8**	**71.2**	**73.2**	**76.1**	**78.8**	**81.1**	**83.9**	*86.8*	*88.8*
Total Industrial Production (index, 1987=1.000)	**0.880**	**0.890**	**0.931**	**0.974**	**0.991**	**0.990**	**0.970**	**1.000**	**1.036**	**1.092**	**1.146**	**1.185**	**1.244**	*1.285*	*1.316*
Housing Stock (millions)	**96.3**	**98.0**	**99.8**	**101.6**	**102.9**	**103.5**	**104.5**	**105.5**	**106.8**	**108.2**	**109.6**	**111.0**	**112.5**	*114.3*	*115.6*
Weather [a]															
Heating Degree-Days															
U.S.	**4642**	**4295**	**4334**	**4653**	**4726**	**4016**	**4200**	**4441**	**4700**	**4483**	**4531**	**4713**	**4542**	*4212*	*4576*
New England	**6571**	**6517**	**6546**	**6715**	**6887**	**5848**	**5960**	**6844**	**6728**	**6672**	**6559**	**6679**	**6662**	*6118*	*6621*
Middle Atlantic	**5660**	**5665**	**5699**	**6088**	**6134**	**4998**	**5177**	**5964**	**5948**	**5934**	**5831**	**5986**	**5809**	*5258*	*5839*
U.S. Gas-Weighted	**4856**	**4442**	**4391**	**4804**	**4856**	**4139**	**4337**	**4458**	**4754**	**4659**	**4707**	**5040**	**4886**	*4382*	*4732*
Cooling Degree-Days (U.S.)	**1194**	**1249**	**1269**	**1283**	**1156**	**1260**	**1331**	**1040**	**1218**	**1220**	**1293**	**1180**	**1156**	*1328*	*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 CONTROL0898.

Table A3. Annual International Petroleum Supply and Demand Balance

(Millions Barrels per Day, Except OECD Commercial Stocks)

	Year														
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Demand [a]															
OECD															
U.S. (50 States)	**15.8**	**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*	*19.1*
Europe [b]	**11.7**	**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*	*14.9*
Japan	**4.4**	**4.4**	**4.5**	**4.8**	**5.0**	**5.1**	**5.3**	**5.4**	**5.4**	**5.7**	**5.7**	**5.9**	**5.7**	*5.6*	*5.6*
Other OECD	**2.5**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**	**2.7**	**2.7**	**2.8**	**2.9**	**3.0**	**3.0**	**3.0**	*3.1*	*3.2*
Total OECD	**34.3**	**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*
Non-OECD															
Former Soviet Union	**9.0**	**9.0**	**9.0**	**8.9**	**8.7**	**8.4**	**8.3**	**6.8**	**5.6**	**4.8**	**4.6**	**4.4**	**4.4**	*4.5*	*4.7*
Europe	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**	**1.9**	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**	*1.5*	*1.5*
China	**1.9**	**2.0**	**2.1**	**2.3**	**2.4**	**2.3**	**2.5**	**2.7**	**3.0**	**3.1**	**3.3**	**3.5**	**3.9**	*4.1*	*4.4*
Other Asia	**3.6**	**3.8**	**4.1**	**4.4**	**4.9**	**5.3**	**5.7**	**6.2**	**6.8**	**7.3**	**7.9**	**8.3**	**8.8**	*8.7*	*8.8*
Other Non-OECD	**9.1**	**9.5**	**9.7**	**10.0**	**10.3**	**10.5**	**10.6**	**11.0**	**11.4**	**11.8**	**12.2**	**12.5**	**13.0**	*13.4*	*13.8*
Total Non-OECD	**25.8**	**26.5**	**27.1**	**27.7**	**28.3**	**28.5**	**28.5**	**28.0**	**28.1**	**28.4**	**29.4**	**30.1**	**31.4**	*32.2*	*33.3*
Total World Demand	**60.1**	**61.8**	**63.1**	**64.9**	**66.0**	**66.0**	**66.6**	**66.8**	**67.0**	**68.3**	**69.9**	**71.5**	**73.2**	*74.2*	*75.9*
Supply [c]															
OECD															
