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Natural Gas Productive Capacity for the Lower 48 States 1980 through 1996

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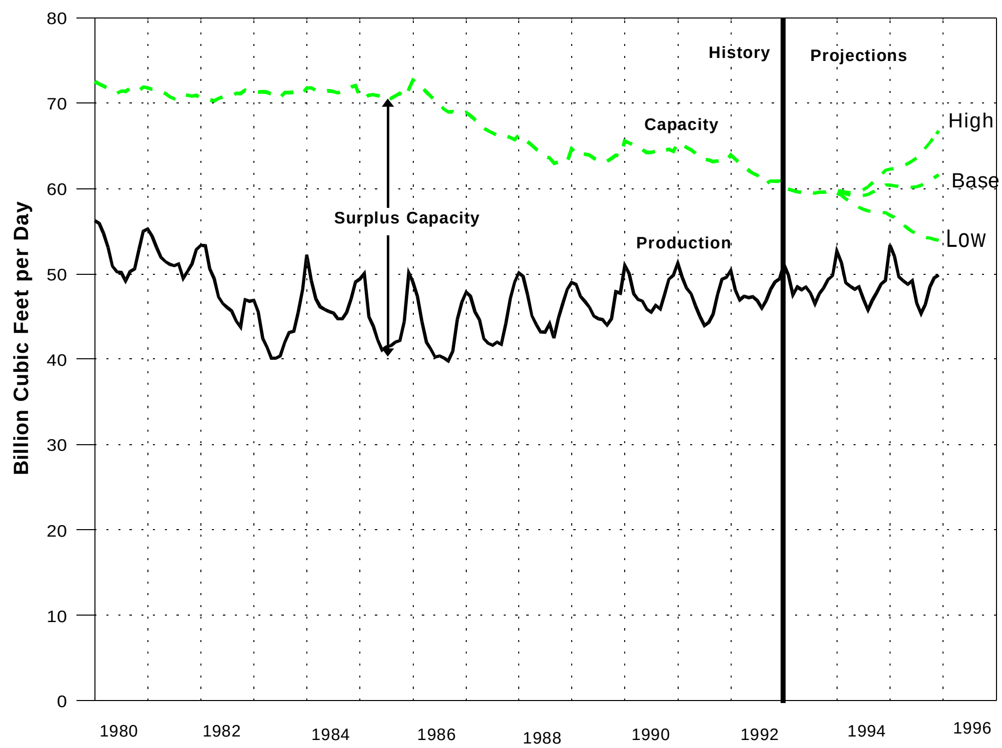
Executive Summary

The purpose of this report is to analyze monthly natural gas wellhead productive capacity in the lower 48 States from 1980 through 1992 and project this capacity from 1993 through 1995.

For decades, natural gas supplies and productive capacity have been adequate to meet demand. In the 1970's the capacity surplus was small because of market structure (split between interstate and intrastate), increasing demand, and insufficient drilling. In the early 1980's, lower demand, together with increased drilling, led to a large surplus capacity as new productive capacity came on line. After 1986, this large surplus began to decline as demand for gas increased, gas prices fell, and gas well completions dropped sharply. In late December 1989, the decline in this surplus, accompanied by exceptionally high demand and temporary weather-related production losses, led to concerns about the adequacy of monthly productive capacity for natural gas. These concerns should have been moderated by the gas system's performance during the unusually severe winter weather in March 1993 and January 1994.

The declining trend in wellhead productive capacity is expected to be reversed in 1994 if natural gas prices and drilling meet or exceed the base case assumption. This study indicates that in the low, base, and high drilling cases, monthly productive capacity should be able to meet normal production demands through 1995 in the lower 48 States (Figure ES1). Exceptionally high peak-day or peak-week production demand might not be met because of physical limitations such as pipeline capacity. Beyond 1995, as the capacity of currently producing wells declines, a sufficient number of wells and/or imports must be added each year in order to ensure an adequate gas supply.

Figure ES1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.

The major conclusions of this study are:

- Monthly wellhead productive capacity of dry gas will be adequate during the 1993-1995 period.
- In 1994 and 1995, monthly wellhead productive capacity will increase in the base and high drilling cases.
- The two largest gas producing areas (Gulf of Mexico Outer Continental Shelf and Texas) are expected to meet their historical market share of U.S. production.
- The level of successful drilling activity (brought about by assumed price levels) and gas demand are the two major factors that determine the adequacy of natural gas productive capacity for the lower 48 States.

This report deals with the capacity for gas production from both gas wells and oil wells in the lower 48 States. In December 1992, an average of 49.4 billion cubic feet of dry natural gas was produced per day in the lower 48 States from a wellhead productive capacity of 60.9 billion cubic feet. The capacity utilization (gas production divided by productive capacity) was 81 percent (Table ES1). In December 1995, capacity utilization in the base case is estimated to be 81 percent. In the high and low cases, capacity utilization is expected to be 75 percent and 93 percent, respectively. All of the surplus capacity is attributed to gas-well gas because oil-well gas is a function of oil production and oil production is essentially at capacity.

The different drilling levels assumed in the three cases are functions of oil and gas prices and gas demand as shown in the first quarter 1994 *Short-Term Energy Outlook*. The estimated gas prices for 1995 for the low, base, and high cases are $1.87, $2.20, and $2.55, respectively, compared with actual prices of $1.74 per thousand cubic feet in 1992 and $1.99 in 1993.

The existence of a surplus productive capacity at the wellhead does not mean that this entire gas capacity could actually be produced and delivered. The ability of a well to deliver gas into a pipeline system (deliverability) is always equal to or less than wellhead productive capacity. Deliverability is that volume of gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions, taking into account restrictions imposed by pipeline capacity, gas plant capacity, contracts, or regulatory bodies.

At the end of 1992, dry gas pipeline system deliverability for the lower 48 States was estimated to be 54.0 billion cubic feet per day, which was only 89 percent of the dry gas productive capacity at the wellhead. However, there is substantial uncertainty in this deliverability estimate. If the surplus in wellhead productive capacity declines, more reliance will be placed on withdrawal from storage to meet peak gas demand. Gas storage requirements can be met by maintaining gas production closer to gas productive capacity throughout the year. This will lead to smaller seasonal variations in gas production.

Table ES1. Lower 48 States Dry Gas Production and Wellhead Productive Capacity, December 1980, 1992, and 1995

Year/Case	Production (billion cubic feet per day)	Capacity (billion cubic feet per day)	Productive Total Surplus (billion cubic feet per day)	Capacity Utilization (percent)
1980	55.0	71.9	16.9	76.5
1992	49.4	60.9	11.5	81.2
Projections				
1995/Low Case	49.9	54.0	4.1	92.5
1995/Base Case	49.9	61.6	11.7	81.0
1995/High Case	49.9	66.8	16.9	74.7

Sources: •History: Energy Information Administration, Office of Oil and Gas Dwight's Energydata, Inc. •Projections: Model GASCAP93 C060194.

1. Introduction

Natural gas demand in the lower 48 States has been increasing during the last few years while drilling has remained at low levels. This has raised concerns about the adequacy of future gas supplies, especially in periods of peak demand.

The purpose of this report is to address these concerns by preparing a historical analysis of the monthly productive capacity of natural gas at the wellhead for 1984 through 1996 and estimating productive capacity for 1994, 1995, and 1996. The impact of drilling, oil and gas price assumptions, and demand on gas productive capacity are integrated into the capacity projections as low, base, and high cases. Gas-well gas and oil-well gas and coalbed gas in New Mexico, Colorado, Wyoming and Alabama are included.

This is the fourth report of a series. The three previous reports were published in 1991, 1993, and 1994.{1,2,3} This report should be of particular interest to those in the Congress, Federal and State agencies, industry, and the academic community, who are concerned with the future availability of natural gas.

The Energy Information Administration's (EIA) Dallas Field Office has prepared five other reports on gas productive capacity over the past several years. These reports dealt with selected large gas fields in some of the major gas producing areas.{4,5,6,7} The data in the reports were based on gas-well back-pressure tests and estimates of gas in-place for each field or reservoir. Most of the well testing theory used in these reports has been known since 1936 when the Bureau of Mines published Monograph 7.{9}

In the study described in this report, production data by well for a large number of the gas producing States and the Gulf of Mexico Outer Continental Shelf (OCS) were obtained from Dwight's Energydata, Inc. (Dwight's) and were categorized by vintage (the year a well first produced). That is, all gas production from wells that began production in a given year were grouped together. This approach was selected and applied to 14 States and the Gulf of Mexico OCS, which account for **96** percent of the dry gas production in the lower 48 States. A different technique was used for the remaining 18 gas producing States as production data by well were not available. These States were placed in a separate group that used monthly state-wide production data from EIA's *Natural Gas Monthly* reports and well completions from API drilling statistics. The method used to estimate natural gas productive capacity is outlined in the following paragraphs. The details of the methodology are found in **Chapter 4**.

Estimates of gas-well productive capacity were obtained using monthly gas-well production data. A monthly peak-rate was selected each year for every vintage in each State or area. Vintage-level peak-rates were summed to obtain the total peak-rates for each State or area. The resulting rates were assumed to be the historical productive capacities. These rates were then used in the *Wellhead Productive Capacity Model* (Appendix C) to estimate low, base and high case productive capacities for 1994, 1995, and 1996.

Gas production from oil wells is assumed to be at capacity because oil production is assumed to be at capacity.

The projected domestic gas production was prorated by State and area on the basis of its historical market share. If gas-well gas demand was less than gas-well gas productive capacity in a given State, the demand was set equal to production and scheduled to be produced. If gas-well gas demand was greater than gas-well gas productive capacity in a given State, production was set equal to productive capacity, and the excess demand was prorated to other States or areas that had surplus productive capacity.

Total productive capacity is the summation of conventional gas-well, coalbed gas-well, and oil-well gas productive capacities. A positive difference between productive capacity and demand is surplus gas productive capacity. Productive capacity at the wellhead is defined as the maximum production rate that can be sustained for a specific month. It changes over time and is a function of gas production and drilling.

Assumptions are summarized as follows:

Wellhead gas productive capacity is a function of drilling, which adds new capacity, and production that lowers existing capacity.

The number of new gas-well completions is a function of drilling.

Abandonment of individual conventional and coalbed gas-well completions is captured by the function for the group of wells included in a given vintage year for each area.

Producing characteristics of new conventional gas and coalbed completions can be modeled from the characteristics of historical completions.

Oil-well completions are currently producing at full capacity; therefore, oil-well gas production and oil-well gas capacity are equal.

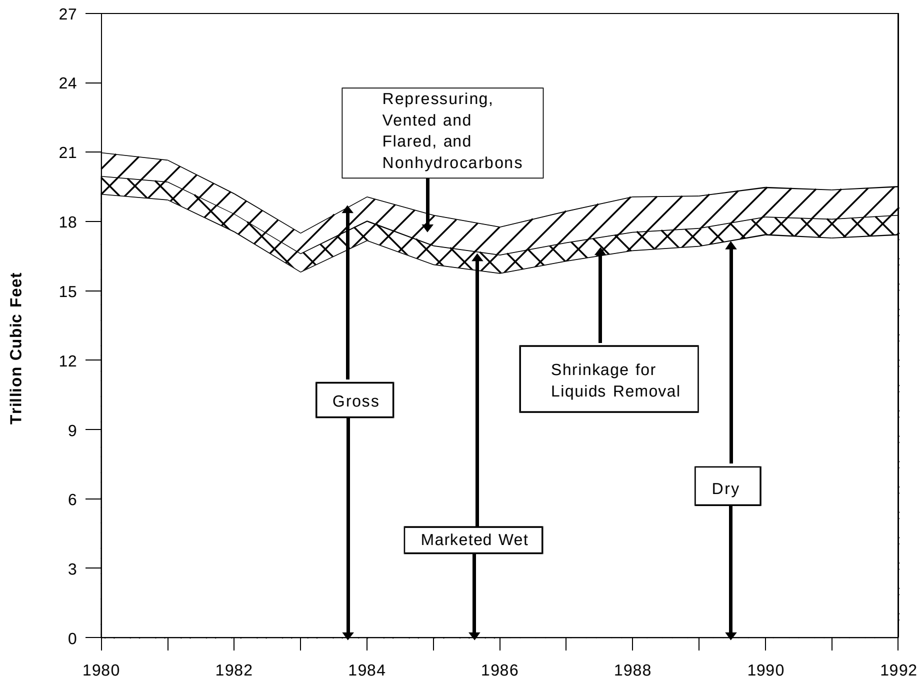
U.S. gas demand can be allocated to the lower-48 producing areas by month based on the 1993 production market share.

2. Gas Productive Capacity

The results of this report are stated in terms of dry natural gas. This is the type of gas generally transported by transmission systems and delivered to consumers. However, the fundamental data for gas production at the wellhead are in terms of gross gas.

Gross gas production becomes marketed wet production after the removal of gas used in field repressuring operations, nonhydrocarbon gases, and the small quantity of gas that is vented or flared. Marketed wet gas production is further reduced to become dry gas production when natural gas liquids are removed at natural gas processing plants. In 1992, dry gas production represented 89 percent of gross gas production for the lower 48 States (Figure 1).

Figure 1. Lower 48 States Natural Gas Production, 1980-1992

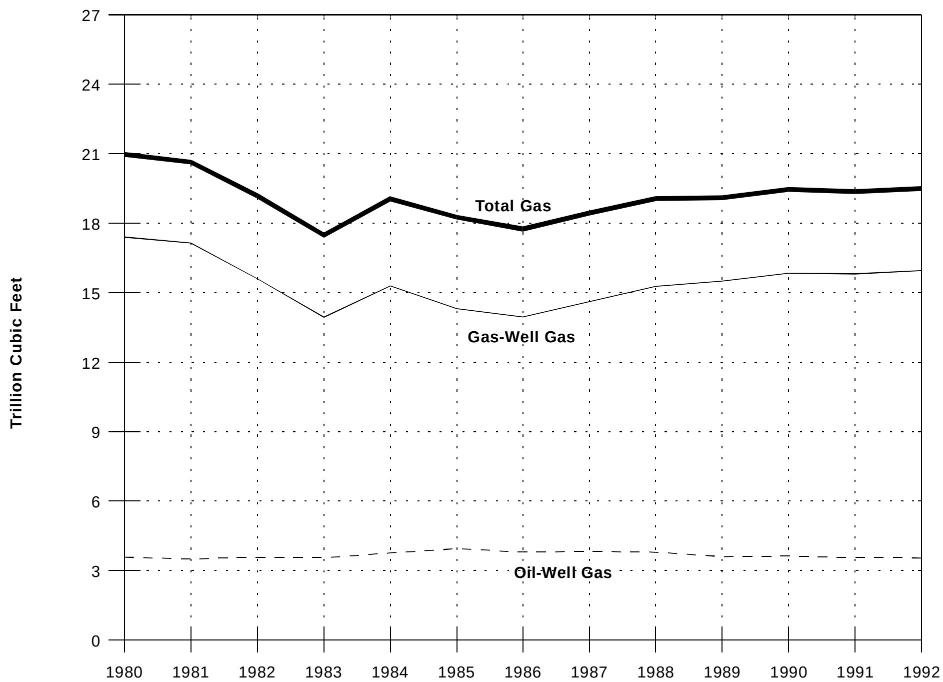


Source: Energy Information Administration, *Nautral Gas Annual,* DOE/EIA-0131, 1980-1992.

The total gross gas production from 1980 through 1992 came from both gas wells and oil wells (Figure 2). Gas production from oil wells was stable over this time period as increases in gas-oil ratios roughly compensated for the declines in oil production. In 1992, gas production from oil wells was 18 percent of total production in the lower 48 States. If oil production declines in 1993, 1994, and 1995 as expected, gas production from oil wells will also decline if the gas-oil ratio stays at its 1992 level, as assumed in this study. As total demand for gas steadily increased after 1986, the portion of the total gross production from gas wells increased from 79 percent in 1986 to 82 percent in 1992 (Figure 2).

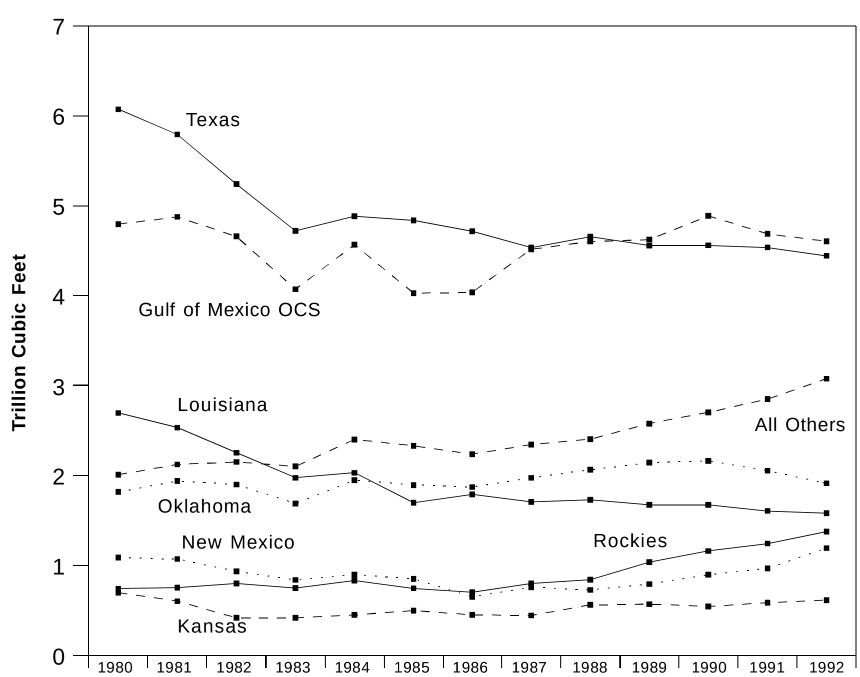
The dry natural gas production contribution from major gas producing States and areas is shown by Figure 3. The two largest gas producing areas are the Gulf of Mexico OCS and Texas. Together these areas produce over one-half of the dry gas in the lower 48 States. The Gulf of Mexico, in particular has made the largest

Figure 2. Lower 48 States Gross Natural Gas Production by Type, 1980-1992



Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1980-1992.

Figure 3. Dry Natural Gas Production from Lower 48 Producing States, 1980-1992



Note: State production for Texas and Louisiana does not include Gulf of Mexico OCS production.

Sources: •Energy Information Administration, Natural Gas Annual, DOE/EIA-0131, 1990-1992. •Production for Texas, Louisiana, and Gulf of Mexico OCS-Energy Information Administration, Office of Oil and Gas.

contribution to meeting major seasonal swings in demand. Other significant producing States include Oklahoma, Louisiana, New Mexico, and Kansas.

The market share of production among States has been fairly stable for the period from 1980 through 1992. The 1992 historical production patterns were generally used to allocate the projected gas demand for 1993, 1994, and 1995 among States and areas.

In preparing this report, dry gas productive capacity was determined for 10 areas (Figure 4). The United States quarterly gas production forecast in the first-quarter 1994 *Short-Term Energy Outlook* was used to determine the lower 48 States' production. This production was prorated into 10 areas on the basis of their historical market shares. The quarterly production was further prorated into monthly data. If a given area could not meet its historical market share of production demand, the unmet production demand was prorated to areas with surplus productive capacity. It was assumed that the pipeline facilities exist to transport this additional production from another supply area to its end market.

Dry Gas Productive Capacity

Dry gas productive capacity substantially exceeded production throughout the 1980's (Figure 5). There was still an adequate although diminishing dry gas productive capacity through 1993. The surplus dry productive capacity (the positive difference between the dry gas productive capacity and dry gas production) was generally over 20 billion cubic feet per day from 1983 through 1986 as gas-well drilling remained strong into 1986 while gas demand was dropping. Gas capacity began declining in 1986 as drilling rapidly declined.

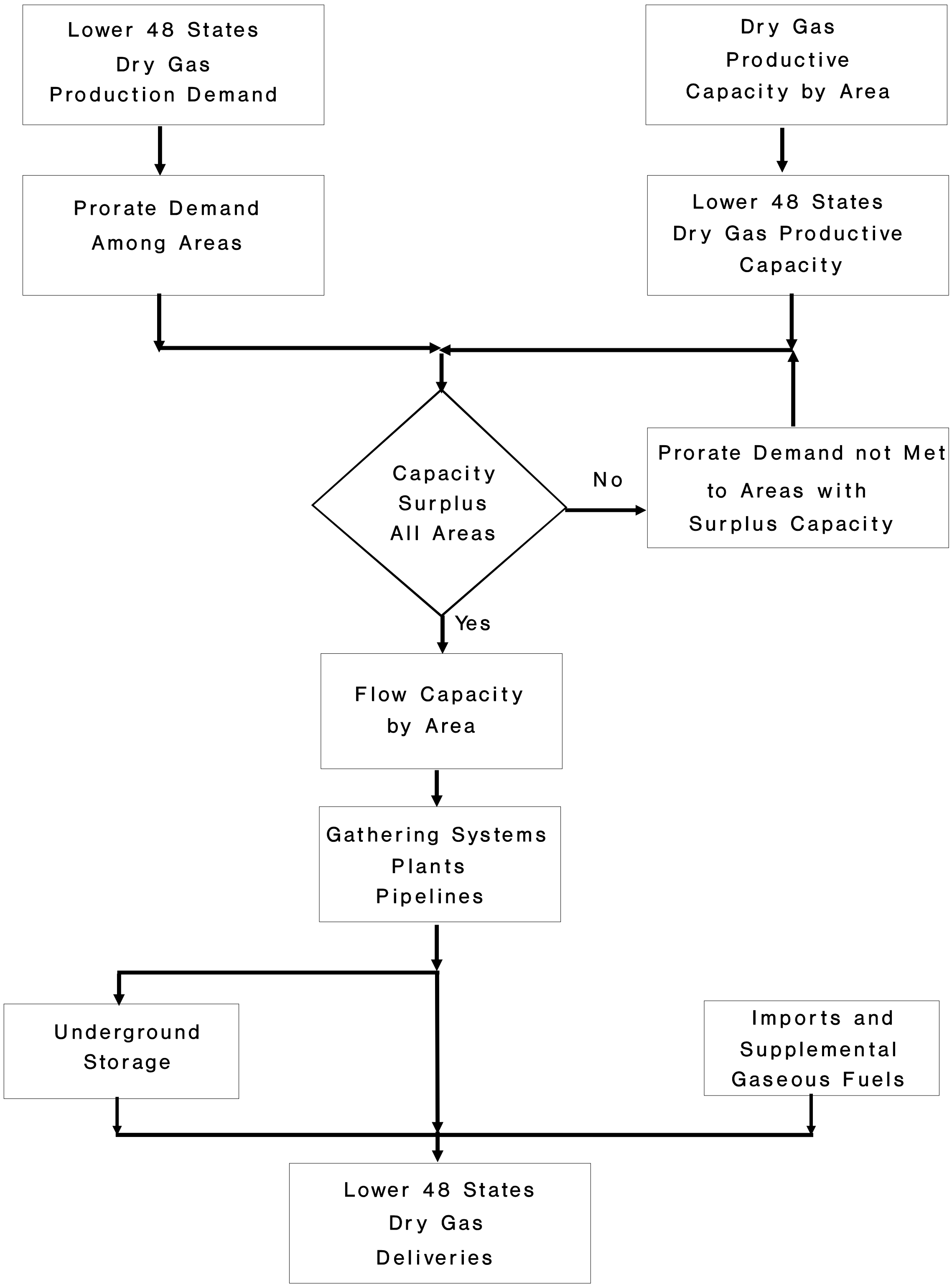
Monthly production varies seasonally (Figure 5). Normally, production is highest in the months of January or February, substantially lower in June, and relatively higher in December. For example, in 1986 dry gas production was 22.0 percent higher in January than in June (Table 1). However, the minimum monthly production rate for a given year may fall in other months such as September when there is neither a large cooling nor heating demand.

Gas well completions remained relatively high through December 1985 (Figure 6), helping to sustain a relatively high gas productive capacity. At the same time dry gas production, limited by demand, was generally dropping, and led to increased surplus gas productive capacity. Dry gas production was 40.1 billion cubic feet per day in June 1983. At that time, the surplus productive capacity at the wellhead in the lower 48 States was 31.0 billion cubic feet per day. On an annual basis, this surplus productive capacity represented 11.3 trillion cubic feet. The capacity utilization (gas production divided by productive capacity) in June 1983 was 56 percent. The public and industry clearly perceived that there was a "gas bubble" at this time, but its magnitude, causes, and likely duration were not well understood.

Historical monthly gas production and productive capacity for the lower 48 States are presented in Table 1. Estimates are presented only for the months of January, June, and December. January and December represent the typical peak winter months, and June represents an off season month. Production and capacity data for all 12 months can be obtained from the authors. Higher gas demand in 1984 increased the capacity utilization only to have a lower gas demand again in 1985 that decreased capacity utilization. The surplus dry gas productive capacity was roughly the same volume (30.1 billion cubic feet per day) in June 1986 as in June 1983. The surplus dry gas productive capacity began declining after 1986 as gas demand increased and gas well completions dropped sharply in 1986.

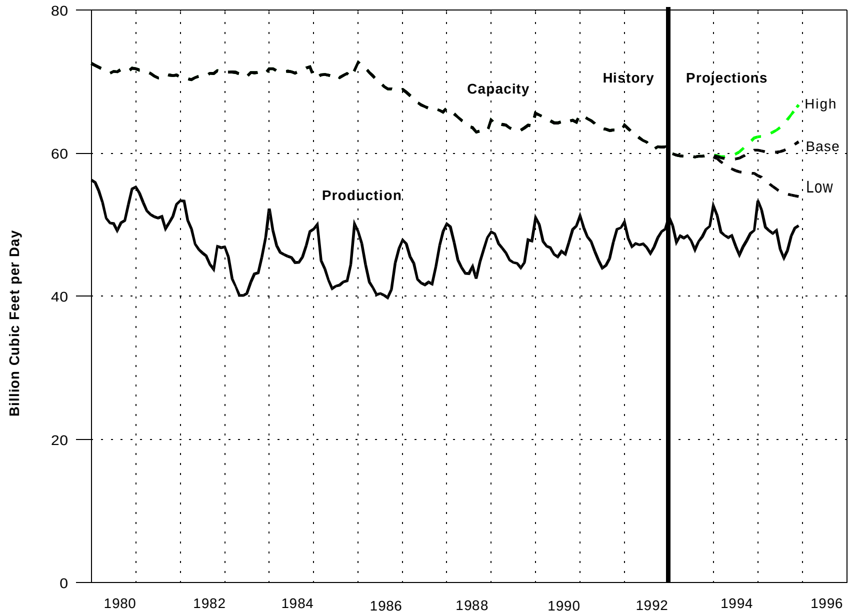
The average wellhead value of natural gas (in constant 1992 dollars) peaked in 1983 at $3.59 per thousand cubic feet{9}, dropped sharply in 1986, and continued to decline to $1.68 per thousand cubic feet in 1991 (a 53 percent drop).{10} The average price increased slightly in 1992 to $1.74. For comparison, domestic crude

Figure 4. Lower 48 States Productive Capacity and Supply Schematic



Source: Energy Information Administration, Office of Oil and Gas.

