DOE/EIA-0202(89)
Distribution Category UC-98

DOE/EIA--0202(89)

DE90 002593

Short-Term Energy Outlook Annual Supplement 1989

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

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Contacts

The Short-Term Energy Outlook is prepared by the Energy Information Administration (EIA), Office of Energy Markets and End Use (EMEU). General questions concerning the content of the report may be referred to W. Calvin Kilgore (202/586-1617), Director of EMEU; John Pearson (202/586-6160), Director of the Energy Analysis and Forecasting Division; or Edward J. Flynn (202/586-5748), Chief of the Demand Analysis and Forecasting Branch.

Detailed questions may be referred to David Costello (202/586-1468) and Neil Gamson (202/586-2418), or to the following analysts, who can be reached at the Energy Analysis and Forecasting Division (202/586-5382).

Forecast Evaluation:	Neil Gamson
Demand for Petrochemical Feedstocks:	John Scott
Determinants of Natural Gas Wellhead Prices:	Neil Gamson
Modeling Short-Term Natural Gas Demand:	David Costello
Regional Trends in the Demand for Fuel by Electric Utilities:	David Boomsma
Industrial Coal Use Patterns:	David Costello
Comparison of EIA and Other Forecasts for 1989:	Evelyn Amerchih

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1. Introduction

The *Short-Term Energy Outlook Annual Supplement* (*Supplement*) is published once a year as a complement to the *Short-Term Energy Outlook, Quarterly Projections* (*Outlook*). The purpose of the supplement is to review the accuracy of the forecasts presented in the *Outlook*, make comparisons with other independent energy forecasts, and examine current energy topics that affect the forecasts. A brief description of the content of each chapter follows below:

Chapter 2 evaluates the accuracy of the short-term energy forecasts published in the last 6 issues of the *Outlook*, for 1988/1989.

Chapter 3 discusses the economics of the petrochemical feedstock market, and describes a new model which more fully captures the determinants of feedstock demand. In the current *Outlook* model, only the prices of the fuels used(e.g., ethane, naphtha) as feedstocks and an output index are included in the demand model. The proposed model focuses on profit maximization in the petrochemical industry, which recognizes that the relative price of the petrochemical outputs (e.g., ethylene and propylene) should also be an important determinant in feedstock demand. Although there is flexibility in feedstock choice, the fuels do not yield identical outputs, thereby making the price of the output a significant factor in the desirability of a particular feedstock input.

Chapter 4 examines present and proposed new methods of forecasting short-term natural gas prices at the wellhead and spot prices. Currently, forecasts for natural gas prices are based on relatively simple relationships. Natural gas wellhead price forecasts, for example, are driven by the world price of oil. This chapter focusses on other exogenous variables, particularly the relationship between spot prices and working gas underground storage on a regional level.

Chapter 5 discusses the modeling of natural gas demand in the short term. Short-term forecasts for natural gas demand are generated from three independent linear regression models representing the three major gas market sectors -- residential, commercial, and industrial. The first two models depend on the number of heating and cooling degree-days, and on the respective number of customers (gas-meter hookups). The industrial sector model depends on a lagged structure for the gas-to-oil price ratio, as well as a weighted index of industrial production for the six largest 2-digit SIC gas consumers.

Chapter 6 discusses regional trends in the demand for fuel by electric utilities. In the past 2 years, there has been considerable variation in fuel consumption at electric utilities, particularly at a regional level. This chapter discusses the causes behind these variations, focusing especially on regional weather variations and regional price variations. Topics of interest include regional variations in precipitation affecting hydroelectric generation; the introduction of additional nuclear capacity; curtailments of natural gas shipments to electric utilities; and wide variations in the relative price of petroleum to the price of natural gas.

Chapter 7 focuses on industrial coal use trends in recent years. Coal demand by the industrial sector grew by an average 0.4 percent from 1985 to 1988. During this same period, industrial production increased by an average 4.2 percent. Various factors, including stricter emission controls and fuel switching, accounted for coal's relative market disadvantage. A potential source for increased coal demand, on the other hand, may come from industrial cogeneration of electricity.

Chapter 8 compares EIA's base case energy projections as published in the *Outlook*(89/2Q) with recent projections made by three other major forecasting groups. The chapter focuses on macroeconomic assumptions, primary energy demand, and primary energy supply, showing the differences and similarities in the four forecasts. Not surprisingly, there are more similarities than differences. Furthermore, the EIA forecast tends to be in the middle.

2. Forecast Evaluation

This chapter presents an evaluation of the forecasts of the major energy demand, supply, and prices published in the January 1988 through April 1989 issues of the *Short-Term Energy Outlook* (*Outlook*). Past issues of the *Supplement* evaluated forecasts from the previous 13 issues of the *Outlook* for 28 energy or related products. This issue of the *Supplement* concentrates on eight of the major energy products, evaluating the results of the previous six *Outlooks.* Evaluation tables follow each evaluation. The figures in this section compare the actual data for these products with forecasts of these products that were made in the previous quarter and in the previous year. Appendix A will present evaluation tables for other important forecasts of the *Outlook*. The eight major forecast evaluations covered in this section are:

1. Refiner Acquisition Cost of Imported Crude Oil
2. Retail Motor Gasoline Prices
3. Motor Gasoline Demand
4. Net Petroleum Imports
5. Natural Gas Consumption
6. Electricity Sales
7. Electric Utility Fuel Shares
8. Petroleum Stocks

For Tables 2 through 10 in this chapter and Tables A1 through A17 in the Appendix, the average absolute error by report (the two rows on the bottom) is calculated vertically down the table, by taking the mean of the absolute values of the differences between the actual and the forecasted values for each quarter of the report. The average absolute error by quarter (the last two columns on the right-hand side) is calculated horizontally across the table, by taking the mean of the absolute values of the differences between the actual value and the forecasted values for each report, by quarter. The overall error (shown in the lower right-hand corner of each table) is the mean of all of the absolute errors in the table. It can be calculated either by taking the weighted average (weighted by the number of cells per column) of the average absolute errors by report, or by taking the weighted average (weighted by the number of cells per row) of the average absolute error by quarter.

Three forecasts, based on three different scenarios for world oil prices, are presented in each *Outlook*. Only the base case scenario is evaluated for this analysis.

The terms "demand", "consumption", or "product supplied" are interchangeable terms for this report.

Table 1 presents a summary of the average absolute errors for the forecasts published in the January 1988 through April 1989 issues of the *Outlook*. (To weight each observation properly, these errors are calculated from the individual quarterly errors in the body of each table, rather than as an average of the "average errors" at the bottom of each table.) Each *Outlook* projects an average of five quarters into the future. Over the past six issues of the *Outlook*, on an individual fuel basis, the forecasts for electricity generation from petroleum had the largest average absolute errors; motor gasoline and electricity sales had the smallest errors. Errors for prices ranged from 1.4 percent for residential electricity to 12.6 percent for the refiner acquisition cost of crude oil.

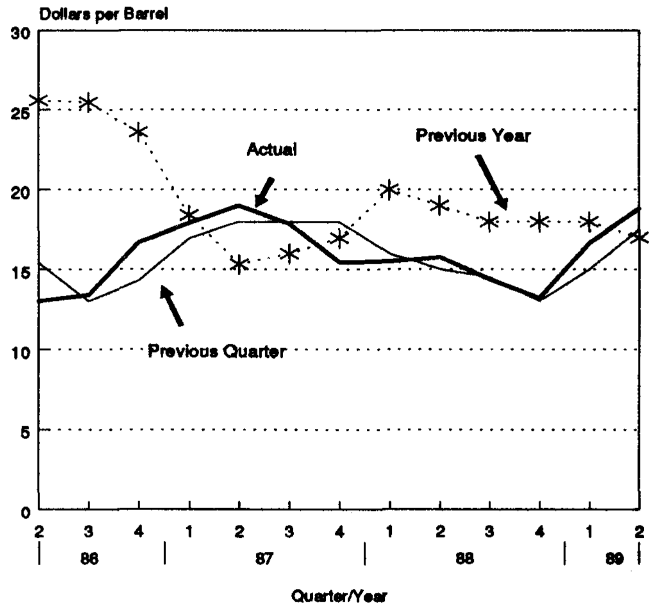
Table 1. Summary of Average Absolute Errors, January 1988 Through April 1989 Issues of the *Outlook*

Variable	Percentage Error
Prices	
Refiner Acquisition Cost of Crude Oil	12.6
Motor Gasoline	6.2
Distillate	5.1
Residual Fuel Oil	13.1
Residential Electricity	1.4
Residential Natural Gas	2.5
Macroeconomic	
Real Personal Disposable Income	2.0
Industrial Production Index Of Manufacturing	2.1
Demands	
Total Petroleum Product Supplied	2.3
Motor Gasoline Demand	1.3
Distillate Fuel Demand	3.2
Residual Fuel Oil Demand	12.2
Other Petroleum Products Demand	2.7
Net Oil Imports	6.1
Natural Gas Consumption	3.0
Domestic Coal Consumption	4.0
Electricity Sales	2.0
Electricity Generation by Fuel	
Coal	3.6
Petroleum	27.7
Natural Gas	11.7
Nuclear Power	5.6
Hydroelectric Power	14.8
Supply	
Domestic Crude Oil Production	2.1
Natural Gas Production	2.2
Coal Production	4.1
Total Petroleum Stocks	1.8

Refiner Acquisition Cost of Imported Crude Oil

This is the principal driving variable for many of the forecasts. Thus, errors in forecasting for this variable can adversely affect the results of many of the other products forecasted in the *Outlook*. Table 2 indicates that the overall average absolute error for the refiner acquisition cost (RAC) of imported crude oil was about $2.00 per barrel, or 13 percent, over the past six issues of the *Outlook*. This compares with previously reported errors of 25 percent in the 1987 *Supplement* and 26 percent in the 1988 *Supplement*. The major reason for the improvement in this year's forecast is that there have been less dramatic price swings in the 1988-1989 period than earlier, such as the price collapse that occurred in 1986 (Figure 1). Anticipating the timing of such price swings is very difficult. Although market weakness or strength may be anticipated in future periods, it is almost impossible to determine correctly in which quarter such market conditions will manifest themselves in large price movements. Accordingly, over the past six *Outlooks*, the largest errors resulted in projecting the price drop that occurred during the fourth quarter of 1988 that resulted from overproduction by OPEC countries immediately preceding their fall meeting.

Figure 1. Crude Oil Prices, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Table 2. Refiner Acquisition Cost of Imported Crude Oil, Actual Versus Forecasts
(Dollars per Barrel)
(Percent Difference from Actual)

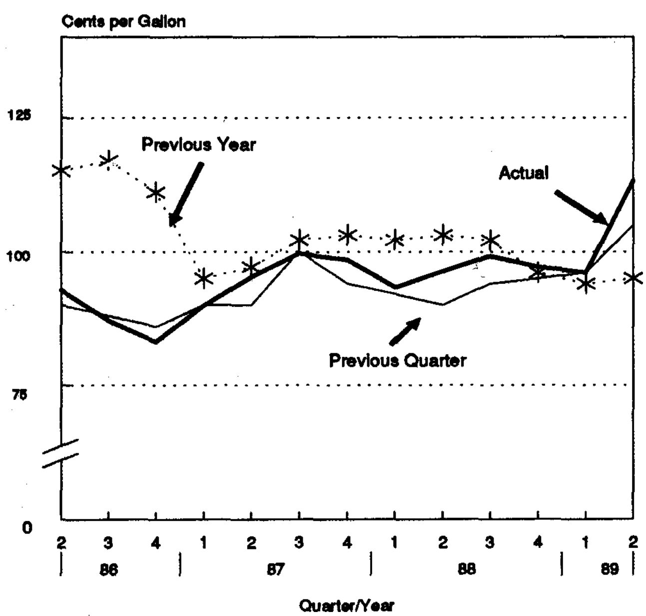
Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter: Dollars/ Barrel	Percent
1Q 88	15.48	16.00 3.4%	--	--	--	--	--	0.5	3.4
2Q 88	15.75	17.00 7.9%	15.00 -4.8%	--	--	--	--	1.0	6.3
3Q 88	14.36	18.00 25.3%	16.00 11.4%	14.50 1.0%	--	--	--	1.8	12.6
4Q 88	13.21	18.00 36.3%	17.00 28.7%	16.00 21.1%	13.00 -1.6%	--	--	2.9	21.9
1Q 89	16.65	19.00 14.1%	18.00 8.1%	17.00 2.1%	15.00 -9.9%	15.00 -9.9%	--	1.5	8.8
2Q 89	18.80	--	18.00 -4.3%	17.00 -9.6%	15.00 -20.2%	14.00 -25.5%	17.50 -6.9%	2.5	13.3
Average Absolute Error by Report									
Dollars/Barrel		2.51	1.67	1.27	1.89	3.22	1.30	1.97	
Percent		16.6	10.6	8.1	11.6	18.2	6.9	--	12.6

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, various issues; forecasts are taken from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Retail Motor Gasoline Prices

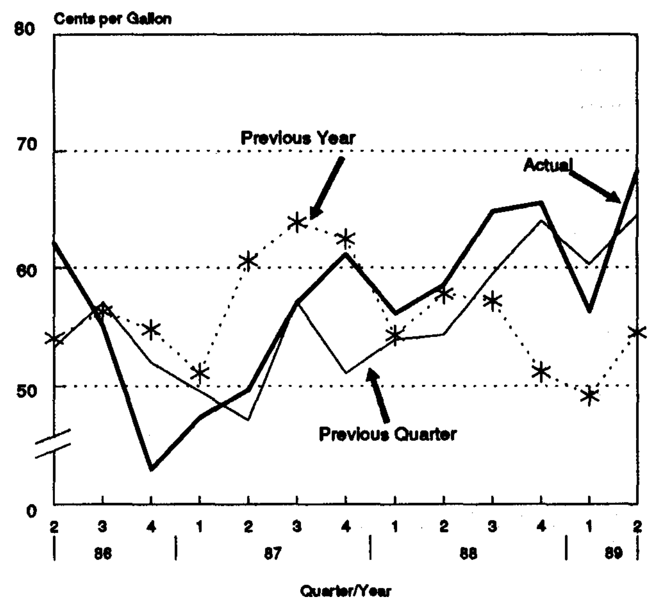
Motor gasoline price forecasts had an average absolute error of 6.2 percent or 6.6 cents per gallon over the last six *Outlooks*. This compares with an error of 4.2 percent for a comparable period evaluated in the previous *Supplement*. Most of the forecasts underestimated prices, but only by a small amount. However, the forecasts for the second quarter of 1989 averaged over 13 percent or 15 cents per gallon, (Table 3 and Figure 2), while the October 1988 *Outlook* underestimated prices by 20 cents per gallon for the second quarter. Part of the large error can be attributed to underestimating the price of crude oil. In the example above, this would account for a large portion of that error. Other factors which caused the high price of gasoline that were unanticipated in the forecasts were refinery shutdowns and the added cost of EPA regulations. Figure 3 illustrates that for one-year-ahead projections, gross margin forecasting errors have changed direction over time.

Figure 2. Motor Gasoline Prices, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues; projections from the *Short-Term Energy Outlook*, various issues.

Figure 3. Motor Gasoline Margins, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues ; projections from the *Short-Term Energy Outlook*, various issues.

Forecasts made in 1985 and 1986 (for 1986 and 1987, respectively), generally overestimated margins, while the reverse was generally true for forecasts made in 1987 and 1988 (for 1988 and 1989, respectively). This pattern reflects the instability of motor gasoline gross price margins (refiner margin plus retail margin plus Federal and State taxes) in recent periods, since the basic forecasting methodology allows for relatively short-lived disturbances from average or normal differences between crude oil input prices and gasoline prices.

Table 3. Retail Motor Gasoline Prices, Actual Versus Forecasts
(Cents per Gallon)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter Cents/ Gallon	Percent
1Q 88	93	92 -1.3%	--	--	--	--	--	1.2	1.3
2Q 88	96	93 -3.3%	89 -7.5%	--	--	--	--	5.2	5.4
3Q 88	99	95 -4.0%	90 -9.1%	94- -5.1%	--	--	--	6.0	6.1
4Q 88	97	96 -1.0%	92 -5.2%	93 -4.1%	95 -2.1%	--	--	3.0	3.1
1Q 89	96	98 2.1%	94 -2.1%	92 -4.2%	89 -7.3%	96 0.0%	--	3.0	3.1
2Q 89	113	--	97 -14.2%	95 -15.9%	93 -17.7%	100 -11.5%	105 -7.1%	15.0	13.3
Average Absolute Error by Report									
Cents/Gallon		2.3	7.8	7.8	9.7	6.5	8.0	6.6	
Percent		2.4	7.8	7.7	9.5	6.2	7.1		6.2

-- = Not applicable.

Note: Gasoline prices are an average of all grades and services, including taxes.

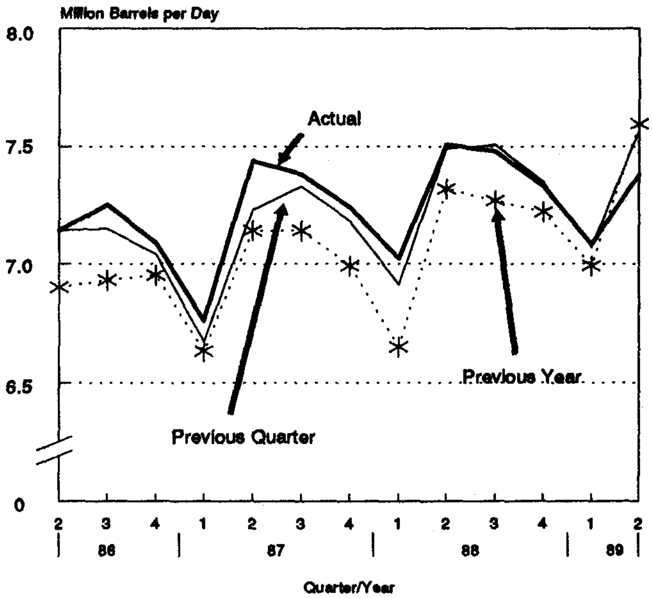
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Motor Gasoline Demand

Motor gasoline demand forecasts over the last six *Outlooks* had an average absolute error of 1.3 percent, with the largest error for a quarter being a 3.5-percent underestimation for the second quarter 1989 forecast generated in the October 1988 *Outlook* (Table 4). The forecasts for principal economic growth variables have consistently been underestimated in the last six issues of the *Outlook*. While motor gasoline demand has been underpredicted in recent *Outlooks* (11 times out of 20 for these same six *Outlooks*), the forecast errors have been generally diminishing since 1986 (Figure 4). One reason for a significant portion of the underestimation in motor gasoline was the low macroeconomic projections incorporated in past *Outlooks*. Another reason for the underestimation of motor gasoline demand in 1988 is that 1988 was the first full year in which a significant number of States had 65-mile-per-hour highway speed limits in effect, which tended to reduce average fleet miles per gallon (mpg). This tendency, which could have been anticipated but which would have been difficult to quantify precisely, was not incorporated into any of the affected forecasts. The average quarterly forecast for the year 1988 reported in the January 1988 *Outlook* was a 90,000-barrel-per-day underestimation. Because of the already existing effect of underpredicted macroeconomic drivers for 1988, the evidence based on the *Outlook* models is that the mpg degradation effect in 1988 was below 90,000 barrels per day. This large discrepancy can best be explained by using the January 1988 forecast because it is the only one for which all of 1988 is a projection. Based on a conservative estimate for the elasticity of motor gasoline demand with respect to income of 0.5, at least 60,000 barrels per day of the 90,000-barrel-per-day underestimation was apparently due to a too-conservative view of the economy at the time of the forecast.

This analysis suggests that the mpg degradation effect of the 65-mile-per-hour speed limits may have been less than has been suggested elsewhere, since estimates have ranged as high as 100,000 barrels per day or more. It should also be noted that, beyond a tendency to use conservative income growth projections in 1988, overestimation of oil prices were also important factors for the 1988 projections. Thus, based on the gasoline forecasting methodology used in the *Outlook*, it is possible that any effects on mpg (and thus gasoline demand) due to speed limit changes in 1988 were small.

Figure 4. Motor Gasoline Demand, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Table 4. Motor Gasoline Product Supplied, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter: MMB/ Day	Percent
1Q 88	7.02	6.91 -1.6%	--	--	--	--	--	0.11	1.6
2Q 88	7.51	7.44 -0.9%	7.49 -0.3%	--	--	--	--	0.04	0.6
3Q 88	7.48	7.41 -0.9%	7.45 -0.4%	7.51 0.4%	--	--	--	0.04	0.6
4Q 88	7.33	7.22 -1.5%	7.34 0.1%	7.32 -0.1%	7.35 0.3%	--	--	0.04	0.5
1Q 89	7.08	6.92 -2.3%	6.99 -1.3%	7.03 -0.7%	7.09 0.1%	7.07 -0.1%	--	0.06	0.9
2Q 89	P7.38	--	7.52 1.9%	7.60 3.0%	7.64 3.5%	7.61 3.1%	7.57 2.6%	0.21	2.8
Average Absolute Error by Report									
MMB per day		0.10	0.06	0.08	0.10	0.12	0.19	0.09	
Percent		1.4	0.8	1.1	1.3	1.7	2.6		1.3

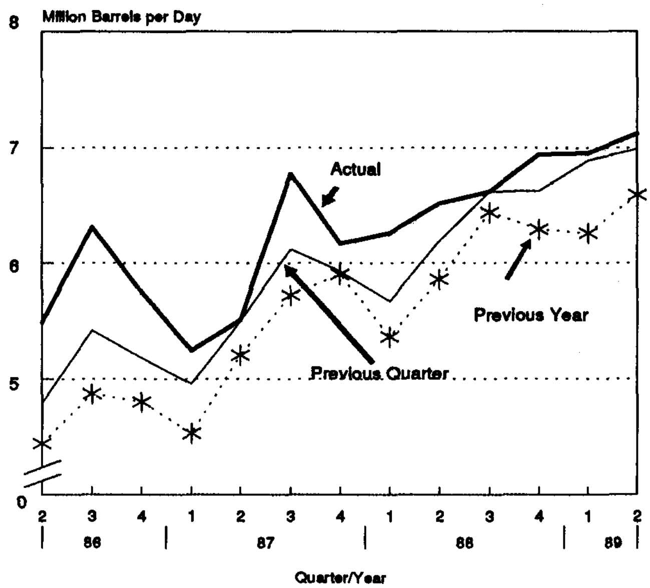
-- = Not applicable.
P = Preliminary.
MMB = Million Barrels.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Net Petroleum Imports

The forecast for net imports is dependent on the accuracy of the forecasts of the other components of both supply and demand and, as a result, is the forecast with the greatest overall error. The forecasts shown in Table 5 have an average absolute error of 6.1 percent. However, forecasts clearly have been improving even for this elusive category, as indicated by the gradual reduction in the negative difference between predicted and actual values (Figure 5).

