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Natural Gas Productive Capacity for the Lower 48 States 1984 through 1996

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Executive Summary

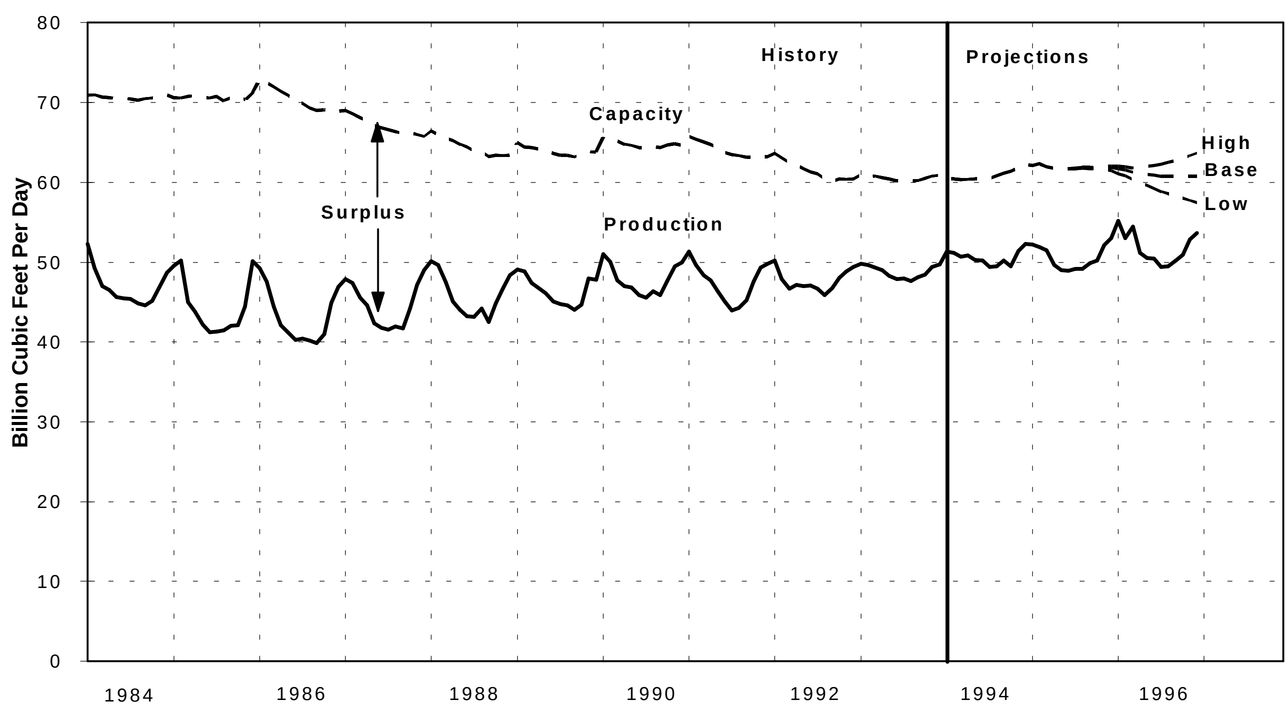
This is the fourth in the series of EIA reports on natural gas wellhead productive capacity in the lower 48 States. The series documents a decline in gas productive capacity beginning in 1986. This edition of the series projects (in the base drilling case) a flattening of this declining trend through 1996. A flat productive capacity, in conjunction with rising natural gas production, results in a gradual tightening of the surplus capacity (Figure ES1). This gradual decline in surplus capacity reflects improving efficiencies in natural gas markets. These efficiences reduce the need for previous levels of surplus capacity.

This report concludes that, despite the declining surplus capacity, monthly natural gas productive capacity in the lower 48 States is adequate to meet normal production requirements through 1996. However, exceptionally high peak-day or peak-week heating or cooling demand may exceed projected productive capacity, or production may be limited by other factors such as pipeline availability. Nonetheless, the natural gas industry has developed methods to meet peak demand such as deliveries from storage and peak-day shaving. These developments have been greatly promoted at the Federal level by the movement to less regulation by the Federal Energy Regulatory Commission. This increased reliance on market forces also encourages industry efficiency as customers with fuel-switching capability consume other fuels in response to higher gas prices. Lastly, effective demand might be lowered by curtailing customers that have interruptible contracts.

The major conclusions of this study are:

- Monthly wellhead productive capacity of dry gas will be adequate in the *low, base,* and *high* cases through 1996.
- In 1995 and 1996, monthly wellhead productive capacity increases in the *high* drilling case.

Figure ES1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

- 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.
- Beyond 1996, a sufficient number of new wells and/or imports must be added each year in order to ensure an adequate gas capacity and supply.

For decades the lower 48 States natural gas productive capacity has been adequate to meet production requirements. In the 1970's the capacity surplus was small because of market structure (split between interstate and intrastate), increasing production requirements, and insufficient drilling. In the early 1980's, lower production requirements, together with increased drilling, led to a large surplus capacity. After 1986, this large surplus began to decline as requirements 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 requirements and temporary weather-related production losses, led to concerns about the adequacy of productive capacity for natural gas. These concerns were moderated by the gas system's performance during the unusually severe winter weather in March 1993 and January 1994.

This report deals with monthly natural gas wellhead productive capacity from conventional and coalbed gas-well completions and oil-well completions in the lower 48 States. The different drilling levels assumed in three cases are functions of oil and gas prices and gas production requirements **(**Table ES1).

The existence of a surplus wellhead productive capacity does not signify that the entire gas capacity could 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 1993, dry gas pipeline system deliverability in the lower 48 States was estimated to be 54 billion cubic feet per day, only 90 percent of the dry gas productive capacity at the wellhead. However, there is substantial uncertainty in this deliverability estimate. Pipeline system deliverability was expected to increase 6 percent by the end of 1994. If the surplus in wellhead productive capacity declines, more reliance will be placed on gas withdrawals from storage to meet peak heating and cooling 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. Annual Wellhead Price, December Production, and December Productive Capacity, 1984, 1993, 1995, and 1996

Year/Case	Price (Nominal Dollars)	Production (billion cubic feet per day)	Capacity (billion cubic feet per day)	Productive Total Surplus (billion cubic feet per day)	Capacity (Utilization (percent)
1984	2.66	48.7	71.0	22.3	68.6
1993	2.03	49.7	60.9	11.2	81.7
Projections					
1995/Low	1.60	53.0	61.4	8.5	86.2
1995/Base	1.68	53.0	61.8	8.8	85.7
1995/High	1.77	53.0	62.0	9.1	85.4
1996/Low	1.54	53.7	57.5	3.8	93.4
1996/Base	1.88	53.7	60.8	7.1	88.3
1996/High	2.31	53.7	63.7	10.0	84.3

Sources: • History: Energy Information Administration, Office of Oil and Gas Dwight's Energydata, Inc. • Projections: Short-Term Energy Outlook Quarterly Projections Third Quarter 1995 and Model GASCAP94 C051995.

1. Introduction

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

The EIA Dallas Field Office has prepared five earlier reports regarding natural gas productive capacity. These reports, *Gas Deliverability and Flow Capacity of Surveillance Fields*, reported deliverability and capacity data for selected gas fields in major gas producing areas.{4,5,6,7,8} The data in the reports were based on gas-well back-pressure tests and estimates of gas-in-place for each field or reservoir. These reports use proven well testing theory, most of which has been employed by industry since 1936 when the Bureau of Mines first published Monograph 7.{9}

Demand for natural gas in the United States is met by a combination of natural gas production, underground gas storage, imported gas, and supplemental gaseous fuels. Natural gas production requirements in the lower 48 States have been increasing during the last few years while drilling has remained at low levels. This has raised some concern about the adequacy of future gas supplies, especially in periods of peak heating or cooling demand.

The purpose of this report is to address these concerns by presenting a 3-year projection of the total productive capacity of natural gas at the wellhead for the lower 48 States. Alaska is excluded because Alaskan gas does not enter the lower-48 States pipeline system.

The Energy Information Administration (EIA) generates this 3-year projection based on historical gas-well drilling and production data from State, Federal, and private sources. In addition to conventional gas-well gas, coalbed gas and oil-well gas are also included.

Unpredictable market forces affect the number of new well completions and recompletions, which are related to drilling activity and prices for oil and gas. To account for these unpredictable forces, the EIA prepares three separate projections: a *high, base*, and *low* case. The "*base*" case reflects what would most likely occur if current market trends continue and drilling and production levels perform as they have in the past. The *high* case reflects an increase in the amount of drilling and favorable market conditions, while the "*low*" case reflects a decrease in drilling due to less favorable market conditions.