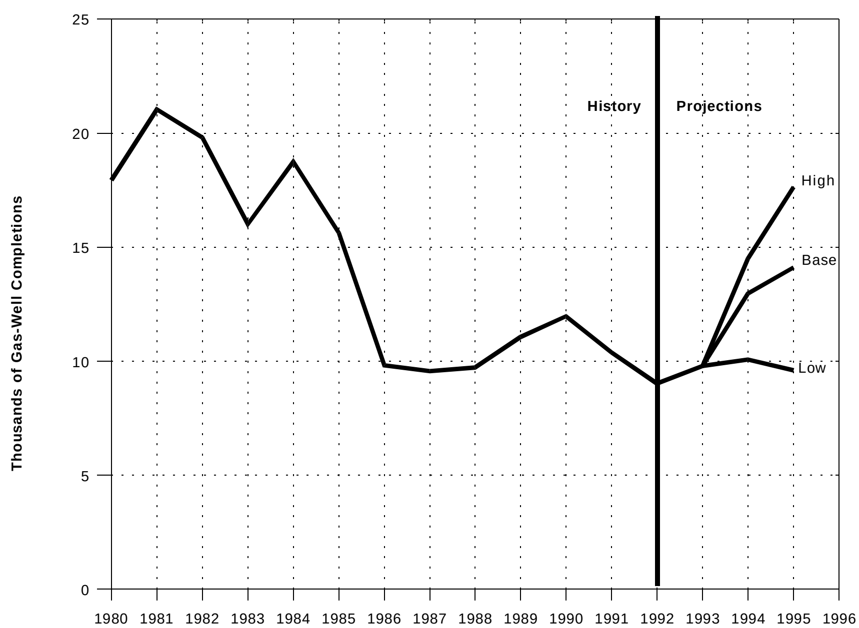
Figure 5. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. Productive Capacity: GASCAP93 C060194. Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly* Projections First Quarter 1994 and Model GASCAP93 C060194.

Figure 6. Lower 48 States Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information , Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Table 1. Lower 48 States Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Billion Cubic Feet per Day)

Month/ Utilization Year	Dry Production	Dry Gas Productive Capacity			Total Surplus	Capacity (percent)
		Gas-Well Gas	Oil-Well Gas	Total Gas		
Jan-80	56.3	63.8	8.8	72.6	16.3	77.6
Jun-80	50.3	62.6	8.6	71.2	20.9	70.6
Dec-80	55.0	63.2	8.7	71.9	16.9	76.5
Jan-81	55.3	63.3	8.5	71.8	16.5	77.0
Jun-81	51.2	62.2	8.6	70.8	19.6	72.3
Dec-81	52.9	62.4	8.6	70.9	18.1	74.5
Jan-82	53.4	62.3	8.3	70.6	17.2	75.6
Jun-82	46.6	62.3	8.4	70.8	24.2	65.8
Dec-82	46.8	63.2	8.4	71.5	24.7	65.5
Jan-83	46.9	63.0	8.4	71.3	24.4	65.8
Jun-83	40.1	62.7	8.5	71.1	31.0	56.4
Dec-83	48.2	63.2	7.9	71.2	22.9	67.8
Jan-84	52.3	63.1	8.7	71.8	19.5	72.8
Jun-84	45.6	62.5	8.9	71.5	25.9	63.8
Dec-84	49.1	63.2	8.9	72.1	23.0	68.1
Jan-85	49.4	61.6	9.0	70.6	21.2	70.0
Jun-85	41.1	61.6	9.2	70.8	29.7	58.0
Dec-85	50.1	62.3	9.2	71.6	21.4	70.1
Jan-86	49.1	63.0	9.7	72.7	23.6	67.5
Jun-86	40.2	61.4	8.9	70.3	30.1	57.2
Dec-86	46.7	60.1	8.7	68.8	22.1	67.9
Jan-87	47.9	59.9	9.0	68.9	21.0	69.5
Jun-87	41.9	58.0	8.8	66.8	24.9	62.7
Dec-87	49.1	57.1	8.7	65.7	16.7	74.6
Jan-88	50.1	57.5	8.8	66.3	16.2	75.6
Jun-88	43.2	55.4	8.8	64.2	21.0	67.3
Dec-88	48.2	54.6	8.5	63.1	14.9	76.4
Jan-89	49.0	55.9	8.8	64.6	15.6	75.8
Jun-89	45.1	55.2	8.4	63.6	18.5	70.9
Dec-89	47.8	56.0	7.9	63.8	16.1	74.8
Jan-90	51.0	56.9	8.7	65.6	14.6	77.8
Jun-90	45.9	55.8	8.4	64.2	18.3	71.5
Dec-90	49.9	55.9	8.4	64.4	14.5	77.5
Jan-91	51.3	57.0	8.4	65.4	14.1	78.4
Jun-91	45.1	55.4	8.3	63.7	18.7	70.7
Dec-91	49.6	54.9	8.3	63.2	13.6	78.5
Jan-92	50.4	55.4	8.5	63.9	13.5	78.8
Jun-92	47.4	53.4	8.4	61.8	14.4	76.6
Dec-92	49.4	52.6	8.3	60.9	11.5	81.2

Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

oil prices dropped 56 percent from 1983 through 1992. Given the lower prices and consequent decrease in drilling, it is understandable that wellhead productive capacity would decline to values closer to gas demand.

Dry gas productive capacity began a sharp decline in January 1986 that continued through December 1988 (Table 1). In December 1988, productive capacity was 63.1 billion cubic feet per day or 13 percent lower than in January 1986. Productive capacity was relatively stable during the period 1989 through 1991. In December 1992, productive capacity was 60.9 billion cubic feet per day or 3 percent lower than in December 1988. However, in the low case projection, dry gas productive capacity will decline 11 percent from December 1992 through December 1995. For the base case projection, productive capacity shows an overall increase of 1 percent from December 1992 through December 1995. In the high case (high price, high drilling), productive capacity also shows an increase in 1994 and 1995, reaching 66.8 billion cubic feet per day in December 1995.

In the low case, the surplus dry gas productive capacity drops to 4.1 billion cubic feet per day in December 1995. In the base case, the December 1995 surplus productive capacity climbs to 11.7 billion cubic feet per day. In the high case, the surplus productive capacity (16.9 billion cubic feet per day) in December 1995 is 47 percent higher than in December 1992. Gas productive capacity should be adequate to meet the normal projected seasonal monthly gas demand through December 1995, even in the low case. Beyond this time, more new gas-well completions will be needed to maintain surplus productive capacity.

New Well Completions

It is hard to overemphasize the impact of gas-well completions on gas productive capacity. If there had been no more gas completions after 1992, the surplus gas productive capacity would have gone from 11.5 billion cubic feet per day in December 1992 to zero by December, 1993. Productive capacity would have dropped by 18 percent between December 1992 and December 1993, with no new drilling after 1992. Gas production, then limited by capacity and not demand, would rapidly decline.[1]

This contrasts with the surplus capacity picture in the late 1980's. Gas-well completions dropped from 15,634 in 1985 to 9,810 in 1986 with even fewer completions in 1987 and 1988 (Figure 6). Despite this large decline, the general improvement in the average productive capacity of new completions precluded a serious loss of surplus capacity (Figure 5).

Gas-well completions added for the 3-year period 1993 through 1995 are estimated to be 29,439 for the low case, 36,877 for the base case, and 41,922 for the high case (Figure 6). The larger number of completions yield a dry gas productive capacity for the high case in December 1995 that is 66.8 billion cubic feet per day (Table 2) or 24 percent higher than the 54.0 billion cubic feet per day in the low case. Gas demand was assumed to be the same in both cases.

A new gas-well completion is estimated to add about 1 million cubic feet per day of capacity (Appendix D). In 1995 for the low case, the productive capacity is estimated to decline 3.2 billion cubic feet per day. To avert this decline, 3,200 gas-well completions need to be brought on production in 1995.

For the low, base, and high cases, the corresponding gas-well completions were estimated primarily as a function of gas price and production. The 1995 gas prices for the three cases were $1.87, $2.20, and $2.55 per thousand cubic feet as shown in the first-quarter 1994 *Short-Term Energy Outlook*. The actual gas prices were $1.74 per thousand cubic feet in 1992 and $1.99 in 1993.

[1]Model GASCAP93 C060194.

Table 2. Lower 48 States Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Billion Cubic Feet per Day)

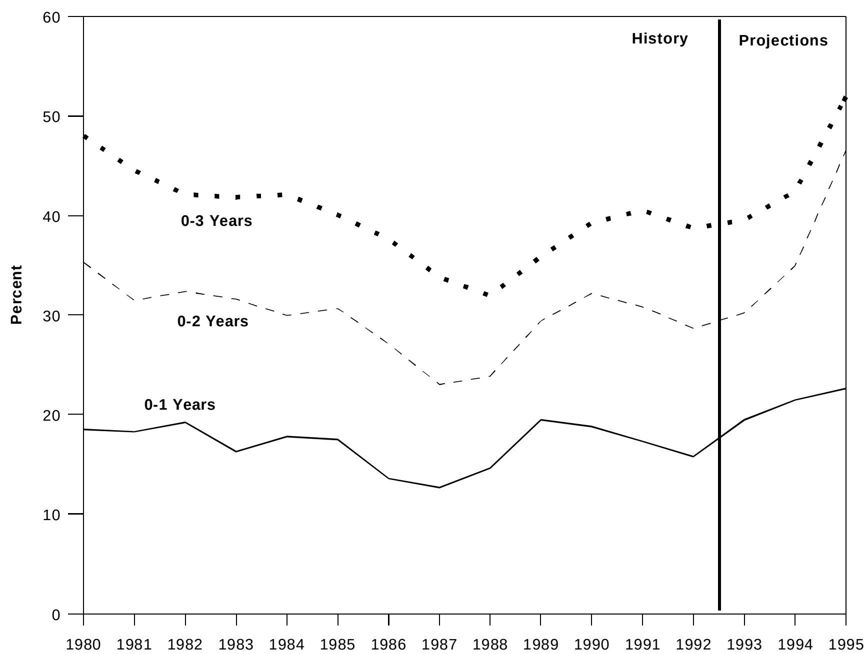
		Dry Gas Productive Capacity				
Month/ Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
		Low Case Projection				
Jan-93	51.1	51.9	8.2	60.1	9.0	85.1
Jun-93	48.5	51.6	8.0	59.6	11.2	81.3
Dec-93	49.8	51.9	8.0	59.9	10.0	83.2
Jan-94	52.7	51.6	7.9	59.5	6.8	88.6
Jun-94	48.5	50.3	7.5	57.8	9.3	83.9
Dec-94	49.2	49.8	7.4	57.2	8.0	86.1
Jan-95	53.4	49.5	7.3	56.9	3.4	93.9
Jun-95	49.2	47.9	7.1	55.0	5.8	89.5
Dec-95	49.9	47.1	6.9	54.0	4.1	92.5
		Base Case Projection				
Jan-93	51.1	51.9	8.2	60.1	9.0	85.1
Jun-93	48.5	51.6	8.0	59.6	11.2	81.3
Dec-93	49.8	51.9	8.0	59.9	10.0	83.2
Jan-94	52.7	51.7	8.0	59.7	7.0	88.3
Jun-94	48.5	51.4	7.8	59.2	10.6	82.0
Dec-94	49.2	52.7	7.7	60.5	11.2	81.4
Jan-95	53.4	52.7	7.7	60.4	7.0	88.4
Jun-95	49.2	52.6	7.5	60.2	10.9	81.8
Dec-95	49.9	54.1	7.5	61.6	11.7	81.0
		High Case Projection				
Jan-93	51.1	51.9	8.2	60.1	9.0	85.1
Jun-93	48.5	51.6	8.0	59.6	11.2	81.3
Dec-93	49.8	51.9	8.0	59.9	10.0	83.2
Jan-94	52.7	51.7	8.1	59.7	7.1	88.2
Jun-94	48.5	51.8	7.9	59.7	11.2	81.3
Dec-94	49.2	54.2	7.9	62.1	12.9	79.2
Jan-95	53.4	54.4	7.9	62.3	8.9	85.8
Jun-95	49.2	55.5	7.8	63.2	14.0	77.8
Dec-95	49.9	59.0	7.8	66.8	16.9	74.7

Sources: •Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

New Productive Capacity

Most of the contribution to the productive capacity is made by newer well completions (Figure 7). Wells less than 3 years old contributed over 40 percent of the December productive capacity from 1980 through 1985. This percentage dropped to 32 percent by 1988 but is projected to be 52 percent in 1995 in the base drilling case. In December 1980, 18 percent of the productive capacity was from wells less than 1 year old; i.e., wells completed in 1980. Wells less than 1 year old generally represented 13 to 23 percent of the total December productive capacity from 1980 through 1995. This percentage fell to 14 percent in 1986 and 13 percent in 1987 as drilling plummeted after 1985. In the base case, gas wells less than 1 year old are projected to be 23 percent of the December gas well capacity in 1995. Total December gas well capacity and surplus gas productive capacity are projected to increase slightly from 1992 through 1995.

Figure 7. Percent of Total Wellhead Productive Capacity of Lower 48 States Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. •Projections: Model GASCAP93 C060194.

Potential Short-Term Supply Problems

Even with a large dry gas productive capacity, there can be short-term regional gas supply problems as occurred in December 1983 and December 1989. Before this subject is addressed the tremendous differences in annual average-day demand, peak-month average-day demand, and peak-day demand must be pointed out.

Demand Category		Demand Rate
Annual Average-Day Demand, 1991	=	52 billion cubic feet per day
January Average-Day Demand, 1991	=	74 billion cubic feet per day
January Peak-Day Demand, 1991	=	102 billion cubic feet per day

The peak-day demand may be twice the annual average-day demand. The National Petroleum Council(NPC){11} estimated that firm peak-day consumption in 1991 reached 102 billion cubic feet per day. The period from December 23 to December 27, 1989 was extraordinarily cold and demand may well have approached this peak rate.

This peak-day demand cannot be met by increasing gas production at the wellhead and should not be expected to be met by production in the future. Peak-day demand usually occurs in December, January, or February during very cold weather. The cold weather, while increasing gas demand, may also decrease potential supply because of weather-related production and transportation problems.

So that consumers will be better served, the natural gas industry has developed methods to meet peak demand such as delivery from gas storage facilities (54 billion cubic feet per day) and peak-day shaving capacity (3 billion cubic feet per day). Some projects have recently been placed in service and others are proposed that allow greater access to supply areas and support increasing natural gas consumption.

It could be argued that in periods of high gas demand, price increases at the wellhead could both increase supply quantities and decrease consumption until they balance. Over a sufficient period of time this is true. However, in the very short term (days), wellhead average prices are relatively unresponsive to demand, although gas prices normally increase during periods of high seasonal demand. The vast majority of gas is covered by 30-day or longer contracts. Therefore, if there is a sudden large increase in gas demand, there is not an accompanying sudden, large increase in the average price of gas at the wellhead. However, small volumes of gas may sell at very high prices on the spot market. Therefore, very little gas would actually be available at the wellhead at an unexpected price surge to $5 per thousand cubic feet that would not be available at $3 per thousand cubic feet on the same day.

Effective gas demand is typically lowered by curtailing deliveries to customers with interruptible contracts or by customers with fuel-switching capability responding to higher gas prices by switching to another fuel. A price increase would have little impact on reducing residential gas demand. It is residential demand that is most likely to have a sudden upward surge related to weather. Residential consumers used 5.2 times as much gas in December 1990 as they did in August 1990 and 5.7 times as much gas in December 1992 as they did in August 1992.{12}

Because cost–of–service pricing lowers the unit cost of gas during periods when large volumes are being delivered, the residential cost of gas per thousand cubic feet actually dropped from $7.04 in August 1990 to $5.60 in December 1990, even though the price at the wellhead increased during the same period.{12} Again in 1992, the residential cost of gas dropped from $7.45 in August to $5.74 in December. Therefore, small increases in the average price of natural gas at the wellhead—despite large price increases of small volumes of gas at the margin of supply—do not effectively dampen weather-related residential gas demand in the short term.

The December 1989 average-day production of dry gas was only 47.8 billion cubic feet per day (Table 1), which was practically the same as December 1988. However, some regional peak-day demands for production in late December 1989 were not met. Some customers with firm contracts had their gas supplies curtailed. This was in large part due to weather-related production problems that are not likely to occur again soon with the same severity. Weather-related increases in gas demand and decreases in supply also occurred in December 1983. In December 1983 the problems were most severe in south Texas. In December 1989 they were most severe in the Gulf of Mexico OCS.

One problem that is associated with the handling of natural gas is the phenomenon of a production line or well "freezing up." This problem occurs when water vapor and hydrocarbon vapors combine to form snow-like substances, called hydrates. Under suitable pressure conditions hydrates may be formed at temperatures well above the freezing point of water. One of the problems in handling natural gas is the prevention of the formation of hydrates and their removal once formed.

The proper winterization of wells, pipelines, and gas processing facilities is a relatively straightforward and inexpensive process. Operators in south Texas prepared for severe weather after December 1983 and were not severely affected in December 1989. Gulf of Mexico OCS operators were reported to be rapidly winterizing their facilities during 1990.

This raises two questions:

- Could the 1989 December peak-day production demand have been met if there had been no weather-related production problems?
- What percentage of the wellhead productive capacity can actually be delivered to and through the pipeline system?

The answer to the first question in all likelihood is yes. The uncertainties in the actual production demand and deliverability are too great to say yes with certainty. The answer to the second question has been changing over time and is also uncertain; it was estimated to be 95 percent of dry gas productive capacity at the wellhead in January 1993. The 95 percent was obtained by dividing the January 1993 dry gas production of 51.1 billion cubic feet per day (Table 2) by the deliverability estimate of 54.0 billion cubic feet per day for January 1993, which was obtained by scaling up the 1993 Natural Gas Supply Association Survey.{13}

Peak production demand is met by well completions with surplus capacity. A peak demand may only last for a few days, but when it comes, there must be an adequate number of wells with adequate productive capacity to meet the demand required. Peak demand requirements can be caused by severe weather; i.e., extremely cold weather in some or all parts of the country. Interruptions in regional supply can cause a peak production demand in other areas. For example, a storm in the Gulf of Mexico OCS–such as hurricane Andrew in August 1992–damaged 243 sites in the Gulf. Some 5 percent of the Nation’s gas supply, or about 2.5 to 2.75 billion cubic feet per day was abruptly shut in. A month-and-a-half later, in early October, 750-800 million cubic feet of production was still shut in. Needed gas was supplied to consumers from other areas or from storage during part of this time.

Again in March 1993, "The Storm of the Century" hit the Southeast States and the East Coast States causing the highest level of March consumption since monthly data have been collected. Then, less than a year later in January 1994, the industry met an even more severe test when the system delivered record amounts of gas to these areas.

Surplus productive capacity is necessary to ensure an adequate supply of gas when required. It is also necessary for gas to move through the gathering lines, plants, pipelines, and the many interconnections to the final destination.

In order to meet peak-month or peak-day demand, pipelines must have enough capacity to deliver the gas to the final destination. Pipeline systems must have adequate diameters, properly spaced compressors, and adequate interconnections between pipelines. Gas pipeline systems must be able to transport gas efficiently from a well in south Texas, for example, to a location in the northeast, midwest, or wherever the need might arise.

Traditionally, seasonal swings in gas demand have been met in large part by corresponding swings in wellhead production. Some of the States and areas have a large surplus productive capacity, while others may not always be able to meet their historical market share of U.S. peak-month demand.

As shown in Chapter 3, the Gulf of Mexico OCS had the largest surplus productive capacity of any State or area in 1992. In this area, most of the wells are prolific producers. A sufficient number of well completions have been added each year through 1992 to sustain a large surplus. This surplus is predicted to continue through 1995 in the base and high cases.

Texas and the Gulf of Mexico OCS are the largest producers of natural gas. Texas underwent a relatively rapid decline in surplus productive capacity between 1985 and 1992. This trend is expected to level off during 1993 and increase from 1994 through 1995 for the base and high cases.

The surplus productive capacity in the States of New Mexico, Kansas, and in the Southeast Area (Arkansas, Alabama, and Mississippi) is predicted to be adequate through 1995. However, in Oklahoma it is projected to be barely adequate to meet demand in 1995 in the base case and inadequate in the low case. Based on historical market share, California, Louisiana, and the 18 States group are expected to fail to meet 1993-1995 peak production demand.

The new State proration rules enacted by Texas and Oklahoma in 1992 are not expected to limit gas deliverability. The two States have indicated that changes in the proration rules will not cause less gas to be produced than is needed to meet market demand. Oklahoma and Kansas both increased their production levels to help meet the increased demand resulting from Hurricane Andrew.

Meeting Lower 48 States Gas Demand

The United States has sufficient dry gas productive capacity to meet forecast monthly production demand through 1995. Any potential shortfalls in States with low surplus productive capacity could probably be met by those areas with surplus productive capacity.

The existence of a high gas productive capacity at the wellhead does not mean that the entire productive capacity could actually be produced and delivered. The ability of a well to deliver gas into a pipeline system (deliverability) is always equal to or less than wellhead productive capacity. Deliverability is that volume of gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions, taking into account restrictions imposed by pipeline capacity, contracts, or regulatory bodies.

A useful comparison of productive capacity and deliverability can be made. Consider the data collected by the Natural Gas Supply Association (NGSA) in its *NGSA Survey on 1993 Natural Gas Field Deliveries* & *Productive Capacity*.{13} These data were collected on an operator basis for seven lower-48 regions. The survey covered 75 percent of the production for the Offshore Gulf Coast, the highest for any region in the survey. The NGSA collects connected-gas-well capacity as of January 1, which is equivalent to deliverability. The ratio of the NGSA January 1, 1993 connected gas field capacity to the annual 1992 field deliveries was 1.13, or deliverability was 13 percent higher than annual production. The equivalent deliverability for all Offshore Gulf Coast operators was 15 billion cubic feet per day if the NGSA surveyed operators are representative of all operators in the region.

During the 1980’s and most recently with FERC Order 636 in 1992, major changes have occurred in regulations, contracts, interconnections between trunklines, access to transportation, and markets. These changes have introduced a much greater degree of flexibility and responsiveness in the natural gas industry. This flexibility makes it likely that a higher percentage of the productive capacity can be delivered in 1993 than in 1980. More gas can get from where it is produced to where it is needed. However, in some cases pipeline capacity may limit gas deliverability.

As of January 1, 1993, dry gas deliverability into the pipeline system for the lower 48 States was estimated to be 54.0 billion cubic feet per day, which was only 89 percent of the dry gas productive capacity at the wellhead. This estimate was obtained by scaling up the NGSA gas deliverability survey of 149 producers that accounted for 60 percent of the lower 48 States dry gas production. The scaling up was done for each of the regions used by the NGSA. However, there is a substantial uncertainty in this deliverability estimate. Part of the uncertainty comes from the possibility that the 149 producers in the NGSA survey may not be representative of the total producer population.

The NGSA capacity volume that best met the EIA definition of deliverability was the January 1, 1993 connected field capacity, which takes into account capacity limitations imposed by field facilities, gathering systems, and gas processing plants. Dry gas production was estimated to be roughly 51 billion cubic feet per day in January 1993 or 94 percent of the 54.0 billion cubic feet per day deliverability in January 1993 (Table 2).

A substantial surplus of dry gas productive capacity implies that there will be no precipitous loss of gas deliverability. Consequently, when the surplus wellhead productive capacity is relatively small, gas deliverability can decline rapidly. As productive capacity approaches deliverability, a higher percentage of productive capacity will be produced until productive capacity equals deliverability.

It is possible that a peak-day gas production demand could not be met during nationwide extreme cold weather. This situation would cause difficulties for some, but it need not lead to serious problems in meeting an exceptionally high peak-day gas demand. Consumer demand can be lowered by not supplying customers having interruptible contracts or by fuel switching. Remaining peak demand would be met by withdrawals from storage and by peak shaving as was successfully done in the extraordinarily high peak-day demand period in late December 1989. Sufficient dry gas productive capacity will exist during the years 1993 through 1995 to increase the underground natural gas storage inventory if needed. Gas storage requirements can be met by maintaining gas production closer to gas productive capacity throughout the year. This will lead to smaller seasonal variations in gas production. Planned additions to underground storage during 1993 through 1995 are expected to increase deliverability from storage by 15 billion cubic feet per day{12}. Increased use of storage reduces the need for excess productive capacity, thus promoting improved economic efficiency in production.

3. Major Producing Areas

In preparing this report, the lower 48 States were divided into States and areas that have production data by well completion obtained from Dwight's Energydata, Inc. (Dwight's). Dwight's gas-well gas production data were available for 14 States and the Gulf of Mexico Federal Offshore Outer Continental Shelf (OCS). From these data, individual studies were made for each of six States and the OCS area: California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and the OCS.

The remaining States were combined into 3 groups. Five were grouped together as *Rocky Mountains*: Colorado, Montana, North Dakota, Utah, and Wyoming and 3 as the *Southeast* group, consisting of Alabama, Arkansas, and Mississippi. The third group was made up of *18 States*: 3 States with Dwight's data–Michigan, Nebraska, and South Dakota and 15–Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Missouri, Nevada, New York, Ohio, Oregon, Pennsylvania, Tennessee, Virginia, and West Virginia for which no Dwight's data were available.

Each State/area or group of States had its own unique, initially scheduled monthly gas production rate for January 1993 set to the same values for the low, base, and high cases. However, the actual production rate in an area will be less than its initially scheduled production rate if its scheduled production rate exceeds its gas productive capacity. Scheduled gas production is the production demand for the United States taken from the *Short-Term Energy Outlook*, February 1994 and prorated among the States and areas.

For each State or area where the scheduled production exceeds the gas productive capacity, the deficit capacity (the negative difference between capacity and scheduled production) is rescheduled to States and areas with surplus capacity. The production for these deficit capacity States will be greater in the base and high cases because there will be more well completions. The larger number of well completions adds more capacity and reduces or eliminates the deficit capacity.

For States or areas where the scheduled production does not exceed capacity, the surplus capacity (the positive difference between capacity and scheduled production) is used to replace the deficit capacity of the States and areas with deficit capacities. For these surplus capacity States, the production rate will be highest in the low case because there is a larger deficit capacity to make up.

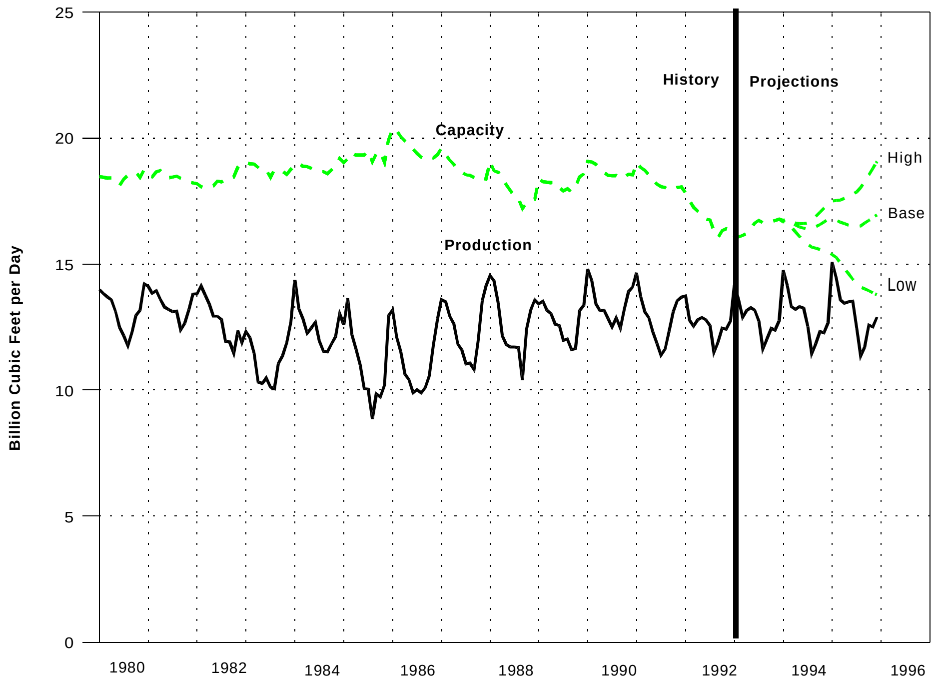
Coalbed methane gas was not treated separately in this report because of data and time constraints. In the next report, it will be treated separately. Coalbed gas as a percent of the lower 48 States' gas production has increased each year. In 1990 it was 1 percent, in 1991–2 percent, and in 1992–3 percent.