After the January 1988 *Outlook*, in which gross crude oil imports (Table 5) were projected to be 4.71 million barrels per day, the forecasts for the 1988 annual crude oil import level were fairly close to the 5.06 million barrels reported in the 1988 *Petroleum Supply Annual*. This means that the underprediction noted above occurred in the forecasts of petroleum product imports, in particular residual fuel oil in the second half of the year, and "other" petroleum products.

Figure 5. Net Petroleum Imports, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Table 5. Net Oil Imports (Including SPR), Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter: MMB/ Day	Percent
1Q 88	6.26	5.67	--	--	--	--	--	0.59	9.4
		-9.4%							
2Q 88	6.52	5.91	6.19	--	--	--	--	0.47	7.2
		-9.4%	-5.1%						
3Q 88	6.62	6.25	6.50	6.62	--	--	--	0.16	2.5
		-5.6%	-1.8%	0.0%					
4Q 88	6.94	6.30	6.61	6.52	6.63	--	--	0.43	6.1
		-9.2%	-4.8%	-6.1%	-4.5%				
1Q 89	6.95	5.95	6.26	6.23	6.42	6.89	--	0.60	8.6
		-14.4%	-9.9%	-10.4%	-7.6%	-0.9%			
2Q 89	P7.12	--	6.40	6.60	6.92	7.14	6.99	0.32	4.5
			-10.1%	-7.3%	-2.8%	0.3%	-1.8%		
Average Absolute Error by Report									
MMB per day		0.64	0.44	0.42	0.35	0.04	0.13	0.42	
Percent		9.6	6.4	6.0	5.0	0.6	1.8		6.1

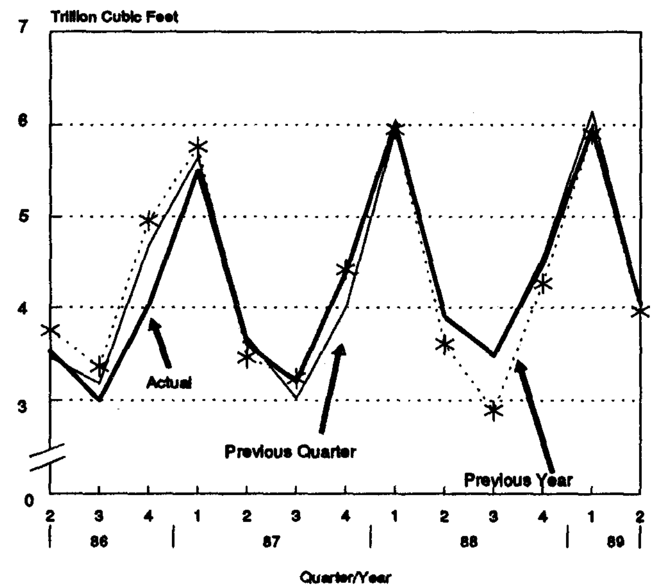
-- = Not applicable.
P = Preliminary.
SPR = Strategic Petroleum Reserve.
MMB = Million Barrels.
Sources: Actual data are based on published numbers from the Energy Information Administration *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.,

Natural Gas Consumption

Except for the fourth quarter of 1988, the forecasts for each quarter of 1988 underestimated actual consumption (Table 6). This apparent inaccuracy is due in large part to a change in methodology in 1988 in collecting natural gas consumption data by sector.[1] The actual values for 1988 have consequently been revised upward. Forecasts for the fourth quarter of 1988 and the first quarter of 1989 in general overestimated actual demand. Milder-than-expected winter weather appears to have played a part in the outcome. However, quarterly forecasts made in 1987 for 1988 in predicting gas use were the most conservative in the spring and summer quarters (Figure 6). The average absolute errors of the most recent reports contrast favorably against the pre-1988 reports. One likely reason for the greater accuracy of recent forecasts is the addition of the number of natural gas customers as an independent variable in the residential and commercial forecasting models.

[1]See the *Short-Term Energy Outlook*, July 1988 issue, p.33.

Figure 6. Natural Gas Consumption, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Table 6. Total Natural Gas Consumption, Actual Versus Forecasts
(Trillion Cubic Feet)
(Percent Difference from Actual)

		Forecast Report						Average Absolute Error by Quarter	
Forecast Quarter	Actual	Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Tcf	Percent
1Q 88	6.01	5.92	--	--	--	--	--	0.09	1.5
		-1.5%							
2Q 88	3.91	3.67	3.84	--	--	--	--	0.16	4.0
		-6.1%	-1.8%						
3Q 88	3.49	3.07	3.37	3.48	--	--	--	0.18	5.3
		-12.0%	-3.4%	-0.3%					
4Q 88	4.48	4.27	4.57	4.73	4.56	--	--	0.16	3.5
		-4.7%	2.0%	5.6%	1.8%				
1Q 89	5.95	6.02	5.90	6.23	6.10	6.14	--	0.15	2.5
		1.2%	-0.8%	4.7%	2.5%	3.2%			
2Q 89	P4.05	--	3.93	3.96	3.93	4.07	4.07	0.07	1.8
			-3.0%	-2.2%	-3.0%	0.5%	0.5%		
Average Absolute Error by Report									
Tcf		0.21	0.09	0.16	0.12	0.10	0.02	0.13	
Percent		4.3	2.1	3.5	2.4	2.1	0.5		3.0

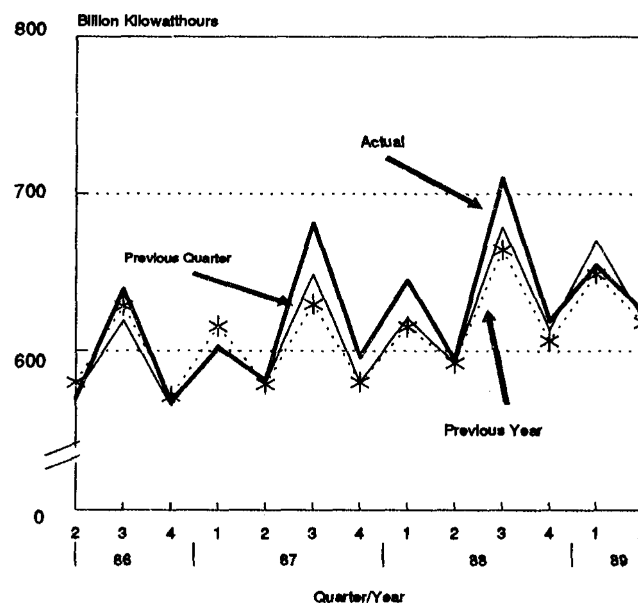
-- = Not applicable.
P = Preliminary.
Tcf = Trillion cubic feet.
Sources: Actual data are based on published numbers from the Energy Information Administration *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Electricity Sales

One of the most significant influences on electricity demand in the short term is weather. Significant errors in predicting electricity sales levels can also be attributed to macroeconomic factors (such as inaccurate projections for gross national product), although the lags in the effects of macroeconomic shifts tend to be long for some sectors. Thus, the accuracy of the forecast relies on the probability of normal temperatures and a fairly accurate estimate of economic growth. (Normal weather is defined as 30-year fixed averages of heating and cooling degree-days.) Some of the largest forecasting errors, which were generally underpredictions, were in the third quarter of 1988 (Table 7). These large errors were attributed to abnormal temperatures in 1987 and 1988--in both summer and winter--and a tendency to underpredict economic growth (Figure 7). Because the weather greatly affects the demand for electricity, a special simulation procedure was developed to evaluate short-term weather effects on electricity sales and to better evaluate the accuracy of the model.[2] This simulation was used to compare what the electricity sales forecast would have been if actual weather had been known (all other factors held constant) to actual sales levels. This analysis uncovered underlying short-term trends in electricity demand and resulted in noticeably lower forecast errors than shown in Table 7.

The current methodology for forecasting electricity sales involves examining both long-term economic trends, as well as short-term weather effects at a detailed level. These trends are identified separately for each end-use sector within the electric utility market: residential, commercial, industrial, and other (street lighting, Government consumption, railways, and miscellaneous). The residential sector is affected a great deal by weather in the short term and by such things as population growth and household formation over the long term. The weather is measured by electric customer-weighted heating and cooling degree-days. This variable tracks weather influences on electricity demand in areas where residential electricity customers are concentrated. Commercial sector electricity sales are estimated from similar variables, except the weather is less influential and population-weighted degree-days are substituted for electric customer-weighted degree-days, as commercial activity varies with the basic distribution of the population. Commercial sales are assumed to be influenced by long-term economic growth factors, and by some short-term responses to changes in the aggregate output of the economy.

Figure 7. Electricity Sales, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

[2]The detailed results of this simulation are available upon request.

Electricity sales to the industrial sector vary primarily with the general health of the manufacturing sector, as measured by the industrial output index. Though extremely abnormal weather patterns are suspected of having a noticeable impact on electricity sales to this sector, seasonal weather patterns do not register as significant variables in this equation. Sales of electricity for miscellaneous uses (the other sector) are a simple function of a time trend and seasonal factors.

Table 7. Total Electricity Sales: Actual Versus Forecasts
(Billion Kilowatthours)
(Percent Difference from Actual)

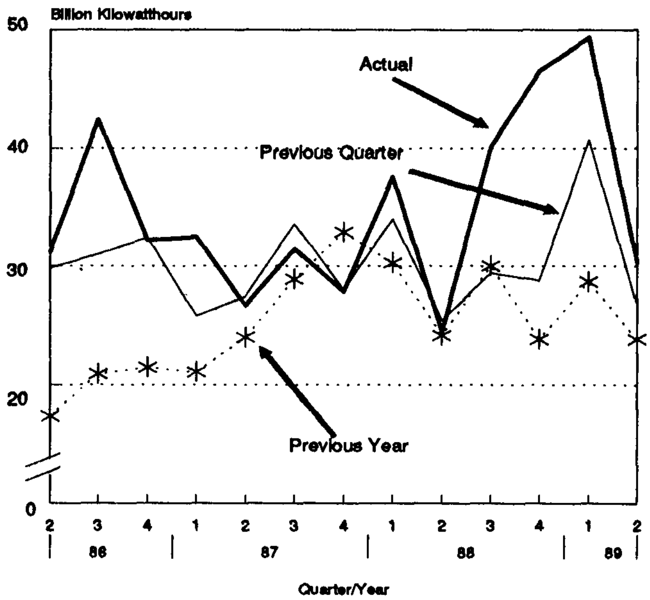
		Forecast Report						Average Absolute Error by Quarter	
Forecast Quarter	Actual	Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Billion/ kWh	Percent
1Q 88	644.2	620.3	--	--	--	--	--	23.9	3.7
		-3.7%							
2Q 88	594.2	599.6	591.7	--	--	--	--	3.9	0.7
		0.9%	-0.4%						
3Q 88	709.4	667.8	674.1	678.9	--	--	--	35.8	5.0
		-5.9%	-5.0%	-4.3%					
4Q 88	618.4	606.0	602.2	610.1	612.6	--	--	10.7	1.7
		-2.0%	-2.6%	-1.3%	-0.9%				
1Q 89	654.0	630.1	648.1	655.7	660.0	670.0	--	10.7	1.6
		-3.7%	-0.9%	0.3%	0.9%	2.4%			
2Q 89	P624.5	--	609.4	617.3	622.3	622.1	619.4	6.4	1.0
			-2.4%	-1.2%	-0.4%	-0.4%	-0.8%		
Average Absolute Error by Report									
Billion kWh		21.4	15.0	11.9	4.7	9.2	5.1	13.4	
Percent		3.3	2.3	1.8	0.7	1.4	0.8		2.0

-- = Not applicable.
P = Preliminary.
kWh = Kilowatthour.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Electric Utility Fuel Shares

Forecasting petroleum and natural gas use at electric utilities has been difficult because many of the Nation's power plants have the capability to switch fuels on very short notice, depending upon price and availability. Moreover, other factors such as total electricity generation, weather, and rainfall add enormously to the uncertainty.

Figure 8. Electricity Generation From Oil, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Petroleum Generation

The forecasts for residual fuel oil use at electric utilities have suffered from large errors reported in the last six *Outlooks* (Figure 8). The average absolute error reached as high as 37 percent for two of the six quarters (Table 8). In every quarter, except the second quarter of 1988, petroleum generation was underestimated.

Based on an analysis of recent trends in fuel conservation at electric utilities, several reasons for the underestimation of petroleum generation stand out.[3] One important reason was the drought conditions which caused low watershed levels throughout much of the Nation. As a result, hydroelectric generation was lower than expected, putting upward pressure on the demands for all other fuel sources.

Another reason for the underestimation of petroleum generation was the lack of availability of natural gas. In both the first quarter of 1988 and the first quarter of 1989, there were curtailments of shipments of natural gas to electric utilities to enable gas suppliers to provide gas to residential and commercial customers. Moreover, in the second quarter of 1989, the Southern California Gas Company restricted gas availability to electric utilities to fill its existing storage capacity to avoid the kind of supply shortage problems that had occurred in previous quarters.[4]

[3]Energy Information Administration, "Monthly Power Plant Report", Form EIA-759. For further analysis, see Chapter 6, page 39.

[4]Based on a telephone conversation with a representative from Southern California Gas Company, Los Angeles, CA.

Table 8. Electricity Generation from Petroleum, Actual Versus Forecasts
(Billion Kilowatthours)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter Billion/ kWh	Percent
1Q 88	37.6	34.0	--	--	--	--	--	3.6	9.6
		-9.6%							
2Q 88	24.4	24.2	25.4	--	--	--	--	0.6	2.5
		-0.8%	4.1%						
3Q 88	40.1	28.7	30.2	29.4	--	--	--	10.7	26.6
		-28.4%	-24.7%	-26.7%					
4Q 88	46.6	23.8	25.0	27.6	28.8	--	--	20.3	43.6
		-48.9%	-46.4%	-40.8%	-38.2%				
1Q 89	49.4	28.6	28.7	24.2	25.9	40.7	--	19.8	40.0
		-42.1%	-41.9%	-51.0%	-47.6%	-17.6%			
2Q 89	P30.3	--	23.0	23.8	25.5	26.8	26.7	5.1	17.0
			-24.1%	-21.5%	-15.8%	-11.6%	-11.9%		
Average Absolute Error by Report									
Billion kWh		11.8	12.1	15.4	15.4	6.1	3.6	12.1	
Percent		29.7	31.7	36.9	36.5	15.3	11.9		27.7

-- = Not applicable.
P = Preliminary
kWh = Kilowatthours.
Sources: Actual data are based on published numbers from the Energy Information Administration *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

In some quarters, both petroleum and natural gas generation were underestimated due to unexpectedly high demand for total generation, and because of a high demand for fossil fuel generation due to low watershed levels in hydroelectric power producing regions. Although the forecasts were adjusted to account for low watershed levels, normal precipitation was assumed for each forecast period which led to a persistent underestimation of hydroelectric generation.

Finally, extremely high temperatures for most of the country in the third quarter of 1988 caused the demand for petroleum generation to be high. Often, when electricity demand is high, residual fuel oil is used to meet peak demand. Moreover, temperatures were particularly high in the Northeast, whose primary fuel at electric utilities is petroleum. Odds are good that the United States will not get a summer as hot as the summer of 1988 in the next 50 years.

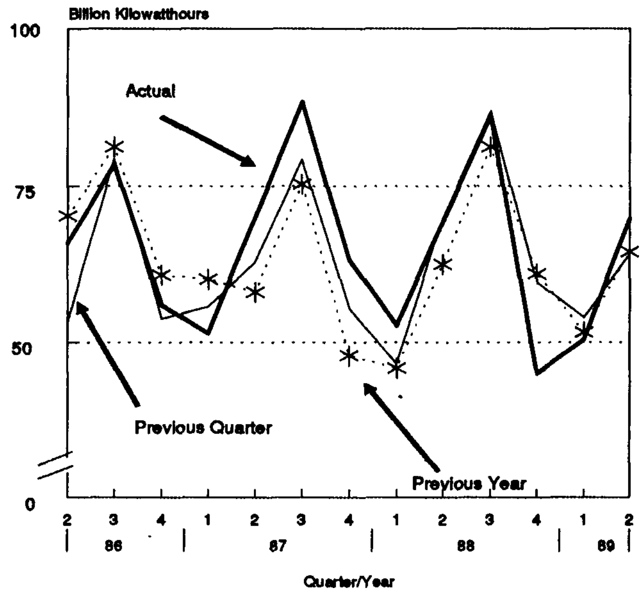
Natural Gas Generation

The errors in the forecasts of electricity generation from natural gas averaged 12 percent in absolute terms for all of 1988 and the first half of 1989 (Table 9). Because petroleum and natural gas often substitute for each other, and since petroleum use at electric utilities was unexpectedly high over the past year and a half, most of the forecast errors reflect just the opposite of the forecast errors for petroleum generation (Figure 9).

The largest average absolute error (33 percent) occurred in the fourth quarter of 1988. This overestimation occurred primarily because the average price of petroleum to electric utilities became unexpectedly competitive with the average price of gas, actually dropping below the average price of gas in this quarter. Moreover, the July 1988 and the October 1988 *Outlooks* overestimated natural gas generation for the first quarter of 1989, primarily because of gas supply curtailments, which are difficult to predict, and a favorable price of petroleum in the early part of the quarter.

Lower-than-expected prices for residual fuel oil to electric utilities stimulated growth in petroleum generation, particularly in the fourth quarter of 1988. In this quarter, the average price of residual fuel oil dropped below the average price of natural gas, contributing to an increase in petroleum generation of over 65 percent compared to the fourth quarter of 1987. This drop in the residual fuel oil price and concurrent increase in the price of natural gas was not fully anticipated.

Figure 9. Electricity Generation from Natural Gas, Actual and Earlier Forecasts



Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues .

Table 9. Electricity Generation From Natural Gas: Actual Versus Forecasts
(Billion Kilowatthours)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter: Billion/ kWh	Percent
1Q 88	52.5	46.5 -11.4%	--	--	--	--	--	6.0	11.4
2Q 88	69.2	66.1 -4.5%	70.0 1.2%	--	--	--	--	2.0	2.8
3Q 88	86.2	84.5 -2.0%	84.3 -2.2%	87.0 0.9%	--	--	--	1.5	1.7
4Q 88	44.9	60.8 35.4%	60.7 35.2%	58.4 30.1%	59.5 32.5%	--	--	15.0	33.3
1Q 89	50.3	50.4 0.2%	51.5 2.4%	58.6 16.5%	61.3 21.9%	53.8 7.0%	--	4.8	9.6
2Q 89	P69.7	--	65.3 -6.3%	64.3 -7.7%	67.4 -3.3%	65.6 -5.9%	63.9 -8.3%	4.4	6.3
Average Absolute Error by Report									
Billion kWh		5.4	4.8	7.0	9.3	3.8	5.8	6.0	
Percent		8.8	7.5	11.2	16.9	6.3	8.3		11.7

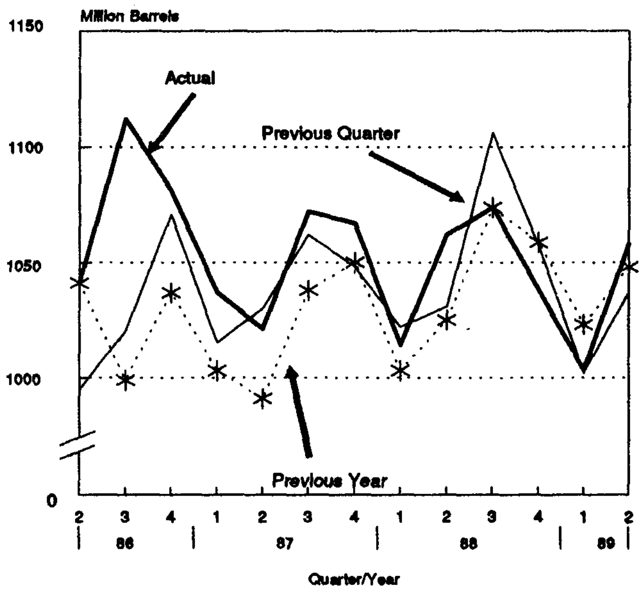
-- = Not applicable.
P = Preliminary.
kWh = Kilowatthours.
Sources: Actual data are based on published numbers from the Energy Information Administration *Monthly Energy Review*, various issues; forecasts are from the base case scenarios from various issues of the *Short-Term Energy Outlook*.

Petroleum Stocks

Of the stock forecasts published since January 1988, the July 1988 *Outlook* had the highest average error (Table 10 and Figure 10). The reason for this was the overestimation of crude oil stocks. At the time the projection was made, crude oil stocks were estimated to be 363 million barrels, and the July 1988 *Outlook* predicted that they would remain near that level until the heating season demand picked up in the fourth quarter, with the forecast remaining around the 350-million-barrel level after that. Crude oil stocks returned to 330 million barrels in the third quarter of 1988, resulting in a forecast that was 20 to 30 million barrels high. The forecast for product stocks in the same *Outlook* was much better, except in the fourth quarter of 1988, overpredicting distillate by about 18 million barrels.

The forecasts for the second and fourth quarters of 1988 contain the highest errors across the *Outlooks* because of overestimating crude oil stocks and distillate fuel oil stocks.

Figure 10. Petroleum Stocks, Actual and Earlier Forecasts



Excludes SPR.
Sources: Actual data from Energy Information Administration, *Monthly Energy Review*, various issues and projections from the *Short-Term Energy Outlook*, various issues.