U.S. (50 States)	**11.2**	**11.0**	**10.7**	**10.5**	**9.9**	**9.7**	**9.9**	**9.8**	**9.6**	**9.4**	**9.4**	**9.4**	**9.5**	*9.4*	*9.4*
Canada	**1.8**	**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*
North Sea [d]	**3.6**	**3.8**	**3.8**	**3.8**	**3.7**	**3.9**	**4.1**	**4.5**	**4.8**	**5.5**	**5.9**	**6.3**	**6.2**	*6.4*	*6.9*
Other OECD	**1.4**	**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*	*1.7*
Total OECD	**18.1**	**17.9**	**17.9**	**17.8**	**17.1**	**17.1**	**17.5**	**17.9**	**18.0**	**18.7**	**19.2**	**19.7**	**19.9**	*20.1*	*20.7*
Non-OECD															
OPEC	**17.2**	**19.3**	**19.6**	**21.5**	**23.3**	**24.5**	**24.6**	**25.8**	**26.6**	**27.0**	**27.6**	**28.3**	**29.9**	*30.1*	*30.1*
Former Soviet Union	**11.9**	**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*
China	**2.5**	**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*	*3.3*
Mexico	**3.0**	**2.8**	**2.9**	**2.9**	**2.9**	**3.0**	**3.2**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.4**	*3.6*	*3.6*
Other Non-OECD	**6.6**	**11.0**	**6.9**	**7.3**	**7.7**	**8.0**	**8.1**	**8.4**	**8.7**	**9.2**	**9.9**	**10.2**	**10.4**	*10.7*	*11.2*
Total Non-OECD	**41.2**	**43.9**	**44.6**	**47.0**	**48.9**	**49.7**	**49.1**	**49.1**	**49.4**	**49.6**	**50.7**	**52.0**	**54.1**	*54.8*	*55.4*
Total World Supply	**59.3**	**61.8**	**62.5**	**64.8**	**65.9**	**66.8**	**66.7**	**67.0**	**67.4**	**68.3**	**69.9**	**71.8**	**74.0**	*74.9*	*76.1*
Total Stock Withdrawals	**0.8**	**0.0**	**0.6**	**0.1**	**0.0**	**-0.8**	**-0.1**	**-0.2**	**-0.3**	**0.1**	**0.1**	**-0.2**	**-0.8**	*-0.7*	*-0.2*
OECD Comm. Stocks, End (bill. bbls.)	**2.6**	**2.7**	**2.7**	**2.6**	**2.6**	**2.7**	**2.7**	**2.7**	**2.8**	**2.8**	**2.7**	**2.7**	**2.7**	*2.8*	*2.8*
Net Exports from Former Soviet Union	**3.0**	**3.4**	**3.5**	**3.6**	**3.4**	**3.0**	**2.1**	**2.1**	**2.3**	**2.4**	**2.5**	**2.7**	**2.7**	*2.7*	*2.6*

[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														
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Imported Crude Oil [a]															
(dollars per barrel)	**26.99**	**14.00**	**18.13**	**14.57**	**18.08**	**21.75**	**18.70**	**18.20**	**16.14**	**15.52**	**17.14**	**20.61**	**18.57**	*12.52*	*13.65*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**2.51**	**1.94**	**1.66**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.16**	**2.23**	*1.93*	*2.12*
Petroleum Products															
Gasoline Retail [b] (dollars per gallon)															
All Grades	**1.15**	**0.88**	**0.91**	**0.92**	**1.02**	**1.17**	**1.15**	**1.14**	**1.13**	**1.13**	**1.16**	**1.25**	**1.24**	*1.09*	*1.12*
Regular Unleaded	**1.17**	**0.88**	**0.91**	**0.91**	**0.99**	**1.13**	**1.10**	**1.09**	**1.07**	**1.08**	**1.11**	**1.20**	**1.20**	*1.04*	*1.08*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	**1.16**	**0.88**	**0.93**	**0.91**	**0.99**	**1.16**	**1.12**	**1.10**	**1.11**	**1.11**	**1.11**	**1.23**	**1.19**	*1.06*	*1.08*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	**0.78**	**0.49**	**0.53**	**0.47**	**0.56**	**0.70**	**0.62**	**0.58**	**0.54**	**0.51**	**0.51**	**0.64**	**0.59**	*0.44*	*0.48*