Gulf of Mexico OCS

The Gulf of Mexico OCS is a prolific natural gas producer with large seasonal variations in producing rate. In 1992, 26.4 percent of the lower 48 States' total dry gas production came from this area. The producing formations generally consist of high permeability structural traps with water drives. The Tiger Shoal and Matagorda Island Block 623 fields, the largest producers of natural gas in the Gulf of Mexico OCS, produced 65 and 63 billion cubic of gas respectively in 1992.

Figure 8 shows the dry gas monthly production rate and wellhead productive capacity from 1980 through 1992 with projections through 1995. The January, June, and December historical production rates and capacities are presented in Table 3. The production rate decreased 10 percent from December 1980 through December 1992 while productive capacity declined 13 percent during the same period. The December 1995 forecast demand for the base case is 1 percent greater than the historical December 1992 rate, while at the same time the productive capacity is projected to increase 4 percent (Table 4).

Figure 8. Gulf of Mexico OCS Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194.*

Surplus capacity was adequate from 1980 through 1992. It was fairly constant at 5 to 6 billion cubic feet day from December 1986 through September 1991 but declined to 4 billion cubic feet in December 1992 (Table 4). Projections show gradual increases for the base and high cases. However, surplus capacity for the low case is almost nonexistent by December 1995.

Figure 9 shows the number of gas-well completions added during the year and producing in December from 1980 through 1992 and projected through 1995. During this period well completions peaked in 1990 and declined in both 1991 and 1992. The base case forecasts an increase in the number of new completions in 1993 followed by a slight decrease in 1994 and then an increase in 1995.

The initial flow rates per well completion for the Gulf of Mexico are generally high–nearly 8 million cubic feet per day (Appendix D). A large number of reservoirs in the Gulf of Mexico have high permeabilities and are water-drive reservoirs. This usually means that the reservoir can sustain a high flow rate throughout most of its producing life. However, the recovery efficiency is generally less than the recovery efficiency for reservoirs with other types of drive mechanisms. It is not uncommon for a Gulf of Mexico OCS gas-well completion to produce 8 billion cubic feet of gas over its life.

Figure 10 shows the percent of the Gulf of Mexico OCS gas-well gas productive capacity in December of each year by the age of the well. Gas-well completions that have been producing gas for less than 1 year contributed from 16 to 30 percent of the gas-well gas productive capacity from 1980 through 1992. A low of 16 percent occurred in 1983 and 1987, and a high of 30 percent occurred in 1989.

Table 3. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	13,993	17,409	1,066	18,475	4,482	75.7
Jun-80	12,483	17,142	985	18,127	5,644	68.9
Dec-80	14,223	17,726	1,015	18,741	4,518	75.9
Jan-81	14,129	17,541	964	18,505	4,376	76.4
Jun-81	13,208	17,465	962	18,427	5,219	71.7
Dec-81	13,817	17,220	1,000	18,220	4,403	75.8
Jan-82	13,829	17,216	970	18,186	4,357	76.0
Jun-82	12,935	17,284	1,005	18,289	5,354	70.7
Dec-82	11,873	17,902	1,129	19,031	7,158	62.4
Jan-83	12,315	17,932	1,087	19,019	6,704	64.8
Jun-83	10,474	17,538	1,197	18,735	8,261	55.9
Dec-83	12,693	17,551	1,201	18,752	6,059	67.7
Jan-84	14,381	17,741	1,225	18,966	4,585	75.8
Jun-84	12,676	17,370	1,366	18,736	6,060	67.7
Dec-84	13,029	17,822	1,371	19,193	6,164	67.9
Jan-85	12,585	17,658	1,373	19,031	6,446	66.1
Jun-85	10,050	17,786	1,539	19,325	9,275	52.0
Dec-85	12,966	18,413	1,530	19,943	6,977	65.0
Jan-86	13,181	18,801	1,585	20,386	7,205	64.7
Jun-86	9,883	18,096	1,460	19,556	9,673	50.5
Dec-86	12,823	17,840	1,489	19,329	6,506	66.3
Jan-87	13,601	18,185	1,416	19,601	6,000	69.4
Jun-87	11,587	17,346	1,317	18,663	7,076	62.1
Dec-87	14,144	17,124	1,252	18,376	4,232	77.0
Jan-88	14,547	17,833	1,254	19,087	4,540	76.2
Jun-88	11,701	16,615	1,309	17,924	6,223	65.3
Dec-88	13,580	16,255	1,314	17,569	3,989	77.3
Jan-89	13,434	17,091	1,286	18,377	4,943	73.1
Jun-89	12,544	16,809	1,224	18,033	5,489	69.6
Dec-89	13,378	17,498	1,085	18,583	5,205	72.0
Jan-90	14,818	17,863	1,220	19,083	4,265	77.7
Jun-90	12,832	17,340	1,184	18,524	5,692	69.3
Dec-90	14,089	17,316	1,228	18,544	4,455	76.0
Jan-91	14,664	17,723	1,301	19,024	4,360	77.1
Jun-91	11,847	16,859	1,314	18,173	6,326	65.2
Dec-91	13,698	16,638	1,434	18,072	4,374	75.8
Jan-92	13,738	16,495	1,321	17,816	4,078	77.1
Jun-92	12,784	15,498	1,292	16,790	4,006	76.1
Dec-92	12,741	15,090	1,263	16,353	3,612	77.9

Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. • Productive Capacity: GASCAP93 C060194.

Table 4. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

		Dry Gas Productive Capacity				
Month/ Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
	Low Case Projection					
Jan-93	14,181	14,832	1,267	16,099	1,918	88.1
Jun-93	13,178	15,381	1,252	16,633	3,455	79.2
Dec-93	12,746	15,520	1,272	16,792	4,046	75.9
Jan-94	14,772	15,433	1,255	16,688	1,916	88.5
Jun-94	13,304	14,740	1,201	15,941	2,637	83.5
Dec-94	12,734	14,320	1,183	15,503	2,769	82.1
Jan-95	15,265	14,202	1,182	15,384	119	99.2
Jun-95	13,673	13,276	1,143	14,419	746	94.8
Dec-95	13,045	12,659	1,129	13,788	743	94.6
	Base Case Projection					
Jan-93	14,181	14,832	1,267	16,099	1,918	88.1
Jun-93	13,178	15,381	1,252	16,633	3,455	79.2
Dec-93	12,746	15,520	1,272	16,792	4,046	75.9
Jan-94	14,764	15,458	1,275	16,733	1,969	88.2
Jun-94	13,263	15,174	1,250	16,424	3,161	80.8
Dec-94	12,664	15,528	1,247	16,775	4,111	75.5
Jan-95	15,090	15,525	1,248	16,773	1,683	90.0
Jun-95	13,538	15,287	1,222	16,509	2,971	82.0
Dec-95	12,890	15,736	1,221	16,957	4,067	76.0
	High Case Projection					
Jan-93	14,181	14,832	1,267	16,099	1,918	88.1
Jun-93	13,178	15,381	1,252	16,633	3,455	79.2
Dec-93	12,746	15,520	1,272	16,792	4,046	75.9
Jan-94	14,760	15,458	1,289	16,747	1,987	88.1
Jun-94	13,249	15,340	1,273	16,613	3,364	79.8
Dec-94	12,626	16,150	1,279	17,429	4,803	72.4
Jan-95	15,035	16,227	1,281	17,508	2,473	85.9
Jun-95	13,469	16,502	1,262	17,764	4,295	75.8
Dec-95	12,794	17,805	1,274	19,079	6,285	67.1

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

Figure 9. Gulf of Mexico OCS Gas-Well Completions Added During Year and Producing as of December, 1980-1995

Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 10. Percent of Total Wellhead Productive Capacity of Gulf of Mexico OCS Gas Wells, by Age, 1980-1995 (Base Case)

Sources: •History: Energy Information Administration, Office of Oil andDwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Historically, the total surplus dry gas productive capacity in the Gulf of Mexico OCS has been declining. Its ability to meet the major seasonal swings in the lower 48 States gas requirements is threatened if future well completions do not exceed the 1995 low case level.

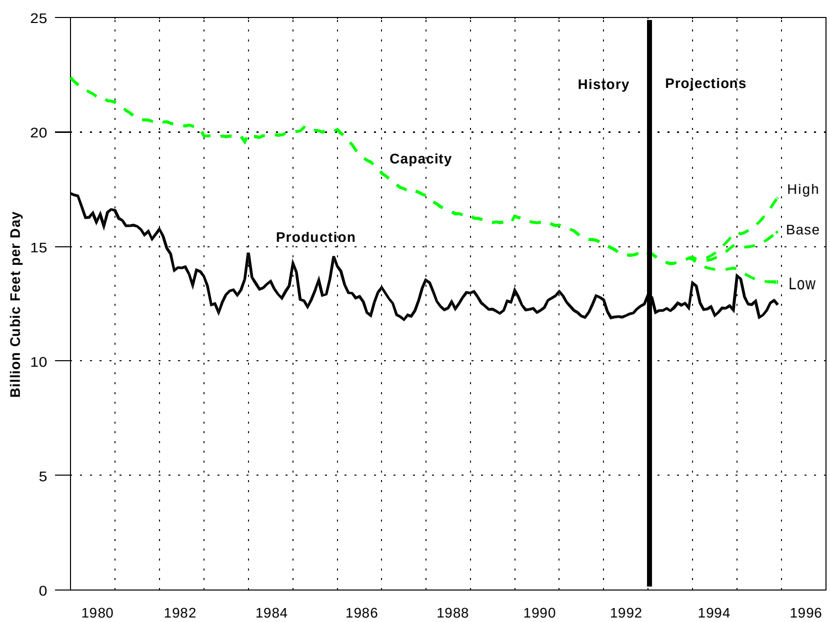
Texas (Excluding Gulf of Mexico OCS)

For many years Texas has been the largest natural gas producing State. Gas producing zones range from high permeability, water-drive formations on the Gulf Coast to the low permeability "Tight Gas" reservoirs of the East Texas and Gulf Coast basins. The two largest gas producing areas in 1992 in the State were the Carthage and the Panhandle West fields which produced 178 and 166 billion cubic feet of gas respectively.

In 1992, Texas produced 4.45 trillion cubic feet or 25.5 percent of the total dry gas in the lower 48 States, slightly less than the 4.61 trillion cubic feet produced from the Gulf of Mexico Federal OCS.{10}

Figure 11 shows the monthly dry gas production rate and wellhead productive capacity from 1980 through 1992 and projections through 1995. The January, June, and December production rates and capacities are presented in Tables 5 and 6. The production rate for December 1992 is 25 percent lower than the production rate for December 1980. The December 1995 production rate for the base case is projected to be 0.3 percent less than the December 1992 rate. Productive capacity declined from 1980 through 1992 and showed a very pronounced downturn beginning in 1986. The December 1992 capacity is 31 percent lower than the December 1980 capacity.

Figure 11. Texas (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Well-head Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GAS-CAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.*

Table 5. Texas (Excluding Gulf of Mexico) Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	17,322	19,185	3,209	22,394	5,072	77.4
Jun-80	16,286	18,643	3,125	21,768	5,482	74.8
Dec-80	16,631	18,270	3,086	21,356	4,725	77.9
Jan-81	16,589	18,050	3,266	21,316	4,727	77.8
Jun-81	15,942	17,499	3,225	20,724	4,782	76.9
Dec-81	15,545	17,301	3,146	20,447	4,902	76.0
Jan-82	15,764	17,261	3,247	20,508	4,744	76.9
Jun-82	14,094	17,111	3,226	20,337	6,243	69.3
Dec-82	13,923	16,973	3,196	20,169	6,246	69.0
Jan-83	13,708	16,557	3,296	19,853	6,145	69.0
Jun-83	12,560	16,554	3,282	19,836	7,276	63.3
Dec-83	13,576	16,525	3,054	19,579	6,003	69.3
Jan-84	14,737	16,419	3,488	19,907	5,170	74.0
Jun-84	13,363	16,444	3,401	19,845	6,482	67.3
Dec-84	13,298	16,562	3,393	19,955	6,657	66.6
Jan-85	14,287	16,633	3,398	20,031	5,744	71.3
Jun-85	12,657	16,644	3,398	20,042	7,385	63.2
Dec-85	14,589	16,617	3,421	20,038	5,449	72.8
Jan-86	14,148	16,604	3,509	20,113	5,965	70.3
Jun-86	12,749	15,953	3,267	19,220	6,471	66.3
Dec-86	13,007	15,329	3,146	18,475	5,468	70.4
Jan-87	13,217	15,071	3,140	18,211	4,994	72.6
Jun-87	11,918	14,559	3,033	17,592	5,674	67.7
Dec-87	13,196	14,271	3,025	17,296	4,100	76.3
Jan-88	13,542	14,084	3,150	17,234	3,692	78.6
Jun-88	12,233	13,601	3,074	16,675	4,442	73.4
Dec-88	13,001	13,360	2,993	16,353	3,352	79.5
Jan-89	12,969	13,304	3,080	16,384	3,415	79.2
Jun-89	12,247	13,138	2,954	16,092	3,845	76.1
Dec-89	12,564	13,216	2,833	16,049	3,485	78.3
Jan-90	13,096	13,366	2,963	16,329	3,233	80.2
Jun-90	12,292	13,176	2,888	16,064	3,772	76.5
Dec-90	12,839	12,941	2,982	15,923	3,084	80.6
Jan-91	13,044	13,002	2,951	15,953	2,909	81.8
Jun-91	12,104	12,728	2,839	15,567	3,463	77.8
Dec-91	12,778	12,404	2,809	15,213	2,435	84.0
Jan-92	12,667	12,252	2,925	15,177	2,510	83.5
Jun-92	11,912	11,872	2,826	14,698	2,786	81.0
Dec-92	12,489	12,018	2,818	14,836	2,347	84.2

Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

Table 6. Texas (Excluding Gulf of Mexico) Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Dry Gas Productive Capacity: Oil-Well Gas	Dry Gas Productive Capacity: Total Gas	Total Surplus	Capacity Utilization (percent)
	Low Case Projection					
Jan-93	12,890	11,895	2,820	14,715	1,825	87.6
Jun-93	12,292	11,602	2,709	14,311	2,019	85.9
Dec-93	12,316	11,821	2,681	14,502	2,186	84.9
Jan-94	13,428	11,818	2,639	14,457	1,029	92.9
Jun-94	12,409	11,538	2,503	14,041	1,632	88.4
Dec-94	12,293	11,634	2,435	14,069	1,776	87.4
Jan-95	13,890	11,615	2,428	14,043	153	98.9
Jun-95	12,737	11,253	2,327	13,580	843	93.8
Dec-95	12,602	11,199	2,271	13,470	868	93.6
	Base Case Projection					
Jan-93	12,890	11,895	2,820	14,715	1,825	87.6
Jun-93	12,292	11,602	2,709	14,311	2,019	85.9
Dec-93	12,316	11,821	2,681	14,502	2,186	84.9
Jan-94	13,421	11,833	2,681	14,514	1,093	92.5
Jun-94	12,371	11,841	2,605	14,446	2,075	85.6
Dec-94	12,226	12,473	2,568	15,041	2,815	81.3
Jan-95	13,731	12,529	2,565	15,094	1,363	91.0
Jun-95	12,611	12,568	2,487	15,055	2,444	83.8
Dec-95	12,452	13,209	2,457	15,666	3,214	79.5
	High Case Projection					
Jan-93	12,890	11,895	2,820	14,715	1,825	87.6
Jun-93	12,292	11,602	2,709	14,311	2,019	85.9
Dec-93	12,316	11,821	2,681	14,502	2,186	84.9
Jan-94	13,417	11,833	2,710	14,543	1,126	92.3
Jun-94	12,358	11,961	2,652	14,613	2,255	84.6
Dec-94	12,189	12,913	2,632	15,545	3,356	78.4
Jan-95	13,680	13,018	2,632	15,650	1,970	87.4
Jun-95	12,547	13,365	2,569	15,934	3,387	78.7
Dec-95	12,359	14,594	2,563	17,157	4,798	72.0

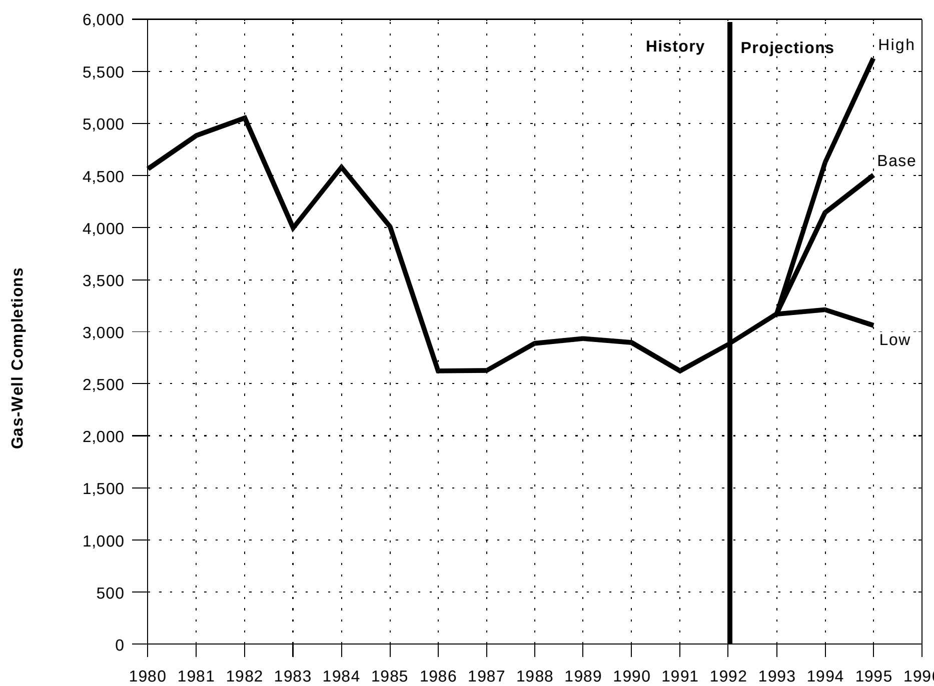
Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

The productive capacity in the low case is projected to decline 9 percent between December 1992 and December 1995 but will increase in both the base and high cases over the same period (Figure 11).

Surplus capacity and capacity utilization remained relatively stable from 1982 through 1986. After 1986, surplus capacity began to diminish (Figure 11). Consequently, capacity utilization increased from 1986 through 1992 (Table 5). The surplus capacity is projected to continue to decrease through 1995 for the low case, but will increase in both the base and high cases. Compared with the OCS, surplus capacities have not shown large increases in June. This indicates that the demand for gas in Texas is less seasonal than it is for the Gulf of Mexico OCS.

The high case December 1995 productive capacity exceeds the base and low case December 1995 productive capacity (Table 6). More drilling was assumed in the high case; hence, there will be more well completions and a larger capacity. Figure 12 shows the number of gas-well completions added during the year and producing in December from 1980 through 1992 with projections through 1995. The number of gas-well completions declined sharply in 1986. The obvious effect of this decrease was a rapid decline in dry gas-well gas productive capacity that started in January 1986 (Figure 11).

Figure 12. Texas (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year and Producing as of December, 1980-1995

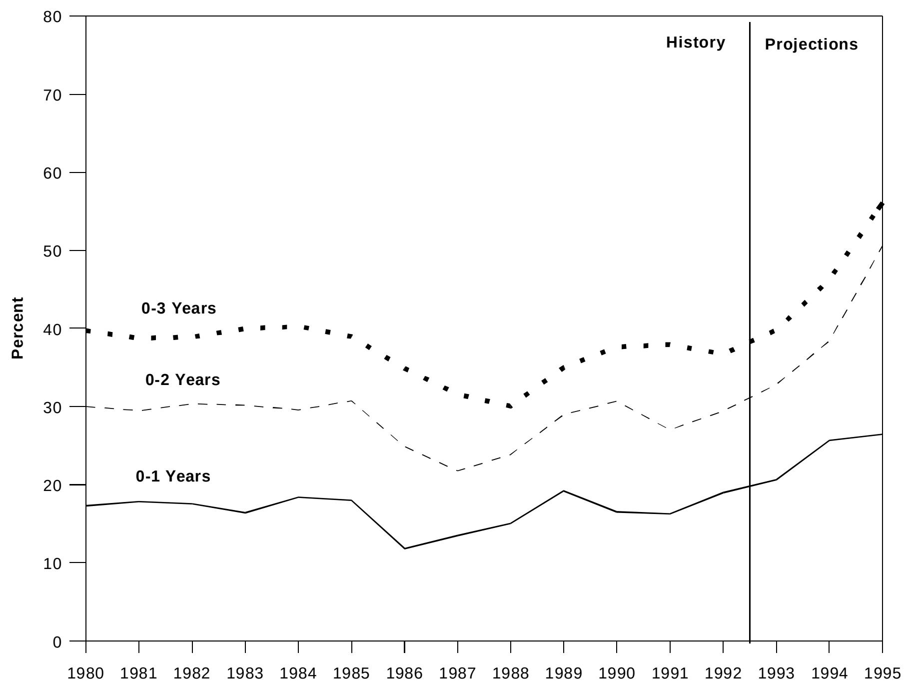


Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

The average initial flow rate per well in Texas has been about 1 million cubic feet per day for the last few years (Appendix D). Some Texas wells have high initial rates, such as the wells on the Gulf Coast, while others have relatively low initial rates.

Figure 13 shows the percent of the Texas gas-well gas productive capacity in December of each year by age of well. Well completions that have been producing gas for less than 1 year contributed 19 percent of the gas-well gas productive capacity in 1992. This is forecast to increase to 21 percent for December 1993, and to 26 percent for 1994 and 1995. A low of 12 percent was reached in 1986.

Figure 13. Percent of Total Wellhead Productive Capacity of Texas (Excluding Gulf of Mexico OCS) Gas Wells, by Age, 1980-1995 (Base Case)

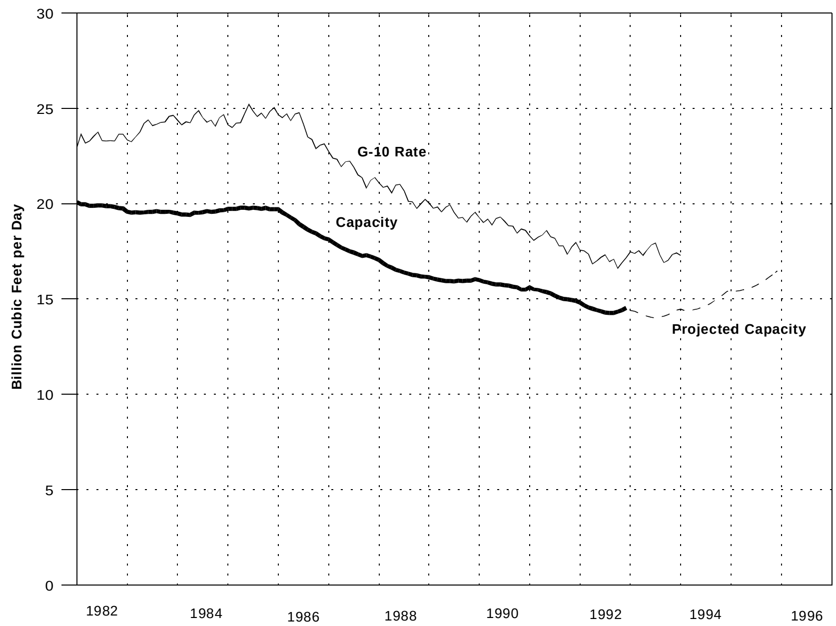


Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Figure 14 shows a comparison of the monthly deliverability determined by the Texas Railroad Commission (TRC) and the monthly gross gas-well gas productive capacity estimated in this study. Operators of Texas gas wells are required to make a production test of each gas well semi-annually and report the test on Form G-10 unless the well is exempt from testing. All gas wells producing less than 100 thousand cubic feet per day are automatically exempt. Each month, the TRC determines statewide gas well deliverability by summing the latest available G-10 test rates. However, the TRC does not necessarily expect that this deliverability (sum of G-10 test rates) can be achieved. As expected, the magnitude of the deliverability as determined by the TRC from the G-10 tests is higher than the productive capacity estimated in this report. This is true for the following reasons:

- The daily rate reported on a Form G-10 is of 72 hours duration, and that rate cannot be sustained for a month by most gas-well completions.
- If all gas-well completions were produced at the daily rate shown on a G-10, increased back-pressures would result, prohibiting gas from many wells from getting into the pipeline system.
- The daily rates reported on the G-10's reflect the ability of gas-well completions to produce at the time they are tested. However, each TRC deliverability estimate (sum of latest G-10 tests) contains well test data that may be as much as 5 or more months old.

Figure 14. Texas (Excluding Gulf of Mexico OCS) Gross Gas-Well Gas Productive Capacity and G-10 Rate, 1982-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Railroad Commission of Texas. •Projections: Model GASCAP93 C060194.

The two curves shown by Figure 14 are useful in that the similar downward trend exhibited by both curves indicates a diminishing surplus capacity. The deliverability determined from G-10 test data declined 31 percent from December 1985 through December 1992 and then increased slightly from 17.2 Bcf to 17.4 Bcf to December 1993. The gross gas-well gas productive capacity declined 26 percent from 1985 through 1992. In December 1992, the sum of the G-10 test rates was 17.2 billion cubic feet per day and the gross gas-well gas productive capacity was 14.5 billion cubic feet per day. The December 1992 sum of the Form G-10 test rates was 18.6 percent greater than the gross gas productive capacity estimated in this report. This suggests that the productive capacities estimated in this report are not overly optimistic.

Louisiana (Excluding Gulf of Mexico OCS)

Louisiana has been a large producer of natural gas for many years. Gas production comes from high permeability, water-drive, deep, and sometimes over-preassured fromations on the Gulf Coast as well as from low permeability and relatively shallow reservoirs in North Louisiana. In 1992, the field producing the largest volume of natural gas in the State was the Lake Arthur South field, according to Dwight's data. In 1992, 9 percent of the total dry gas production of the lower 48 States came from Louisiana.

On the following pages are Tables 7 and 8 and Figures 15 through 17. Data does not include the Gulf of Mexico OCS.