Table 10. Total Petroleum Stocks (Excluding SPR), Actual Versus Forecasts
(Million Barrels)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct 1988	Jan 1989	Apr. 1989	Average Absolute Error by Quarter: Million/ Barrels	Percent
1Q 88	1014	1022 0.8%	--	--	--	--	--	8	0.8
2Q 88	1062	1037 -2.4%	1031 -2.9%	--	--	--	--	28	2.6
3Q 88	1074	1070 -0.4%	1066 -0.7%	1106 3.0%	--	--	--	15	1.4
4Q 88	1038	1059 2.0%	1062 2.3%	1087 4.7%	1057 1.8%	--	--	28	2.7
1Q 89	1003	1007 0.4%	1023 2.0%	1029 2.6%	1004 0.1%	1002 -0.1%	--	10	1.0
2Q 89	P1058	--	1034 -2.3%	1048 -0.9%	1031 -2.6%	1034 -2.3%	1037 -2.0%	21	2.0
Average Absolute Error by Report									
Million Barrels		12	21	29	16	13	21	19	
Percent		1.2	2.0	2.8	1.5	1.2	2.0		1.8

SPR = Strategic Petroleum Reserve.
-- = Not applicable.
P = Preliminary.
MMB = Million Barrels.
Sources: *Actual data are based on published numbers from the Energy Information Administration Monthly Energy Review, various issues; forecasts are from the base case scenarios from various issues of the Short-Term Energy Outlook.*

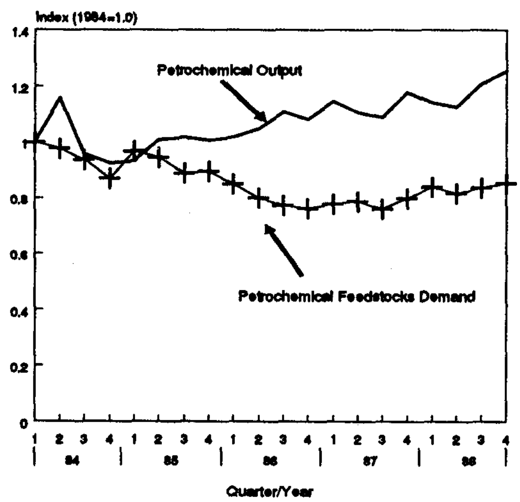
3. Demand for Petrochemical Feedstocks

Introduction and Background

A combination of factors make it difficult to project the short-term demand for petrochemical feedstocks. First, although these petroleum products comprise the largest volume of material used to produce petrochemicals (basic chemicals), measured demand has not tended to track the level of activity in the chemical industry. Second, petrochemical producers have achieved greater flexibility in choosing among petroleum products. This analysis develops a framework for exploring these issues. One objective in addressing these issues is to better understand how to specify a model for predicting demand for feedstocks by component. Improving the accuracy of the forecasts is important because with the increasing demand for chemical products, the derived demand for feedstocks is becoming an increasingly important part of the overall demand for petroleum in the United States. In 1987, an estimated 8 percent (almost 1.3 million barrels per day) of total petroleum demand was used to produce petrochemicals.[5] That share is likely to grow as expanding chemical output is expected to continue to increase the demand for feedstocks. One estimate is that the domestic capacity to produce petrochemicals (in particular, ethylene) will increase by up to 35 percent within the next 5 years.[6]

Figure 11 illustrates the trends in the output of the petrochemical industry compared to trends in the demand for petrochemical feedstocks. (Petrochemical feedstocks are defined as naphtha and other oil-based feedstocks plus ethane, a gas liquid primarily used as feedstock.) The output is ethylene plus propylene (the most highly produced petrochemicals), which exhibits a pattern similar to that of other chemical outputs, diverging significantly from the demand for feedstocks, particularly after 1984. Any attempt to use this output measure in projecting the demand for

Figure 11. Indices of Petrochemical Output and Feedstocks Demand



Sources: *Pace Petrochemical Service* and Energy Information Administration.

feedstocks would require strong allowances for producers of petrochemicals to increase the efficiency of inputs to manufacture petrochemicals (or for decreasing intensity in the use of feedstocks due to other factors, such as shifts in the chemicals output mix). The domestic industry is aggressively pursuing measures to reduce costs and to increase the international competitiveness of manufacturing chemicals in the United States. Aside from apparent aggregate efficiency trends, another important factor in the divergence of output to input of feedstocks may be the increasing use of propane in producing petrochemicals. Propane is excluded from the feedstocks measure because a time series of its feedstock component is not readily available. While propane may pose a problem for the analysis, it is not explicitly treated. Estimates of its importance are provided at the end of this chapter.

Petrochemical producers tend to switch between oil-based feedstocks (naphtha and gas-oil) and ethane when relative prices change (Figure 12). This shift is evident especially in 1986, and in late 1988. Demand for oil-based feedstocks increased compared to ethane. However, no sharp reduction in this preference materialized during the oil price rebound

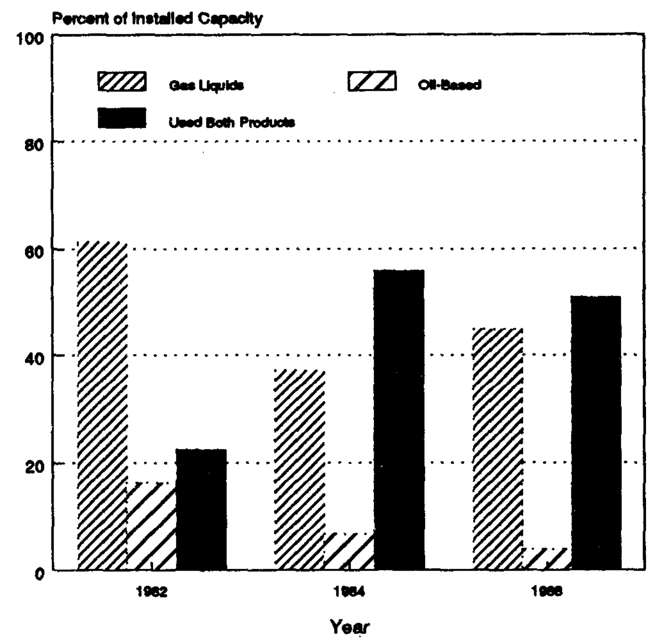
[5]Energy Information Administration, *Petroleum Supply Annual 1988* Volume 1, DOE/EIA-0340(88)/1 and The Pace Consultants, Inc., *Pace Petrochemical Service*, Annual Issue 1988. Houston: September 1988.

[6]*Oil and Gas Journal*, "NGL Markets Entering a Decade of Change", Tulsa: PennWell Publishing Co., Vol. 87, No. 28, July 10, 1989, p.42.

in 1987. One explanation may be that the average revenues from producing petrochemical products in which naphtha has a favorable yield (i.e., propylene) were increasing relative to more ethane-intensive outputs (i.e., ethylene). The "revenue ratio" (Figure 12) is indicative of the effect that chemical prices can have on output in keeping the demand for any particular feedstock high even as the cost of the feedstock increases (as happened in 1987). The extent to which producers can switch from one feedstock to another has evolved in the current decade, particularly from 1982 through 1984 (Figure 13). In 1982, many ethylene plants (comprising 61 percent of total capacity to produce ethylene) relied completely on gas liquid (mostly ethane, propane, and butane) for feedstock. By 1984, plants that used only gas liquid comprised 38 percent of capacity. Over the same period, the number of plants that switched between gas liquids and oil-based feedstocks increased from 23 percent to 56 percent of industry capacity.

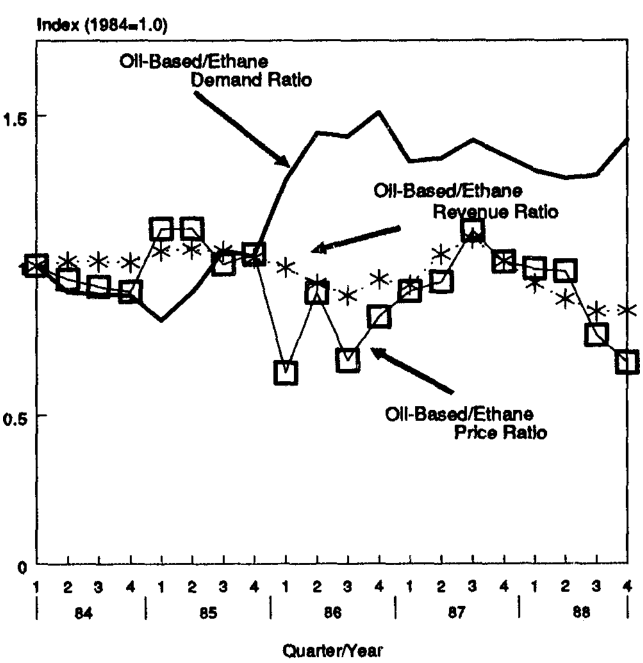
In light of the above, an analysis was conducted to examine the short-term determinants of the demand for petrochemical feedstocks. The major results of the analysis are threefold. First, a difference in relative costs of feedstocks can induce significant substitution in the short-term between oil-based feedstocks and ethane. Second, a significant factor in determining feedstocks composition can be potential dollar revenues gained from altering product slates of petrochemicals to emphasize chemicals which increase in relative value, a factor that may alter the intensity of use for a particular feedstock. Accounting for this factor constitutes an advance over the current method for forecasting the demand for feedstocks in the *Short Term Energy Outlook*. Third, significant apparent efficiency trends are measured, although a cautious interpretation must be taken.

Figure 13. Feedstock Use in Ethylene Plants: Percent Composition in Various Years



Source: *Oil and Gas Journal.*

Figure 12. Feedstock Proportions and Relative Prices in Chemical Manufacture



Sources: *Pace Petrochemical Service;* Energy Information Administration; and Leffler, William L., *Petroleum Refining,* Tulsa: 1979.

A Model of Short-Term Demand

In order to provide a simplified framework for incorporating the types of considerations discussed above in producing demand forecasts for feedstocks, a two-equation model was developed. The two equations relate (in barrels or barrels equivalent) to the demand for oil-based feedstocks and ethane, respectively. The structure of the model assumes that firms in the petrochemical industry maximize profits and that the short-term demand for petrochemical feedstocks is separate from the problem of determining optimal levels of other types of inputs, such as capital and labor (or even fuel). Although aggregate demand for feedstocks is a function of producing petrochemicals, the possibility of substitution exists between products used for feedstocks (e.g., naphtha and ethane). Substitution is induced by relative changes in input prices, such as higher oil prices pushing naphtha prices up while ethane and propane prices remain stable. Besides input price changes, changes in the relative prices (and profitability) of chemicals may affect the relative importance of certain types of feedstocks. For example, higher ethylene prices may result in a shift to ethane to maximize the ethylene yield of a petrochemical batch.

The model allows for the possibility of a trend in the overall productivity of using feedstocks, by introducing an interaction term between time and the level of petrochemical output, so that the total output effect on the demand for feedstocks may, in effect, change over time. Equations 1 and 2 present the model more formally:

$$(1)\ D_{o,t} = a_0 + a_1[D_c]_t + a_2[(P_o/P_e]_t + a_3[P_{ey}/P_{py}]_t + a_4[D_c]_t[t] + e_{o,t},$$

$$(2)\ D_{e,t} = b_0 + b_1[D_c]_t + b_2[(P_o/P_e]_t + b_3[P_{ey}/P_{py}]_t + b_4[D_c]_t[t] + e_{e,t},$$

$D_{o,t}$ = derived demand for oil-based feedstocks (million barrels per day) in time t,

$D_{e,t}$ = derived demand for ethane feedstocks (million barrels per day) in time t,

D_c = output of ethylene and propylene (billion pounds per day),

P_o,P_e = price of oil-based feedstocks and ethane (cents per pound), respectively,

P_{ey},P_{py} = price of ethylene and propylene (cents per pound), respectively,

t = monthly time trend

$a_0 \ldots a_4$ = parameters (to be estimated) of the equation for oil-based feedstocks,

$b_0 \ldots b_4$ = parameters (to be estimated) of the equation for ethane, and

e_o, e_e are normally distributed error terms.

The specification of the basic model could include certain restrictions that, when specified across the two equations, ensure conditions pertaining to the materials composition of petroleum inputs. That is, as a result of relative input and output price change a barrel of one type of feedstock is substituted in proportion to the chemical-yield equivalent of the alternative feedstock. This would ensure that the substitution is consistent with constant petrochemical output. Another restriction considered would ensure that as output increases, increases in demands for feedstocks are consistent with the average input mix of feedstocks of a typical petrochemical production slate. These restrictions may be severe in that they ultimately imply either constant relative input proportions given constant input and output prices, or constant relative yields from ethane and oil-based feedstocks. To allow for the possibility of more independent trends in relative input proportions and relative yields, the model is presently estimated and tested without such restrictions.

Data Description and Estimation Techniques

Data for ethane and oil-based feedstocks are taken from the Energy Information Administration, *Petroleum Supply Annual (PSA)*. All ethane (D_e from equation (2) above) is assumed to be used as chemical feedstock, although some ethane finds other uses, such as refinery fuel. The oil-based feedstocks (D_o from equation (1) above) are defined as a combination of petrochemical feedstocks both above and below 400° API. Chemical output (propylene plus ethylene) is taken from The Pace Consultants Inc. (see footnote 8), as are the series for propylene and ethylene prices, and the prices for both kinds of feedstocks. The output data are interpolated from a quarterly to a monthly basis. The price of natural gasoline is used as an approximation for the price of oil-based feedstocks. The May 1986 observation was considered an outlier and was smoothed prior to model estimation. Conversion factors to convert feedstock prices to pound equivalents are referenced in Leffler (see footnote 8). Also prior to estimation, all data were seasonally adjusted using the Census Bureau's X-11 procedure (multiplicative version).

It was assumed that the effects of short-term changes in input and output prices in the feedstocks model could be represented by a polynomial distributed lag of order 2. Pre-tests indicated that a lag length of three periods worked best for both the input and output price effects, therefore this specification was adopted throughout. Some significant correlation of the errors across time was apparent in pre-tests of the data, so a first-order autoregressive correction was applied to all model estimations.

Estimation and Forecast Results

The model was estimated in its polynomial distributed lag form (described above) with the autoregressive correction. Results of the estimation of the model are shown in Table 11. The price effects are in the correct direction, indicating (in a statistical sense) significant switching between oil-based feedstocks and ethane. The switching is a result of swings in the relative cost of the two alternative inputs, and relative movements in output prices. It is consistently found that, correcting for any input cost effects, higher prices for ethylene output will tend to create shifts in the mix of petrochemical inputs away from oil-based feedstocks to the higher ethylene yielding ethane. It seems that a tendency to conserve on ethane over time may be offset by more liberal use of oil-based feedstocks, as demonstrated by the parameter estimates (a_4 and b_4) for the time and output interaction terms of the model.

In general, the overall fit of the data, as gauged by the individual R-square statistics provided in Table 11, is not particularly tight. One hypothesis which was tested (not shown) was that the input price effect was not constant across all ranges of relative price, but that most input-switching would only occur within relatively narrow ranges of relative price. Little short-term switching may be exhibited over a range of relative prices in which oil-based feedstocks are clearly very expensive. However, over some relatively narrow "critical range" of relative input price, substantial short-term switching may occur. The model may be improved by identifying this relatively narrow band and confining most of the switching activity to periods in which the range is attained. Since this range is difficult to know a priori, some subjective judgment was used to identify a likely candidate. For periods when significant switching was suspected, the relative price of oil-based feedstocks to ethane ranged between 0.8 and 1.2. While this is a very rough demarcation, it is believed to be more than adequate to test the general proposition of asymmetry. Accordingly, a dummy slope variable which allows for the estimation of separate input price coefficients inside and outside of the relative price range described above was constructed. Additional regressions using this dummy slope variable resulted in alternative coefficients for relative input price, inside and outside the "critical range". However, only marginal improvements to the oil-based feedstocks model were obtained and the difference between the "inside" and "outside" price effects was small.[7]

[7]Results from these regressions are available upon request.

Table 11. Regression Results of the Model Equations for Derived Demand for Petrochemical Feedstocks

Parameter	Estimate	t-statistic
a_0	0.560	5.01
a_1	0.781	1.07
a_2[a]	-0.190	-4.46
a_3[a]	-0.084	-2.59
a_4	0.017	4.46
RHO1[b]	0.251	1.97
b_0	0.012	0.93
b_1	2.810	3.38
b_2[a]	0.128	2.42
b_3[a]	0.079	1.97
b_4	-0.023	-5.34
RHO2[b]	0.352	2.64
Equation Summary:		
Oil-based Equation		
Adj R-Sq.	0.760	
RMS Error	0.028	
Dep. Mean	0.419	
Ethane		
Adj R-Sq.	0.576	
RMS Error	0.031	
Dep. Mean	0.529	

[a]Cumulative (total) price-effect and associated t-value shown.
[b]RHO1 and RHO2 are the first order autoregressive parameters for the oil-based and ethane equations, respectively.

Table 12 provides a summary of key elasticities from the two equations with respect to a change in prices and output for one and four months. These estimates are computed based on 1988 sample means and thus are more reflective of current elasticities. The price elasticities for oil-based feedstocks are higher than those of ethane and in the opposite direction, in a range of what would be expected given substitution in terms of equivalent chemical yields. Another aspect of the elasticities is that generally the output effect is small over a one-month period. Correcting for other effects such as relative price changes, an output elasticity of about 1.0 at any point in time would be expected. A test on the model was performed restricting the output elasticity to 1.0 for both equations, and it was found that the model estimates did not improve and that price effect signs were unreasonable. These output elasticities may reflect efficiency gains or an increasing role over time for propane and butane as feedstocks. As noted earlier, oil-based feedstocks exhibit an increasing output elasticity over time, while ethane exhibits a decreasing output elasticity. Simulation tests may indicate whether these model results exhibit reasonable properties.

Table 12. Elasticity[a] Comparisons for the Model Equations for Derived Demand for Petrochemical Feedstocks

Elasticity	Oil-based	Ethane
Input Price		
1-Month	-0.105	0.054
4-Month	-0.524	0.270
Output Price		
1-Month	-0.046	0.025
4-Month	-0.235	0.130
Output Production		
1-Month	0.381	0.507
4-Month	0.381	0.507

[a]The percentage change in feedstocks demand from a 1.0-percent increase in prices or output. Elasticities are computed from parameters in Table 11, and are based on sample means of the dependent and independent variables, holding the effect of time constant.

Note: The total effect of a change in price or output in the current month is estimated to be distributed over the current and next three successive months.

Table 13 provides simulations of the petrochemical feedstocks model from 1989 to 1990. Forecasts are based on input growth rate assumptions from the July 1989 *Short -Term Energy Outlook* (*Outlook*), holding relative chemical prices constant. Only annual summaries are provided. These forecasts, compared to the published forecasts in the July 1989 *Outlook*, are more favorable for oil-based feedstocks compared with ethane, although not much different in the aggregate. However, the new forecasts do not reflect the incorporation in the model of a strictly linear time trend related to efficiency in feedstocks use, which may be a rather strong assumption.

Table 13. Alternative Forecasts of Oil-Based Petrochemical Feedstocks and Ethane Demands (Million Barrels per Day)

Forecasts	Model Version July 1989 STEO	Equations 1 and 2
Oil-Based		
1989	0.460	0.480
1990	0.470	0.500
Ethane		
1989	0.530	0.510
1990	0.510	0.490

Summary

An analysis was conducted concerning the oil-based (naphtha and gas-oil) and ethane components of the short-term demand for petrochemical feedstocks. A model was developed and tested that accounts for the output of chemicals and the effects of changes in relative prices in forecasting these components. It was found that a change in the relative price of feedstocks results in a significant shift in the composition of feedstocks, the total shift occurring over a period of months. Another important factor in determining feedstocks composition is the relative price of petrochemical outputs, where the feedstocks slate may be altered to emphasize feedstocks with a favorable yield of the petrochemical with the highest relative value.

Figure 11 illustrates a growing divergence between petrochemical output and feedstocks demand, based on the two primary categories of feedstocks, oil-based and ethane. Productivity gain, related to processing technology in the use of petroleum inputs may have contributed to some of that divergence. However, such a large difference suggests increased amounts of propane (and butane) are being used in petrochemical production. Accounting for these feedstocks will likely enhance the fit of the other feedstocks data to the model that was developed. Assuming no productivity gain, it is estimated separately that gas liquid (mostly propane and butane), besides ethane, increased from about 0.250 to 0.440 million barrels per day between 1984 and 1988.[8]

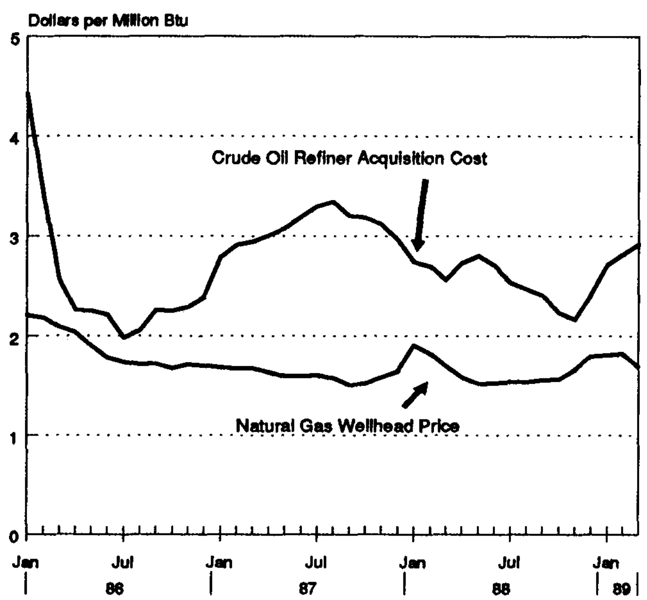
In focusing on determinants of the demand for feedstocks in the short-term, important long-term issues were not discussed. Among these are that the growing international scope of producing chemicals may alter the conditions of feedstocks availability. Forecasting the demand for petrochemical feedstocks will necessitate following these and other developments influencing the demand composition of petrochemical feedstocks.

[8]Energy Information Administration, *Petroleum Supply Annual 1988 Volume 1*, DOE/EIA-0340(88)/1; The Pace Consultants, Inc., *Pace Petrochemical Service*, various issues, Houston; and Leffler, William L., *Petroleum Refining*, Tulsa: 1979.

4. Determinants of Natural Gas Wellhead Prices

Natural gas wellhead prices, on average, have become more volatile over the last several years. One reason cited for this volatility is that more initial purchases of gas are made on the spot market, which involve short-term commitments for delivery of gas rather than long-term commitments. Moreover, as increasing numbers of wellhead purchases of gas are made on the spot market, a stronger relationship is observed between the average wellhead price and spot prices. This chapter identifies the seasonality in wellhead prices and demonstrates to what degree this seasonality is related to consumption and to underground natural gas storage activity. A major purpose of this chapter is to develop an econometric relationship between the price of natural gas and the volume of natural gas in underground working storage. Understanding these determinants of price may result in more accurate short-term forecasts for natural gas wellhead prices.

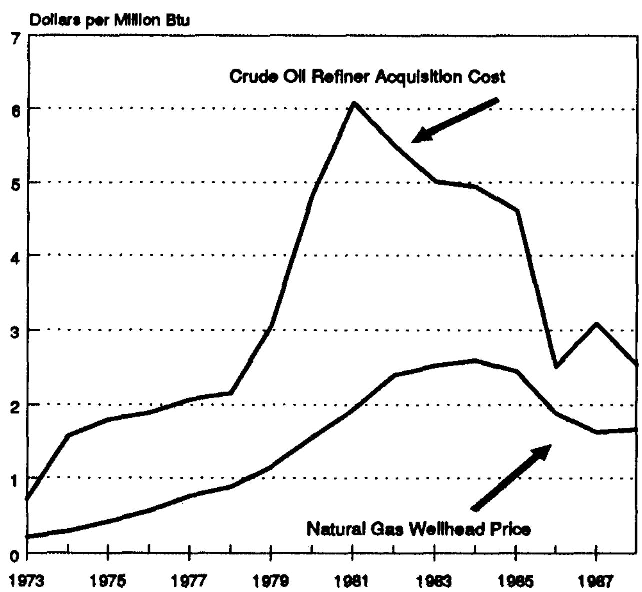
Figure 14. Natural Gas Wellhead Prices and Refiner Acquisition Cost of Crude Oil, January 1986-March 1989



Sources: Spot Prices: "Gas Price Trends", *Natural Gas Week*, various issues and Working Gas Storage; Energy Information Administration, Forms FERC-8 and EIA-191.