EIA obtained monthly gas-well production data on a per completion basis for 14 States and the Gulf of Mexico Outer Continental Shelf (OCS) from Dwight's EnergyData, Inc. (Dwight's). Dwight's data is not available for the entire lower 48 States region. Production data on a State basis for the remaining States were obtained from EIA's *Natural Gas Monthly* reports, and the number of gas-well completions were obtained from the American Petroleum Institute (API) drilling statistics.

Estimates of gas-well productive capacity were generated using monthly gas-well production data. Wells were grouped 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. A monthly peak production 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, which were assumed to be the historical productive capacities. These rates were then input to the *Wellhead Productive Capacity Model* (Appendix B) to estimate *low*, *base* and *high* case productive capacities for 1994, 1995, and 1996.

Assumptions used in the *Wellhead Productive Capacity Model* are summarized as follows:

- Wellhead gas productive capacity is a function of drilling, which adds new capacity, and production, which lowers existing capacity over time.
- The number of new gas-well completions is a function of drilling.

- Abandonment of individual conventional and coalbed gas-well completions is captured by decline functions for the group of wells included in a given vintage year for each area.
- Producing characteristics of new conventional and coalbed gas-well completions can be modeled from the characteristics of historical completions.
- Oil-well completions are currently producing at full capacity; therefore, the oil-well gas production rate equals oil-well gas capacity.
- U.S. gas production requirements can be allocated to the lower-48 producing areas by month based on 1993's production market share.

The projected domestic gas production was prorated by State and area on the basis of historical market share. If gas-well gas production rate was less than gas-well gas productive capacity in a given State, the production rate required was set equal to the actual production rate. If the required gas-well gas production rate was greater than gas-well gas productive capacity in a given State, the production rate was set equal to productive capacity. The lack of capacity for the given State was then prorated to other States or areas that had surplus productive capacity.

A positive difference between productive capacity and the natural gas production rate required 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. A detailed methodology used for this report is found in Appendix A.

2. Gas Productive Capacity

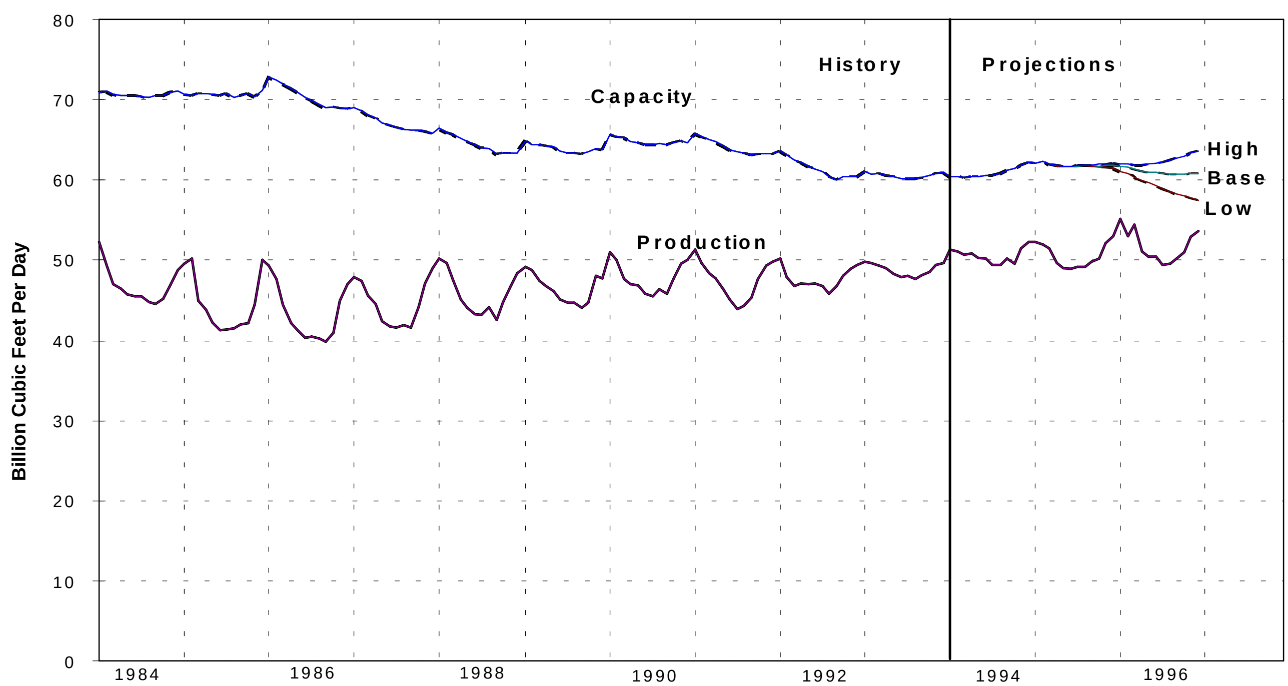
Gas Capacity to Meet Lower 48 States Requirements

The United States has sufficient dry gas productive capacity at the wellhead to meet forecast monthly production requirements through 1996 (Figure 1). Any potential shortfalls in States with surplus productive capacity could probably be met by transfers from those areas with surplus productive capacity.

Dry gas is the type of gas generally transported by transmission systems and delivered to customers. *Gross gas* is the full stream volume, including all natural gas plant liquids and nonhydrocarbon gases but excluding lease condensate. In 1993, dry gas production represented 90 percent of the gross gas production in the lower 48 States (Figure 2).

For reporting and analysis, the lower 48 States were grouped into 10 separate producing States or areas based on gas production volumes (see Figure 3). Dry gas productive capacity was determined for each of these 10 areas. The United States quarterly gas production forecast in the *Third-Quarter 1995 Short-Term Energy Outlook* {10} 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, the unmet production requirements were 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. Recent historical production

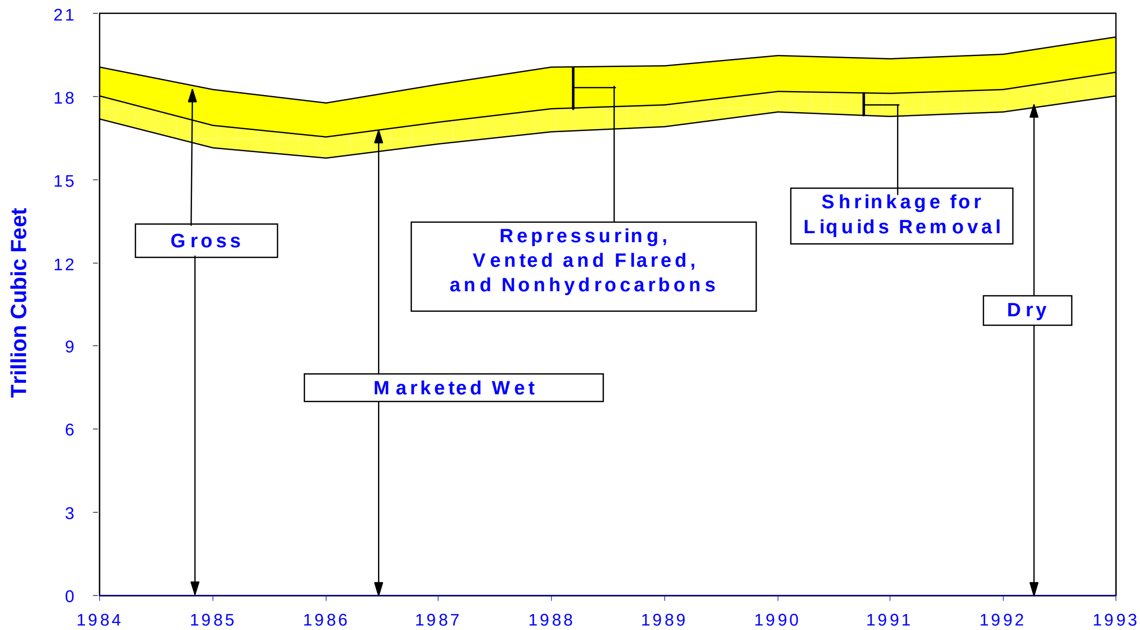
Figure 1. Lower 48 States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Figure 2. Lower 48 States Natural Gas Production, 1984-1993



Sources: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1984-1993.

patterns were used to allocate the projected gas lower 48 gas production requirements for 1994, 1995, and 1996 among States and areas (Figure 4). Appendix A contains a full description of the methodology used for this report.

Historical Data

Dry Gas Productive Capacity Trends

Historical monthly gas production and productive capacity for the lower 48 States for the months of January, June, and December are presented in Table 1. January and December represent the typical peak winter months, and June represents an off season month. Production and capacity for all 12 months can be obtained from the authors.

Dry gas productive capacity in the lower 48 States substantially exceeded production throughout the 1980's. The lower 48 States maintained an average surplus capacity of approximately 22 billion cubic feet per day through December 1986. However, gas capacity began declining in 1986 as drilling and new well completions rapidly declined. This continuing decline reduced the surplus capacity by 50 percent to 11 billion cubic feet in December 1993.