Table 7. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	7,888	9,300	629	9,929	2,041	79.4
Jun-80	7,251	8,860	611	9,471	2,220	76.6
Dec-80	7,376	8,859	591	9,450	2,074	78.1
Jan-81	7,340	8,655	678	9,333	1,993	78.6
Jun-81	6,873	8,233	663	8,896	2,023	77.3
Dec-81	6,732	8,118	649	8,767	2,035	76.8
Jan-82	6,439	8,088	497	8,585	2,146	75.0
Jun-82	5,988	7,839	509	8,348	2,360	71.7
Dec-82	5,671	7,754	485	8,239	2,568	68.8
Jan-83	5,696	7,676	607	8,283	2,587	68.8
Jun-83	5,164	7,422	606	8,028	2,864	64.3
Dec-83	5,537	7,362	586	7,948	2,411	69.7
Jan-84	5,838	7,247	591	7,838	2,000	74.5
Jun-84	5,632	7,047	619	7,666	2,034	73.5
Dec-84	5,536	6,992	614	7,606	2,070	72.8
Jan-85	5,029	6,548	525	7,073	2,044	71.1
Jun-85	4,581	6,417	539	6,956	2,375	65.9
Dec-85	4,877	6,437	516	6,953	2,076	70.1
Jan-86	5,357	7,028	585	7,613	2,256	70.4
Jun-86	4,719	6,776	538	7,314	2,595	64.5
Dec-86	4,950	6,451	579	7,030	2,080	70.4
Jan-87	4,937	6,287	583	6,870	1,933	71.9
Jun-87	4,523	5,971	570	6,541	2,018	69.1
Dec-87	4,764	5,800	573	6,373	1,609	74.8
Jan-88	4,773	5,885	569	6,454	1,681	74.0
Jun-88	4,598	5,756	546	6,302	1,704	73.0
Dec-88	4,795	5,651	540	6,191	1,396	77.5
Jan-89	4,730	5,624	502	6,126	1,396	77.2
Jun-89	4,572	5,543	483	6,026	1,454	75.9
Dec-89	4,333	5,636	420	6,056	1,723	71.5
Jan-90	4,803	5,754	440	6,194	1,391	77.5
Jun-90	4,485	5,603	432	6,035	1,550	74.3
Dec-90	4,631	5,740	443	6,183	1,552	74.9
Jan-91	4,709	5,713	419	6,132	1,423	76.8
Jun-91	4,331	5,403	415	5,818	1,487	74.4
Dec-91	4,544	5,349	422	5,771	1,227	78.7
Jan-92	4,561	5,234	512	5,746	1,185	79.4
Jun-92	4,343	4,905	504	5,409	1,066	80.3
Dec-92	4,445	4,664	497	5,161	716	86.1

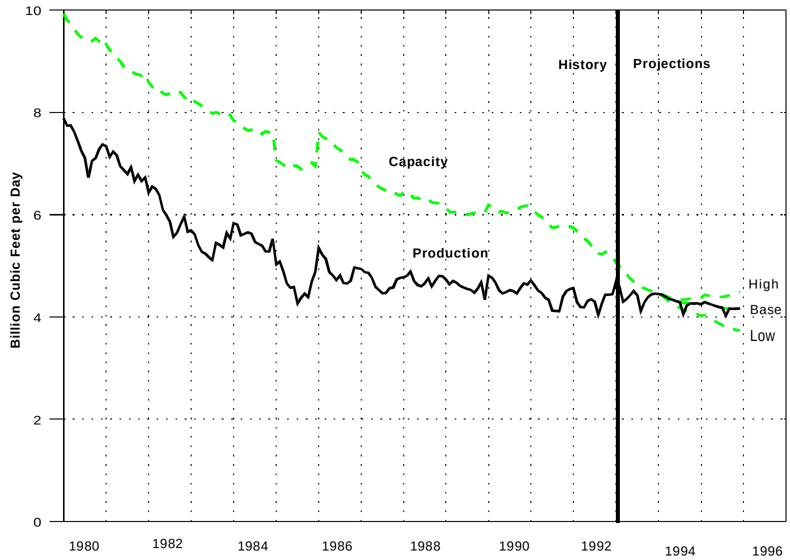
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. • Productive Capacity: GASCAP93 C060194.

Table 8. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
		Low Case Projection				
Jan-93	4,692	4,573	492	5,065	373	92.6
Jun-93	4,510	4,204	481	4,685	175	96.3
Dec-93	4,453	4,009	475	4,484	31	99.3
Jan-94	4,434	3,966	468	4,434	0	100.0
Jun-94	4,213	3,767	446	4,213	0	100.0
Dec-94	4,050	3,613	437	4,050	0	100.0
Jan-95	4,019	3,583	436	4,019	0	100.0
Jun-95	3,873	3,453	420	3,873	0	100.0
Dec-95	3,731	3,319	412	3,731	0	100.0
		Base Case Projection				
Jan-93	4,692	4,573	492	5,065	373	92.6
Jun-93	4,510	4,204	481	4,685	175	96.3
Dec-93	4,453	4,009	475	4,484	31	99.3
Jan-94	4,446	3,970	476	4,446	0	100.0
Jun-94	4,307	3,843	464	4,307	0	100.0
Dec-94	4,262	3,801	461	4,262	0	100.0
Jan-95	4,245	3,785	460	4,245	0	100.0
Jun-95	4,193	3,744	449	4,193	0	100.0
Dec-95	4,166	3,720	446	4,166	0	100.0
		High Case Projection				
Jan-93	4,692	4,573	492	5,065	373	92.6
Jun-93	4,510	4,204	481	4,685	175	96.3
Dec-93	4,453	4,009	475	4,484	31	99.3
Jan-94	4,451	3,970	481	4,451	0	100.0
Jun-94	4,346	3,873	473	4,346	0	100.0
Dec-94	4,380	3,908	472	4,380	0	100.0
Jan-95	4,373	3,900	473	4,373	0	100.0
Jun-95	4,391	3,928	463	4,391	0	100.0
Dec-95	4,459	4,024	465	4,489	30	99.3

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

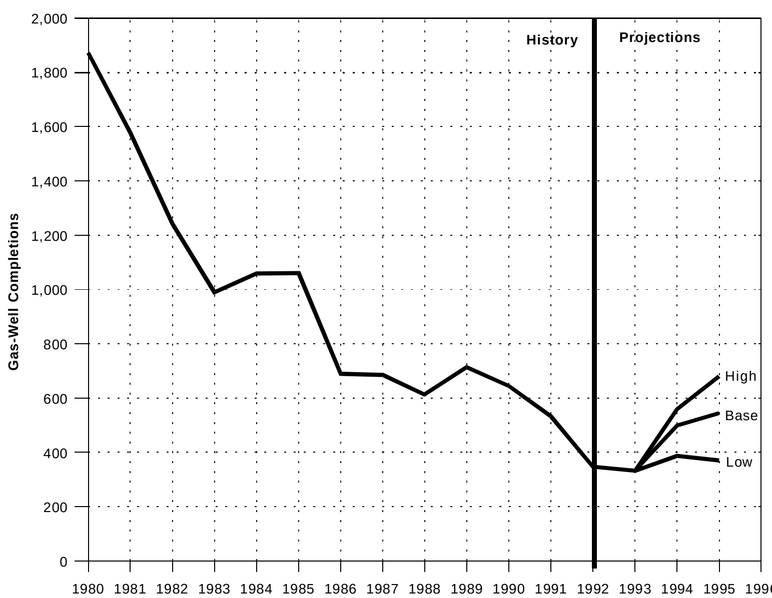
Figure 15. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

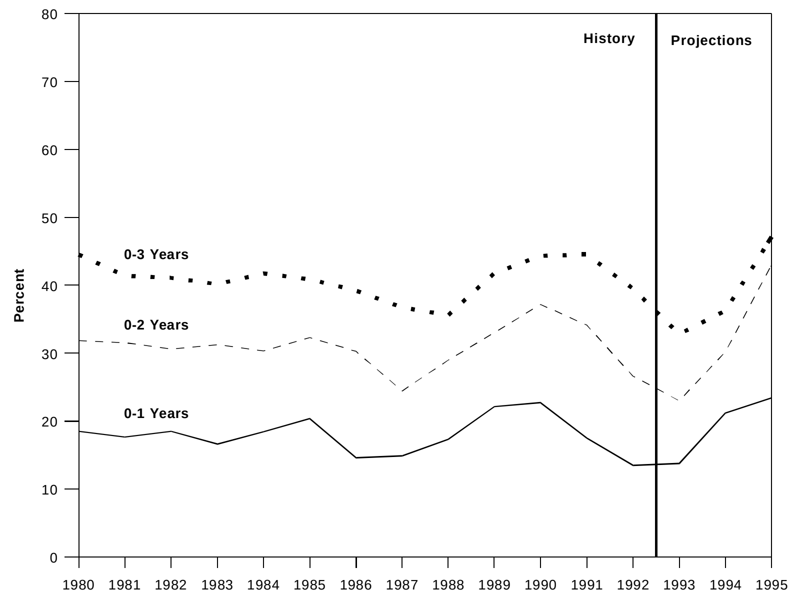
Sources: •Production History: Energy Information, Office of Oil and Gas; Dwight's Energydata, Inc.: and Model GASCAP93 C060194. Production •Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.*

Figure 16. Louisiana (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 17. Percent of Total Wellhead Productive Capacity of Louisiana (Excluding Gulf of Mexico OCS) Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

California (Including Pacific OCS)

California is a net importer of natural gas. All California gas produced is used within the State. In 1992, more than half the total gas produced in California and the Pacific OCS was oil-well gas. {10}

In 1992, Elk Hills and Lost Hills oil fields were the two largest producers of natural gas in the State. There are about 10 fields in California and the Pacific OCS that produced almost 70 percent of the gas-well gas. The two largest gas fields were Bunker and Pitas Point, the latter is in the Pacific OCS. This information was obtained from the California Department of Conservation.

On the following pages are Tables 9 and 10 and Figures 18 through 20. Data includes the Pacific OCS.

Table 9. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

		Dry Gas Productive Capacity				
Month/ Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	921	574	500	1,074	153	85.8
Jun-80	694	551	508	1,059	365	65.5
Dec-80	954	565	529	1,094	140	87.2
Jan-81	1,033	642	555	1,197	164	86.3
Jun-81	1,000	620	591	1,211	211	82.6
Dec-81	973	598	600	1,198	225	81.2
Jan-82	1,087	574	664	1,238	151	87.8
Jun-82	949	575	673	1,248	299	76.0
Dec-82	1,149	557	669	1,226	77	93.7
Jan-83	1,197	718	688	1,406	209	85.1
Jun-83	1,032	703	701	1,404	372	73.5
Dec-83	1,156	697	696	1,393	237	83.0
Jan-84	1,279	735	735	1,470	191	87.0
Jun-84	1,254	739	729	1,468	214	85.4
Dec-84	1,253	724	747	1,471	218	85.2
Jan-85	1,335	759	751	1,510	175	88.4
Jun-85	1,269	736	770	1,506	237	84.3
Dec-85	1,337	726	786	1,512	175	88.4
Jan-86	1,347	725	775	1,500	153	89.8
Jun-86	1,231	664	734	1,398	167	88.1
Dec-86	1,175	614	703	1,317	142	89.2
Jan-87	1,165	584	696	1,280	115	91.0
Jun-87	1,120	536	714	1,250	130	89.6
Dec-87	1,086	486	707	1,193	107	91.0
Jan-88	1,065	493	695	1,188	123	89.6
Jun-88	1,071	465	692	1,157	86	92.6
Dec-88	996	427	655	1,082	86	92.1
Jan-89	979	428	659	1,087	108	90.1
Jun-89	951	401	658	1,059	108	89.8
Dec-89	940	390	648	1,038	98	90.6
Jan-90	954	430	652	1,082	128	88.2
Jun-90	933	427	638	1,065	132	87.6
Dec-90	976	431	637	1,068	92	91.4
Jan-91	990	533	625	1,158	168	85.5
Jun-91	991	518	628	1,146	155	86.5
Dec-91	996	476	635	1,111	115	89.6
Jan-92	1,030	451	632	1,083	53	95.1
Jun-92	956	423	630	1,053	97	90.8
Dec-92	907	403	628	1,031	124	88.0

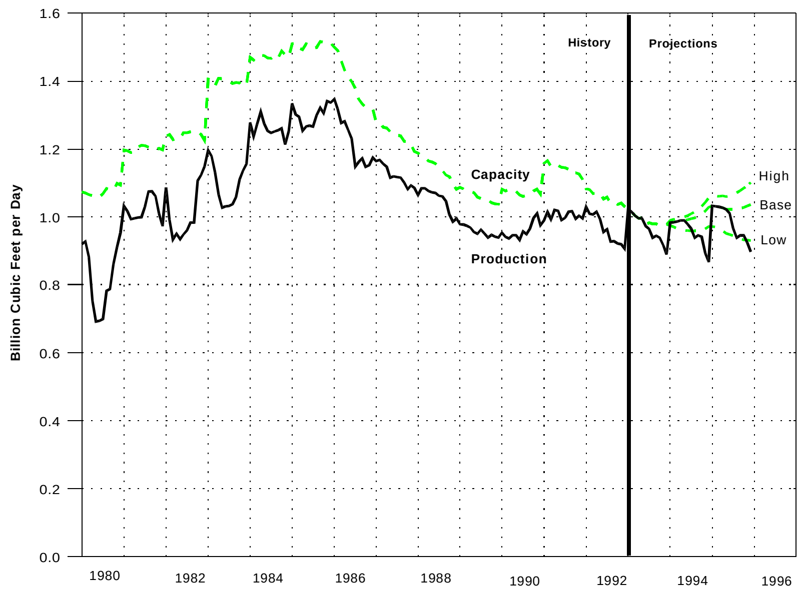
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194.

Table 10. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Low Case Projection						
Jan-93	1,024	397	627	1,024	0	100.0
Jun-93	973	358	620	978	5	99.5
Dec-93	890	354	625	979	89	90.9
Jan-94	975	355	620	975	0	100.0
Jun-94	960	348	612	960	0	100.0
Dec-94	872	349	623	972	100	89.7
Jan-95	972	349	623	972	0	100.0
Jun-95	949	344	605	949	0	100.0
Dec-95	909	336	595	931	22	97.6
Base Case Projection						
Jan-93	1,024	397	627	1,024	0	100.0
Jun-93	973	358	620	978	5	99.5
Dec-93	890	354	625	979	89	90.9
Jan-94	984	355	629	984	0	100.0
Jun-94	979	358	634	992	13	98.7
Dec-94	867	377	652	1,029	162	84.3
Jan-95	1,033	381	652	1,033	0	100.0
Jun-95	1,011	383	640	1,023	12	98.8
Dec-95	898	401	636	1,037	139	86.6
High Case Projection						
Jan-93	1,024	397	627	1,024	0	100.0
Jun-93	973	358	620	978	5	99.5
Dec-93	890	354	625	979	89	90.9
Jan-94	990	355	635	990	0	100.0
Jun-94	978	360	644	1,004	26	97.4
Dec-94	865	390	666	1,056	191	81.9
Jan-95	1,063	397	666	1,063	0	100.0
Jun-95	1,006	405	658	1,063	57	94.6
Dec-95	891	443	659	1,102	211	80.9

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

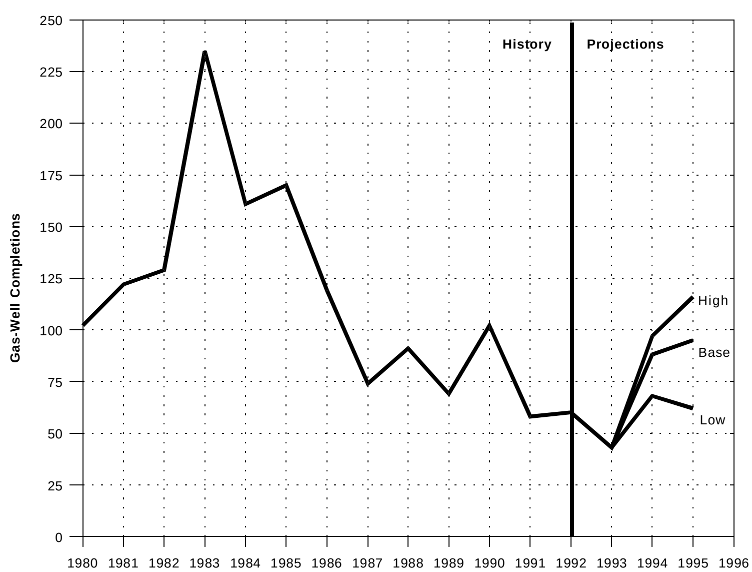
Figure 18. California (Including Pacific OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

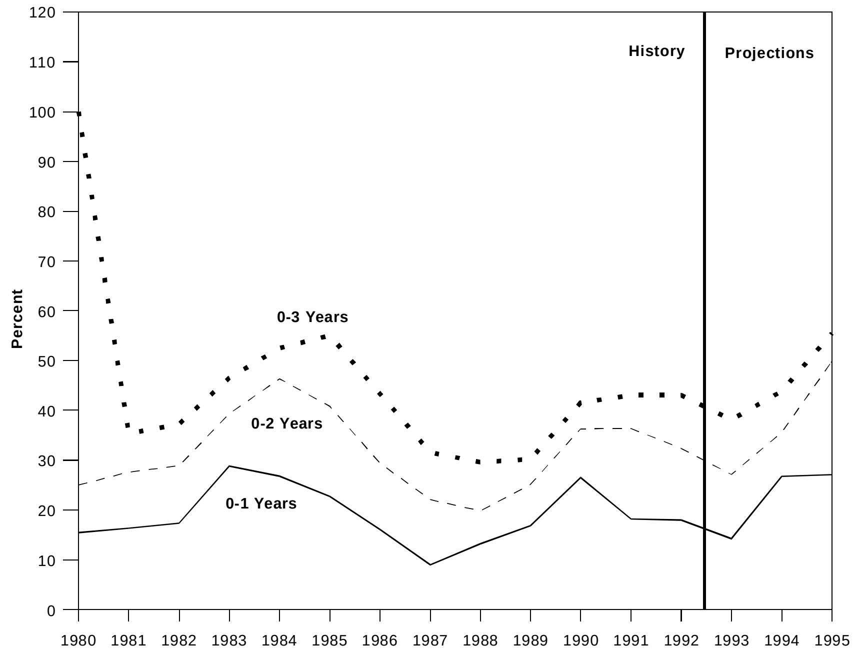
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.*

Figure 19. California (Including Pacific OCS) Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 20. Percent of Total Wellhead Productive Capacity of California (Including Pacific OCS) Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Kansas

Approximately 62 percent of the total gas produced in the State of Kansas was from the giant Hugoton gas field in 1992. This information was obtained from Dwight's. The Hugoton field occupies almost all of the western one half of Kansas, and it extends south into Oklahoma and into the northern part of the Texas Panhandle. Production from this field generally comes from low permeability sandy carbonate reservoir rocks.

On the following pages are Tables 11 and 12 and Figures 21 through 23.

Table 11. Kansas Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Dry Gas Productive Capacity: Oil-Well Gas	Dry Gas Productive Capacity: Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	2,672	3,221	332	3,553	881	75.2
Jun-80	1,526	3,172	341	3,513	1,987	43.4
Dec-80	1,954	3,120	353	3,473	1,519	56.3
Jan-81	2,343	3,147	260	3,407	1,064	68.8
Jun-81	1,603	3,089	286	3,375	1,772	47.5
Dec-81	1,693	3,050	300	3,350	1,657	50.5
Jan-82	2,163	3,108	185	3,293	1,130	65.7
Jun-82	882	3,076	209	3,285	2,403	26.8
Dec-82	1,129	3,099	195	3,294	2,165	34.3
Jan-83	1,124	3,038	208	3,246	2,122	34.6
Jun-83	833	3,024	199	3,223	2,390	25.8
Dec-83	1,974	2,999	186	3,185	1,211	62.0
Jan-84	1,960	2,861	202	3,063	1,103	64.0
Jun-84	868	2,828	220	3,048	2,180	28.5
Dec-84	1,413	2,806	212	3,018	1,605	46.8
Jan-85	1,749	2,812	227	3,039	1,290	57.6
Jun-85	928	2,787	233	3,020	2,092	30.7
Dec-85	1,981	2,758	241	2,999	1,018	66.1
Jan-86	1,806	2,786	287	3,073	1,267	58.8
Jun-86	897	2,787	245	3,032	2,135	29.6
Dec-86	1,702	2,760	226	2,986	1,284	57.0
Jan-87	1,597	2,808	251	3,059	1,462	52.2
Jun-87	994	2,755	252	3,007	2,013	33.1
Dec-87	1,720	2,717	248	2,965	1,245	58.0
Jan-88	2,003	2,782	281	3,063	1,060	65.4
Jun-88	1,197	2,721	302	3,023	1,826	39.6
Dec-88	1,752	2,744	279	3,023	1,271	58.0
Jan-89	2,071	2,727	248	2,975	904	69.6
Jun-89	1,472	2,717	244	2,961	1,489	49.7
Dec-89	1,736	2,764	218	2,982	1,246	58.2
Jan-90	1,746	2,783	279	3,062	1,316	57.0
Jun-90	1,324	2,737	275	3,012	1,688	44.0
Dec-90	1,956	2,775	268	3,043	1,087	64.3
Jan-91	1,886	2,733	200	2,933	1,047	64.3
Jun-91	1,445	2,721	202	2,923	1,478	49.4
Dec-91	1,952	2,733	193	2,926	974	66.7
Jan-92	2,022	2,830	215	3,045	1,023	66.4
Jun-92	1,482	2,812	205	3,017	1,535	49.1
Dec-92	2,074	2,752	201	2,953	879	70.2

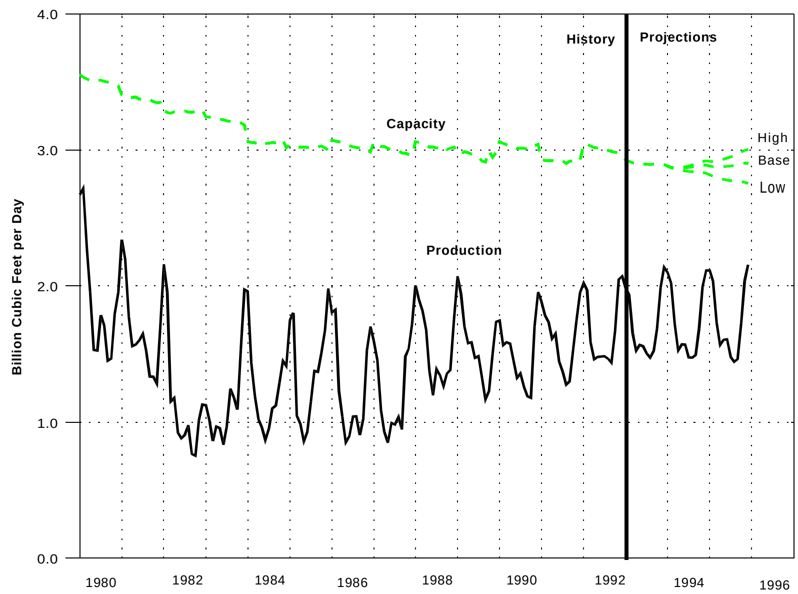
Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

Table 12. Kansas Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
	Low Case Projection					
Jan-93	1,986	2,734	193	2,927	941	67.9
Jun-93	1,557	2,704	194	2,898	1,341	53.7
Dec-93	2,139	2,706	187	2,893	754	73.9
Jan-94	2,102	2,697	184	2,881	779	73.0
Jun-94	1,572	2,672	175	2,847	1,275	55.2
Dec-94	2,128	2,661	170	2,831	703	75.2
Jan-95	2,140	2,649	170	2,819	679	75.9
Jun-95	1,624	2,618	163	2,781	1,157	58.4
Dec-95	2,184	2,597	159	2,756	572	79.2
	Base Case Projection					
Jan-93	1,986	2,734	193	2,927	941	67.9
Jun-93	1,557	2,704	194	2,898	1,341	53.7
Dec-93	2,139	2,706	187	2,893	754	73.9
Jan-94	2,101	2,696	187	2,883	782	72.9
Jun-94	1,568	2,687	182	2,869	1,301	54.7
Dec-94	2,116	2,710	180	2,890	774	73.2
Jan-95	2,116	2,704	180	2,884	768	73.4
Jun-95	1,608	2,706	174	2,880	1,272	55.8
Dec-95	2,158	2,732	172	2,904	746	74.3
	High Case Projection					
Jan-93	1,986	2,734	193	2,927	941	67.9
Jun-93	1,557	2,704	194	2,898	1,341	53.7
Dec-93	2,139	2,706	187	2,893	754	73.9
Jan-94	2,101	2,694	189	2,883	782	72.9
Jun-94	1,566	2,693	185	2,878	1,312	54.4
Dec-94	2,110	2,737	184	2,921	811	72.2
Jan-95	2,108	2,735	184	2,919	811	72.2
Jun-95	1,600	2,761	180	2,941	1,341	54.4
Dec-95	2,142	2,825	180	3,005	863	71.3

Sources: ●Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

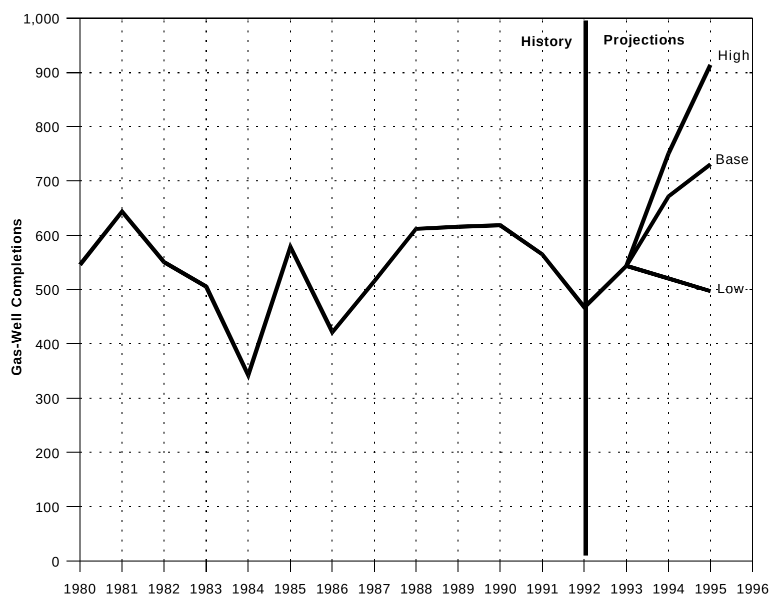
Figure 21. Kansas Dry Gas Monthly Production Rate and Wellhead Productive Capacity 1980-1995



Note: Production projection plotted for base case only.