The forecasting equation for natural gas wellhead prices in the *Short-Term Energy Outlook* (*Outlook*) is based on the relationship between the wellhead price and the refiner acquisition cost (RAC) of crude oil. As Figure 14 illustrates, not much of a relationship exists between the two series in recent years. At the beginning of 1986, the RAC plunged, then rose in the second half of the year through the first half of 1987. During this time, wellhead gas prices also fell, but at a much slower rate. Moreover, they continued to fall, while the RAC was rising. It is apparent that the historically close movement of natural gas prices and crude oil prices is changing (Figure 15), especially across the seasons.

Figure 15. Natural Gas Wellhead Prices and Refiner Acquisition Cost of Crude Oil, 1973-1988

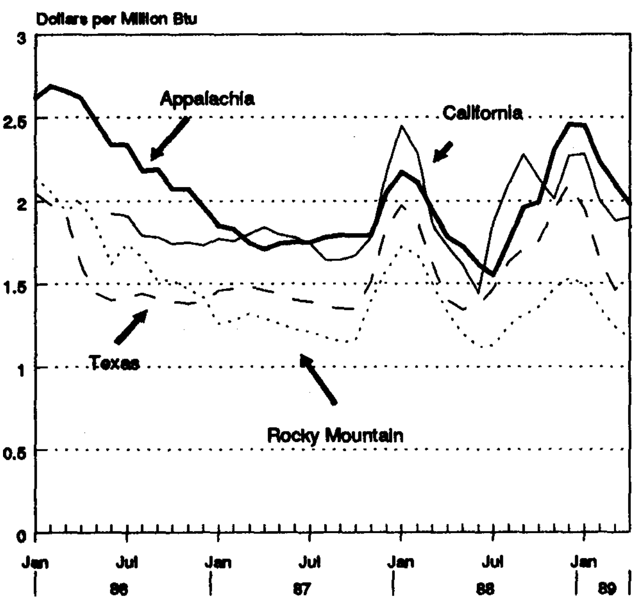


Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(89/04).

The larger proportion of wellhead purchases made on the spot market over the last few years has resulted in the emergence of a clearly defined seasonality in wellhead gas prices. As the seasonality has become more pronounced, less overlapping of prices across regions has occurred (Figure 16). The two regions with the highest degree of fuel switching, California and

Appalachia (representing the Northeast) also show the most fluctuation in price. Thus, oil prices, especially for residual fuel oil, on a regional level could affect the spot price of natural gas. Spot-price increases were unusually large in California in August and September 1988. Due to high smog levels around Los Angeles during these months, oil burning by electric utilities was restricted, leading to a surge in demand for natural gas.

Figure 16. Regional Spot Natural Gas Prices, January 1986-April 1989

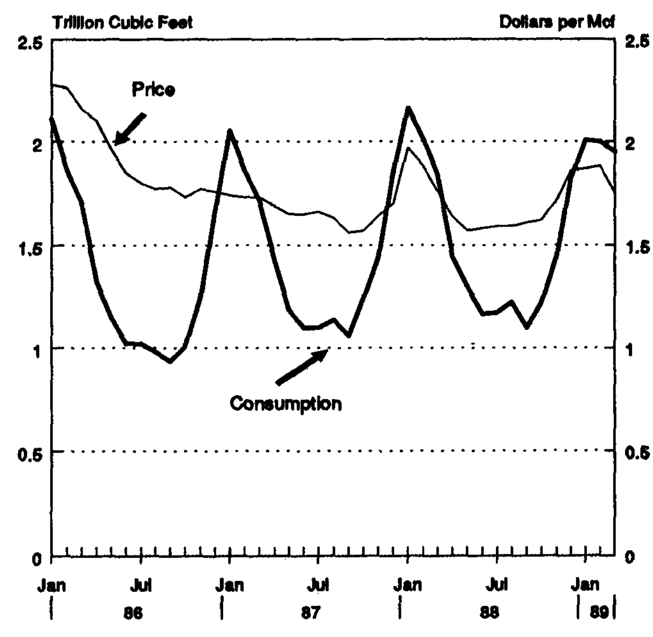


Source: *Natural Gas Week*, various issues, 1986-1989.

As demand for natural gas increases, particularly during the heating season, its price rises. Close seasonal correlation between gas consumption and the wellhead price has occurred since the latter half of 1987 (Figure 17). Prior to the emergence of the spot market, only the end-use prices were seasonal, while the wellhead price, being tied to long-term contracts, was much flatter. Spot prices are by nature more pronounced.

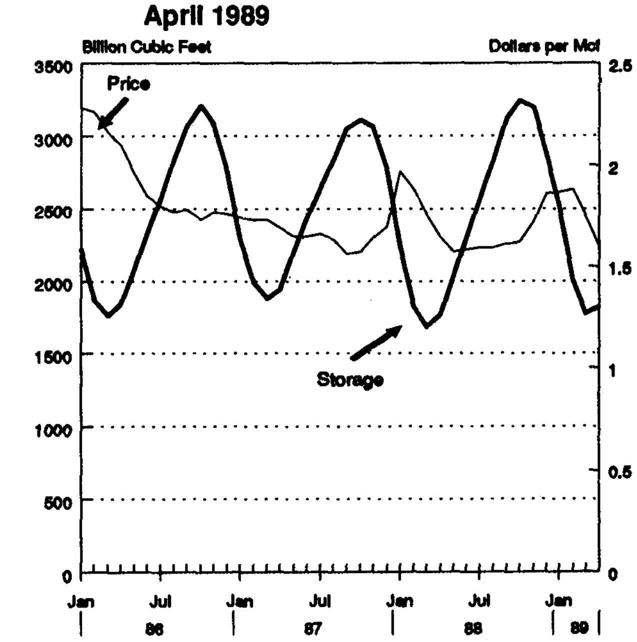
Other factors appear to be related to wellhead prices (Figure 18). Underground gas storage is composed of base gas (the amount needed to maintain enough pressure for withdrawal), and working gas (the amount above the base level, which is normally

Figure 17. National Wellhead Price and Consumption of Natural Gas, January 1986-March 1989



Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(89/04).

Figure 18. Working Storage and National Gas Wellhead Price, January 1986 - April 1989

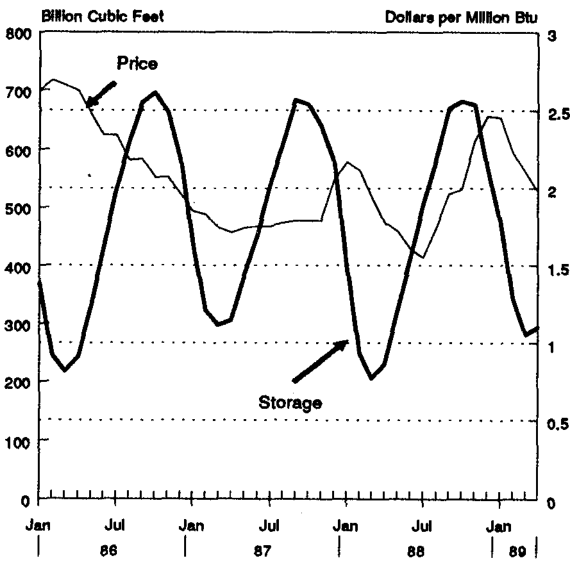


Sources: Spot Prices: "Gas Price Trends" *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, Forms FERC-8 and EIA-191.

withdrawn). In this chapter, only working gas storage is discussed, since this type of storage is relevant to prices. Although some storage, especially for large pipeline companies, can be interregional, enough storage facilities are operated by local distribution companies for regional differentiation to be observed.

Figures 19 through 22 show a high degree of seasonality of working gas storage for four regions, while Figure 23 shows the seasonality for a pipeline that operates across regions.

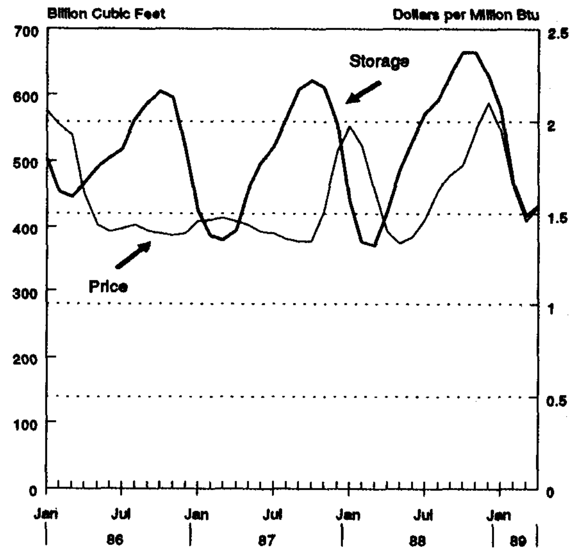
Figure 19. Northeast Region: Spot Price and Storage, January 1986 - April 1989



Sources: Spot Prices: "Gas Price Trends" Table, *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, forms FERC-8 and EIA-191.

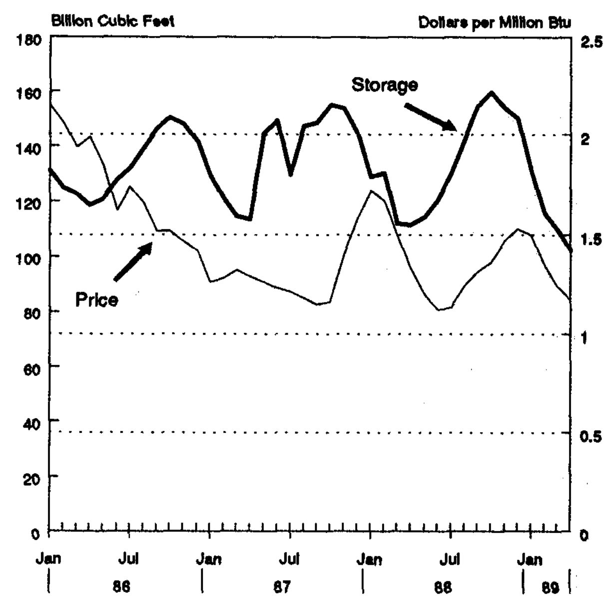
Since 1987, prices have been at their highest when storage is lowest, and vice-versa. Storage operators inject gas to meet their expected peak demands for the winter in the spring and in the summer. (Typically, the withdrawal season is from November 1 through March 31 when demand is highest, while the injection season runs from April 1 through October 31 when demand is lowest. However, withdrawals and injections may occur at any time of the year, if necessary.) Storage facility operators typically plan their injections and withdrawals several months ahead. Thus, for the proposed equation, prices for the month of January, for example, will be a function of planned

Figure 20. Southwest Region: Spot Price and Storage, January 1986-April 1989



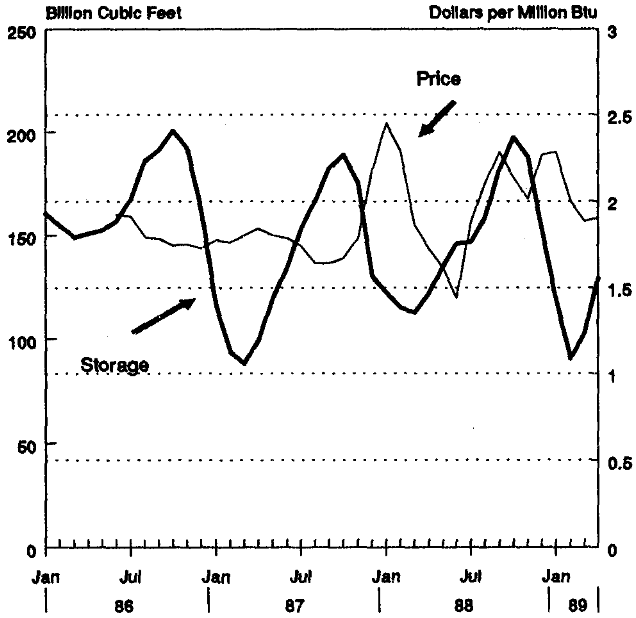
Sources: Spot Prices: "Gas Price Trends" Table, *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, forms FERC-8 and EIA-191.

Figure 21. Rocky Mountain Region: Spot Price and Storage, January 1986-April 1989



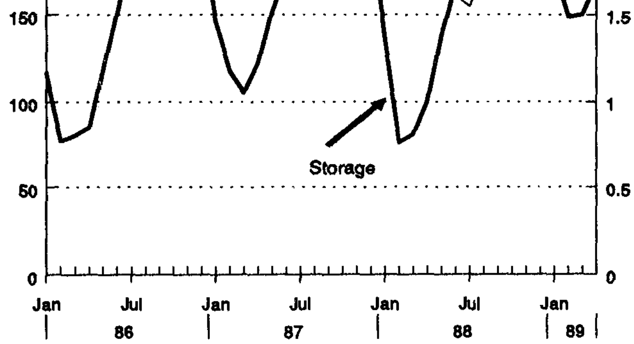
Sources: Spot Prices: "Gas Price Trends" *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, Forms FERC-8 and EIA-191.

Figure 22. California: Spot Price and Storage, January 1986-April 1989



Sources: Spot Prices: "Gas Price Trends" Table, *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, Forms FERC-8 and EIA-191.

Figure 23. Columbia Gas Transmission Co.: Spot Price and Storage, January 1986-April 1989



Sources: Spot Prices: "Appalachian Price" Table, *Natural Gas Week*, various issues 1986-1989. Working Gas Storage: Energy Information Administration, Forms FERC-8 and EIA-191.

storage in March. It appears that if storage targets are not or cannot be met, spot prices will increase. This occurred in California (Figure 22) towards the end of 1987 and beginning of 1988 when storage operators undershot their targets, sending spot prices up.

An econometric relationship between spot prices and storage volume can be established for some of the regions. The equation is defined as follows:

$$P_{r,t} = C + B_1 S_{r,t+2} + B_2 Dum86_t,$$

where:

P_t = spot price, in dollars per million Btu, at region r, in month t,

S_{t+2} = Underground working storage in billion cubic feet, two months into the future at region r,

$Dum86_t$ = Dummy variable, equals 1 for 1986 when gas prices plunged), 0 otherwise.

The results of these regressions are shown in Table 14. Table 14 shows the outcome of estimating Appalachian spot prices (the price used on the East Coast) as a function of the demand by a single large pipeline company, Columbia Gas Transmission Corp. The regression results are similar to the results for the Northeast region taken as a whole, reflecting similar storage patterns. Analysis of the regressions shows that there is a strong inverse relationship between expected storage volume and spot prices in the four regions. Thus, these equations may be helpful in predicting spot prices in the very near term. However, the explanatory power of the equations representing the California and Southwest regions (low R-Squared) is weak.

In conclusion, spot prices, consumption, and working storage of natural gas are all highly seasonal on both national and regional levels. The correlation between the spot price and storage is highly correlated in the Northeast and Rocky Mountain regions, as well as for the Columbia Gas pipeline which operates primarily in the East.

Results for the Southwest and California regions were less encouraging. For the Southwest region, storage at the regional level is not a good explanatory variable for the regional price since this region supplies most of the gas for the whole country. Also, for this region, the Dum86 variable was not statistically significant. The results for California are also discouraging. It is likely that spot price movements are affected by factors other than storage. Some of these explanatory variables that should be examined for future study are: consumption, imports, shut-in production, transportation costs, and the so called "surplus" of available natural gas.

Table 14. Regional Spot Gas Price Regression Results

Region/Variable	Coefficient Estimate	t-Statistic
Appalachian Spot Price		
(Storage includes Northeast)		
Constant	2.39	6.75
$Storage_{t+2}$	-0.10	-3.53
Dum86	0.42	3.95
Rho	0.47	3.23
R-Squared=0.72		
Estimation Interval=January 1986 - April 1989		
Estimation technique=Yule-Walker		
Texas Gulf Coast On-Shore Spot Price		
(Southwest storage)		
Constant	2.35	10.58
$Storage_{t+2}$	-0.15	-3.51
R-Squared=0.30		
Estimation Interval=January 1986 - April 1989		
Estimation technique=Ordinary Least Squares		
Durbin-Watson=1.40		
Rocky Mountain Spot Price		
Constant	2.34	9.10
$Storage_{t+2}$	-0.73	-3.88
Dum86	0.46	7.78
R-Squared=0.67		
Estimation Interval=January 1986 - April 1989		
Estimation technique=Ordinary Least Squares		
Durbin-Watson=2.09		

Table 14. Regional Spot Gas Price Regression Results (Continued)

Region/Variable	Coefficient Estimate	t-Statistic
California Spot Price		
$Storage_{t+2}$	-0.31	-3.88
Dum86	0.25	2.54
R-Squared=0.17		
Estimation Interval=January 1986 - April 1989		
Estimation technique=Ordinary Least Squares		
Durbin-Watson=1.26		
Columbia Gas Transmission Co. Spot Price		
Constant	2.41	13.56
$Storage_{t+2}$	-0.21	-3.43
Dum86	0.17	1.66
Rho	0.85	10.08
R-Squared=0.90		
Estimation Interval=January 1986 - April 1989		
Estimation technique=Yule-Walker		

5. Modeling Short-Term Natural Gas Demand

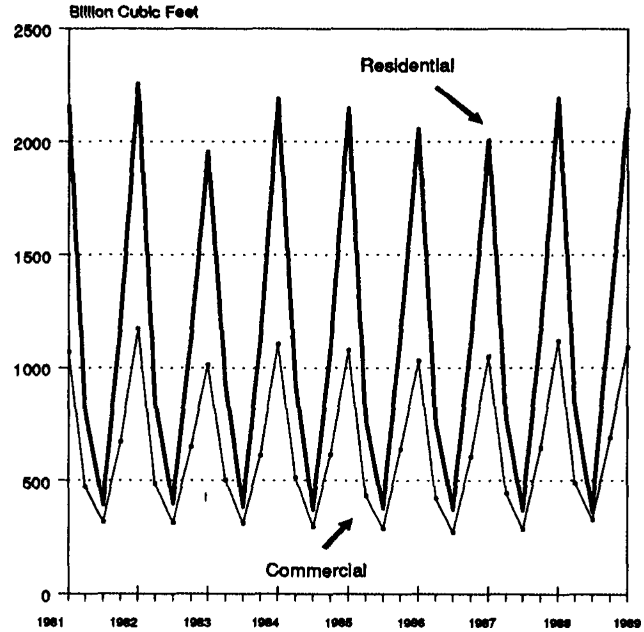
At present, one aspect that is not explicitly treated in the short-term forecasting of natural gas demand is whether or not carefully accounting for trends in gas intensity by sector makes a significant difference in the types of short-term forecasts generated. This chapter presents an analysis that incorporates gas intensity trends into the *Short Term Energy Outlook* (*Outlook*) forecasting methodology and which assesses the significance of these trends for the short-term outlook for gas demand in the residential, commercial, and industrial sectors.

The Energy Information Administration (EIA) regularly publishes monthly data on domestic natural gas consumption by sector, which is the primary source of information used in constructing the demand forecasting equations used in deriving EIA's (*Outlook*) forecasts. The main sectors are residential, commercial, industrial, and electric utility. Other sectors include fuel for natural gas production facilities and transportation (pipeline fuel), but these sectors tend to be largely dependent upon demand in the main sectors and are not discussed in this chapter. Forecasting natural gas consumption by electric utilities requires an analysis of fuel choice and is discussed in another chapter (see Chapter 6, "Regional Trends in the Demand for Fuel by Electric Utilities").

Residential and Commercial Sectors

The most important influence on short-term natural gas demand in the residential and commercial sectors is weather (Figure 24). Use of natural gas for space-heating purposes produces significant seasonal peaks in the first and fourth quarters of the year. The most relevant indicator of weather patterns that affects gas demand is heating degree-days.[9]

Figure 24. Quarterly Natural Gas Demand



Source: Energy Information Administration, *Natural Gas Monthly* (DOE/EIA-0130), various issues.

The current forecasting approach uses exogenous forecasts of gas customers in the residential and commercial sectors to explain the remaining variance in demand not accounted for by weather. Specifically, by extrapolating current trends in the number of customers by sector and by examining average use rates per customer,[10] an estimate can be made of the contribution to gas demand from increases in gas customers from average per-customer use rates. Both heating degree-days and the number of customers

[9]Heating degree-days used in the residential sector model are weighted across regions by the number of gas home-heating customers. In the commercial sector, heating degree-days are weighted by population. A small percentage of homes have gas-powered air-conditioning systems; hence, cooling degree-days may also be an indicator of residential gas demand. The effect from this source tends to be small, however, and has been excluded from this analysis. The source of this data is the National Oceanic and Atmospheric Administration.