The rapid decline in drilling and new well completions was caused by reduced prices. The wellhead price for natural gas declined almost $1.00 per thousand cubic feet from 1985 to 1986, and began fluctuating seasonally after 1987 (see Figure 5).

Gas Production

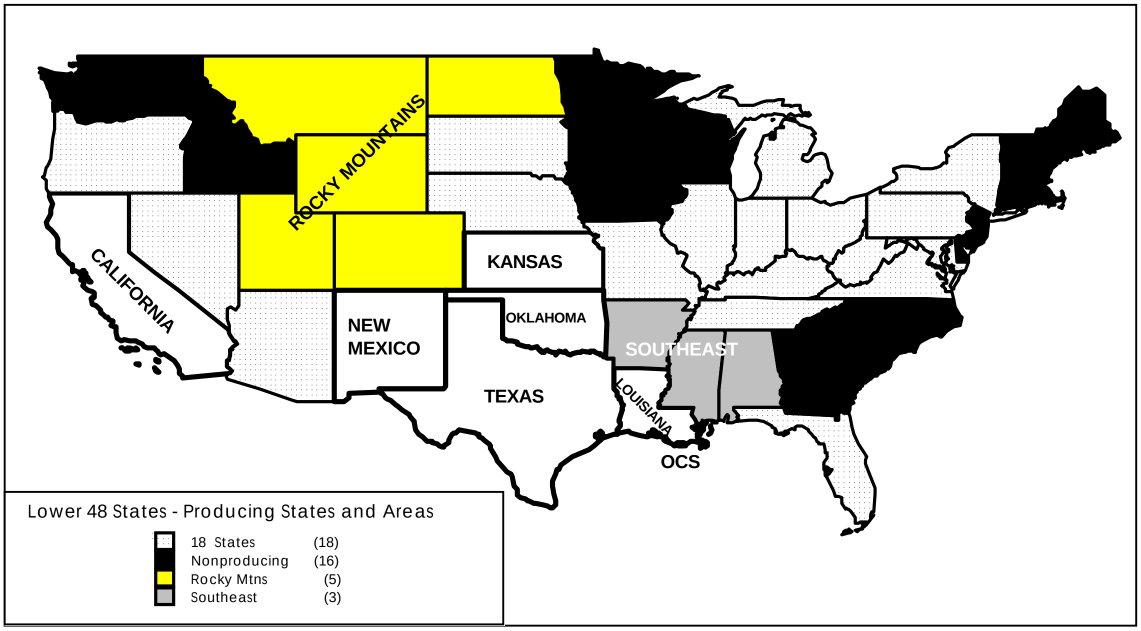
Total gross gas production (composed of gas-well and oil-well gas) from 1984 through 1993 is shown in Figure 6. Gas production from oil wells was stable over this time period, although oil production declined. Increases in producing gas-oil ratios roughly compensated for the declines in oil production. In 1993, gas

Table 1. Lower 48 States Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(Billion 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-84	52.3	62.2	8.7	71.0	18.7	73.7
Jun-84	45.4	61.6	8.9	70.5	25.1	64.4
Dec-84	48.7	62.2	8.8	71.0	22.3	68.6
Jan-85	49.5	61.6	9.0	70.6	21.1	70.1
Jun-85	41.2	61.4	9.2	70.6	29.3	58.4
Dec-85	50.1	62.0	9.2	71.2	21.1	70.4
Jan-86	49.3	63.0	9.8	72.9	23.6	67.6
Jun-86	40.3	61.3	9.0	70.3	30.0	57.3
Dec-86	46.9	60.1	8.8	68.9	22.0	68.1
Jan-87	47.9	60.0	9.0	69.0	21.1	69.4
Jun-87	41.8	58.0	8.8	66.8	25.1	62.5
Dec-87	49.0	57.1	8.7	65.8	16.7	74.6
Jan-88	50.1	57.6	8.8	66.4	16.3	75.5
Jun-88	43.2	55.6	8.8	64.4	21.2	67.1
Dec-88	48.4	54.8	8.5	63.4	15.0	76.3
Jan-89	49.1	56.2	8.8	65.0	15.9	75.6
Jun-89	45.0	55.2	8.4	63.6	18.6	70.8
Dec-89	47.8	55.9	7.9	63.8	16.0	74.9
Jan-90	51.0	56.9	8.7	65.6	14.7	77.7
Jun-90	45.8	55.9	8.4	64.3	18.5	71.2
Dec-90	50.0	56.2	8.4	64.6	14.6	77.3
Jan-91	51.3	57.3	8.4	65.7	14.4	78.1
Jun-91	45.1	55.5	8.3	63.8	18.7	70.7
Dec-91	49.8	54.9	8.3	63.2	13.5	78.7
Jan-92	50.2	55.1	8.5	63.6	13.5	78.8
Jun-92	47.1	52.9	8.4	61.3	14.2	76.8
Dec-92	49.4	52.1	8.3	60.4	11.0	81.7
Jan-93	49.8	52.8	8.2	61.0	11.2	81.7
Jun-93	47.8	52.1	8.1	60.2	12.3	79.5
Dec-93	49.7	53.0	7.9	60.9	11.2	81.6

Sources: Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. Productive Capacity: GASCAP94 C051995.

Figure 3. Lower 48 States - Producing States and Areas



Note: 18 States: Arizona, Florida, Illinois. Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia; Non-producing States: Connecticut, Georgia, Delaware, Idaho, Iowa, Maine, Massachusetts, Minnesota, New Jersey, New Hampshire, North Carolina, Rhode Island, South Carolina, Vermont, Washington, and Wisconsin; Rocky Mountains: Colorado, Montana, North Dakota, Utah, and Wyoming; Southeast: Alabama, Arkansas, and Mississippi.

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

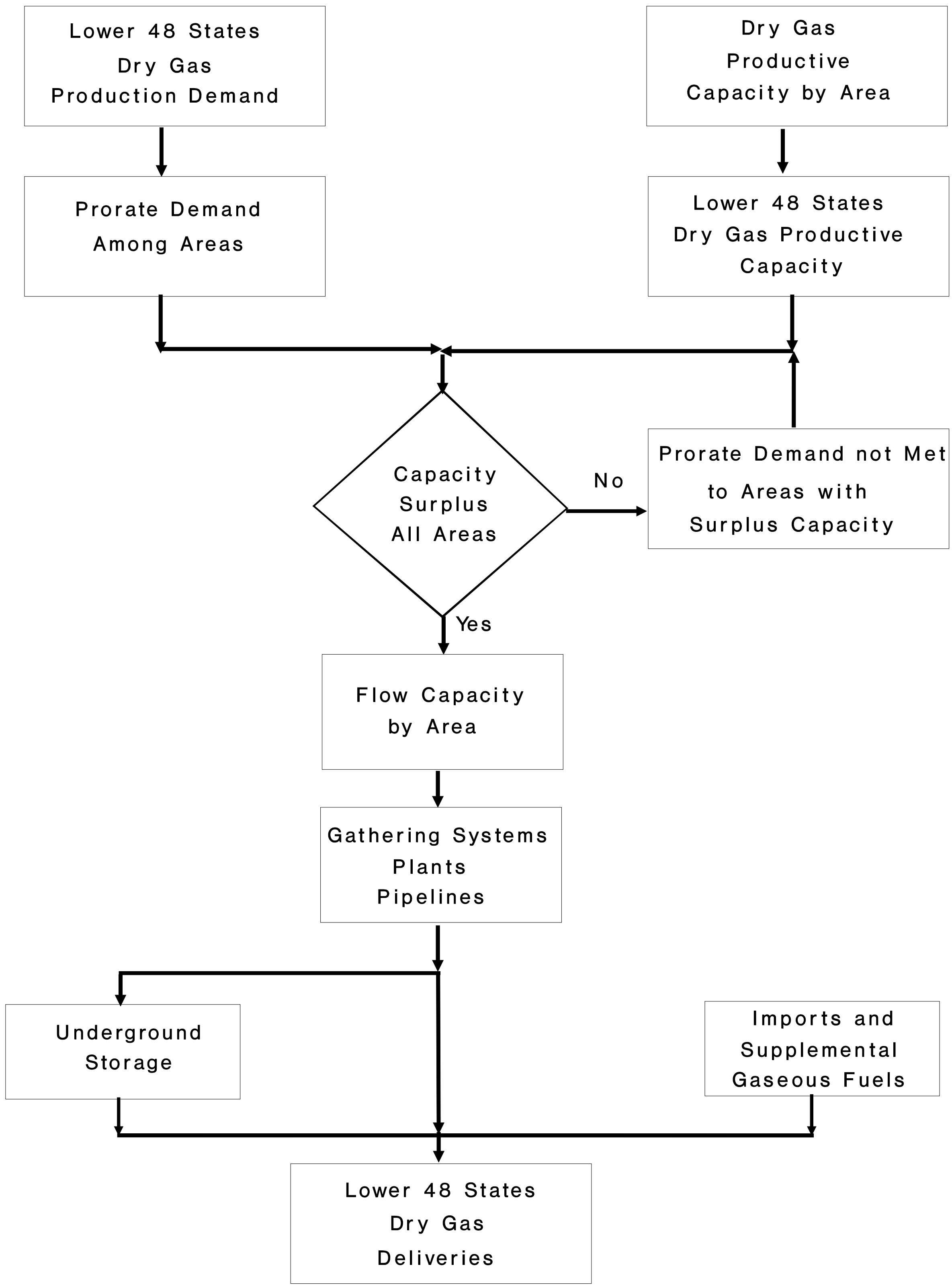
production from oil wells was 17 percent of total gas production in the lower 48 States. If oil production declines in 1994, 1995, and 1996 as expected, gas production from oil wells will also decline if the producing gas-oil ratio stays at its 1993 level. The share of total gross production from gas wells increased from 79 percent in 1986 to 83 percent in 1993.