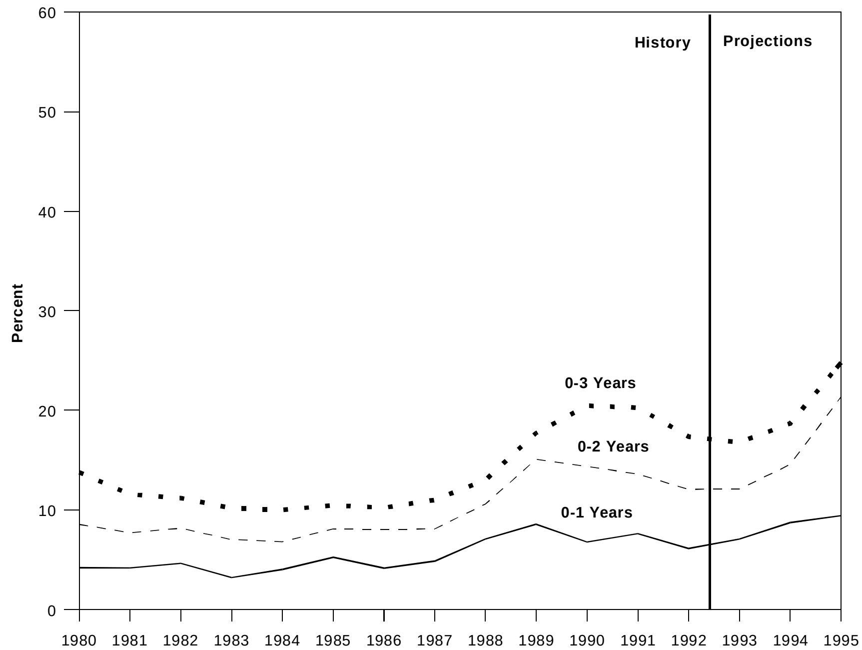
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.*

Figure 22. Kansas Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 23. Percent of Total Wellhead Productive Capacity of Kansas Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. •Projections: Model GAS-CAP93 C060194.

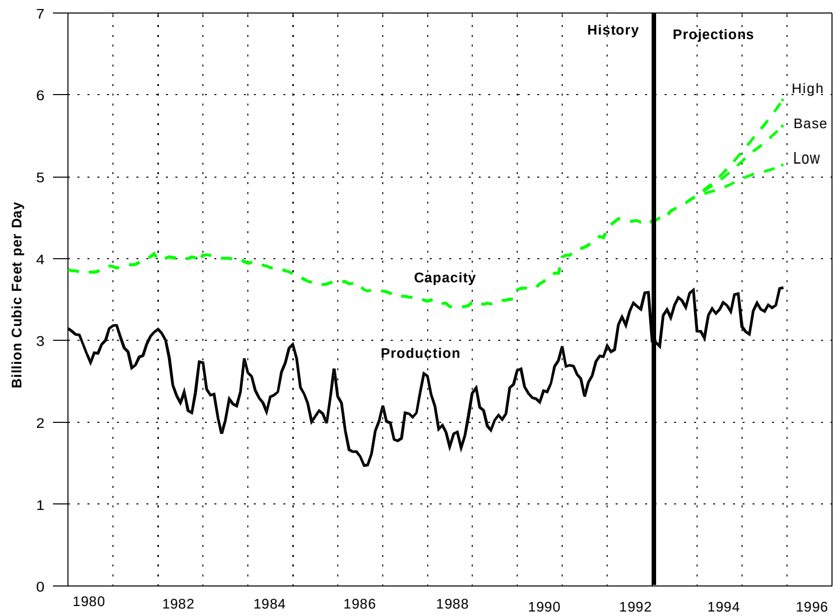
New Mexico

Most of this State's natural gas is produced in northwestern New Mexico from the San Juan Basin. Practically all of the oil-well gas production comes from the formations in the Permian Basin of southeast New Mexico.

Coalbed methane gas production in New Mexico was about 15 percent of the State's total dry gas production in 1990, 23 percent in 1991, and 31 percent in 1992.{8} However, coalbed methane was treated as gas-well gas.

On the following pages are Tables 13 and 14 and Figures 24 through 26.

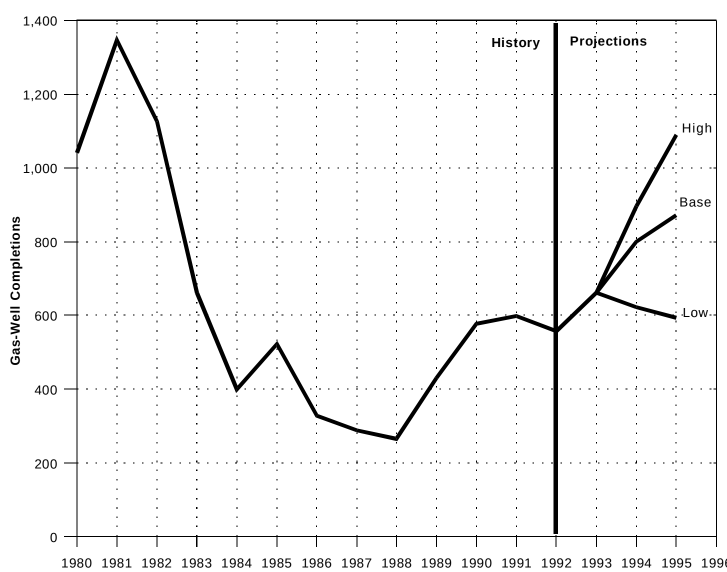
Figure 24. New Mexico Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

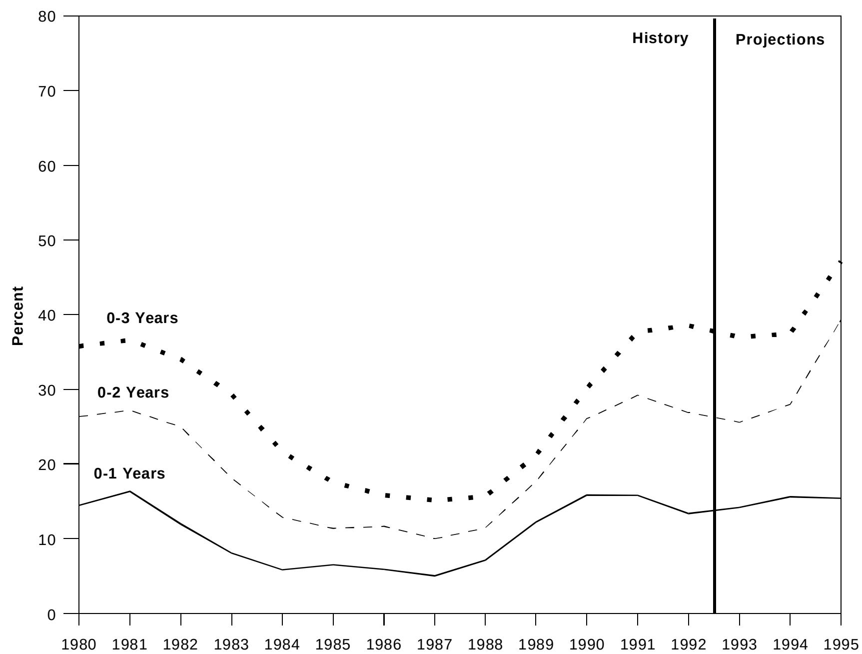
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections First Quarter 1994 and Model GASCAP93 C060194.*

Figure 25. New Mexico Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 26. Percent of Total Wellhead Productive Capacity of New Mexico Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Oklahoma

Oklahoma is in the top three gas producing States (Figure 3). There are numerous large and small gas fields scattered throughout western Oklahoma. Oil fields with large volumes of associated-dissolved gas are also present in this State and are located generally in central Oklahoma. In 1992, the top two gas producing areas were the Mocane-Laverne area and the Watonga-Chickasha trend (Dwight's). The Mocane-Laverne area located in Northwest Oklahoma consists of over 50 fields, and the Watonga-Chickasha trend consist of more than 70 fields.

On the following pages are Tables 15 and 16 and Figures 27 through 29.

Table 15. Oklahoma Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Dry Gas Productive Capacity: Oil-Well Gas	Dry Gas Productive Capacity: Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	5,505	6,295	973	7,268	1,763	75.7
Jun-80	4,828	6,346	936	7,282	2,454	66.3
Dec-80	5,551	6,502	1,055	7,557	2,006	73.5
Jan-81	5,685	6,754	1,010	7,764	2,079	73.2
Jun-81	5,335	6,633	1,109	7,742	2,407	68.9
Dec-81	5,681	7,184	1,106	8,290	2,609	68.5
Jan-82	5,792	6,871	1,137	8,008	2,216	72.3
Jun-82	4,870	7,056	1,195	8,251	3,381	59.0
Dec-82	4,903	7,260	1,150	8,410	3,507	58.3
Jan-83	5,008	6,950	1,059	8,009	3,001	62.5
Jun-83	3,995	7,019	1,079	8,098	4,103	49.3
Dec-83	5,158	7,143	881	8,024	2,866	64.3
Jan-84	5,839	7,217	1,107	8,324	2,485	70.1
Jun-84	4,795	7,278	1,146	8,424	3,629	56.9
Dec-84	5,560	7,398	1,104	8,502	2,942	65.4
Jan-85	5,748	7,459	1,187	8,646	2,898	66.5
Jun-85	4,693	7,460	1,138	8,598	3,905	54.6
Dec-85	5,574	7,480	1,207	8,687	3,113	64.2
Jan-86	5,664	7,557	1,345	8,902	3,238	63.6
Jun-86	4,706	7,528	1,156	8,684	3,978	54.2
Dec-86	5,445	7,424	1,128	8,552	3,107	63.7
Jan-87	5,590	7,538	1,228	8,766	3,176	63.8
Jun-87	5,063	7,408	1,296	8,704	3,641	58.2
Dec-87	5,752	7,368	1,211	8,579	2,827	67.0
Jan-88	5,903	7,244	1,202	8,446	2,543	69.9
Jun-88	5,441	7,157	1,222	8,379	2,938	64.9
Dec-88	6,004	7,041	1,183	8,224	2,220	73.0
Jan-89	6,037	7,145	1,222	8,367	2,330	72.2
Jun-89	5,826	7,019	1,141	8,160	2,334	71.4
Dec-89	5,806	6,907	1,033	7,940	2,134	73.1
Jan-90	6,322	6,965	1,224	8,189	1,867	77.2
Jun-90	5,884	6,782	1,094	7,876	1,992	74.7
Dec-90	5,744	6,698	1,010	7,708	1,964	74.5
Jan-91	5,920	6,826	940	7,766	1,846	76.2
Jun-91	5,408	6,595	941	7,536	2,128	71.8
Dec-91	5,761	6,464	892	7,356	1,595	78.3
Jan-92	5,659	6,473	903	7,376	1,717	76.7
Jun-92	5,112	6,236	894	7,130	2,018	71.7
Dec-92	5,114	6,023	886	6,909	1,795	74.0

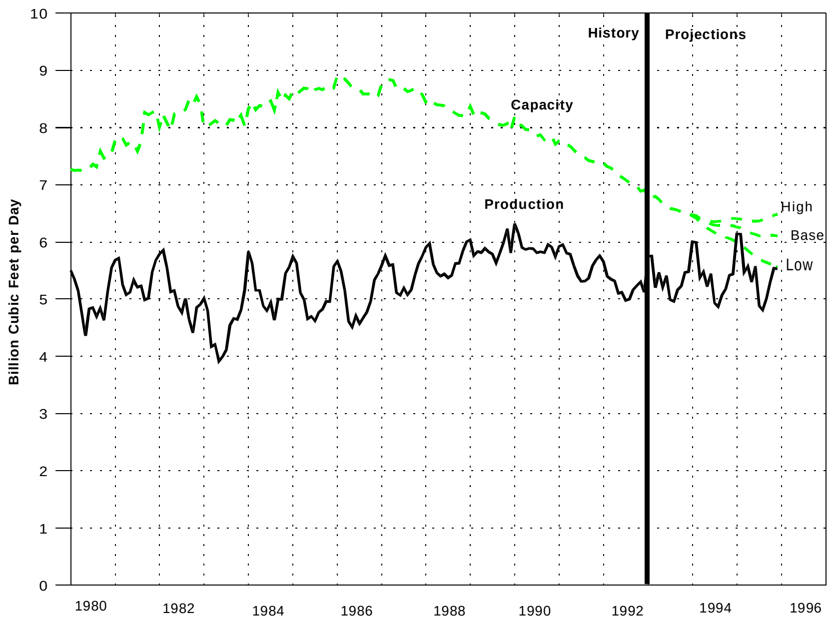
Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

Table 16. Oklahoma Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
			Low Case			
Jan-93	5,752	5,961	846	6,807	1,055	84.5
Jun-93	5,415	5,782	848	6,630	1,215	81.7
Dec-93	5,483	5,654	847	6,501	1,018	84.3
Jan-94	6,010	5,616	834	6,450	440	93.2
Jun-94	5,467	5,414	791	6,205	738	88.1
Dec-94	5,471	5,263	771	6,034	563	90.7
Jan-95	5,991	5,222	769	5,991	0	100.0
Jun-95	5,634	5,013	737	5,750	116	98.0
Dec-95	5,557	4,837	720	5,557	0	100.0
			Base Case Projection			
Jan-93	5,752	5,961	846	6,807	1,055	84.5
Jun-93	5,415	5,782	848	6,630	1,215	81.7
Dec-93	5,483	5,654	847	6,501	1,018	84.3
Jan-94	6,006	5,620	847	6,467	461	92.9
Jun-94	5,450	5,491	824	6,315	865	86.3
Dec-94	5,441	5,471	813	6,284	843	86.6
Jan-95	6,141	5,449	812	6,261	120	98.1
Jun-95	5,578	5,344	788	6,132	554	91.0
Dec-95	5,531	5,331	779	6,110	579	90.5
			High Case Projection			
Jan-93	5,752	5,961	846	6,807	1,055	84.5
Jun-93	5,415	5,782	848	6,630	1,215	81.7
Dec-93	5,483	5,654	847	6,501	1,018	84.3
Jan-94	6,004	5,620	856	6,476	472	92.7
Jun-94	5,445	5,522	838	6,360	915	85.6
Dec-94	5,424	5,581	833	6,414	990	84.6
Jan-95	6,118	5,571	833	6,404	286	95.5
Jun-95	5,550	5,550	814	6,364	814	87.2
Dec-95	5,490	5,673	813	6,486	996	84.6

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

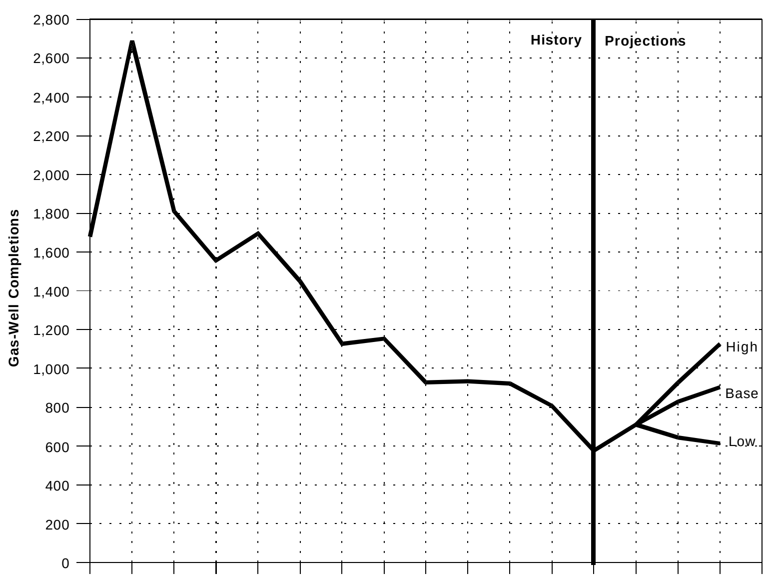
Figure 27. Oklahoma Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

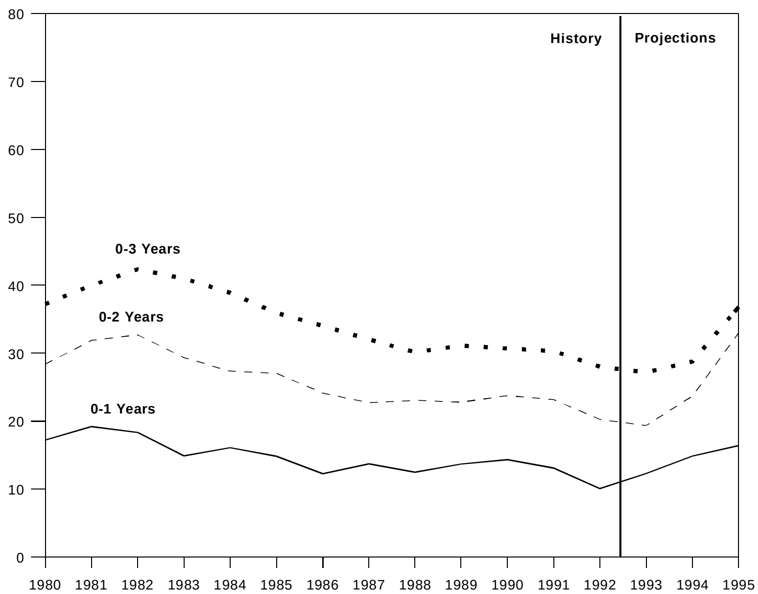
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly* Projections First Quarter 1994 and Model GASCAP93 C060194.

Figure 28. Oklahoma Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 29. Percent of Total Wellhead Productive Capacity of Oklahoma Gas Wells, by Age 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Southeast

The Southeast area in this report includes the States of Arkansas, Mississippi, and Alabama. Production is from the highly permeable deep formations on the Gulf Coast as well as low permeability and relatively shallow formations in Arkansas, northern Mississippi, and northern Alabama.

Coalbed methane gas production in Alabama was 35 percent of the State's total dry gas production in 1990, 47 percent in 1991, and 35 percent in 1992. However, coalbed methane gas was treated as gas-well gas.

On the following pages are Tables 17 and 18 and Figures 30 through 32.

Table 17. Southeast Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

		Dry Gas Productive Capacity				
Month/ Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Dec-80	999	1,128	126	1,254	255	79.7
Jun-80	916	1,120	121	1,241	325	73.8
Dec-80	1,038	1,184	121	1,305	267	79.5
Dec-81	992	1,117	116	1,233	241	80.5
Jun-81	971	1,139	116	1,255	284	77.4
Dec-81	1,008	1,199	118	1,317	309	76.5
Dec-82	1,025	1,207	120	1,327	302	77.2
Jun-82	953	1,269	124	1,393	440	68.4
Dec-82	1,020	1,292	120	1,412	392	72.2
Dec-83	1,156	1,363	141	1,504	348	76.9
Jun-83	932	1,348	137	1,485	553	62.8
Dec-83	1,018	1,374	139	1,513	495	67.3
Dec-84	1,177	1,402	133	1,535	358	76.7
Jun-84	985	1,393	134	1,527	542	64.5
Dec-84	1,090	1,436	135	1,571	481	69.4
Dec-85	1,266	1,497	141	1,638	372	77.3
Jun-85	1,041	1,523	147	1,670	629	62.3
Dec-85	1,226	1,590	150	1,740	514	70.5
Dec-86	1,132	1,490	146	1,636	504	69.2
Jun-86	935	1,523	137	1,660	725	56.3
Dec-86	1,159	1,586	131	1,717	558	67.5
Dec-87	1,177	1,556	128	1,684	507	69.9
Jun-87	1,042	1,530	130	1,660	618	62.8
Dec-87	1,144	1,511	127	1,638	494	69.8
Dec-88	1,198	1,444	124	1,568	370	76.4
Jun-88	1,062	1,396	121	1,517	455	70.0
Dec-88	1,171	1,385	119	1,504	333	77.9
Dec-89	1,216	1,370	126	1,496	280	81.3
Jun-89	1,067	1,356	127	1,483	416	71.9
Dec-89	1,084	1,345	115	1,460	376	74.2
Dec-90	1,167	1,347	109	1,456	289	80.2
Jun-90	1,067	1,370	110	1,480	413	72.1
Dec-90	1,154	1,453	112	1,565	411	73.7
Dec-91	1,294	1,666	94	1,760	466	73.5
Jun-91	1,114	1,762	92	1,854	740	60.1
Dec-91	1,412	1,825	93	1,918	506	73.6
Dec-92	1,815	2,210	160	2,370	555	76.6
Jun-92	1,759	2,124	154	2,278	519	77.2
Dec-92	1,880	2,049	155	2,204	324	85.3

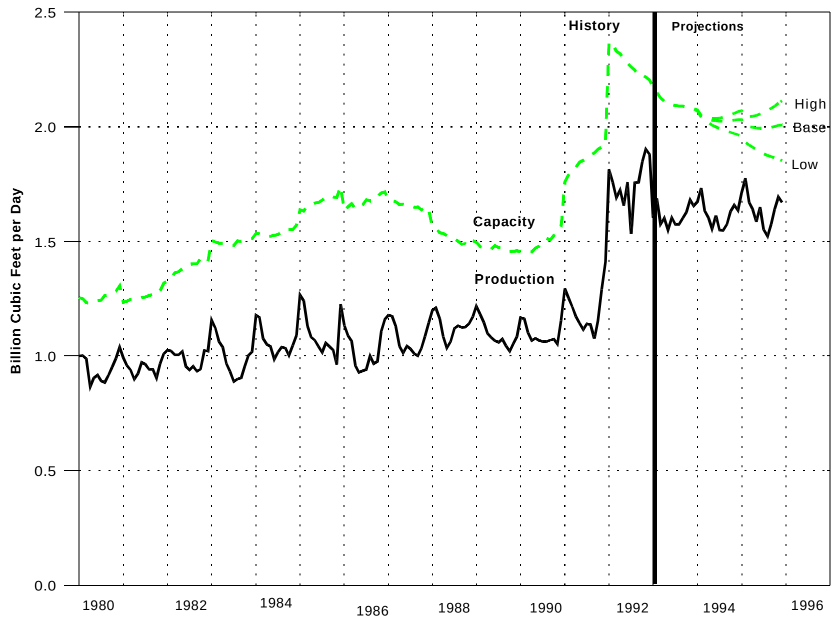
Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

Table 18. Southeast Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

		Dry Gas Productive Capacity				
Month/ Year	Dry Production	Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
		Low Case Projection				
Dec-93	1,602	2,021	152	2,173	571	73.7
Jun-93	1,604	1,964	133	2,097	493	76.5
Dec-93	1,656	1,934	144	2,078	422	79.7
Dec-94	1,675	1,928	141	2,069	394	81.0
Jun-94	1,619	1,866	134	2,000	381	81.0
Dec-94	1,645	1,835	131	1,966	321	83.7
Dec-95	1,732	1,829	130	1,959	227	88.4
Jun-95	1,667	1,766	125	1,891	224	88.2
Dec-95	1,691	1,731	122	1,853	162	91.3
		Base Case Projection				
Dec-93	1,602	2,021	152	2,173	571	73.7
Jun-93	1,604	1,964	133	2,097	493	76.5
Dec-93	1,656	1,934	144	2,078	422	79.7
Dec-94	1,674	1,929	144	2,073	399	80.8
Jun-94	1,614	1,887	140	2,027	413	79.6
Dec-94	1,636	1,894	138	2,032	396	80.5
Dec-95	1,712	1,894	138	2,032	320	84.3
Jun-95	1,651	1,861	133	1,994	343	82.8
Dec-95	1,671	1,877	132	2,009	338	83.2
		High Case Projection				
Dec-93	1,602	2,021	152	2,173	571	73.7
Jun-93	1,604	1,964	133	2,097	493	76.5
Dec-93	1,656	1,934	144	2,078	422	79.7
Dec-94	1,674	1,929	145	2,074	400	80.7
Jun-94	1,612	1,895	142	2,037	425	79.1
Dec-94	1,631	1,925	141	2,066	435	78.9
Dec-95	1,706	1,929	141	2,070	364	82.4
Jun-95	1,643	1,918	138	2,056	413	79.9
Dec-95	1,658	1,976	138	2,114	456	78.4

Sources: ●Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

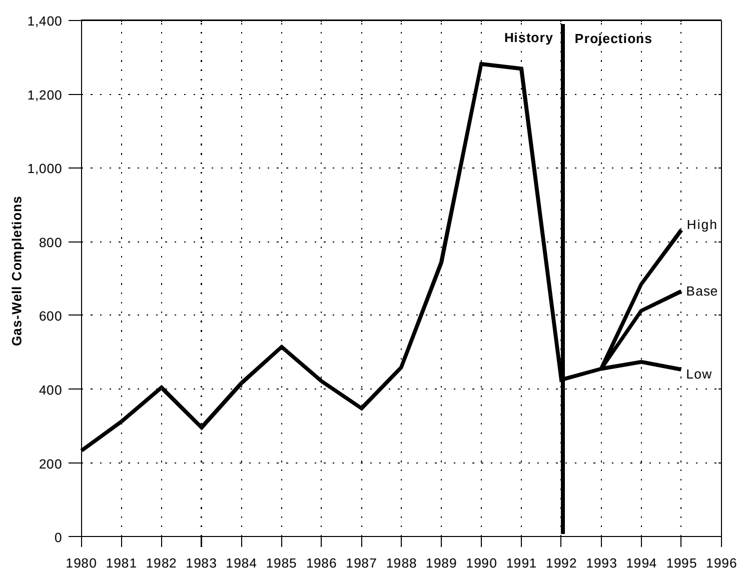
Figure 30. Southeast Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

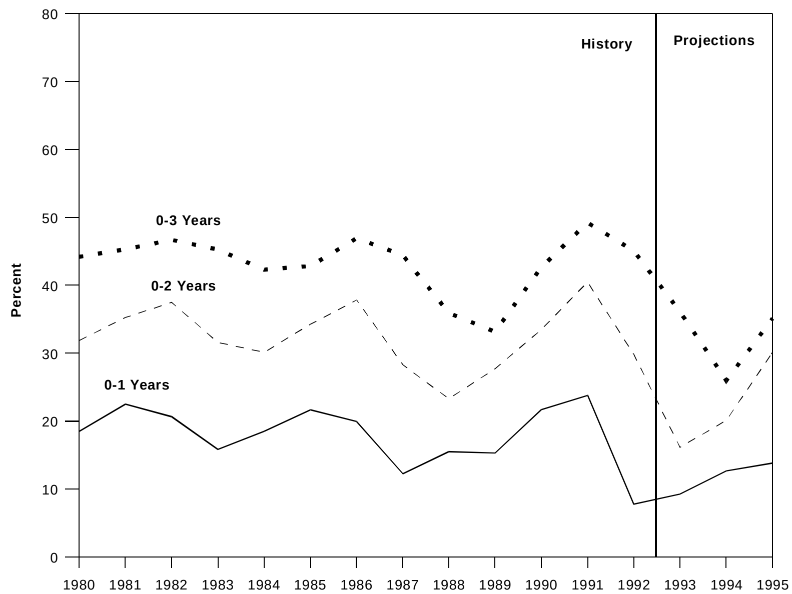
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly* Projections First Quarter 1994 and Model GASCAP93 C060194.

Figure 31. Southeast Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 32. Percent of Total Wellhead Productive Capacity of Southeast Gas Wells, by Age 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Rocky Mountains

The Rocky Mountains area in this report includes Colorado, Montana, North Dakota, Utah, and Wyoming. Geologically, the region is diverse and complex with many low permeability formations.

Coalbed methane gas production in Colorado was about 11 percent of the State's total dry gas production in 1990, 17 percent in 1991, and 26 percent in 1992. However, coalbed methane was treated as gas-well gas.

On the following pages are Tables 19 and 20 and Figures 33 through 35.