[10]The number of gas customers by sector is estimated quarterly by the American Gas Association. Forecasts are generated by an autoregressive integrated moving average model.

appear in the residential and commercial equations, and estimates of the parameters pertaining to these determinants (derived from linear multiple regression analysis), represent average gas demand response rates per degree-day and per customer, respectively. The equation can be represented as follows:

(1) $D_{it} = f(W_t C_{it}) + e_{it} = b_i W_t + c_i C_{it} + e_{it}$,

where:

D_{it} = gas demand, sector i, time t,

W_t = heating degree-days time t,

C_{it} = gas customers, sector i, time t,

b_i, c_i = parameters estimated for sector i,

where

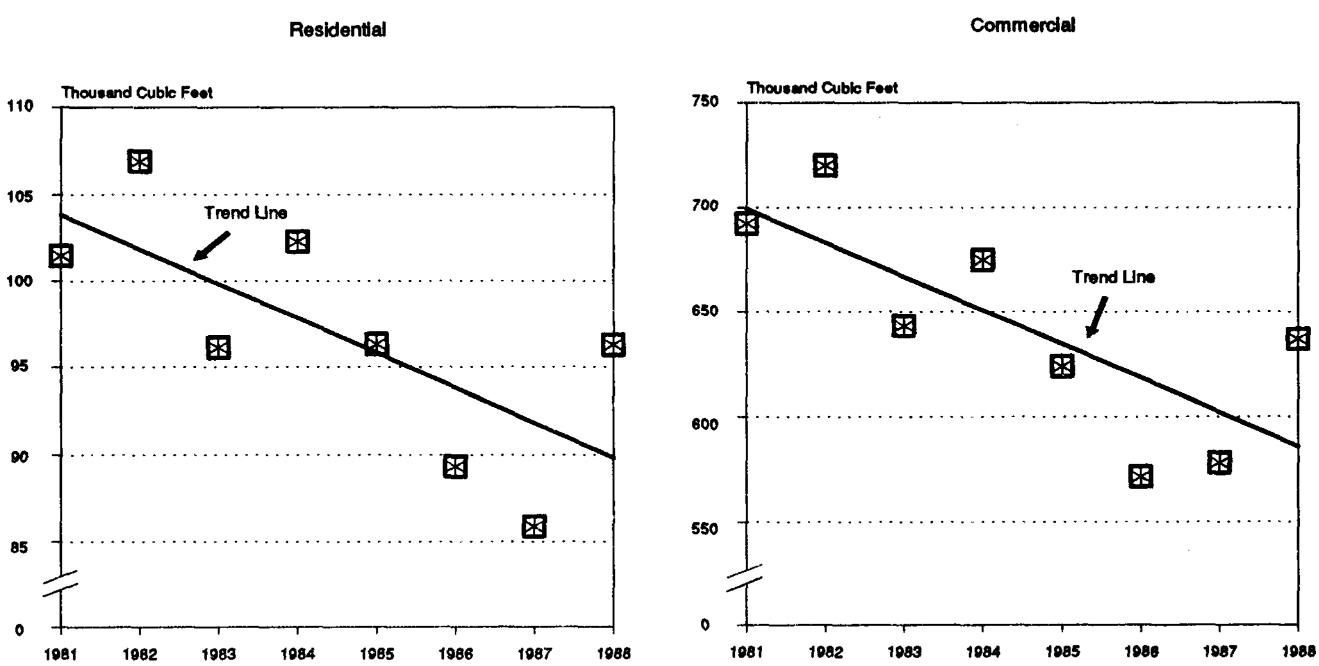
b_i and c_i are the average degree-day and customer response rates, respectively,

e_{it} = normally distributed error term,

t = 1, 2, 3...n, where n is the number of observations, or an index of time.

Equation (1) represents the general natural gas demand equations used in the *Outlook* for the residential and commercial sectors. As they are currently used, these equations are strictly linear in variables and parameters, and no variable response rates are allowed. If gas intensity for these sectors is defined as use per customer, the models conforming to equation (1) predict constant gas intensity, given normal or constant weather conditions. It is likely that intensity will fall, because more energy-efficient technology is employed in replacing old heating equipment or in the construction of new buildings. While these developments are longer term effects, failing to account for them in the short-term model may risk significant prediction bias that is perceptible even in a one-year time horizon. The longer term effects may ultimately be the result of past shifts in real gas prices (or energy prices in general), or they may stem from general technological improvements. The relative role of prices and technology improvements (or conservation) is a crucial question in mid- to long-term

Figure 25. Residential and Commercial Natural Gas Use per Customer



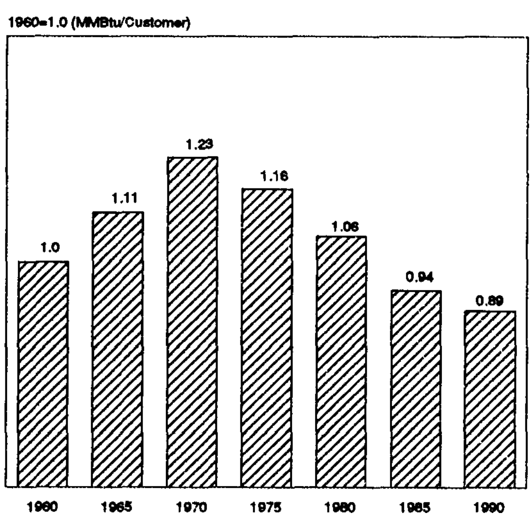
Note: The gas consumption rates for this figure are corrected for weather variations using the July 1989 Unified Demand and Price Analysis Subsystem model used in developing the *Short Term Energy Outlook*.
Source: Energy Information Administration, Energy Analysis and Forecasting Branch, unpublished estimates.

forecasting. For purposes of short-term forecasting they may be most easily incorporated using trend terms.[11]

In both the residential and the commercial sectors, gas use per customer has tended to decline in recent years (Figure 25). This indicator has been adjusted to correct for variations in the weather, using estimated heating degree-day effects. The trend lines shown are illustrative of the apparent trends in each sector. While movements in gas use per customer may mask certain relevant changes, such as shifts in the average size of households or general shifts in the relative importance of space heating in overall gas use, it is assumed that the measure of use per customer is indicative of important trends in end-use intensity. The longer term perspective of the residential sector reveals that gas use per customer peaked in the early to mid-1970's, but has declined steadily since then (Figure 26).

[11]Using monthly data, it may be difficult to accurately capture long-term price effects without extremely long, perhaps complex lag specifications. If the momentum in use per-customer trends due to long-term price and other effects can be adequately captured using a trend term, the likely short-run effects may be more easily sorted out.

Figure 26. Trends in Residential Gas Consumption per Customer



Source: Energy Information Administration, *Natural Gas Monthly* (DOE/EIA-0130), various issues, and American Gas Association, quarterly gas customer reports. The 1990 figure is based on the July 1989 *Short-Term Energy Outlook* (DOE/EIA-0202)(89/3Q).

Gas use per customer rose noticeably in 1988, however, for both the residential and commercial sectors (Figure 25). In the statistical analysis presented below, "Estimation and Forecasting Results", simple tests on the stability of the intensity trends are discussed, with a view toward establishing whether a continuation of these trends seems appropriate. For the residential sector, an examination of a more direct end-use efficiency measure (such as that portrayed in Figure 27) suggests that the trend of declining gas use per customer will resume.

The average efficiency of gas space heaters sold in the United States appears to be on a long-term growth path that averaged 1.2 percent per year from 1972 to 1989, although this rate has slowed to just under 1 percent since 1983 (Figure 27). Short-term shifts in energy prices may also cause the amount of gas used per customer to change, although in many instances, estimating these price effects for simple equations like (1) may lead to overestimates, if fairly complex and long lag structures for price influence the aggregate data.

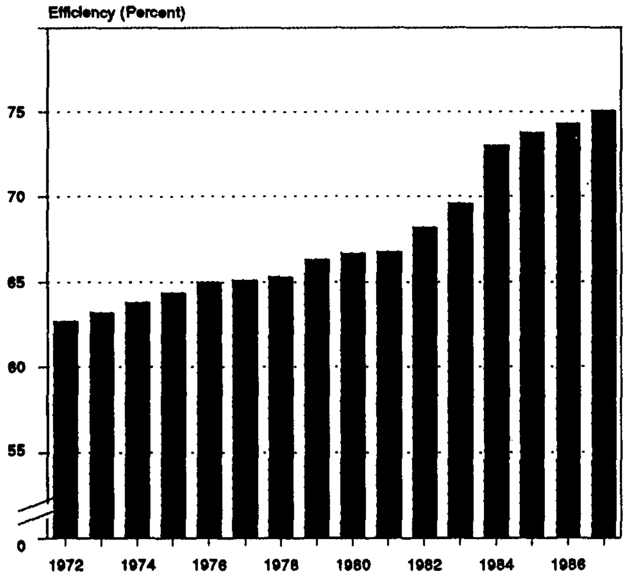
An alternative to equation (1) above is shown below, starting with a recasting of the formal demand relationship into a structure in which the dependent variable is demand per customer:

(1)' $(D_{it}/C_{it})=a_i + b_iW_t + e_{it}$

Equation (1)' is similar to equation (1) in that it does not allow for variable per-customer use rates, abstracting from variations in weather. Equation (1)' differs from equation (1), however, in that it allows for short-term weather effects on gas use per customer that are independent of the initial number of customers. Equation (1)' is a basic restricted model (in terms of trends in gas use per customer) that will be used as a benchmark against which some variable per-customer use rate models will be gauged.[12]

[12]An independent review concluded that the stability of the coefficient b_i may be at issue, particularly if the share of space heating in overall gas use changes significiantly for the individual sectors over time. The estimate of the b_i could be biased upward so far as the forecast is concerned if space heating is declining in relative importance. However, the results of analysis of covariance performed to specifically check the basic equation (1)' for stability of the b_i seem to dispel worries on this score. Results of this additional analysis are available upon request.

Figure 27. Residential Gas Space Heater Efficiency Trends



Source: 1972: Form CS-179, U.S.Department of Energy Survey of Manufacturers; 1975 -1980: Lennox Corporation and Carrier Corporation (average); 1982 interpolated; 1983-1987: GAMA.

Equation (1)" below provides a general formula of a simple residential/commercial gas use model which allows explicitly for linear changes over time in use rates per customer:

(1)" $(D_{it}/C_{it}) = a_i + b_i W_t + c_{it} e_{it}$.

The variable c_{it} is the coefficient for trends in use per customer, subsuming with it the average effects of long-term changes in real gas prices and other factors, including general technological advances affecting energy use in the residential or commercial sector.

In equation (1)", short-term price effects are ignored to give a more direct comparison with the basic (no trend) model which is most like the current *Outlook* model. However, short-term movements in real gas prices affect a consumer's inclination toward conservation. Therefore, additional versions of the model are introduced: one that replaces the trend term with price and one that uses both price and the trend term.

Industrial Sector

In the 1980's, industrial gas use fell relative to an index of output in the key gas consuming industrial sectors. Between 1982 and 1988, gas use per unit of output in manufacturing fell by 21 percent (Figure 28).[13] Despite growth in manufacturing output of almost 40 percent from 1982 to 1988, industrial gas use only increased by 8 percent over that period.[14] Petroleum use by the industrial sector apparently increased by a similar average rate.[15] In contrast to the oil and gas trends, industrial use of electricity increased by 19 percent from 1982 to 1988, reflecting a trend toward the electrification of industry.[16]

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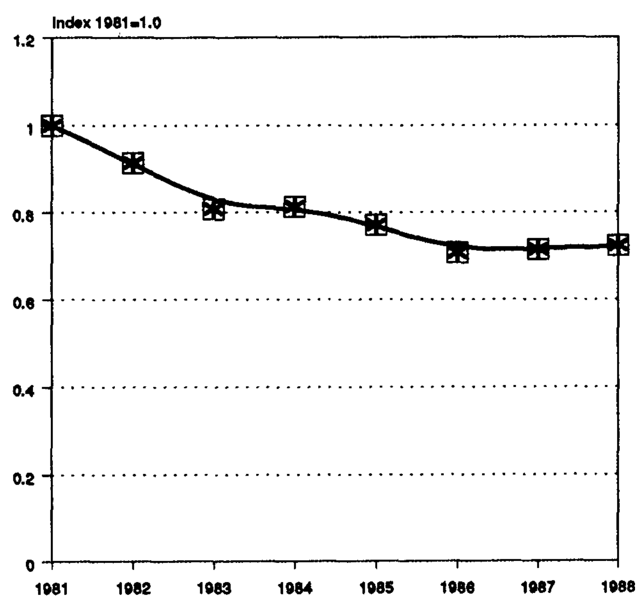
[13]Industrial gas use per unit output is obtained by taking the ratio of industrial gas consumption to a gas-consumption weighted measure of industrial production in the following key industries: Standard Industrial Classifications: 20,26, 28, 29, 32, and 33. The weights are taken from the *1985 Manufacturing Energy Consumption Survey (MECS)* natural gas consumption.

[14]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(89/06) and Federal Reserve System Statistical Release G.12.3 for industrial output index by industry

[15].Calculated from data in the Energy Information Administration, *Monthly Energy Review*, Table 2.4.

[16]Calculated from data in the Energy Administration Administration, *Monthly Energy Review*, Table 2.4.

Figure 28. Index of Industrial Natural Gas Consumption per Unit of Output



Source: Ratio of industrial gas consumption from the Energy Information Administration, *Natural Gas Monthly* (DOE/IEA-0130), to a gas-weighted index of industrial production based on Federal Reserve Board data.

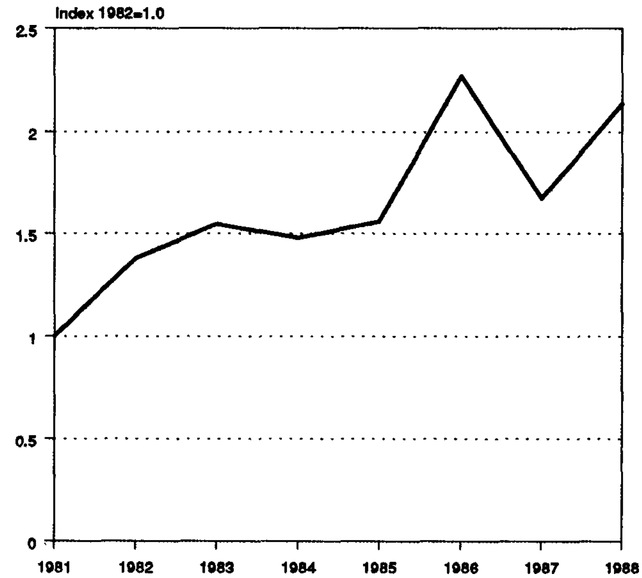
While increases in the relative importance of electricity in the industrial sector are relevant, it is assumed that short-term substitution possibilities are restricted mostly to competition between oil and gas. These fuels substitute easily for each other in the production of process heat and in the industrial cogeneration of electricity. For practical purposes, coal is excluded from this analysis, because trends in its use are driven mostly by environmental reasons and other factors besides price or availability (see Chapter 7, "Industrial Coal Use Patterns").

Some of the movements in gas use per unit of output in industry are related to fuel switching due to relative price shifts between oil and gas (Figure 29). The 1986 spike in relative gas prices was accompanied by easily discernible switching to oil from gas, although the evidence of this is partly obscured by a decline in overall industrial energy demand.[17] In 1988, declines in oil prices relative to gas prices were not accompanied by a relative shift to oil in the nonutility industrial sector. In fact, gas demand growth was quite robust in 1988, accounting for about half of all industrial net energy demand growth.[18] Growth in 1987 was even higher, but was consistent with a downward shift in relative gas prices, as oil prices rebounded from the 1986 price collapse.

It is not certain whether this recent decline in gas intensity in the industrial sector will persist. A resumption of the longer term trend, as opposed to a forecast for flat intensity (held at 1988 levels), implies a difference in industrial gas use of at least 77 billion cubic feet by 1990, based on recent industrial growth rate forecasts.[19]

The equation for the industrial sector used in the current *Outlook* is of a basic format and is summarized as follows:

Figure 29. Index of Industrial Natural Gas Prices



Source: Ratio of industrial gas consumption from the Energy Information Administration, *Natural Gas Monthly* (DOE/EIA-0130), to a gas-weighted index of industrial production based on Federal Reserve Board data.

(2) $G(I) = a + bQ_t + c(P_g/P_o) + e_t$,

where:

$G(I)$=industrial gas demand,

Q=gas-weighted index of manufacturing output,

P_g=price of natural gas sold to industrial customers,

P_o=price of residual fuel oil,

a,b,c=parameters to be estimated,

e_t=a normally distributed random error term.

An improved form of the model makes the relative price effect on gas use per unit of output independent of the level of output. This modification involves recasting the equation in terms of gas use per output unit:

(2)' $(G(I)/Q_t) = a + c(P_g/P_o) + e_t$.

Equation (2)' will serve as a basic restricted (no intensity trend) model against which alternative models, which allow for trends in consumption per unit output, will be evaluated.

[17] Energy Information Administration, *Monthly Energy Review*, July 1989, p.2.4

[18] Energy Information Administration, *Monthly Energy Review*, July 1989, p.2.4

[19] This calculation is derived from Table 12 on page 21.

Equation (2)″ presents a general formulation of an alternative to equation (2)′ which explicitly includes a trend term for industrial gas use intensity.

$$(2)'' \quad (G(I)/Q(t)) = a + c(P_g/P_o) + dT + e_t,$$

where:

d=trend coefficient on use per unit output.

Equation (2)″ will be tested against the basic equation (2)′ to check for superiority of fit, which is expected, given the apparent trends in gas intensity. Tests for stability of the trend term over time will also be performed to determine whether, given relative gas price movements, gas intensity in the industrial sector is likely to resume its long-term decline.

Estimation and Forecasting Results

The discussion surrounding the gas demand equations presented above suggests estimating equations that can be used to investigate the importance and likely persistence of apparent trends in gas intensity for major gas-consuming sectors in the United States. Although the discussion so far has focused mainly on the gas-use-per-customer or use-per-output measures, estimation of the normalized form of the equation is returned to a consumption rate form (billion cubic feet per month) by multiplying through by the number of customers or by output. This ensures that root mean squared error (RMSE) calculations are in familiar units.

Tables 15 through 17 provide statistical results from linear regression analysis performed using alternate versions of the residential, commercial, and industrial models discussed above. Parameter estimates are given, with associated t-statistics given in parentheses below, followed by summary regression statistics and variable definitions. The basic format of the tables provides a version of the basic model (no intensity trend), a simple trend version, and an alternate trend version which provides for a test of the stability of any underlying trend. This is done by introducing a variable which, in effect, allows for a shift in the trend over time. The null hypothesis for the test is that, given stable short-term effects (weather and price effects as applicable), the trend term is not significantly different in the second half of the sample period from the first half of the sample period.

The observations are of monthly data extending from January 1981 through March 1989. An important exception to this pertains to the industrial model results presented in Table 17. Consistent monthly industrial gas price information is not available prior to January 1984, and, because of the importance of the relative price effects on short-term shifts in demand for this sector, the estimation period extends only as far as the price data allow. Additional regressions are presented in Table 17, however, which do extend back to 1981, but which exclude the price variable. This at least allows for a longer term view of the significance of the trend in the industrial sector. The commercial model results, summarized in Table 16 exclude price terms from the estimation because consistent monthly data on commercial prices are not available prior to 1984. Monthly price data for the residential sector are available from 1981 and alternative regressions with and without price are presented.

Residential Sector

From Table 15 it is apparent that, correcting for weather, a statistically significant downward trend in use per customer characterizes gas consumption in the residential sector. Adding the trend to the basic model does reduce the RMSE of the model, although the reduction is not very large (about 4 percent--model R2 versus model R1). The null hypothesis on the stability of the trend in the residential sector is accepted, as no significant additional reduction in RMSE is indicated by adding a slope dummy for the trend term (model R3 versus model R2). It also appears that short-term price effects are not apparent, at least when considering the effects of current period price movements. This conclusion is based on comparing model R4 to model R1 and model R5 to model R2. In neither of those comparisons does adding a residential natural gas price term reduce the RMSE of the model, as the price coefficients are not statistically significant. It is possible that a distributed lag on price may help improve the explanatory power of the model, although preliminary tests with lags of up to six periods showed no significant improvement. For all models

Table 15. Residential Sector Natural Gas Regression Results (Dependent variable = residential gas consumption)

Independent Variables	Parameter Estimate (with t value) Model Version				
	R1	R2	R3	R4	R5
GHDDxCUST	0.016	0.016	0.016	0.016	0.016
	(76.6)	(80.4)	(80.0)	(65.8)	(67.9)
CUST	1.917	3.301	3.630	1.447	3.2
	(17.7)	(7.7)	(4.4)	(2.1)	(3.5)
TIMExCUST		-0.008	-0.009		-0.007
		(3.3)	(2.3)		(3.0)
TDUMxCUST			-0.0000*		
			(0.5)		
PRICExCUST				.001*	.006*
				(0.7)	(0.1)
Adj. R Square	0.984	0.985	0.985	0.984	0.985
Root M.S. Error	31.26	29.76	29.88	31.34	29.9
F Value	5949.0	3287.4	2173.7	2958.6	2169.1

* Not statistically significant at the 5 percent level.
Variable Definitions:
GHDD= gas home-heating customer-weighted heating degree-days
CUST = number of residential gas customers, in millions
TIME = integer valued index of time = 1,2,...n, where n = number of observations
TDUM = time x DUMHALF
DUMHALF = 1 when date is before 1985, 0 otherwise
PRICE = residential gas price deflated by the Consumer Price Index

reported on Table 15, the estimated weather effect was quite consistent, indicating that use per customer may be expected to rise by an average of 16 cubic feet per month for every additional heating degree-day. However, long-term efficiency and conservation trends point toward an average savings of about 8 cubic feet per month, or 1,100 cubic feet per year on a per-customer basis.

Commercial Sector

As in the case of the residential sector, the commercial sector results show that weather-corrected consumption (actual consumption minus consumption due to weather influences) exhibits a statistically significant (though relatively small) downward trend on a per-customer basis, and that the trend does not appear to have slowed significantly in recent years. Adding the trend term reduces the RMSE (model C2 versus model C1) but the null hypothesis on the trend term is accepted (model C3 versus model C2), so that no significant deceleration of the trend is evident in recent years. A typical commercial customer responds to an additional heating degree-day by increasing gas consumption by an estimated 85 cubic feet per month on average. The weather-corrected trend in commercial use per customer is noticeably larger than that for the residential sector, implying an annual reduction of 14,000 cubic feet on a per-customer basis.

Industrial Sector

Based on the regression results from Table 17, at least for a somewhat limited sample of observations, changes in natural gas consumption per unit of output do not exhibit a statistically significant trend in addition

Table 16. Commercial Sector Natural Gas Regression Results (Dependent variable = commercial gas consumption)

Independent Variables	Parameter Estimate (with t value) Model Version C1	C2	C3
HDDxCUST	.086	.085	.085
	(41.8)	(50.0)	(50.0)
CUST	20.01	37.61	33.5
	(16.1)	(8.9)	(4.4)
TIMExCUST		-0.094	-0.075
		(4.2)	(2.0)
TDUMxCUST			.008*
			(0.6)
Adj. R Square	0.976	0.979	0.980
Root M.S. Error	15.83	14.96	15.01

* Not statistically significant at the 5 percent level.
Note: Commercial price data not available before 1984.
Variable Definition:
HDD = population-weighted heating degree-days
CUST = number of commercial customers, in millions
TIME = integer valued index of time = 1,2,...n,
where n = number of observations
TDUM = time x DUMHALF
DUMHALF=1 when date is before 1985, 0 otherwise

to effects from movements in the price of natural gas relative to the price of residual fuel. Models I1 to I3 in Table 17 are estimated over the January 1984 to March 1989 period, as consistent monthly industrial gas prices are not available prior to that period. The relative price term is introduced into the industrial model as a seven-period distributed lag, based on a quadratic lag distribution function, with endpoint restrictions placed on both ends of the distribution. This set-up tends to be highly restrictive, but helps ensure negativity of all price terms (which is theorectically most plausible and ensures a symmetrical lag pattern). Pre-tests of alternative lag lengths and structures were tried but were not found to be superior to the one adopted here.