The dry natural gas production contribution from the major gas producing States and areas is shown by Figure 7. The market share of production among States has been fairly stable from 1984 through 1993. 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 has made the largest contribution to meeting major seasonal swings in demand. Other significant natural gas producing States include Oklahoma, Louisiana, New Mexico, and Kansas. Chapter 3 reviews State and area gas production in detail.

Monthly gas production varies seasonally. Normally, production is highest in the months of January or February (because of high heating demand), substantially lower in June, and relatively higher in December. 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.

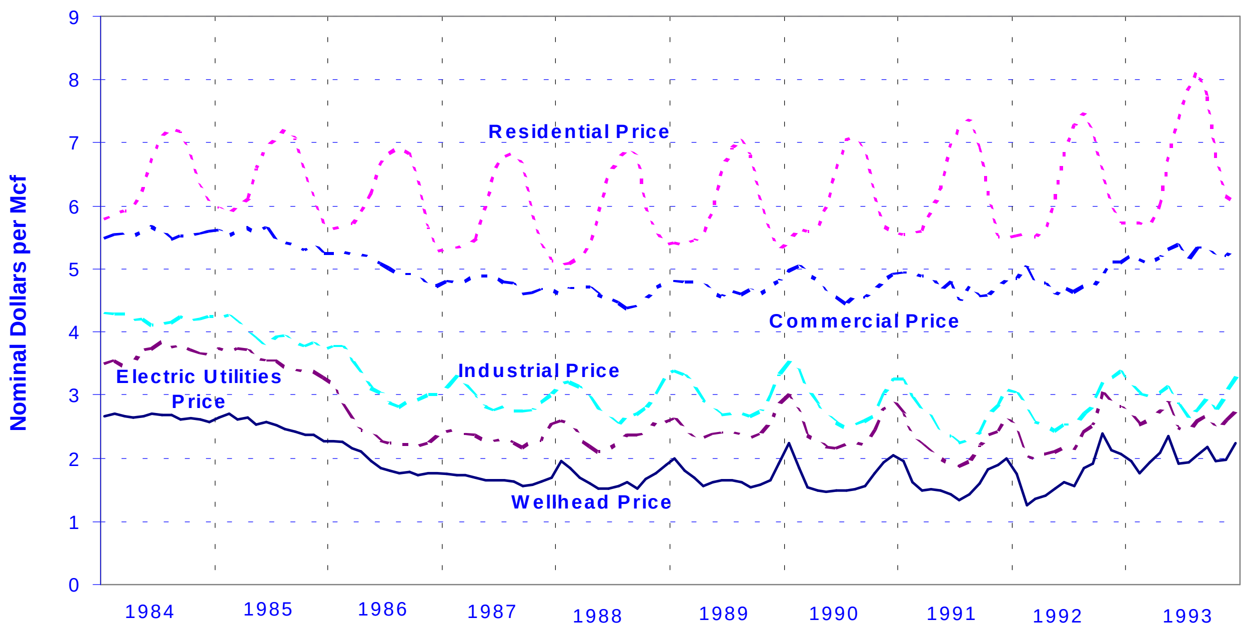
Coalbed gas was treated separately in this report for New Mexico and the Southeast and Rocky Mountains areas (Figure 8). These are the three major coalbed gas producing areas. Coalbed gas production has increased one percent per year as a percentage of the lower 48 States' gas production since 1990. Coalbed gas production was 4 percent of the lower-48 total gas produced in 1993.

Figure 4. Lower 48 States Productive Capacity and Supply Schematic



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

Figure 5. Natural Gas Price by Category, 1984-1993



Source: Energy Information Administration, Natural Gas Annual, DOE/EIA-0131, 1984-1993.

Gas Prices

The average real wellhead value of natural gas peaked in 1983 at $3.69 (in constant 1993 dollars) per thousand cubic feet{11}, dropped sharply in 1986, and continued to decline to $1.73 per thousand cubic feet in 1991 (a 53 percent drop over 8 years). The average price increased in 1993 to $2.03.{12} For comparison, real domestic crude oil prices dropped from $37.30 per barrel in 1983 to $14.20 in 1993, a 62 percent drop.{11} Given the lower prices and consequent decrease in drilling, it is understandable that wellhead productive capacity has declined to values closer to gas production requirements.

Projections

Dry Gas Productive Capacity and Production

EIA projects the natural gas wellhead productive capacity for the lower 48 States using the *Wellhead Productive Capacity Model*. For a description of the model and its methodology, see Appendix B. The model generates a 3-year projection of production and wellhead gas capacity. To account for unpredictable market forces and changing drilling activity levels, gas productive capacity projections are formulated for *low*, *base*, and *high* cases. The *base* case reflects what would most likely occur if current market trends continue and drilling and production levels continue to perform as they have performed in the past. The *high* case reflects an increase in the amount of drilling under more favorable market conditions, while the *low* case reflects a decrease under less favorable conditions. The model results are listed in Table 2.

In December 1993, the wellhead productive capacity of the lower 48 States was 60.9 billion cubic feet per day of dry natural gas. For the lower 48 States, the model projects the following:

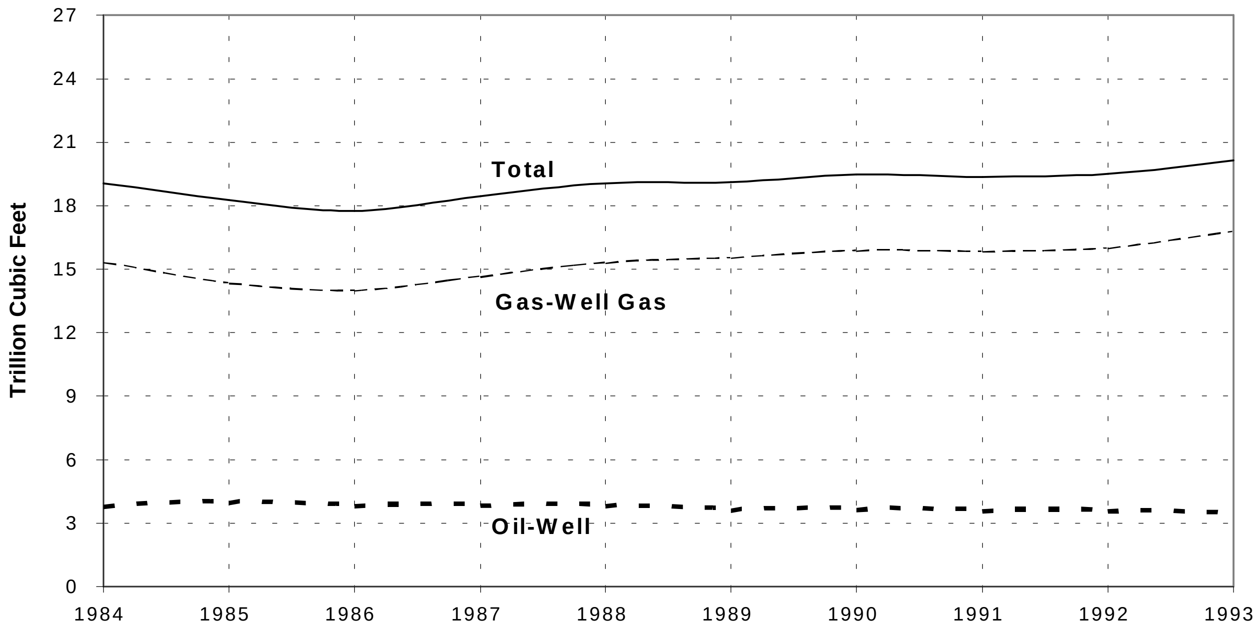
- In the *low* case projection, dry gas productive capacity will decline 6 percent to 57.5 billion cubic feet per day in December 1996.