Table 19. Rocky Mountains Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Dry Gas Productive Capacity: Oil-Well Gas	Dry Gas Productive Capacity: Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	2,096	1,402	983	2,385	289	87.9
Jun-80	1,905	1,445	1,023	2,468	563	77.2
Dec-80	2,207	1,538	1,051	2,589	382	85.2
Jan-81	2,163	1,937	766	2,703	540	80.0
Jun-81	1,946	1,977	784	2,761	815	70.5
Dec-81	2,288	2,052	783	2,835	547	80.7
Jan-82	2,443	2,300	711	3,011	568	81.1
Jun-82	2,035	2,375	735	3,110	1,075	65.4
Dec-82	2,510	2,585	732	3,317	807	75.7
Jan-83	2,345	2,887	501	3,388	1,043	69.2
Jun-83	1,796	3,263	503	3,766	1,970	47.7
Dec-83	2,543	3,814	483	4,297	1,754	59.2
Jan-84	2,492	3,659	489	4,148	1,656	60.1
Jun-84	2,167	3,698	531	4,229	2,062	51.2
Dec-84	2,794	3,820	500	4,320	1,526	64.7
Jan-85	2,187	2,566	634	3,200	1,013	68.3
Jun-85	1,843	2,638	636	3,274	1,431	56.3
Dec-85	2,368	2,736	609	3,345	977	70.8
Jan-86	2,148	2,443	650	3,093	945	69.4
Jun-86	1,736	2,499	600	3,099	1,363	56.0
Dec-86	2,255	2,673	562	3,235	980	69.7
Jan-87	2,368	2,479	785	3,264	896	72.5
Jun-87	2,048	2,465	761	3,226	1,178	63.5
Dec-87	2,386	2,480	763	3,243	857	73.6
Jan-88	2,459	2,423	802	3,225	766	76.2
Jun-88	2,187	2,429	804	3,233	1,046	67.6
Dec-88	2,506	2,472	754	3,226	720	77.7
Jan-89	3,077	2,972	909	3,881	804	79.3
Jun-89	2,623	2,946	873	3,819	1,196	68.7
Dec-89	3,071	2,949	861	3,810	739	80.6
Jan-90	3,296	3,045	1,061	4,106	810	80.3
Jun-90	2,913	3,042	1,045	4,087	1,174	71.3
Dec-90	3,338	3,093	1,015	4,108	770	81.3
Jan-91	3,550	3,150	1,102	4,252	702	83.5
Jun-91	3,173	3,142	1,077	4,219	1,046	75.2
Dec-91	3,383	3,168	1,048	4,216	833	80.2
Jan-92	3,875	3,596	1,064	4,660	785	83.2
Jun-92	3,663	3,581	1,054	4,635	972	79.0
Dec-92	3,936	3,654	1,009	4,663	727	84.4

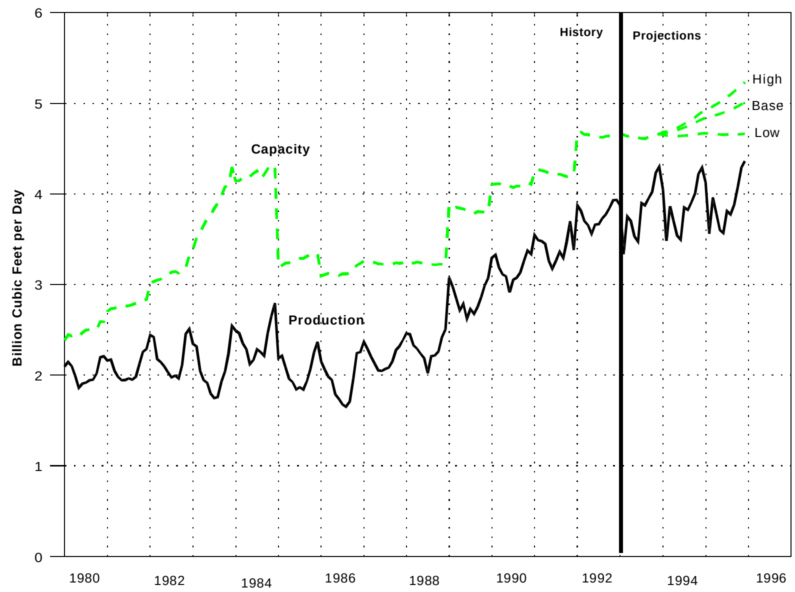
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. • Productive Capacity: GASCAP93 C060194.

Table 20. Rocky Mountains Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
		Low Case Projection				
Jan-93	3,877	3,647	1,015	4,662	785	83.2
Jun-93	3,476	3,645	975	4,620	1,144	75.2
Dec-93	4,301	3,710	952	4,662	361	92.3
Jan-94	4,050	3,717	938	4,655	605	87.0
Jun-94	3,509	3,747	893	4,640	1,131	75.6
Dec-94	4,315	3,796	873	4,669	354	92.4
Jan-95	4,174	3,799	872	4,671	497	89.4
Jun-95	3,606	3,816	839	4,655	1,049	77.5
Dec-95	4,417	3,842	823	4,665	248	94.7
		Base Case Projection				
Jan-93	3,877	3,647	1,015	4,662	785	83.2
Jun-93	3,476	3,645	975	4,620	1,144	75.2
Dec-93	4,301	3,710	952	4,662	361	92.3
Jan-94	4,048	3,719	953	4,672	624	86.6
Jun-94	3,498	3,788	930	4,718	1,220	74.1
Dec-94	4,292	3,904	921	4,825	533	89.0
Jan-95	4,126	3,920	921	4,841	715	85.2
Jun-95	3,571	4,002	896	4,898	1,327	72.9
Dec-95	4,364	4,119	890	5,009	645	87.1
		High Case Projection				
Jan-93	3,877	3,647	1,015	4,662	785	83.2
Jun-93	3,476	3,645	975	4,620	1,144	75.2
Dec-93	4,301	3,710	952	4,662	361	92.3
Jan-94	4,047	3,720	963	4,683	636	86.4
Jun-94	3,495	3,804	946	4,750	1,255	73.6
Dec-94	4,279	3,961	944	4,905	626	87.2
Jan-95	4,111	3,984	945	4,929	818	83.4
Jun-95	3,552	4,113	926	5,039	1,487	70.5
Dec-95	4,332	4,304	929	5,233	901	82.8

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

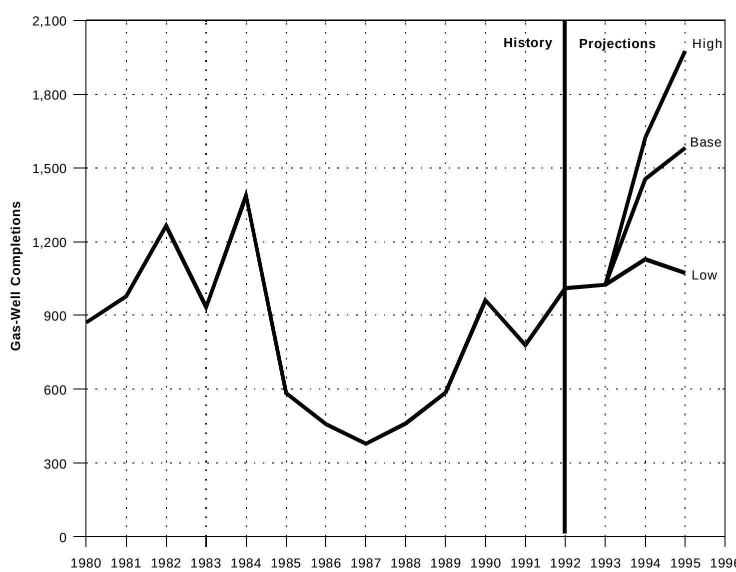
Figure 33. Rocky Mountains Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only.

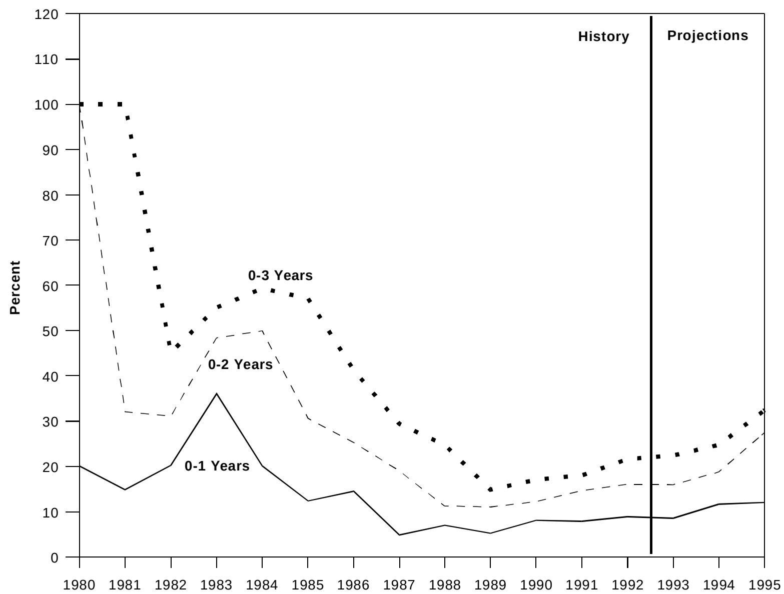
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly* Projections First Quarter 1994 and Model GASCAP93 C060194.

Figure 34. Rocky Mountains Gas-Well Completions Added During Year and Producing as of December, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP93 C060194.

Figure 35. Percent of Total Wellhead Productive Capacity of Rocky Mountains Gas Wells, by Age, 1980-1995 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP93 C060194.

Eighteen States

An additional 18 States were considered as one group. Data are limited for this group of States, and only 3 of the 18 States are included in Dwight's data fields; namely, Nebraska, Oregon, and South Dakota. Production data are available from EIA for each of the 18 States but not by well completion. The 18 States are:

- Arizona
- Florida
- Illinois
- Indiana
- Kentucky
- Maryland
- Michigan
- Missouri
- Nebraska
- Nevada
- New York
- Ohio
- Oregon
- Pennsylvania
- South Dakota
- Tennessee
- Virginia
- West Virginia

On the following pages are Tables 21 and 22 and Figures 36 through 37.

Table 21. Eighteen States Dry Gas Production and Wellhead Productive Capacity, 1980-1992 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Oil-Well Gas	Total Gas	Total Surplus	Capacity Utilization (percent)
Jan-80	1,724	2,052	297	2,349	625	73.4
Jun-80	1,547	2,096	318	2,414	867	64.1
Dec-80	1,937	2,102	319	2,421	484	80.0
Jan-81	1,835	2,174	287	2,461	626	74.6
Jun-81	1,609	2,181	275	2,456	847	65.5
Dec-81	2,017	2,192	262	2,454	437	82.2
Jan-82	1,698	2,249	226	2,475	777	68.6
Jun-82	1,520	2,247	251	2,498	978	60.8
Dec-82	1,904	2,234	235	2,469	565	77.1
Jan-83	1,650	2,301	270	2,571	921	64.2
Jun-83	1,450	2,277	261	2,538	1,088	57.1
Dec-83	1,793	2,277	228	2,505	712	71.6
Jan-84	1,972	2,358	231	2,589	617	76.2
Jun-84	1,738	2,370	238	2,608	870	66.6
Dec-84	2,206	2,381	232	2,613	407	84.4
Jan-85	2,281	2,453	203	2,656	375	85.9
Jun-85	2,007	2,448	216	2,664	657	75.3
Dec-85	2,565	2,411	208	2,619	54	97.9
Jan-86	1,976	2,447	218	2,665	689	74.1
Jun-86	1,721	2,414	207	2,621	900	65.7
Dec-86	2,187	2,387	194	2,581	394	84.7
Jan-87	2,029	2,375	218	2,593	564	78.2
Jun-87	1,781	2,372	221	2,593	812	68.7
Dec-87	2,272	2,368	219	2,587	315	87.8
Jan-88	2,095	2,358	214	2,572	477	81.5
Jun-88	1,848	2,354	227	2,581	733	71.6
Dec-88	2,341	2,311	207	2,518	177	93.0
Jan-89	2,166	2,253	237	2,490	324	87.0
Jun-89	1,890	2,255	228	2,483	593	76.1
Dec-89	2,382	2,223	194	2,417	35	98.6
Jan-90	2,173	2,207	264	2,471	298	87.9
Jun-90	1,883	2,203	239	2,442	559	77.1
Dec-90	2,390	2,164	226	2,390	0	100.0
Jan-91	2,275	2,133	253	2,386	111	95.3
Jun-91	2,105	2,128	239	2,367	262	88.9
Dec-91	2,285	2,116	244	2,360	75	96.8
Jan-92	2,104	2,059	256	2,315	211	90.9
Jun-92	2,165	2,052	259	2,311	146	93.7
Dec-92	2,254	2,051	257	2,308	54	97.7

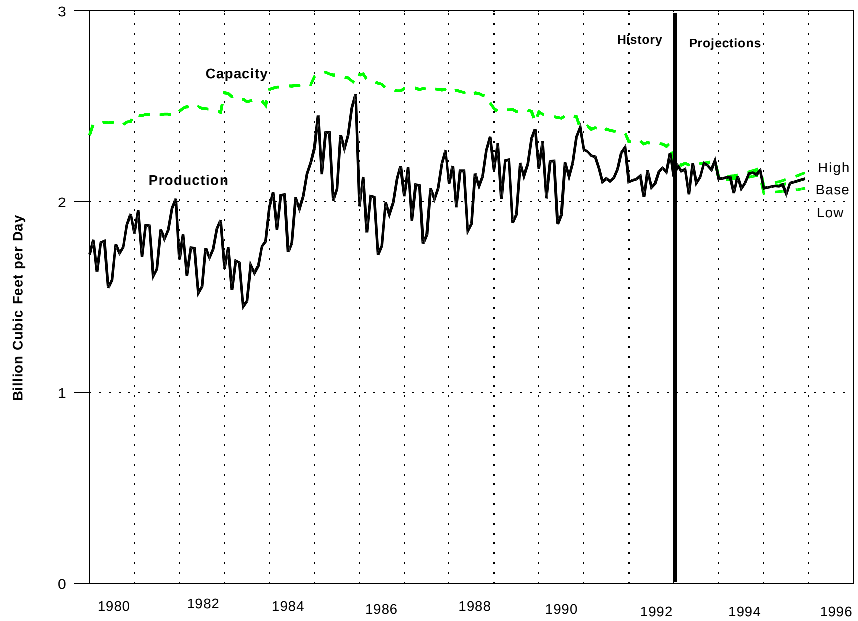
Sources: ●Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP93 C060194. ●Productive Capacity: GASCAP93 C060194.

Table 22. Eighteen States Dry Gas Production and Wellhead Productive Capacity Projections, 1993-1995 (Million Cubic Feet per Day)

Month/ Year	Dry Production	Dry Gas Productive Capacity: Gas-Well Gas	Dry Gas Productive Capacity: Oil-Well Gas	Dry Gas Productive Capacity: Total Gas	Total Surplus	Capacity Utilization (percent)
			Low Case Projection			
Jan-93	2,130	1,956	230	2,186	56	97.4
Jun-93	2,203	1,965	238	2,203	0	100.0
Dec-93	2,215	1,987	228	2,215	0	100.0
Jan-94	2,116	1,891	225	2,116	0	100.0
Jun-94	2,123	1,909	214	2,123	0	100.0
Dec-94	2,140	1,930	210	2,140	0	100.0
Jan-95	2,045	1,836	209	2,045	0	100.0
Jun-95	2,055	1,853	202	2,055	0	100.0
Dec-95	2,071	1,873	198	2,071	0	100.0
			Base Case Projection			
Jan-93	2,130	1,956	230	2,186	56	97.4
Jun-93	2,203	1,965	238	2,203	0	100.0
Dec-93	2,215	1,987	228	2,215	0	100.0
Jan-94	2,120	1,892	228	2,120	0	100.0
Jun-94	2,136	1,913	223	2,136	0	100.0
Dec-94	2,164	1,943	221	2,164	0	100.0
Jan-95	2,071	1,850	221	2,071	0	100.0
Jun-95	2,091	1,876	215	2,091	0	100.0
Dec-95	2,121	1,907	214	2,121	0	100.0
			High Case Projection			
Jan-93	2,130	1,956	230	2,186	56	97.4
Jun-93	2,203	1,965	238	2,203	0	100.0
Dec-93	2,215	1,987	228	2,215	0	100.0
Jan-94	2,122	1,891	231	2,122	0	100.0
Jun-94	2,142	1,915	227	2,142	0	100.0
Dec-94	2,176	1,949	227	2,176	0	100.0
Jan-95	2,084	1,857	227	2,084	0	100.0
Jun-95	2,111	1,888	223	2,111	0	100.0
Dec-95	2,152	1,928	224	2,152	0	100.0

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections First Quarter 1994, DOE/EIA-0202(94/1Q) and Model GASCAP93 C060194. Productive Capacity Projections: GASCAP93 C060194.

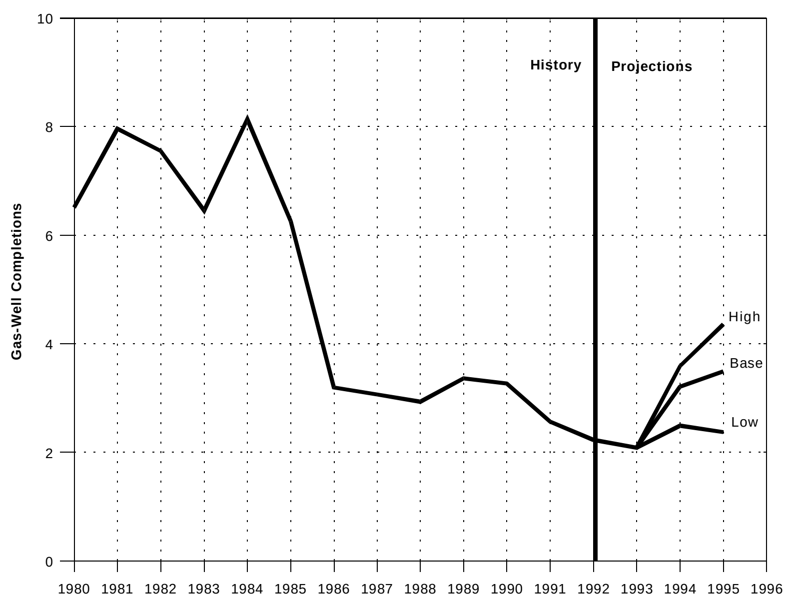
Figure 36. Eighteen States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1980-1995



Note: Production projection plotted for base case only. The low, base, and high capacity projection plots are difficult to distinguish.

Sources: •Production History: Energy Information Administration, Office of Oil and Gas and Model GASCAP93 C060194. •Productive Capacity: GASCAP93 C060194. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly* Projections First Quarter 1994 and Model GASCAP93 C060194.

Figure 37. Eighteen States Gas-Well Completions Added During Year, 1980-1995



Sources: •History: Energy Information Administration, Office of Oil and Gas. Estimates of gas-well completions based on API well completion data. •Projections: Model GASCAP93 C060194.

4. Methodology

This chapter contains a description of the process used to estimate the gas productive capacity of both oil and gas wells for each State or area with projections for 1993, 1994, 1995. For further details see Appendix B or the *Wellhead Gas Productive Capacity (GASCAP) Model Documentation.* {20} Lack of back-pressure test data and gas-in-place estimates by reservoir for a sizeable portion of the lower 48 States precluded doing the conventional type gas-well productive capacity studies that have been done in the past for specific States and areas. Only production data were available for the lower 48 States; therefore, another technique had to be used. The lower 48 States were divided into States and areas that have production data by well listed by Dwight's Energydata, Inc. (Dwight's). This consisted of production data from gas-wells in 14 States and the Gulf of Mexico Federal Offshore Outer Continental Shelf (OCS). The Gulf of Mexico OCS, and each of six States (Texas, Louisiana, California, Kansas, New Mexico, and Oklahoma) were studied individually. Five States were grouped together as the Rocky Mountains: Colorado, Montana, North Dakota, Utah, and Wyoming. The Southeast group consisted of Alabama, Arkansas, and Mississippi.

An additional 18 States were studied as one group using EIA monthly production data and API drilling statistics. These States are: Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia.

The basis of the initial data preparation is the calendar year. Monthly and annual gas-well production data from Dwight's and EIA data series are not always the same; however, the differences in production between the two sources has generally been small. Annual adjustment factors were developed and applied to Dwight's data to ensure that the difference between the production data from the two sources was eliminated on an annual basis. However, the historical monthly production data presented in this report may still differ from the monthly data published in other EIA publications.

Gas-Well Gas Productive Capacity

The first step in estimating gas-well productive capacity was to obtain the production for each gas-well completion in every State and area by month. This was available from Dwight's data files for all States and areas except for the 18 States previously identified where monthly production data were available from EIA but not by well completion. Data edits were performed on the historical monthly data.

The historical average vintage productive capacities on a per well basis were established and projected using the estimated number of monthly new wells going on production. The projected 1993, 1994, and 1995 productive capacities (low, base, and high cases) are based on the *Wellhead Productive Capacity Model* (GASCAP) described in Appendix B.

Historical Production

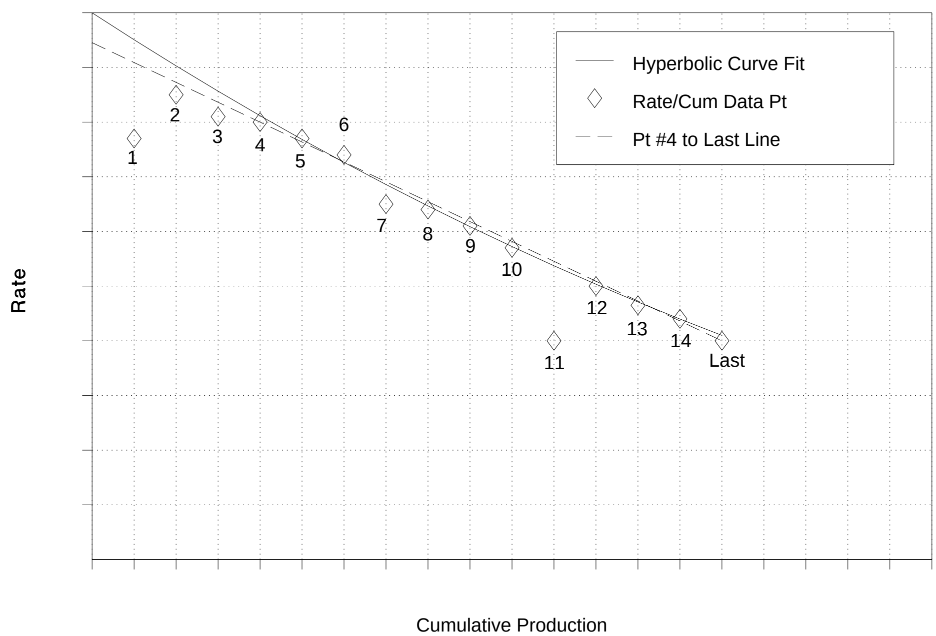
The monthly gas-well production belonging to each State or area vintage was tabulated and plotted versus its cumulative production. Vintage gas-well production is defined as the production from all well completions in a State or area with first production beginning in the same calendar year. For example, production from all well completions going on stream for the first time in Texas in 1972 would be called the Texas 1972 vintage gas-well production.

Historical Productive Capacity

A peak production rate was determined each year for every vintage in each State or area. The peak-rate selected is the sum of all of the gas-well completion peak-rates within a particular vintage year without regard to the month in which the gas-well completion peak-rate occurred. It is assumed that if a gas-well completion in a vintage produced at a maximum rate during any month of the year, the gas-well completion should have been capable of at least this production rate in prior months.

After the peak rates are determined, a screening process (Figure 38) is used to eliminate points that are not producing near capacity. The first peak rate in each vintage is eliminated because not all of the gas-well completions have produced gas for the entire first year. Furthermore, beginning with the last point, each point is compared with the previous year's point until the initial point is reached. If the previous point is higher, it is retained. If it is lower, it is rejected (point 11). This is done because a rate versus cumulative production curve should show a decline when the wells are producing near productive capacity. Next, a straight line is used to connect the fourth and last points and extended backward through the second and third points. The second and third points are rejected if these points fall below the straight line. This process is repeated using the last and third data points to check the second data point. If the data points fall below both straight lines, it is assumed that the low peak rates could be attributed to reasons other than physical limitations of the wells; i.e., low demand, proration, temporary mechanical problems, etc.

Figure 38. Screening Process



Note:

Point No.	Reason for Point Rejection
1	Point 1 always omitted
2&3	Falls below straight line connecting 4th and last points
7	More than one standard deviation below the estimated value
11	Point 12 is larger.

Source: Energy Information Administration, Office of Oil and Gas.

After the first trial of the screening process is complete, the next step is to fit the remaining points with a hyperbolic curve. The hyperbolic curve fit is chosen because it is the decline curve most normally encountered. For example, Figure 39 shows a hyperbolic fit for the peak rates versus cumulative gas production for the 1982 vintage wells in the Gulf of Mexico OCS. Initial estimates are made for the initial rate (q_i) or the Y - intercept, and the ultimate recovery, (G_{ul}) or the X - intercept. Although this curve might appear to be exponential, there is a slight curvature. The exponent B is close to 1, indicating that the curve comes close to being an exponential curve.

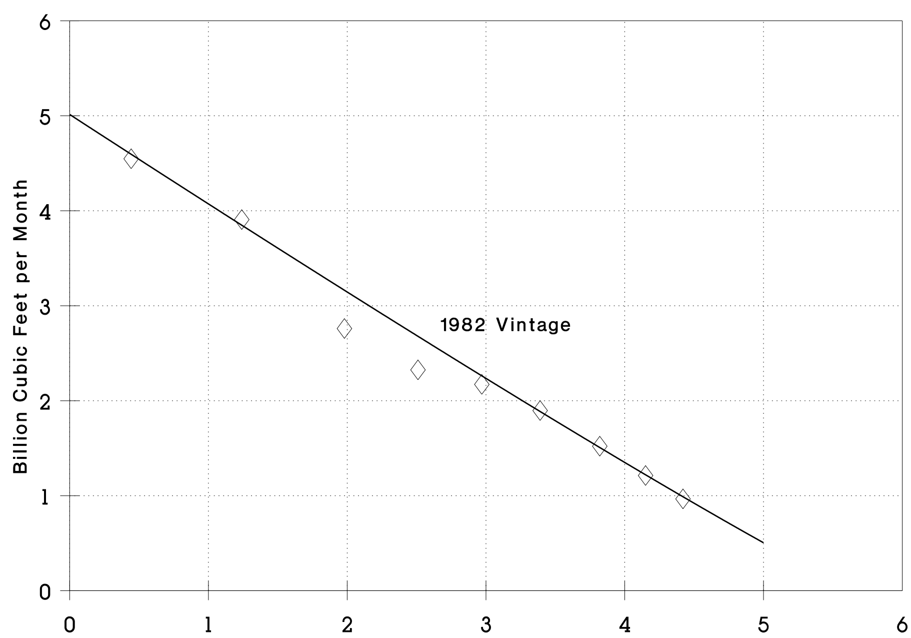
The rate versus cumulative production relationship {15} for this type of decline is:

$$G_p = \frac{q_i^{\,b}}{D_i(1-b)} \left(q_i^{\,1-b} - q^{\,1-b}\right) \qquad (1)$$

where

G_p = cumulative gas produced, thousand cubic feet per day
q_i = initial gas flow rate at capacity, thousand cubic feet per day
q = gas flow rate at capacity, thousand cubic feet per day
D_i = initial daily decline rate
b = hyperbolic decline exponent.