Comparing model I2 to model I1 suggests that, after correcting for relative price movements, no statistically significant trend in use per unit of output is detectable given the very small improvement in the RMSE in model I2. However, it is interesting to note that the RMSE can be reduced somewhat by introducing a dummy slope variable for the trend term (model I3 versus model I2). Given the definition of this dummy variable though, any measurable trend appears to have been less severe for the first half of the sample compared to the more recent period, which is not the expected pattern. As shown, the trend and trend dummy variables are defined such that the parameter estimated for the trend term (TIMEXQ) represents the trend for July 1986 through March 1989 while that estimated for the trend dummy variable (TIMEXQD) represents the difference between the trend for January 1984 and June 1986 and the trend for the second half of the estimation period. While this latter parameter is marginally significant, the trend from the earlier period (-0.002 = -0.004+0.002) has a standard error of 0.003 and is thus not significantly different from zero at the 5-percent level. Nevertheless, because of the indication of some improvement in the basic model fit by adopting model I3, this model will be evaluated in the forecast comparison section below.

In order to put these industrial sector results into perspective, additional regressions (I4 and I5) are provided in Table 17 to roughly demonstrate the size and persistence of the trend in use per unit of output for a longer period of time (January 1981 to March 1989). Price terms are excluded because of the lack of consistent data from as far back as 1981. The estimated trend term is quite large and is generally stable over the time period for models I4 and I5. However, the RMSE is quite large for these simple representations and it seems clear that the absence of some accounting for relative price movements is too important to judge these models as being useful for short-run forecasting.

Forecast Comparisons

Table 18 provides summary comparisons between natural gas forecasts from a recent *Short Term Energy Outlook* and selected models estimated here. All of the forecasts are benchmarked so as to reproduce historical values for the latest 12-month period of data. Thus, what is being compared directly here are changes from one period to the next rather than absolute

Table 17. Industrial Sector Natural Gas Regression Results (Dependent variable = industrial gas consumption)

Independent Variables	Parameter Estimate (with t-value) Model Version				
	I1	I2	I3	I4	I5
Q	15.93	16.01	18.08	24.01	23.39
	(33.1)	(173.6)	(180.4)	(24.01)	(10.0)
PRICExQ	-0.013	-0.011	-0.009		
	(6.0)	(4.2)	(3.8)		
PRICE1xQ	-0.022	-0.018	-0.016		
	(6.0)	(4.2)	(3.8)		
PRICE2xQ	-0.028	-0.023	-0.020		
	(6.0)	(4.2)	(3.8)		
PRICE3xQ	-0.030	-0.024	-0.021		
	(6.0)	(4.2)	(3.8)		
PRICE4xQ	-0.028	-0.023	-0.020		
	(6.0)	(4.2)	(3.8)		
PRICE5xQ	-0.022	-0.018	-0.016		
	(6.0)	(4.2)	(3.8)		
PRICE6xQ	-0.013	-0.011	-0.009		
	(6.0)	(4.2)	(3.8)		
TIMExQ		-.0003*	-0.004*	-0.053	-0.050
		(0.9)	(1.4)	(7.6)	(4.1)
TDUMxQ			0.002		0.001*
			(2.7)		(0.3)
Adj. R Square	0.845	0.850	0.866	0.490	0.410
Root M.S.Error	23.26	23.07	21.61	71.14	71.53
F Value	26.44	26.93	28.88	6.91	6.32

*Not statistically significant at the 5 percent level.
Variable Definition:
Q = gas-consumption-weighted industrial production of SIC 20, 26, 28, 29, 32, 33
PRICE = ratio of industrial gas price to residual fuel oil price X weighted industrial production, period i, i = 0,...-6
TIME =integer valued index of time = 1,2,...n, where n= number of observations
TDUM = time x DUMHALF
DUMHALF = 1 when date is before 1985 (1984 in I4 and I5),) otherwise

levels. For the residential sector, the comparison forecast is from model R2. Model C2 is used for the commercial sector comparison. Both models I1 (no trend) and I3 (variable trend) are used for the industrial sector comparisons.

As one would expect from the regression results, the natural gas consumption forecasts would be lower than those from the current *Outlook* models for both the residential and commercial sectors, inasmuch as the estimated use-per-customer trends are negative. Also, as expected from Tables 16 and 17, the adjustment to the forecast is greater for the commercial sector than for the residential sector.

The industrial model forecast using model I1 is not very different from the July 1989 *Outlook* forecast. However, allowing for a use-per-unit-output trend as estimated in model I3 does result in a somewhat less robust outlook for industrial gas, perhaps lowering aggregate industrial gas demand by as much as 1.2 percent in 1990.

Allowing explicitly for trends in natural gas use intensity, gas consumption models used in the July *Outlook* may be expected to reduce the gas consumption outlook by as much as 1 percent for the combined non-utility sectors in 1990. Of particular concern is the commercial sector, although additional historical observations on commercial prices might allow a clearer assessment of the strength of longer term efficiency and conservation trends. The same is true of the industrial sector, which may prove to be on the verge of resuming a strong downward trend in use per unit of output. A more detailed look at this sector, in terms of the role of industrial mix versus industry-specific efficiency trends (possibly using input-output analysis) may shed some additional light on how well the trajectory for the short-term gas consumption outlook aligns with long-term trends. Models R2, C2, and I1 will replace the current models for natural gas demand, marginally reducing the underlying strength of the gas consumption outlook.

Table 18. Alternative Natural Gas Demand Forecasts Using July 1989 *Outlook* Assumptions (in billion cubic feet)

Sector/Year	July STEO	Forecasts New Models	
Residential		**Model R2**	
1988	*4634	*4634	
1989	4592	4559	
1990	4702	4699	
Commercial		**Model C2**	
1988	*2617	*2617	
1989	2587	2543	
1990	2620	2577	
Industrial		**Model I1**	**Model I3**
1988	*6306	*6306	*6306
1989	6499	6474	6446
1990	6613	6611	6536

* Indicates actual historical data.

6. Regional Trends in the Demand for Fuel by Electric Utilities

In the past 2 years, there has been considerable variation in fuel consumption at electric utilities, particularly at the regional level. This chapter discusses the causes behind these variations, focusing on regional aspects such as fuel supply and price, and weather, examining certain key fuel supply considerations which were major determinants of fuel use over the past 2 years; the effects of severe temperature on electricity demand and fuel consumption; and the effect of variations in the relative price of fuel supplied to electric utilities on the choice between natural gas and petroleum consumption.

Key Supply Considerations

Over the last 2 years, the most significant development in the area of fuel choice at electric utilities has been the persistent drought, which greatly affected the Nation's watershed levels. From 1986 to 1988, hydroelectric power declined by an average of 12 percent per year, yielding a level of generating capacity in 1988 which was 77 percent of the level in 1986. Consequently, other fuels had to meet the Nation's electricity generation needs. In 1987 and 1988, coal generation grew by an average of 5.4 percent per year, nuclear generation increased by 13 percent per year, and the combined share of petroleum and natural gas use by electric utilities broke its steady decline by growing about 2.1 percent per year.[20]

The areas most affected by the hydroelectric power shortage were the Mountain and Pacific Census Divisions, which had been dependent on hydroelectricity for greater than 20 percent of their fuel requirements in 1986. In the Pacific Division, increased use of natural gas covered for the decline in hydroelectric power in 1987, and nuclear and petroleum generation covered most of the shortfall in 1988. For the Mountain Division, in both 1987 and 1988, the deficiency was met primarily with increases in coal generation along with strong increases in nuclear generation. For other areas, the influence of the drought was less dramatic, as 6 out of 9 census divisions have generation levels of hydroelectricity that exceed 5 percent of their total needs.

In both 1987 and 1988, large increases in nuclear generation occurred, although in 1987 the growth rate varied considerably by region. In that year, nuclear generation increased by 10 percent (Table 19), even though generation from this source actually declined in the New England, West North Central, and Pacific Census Divisions. In these divisions, six separate plants went off-line for refueling in 1987, returning to operation later in the year. Moreover, the Hanford plant in Washington State went off-line and is not expected to return to operation.[21] Almost half of the increase in nuclear generation in 1987 occurred in the South Atlantic and East North Central Divisions. In these divisions, four new nuclear plants became operable in 1987: Vogtle 1 in Georgia (3/87), Shearon Harris 1 in North Carolina (1/87), and Braidwood 1 (7/87) and Byron 2 (1/87) in Illinois.[22] In 1988, nuclear generation increased by 16 percent for the Nation as a whole.

In many areas, the increase in nuclear generation replaced the shortfall of hydroelectric power, yet in other regions it displaced fossil fuel generation. For example, in 1987 both hydroelectric and nuclear generation increased in the South Atlantic Census Division, and petroleum generation suffered, declining by 21 percent in this division compared to 1986. Moreover, in the West South Central Division, which

[20]Increased electricity imports (primarily from Canada) and increased purchases of electricity from nonutility generators also added to the electricity supply. The conclusions about regional compensations for hydroelectric downturn are suggestive in the sense that often many factors can influence the choice of an electricity source at the same time. Although many factors other than the drought affected the demand for fuel at electric utilities, it is beyond the scope of this chapter to specify which factors are most important for a given region in a given time period.

[21]The Hanford plant was designed to produce weapons grade fuel with electricity generation as a byproduct. In 1987, it was deemed unsafe to operate and too costly to bring up to safety standards. It is presently in a "cold standby" status.

[22]Energy Information Administration, *Commercial Nuclear Power 1988*, DOE/EIA-0438(88) (Washington, DC, 1988).

Table 19. Electricity Generation By Census Division

Fuel Source	Census Divisions: New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	United States
	(million kilowatthours and year-over-year percent changes)									
Coal										
87 Annual	16674	128211	348954	145252	314800	176677	161969	162834	8410	1463781
	17.8%	7.4%	2.6%	8.6%	4.4%	0.0%	4.0%	16.5%	58.3%	5.6%
88 Annual	16979	136319	350826	159836	323186	185856	175508	180748	8957	1538203
	1.8%	6.3%	0.5%	10.0%	2.7%	5.2%	8.4%	11.0%	6.5%	5.1%
89 Q1	4713	35695	91223	40117	83724	41840	43046	45029	2989	388376
	-5.2%	0.2%	3.9%	1.4%	2.5%	-10.2%	5.6%	2.0%	21.1%	1.3%
Petroleum										
87 Annual	32831	42202	2877	314	28991	356	646	698	9577	118493
	-18.0%	-7.0%	-18.1%	-4.6%	-21.2%	-68.3%	-28.1%	26.7%	-6.7%	-13.2%
88 Annual	37811	52878	3006	571	35932	1079	1189	896	15458	148819
	15.2%	25.3%	4.5%	81.8%	23.9%	203.1%	84.1%	28.4%	61.4%	25.6%
89 Q1	12150	17768	451	229	9453	420	1470	332	7110	49383
	4.3%	22.5%	30.3%	209.5%	41.5%	333.0%	114.6%	23.9%	113.1%	31.2%
Natural Gas										
87 Annual	4744	22933	940	2094	18561	3638	148897	5484	65330	272621
	244.5%	47.1%	-37.7%	36.0%	7.7%	-16.4%	-5.6%	-0.3%	49.3%	9.7%
88 Annual	1933	18499	1584	2588	15976	3092	146431	5925	56750	252779
	-59.3%	-19.3%	68.5%	23.6%	-13.9%	-15.0%	-1.7%	8.0%	-13.1%	-7.3%
89 Q1	214	2766	359	329	3828	417	29113	1614	11697	50337
	269.0%	-7.3%	9.5%	3.8%	26.8%	27.5%	-8.0%	46.9%	-12.7%	-4.1%
Nuclear										
87 Annual	29256	80606	83407	35421	130137	18857	23693	13632	40263	455270
	-0.4%	5.1%	26.2%	-1.1%	9.1%	21.3%	21.4%	35.9%	-8.5%	10.0%
88 Annual	32499	85928	106893	37865	144010	26504	26401	23600	43202	526905
	11.1%	6.5%	28.2%	6.9%	10.7%	40.6%	11.4%	73.1%	7.3%	15.7%
89 Q1	7580	18081	26394	10522	29383	8154	6615	4878	13083	124689
	14.7%	-13.1%	-11.6%	10.2%	-18.6%	47.5%	6.4%	10.3%	12.7%	-4.7%
Hydro										
87 Annual	4109	28365	2505	12050	13330	17962	7513	33281	130580	249695
	-14.6%	-7.4%	9.8%	-11.4%	60.1%	35.2%	-2.9%	-29.2%	-19.3%	-14.0%
88 Annual	3819	24384	2389	11240	7149	12374	6064	28072	127449	222938
	-7.1%	-14.0%	-4.6%	-6.7%	-46.4%	-31.1%	-19.3%	-15.7%	-2.4%	-10.7%
89 Q1	748	5822	708	2206	3055	7558	2115	6442	32573	61227
	-21.3%	-14.6%	-1.0%	-27.3%	5.4%	76.6%	-28.2%	-12.7%	2.8%	0.9%
Other										
87 Annual	156	0	506	108	51	0	234	215	10998	12267
	83.5%	--	29.4%	54.3%	34.2%	--	-24.0%	-9.7%	6.0%	6.6%
88 Annual	342	0	514	210	58	0	0	231	10628	11984
	119.2%	--	1.6%	94.4%	13.7%	--	--	7.4%	-3.4%	-2.3%
89 Q1	93	0	114	49	4	0	0	63	2510	2833
	158.3%	--	-15.6%	-10.9%	83.6%	--	--	-1.6%	-6.0%	-4.6%
Total										
87 Annual	87769	302317	439189	195238	505870	217490	342952	216143	265158	2572127
	0.3%	5.1%	5.9%	5.5%	4.7%	8.1%	0.3%	6.4%	-3.0%	3.4%
88 Annual	93383	318007	465201	212310	526311	228905	355592	239472	262444	2701624
	6.4%	5.2%	5.9%	8.7%	4.0%	5.2%	3.7%	10.8%	-1.0%	5.0%
89 Q1	25498	80132	119249	53453	129447	58388	82359	58358	69962	676846
	5.1%	-0.8%	0.0%	1.7%	-0.7%	2.8%	1.1%	1.7%	7.4%	1.3%

-- = Not applicable.

Notes: o Shaded area indicates percent change from year above. o The other category includes generation from geothermal, wood, wind, waste, and solar. o Totals may not equal sum of components due to independent rounding.

Source: *Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."*

uses little hydroelectric power, nuclear generation increased by over 21.4 percent in 1987, which caused both petroleum and natural gas generation to decline.

Restrictions in the supply of natural gas to electric utilities have affected the choice of fuel in certain areas of the country. For example, in the first quarter of 1989, gas supplies to utilities in southern California were curtailed. The Southern California Gas Company (SCGC) needed to provide a great deal of natural gas to residential and commercial customers due to a cold snap in February, and due to SCGC's policy decision to fill their storage capacity before supplying natural gas to electric utilities to ensure adequate supplies for the summer months as well as for the following winter.[23] These types of restrictions kept the demand for petroleum strong. Whereas natural gas generation declined by 13 percent in the Pacific Division in the first quarter of 1989, petroleum generation increased by 113 percent.

Effects of Extreme Temperature

Just as lack of precipitation can have a tremendous impact on the sources of electricity supply, severe temperatures can often greatly affect demand by increasing the use of heating and air-conditioning. Table 20 reveals the severity of weather by showing the percent deviation from normal of actual heating degree-days (in the winter months) and cooling degree-days (in the summer months). In 1987, the temperature was about 6.3 percent milder than normal in the winter quarters (first and fourth quarters), and 3.4 percent more extreme in the summer quarters (second and third quarters). In 1988, the temperature was about 1.0 percent colder than normal in the winter quarters, and 6.7 percent hotter than normal in the summer quarters. In general, for every 1 percent that heating degree-days or cooling-degree days are above normal, electricity generation increases by about 0.2 percent.[24]

Often if the severity of the weather varies across regions, temperature extremes can influence the types of fuel used at electric utilities along with the total amount of electricity generated. A notable example is in the third quarter of 1988. For most areas of the country, the weather was hotter than normal in this quarter, cooling degree-days being 11 percent above normal for the Nation. Nonetheless, very extreme temperatures occurred in the North Central and Northeastern States, with cooling degree-days reaching as high as 28 percent above normal in New England. Consequently, total generation increased by 5.0 percent for the Nation in the third quarter of 1988, while total generation went up by 12 percent in the New England Division. Because this division relies on petroleum for about 40 percent of its fuel generation needs, strong pressure was put on the demand for petroleum, which increased by 23 percent in this division in the third quarter.[25]

Extreme temperatures exert extra demand on electricity sources which are used in times of peak demand. Hydroelectricity, nuclear, and coal are primarily used for base loads, while petroleum and natural gas are often used for base and peak loads. Although petroleum and natural gas plants are relatively cheap to build compared to plants using other sources, they are more expensive to operate, making oil and gas plants good choices for utilization in times of high demand, such as days with extreme temperatures. More than any other electricity source, petroleum is reserved for times of peak demand. Given the extreme temperatures and favorable price for oil in several areas in the third quarter of 1988, it is not surprising that petroleum generation increased by 27 percent nationwide in the third quarter of 1988.

[23]Based on a telephone conversation with a representative from the Southern California Gas Company (Los Angeles, CA).

[24]This factor was derived using electricity model estimates used in the forecasts of the *Short -Term Energy Outlook*, DOE/EIA-0202 (89/3Q). When degree-days deviate greatly, the effects on electricity generation can be even greater.

[25]Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 20. Percentage Deviations From Normal for Heating Degree-Days (Winter Months) and Cooling Degree-Days (Summer Months)

	Cenus Divisions									
Period	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	United States
87Q1	-0.97	-4.44	-14.46	-24.63	-0.68	-6.24	-3.93	-4.20	-5.11	-8.13
87Q2	1.08	5.98	9.03	-2.08	16.33	18.83	6.90	-9.86	-26.81	5.84
87Q3	-8.64	-1.28	11.97	2.02	10.05	6.12	-0.41	-4.00	-44.19	1.55
87Q4	-0.05	-0.95	-3.03	-4.46	-3.51	-6.02	-7.00	-1.98	-3.19	-2.9
87 Annual	-0.83	-1.86	-5.26	-12.11	4.25	0.58	-1.28	-4.05	-10.90	-3.33
88Q1	-0.62	-0.33	1.55	0.26	4.81	6.14	7.48	-2.20	-12.45	0.62
88Q2	7.76	8.04	7.06	10.37	-1.54	-3.01	-5.25	4.93	-15.85	2.27
88Q3	27.57	16.94	25.48	17.92	6.05	7.64	3.52	6.06	-2.27	11.01
88Q4	4.59	4.72	5.19	1.69	2.86	0.88	-16.89	-6.58	-3.77	1.65
88 Annual	4.07	3.98	5.74	3.75	3.74	3.95	-0.13	-1.61	-8.45	2.69
89Q1	-4.92	-7.44	-7.46	-2.54	-18.35	-17.57	-5.51	-0.68	2.09	-6.93
89Q2	9.07	10.14	2.84	-12.39	8.45	-2.68	2.01	-7.70	-47.25	0.46

Note: Quarters one and four show the percent deviation from normal for heating degree-days; quarter three shows the percent deviation from normal for cooling degree-days; quarter two shows the percent deviation from normal for heating degree-days in April and the percent deviation from normal of cooling degree-days in May and June. Heating degree-days and cooling degree-days are population weighted .

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA) Microcomputer Management System (Suitland, MD).

Effects of Fuel Price

The relative cost of producing electricity from the various electricity sources is an important determinant of the use of those sources. Hydroelectric power is the least expensive to produce, with nuclear power generally being the second cheapest. Utilities prefer these sources and the limits to their use are set primarily by the available supply. (For both nuclear and hydroelectric power, regulatory constraints may be significant barriers to effective availability of existing and new capacity.) Coal-fired power is the next cheapest source, with petroleum and natural gas being the most expensive. Because natural gas and petroleum are relatively more expensive, these sources are often reserved for times of peak demand, although they are still primarily used for base load generation. Since many utilities have the capability to switch between oil and gas, the demand for these fuels is quite price sensitive. For much of the 1980's, natural gas has been less expensive for most utilities to purchase, although at times petroleum can be price competitive. Often natural gas is the desired fuel, but there can be localized supply impediments.

Table 21 shows the oil to gas price ratio by Census Division and quarter for 1986 through 1989. On an annual basis for all divisions, the petroleum price was only slightly higher than the natural gas price for 1986 and 1988. In 1987, the price ratio for all divisions was 1.32. However, the national ratios obscure the considerable variation across divisions. In 1987, the ratio varied from 1.00 in the Mountain Division to about 1.61 in the West South Central Division. In 1988, the ratio dipped as low as 0.72 in New England and was as high as 1.60 in the East South Central Division.

The fourth quarter of 1988 was notable, because the average price of oil for the United States dipped below the price of gas. Again, regional differences were dramatic. In New England, the ratio was 0.67 in this quarter, and it was as high as 1.31 in the East South Central Division. For all divisions, except the South Atlantic and West North Central Divisions, the price ratio dropped from its year earlier level. Not surprisingly, petroleum usage increased dramatically in this quarter, increasing by 68 percent for the Nation. By the first quarter of 1989, the national oil to gas price ratio rose to 1.10. Based on this observation alone, the assumption is that the price advantage of oil at electric utilities had vanished in this quarter. However, the New England, East North Central, West North Central and Pacific Divisions still had oil to gas price ratios which were less than 1.0 in the first quarter of 1989. Moreover, the price of oil remained lower than the price of gas until March in the heavy oil consuming Mid-Atlantic Division. The price incentives and somewhat limited natural gas availability kept petroleum generation growing by 31 percent in this quarter for the Nation.

Conclusion

There are important regional differences in the factors which influence fuel consumption at electric utilities. Differences in fuel availability, precipitation patterns, severity of temperature, and fuel price all impact the utilities' choice of fuel. Although the current *Short-Term Energy Outlook* is limited to forecasting electricity fuel consumption with based on an aggregate national model, regional analyses can augment this model and improve EIA's ability to judge its reasonableness. In the future, undertaking similar regional analyses will enhance the ability to assess likely alternative fuel choice developments within the forecast period.