Table 2. Lower 48 States Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (Billion 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-94	51.4	52.5	7.9	60.4	9.0	85.0
Jun-94	50.2	52.7	7.8	60.5	10.3	82.9
Dec-94	52.3	54.4	7.8	62.2	10.0	84.0
Jan-95	52.2	54.4	7.7	62.1	9.8	84.1
Jun-95	48.9	53.9	7.7	61.6	12.7	79.4
Dec-95	53.0	53.8	7.6	61.4	8.5	86.2
Jan-96	55.2	53.4	7.6	61.0	5.8	90.4
Jun-96	50.4	51.6	7.7	59.2	8.8	85.1
Dec-96	53.7	49.9	7.6	57.5	3.8	93.4
	Base Case Projection					
Jan-94	51.4	52.5	7.9	60.4	9.0	85.0
Jun-94	50.2	52.7	7.8	60.5	10.3	82.9
Dec-94	52.3	54.4	7.8	62.2	10.0	84.0
Jan-95	52.2	54.4	7.7	62.1	9.8	84.1
Jun-95	48.9	54.0	7.7	61.7	12.8	79.3
Dec-95	53.0	54.3	7.6	61.8	8.8	85.7
Jan-96	55.2	54.1	7.6	61.7	6.5	89.5
Jun-96	50.4	53.4	7.5	60.9	10.5	82.8
Dec-96	53.7	53.4	7.4	60.8	7.1	88.3
	High Case Projection					
Jan-94	51.4	52.5	7.9	60.4	9.0	85.0
Jun-94	50.2	52.7	7.8	60.5	10.3	82.9
Dec-94	52.3	54.4	7.8	62.2	10.0	84.0
Jan-95	52.2	54.4	7.7	62.1	9.8	84.1
Jun-95	48.9	54.0	7.7	61.7	12.8	79.3
Dec-95	53.0	54.4	7.6	62.0	9.1	85.4
Jan-96	55.2	54.4	7.6	62.0	6.8	89.0
Jun-96	50.4	54.5	7.7	62.1	11.7	81.1
Dec-96	53.7	56.1	7.6	63.7	10.0	84.3

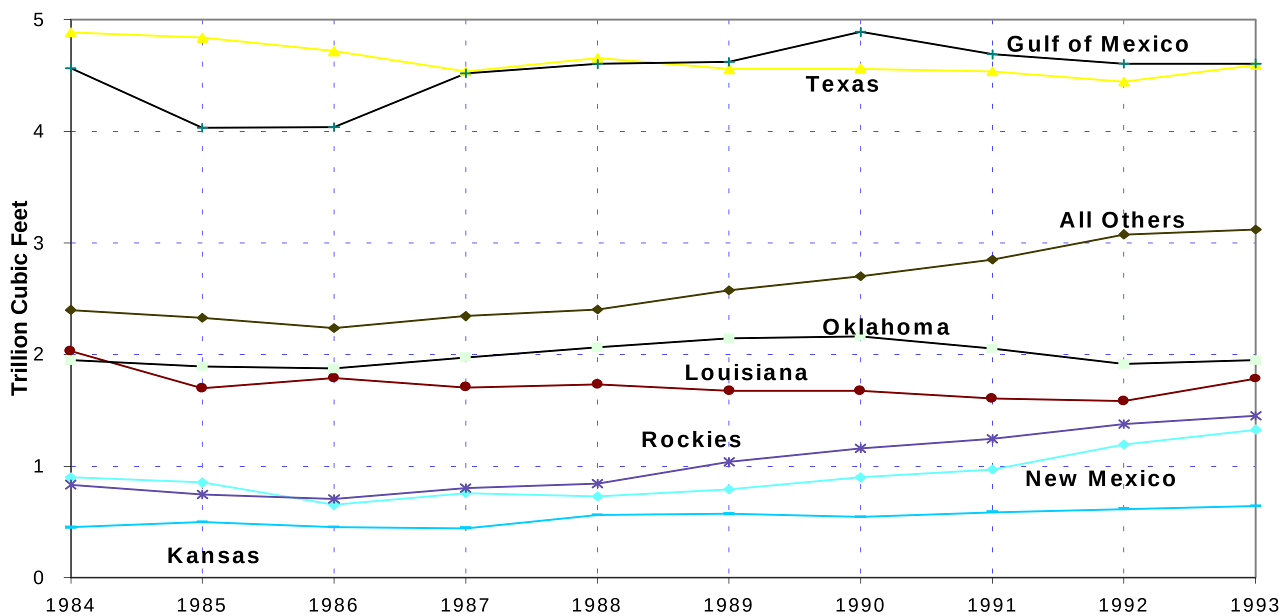
Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 6. Lower 48 States Gross Natural Gas Production by Type, 1984-1993



Source: Energy Information Administration, *Natural Gas Annual*, DOE/EIA-0131, 1984-1993.

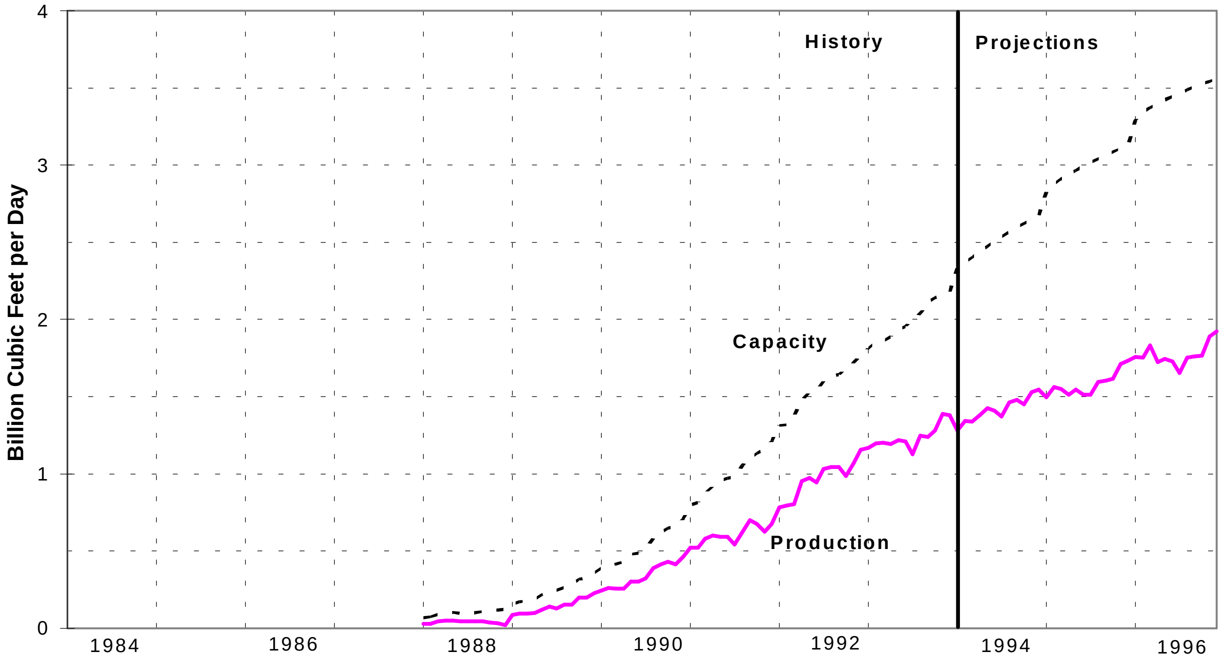
Figure 7. Dry Natural Gas Production from Lower 48 Producing States, 1984-1993



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, 1984-1993. •Production for Texas, Louisiana, and Gulf of Mexico OCS-Energy Information Administration, Office of Oil and Gas.

Figure 8. Lower 48 States Dry Coalbed Gas Monthly Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

- For the *base* case projection, productive capacity in December 1996 remains effectively the same as in December 1993.
- In the *high* case, productive capacity increases 5 percent from the December 1993 level, reaching 63.7 billion cubic feet per day in December 1996.

For surplus capacity in the lower 48 States:

- In the *low* case, the surplus capacity declines from 11.2 billion cubic feet per day to 3.8 billion cubic feet per day in December 1996.
- In the *base* case, surplus capacity declines to 7.1 billion cubic feet per day in December 1996.
- In the *high* case, the surplus capacity declines to 10.0 billion cubic feet per day in December 1996.

Despite the declining surplus capacity, gas productive capacity should be adequate to meet the projected monthly gas production requirements of the lower 48 States through December 1996, even in the *low* case. Beyond this time, more gas-well completions will be needed to prevent surplus capacity from declining to zero.

New Well Completions

Gas production capacity is increased by new gas-well completions. If there had been no new gas-well completions projected after 1993, the surplus capacity would have gone from 11.2 billion cubic feet per day in December 1993 to zero by November, 1994. With no new completions, productive capacity would not have been adequate to meet the forecast production requirements. Gas-well completions must be added continuously to sustain an adequate productive capacity.