Figure 39. Gross Gas-Well Gas Productive Capacity for the Gulf of Mexico OCS 1982 Vintage



Cumulative Production, Trillion Cubic Feet

Source: Energy Information Administration Model GASCAP93 C060194, based on production data from Dwight's Energydata, Inc.

In equation (1), cumulative gas produced, G_p, becomes the ultimate recoverable gas, G_{ul}, when the flow rate, q, is at abandonment conditions. Assuming that the flow rate at abandonment conditions is zero, equation (1) becomes:

$$G_{ul} = \frac{q_i}{D_i\,(1-b)} . \tag{2}$$

Rearranging (1),

$$q = \left(q_i^{1-b} - \frac{D_i\,(1-b)}{q_i^{\,b}}\, G_p \right)^{\frac{1}{1-b}} . \tag{3}$$

Simplifying (3),

$$q = q_i \left(1 - \frac{D_i\,(1-b)}{q_i}\, G_p \right)^{\frac{1}{1-b}} . \tag{4}$$

Substituting (2) in (4),

$$q = q_i \left(1 - \frac{G_p}{G_{ul}} \right)^{\frac{1}{1-b}} . \tag{5}$$

Substituting B for $\frac{1}{1-b}$,

$$q = q_i \left(1 - \frac{G_p}{G_{ul}} \right)^{B} . \tag{6}$$

Equation (6) was used to describe the hyperbolic decline of the peak flow rates of each vintage curve.

In 1956, J.J. Arps in his report entitled *Estimation of Primary Oil Reserves*{15}, in the Transactions of the American Institute of Mining, Metallurgical and Petroleum Engineers, stated that W.W. Cutler, Jr., of the U.S. Bureau of

Mines{16} indicated that most decline curves normally encountered are of the hyperbolic type with values for the exponent b between 0 and 0.7, with the majority between 0 and 0.4. This means that the values of the exponent B are between 1.0 and 3.3, with the majority between 1.0 and 1.7. The accepted range for B in the GASCAP model is from 1.001 to 3.0. The lower value of 1.001 was chosen rather than 1.0 because a value of 1.0 used in equation (9) would result in division by 0 which would cause the model to abort. Values of B greater than 3.0 tend to give unrealistically large values of G_{ul}. In addition, the raw production data was often distorted by low gas demand. This caused an apparent very rapid production rate decline and an accompanying large B that was not based on the physical capability of wells to produce gas. A data screening algorithm was used during the decline curve fitting process to identify low production rate data points caused by low demand. The highest B allowed during a curve fit to initiate this process was 3.0.

Productive capacity rather than peak rate is desired for the vintage curves. However, only the vintage curve's peak rate could be obtained. Peak rate can be close to productive capacity if the demand for gas is much higher than normal for at least 1 month during the year. In the model, demand is defined as the monthly gas volume produced for the lower 48 States, State/areas, or vintage. If demand were to remain low for every month of the year, the highest peak rate for the year would be lower than the actual productive capacity.

Another screening process is performed to eliminate low rates that could be a result of low demand and affect the curve so that the productive capacity points, which are approximated by the peak rates, would be low. In this model, if an actual or observed point is more than one standard deviation lower than the corresponding calculated value on the vintage curve, the actual point would be rejected.

The remaining data points are then refitted keeping B constant and allowing q_i and G_{ul} to vary. This process is applied to all vintages except the last three.

The initial rates (q_i) for the last three vintage years are calculated independently of the regression analysis. The q_i for the last historical vintage year is a historical average on a per well basis as described later. The q_i for the previous two vintages is determined by averaging the ratio between the calculated q_i and the peak rate in the second year of production. These average ratios were taken for the 7 years prior to the last 3 years. The resulting ratios were multiplied by the peak rate in the second year of production to provide a fixed q_i.

For the projections of the capacity for vintage curves beginning with the last historical vintage year, the values of q_i, G_p, and the corresponding q are needed on a well completion basis and are obtained by averaging these values for the last 3 historical vintage years, not including the last one. The gas flow rate, q_v, is the average of the per-well capacities for December of the second production year. G_{pv} is the average gas produced per well through December of the second production year. G_{ulv} is the average ultimate recovery on a per well completion basis and was obtained by substituting the previously derived values for q_{iv}, G_{pv}, and q_v in the following equation, which is a rearrangement of equation (6) after dividing each term by the number of gas-well completions, ν,

$$G_{ul\nu} = \frac{G_{p\nu}}{1 - \left(q_\nu / q_{i\nu}\right)^{1/B}} . \qquad (7)$$

The q_i and G_{ul} on a per-well completion basis were multiplied by the number of new well completions in each year to obtain the q_i and G_{ul} for each year.

Projections of Productive Capacity

Projected Productive Capacity of Old Vintage Wells

After the historical productive capacity vintage curves were developed through the last historical data year, these curves were projected for 2 more years. Productive capacity curves also had to be developed for all well completions going on stream in these projected years. It is assumed that the productive capacity for the total well completions beginning production during the vintage year will increase throughout the vintage year and will start to decline the next year.

To start the projection routine, the flow rate at capacity was calculated from each vintage for each month starting in January of the first projected year. The production for each vintage for any month is calculated by allocating the expected demand to each vintage based on the capacity of each vintage. The cumulative production for each vintage is the sum of the cumulative production at the beginning of the month and the allocated production. The new well completions (well completions going on production each month for the first time) are used for the current vintage capacity calculations.

All old vintages are projected for 2 years. The production rate as a function of cumulative production, G_p, is given by equation (6). The production rate can also be written as a function of time, t, as described by Arps, although in his formulation, B = $\frac{1}{1-b}$:

$$q = q_i \left(1 + \frac{q_i \left(B - 1 \right) t}{G_{ul}} \right)^{\frac{B}{1-B}} . \qquad (8)$$

Equation (8) is the hyperbolic equation that describes production rate decline as a hyperbolic function of time.

The calculation of the time, t, that corresponds to the vintage productive capacity at the beginning of the month is calculated by solving equation (9) for time:

$$t = \frac{G_{ul} \left[\left({}^{q}/_{qi} \right)^{\frac{1-B}{B}} - 1 \right]}{(B-1)\, q_i} \qquad (9)$$

where q is the flow rate at capacity (productive capacity) at the beginning of the month. The number of days in the month are added in order to step forward to calculate the vintage productive capacity at the beginning of the next month.

The maximum possible cumulative production to the end of the month is calculated by the following equation which is a rearrangement of equation (6):

$$G_p = G_{ul} \left[1 - \left({}^{q}/_{q_i} \right)^{1/_B} \right]. \tag{10}$$

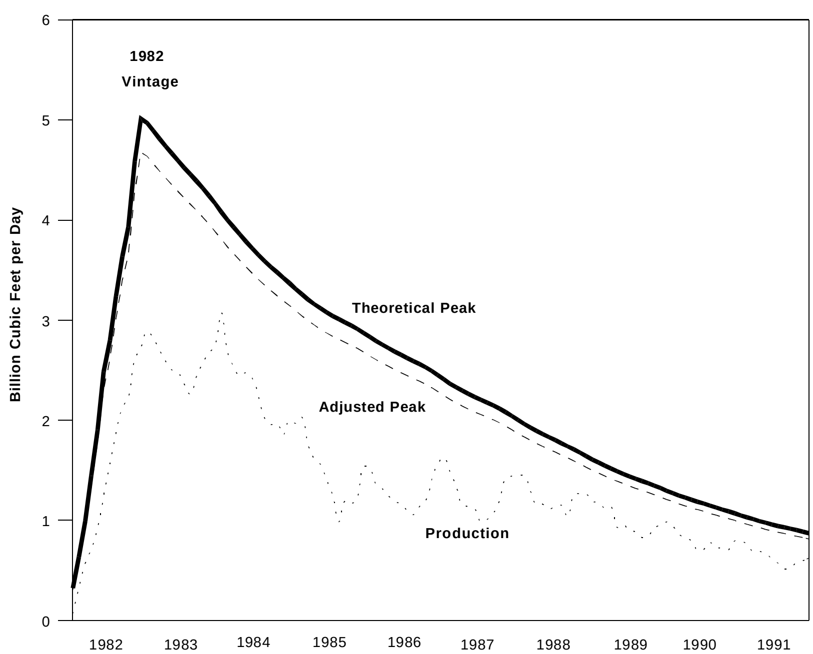
Furthermore, the productive capacities for the nine States/areas are multiplied by load factors. In this model, annual load factors for the last 10 historical years are derived by dividing the annual production from all gas-well completions producing in December of the specific year by the annual production from all gas-well completions that produced in any month during the same year. The load factor for each State/area is obtained by taking an average of the 10 annual load factors. The load factors are applied because frequently there are gas-well completions shut-in because of mechanical problems.

The cumulative gas produced to the beginning of a specific month is subtracted from the maximum possible cumulative gas produced at the end of the month to get maximum productive capacity for the month for each vintage.

The productive capacities for each vintage year are summed and the demand is allocated to each vintage by its percentage of the total capacity. The allocated production is added to the cumulative production at the beginning of a specific month for each vintage and the process is repeated, starting with the calculation of time (t) in equation (9).

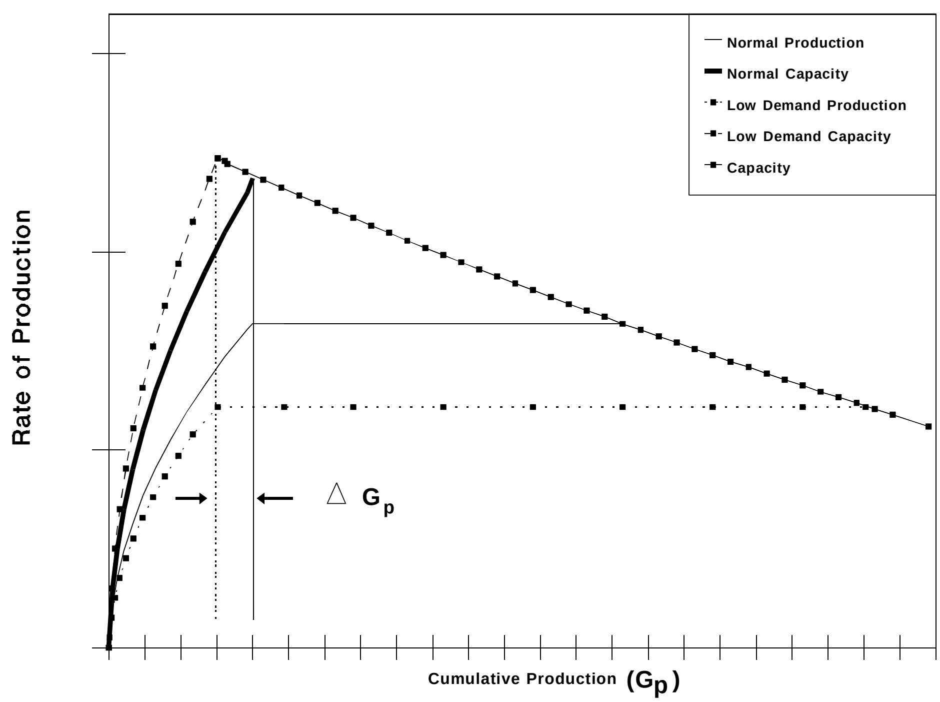
Figure 40 displays the historical production rates, the adjusted peak rates, the theoretical capacity rates, and the projected rates for vintage year 1982 for the Gulf of Mexico OCS.

Figure 40. Capacity and Production Rates for the Gulf of Mexico OCS for 1982 Vintage Year



Sources: •Production: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Theoretical and adjusted peaks: Model GASCAP93 C060194.

Figure 41.Theoretical Hyperbolic Type Curve for Production and Capacity



Sources: Energy Information Administration, Office of Oil and Gas.

Monthly productive capacity for a new vintage year is a function of the wells completed during the month plus the amount contributed by wells completed earlier in the year. Each month the productive capacity for wells completed that month is assumed to be one-half of the month's well completions times the average initial rate (q_i) per well for the previous three vintage years (obtained as described earlier). The productive capacity for earlier wells was determined as a function of normal cumulative production modified by the need to meet the allocated demand from the wells completed in the prior months.

The equation is as follows:

$$q_k = \left(\tfrac{1}{2} \nu_k + \sum_{j=0}^{k-1} \nu_j \right) \left(\frac{q_i}{\nu} \right) \left[1 - \frac{\sum_{j=0}^{k-1} \Delta G_{p_j}}{\left(\frac{G_{ul}}{\nu} \right) \sum_{j=0}^{k-1} \nu_j} \right]^B \tag{11}$$

where q_k = productive capacity in month k, thousand cubic feet per day

ν_k = number of gas-well completions for month k

ν = total number of new gas-well completions for the vintage year

q_i = initial flow capacity, thousand cubic feet per day

ΔG_p = difference between the gas produced during the month and the amount of gas that would have been produced under normal or average conditions, thousand cubic feet

G_{ul} = ultimate gas recovery when q=0, thousand cubic feet

k = month 1,2,....12

j = jth term in the series

$\sum \nu_j$ = cumulative number of gas-well completions through the previous month.

The normal cumulative production is the average cumulative production per well of the historical production of preceding vintages multiplied by the new well completions.

Projected Productive Capacity for the 18 States

Because production and well counts by vintage year are not available for 15 of the 18 States, a different technique is used for these States. Monthly peak rates are determined from monthly gas-well production data obtained from the *Natural Gas Monthly*. The number of new well completions is determined from the API drilling statistics.

The following equation describes the current year's productive capacity as a function of last year's productive capacity and productive capacity from wells brought on in the last 12 months or during the last year.

$$q_{pk\,(m)} = q_{pk\,(m-1)} \exp^{D\,(G_{p\nu\ (m-1)})} + q_{gi}\ \nu_{m-1} \tag{12}$$

where m = year

q_{pk} = peak production rate, thousand cubic feet per day

D	=	decline rate of old production, wells per billion cubic feet
$G_{p\nu}$	=	cumulative production per well, billion cubic feet per well
ν	=	total number of new gas-well completions for the year
q_{gi}	=	initial gas production rate for new wells, thousand cubic feet per day.

For projection purposes the equation was converted to a monthly basis as follows:

$$q_{pk(m,n)} = q_{pk(m,1)} \exp^{D(G_{p\nu(m,n-1)})} + q_{gi}\, \nu_{m,n-1} \tag{13}$$

where

m	=	year
n	=	month
$q_{pk(m,n)}$	=	peak production rate for year (m) and month (n)
$q_{pk(m,1)}$	=	calculated January peak production rate for year (m) used as the starting point to cumulate new well completions for monthly projections
D	=	decline rate for old production, wells per billion cubic feet
$G_{p\nu\,(m,n-1)}$	=	cumulative production per well, to month n-1 for year (m), billion cubic feet per well
$\nu_{m,n-1}$	=	new well completions to month (n-1) for year (m)
q_{gi}	=	initial production rate for new wells, thousand cubic feet per day.

Oil-Well Gas Productive Capacity

Oil-well gas productive capacity was estimated for the same States and areas as gas-well gas productive capacity. Oil wells were considered to be producing at their normal and full capacity as required by the lease operators and State proration/regulation requirements. Oil-well gas production is a function of oil production and the producing gas-oil ratio (GOR); therefore, the difference between productive capacity and gas production for oil wells was assumed negligible.

Monthly gross gas production from oil wells for each State and area from 1980 through 1992 was calculated because it was available on an annual basis only. The annual GOR was calculated by dividing the annual gross oil-well gas production by the annual oil production. Then the monthly oil production was multiplied by the appropriate GOR.

Monthly oil production forecasts for 1993, 1994, and 1995 were used to determine the oil-well gas productive capacity. The monthly oil production estimates for each State and area for 1993,1994, and 1995 were multiplied by the corresponding 1992 GOR. This technique yielded the forecast of the monthly oil-well gas productive capacity for

1993, 1994, and 1995.

Gas Demand

The important part of this report is to determine whether each State or area can provide sufficient gas production in the near future. Therefore, the future gas demand for each State or area must be known. The forecast of gas demand, which will be met by domestic production, is available on a quarterly basis for the United States for 1993, 1994, and 1995 in Table 11 of the *Short-Term Energy Outlook* (STEO).{18} The lower 48 States dry gas demand for each quarter was obtained by subtracting Alaska's projected production from the U.S. gas demand (Table 23).

This lower 48 States quarterly dry gas demand was distributed to each State or area. Dry gas data are not available on a quarterly basis, but marketed production data are available on a quarterly basis for each State or area (Table 24). The quarterly marketed gas production was converted to quarterly dry gas (Table 25). For example in Texas (excluding Gulf of Mexico OCS), the first quarter's marketed production of 1,199,283 million cubic feet (Table 24) is multiplied by .92361 (Table 24) to obtain the dry gas production of 1,107,664 million cubic feet (Table 25). Then the quarterly dry gas production is added for all the areas for each quarter (Table 25).
The quarterly dry gas is divided by total dry gas for that quarter and is expressed as a fraction (Table 26). For example, in Texas (excluding Gulf of Mexico OCS) the first quarter's dry gas production of 1,107,664 million cubic feet is divided by the first quarter's total production of 4,352,407 million cubic feet which is 0.25449 (Table 26).

To obtain quarterly demand for each area, the lower 48 gas demand is multiplied by the quarterly dry gas fraction for that State or area and by the ratio of gross gas to dry gas for that State or area. The reason to convert demand from dry gas to gross gas is that the basic gas production data from Dwight's used in the report are on a gross gas basis. For example for Texas (excluding Gulf of Mexico OCS), 4.485 trillion cubic feet (first Quarter 1993) in Table 23 is multiplied by .25449 (Table 26) and by the gross gas to dry gas ratio which is 1.20917 (Table 24) to obtain 1.380 trillion cubic feet of gross gas demand for first quarter of 1993 (Table 27).

Table 23. Quarterly Dry Gas Demand, 1993, 1994, and 1995
(Trillion Cubic Feet)

Dry Gas Production	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1993					
U.S. Total Dry Gas Production	4.593	4.532	4.477	4.663	18.265
Alaska Total Dry Gas Production	0.108	0.101	0.093	0.110	0.412
Lower-48 Total Dry Gas Production	4.485	4.431	4.384	4.553	17.853
1994					
U.S. Total Dry Gas Production	4.726	4.536	4.405	4.612	18.279
Alaska Total Dry Gas Production	0.108	0.101	0.093	0.110	0.412
Lower-48 Total Dry Gas Production	4.618	4.435	4.312	4.502	17.867
1995					
U.S. Total Dry Gas Production	4.798	4.596	4.366	4.671	18.431
Alaska Total Dry Gas Production	0.108	0.101	0.093	0.110	0.412
Lower-48 Total Dry Gas Production	4.690	4.495	4.273	4.561	18.019

Source: Energy Information Administration, *Short-Term Energy Outlook Quarterly Projections*. DOE/EIA-0202 (94/1Q).

Table 24. Marketed, Dry, and Gross Gas Production for 1992
(Million Cubic Feet)

State/Area	Marketed Gas Production					Dry and Gross Gas Production and Ratios			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Dry Gas	Dry[a]/ Mkt	Gross Gas	Gross[b]/ Dry
Gulf of Mexico	1,210,221	1,185,072	1,114,776	1,167,027	4,677,096	4,606,057	0.98481	4,716,512	1.02398
Texas (Excl. Gulf of Mexico)	1,199,283	1,170,850	1,209,066	1,233,778	4,812,977	4,445,291	0.92361	5,375,129	1.20917
Louisiana (Excl. Gulf of Mexico OCS)	413,546	407,903	404,153	423,768	1,649,370	1,579,794	0.95782	1,673,134	1.05908
California (Incl. Pacific OCS)	95,015	93,692	90,206	86,718	365,631	353,247	0.96613	448,855	1.27065
Kansas	174,794	146,305	145,436	191,473	658,008	615,274	0.93506	659,741	1.07227
New Mexico	277,323	312,221	334,820	344,498	1,268,862	1,193,343	0.94048	1,289,780	1.08081
Oklahoma	515,897	499,446	480,191	521,821	2,017,355	1,912,747	0.94815	2,017,355	1.05469
Southeast									
Alabama	64,989	66,576	70,627	73,625	--	271,541	--	334,320	--
Arkansas	51,271	49,308	48,875	53,026	--	202,066	--	210,907	--
Mississippi	24,059	22,598	22,125	22,913	--	91,281	--	165,537	--
Total Southeast	**140,319**	**138,482**	**141,627**	**149,564**	**569,992**	**564,888**	**0.99105**	**710,764**	**1.25824**
Rocky Mountains									
Colorado	77,410	77,726	78,818	89,087	--	304,892	--	333,994	--
Montana	15,112	12,657	11,374	14,724	--	52,960	--	54,810	--
North Dakota	14,052	13,311	13,630	13,888	--	48,828	--	59,979	--
Utah	35,836	38,540	43,605	53,312	--	159,442	--	314,275	--
Wyoming	196,346	188,440	224,688	233,104	--	811,198	--	1,036,818	--
Total Rocky Mountains	**338,756**	**330,674**	**372,115**	**404,115**	**1,445,660**	**1,377,320**	**0.95273**	**1,799,876**	**1.30680**
18 States	**195,442**	**197,231**	**201,166**	**209,415**	**803,254**	**780,045**	**0.97111**	**815,391**	**1.04531**
Lower-48 Total	**4,560,596**	**4,481,876**	**4,493,556**	**4,732,177**	**18,268,205**	**17,428,006**	**--**	**19,506,537**	**--**

[a] Dry gas divided by marketed gas.
[b] Gross gas divided by dry gas.
--=Not Applicable.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Adminitration, *Natural Gas Annual,* 1992 Volume 1 pp104-205.

Table 25. Quarterly Dry Gas Production by State and Area for 1992
(Million Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Gulf of Mexico OCS	1,191,839	1,167,072	1,097,844	1,149,301	4,606,056
Texas (Excl. Gulf of Mexico OCS)	1,107,664	1,081,403	1,116,700	1,139,524	4,445,291
Louisiana (Excl. Gulf of Mexico OCS)	396,101	390,696	387,104	405,892	1,579,793
California (Incl. Pacific OCS)	91,797	90,519	87,151	83,781	353,248
Kansas	163,442	136,803	135,991	179,038	615,274
New Mexico	260,818	293,639	314,892	323,994	1,193,343
Oklahoma	489,146	473,548	455,291	494,762	1,912,747
Southeast	139,063	137,242	140,359	148,225	564,889
Rocky Mountain	322,742	315,042	354,524	385,011	1,377,319
18 States	189,795	191,532	195,354	203,364	780,045
Lower-48 Total	**4,352,407**	**4,277,496**	**4,285,210**	**4,512,892**	**17,428,005**

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Natural Gas Annual. DOE/EIA-0131(92).

Table 26. Quarterly Dry Gas Fraction by State and Area for 1992

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Gulf of Mexico OCS	0.27383	0.27284	0.25619	0.25467
Texas (Excl. Gulf of Mexico OCS)	0.25449	0.25281	0.26059	0.25250
Louisiana (Excl. Gulf of Mexico OCS)	0.09101	0.09134	0.09033	0.08994
California (Incl. Pacific OCS)	0.02109	0.02116	0.02034	0.01856
Kansas	0.03755	0.03198	0.03173	0.03967
New Mexico	0.05993	0.06865	0.07348	0.07179
Oklahoma	0.11239	0.11071	0.10625	0.10963
Southeast	0.03195	0.03208	0.03275	0.03284
Rocky Mountains	0.07415	0.07365	0.08273	0.08531
18 States	0.04361	0.04478	0.04559	0.04506
Lower-48 Total	**1.00000**	**1.00000**	**1.00000**	**1.00000**

Source: Energy Information Administration, Office of Oil and Gas.

Table 27. Quarterly Gross Gas Demand by State and Area for 1993, 1994, and 1995
(Trillion Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			1993		
Gulf of Mexico OCS	1.258	1.238	1.150	1.187	4.833
Texas (Excl. Gulf of Mexico OCS)	1.380	1.355	1.381	1.390	5.506
Louisiana (Excl. Gulf of Mexico OCS)	0.432	0.429	0.419	0.434	1.714
California (Incl. Pacific OCS)	0.120	0.119	0.113	0.107	0.460
Kansas	0.181	0.152	0.149	0.194	0.675
New Mexico	0.290	0.329	0.348	0.353	1.321
Oklahoma	0.532	0.517	0.491	0.526	2.067
Southeast	0.180	0.179	0.181	0.188	0.728
Rocky Mountains	0.435	0.426	0.474	0.508	1.843
18 States	0.204	0.207	0.209	0.214	0.835
Lower-48 Total	**5.012**	**4.951**	**4.916**	**5.102**	**19.982**
			1994		
Gulf of Mexico OCS	1.295	1.239	1.131	1.174	4.839
Texas (Excl. Gulf of Mexico OCS)	1.421	1.356	1. 359	1.375	5.510
Louisiana (Excl. Gulf of Mexico OCS)	0.445	0.429	0.413	0.429	1.715
California (Incl. Pacific OCS)	0.124	0.119	0.111	0.106	0.461
Kansas	0.186	0.152	0.147	0.192	0.676
New Mexico	0.299	0.329	0.342	0.349	1.320
Oklahoma	0.547	0.518	0.483	0.521	2.069
Southeast	0.186	0.179	0.178	0.186	0.728
Rocky Mountains	0.447	0.427	0.466	0.502	1.842
18 States	0.211	0.208	0.205	0.212	0.836
Lower-48 Total	**5.161**	**4.956**	**4.836**	**5.045**	**19.997**
			1995		
Gulf of Mexico OCS	1.315	1.256	1.121	1.189	4.881
Texas (Excl. Gulf of Mexico OCS)	1.443	1.374	1. 346	1.393	5.556
Louisiana (Excl. Gulf of Mexico OCS)	0.452	0.435	0.409	0.434	1.730
California (Incl. Pacific OCS)	0.126	0.121	0.110	0.108	0.465
Kansas	0.189	0.154	0.145	0.194	0.682
New Mexico	0.304	0.334	0.339	0.354	1.331
Oklahoma	0.556	0.525	0.479	0.527	2.087
Southeast	0.189	0.181	0.176	0.188	0.735
Rocky Mountains	0.454	0.433	0.462	0.508	1.858
18 States	0.214	0.210	0.204	0.215	0.843
Lower-48 Total	**5.241**	**5.023**	**4.792**	**5.111**	**20.167**

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas.

This quarterly gross gas (gas-well gas plus oil-well gas) was then distributed on a monthly basis for each State or area based upon its monthly marketed production for 1992. The monthly gross oil-well gas production was determined by multiplying the 1992 annual GOR by the monthly historic oil production for each State or area from 1980 through 1992. Monthly gas production from oil wells was subtracted from monthly gross gas to get gas production from gas wells.

The monthly gross gas-well gas demand for each State or area was compared with the monthly gross gas-well gas productive capacity. If the productive capacity was equal to or greater than the demand, the demand was scheduled as production. If the productive capacity was less than the demand, then productive capacity was scheduled as production.

For States or areas where monthly gross gas-well gas productive capacity was less than the gross gas-well gas demand, their monthly deficits were prorated among the States and areas with surplus gross gas-well gas capacity. This process was repeated until the sum of the monthly scheduled production from all States and areas equaled the monthly lower 48 States gas demand for 1993, 1994, and 1995.