No. 2 Heating Oil, Retail															
(dollars per gallon)	**1.05**	**0.84**	**0.80**	**0.81**	**0.90**	**1.06**	**1.02**	**0.93**	**0.91**	**0.89**	**0.87**	**0.99**	**0.99**	*0.86*	*0.89*
No. 6 Residual Fuel Oil, Retail [c]															
(dollars per barrel)	**25.57**	**14.46**	**17.76**	**14.04**	**16.20**	**18.66**	**14.32**	**14.21**	**14.00**	**14.79**	**16.49**	**18.97**	**17.80**	*12.98*	*13.68*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	**1.65**	**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*
Heavy Fuel Oil [d]															
(dollars per million Btu)	**4.26**	**2.40**	**2.98**	**2.41**	**2.85**	**3.22**	**2.49**	**2.46**	**2.36**	**2.40**	**2.60**	**3.01**	**2.79**	*2.11*	*2.21*
Natural Gas															
(dollars per million Btu)	**3.43**	**2.35**	**2.24**	**2.26**	**2.36**	**2.32**	**2.15**	**2.33**	**2.56**	**2.23**	**1.98**	**2.64**	**2.76**	*2.46*	*2.66*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	**6.12**	**5.83**	**5.55**	**5.47**	**5.64**	**5.80**	**5.82**	**5.89**	**6.17**	**6.41**	**6.06**	**6.35**	**6.94**	*6.75*	*7.07*
Electricity															
(cents per kilowatthour)	**7.8**	**7.4**	**7.4**	**7.5**	**7.6**	**7.8**	**8.1**	**8.2**	**8.3**	**8.4**	**8.4**	**8.4**	**8.5**	*8.3*	*8.2*

[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														
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Supply															
Crude Oil Supply															
Domestic Production [a]	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	*6.41*	*6.38*
Alaska	**1.83**	**1.87**	**1.96**	**2.02**	**1.87**	**1.77**	**1.80**	**1.71**	**1.58**	**1.56**	**1.48**	**1.39**	**1.30**	*1.19*	*1.10*
Lower 48	**7.15**	**6.81**	**6.39**	**6.12**	**5.74**	**5.58**	**5.62**	**5.46**	**5.26**	**5.10**	**5.08**	**5.07**	**5.16**	*5.23*	*5.28*
Net Imports (including SPR) [b]	**3.00**	**4.02**	**4.52**	**4.95**	**5.70**	**5.79**	**5.67**	**5.99**	**6.69**	**6.96**	**7.14**	**7.40**	**8.12**	*8.37*	*8.32*
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**	*0.00*	*0.00*
Stock Draw (Including SPR)	**-0.05**	**-0.08**	**-0.12**	**0.00**	**-0.09**	**0.02**	**-0.01**	**0.01**	**-0.06**	**-0.02**	**0.09**	**0.05**	**-0.06**	*-0.06*	*0.01*
Product Supplied and Losses	**-0.06**	**-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*
Unaccounted-for Crude Oil	**0.15**	**0.14**	**0.14**	**0.20**	**0.20**	**0.26**	**0.20**	**0.26**	**0.17**	**0.27**	**0.19**	**0.22**	**0.14**	*0.19*	*0.24*
Total Crude Oil Supply	**12.00**	**12.72**	**12.85**	**13.25**	**13.40**	**13.41**	**13.30**	**13.41**	**13.61**	**13.87**	**13.97**	**14.19**	**14.66**	*14.91*	*14.94*
Other Supply															
NGL Production	**1.61**	**1.55**	**1.59**	**1.62**	**1.55**	**1.56**	**1.66**	**1.70**	**1.74**	**1.73**	**1.76**	**1.83**	**1.82**	*1.78*	*1.80*
Other Hydrocarbon and Alcohol Inputs	**0.11**	**0.11**	**0.12**	**0.11**	**0.11**	**0.13**	**0.15**	**0.20**	**0.25**	**0.26**	**0.30**	**0.31**	**0.34**	*0.35*	*0.35*
Crude Oil Product Supplied	**0.06**	**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*