To project gas productive capacity, a projection of new gas-well completions is required. The projection of new well completions is based on a projection of rigs running and an estimate of completions per rig. Forecasts of the 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 EIA's Short Term Energy Outlook (STEO). The Drilling Rig Model is described in Appendix A.

Gas-well completions dropped from 15,655 in 1985 to 9,807 in 1986 with even fewer completions in 1987 and 1988 (Figure 9). Despite this large decline, the general improvement in the average productive capacity of new completions precluded a serious loss of surplus capacity (Figure 1).

Gas-well completions added for the 3-year period 1994 through 1996 are estimated to be 32,075 for the low case, 35,519 for the base case, and 38,129 for the *high* case (Figure 9). The larger number of completions yield a dry gas productive capacity for the *high* case in December 1996 that is 63.7 billion cubic feet per day (Table 2) or 11 percent higher than the 57.5 billion cubic feet per day in the *low* case. Gas production requirements were 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 1996 for the *low* case, the productive capacity is estimated to decline nearly 1 billion cubic feet per day. To avert this decline, 1,000 gas-well completions need to be brought on production in 1996.

For the *low*, *base*, and *high* cases, the corresponding gas-well completions were estimated primarily as a function of gas price and production. The 1996 gas prices for the three cases were respectively $1.54, $1.88, and $2.31 per thousand cubic feet as shown in the *Third-Quarter 1995 Short-Term Energy Outlook* {10}. The actual gas prices were $2.03 per thousand cubic feet in 1993 {12} and $1.82 in 1994 {10}.

The newer gas-well completions contribute most of the productive capacity in the lower 48 States. Wells less than 3 years old contributed 44 percent of the productive capacity in the lower 48 States in December 1993. Wells less than 2 years old provided 34 percent, while wells completed that year provided 22 percent (Figure 10).

Gas Productive Capacity Issues

Demand

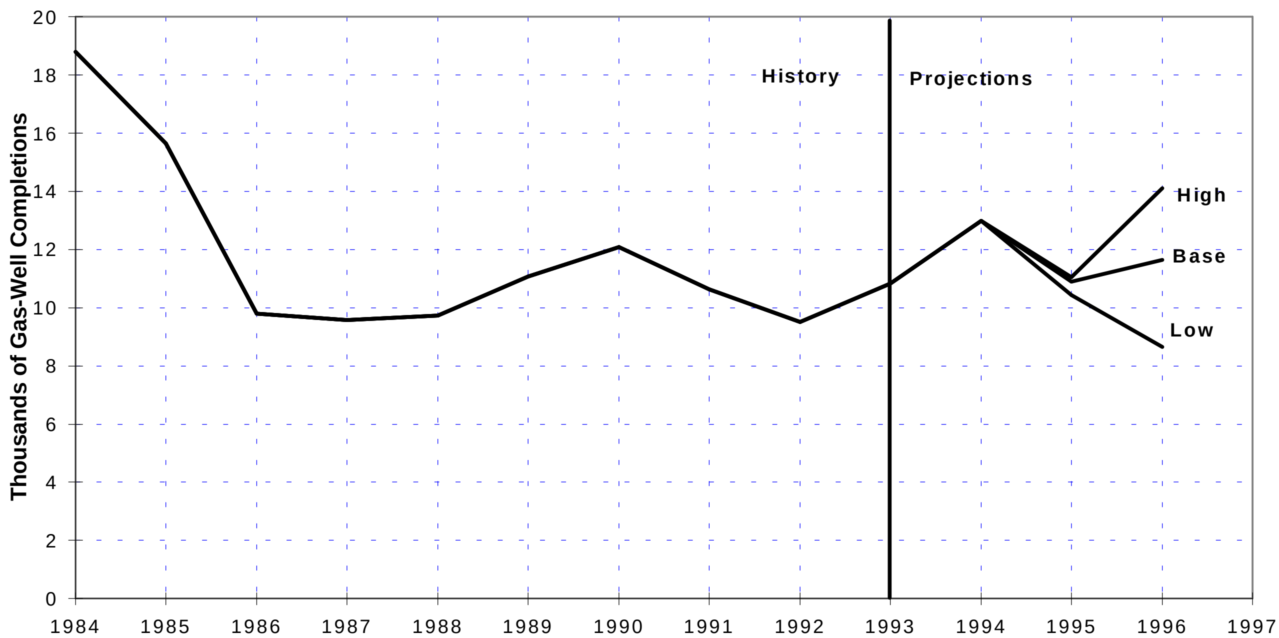
Even with a large surplus dry gas productive capacity, there can be short-term regional gas supply problems such as occurred in December 1983 and December 1989.

Peak-day demand may be twice the annual average-day demand. The National Petroleum Council (NPC){13} 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.

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.

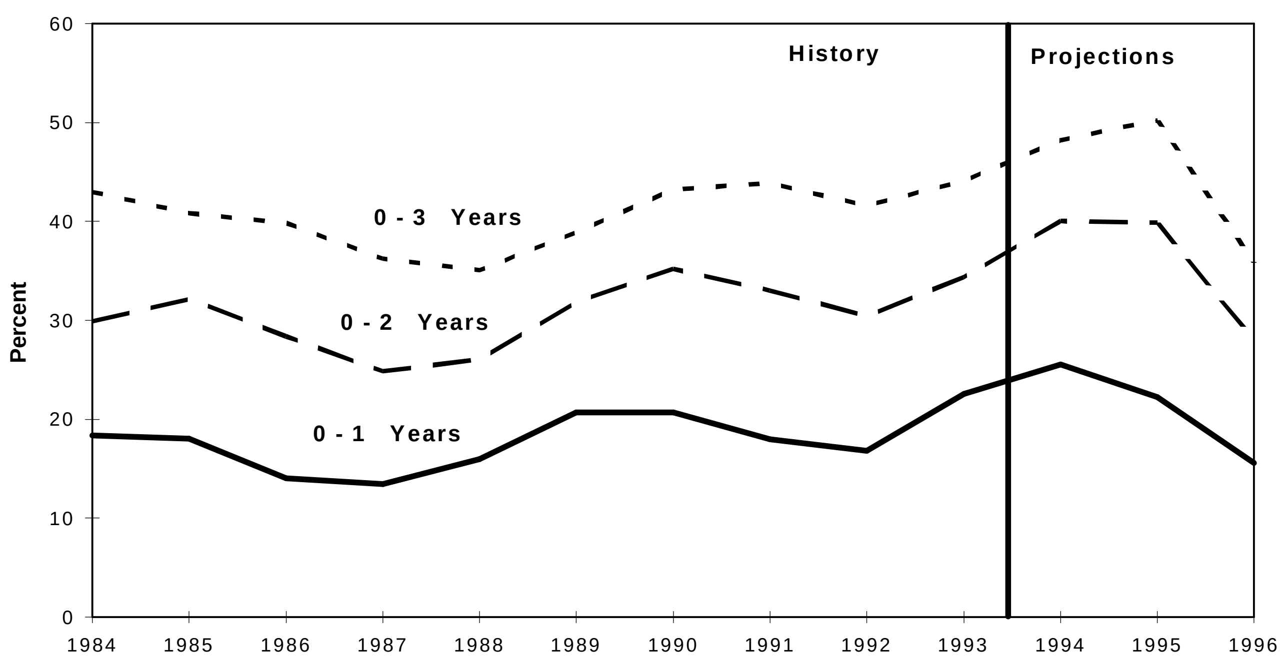
To better serve its customers, the natural gas industry has developed methods to meet peak demand such as delivery from gas storage facilities (54 billion cubic feet per day) and peak-day shaving capacity facilities (3

Figure 9. Lower 48 States Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 10. Percent of Total Wellhead Productive Capacity of Lower 48 States Gas Wells (Minus the 18 States Group) by Well Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

billion cubic feet per day){13}. 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), average wellhead prices are relatively unresponsive to demand, although residential, commercial, industrial, and electric utility gas prices normally increase during periods of high seasonal demand (Figure 5). 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.

Effective gas demand in peak periods 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 requirements. It is residential heating or cooling demand that is most likely to have a sudden upward surge related to weather. Residential consumers used 5.7 times as much gas in December 1992 as they did in August 1992 and 5.9 times as much gas in December 1993 as they did in August 1993.{14}

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 drops in December while the wellhead price of gas increases {14}. Figure 5 shows the relationship of wellhead price to residential, commercial, industrial, and electric utility prices for 1984 through 1993. Therefore, small increases in the average price of natural gas at the wellhead do not effectively dampen weather-related residential gas requirements in the short term.

Production Problems Create Gas Shortages on Peak-Demand Days

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 in December 1988. However, some regional peak-day requirements 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 soon occur again with the same severity. Weather-related increases in gas production requirements 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.