Table 21. Ratio of the Price of Petroleum to Electric Utilities to the Price of Natural Gas to Electric Utilities

	Census Divisions									
Period	New England	Middle Atlantic	North Central	East North Central	West South Atlantic	East South Central	West South Central	Mountain	Pacific	United States
86Q1	0.61	1.08	1.27	1.02	1.16	1.30	1.83	0.99	1.00	1.15
86Q2	0.79	0.96	0.99	0.73	1.09	1.24	0.71	0.70	0.74	0.95
86Q3	0.79	1.01	0.96	0.67	1.02	0.97	0.69	0.77	0.99	0.91
86Q4	0.79	1.03	0.87	0.72	1.06	1.05	0.72	0.65	1.13	1.05
86 Annual	0.73	1.02	1.02	0.78	1.08	1.13	1.03	0.78	0.97	1.02
87Q1	0.79	1.09	1.08	1.03	1.04	1.05	1.26	0.83	0.98	1.25
87Q2	1.18	1.30	1.09	1.07	1.08	NA	1.81	1.10	1.06	1.36
87Q3	1.24	1.25	1.12	1.24	1.10	1.86	1.88	1.08	NA	1.43
87Q4	1.11	1.19	1.16	0.99	1.01	NA	1.54	1.04	1.11	1.24
87 Annual	1.04	1.20	1.11	1.08	1.06	1.42	1.61	1.00	1.06	1.32
88Q1	0.52	1.02	0.90	0.74	0.99	NA	1.77	0.98	0.97	1.04
88Q2	1.05	1.11	0.94	1.05	1.09	2.21	1.44	1.13	0.98	1.03
88Q3	0.99	1.08	1.01	0.95	1.05	1.64	1.92	1.02	0.85	1.05
88Q4	0.67	0.94	0.89	1.11	1.05	1.31	1.11	0.91	0.77	0.98
88 Annual	0.72	1.02	0.93	0.96	1.04	1.60	1.55	0.99	0.87	1.02
89Q1	0.70	1.02	0.93	0.57	1.05	1.23	1.32	1.03	0.92	1.10

NA = Not available.
Note: To arrive at quarterly and annual price values, monthly values were weighted by national generation values.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." The price of natural gas is given by the average cost of gas for steam-electric plants at plants with an installed nameplate capacity of 50 megawatts or larger. The price of petroleum is given by the average cost of heavy oil (fuel oil numbers 4,5,6 and topped crude fuel prices) for steam-electric plants with an installed nameplate capacity of 50 megawatts or larger.

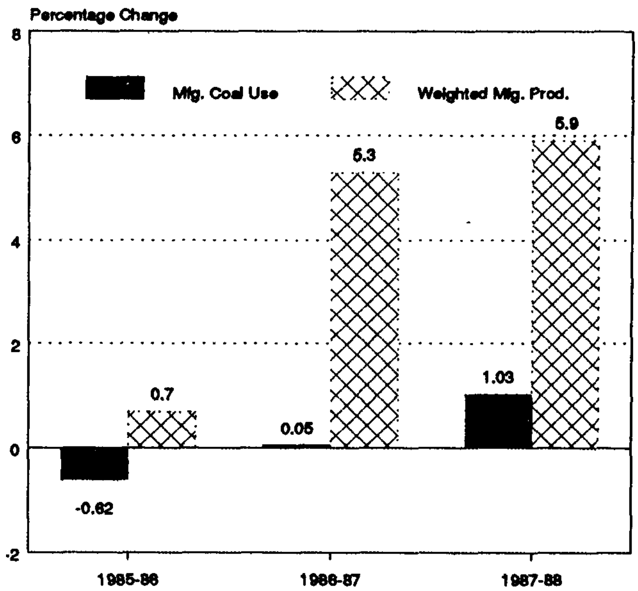
7. Industrial Coal Use Patterns

It has been very evident in recent years that coal demand in the industrial sector has significantly lagged the pace of manufacturing output. Since 1985, there has been little net growth in non-metallurgical industrial coal demand while output for key coal-using manufacturing sectors has increased significantly (Figure 30). This chapter takes a brief look at the factors which are contributing to the consistant downward trend of non-metallurgical coal use relative to industry output.

Coal demand by the industrial sector -- approximately nine-tenths of coal consumption in the Retail and General Industry category in 1988 -- is not expected to increase from last year's level of 76 million short tons despite a projected 2.9-percent rise in industrial production for 1989.[26] This apparent insensitivity of coal demand to manufacturing production first loomed in 1986. While manufacturing production increased by 10 percent between 1986 and 1988, corresponding coal use grew by only one-eighth as much (Figure 30). Disproportionate growth in coal demand relative to manufacturing activity suggests a small elasticity of demand with respect to industrial output, estimated to be about 0.12 from 1985 through 1988. The factors, whether structural or temporary, that underlie this sluggishness in industrial coal use stem from demand behavior in the various manufacturing industries.

Coal consumption by the five largest industrial coal users (Standard Industrial Classifications (SIC) 20, 26, 28, 32, 33) remained essentially flat at 55 million tons from 1985 to 1988.[27] These industries increased coal use at an average annual rate of only 0.15 percent despite of the 3.5-percent average industrial production growth between 1985 and 1988 (Figure 30). The minor coal-consuming manufacturing industries (which accounted for 27 percent of that period's total industrial coal demand) more than doubled their coal use from 7 percent to 16 percent of total manufacturing coal consumption, but not enough to significantly raise net demand.[28]

Figure 30. Coal Used in Manufacturing



Note: Weights are based on coal consumption by SICs 20, 26, 28, 32, and 33; metallurgical coal consumed by coke plants is excluded from SIC 33.
Source: Energy Information Administration, *Quarterly Coal Report*.

The two largest coal consumers -- chemicals and allied products, and stone, clay, and glass products -- reduced coal use starting in 1986. The third major consumer, paper and allied products, began using less coal in 1987. These reductions occurred despite average manufacturing growth rates of 6.3, 2.3, and 5.6 percent, respectively, for each industry group between 1986 and 1988.[29]

Among the sub-industries (4-digit SIC) in the chemicals and allied products group (which use coal primarily for providing process steam and feedstock), the decline was attributed to substitution of natural

[26] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(89/2Q), Tables 4 and 15.
[27] Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121, Table 30.
[28] *Quarterly Coal Report*, Table 30.
[29] *Quarterly Coal Report*, Table 30.

gas or fuel oil for coal, stricter standards of performance for limiting emissions, improvements in production efficiency, and market decline. Within the stone, clay, and glass products group, companies in the cement industry that significantly reduced coal consumption used more of "waste fuels" (nonpremium fuels, such as recycled petroleum solvents or lubricants) to produce process heat, to improve heat transfer inside cement kilns, and to maintain higher kiln temperatures.[30] Some large companies in the paper products industry decreased their demand for coal because of lower prices for natural gas, more restrictive and costly emission control requirements, and wider use of "recovery fuels" -- mainly wood residue.

The new source performance standards for industrial and commercial boilers, first proposed in June 1986, took effect in December 1987.[31] In summary, the rules limit emissions of nitrogen oxides, sulfur dioxide, and particulate matter for coal and oil-fired industrial/commercial/institutional steam generating units, which may either be new, modified, or reconstructed

One potential source for increased coal demand may come from expanded production of electricity by industrial cogenerators and small power producers. The Public Utility Regulatory Policies Act of 1978 (P.L. 95-617), which was implemented in 1980, has recently been effective in encouraging electric utilities to purchase cogenerated electricity or cogeneration capacity from nonutility sources. According to Edison Electric Institute's 1987 survey of nonutility producers of electricity, 15 percent of total cogenerators' supply was generated by coal, which is equivalent to about 10.2 million short tons (or 13.6 percent of industrial coal use). The two leading industrial cogenerators, chemicals and the paper industry, provided almost half of total nonutility generation.

Another source of demand for industrial coal is from synthetic gas production by coal gasification plants, which are projected to consume 7.2 million tons in 1989. This level is almost as large as residential and commercial use combined. The number of plants in operation, however, has been declining and a reversal of this trend is not imminent.

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[30]Based on telephone conversations with representatives from DuPont, Dow, and Monsanto chemical companies on June 20, 1989.

[31]As part of the Clean Air Act, these requirements are described in the Environmental Protection Agency's code of Federal Regulations (40 CFR Part 60).

8. Comparison of EIA and Other Forecasts for 1989

This chapter presents a comparison of EIA's base case forecast for 1989, as published in the April 1989 *Short-Term Energy Outlook*, with the forecasts of three other major U.S. energy forecasting services: DRI/McGraw Hill (DRI), the Independent Petroleum Association of America (IPAA), and the WEFA group (WEFA). Unlike EIA, DRI, and WEFA, IPAA's forecast is an industry consensus position and is not generally reflective of any particular forecast. The comparison focuses on the similarities and differences in the four forecasts with regard to macroeconomic and price assumptions and supply and demand projections for 1989. All four of these forecasts were published in spring 1989.

Economic and Price Assumptions

For 1989, there is a surprisingly high degree of agreement among the four forecasting services in their assumptions for real gross national product (GNP) growth rate, rate of inflation, the energy efficiency ratio, and the weather pattern. (Table 22) IPAA, DRI, and EIA all assumed a GNP growth rate of 2.6 percent, while WEFA assumed a somewhat higher rate of 2.9 percent. All four forecasts show considerable deceleration from 1988's relatively rapid growth of 3.9 percent, reflecting their common expectation of an economic slowdown due to rising inflation and interest rates and slower growth in the trade sector.

IPAA, WEFA, and EIA all assumed an inflation rate of 4.8 percent, up from last year's 3.4 percent, as well as continued growth in real disposable personal income. DRI assumed a somewhat lower rate of inflation at 3.9 percent, partly reflecting DRI's assumption of a relatively low world oil price of $15.81, only $1.00 higher than the 1988 average.

All four forecasters anticipated energy efficiency ratios (defined as gross energy consumption in Btu divided by real GNP) just slightly below that of 1988, showing little change from that of the past 2 years.

There was more disagreement on the growth rates for real disposable personal income and the index of industrial production. Generally, real disposable personal income follows the course of GNP growth with some lag time. WEFA's assumption of 3.7 percent growth in real disposable personal income, down only slightly from the 1988 rate of 3.8 percent, is the high end of the spectrum. DRI's assumption of 2.9 percent is at the low end and EIA is in the middle at 3.2 percent. WEFA's higher assumption is based on its higher forecast of GNP growth and on the expectation that there will be an increase in aggregate income due to a higher minimum wage by the fourth quarter of 1989.

As a result of slowing investment and consumption, all four forecasters assumed lower growth rates for industrial production in 1989 than in 1988. IPAA's rate of 3.5 percent is high relative to DRI's rate of 2.9 percent. WEFA and EIA are in between at 3.3 percent and 3.2 percent, respectively. IPAA's more optimistic forecast is a result of its anticipated growth in the export of manufactured goods.

The world oil price is one of the most uncertain factors influencing the 1989 energy outlook because of conflicting influences on the market such as continued overproduction by OPEC, continued lower production in the United States and North Sea, and questions regarding 1989 world oil demand. In its base case for its April 1989 *Outlook*, EIA expected oil prices to fluctuate over the course of the year from an average of $16.65 per barrel in the first quarter to $17.50 in the second quarter, falling to $17.00 by the third quarter of 1989. WEFA also predicted more volatility in oil prices, but expected a higher price in the second quarter of $19.00 per barrel, falling in the third quarter to $16.38, and averaging $17.10 over the course of the year. DRI expected oil prices to average only $15.81 per barrel in 1989, up $1.00 from the 1988 average, based on its assumption of an annual increase of $1.00 a year over the next 5 years.

Table 22. Comparisons of Alternative Macroeconomic and Price Assumptions

Assumptions	1988 Actual[a]	1989 Forecasts IPAA	DRI	WEFA	EIA
Economic Indicators					
Real GNP in 1982 dollars (% change from prior year)	3.9	2.6	2.6	2.9	2.6
GNP Price Deflator (% change from prior year)	3.4	4.8	3.9	4.8	4.8
Real Disposable Personal Income % change from prior year)	3.8	NA	2.9	3.7	3.2
Index of Industrial Production % change from previous year)	6.0	3.5	2.9	3.3	3.2
Energy Efficiency Gross Energy Use per dollar GNP (thousand Btu per 1982 dollar)	20.0	19.8	19.6	19.7	19.8
Energy Prices[b] World Oil Price ($ per barrel)[c]	$14.71	NA	$15.81	$17.10	$17.00
Petroleum Products ($ per gallon)					
Motor Gasoline (retail)[d]	$0.96	NA	$0.97	$1.02	$1.04
Heating Oil (retail)	$0.81	NA	$0.82	$0.93	$0.84
Natural Gas ($ per thousand cubic feet)					
Residential (retail)	$5.46	NA	$5.49	$5.73	$5.62
Coal ($ per million Btu)					
Average Electric Utility	$1.47	NA	$1.47	$1.56	$1.52

[a] As observed by EIA.
[b] Nominal prices.
[c] Cost of imported crude to U.S. refiners.
[d] Including tax.
NA = Not available.
Sources: DRI/McGraw-Hill, *Energy Review*; Spring 1989; Energy Information Administration, *Short Term Energy Outlook*, Quarterly Projections, April 1989; IPAA Supply and Demand Committee Report, May 9, 1989; The WEFA Group, *Energy Analysis Quarterly*, Spring 1989.

Primary Energy Demand

According to all four forecasters, 1988 energy demand trends were not expected to carry over into 1989 due to slower economic growth and an assumed return to normal weather patterns. (Table 23). Gross energy consumption was expected to slow considerably from the high growth rate of 4.2 percent in 1988. WEFA and EIA both projected a 1.4 percent growth rate. According to EIA, this was mainly due to expectations of increased demand in the electric utility sector,[32] whereas non-utility demand was expected to be only weakly positive, but according to WEFA[33] and DRI,[34] the only sectors showing consumption increases were transportation and electric utilities. IPAA's forecast of gross energy consumption was only slightly higher at 1.5 percent, while DRI's forecast was somewhat lower at 0.6 percent.

Oil demand in 1989 was projected to slow considerably by all four groups, with EIA and DRI showing relatively lower expectations of 0.9 percent, and IPAA and WEFA showing higher expectations of 1.7 percent and 1.5 percent, respectively. These are down from the high growth rate of 3 percent in 1988. In actual barrels per day, these percentages account for between 100,000 and 300,000 barrels per day of increased demand. According to EIA, demand for petroleum products should increase by 150,000 barrels per day compared to the 500,000 barrels per day increase in 1988, but again mostly due to increased demand by the transportation sector. Motor gasoline demand was expected to continue its 6-year growth trend at a rate of about 1.4 percent according to EIA and 1.2 percent according to IPAA. But DRI and WEFA projected an increase in gasoline demand of only 0.7 percent as a result of the impact of slower economic growth and higher gasoline prices.

The four forecasters were most in disagreement on demand for coal, nuclear, hydropower and other energy sources used primarily for electric power generation, despite the similarity in overall energy demand trends. Demand for electricity was expected by all to continue to grow, but only at about half the 1988 level of 4.5 percent. (Table 18) IPAA and WEFA's forecasts for electricity demand growth were the highest at 2.5 percent, followed by EIA at 2.1 percent. DRI's forecast was lowest at 1.1 percent and reflected the belief that electricity consumption, more than any other fuel, was tied to economic performance.

Demand for natural gas and coal was projected to decline by all four services due to resurgence of hydropower in the electric utility sector. Both DRI and WEFA projected negative growth rates for natural gas, while IPAA projected a negligible increase of only 0.3 percent. EIA's forecast for natural gas demand growth was the highest at 1.6 percent due mainly to expectations of increased demand by the industrial sector, reflecting a decline in the gas-to-oil price ratio as well as a 3.2 percent rise in the growth rate for industrial production, and rebounding use of gas by electric utilities.

Demand for coal was expected to remain close to 1988 levels by IPAA, WEFA, and EIA, whose growth rates were almost flat. DRI suggested a growth rate of -1.6 percent, way down from the 5.4 percent growth of 1988, due to expectations of slower growth in electricity sales and slower export growth.

Growth in nuclear power, which increased at a rate of 15.4 percent in 1988, was projected to drop significantly by all four forecasters. DRI's forecast for nuclear growth was the highest at 4.6 percent, reflecting expectations of new capacity additions. WEFA's forecast was next at 3.8 percent, and reflected the belief that hydropower growth in the electric utility sector would edge out nuclear power. EIA's forecast of 1.7 percent also reflected its expectation that the growth in hydropower would make up for its 1988 drop and thereby lessen demand for nuclear power. IPAA's forecasts of both nuclear and hydropower growth were the lowest and explain its forecast of a 3.4-percent gain for residual fuel oil demand, mostly in the power generation area.[35]

[32]EIA, *Annual Energy Outlook*, 1989.
[33]The WEFA Group, *Energy Analysis Quarterly*, Spring 1989.
[34]DRI/McGraw Hill, *Energy Review*, Spring 1989.

[35]IPAA Supply and Demand Committee Report, May 9, 1989.

Table 23. Comparisons of Total Energy Supply and Demand Projections

Projections	1988 Actual[a]	1989 Forecasts IPAA	DRI	WEFA	EIA
Production					
Crude Oil (million barrels per day)	8.1	7.8	7.9	7.9	7.8
NGL (million barrels per day)	1.6	1.6	1.6	1.6	1.6
Natural Gas (trillion cubic feet)	16.7	16.7	16.6	16.5	17.4
Coal (million short tons)	950	NA	956	971	978
Nuclear Power (quadrillion Btu)	5.7	5.8	5.9	5.9	5.8
Hydropower (quadrillion Btu)	2.3	NA	2.7	2.7	2.7
Other (quadrillion Btu)	.24	NA	.30	.26	.24
Net Imports					
Crude Oil (million barrels per day)[b]	4.9	5.7	5.3	5.3	5.4
Petroleum Products (million barrels per day)[b]	1.5	1.5	1.8	1.8	1.6
Natural Gas (trillion cubic feet)	1.2	1.4	1.2	1.2	1.3
Coal (million short tons)	-93	NA	-85	-92	-90
Consumption					
Petroleum Products (million barrels per day)	17.2	17.5	17.3	17.4	17.3
% change from prior year	3.0	1.7	0.9	1.5	0.9
Motor Gasoline	7.3	7.4	7.4	7.4	7.4
% change from prior year	1.4	1.2	0.7	0.7	1.4
Natural Gas (trillion cubic feet)	17.9	18.1	17.7	17.8	18.7
% change from prior year	5.3	0.3	-0.6	-1.4	1.6
Coal (million short tons)	882	888	865	887	884
% change from prior year	5.4	0.7	-1.6	1.2	0.2
Nuclear Power (quadrillion Btu)	5.7	5.8	5.9	5.9	5.8
% change from prior year	15.4	2.8	4.6	3.8	1.7
Hydropower (quadrillion Btu[c]	2.6	3.2	3.1	3.1	3.1
% change from prior year	-17.3	9.4	12.5	17.7	18.5
Other (quadrillion Btu)	.24	NA	.30	.26	.24
% change from prior year	0.0	NA	6.3	10.2	0.0
Electric Utility (quadrillion Btu)	28.6	NA	29.1	29.4	29.1
% change from prior year	4.5	2.5	1.1	2.5	2.1
Gross Energy Consumption (quadrillion Btu)	80.0	81.1	80.3	81.1	81.1
% change from prior year	4.2	1.5	0.6	1.4	1.4
Energy Dependence (percent)[d]	41.	41.	41.	41.	41.

[a]As observed by EIA.
[b] IPPA figures are gross imports for crude oil net imports, less crude oil exports for products.
[c]IPAA figure includes Other energy sources; EIA figure includes net imports of electricity.
[d]Net petroleum imports divided by total petroleum consumption.
NA = Not available.
Sources: DRI/McGraw-Hill, *Energy Review*, Spring 1989; EIA, *Short Term Energy Outlook*, Quarterly Projections, April 1989; IPAA Supply and Demand Committee Report, May 9, 1989; The WEFA Group, *Energy Analysis Quarterly*, Spring 1989.

As for other energy sources, a category that includes solar and geothermal power, WEFA projected surprisingly high demand growth of 10.2 percent. DRI also expected fairly high growth in demand for other alternative energy sources at 6.3 percent, while EIA expected no change at all.

Primary Energy Supply

All forecast services expected the decline in U.S. domestic crude oil production to continue. Their forecasts of production levels were very close at between 7.8 and 7.9 million barrels per day compared to the 8.1 million barrels per day in 1988. The ratio of net imported oil to total oil consumption continued to rise from 37 percent in 1988 to 41 percent in 1989, according to all four forecasters. DRI and WEFA expected the slightly higher domestic production level of 7.9 million barrels per day. Domestic production of NGLs was expected by all to remain constant at 1.6 million barrels per day.

All four forecasters projected net imports of crude oil and petroleum products to increase substantially, ranging from 400,000 to 800,000 barrels per day of crude oil and up to 300,00 barrels per day of products over 1988 levels. IPAA projected the largest increase in crude oil imports at 800,000 barrels per day, in line with its forecasts of lower domestic production and higher demand. (IPAA reports gross crude oil imports only.) DRI and WEFA projected additional crude imports of 400,000 barrels per day, and EIA projected 500,000 barrels per day. DRI and WEFA agreed that product imports would increase to 300,000 barrels per day, while EIA projected a 100,000-barrel-per-day increase. IPAA projected no change from the 1988 level.

Natural gas production was expected by IPAA, DRI, and WEFA to show no gains; only EIA projected an increase of 0.7 trillion cubic feet to 17.4 trillion cubic feet, up from 1988's figure of 16.7 trillion cubic feet. Natural gas net imports are rather flat in line with reduced demand. Forecasts of coal supply levels for 1989 reflect the fact that 85 percent of coal demand is generated by the electric utility sector, whose growth rate is slowing down due to the expected slowing of the economy, the expected return to normal temperatures, and the resurgence of normal hydropower generating capacity. Relatively weak coal demand accounts for projected production of 956 to 978 million short tons compared to 1988 production of 950 million short tons. Coal net exports are expected to be slightly down from 1988 levels.

After reaching a high point in 1988, nuclear power supply was expected to continue to grow at much more modest rates. IPAA and EIA agree on a nuclear power supply of 5.8 quadrillion Btu and DRI and WEFA's projections are only slightly higher at 5.9 quadrillion Btu. Hydropower supply should rebound in 1989 to 2.7 quadrillion Btu, up from 2.3 quadrillion Btu in 1988, according to DRI, WEFA, and EIA.

Summary

Although there are some significant differences on absolute and relative demand by energy source and sector, and on oil prices, EIA, DRI, WEFA, and IPAA were in general agreement on overall economic, and supply and demand trends for 1989. All four forecasting services assumed an economic slowdown in 1989, with accelerating inflation, rising interest rates, and a rising world oil price. Their demand forecasts agree that there will be a considerable slowdown in gross energy consumption growth, and a slowdown in demand for each of the primary energy sources, with the exception of other alternative energy sources (geothermal and solar), where there is some disagreement. Forecast trends of energy supply also show considerable agreement, although they differ substantially on actual import levels. Most significantly, U.S. oil production was projected at record lows, oil import levels at record highs, with U.S. dependence on foreign oil imports continuing to rise.