Processing Gain	**0.56**	**0.62**	**0.64**	**0.66**	**0.66**	**0.70**	**0.71**	**0.77**	**0.76**	**0.77**	**0.77**	**0.84**	**0.85**	*0.85*	*0.85*
Net Product Imports [c]	**1.29**	**1.41**	**1.39**	**1.63**	**1.50**	**1.38**	**0.96**	**0.94**	**0.93**	**1.09**	**0.75**	**1.10**	**1.04**	*0.94*	*1.07*
Product Stock Withdrawn	**0.15**	**-0.12**	**0.09**	**0.03**	**0.13**	**-0.14**	**-0.04**	**0.06**	**-0.05**	**0.00**	**0.15**	**0.03**	**-0.09**	*-0.07*	*0.07*
Total Supply	**15.78**	**16.33**	**16.72**	**17.33**	**17.37**	**17.05**	**16.76**	**17.10**	**17.25**	**17.72**	**17.72**	**18.31**	**18.62**	*18.76*	*19.09*
Demand															
Motor Gasoline [d]	**6.78**	**6.94**	**7.19**	**7.36**	**7.40**	**7.31**	**7.23**	**7.38**	**7.48**	**7.60**	**7.79**	**7.89**	**8.02**	*8.18*	*8.29*
Jet Fuel	**1.22**	**1.31**	**1.38**	**1.45**	**1.49**	**1.52**	**1.47**	**1.45**	**1.47**	**1.53**	**1.51**	**1.58**	**1.60**	*1.56*	*1.62*
Distillate Fuel Oil	**2.87**	**2.91**	**2.98**	**3.12**	**3.16**	**3.02**	**2.92**	**2.98**	**3.04**	**3.16**	**3.21**	**3.37**	**3.44**	*3.49*	*3.56*
Residual Fuel Oil	**1.20**	**1.42**	**1.26**	**1.38**	**1.37**	**1.23**	**1.16**	**1.09**	**1.08**	**1.02**	**0.85**	**0.85**	**0.80**	*0.84*	*0.84*
Other Oils [e]	**3.71**	**3.75**	**3.90**	**4.03**	**3.95**	**3.95**	**3.99**	**4.20**	**4.17**	**4.41**	**4.36**	**4.63**	**4.77**	*4.69*	*4.78*
Total Demand	**15.78**	**16.33**	**16.72**	**17.34**	**17.37**	**17.04**	**16.77**	**17.10**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	*18.76*	*19.09*
Total Petroleum Net Imports	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	*9.31*	*9.39*
Closing Stocks (million barrels)															
Crude Oil (excluding SPR)	**321**	**331**	**349**	**330**	**341**	**323**	**325**	**318**	**335**	**337**	**303**	**284**	**305**	*326*	*324*
Total Motor Gasoline	**223**	**233**	**226**	**228**	**213**	**220**	**219**	**216**	**226**	**215**	**202**	**195**	**210**	*210*	*204*
Jet Fuel	**40**	**50**	**50**	**44**	**41**	**52**	**49**	**43**	**40**	**47**	**40**	**40**	**44**	*46*	*45*
Distillate Fuel Oil	**144**	**155**	**134**	**124**	**106**	**132**	**144**	**141**	**141**	**145**	**130**	**127**	**138**	*146*	*138*
Residual Fuel Oil	**50**	**47**	**47**	**45**	**44**	**49**	**50**	**43**	**44**	**42**	**37**	**46**	**40**	*43*	*42*
Other Oils [f]	**247**	**265**	**260**	**267**	**257**	**261**	**267**	**263**	**273**	**275**	**258**	**250**	**259**	*273*	*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)

	Year														
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Supply															
Total Dry Gas Production	16.45	16.06	16.62	17.10	17.31	17.81	17.70	17.84	18.10	18.82	18.60	18.79	18.93	*19.05*	*19.23*
Net Imports	0.89	0.69	0.94	1.22	1.27	1.45	1.64	1.92	2.21	2.46	2.69	2.78	2.84	*2.90*	*3.12*
Supplemental Gaseous Fuels	0.13	0.11	0.10	0.10	0.11	0.12	0.11	0.12	0.12	0.11	0.11	0.11	0.12	*0.12*	*0.13*
Total New Supply	17.47	16.86	17.66	18.42	18.69	19.38	19.45	19.88	20.42	21.39	21.40	21.69	21.88	*22.08*	*22.48*
Total Underground Storage															