Interruptions in regional supply can cause a peak production requirement in other areas. For example, a storm in the Gulf of Mexico OCS, such as hurricane Andrew in August 1992, damaged 243 producing 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 to 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.

Deliverability

The existence of a high gas productive capacity at the wellhead does not mean that it could actually be produced and delivered. Deliverability is always equal to or less than wellhead productive capacity. Deliverability takes into account restrictions imposed by pipeline capacity, contract, or regulatory bodies.

In order to meet peak-month or peak-day demand, the pipeline system must also have adequate deliverability to the final destination. Pipeline systems must have adequate diameters, properly spaced compressors, and adequate interconnections between pipelines. Gas pipeline systems must be optimized to transport gas efficiently from any well to wherever in the lower 48 States that the need might arise.

Productive capacity and deliverability can be compared using the data collected by the Natural Gas Supply Association (NGSA) in its *NGSA Survey on 1994 Natural Gas Field Deliveries* & *Productive Capacity*.{15} The data was collected on an operator basis for seven lower-48 regions. The survey covered 77 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, 1994 which is equivalent to deliverability. The ratio of the NGSA 1994 connected gas field capacity to the annual 1993 field deliveries was 1.10. In other words, deliverability was 10 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 this region.

For the month of January 1994, it was estimated that 90 percent of the productive capacity at the wellhead could be delivered into the pipeline system. This was obtained by dividing the January 1994 deliverability of 54 billion cubic feet per day (determined by scaling up the NGSA connected-gas-well capacity){15} by the January 1994 dry productive capacity at the wellhead of 60 million cubic feet per day.

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. More gas can get from where it is produced to where it is needed. However, in some cases pipeline capacity may limit gas deliverability.

Gas Storage

Gas storage is a vital part of the natural gas industry. The ability to store gas ensures reliable deliveries during periods of heavy demand. Storage also enables greater system efficiency by allowing more stable production and transmission flows.

Storage withdrawals and peak shaving were used successfully to prevent gas supply curtailment in the extraordinarily high peak-day demand period in December 1989. Sufficient dry gas productive capacity will exist during the years 1994 through 1996 to increase the underground natural gas storage inventory needed. Gas storage requirements can be met by maintaining gas production closer to gas productive capacity throughout the year. Increased use of storage reduces the need for excess productive capacity, thus promoting improved economic efficiency in production.

Imports

Imports have become an increasingly important part of the domestic gas supply picture. Imports made up 5 percent (953 billion cubic feet) of the total gas demand requirements in 1984. In 1993, imports supplied 11 percent (2,469 billion cubic feet) of the total gas demand requirements. Reliance on imported gas has more than doubled in less than a decade.

The imported gas volume was 7 billion cubic feet per day in 1993. Without imported gas, the surplus capacity would be reduced. The surplus capacity in 1993 was only 11 billion cubic feet per day. If demand continues to rise without an increase in gas-well completions, surplus capacity may not be able to cover the loss of imported gas.

3. Producing Areas

This section of the report details the natural gas wellhead productive capacity by State or area where Dwight's gas-well gas production data is available. From these data, individual studies are made for each of six States: California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and the Gulf of Mexico Federal Offshore Outer Continental Shelf (OCS).

The remaining Dwight's data are combined into 3 groups of States. Five states are grouped together as *Rocky Mountains*: Colorado, Montana, North Dakota, Utah, and Wyoming. Three states are combined as the *Southeast* group, consisting of Alabama, Arkansas, and Mississippi. The third group is 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 are available.

Each State or group of States has its own unique, initially scheduled monthly gas production rate for January 1994 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 *Third Quarter Short-Term Energy Outlook* {10} 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.

Gulf of Mexico OCS

The Gulf of Mexico OCS is a prolific natural gas producer with large seasonal variations in producing rate. In 1993, more than a quarter of the lower 48 States' dry gas production came from this area {12}. Matagorda Island Block 623 and South Timbalier Block 172 fields were the largest producers of natural gas in the Gulf of Mexico OCS in 1993.

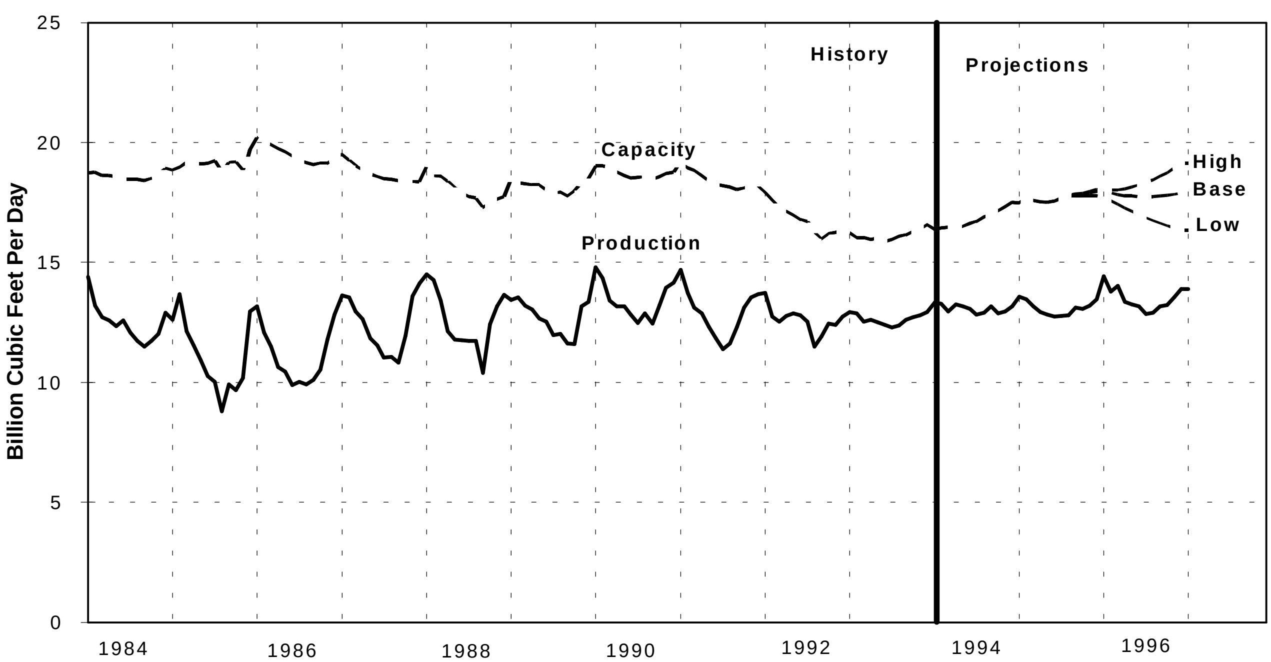
Figure 11 shows the dry gas production rate and wellhead productive capacity from 1984 through 1993 with projections through 1996. The January, June, and December historical production rates and capacities are presented in Table 3. Wellhead productive capacity projections are shown by Table 4.

Surplus capacity was adequate from 1984 through 1993. Projections show gradual increases for the *base* and *high* cases.

Figure 12 shows the number of gas-well completions "added during the year and producing in December" from 1984 through 1993 and projected through 1996. The *base* case forecasts an increase in the number of new completions in 1994 followed by a decrease in 1995 and 1996. Current information indicates that several large platforms are scheduled to come on production during 1996.

The initial flow rates per well completion for the Gulf of Mexico are generally high, about 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 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 11. Gulf of Mexico OCS Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 3. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	14,381	17,505	1,225	18,730	4,349	76.8
Jun-84	12,583	17,099	1,366	18,465	5,882	68.1
Dec-84	12,898	17,560	1,371	18,931	6,033	68.1
Jan-85	12,591	17,478	1,373	18,851	6,260	66.8
Jun-85	10,261	17,595	1,539	19,134	8,873	53.6
Dec-85	12,969	18,168	1,530	19,698	6,729	65.8
Jan-86	13,177	18,631	1,585	20,216	7,039	65.2
Jun-86	9,891	17,961	1,460	19,421	9,530	50.9
Dec-86	12,823	17,773	1,489	19,262	6,439	66.6
Jan-87	13,620	18,084	1,416	19,500	5,880	69.8
Jun-87	11,532	17,268	1,317	18,585	7,053	62.1
Dec-87	14,124	17,099	1,252	18,351	4,227	77.0
Jan-88	14,490	17,737	1,254	18,991	4,501	76.3
Jun-88	11,750	16,629	1,309	17,938	6,188	65.5
Dec-88	13,659	16,427	1,314	17,741	4,082	77.0
Jan-89	13,438	17,168	1,286	18,454	5,016	72.8
Jun-89	12,535	16,782	1,224	18,006	5,471	69.6
Dec-89	13,345	17,419	1,085	18,504	5,159	72.1
Jan-90	14,793	17,797	1,220	19,017	4,224	77.8
Jun-90	12,827	17,338	1,184	18,522	5,695	69.3
Dec-90	14,153	17,525	1,228	18,753	4,600	75.5
Jan-91	14,695	17,871	1,301	19,172	4,477	76.6
Jun-91	11,846	16,959	1,314	18,273	6,427	64.8
Dec-91	13,677	16,758	1,434	18,192	4,515	75.2
Jan-92	13,736	16,594	1,321	17,915	4,179	76.7
Jun-92	12,786	15,501	1,292	16,793	4,007	76.1
Dec-92	12,751	14,926	1,263	16,189	3,438	78.8
Jan-93	12,929	14,880	1,354	16,234	3,305	79.6
Jun-93	12,384	14,496	1,376	15,872	3,488	78.0
Dec-93	12,929	15,194	1,370	16,564	3,635	78.1