The monthly gross gas-well gas productive capacity and oil-well gas production for each State or area were added to obtain the total monthly gross gas productive capacity. This productive capacity was converted to a dry gas basis. The monthly gross gas-well gas scheduled production was added to the oil-well gas production and converted to a dry gas basis.

Drilling and Gas-Well Completions

One facet of gas-well gas productive capacity is the productive capacity of new gas wells. The initial productive capacity of new wells was determined from the regression program. Therefore, a projection of new gas-well completions is needed to complete the forecast.

The number of new well completions coming on stream is based on a projection of the number of rigs running and an estimate of the number of gas-well completions per rig. The history of the number of rigs running by State and area were obtained from Baker Hughes[1] and the history of the number of producing gas-well completions[2] was obtained from Dwight's.

Forecasts of total drilling rigs were obtained from the Drilling Rig Model. This model generates monthly rig counts based on oil and gas revenues which are derived from production and price data appearing in the *Short-Term Energy Outlook* (STEO).

Data input to the Drilling Rig Model are provided by 3 submodels: the Gas Rig Model, the Percentage Rigs Model, and the Rig Efficiency Model. The number of rigs drilling for gas is of particular importance in this study, and the Percent Gas Rigs Model, based on STEO oil and gas revenues, provides a forecast of gas rigs. It is also used as input into the Drilling Rig Model. The Gas Rig Model provides missing historical gas rig counts for input into the Percent Gas Rigs Model. It is based on well completions. The Rig Efficiency Model provides for changes in drilling efficiency and is included as input for the Drilling Rig Model. It is based on an index of the inverse of wells drilled per working rig. All of the models are contained in Microsoft Excel spreadsheets where the Excel Solver routine was used to fit and calibrate each model to historical data. Solver was used to minimize the sum of the differences squared in fitting model output to actual historical data.

[1]Baker Hughes Incorporated, Marketed Research.
[2]Model GASCAP93 C060194.

Gas Rig Model

Because a longer historical data series was required than is available for the number of rigs drilling for gas, it was necessary to estimate the missing data. The Gas Rig Model, based on gas well completions, was developed to fill in the missing data. It is used as input in the Percent Gas Rigs Model. Actual gas rig history begins in August 1987. Therefore, the number of rigs drilling for gas prior to August 1987 was modeled to provide the history for the Percent Gas Rigs Model. The Gas Rig Model is based on the ratio of successful gas wells to total wells from August 1987 through 1992. The number of active rigs comes from Baker Hughes Incorporated, Market Research, and well completion data is obtained from the American Petroleum Institute (API). The Gas Rig Model equation is as follows:

$$GR_i = 57.21408 + 1.182106 * \left(\frac{SGW_i}{STW_i} \right) * SRig3_i + 63 \tag{14}$$

where

GR	=	gas rigs
SGW	=	smoothed gas well completions
STW	=	smoothed total well completions
SRig3	=	smoothed total rigs, 3-month exponential smoothing (exponential smoothing coefficient = 0.5)
57.21408	=	model calibration coefficient
1.182106	=	model calibration coefficient
0.354739	=	*SGW* and *STW* exponential smoothing coefficient
63	=	additive constant used to splice the modeled history to the actual history after the fitting and calibration of the model.

The combined modeled gas rig counts and actual gas rig counts are used as input for the Percent Gas Rigs Model.

Percentage Gas Rigs Model

The Percentage Gas Rigs Model provides gas rigs as a percentage of total rigs. Oil and gas incomes (gross revenue) are the input for the model. Production and prices from STEO projections are used to determine income. Lower-48 production and prices are used. Prices are converted to 1990 constant dollars and multiplied by production to yield real income. Oil prices were adjusted for the effects of the Windfall Profits Tax (WPT) from March 1980 through December 1985. Oil and gas incomes are exponentially smoothed in the model. A coalbed methane adjustment factor is applied to the gas income term to account for the non-market incentive or subsidy to gas well drilling from Section 29 tax credits. The adjustment is phased in over 2 years beginning in January 1988, held constant through March 1992, increased again through January 1993, and then eliminated by March 1993. The timing of the coalbed methane adjustment coincides with the evolution and impact of the tax credits. The Percentage Gas Rigs Model equation is as follows:

$$GRR3_i = a * \left(1 + e * SOI_i + \left(d * \left(\frac{\sum_{i-12}^{i-23} GI_i}{12} \right) * \left(\frac{SGI_i}{SGI_{i-12}} \right) * (1 + CB) \right) \right) * 100 \tag{15}$$

where

GRR3	=	percentage gas rigs (gas rig ratio) with 3-month exponential smoothing (exponential smoothing coefficient = 0.5)
a	=	0.529532, model calibration coefficient
e	=	-0.00454, model calibration coefficient
d	=	0.00367, model calibration coefficient
SOI	=	smoothed oil income
GI	=	gas income
SGI	=	smoothed gas income
CB	=	coalbed methane adjustment factor
0.071373	=	*SOI* exponential smoothing coefficient
0.070378	=	*SGI* exponential smoothing coefficient.

The coalbed methane adjustment factor is as follows:

$$CB = 0.170604 * \left(1 + 0.145584 * [X]_{-5}^{5}\right) * [Y]_{1/24}^{1} * \langle f, i, j \rangle \quad (16)$$

where

CB	=	coalbed methane adjustment factor
0.170604	=	model calibration coefficient
0.145584	=	model calibration coefficient
Y	=	begins January 1988 at 1/24th and increases by 1/24th each month until equal to 1, then held constant at 1
X	=	held constant at -5 through March 1992, then increases by 1 each month until equal to 5, then held constant at 5
f	=	1.781279, model calibration coefficient used only for 1 month, January 1993
i	=	1.22602, model calibration coefficient used only for 1 month, February 1993
j	=	0.0, model calibration coefficient beginning in March 1993 and held constant thereafter.

The coalbed methane adjustment factor is in effect from January 1988 through February 1993 only.

Rig Efficiency Model

The Rig Efficiency Model provides an adjustment for drilling efficiencies as a function of the number of working rigs. It also provides for the long term gradual improvements in efficiency from implementing new and improved technologies. Efficiency is measured as rigs per well. Rigs per well are converted to an index by dividing a running 12-month cumulative rigs per well by an equivalent running 12-month cumulative rigs per well in 1971. The Rig per Well Index is modeled based on exponentially smoothed rig counts and cumulative rig counts. The modeled Rig per Well Index or the Rig Efficiency Model is used as input for the Drilling Rig Model. The Rig Efficiency Model is as follows:

$$RWI_i = c * \left(\exp^{-b*\left(\frac{CumRig_{i-1}}{500,000}\right)} \right) * \left(1 + d * \left(\frac{SSRig_{i-1} - SSRig_{i-13}}{LSRig_{i-25}} \right) \right) \tag{17}$$

where

RWI	=	rig per well index
CumRig	=	cumulative rig count beginning January 1968
SSRig	=	short-time smoothed rig count
LSRig	=	long-time smoothed rig count
c	=	1.137034, model calibration coefficient
b	=	0.2914, model calibration coefficient
d	=	0.925168, model calibration coefficient
0.041736	=	*SSRig* exponential smoothing coefficient
0.016249	=	*LSRig* exponential smoothing coefficient
exp	=	2.71828, base of the natural logarithm.

Drilling Rig Model

Like the Percentage Gas Rigs Model, the Drilling Rig Model forecast is based on oil and gas revenue determined from the STEO. Lower-48 prices (in 1990 constant dollars) and production are multiplied together to obtain the oil and gas revenues. Oil prices are adjusted for the effects of the WPT. The Percentage Gas Rigs Model is also used as input along with the Rig Efficiency Model, a seasonality factor, and an adjustment for the Alternative Minimum Tax (AMT). The AMT adjustment is in effect from January 1987 through November 1993 only. It is phased in over 1 year (1987) and phased out over 1 year (1993). The seasonality factor is adjusted depending on the trend direction of the rig count. This model uses oil and gas income terms with both variable and constant exponential smoothing coefficients. The variable smoothing coefficients for both oil and gas income contain a rig count smoothed with a variable coefficient. The Drilling Rig Model equation and its component equations are as follows:

$$Rigs_i = b * \left((1 + k) * SI_i \right)^d * RWI_i * ASn_i \tag{18}$$

where

Rigs	=	number of active drilling rigs
b	=	1.827278, model calibration coefficient
k	=	-0.05834, model calibration coefficient for AMT (used from January 1987 through November 1993 only)
SI	=	smoothed income term (equation 19)
d	=	1.256763, model calibration coefficient
RWI	=	modeled Rig per Well Index (equation l7)
ASn	=	adjusted seasonality (equations 23 and 24).

The smoothed income term is as follows:

$$SI_i = SOI_i^V + \left(\frac{\left(\frac{GRR3_i}{100} \right)}{\left(\frac{SGI_i^C}{SGI_i^C + SOI_i^C} \right)} \right) * SGI_i^V \tag{19}$$

where

SI	= smoothed income
SOI^V	= smoothed Oil Income with a variable exponential smoothing coefficient (equation 20)
GRR3	= modeled Percentage Gas Rigs (equation 15)
SGI^C	= smoothed gas income with a constant exponential smoothing coefficient
SOI^C	= smoothed oil income with a constant exponential smoothing coefficient
SGI^V	= smoothed gas income with a variable exponential smoothing coefficient (equation 21)
0.0541	= SOI^c and SGI^c constant exponential smoothing coefficient.

The variable exponential smoothing coefficient for SOI^V is determined by the following equation:

$$\alpha_{SOI_i^V} = \frac{2}{2 + \left[\left(\frac{SRig12_{i-1}}{SRig_{i-1}^V} \right) * h * \exp^{c*((SOI6_i - SOI6_{i-2}) - |SOI6_i - SOI6_{i-2}|)} \right]} \tag{20}$$

where

αSOI^V	= exponential smoothing coefficient for SOI^V
SRig12	= 12-month exponentially smoothed rig count (exponential smoothing coefficient = 0.1538)
$SRig^V$	= smoothed rig count with a variable exponential smoothing coefficient (equation 22)
h	= 24, fixed model calibration coefficient
c	= 0.5, model calibration coefficient
SOI6	= 6-month exponentially smoothed oil income (exponential smoothing coefficient = 0.2857)
exp	= 2.71828, base of the natural logarithm.

The variable exponential smoothing coefficient for SGI^V is determined by the following equation:

$$\alpha_{SGI_i^V} = \frac{2}{2 + \left[\left(\frac{SRig12_{i-1}}{SRig_{i-1}^V} \right) * h * \exp^{f*((SGI12_i - SGI12_{i-2}) - |SGI12_i - SGI12_{i-2}|)} \right]} \tag{21}$$

where

αSGI^V	=	exponential smoothing coefficient for SGI^V
$SRig12$	=	12-month exponentially smoothed rig count (exponential smoothing coefficient = 0.1538)
$SRig^V$	=	smoothed rig count with a variable exponential smoothing coefficient (equation 22)
h	=	24, fixed model calibration coefficient
f	=	0.5, model calibration coefficient
$SGI12$	=	12-month exponentially smoothed gas income (exponential smoothing coefficient = 0.1538)
exp	=	2.71828, base of the natural logarithm.

The variable exponential smoothing coefficient for $SRig^V$ is determined by the following equation:

$$\alpha_{SRig_i^V} = \frac{2}{2 + \left[\dfrac{e}{\exp^{0.2*((SRig48_i - SRig48_{i-12}) + |SRig48_i - SRig48_{i-12}|)}}\right]} \tag{22}$$

where

$\alpha SRig^V$	=	exponential smoothing coefficient for $SRig^V$
$SRig48$	=	48-month exponentially smoothed rig count (exponential smoothing coefficient = 0.0408)
e	=	48, fixed model calibration coefficient
exp	=	2.71828, base of the natural logarithm.

Seasonality factors were calculated for each month and calibrated to a preliminary fit of the Drilling Rig Model that excluded seasonality. That is, seasonality parameters where added to the Drilling Rig Model after fitting and calibrating the model without the seasonality parameters. The model was run again holding fixed everything other than the seasonality parameters. This second fit calibrated only the seasonality coefficients. The seasonality was then held fixed while the nonseasonality parameters were recalibrated in a third fit of the Drilling Rig Model.

Seasonality is determined by the following equations:

$$\begin{aligned}
&Sn_{i=1} = f \quad \text{for January}\\
&Sn_{i=2} = f + \frac{1}{2^{i-1}} \quad \text{for February}\\
&Sn_{i=3} = f + \frac{1}{2^{i-2}} + \frac{1}{2^{i-1}} \quad \text{for March}\\
&Sn_{i=4} = f + \frac{1}{2^{i-3}} + \frac{1}{2^{i-2}} + \frac{1}{2^{i-1}} \quad \text{for April}\\
&Sn_{i=5,11} = Sn_{i=4} + j*(i-4) \quad \text{for May thru November}\\
&Sn_{i=12} = Sn_{i=11} + \frac{j}{3} \quad \text{for December}
\end{aligned} \tag{23}$$

where

Sn	=	the 12 different seasonality factors for January through December
i	=	1 through 12 for the corresponding months January through December
f	=	1.051535, model calibration coefficient
l	=	-0.12697, model calibration coefficient
j	=	0.015123, model calibration coefficient.

Next, the seasonality is adjusted according to the trend direction. Seasonality has less impact when rig counts are increasing than when rig counts are falling. Therefore, adjusted seasonality factors replaced the regular seasonality factors and are determined by refitting the Drilling Rig Model with only the adjusted seasonality parameters allowed to change. Then, the newly calibrated adjusted seasonality factors are fixed while the Drilling Rig Model is fit one more time to fine tune the nonseasonal coefficients. The adjusted seasonality equation is as follows:

$$ASn_i = 1 + \frac{(Sn_i - 1) * (0.5 + 0.5 * \exp^{a})}{0.5 + 0.5 * \exp^{\left(a * \frac{SRig_{i-1}}{SRig_{i-13}}\right)}} \tag{24}$$

where

ASn	= adjusted seasonality factors
Sn	= the 12 different seasonality factors for January through December (equation 23)
a	= 3.455216, model calibration coefficient
SRig	= 24-month exponentially smoothed rig count (exponential smoothing coefficient = 0.08)
exp	= 2.71828, base of the natural logarithm.

The Drilling Rig Model must be run one last time to determine the value for *k* in equation 18 (AMT adjustment). The 1+k term is added to the model equation, and all parameters are held constant except *k*. After the value for the coefficient *k* is determined, the projected rig counts are spliced to the historical rig counts. A splicing ratio of actual to predicted rigs calculated for the last month of real data is applied to the projected rig count values.

Exponential Smoothing

Exponential smoothing is used throughout this modeling process. Following is the basic exponential smoothing equation as applied to income in the Drilling Rig Model.

$$SI_i = I_i * \alpha + SI_{i-1} * (1 - \alpha) \tag{25}$$

where

SI	= smoothed income
I	= income
α	= exponential smoothing coefficient
i	= current month.

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Appendix A

Data Sources

Appendix A

Data Sources

The data used in this report are from Dwight's Energydata computer tapes (Dwight's Energydata, Inc., Richardson, Texas), and the Energy Information Administration (EIA) publications. Monthly gas-well gas production was extracted from the 1993 Dwight's tapes. For States not covered by Dwight's, the *Natural Gas Annual* and *Natural Gas Monthly* published by EIA were used to obtain the gas production data. The monthly production was used to construct curves of gas-well gas production rate versus cumulative production by vintage year.

Appendix B

Model Abstract

Appendix B

Model Abstract

Name: Wellhead Gas Productive Capacity

Acronym: GASCAP

Description: GASCAP estimates the historical wellhead productive capacity of natural gas for the lower 48 States and projects the productive capacity for 3 years. The Short-Term Energy Outlook (STEO) output for low, base, and high cases is used to estimate the number of active rigs and oil and gas well completions. The projected oil production is used to estimate the oil-well gas production (which is assumed to be producing at capacity) using a constant gas-oil ratio. The gas demand is also taken from STEO. The difference between demand and oil-well gas production is assumed to be the gas-well gas demand and the production as long as capacity exceeds demand.

Purpose: GASCAP is used to project the natural gas wellhead productive capacity for the lower 48 States. It also allows quantification of the available productive capacity and the projected capacity under differing future scenarios.

Date of Last Model Update: 1994

Part of Another Model: No

References to Any Other Models: None

Documentation reference: Wellhead Gas Productive Capacity Model (GASCAP) Documentation DOE/EIA-M052 June 1993

Official Model Representatives:

- **Office:** Oil and Gas
- **Division:** Reserves and Natural Gas
- **Branch:** Reserves and Production
- **Model Contacts:** John H. Wood, James N. Hicks, Hafeez Rahman, and Velton T. Funk
- **Telephone:** 214-767-2200

Archive Media and Installation Guides: Cartridge tape available from National Energy Information Center for GASCAP94, for the report *Natural Gas Productive Capacity for the Lower 48 States 1980 through 1995*, DOE/EIA-0542(94), published June 1994.

Energy System Described: GASCAP measures and predicts wellhead natural gas productive capacity.

Coverage:

- **Geographic:** Lower-48 natural gas producing States
- **Time Unit/Frequency:** Evaluates 10 years of historical data and projects productive capacity for 3 years.
- **Products:** Natural gas

- **Economic Sectors**: States and groups of lower 48 States

Modeling Features:

- **Model Structure:** The model consists of a series of Statistical Analysis System (SAS) procedures utilizing a modified rate of gas production versus cumulative gas production (Rate-cum) equation.
- **Modeling Techniques:** SAS, utilizing the least squares, nonlinear regression procedure (NLIN) with the Marquardt computational method, was used to fit hyperbolic equations to the data.
- **Special Features**: None

Non-DOE Input Variables and Sources:

- Dwight's EnergyData Inc, Richardson, TX, Oil and Gas Reports
  - State monthly natural gas production by well
- Baker Hughes Incorporated
  - Number of active rotary rigs and number of active rotary gas rigs
- American Petroleum Institute
  - Well completions

DOE Data Input Variables and Sources:

- ***Natural Gas Annual***
  - Marketed gas production by State
  - Gross gas production by State
  - Oil-well gas production by State
- ***Natural Gas Monthly***
  - Marketed production of natural gas by State
- ***Short Term Energy Outlook***
  - Dry gas production forecast
  - Oil and gas price forecasts
- ***Petroleum Supply Annual***
  - Crude oil production

Computing Environment:

Main Frame

- **Hardware:** IBM 3090E Model 400
- **Operating System:** MVS/XA
- **Languages:** FORTRAN / SAS / COBOL
- **Memory requirement:** 1500K
- **Storage requirement:** 1200 tracks of 3380 disk space
- **Estimated run time:** 4 hours CPU time

Personal Computer

- **Hardware:** Compaq Deskpro 386/20
- **Operating System:** MS DOS
- **Software:** LOTUS 123 / EXCEL / ARBITER / HARVARD GRAPHICS

- **Memory requirement:** 2000K
- **Storage requirement:** 10 Mb hard disk space
- **Estimated run time:** 1 hour

Independent Expert Reviews Conducted: None

Status of Evaluation Efforts: Office of Statistical Standards audit has been initiated.

Appendix C

Comparison of Productive Capacity

Appendix C

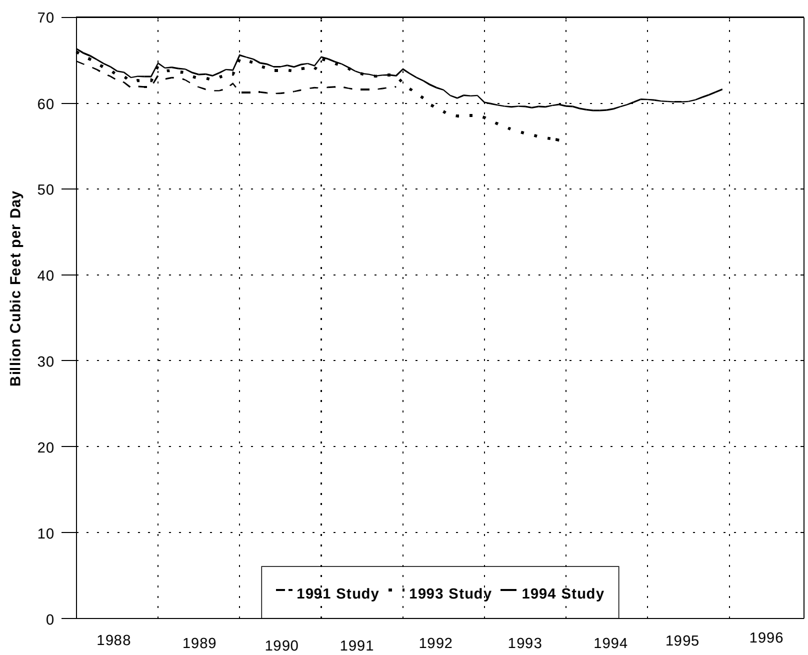
Comparison of Productive Capacity

Comparisons for the period 1988 through 1993, between the current base case productive capacities and those from the 1991 and the 1993 studies, appear in Figure C1. In nearly all cases the current values are higher than those found in the earlier studies.

When comparing the current study with the 1991 study, a review of the data shows that during the period January 1988 through December 1989, the monthly productive capacities from the current study ranged from 2 to 3 percent higher than in the 1991 study. This difference increased to 5 to 7 percent from January 1990 through February 1991 but declined to 2 percent by the end of that year.

A comparison of the current study with the 1993 study shows a difference of less than 1 percent from January 1988 through December 1991. However, while the 1993 study showed a decline in productive capacity during 1993, the productive capacity in the current study remains nearly the same throughout the year. This is attributed to the expectations of higher gas prices and higher drilling levels.

Figure C1.Comparisons of Dry Gas Productive Capacity for the 1991, 1993, and 1994 Studies, 1988 - 1995



Note: Monthly capacity estimates are for base case.

Sources: •1991 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1980 through 1991.* DOE/EIA-0542 (Washington, DC January 24, 1991). •1993 Study: Energy Information Administration. *Natural Gas Productive Capacity for the Lower 48 States 1982 through 1993*. DOE/EIA-0542 (Washington, DC, March 10, 1993) •1994 Study: Model GASCAP93 C060194.

Appendix D

Dry Gas-Well Capacity per New Gas-Well Completion Added

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Dry Gas-Well Capacity per New Gas-Well Completion Added

A dry gas-well gas productive capacity of about 1 billion cubic feet of gas per day is added per 1,000 new gas-well gas completions. This is the difference between the dry gas-well productive capacity change in the high case and the base case during 1995 divided by the difference in gas-well completions in the high and base case during 1995. For productive capacity, the period of change is from December 1994 to December 1995 (Table 2). The well completions in the base and high cases are those added during 1995 (Figure 6). Capacity is in billion cubic feet per day (Bcf/day) and the number of completions are in thousands.

The calculation follows:

$$\frac{(59.0 \text{ Bcf/day} - 54.2 \text{ Bcf/day}) - (54.1 \text{ Bcf/day} - 52.7 \text{ Bcf/day})}{17.6 \text{ thousand completions} - 14.1 \text{ thousand completions}}$$

$$\cong 1 \ \frac{\text{Bcf/day}}{\text{1,000 gas-well completions}}$$

This estimate depends on the cases considered and the time period. It also depends on the assumed production rates. A higher production level causes a more rapid decline in a group of wells productive capacity. In addition, this estimate depends on the distribution of wells by area. The initial flow rates vary substantially from area to area. These flow rates are roughly 20 times as high for wells in the Gulf of Mexico OCS as for wells in Kansas (Table D1).

Table D1. Average Initial Flow Rates, Ultimate Recovery, and Decline Exponent on a Gas-Well Completion Basis for 1989-1991 (Million Cubic Feet per Day)

State/Area	q_i Initial Flow Rate MMcf/day	G_{ul} Ultimate Recovery MMcf	B Decline Exponent
Gulf of Mexico OCS	7.9	4,983	1.1
Texas (Excluding Gulf of Mexico OCS)	1.0	1,154	2.2
Louisiana (Excluding Gulf of Mexico)	2.0	1,846	1.7
California (Including Pacific OCS)	1.5	1,605	1.7
Kansas	0.4	899	2.5
New Mexico	1.0	6,554	2.7
Oklahoma	1.1	1,531	2.4
Southeast	0.4	1,072	1.9
Rocky Mountains	0.6	2,407	3.0

Source: Energy Information Administration Model GASCAP93 C060194.

Glossary

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Associated Gas: Natural gas, commonly known as gas-cap, which overlies and is in contact with crude oil in the reservoir.

Back-pressure: The pressure maintained on equipment or systems through which a fluid flows.

Bcf: Billion cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Connected Field Capacity: The Natural Gas Supply Association's definition of Connected Field Capacity is "the *rate at which gas can be physically injected into the intrastate and interstate pipeline network, on a 30-day sustainable basis,"* under the best of operating conditions (i.e., excluding planned and unplanned downtime). Because the sustainable production rate of a gas field can be lower than that of the individual gas well, the connected capacity is defined on a field basis rather than on a well basis.

Connected field capacity also takes into account the capacity limitations imposed by gathering systems and gas processing plants. For example, if a group of wells can physically produce 100 MMcf/day of dry gas, but the gathering system can only transport 90 MMcf/day and the gas processing plant can only produce 70 MMcf/day of dry gas, then the connected field capacity is stated as 70 MMcf/day. The difference between the 100 MMcf/day well production potential and the 70 MMcf/day actually produced by the gas processing plant (i.e., 30 MMcf/day) is considered unconnected field capacity.

Gas productive capacity used to operate gas production and processing facilities was excluded from the survey's consideration.

Deficit Capacity: The negative difference between gas productive capacity and scheduled gas production.

Deliverability: The volume of gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions, taking into account restrictions imposed by pipeline capacity, contract, or regulatory bodies.

Dissolved Gas: Natural gas in solution in crude oil in the reservoir.

Dry Gas: Marketed gas less extraction loss.

Extraction Loss: The reduction in volume of natural gas resulting from the removal of natural gas liquid constituents at natural gas processing plants.

Flow String: The string of tubing or casing through which gas or oil flows to the surface.

Gas-Well Gas: Nonassociated or associated gas produced from well completions classified as gas-well completions by a regulatory body.

Gross Gas: Full well stream volume, including all natural gas plant liquid and nonhydrocarbon gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.

Lease Condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease or field separation facilities, exclusive of products recovered at natural gas processing plants or facilities.

Marketed Gas: Gross gas less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. Includes all quantities of gas used in field and processing operations.

Mcf: Thousand cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

MMcf: Million cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Nonassociated Gas: Free natural gas not in contact with crude oil in the reservoir.

OCS: Outer Continental Shelf.

Oil-Well Gas: Gas produced from well completions classified as oil-well completions by a regulatory body.

Peak Shaving: Supplying fuel gas such as propane to a distribution system from an auxiliary source during periods of maximum demand, when the primary source is not adequate.

Plant Liquids: Those volumes of natural gas liquids recovered in natural gas processing plants.

Productive Capacity: The volume of gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back-pressure under actual reservoir conditions excluding restrictions imposed by pipeline capacity, contract, or regulatory bodies.

Surplus Capacity: The positive difference between gas productive capacity and scheduled gas production.

Tcf: Trillion cubic feet of gas at a pressure base of 14.73 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit.

Well: A hole made by drilling through one or more reservoirs.

Well Completion: A flow string in a well used to conduct hydrocarbons to the surface from one reservoir or zone. There are one or more well completions in a producing well.