Opening	6.71	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*	*6.74*
Closing	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	*6.74*	*6.53*
Net Withdrawals	0.26	-0.12	0.02	-0.10	0.33	-0.61	0.16	0.14	-0.01	-0.32	0.46	-0.01	-0.01	*-0.22*	*0.21*
Total Supply	17.73	16.74	17.68	18.32	19.02	18.77	19.61	20.02	20.42	21.08	21.86	21.68	21.88	*21.86*	*22.70*
Balancing Item [a]	-0.45	-0.52	-0.47	-0.29	-0.22	-0.05	-0.58	-0.47	-0.14	-0.37	-0.28	0.29	0.10	*-0.33*	*-0.35*
Total Primary Supply	17.28	16.22	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.98	*21.53*	*22.35*
Demand															
Lease and Plant Fuel	0.97	0.92	1.15	1.10	1.07	1.24	1.13	1.17	1.17	1.12	1.22	1.25	1.25	*1.26*	*1.27*
Pipeline Use	0.50	0.49	0.52	0.61	0.63	0.66	0.60	0.59	0.62	0.69	0.70	0.71	0.71	*0.70*	*0.70*
Residential	4.43	4.31	4.31	4.63	4.78	4.39	4.56	4.69	4.96	4.85	4.85	5.24	5.01	*4.62*	*5.03*
Commercial	2.43	2.32	2.43	2.67	2.72	2.62	2.73	2.80	2.86	2.90	3.03	3.16	3.29	*3.13*	*3.43*
Industrial (Incl. Nonutilities)	5.90	5.58	5.95	6.38	6.82	7.02	7.23	7.53	7.98	8.17	8.58	8.87	8.75	*8.64*	*8.78*
Cogenerators [b]	NA	NA	NA	NA	0.00	1.30	1.41	1.67	1.80	1.98	2.18	2.27	2.31	*2.41*	*2.49*
Other Nonutil. Gen. [b]	NA	NA	NA	NA	0.00	0.09	0.16	0.18	0.22	0.17	0.17	0.16	0.18	*0.19*	*0.20*
Electric Utilities	3.04	2.60	2.84	2.64	2.79	2.79	2.79	2.77	2.68	2.99	3.20	2.73	2.97	*3.18*	*3.14*
Total Demand	17.28	16.22	17.21	18.03	18.80	18.72	19.03	19.54	20.28	20.71	21.58	21.96	21.98	*21.53*	*22.35*

[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														
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Supply															
Production	883.6	890.3	918.8	950.3	980.7	1029.1	996.0	997.5	945.4	1033.5	1033.0	1063.9	1089.9	*1110.1*	*1130.9*
Appalachia	NA	NA	NA	NA	464.8	489.0	457.8	456.6	409.7	445.4	434.9	451.9	467.8	*461.5*	*466.1*
Interior	NA	NA	NA	NA	198.1	205.8	195.4	195.7	167.2	179.9	168.5	172.8	170.9	*168.3*	*162.4*
Western	NA	NA	NA	NA	317.9	334.3	342.8	345.3	368.5	408.3	429.6	439.1	451.3	*480.3*	*502.4*
Primary Stock Levels [a]															
Opening	34.1	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*	*32.9*
Closing	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	*32.9*	*33.0*
Net Withdrawals	1.0	1.0	3.8	-2.1	1.4	-4.4	0.4	-1.0	8.7	-7.9	-1.2	5.8	-5.3	*1.0*	*S*
Imports	2.0	2.2	1.7	2.1	2.9	2.7	3.4	3.8	7.3	7.6	7.2	7.1	7.5	*7.8*	*7.3*
Exports	92.7	85.5	79.6	95.0	100.8	105.8	109.0	102.5	74.5	71.4	88.5	90.5	83.5	*79.0*	*79.8*
Total Net Domestic Supply	793.9	808.0	844.7	855.3	884.2	921.6	890.9	897.8	886.9	961.8	950.4	986.3	1008.5	*1040.0*	*1058.4*
Secondary Stock Levels [b]															
Opening	197.2	170.2	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	*106.8*	*114.4*
Closing	170.2	175.2	185.5	158.4	146.1	168.2	167.7	163.7	120.5	136.1	134.6	123.0	106.8	*114.4*	*111.8*
Net Withdrawals	27.0	-5.0	-10.2	27.0	12.3	-22.1	0.5	4.0	43.2	-15.7	1.5	11.7	16.1	*-7.6*	*2.6*
Waste Coal Supplied to IPPs [c]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	8.5	8.8	9.4	*10.0*	*10.6*
Total Supply	820.8	803.1	834.4	882.3	896.5	899.4	891.4	901.8	930.2	954.0	960.4	1006.7	1034.1	*1042.4*	*1071.6*
Demand															