Appendix A

Forecast Evaluation Tables

Table A1. Retail Distillate Prices, Actual Versus Forecasts
(Cents per Gallon)
(Percent Difference from Actual)

		Forecast Report						Average Absolute Error by Quarter	
Forecast Quarter	Actual	Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Cents/ Gallon	Percent
1Q 88	84	82 -2.5%	--	--	--	--	--	2.1	2.5
2Q 88	81	79 -2.9%	75 -7.9%	--	--	--	--	4.4	5.4
3Q 88	75	80 6.7%	74 -1.3%	73 -2.7%	--	--	--	2.7	3.6
4Q 88	78	84 7.7%	82 5.1%	78 0.0%	75 -3.8%	--	--	3.3	4.2
1Q 89	86	89 3.5%	85 -1.2%	82 -4.7%	79 -8.1%	84 -2.3%	--	3.4	4.0
2Q 89	P87	--	81 -6.9%	80 -8.0%	78 -10.3%	76 -12.6%	84 -3.4%	7.2	8.3
Average Absolute Error by Report									
Cents/Gallon		3.7	3.7	3.3	6.3	6.5	3.0	4.2	
Percent		4.6	4.5	4.0	7.6	7.5	3.4		5.1

-- = Not applicable.
P = Preliminary.

Note: Distillate prices is defined as the retail price of No. 2 heating oil.

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A2. Residual Fuel Oil Prices, Actual Versus Forecasts
(Dollars per Barrel)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Dollars/Barrel	Percent
1Q 88	14.76	16.20	--	--	--	--	--	1.44	9.8
		9.8%							
2Q 88	13.94	16.60	14.70	--	--	--	--	1.71	12.3
		19.1%	5.5%						
3Q 88	13.67	17.70	15.30	13.90	--	--	--	1.96	14.4
		29.5%	11.9%	1.7%					
4Q 88	13.68	18.30	17.00	16.24	13.31	--	--	2.72	19.9
		33.8%	24.3%	18.7%	-2.7%				
1Q 89	16.04	18.90	18.00	17.15	14.92	15.85	--	1.45	9.0
		17.8%	12.2%	6.9%	-7.0%	-1.2%			
2Q 89	P17.35	--	17.10	15.86	14.05	13.36	16.04	2.07	11.9
			-1.4%	-8.6%	-19.0%	-23.0%	-7.6%		
Average Absolute Error by Report									
Dollars/Barrel		3.12	1.58	1.35	1.60	2.09	1.31	1.96	
Percent		21.7	10.6	8.9	10.2	12.5	7.6		13.1

-- = Not applicable.
P = Preliminary.
Note: Prices are refiner retail sales, average of all sulfur contents.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A3. Residential Electricity Prices, Actual Versus Forecasts
(Cents per Kilowatthour)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Cents/kWh	Percent
1Q 88	7.00	7.25 3.6%	--	--	--	--	--	0.25	3.6
2Q 88	7.59	7.72 1.7%	7.51 -1.1%	--	--	--	--	0.10	1.4
3Q 88	7.91	8.09 2.3%	7.88 -0.4%	7.87 -0.5%	--	--	--	0.08	1.1
4Q 88	7.47	7.73 3.5%	7.49 0.3%	7.49 0.3%	7.46 -0.1%	--	--	0.08	1.0
1Q 89	7.19	7.43 3.3%	7.18 -0.1%	7.22 0.4%	7.18 -0.1%	6.86 -4.6%	--	0.12	1.7
2Q 89	P7.71	--	7.71 0.0%	7.70 -0.1%	7.79 1.0%	7.38 -4.3%	7.63 -1.0%	0.10	1.3
Average Absolute Error by Report									
Cents/kWh		0.21	0.03	0.02	0.03	0.33	0.08	0.11	
Percent		2.9	0.4	0.3	0.4	4.4	1.0		1.4

-- = Not applicable.
P = Preliminary.
kWh = Kilowatthour

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A4. Residential Natural Gas Prices, Actual Versus Forecasts
(Dollars per Mcf)
(Percent Difference from Actual)

		Forecast Report						Average Absolute Error by Quarter	
Forecast Quarter	Actual	Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Dollars/ Mcf	Percent
1Q 88	5.13	5.46 6.4%	--	--	--	--	--	0.33	6.4
2Q 88	5.71	5.98 4.7%	5.97 4.6%	--	--	--	--	0.27	4.6
3Q 88	6.72	6.90 2.7%	6.90 2.7%	6.65 -1.0%	--	--	--	0.14	2.1
4Q 88	5.50	5.32 -3.3%	5.48 -0.4%	5.42 -1.5%	5.56 1.1%	--	--	0.08	1.5
1Q 89	5.42	5.57 2.8%	5.60 3.3%	5.37 -0.9%	5.35 -1.3%	5.42 0.0%	--	0.09	1.7
2Q 89	P5.84	--	6.27 7.4%	6.02 3.1%	5.90 1.0%	6.00 2.7%	5.85 0.2%	0.17	2.9
Average Absolute Error by Report									
Dollars/Mcf		0.22	0.21	0.09	0.06	0.08	0.01	0.15	
Percent		3.9	3.7	1.6	1.1	1.4	0.2		2.5

-- = Not applicable.
P = Preliminary.
Tcf = Thousand Cubic Feet.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A5. Real Disposable Personal Income, Actual Versus Forecasts
(Billion 1982 Dollars)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Billion 1982 $	Percent
1Q 88	2762	2717 -1.6%	--	--	--	--	--	45	1.6
2Q 88	2762	2718 -1.6%	2738 -0.9%	--	--	--	--	34	1.2
3Q 88	2800	2730 -2.5%	2745 -2.0%	2753 -1.7%	--	--	--	57	2.0
4Q 88	2828	2739 -3.1%	2758 -2.5%	2762 -2.3%	2818 -0.4%	--	--	59	2.1
1Q 89	2882	2755 -4.4%	2777 -3.6%	2784 -3.4%	2856 -0.9%	2852 -1.0%	--	77	2.7
2Q 89	E2872	--	2783 -3.1%	2790 -2.9%	2856 -0.6%	2854 -0.6%	2871 -0.0%	41	1.4
Average Absolute Error by Report									
Billion 1982 $		75	69	73	17	24	1	56	
Percent		2.7	2.4	2.6	0.6	0.8	0.0		2.0

-- = Not applicable.
E = Estimated.
Sources: History from: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, various issues. Forecasts from: Data Resources, Inc., Quarterly Model of U.S. Economy, CONTROL forecasts, adjusted for EIA oil price forecasts for: January 1988, April 1988, July 1988, October 1988, January 1989, and April 1989.

Table A6. Index of Industrial Production, Actual Versus Forecasts
(1977: 100.0)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter: Percent
1Q 88	139.6	136.1 -2.5%	--	--	--	--	--	2.5
2Q 88	141.6	136.5 -3.6%	137.6 -2.8%	--	--	--	--	3.2
3Q 88	144.0	137.8 -4.3%	138.7 -3.7%	142.0 -1.4%	--	--	--	3.1
4Q 88	145.8	139.2 -4.5%	140.8 -3.4%	143.2 -1.8%	145.5 -0.2%	--	--	2.5
1Q 89	146.9	140.6 -4.3%	143.0 -2.7%	144.6 -1.6%	147.2 0.2%	146.3 -0.4%	--	1.8
2Q 89	P147.5	--	145.5 -1.4%	145.6 -1.3%	148.3 0.5%	146.8 -0.5%	147.4 0.1%	0.7
Average Absolute Error by Report Percent		3.9	2.8	1.5	0.3	0.4	0.1	2.1

-- = Not applicable.
P = Preliminary.
Sources: History from: Federal Reserve System, *Statistical Release G.12.3*, various issues. Forecasts from: Data Resources, Inc., Quarterly Model of U.S. Economy, CONTROL forecasts, adjusted for EIA oil price forecasts for: January 1988, April 1988, July 1988, October 1988, January 1989, and April 1989.

Table A7. Total Petroleum Product Supplied, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter: MMB/ Day	Percent
1Q 88	17.59	17.05	--	--	--	--	--	0.54	3.1
		-3.1%							
2Q 88	16.60	16.29	16.53	--	--	--	--	0.19	1.1
		-1.9%	-0.4%						
3Q 88	17.08	16.38	16.59	16.77	--	--	--	0.50	2.9
		-4.1%	-2.9%	-1.8%					
4Q 88	17.86	16.92	17.10	17.31	17.26	--	--	0.71	4.0
		-5.3%	-4.3%	-3.1%	-3.4%				
1Q 89	17.61	17.02	17.12	17.40	17.46	17.78	--	0.32	1.8
		-3.4%	-2.8%	-1.2%	-0.9%	1.0%			
2Q 89	P16.73	--	16.64	16.85	16.96	17.04	16.95	0.19	1.2
			-0.5%	0.7%	1.4%	1.9%	1.3%		
Average Absolute Error by Report									
MMB per day		0.62	0.38	0.30	0.33	0.24	0.22	0.39	
Percent		3.6	2.2	1.7	1.9	1.4	1.3		2.3

-- = Not applicable.
P = Prelimary.
Note:
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A8. Distillate Fuel Oil Product Supplied, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter MMB/Day	Percent
1Q 88	3.55	3.46	--	--	--	--	--	0.09	2.5
		-2.5%							
2Q 88	2.84	2.82	2.85	--	--	--	--	0.02	0.5
		-0.7%	0.4%						
3Q 88	2.78	2.65	2.70	2.79	--	--	--	0.07	2.6
		-4.7%	-2.9%	0.4%					
4Q 88	3.32	3.17	3.16	3.25	3.26	--	--	0.11	3.3
		-4.5%	-4.8%	-2.1%	-1.8%				
1Q 89	3.38	3.49	3.41	3.51	3.53	3.55	--	0.12	3.5
		3.3%	0.9%	3.8%	4.4%	5.0%			
2Q 89	P2.88	--	2.89	3.00	3.04	3.05	3.05	0.13	4.4
			0.3%	4.2%	5.6%	5.9%	5.9%		
Average Absolute Error by Report									
MMB per day		0.10	0.06	0.08	0.12	0.17	0.17	0.10	
Percent		3.2	1.9	2.7	3.9	5.4	5.9		3.2

-- = Not applicable.
P = Preliminary
MMB = Million Barrels.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A9. Residual Fuel Oil Product Supplied, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter MMB/ Day	Percent
1Q 88	1.61	1.57 -2.5%	--	--	--	--	--	0.04	2.5
2Q 88	1.11	1.12 0.9%	1.16 4.5%	--	--	--	--	0.03	2.7
3Q 88	1.26	1.04 -17.5%	1.10 -12.7%	1.13 -10.3%	--	--	--	0.17	13.5
4Q 88	1.53	1.11 -27.5%	1.14 -25.5%	1.17 -23.5%	1.20 -21.6%	--	--	0.38	24.5
1Q 89	1.60	1.42 -11.3%	1.44 -10.0%	1.35 -15.6%	1.41 -11.9%	1.66 3.7%	--	0.17	10.5
2Q 89	P1.26	--	1.12 -11.1%	1.17 -7.1%	1.17 -7.1%	1.16 -7.9%	1.12 -11.1%	0.11	8.9
Average Absolute Error by Report									
MMB per day		0.17	0.18	0.21	0.20	0.08	0.14	0.18	
Percent		12.2	13.3	14.7	13.9	5.6	11.1		12.2

-- = Not applicable.
P = Preliminary
MMB = Million Barrels.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A10. Other Petroleum Products Supplied, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter: MMB/Day	Percent
1Q 88	5.36	5.12 -4.5%	--	--	--	--	--	0.24	4.5
2Q 88	5.10	4.91 -3.7%	5.02 -1.6%	--	--	--	--	0.13	2.6
3Q 88	5.54	5.42 -2.2%	5.34 -3.6%	5.35 -3.4%	--	--	--	0.17	3.1
4Q 88	5.63	5.19 -7.8%	5.46 -3.0%	5.57 -1.1%	5.45 -3.2%	--	--	0.21	3.8
1Q 89	5.52	5.05 -8.5%	5.29 -4.2%	5.51 -0.2%	5.43 -1.6%	5.50 -0.4%	--	0.16	3.0
2Q 89	P5.17	--	5.11 -1.2%	5.09 -1.5%	5.21 0.8%	5.21 0.8%	5.23 1.2%	0.06	1.1
Average Absolute Error by Report									
MMB per day		0.29	0.15	0.08	0.10	0.03	0.06	0.15	
Percent		5.4	2.7	1.6	1.9	0.6	1.2		2.7

-- = Not applicable.

P = Preliminary

MMB = Million Barrels.

Note: Other is defined as all petroleum products supplied except distillate fuel, motor gasoline, and residual fuel oil.

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A11. Total Coal Consumption, Actual Versus Forecasts
(Million Short Tons)
(Percent Difference from Actual)

		Forecast Report						Average Absolute Error by Quarter	
Forecast Quarter	Actual	Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Million Tons	Percent
1Q 88	223	209 -6.3%	--	--	--	--	--	14	6.3
2Q 88	205	198 -3.4%	198 -3.4%	--	--	--	--	7	3.4
3Q 88	238	222 -6.7%	221 -7.1%	226 -5.0%	--	--	--	15	6.3
4Q 88	216	207 -4.2%	208 -3.7%	213 -1.4%	214 -0.9%	--	--	6	2.5
1Q 89	P230	210 -8.7%	210 -8.7%	220 -4.3%	222 -3.5%	225 -2.2%	--	13	5.5
2Q 89	E212	--	202 -4.7%	208 -1.9%	211 -0.5%	210 -0.9%	208 -1.9%	4	2.0
Average Absolute Error by Report									
Million Tons		13	12	7	4	4	4	9	
Percent		5.9	5.6	3.2	1.7	1.6	1.9		4.0

-- = Not applicable.
P = Preliminary.
E = Estimated.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A12. Electricity Generation from Coal, Actual Versus Forecasts
(Billion Kilowatthours)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Billion kWh	Percent
1Q 88	383.6	366.3	--	--	--	--	--	17.3	4.5
		-4.5%							
2Q 88	356.0	343.1	347.9	--	--	--	--	10.5	2.9
		-3.6%	-2.3%						
3Q 88	420.5	389.4	388.7	400.6	--	--	--	27.6	6.6
		-7.4%	-7.6%	-4.7%					
4Q 88	378.2	357.3	356.3	368.7	368.7	--	--	15.4	4.1
		-5.5%	-5.8%	-2.5%	-2.5%				
1Q 89	388.4	363.2	369.3	383.6	386.6	390.7	--	10.6	2.7
		-6.5%	-4.9%	-1.2%	-0.5%	0.6%			
2Q 89	P371.8	--	353.2	363.5	369.2	366.1	362.8	8.8	2.4
			-5.0%	-2.2%	-0.7%	-1.5%	-2.4%		
Average Absolute Error by Report									
Billion kWh		21.5	19.9	10.6	4.6	4.0	9.0	14.0	
Percent		5.6	5.2	2.7	1.2	1.1	2.4		3.6

-- = Not applicable.
P = Preliminary
kWh = Kilowatthours.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A13. Electricity Generation from Nuclear Power, Actual Versus Forecasts
(Billion Kilowatthours)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter: Billion kWh	Percent
1Q 88	130.8	125.7 -3.9%	--	--	--	--	--	5.1	3.9
2Q 88	124.8	115.1 -7.8%	116.9 -6.3%	--	--	--	--	8.8	7.1
3Q 88	145.1	127.4 -12.2%	129.5 -10.8%	132.6 -8.6%	--	--	--	15.3	10.5
4Q 88	126.2	120.4 -4.6%	121.3 -3.9%	124.4 -1.4%	125.1 -0.9%	--	--	3.4	2.7
1Q 89	124.7	129.3 3.7%	129.9 4.2%	132.9 6.6%	132.1 5.9%	132.4 6.2%	--	6.6	5.3
2Q 89	P118.8	--	120.3 1.3%	123.0 3.5%	122.9 3.5%	124.8 5.1%	132.1 11.2%	5.8	4.9
Average Absolute Error by Report									
Billion kWh		8.6	7.0	6.7	4.2	6.9	13.3	7.2	
Percent		6.6	5.5	5.2	3.4	5.6	11.2		5.6

-- = Not applicable.
P = Preliminary
kWh = Kilowatthours.

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A14. Electricity Generation from Hydroelectric Power, Actual Versus Forecasts

(Billion Kilowatthours)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report: Jan. 1988	Forecast Report: Apr. 1988	Forecast Report: Jul. 1988	Forecast Report: Oct. 1988	Forecast Report: Jan. 1989	Forecast Report: Apr. 1989	Average Absolute Error by Quarter: Billion kWh	Average Absolute Error by Quarter: Percent
1Q 88	60.7	70.6	--	--	--	--	--	9.9	16.3
		16.3%							
2Q 88	59.2	73.5	66.1	--	--	--	--	10.6	17.9
		24.2%	11.7%						
3Q 88	49.6	62.5	61.5	51.9	--	--	--	9.0	18.2
		26.0%	24.0%	4.6%					
4Q 88	53.5	65.7	66.1	60.2	58.1	--	--	9.0	16.9
		22.8%	23.6%	12.5%	8.6%				
1Q 89	61.2	79.3	79.3	74.4	67.4	65.6	--	12.0	19.6
		29.6%	29.6%	21.6%	10.1%	7.2%			
2Q 89	P76.7	--	81.0	78.8	74.5	72.9	71.6	3.5	4.6
			5.6%	2.7%	-2.9%	-5.0%	-6.6%		
Average Absolute Error by Report									
Billion kWh		13.5	10.8	6.1	4.3	4.1	5.1	8.6	
Percent		23.7	17.9	10.1	6.8	5.9	6.6		14.8

-- = Not applicable.

P = Preliminary

kWh = Kilowatthours.

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A15. Domestic Crude Oil Production, Actual Versus Forecasts
(Million Barrels per Day)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter MMB/ Day	Percent
1Q 88	8.33	8.31	--	--	--	--	--	0.02	0.2
		-0.2%							
2Q 88	8.23	8.20	8.20	--	--	--	--	0.03	0.4
		-0.4%	-0.4%						
3Q 88	8.01	8.13	8.11	8.20	--	--	--	0.14	1.7
		1.5%	1.2%	2.4%					
4Q 88	8.00	8.09	8.10	8.18	8.06	--	--	0.11	1.3
		1.1%	1.2%	2.2%	0.8%				
1Q 89	7.78	8.07	8.10	8.12	8.04	7.99	--	0.28	3.7
		3.7%	4.1%	4.4%	3.3%	2.7%			
2Q 89	P7.77	--	8.05	8.04	7.94	7.86	7.84	0.18	2.3
			3.6%	3.5%	2.2%	1.2%	0.9%		
Average Absolute Error by Report									
MMB per day		0.11	0.17	0.24	0.16	0.15	0.07	0.16	
Percent		1.4	2.1	3.1	2.1	1.9	0.9		2.1

-- = Not applicable.
P = Preliminary
MMB = Million Barrels.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A16. Natural Gas Production, Actual Versus Forecasts
(Trillion Cubic Feet)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Tcf	Percent
1Q 88	4.40	4.28	--	--	--	--	--	0.12	2.7
		-2.7%							
2Q 88	4.03	4.14	3.96	--	--	--	--	0.09	2.2
		2.7%	-1.7%						
3Q 88	3.91	3.70	3.91	4.01	--	--	--	0.10	2.6
		-5.4%	0.0%	2.6%					
4Q 88	4.30	4.01	4.26	4.47	4.32	--	--	0.13	3.0
		-6.7%	-0.9%	4.0%	0.5%				
1Q 89	4.34	4.45	4.36	4.50	4.37	4.40	--	0.08	1.8
		2.5%	0.5%	3.7%	0.7%	1.4%			
2Q 89	P4.11	--	4.12	4.20	4.03	4.20	4.20	0.07	1.8
			0.2%	2.2%	-1.9%	2.2%	2.2%		
Average Absolute Error by Report									
Tcf		0.17	0.03	0.13	0.04	0.08	0.09	0.09	
Percent		4.0	0.7	3.1	1.0	1.8	2.2		2.2

-- = Not applicable.
P = Preliminary.
Tcf = Trillion Cubic feet.
Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

Table A17. Coal Production, Actual Versus Forecasts
(Million Short Tons)
(Percent Difference from Actual)

Forecast Quarter	Actual	Forecast Report Jan. 1988	Apr. 1988	Jul. 1988	Oct. 1988	Jan. 1989	Apr. 1989	Average Absolute Error by Quarter Million Tons	Percent
1Q 88	237	220	--	--	--	--	--	17	7.2
		-7.2%							
2Q 88	227	225	224	--	--	--	--	3	1.1
		-0.9%	-1.3%						
3Q 88	241	230	223	226	--	--	--	15	6.1
		-4.6%	-7.5%	-6.2%					
4Q 88	245	239	234	238	231	--	--	10	3.9
		-2.4%	-4.5%	-2.9%	-5.7%				
1Q 89	P246	231	229	234	229	242	--	14	5.7
		-6.5%	-7.3%	-5.3%	-7.3%	-2.0%			
2Q 89	E243	--	235	239	237	249	249	6	2.5
			-3.3%	-1.6%	-2.5%	2.5%	2.5%		
Average Absolute Error by Report									
Million Tons		10	12	10	13	6	6	10	
Percent		4.3	4.8	4.0	5.2	2.2	2.5		4.2

-- = Not applicable.
P = Preliminary.
E = Estimated.

Sources: Actual data are based on published numbers from the Energy Information Administration (EIA), *Monthly Energy Review,* DOE/EIA-0035 (Washington, DC), various issues. Forecasts are taken from the base case scenarios from various issues of the EIA *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC).

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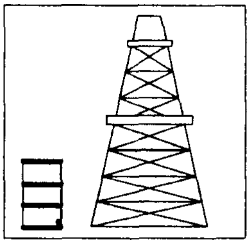

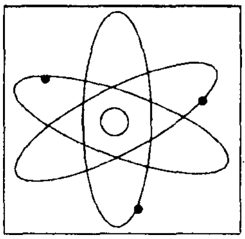

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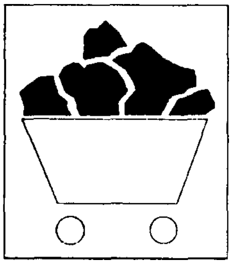

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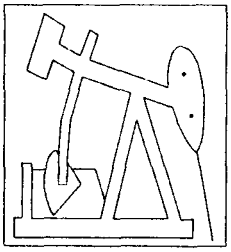

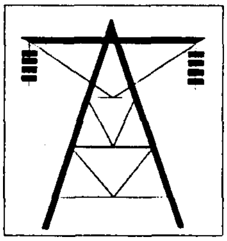

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