Coke Plants	41.1	35.9	37.0	41.9	40.5	38.9	33.9	32.4	31.3	31.7	33.0	31.7	29.4	*28.3*	*29.6*
Electricity Production															
Electric Utilities	693.8	685.1	717.9	758.4	766.9	773.5	772.3	779.9	813.5	817.3	829.0	874.7	900.4	*916.2*	*938.0*
Nonutilities (Excl. Cogen.) [d]	NA	NA	NA	NA	0.9	1.6	10.2	14.8	17.8	20.9	21.2	22.2	23.5	*25.0*	*26.5*
Retail and General Industry [e]	75.4	75.6	75.2	76.3	82.3	83.1	81.5	80.2	81.1	81.2	78.9	76.9	76.4	*76.7*	*77.5*
Total Demand	810.3	796.6	830.0	876.5	890.6	897.1	897.8	907.3	943.7	951.1	962.0	1005.6	1029.7	*1046.2*	*1071.5*
Discrepancy [f]	10.6	6.5	4.4	5.8	5.9	2.4	-6.4	-5.4	-13.5	2.9	-1.6	1.2	4.4	*-3.8*	*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 8.9 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														
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Supply															
Net Utility Generation															
Coal	1402.1	1385.8	1463.8	1540.7	1553.7	1559.6	1551.2	1575.9	1639.2	1635.5	1652.9	1737.5	1787.8	1819.4	1872.6
Petroleum	100.2	136.6	118.5	148.9	158.3	117.0	111.5	88.9	99.5	91.0	60.8	67.3	77.8	108.5	97.1
Natural Gas	291.9	248.5	272.6	252.8	266.6	264.1	264.2	263.9	258.9	291.1	307.3	262.7	283.6	302.5	300.0
Nuclear	383.7	414.0	455.3	527.0	529.4	576.9	612.6	618.8	610.3	640.4	673.4	674.7	628.6	661.1	662.8
Hydroelectric	281.1	290.8	249.7	222.9	265.1	279.9	275.5	239.6	265.1	243.7	293.7	328.0	337.2	316.4	285.5
Geothermal and Other [a]	10.7	11.5	12.3	12.0	11.3	10.7	10.1	10.2	9.6	8.9	6.4	7.2	7.5	6.9	6.8
Subtotal	2469.8	2487.3	2572.1	2704.3	2784.3	2808.2	2825.0	2797.2	2882.5	2910.7	2994.5	3077.4	3122.5	3214.7	3224.7
Nonutility Generation [b]	NA	NA	NA	NA	191.3	221.8	253.7	296.0	325.5	354.9	374.4	382.5	409.4	426.4	437.4
Total Generation	NA	NA	NA	NA	2975.6	3030.0	3078.7	3093.2	3208.1	3265.6	3369.0	3460.0	3531.9	3641.1	3662.1
Net Imports	40.9	35.9	46.3	31.8	11.0	2.0	22.3	28.3	28.4	44.6	37.6	38.0	36.6	28.5	32.7
Total Supply	NA	NA	NA	NA	2986.6	3032.0	3101.0	3121.6	3236.5	3310.3	3406.6	3498.0	3568.5	3669.5	3694.8
Losses and Unaccounted for [c]	NA	NA	NA	NA	231.4	206.1	217.1	226.6	236.9	225.5	235.4	236.2	285.0	275.3	268.0
Demand															
Electric Utility Sales															
Residential	793.9	819.1	850.4	892.9	905.5	924.0	955.4	935.9	994.8	1008.5	1042.5	1082.5	1071.6	1124.4	1139.1
Commercial	606.0	630.5	660.4	699.1	725.9	751.0	765.7	761.3	794.6	820.3	862.7	887.4	913.3	950.7	961.9
Industrial	836.8	830.5	858.2	896.5	925.7	945.5	946.6	972.7	977.2	1008.0	1012.7	1030.4	1032.5	1046.2	1046.1
Other	87.3	88.6	88.2	89.6	89.8	92.0	94.3	93.4	94.9	97.8	95.4	97.5	97.5	99.9	102.0
Subtotal	2324.0	2368.8	2457.3	2578.1	2646.8	2712.6	2762.0	2763.4	2861.5	2934.6	3013.3	3097.8	3114.9	3221.1	3249.1
Nonutility Own Use [b]	NA	NA	NA	NA	108.4	113.4	121.9	131.6	138.1	150.2	157.9	164.0	168.6	173.1	177.7
Total Demand	NA	NA	NA	NA	2755.2	2825.9	2883.9	2895.0	2999.6	3084.8	3171.2	3261.8	3283.5	3394.2	3426.8
Memo:															
Nonutility Sales to Electric Utilities [d]	26.0	39.9	50.0	68.0	83.0	108.5	131.9	164.4	187.4	204.7	216.5	218.5	240.8	253.2	259.7

[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.