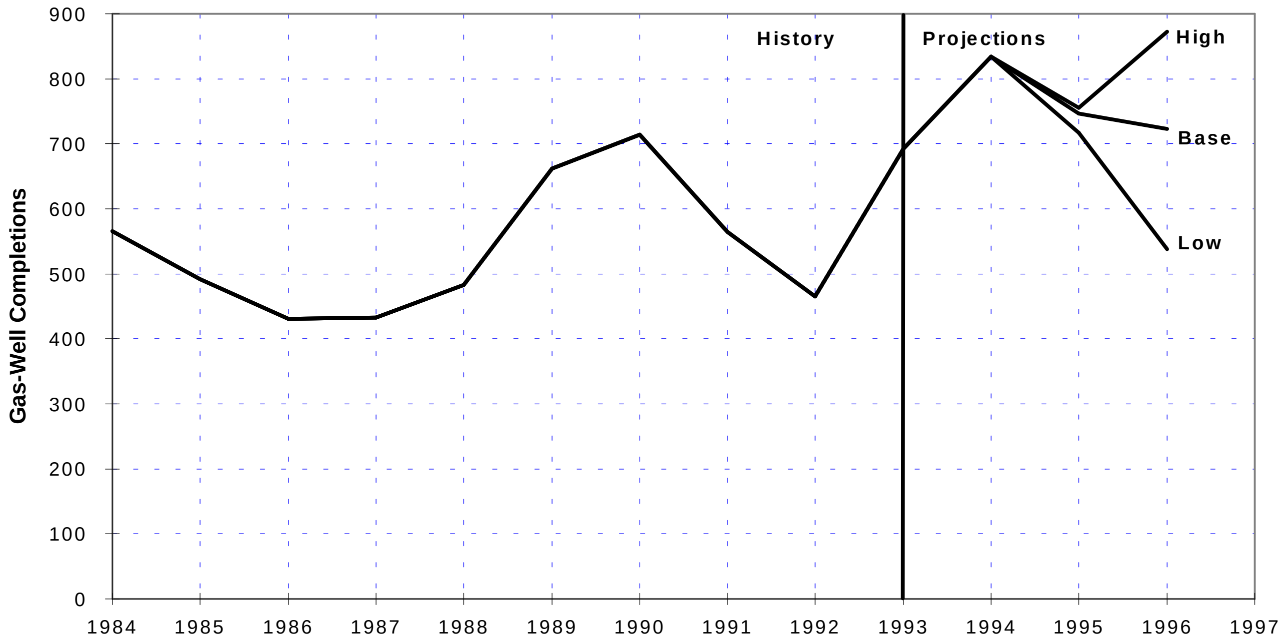
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 4. Gulf of Mexico OCS Dry Gas Production and Wellhead Productive Capacity, Projections, 1994-1996 (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-94	13,324	14,984	1,411	16,395	3,071	81.3
Jun-94	13,065	15,206	1,418	16,624	3,559	78.6
Dec-94	13,183	16,016	1,483	17,499	4,316	75.3
Jan-95	13,561	16,053	1,432	17,485	3,924	77.6
Jun-95	12,747	16,044	1,512	17,556	4,809	72.6
Dec-95	13,475	16,274	1,503	17,777	4,302	75.8
Jan-96	14,434	16,165	1,505	17,670	3,236	81.7
Jun-96	13,173	15,490	1,514	17,004	3,831	77.5
Dec-96	14,185	14,830	1,510	16,340	2,155	86.8
		Base Case Projection				
Jan-94	13,324	14,984	1,411	16,395	3,071	81.3
Jun-94	13,065	15,206	1,418	16,624	3,559	78.6
Dec-94	13,183	16,016	1,483	17,499	4,316	75.3
Jan-95	13,561	16,053	1,432	17,485	3,924	77.6
Jun-95	12,747	16,053	1,512	17,565	4,818	72.6
Dec-95	13,462	16,482	1,488	17,970	4,508	74.9
Jan-96	14,413	16,437	1,489	17,926	3,513	80.4
Jun-96	13,172	16,256	1,488	17,744	4,572	74.2
Dec-96	13,878	16,425	1,471	17,896	4,018	77.5
		High Case Projections				
Jan-94	13,324	14,984	1,411	16,395	3,071	81.3
Jun-94	13,065	15,206	1,418	16,624	3,559	78.6
Dec-94	13,183	16,016	1,483	17,499	4,316	75.3
Jan-95	13,561	16,053	1,432	17,485	3,924	77.6
Jun-95	12,747	16,055	1,512	17,567	4,820	72.6
Dec-95	13,454	16,540	1,503	18,043	4,589	74.6
Jan-96	14,404	16,517	1,505	18,022	3,618	79.9
Jun-96	13,169	16,718	1,514	18,232	5,063	72.2
Dec-96	13,712	17,622	1,510	19,132	5,420	71.7

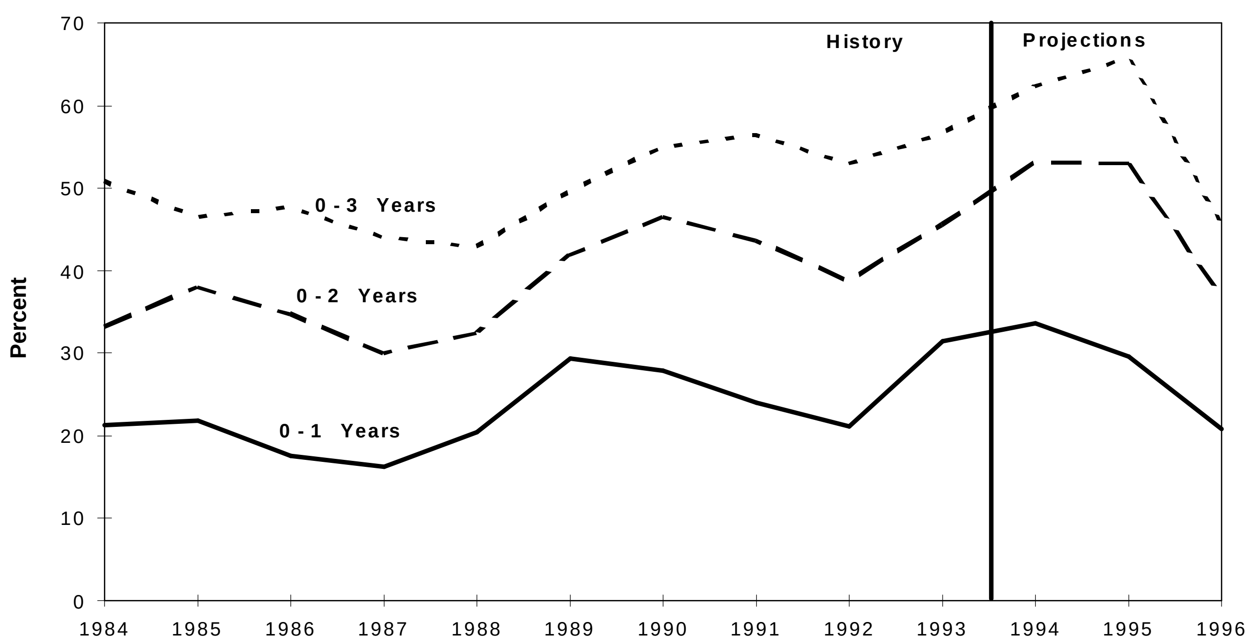
Sources: •Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 12. Gulf of Mexico OCS Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

Figure 13. Percent of Total Wellhead Productive Capacity of Gulf of Mexico OCS Gas Wells, by Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 13 shows the percent of the Gulf of Mexico OCS gas-well gas productive capacity in December of each year by age of the well. Gas-well completions that have been producing gas for less than 1 year contributed from 16 to 31 percent of the productive capacity from 1984 through 1993.

Historically, the total surplus dry gas productive capacity in the Gulf of Mexico OCS has been declining. This area's ability to meet the major seasonal swings in the lower 48 States gas requirements is threatened if future well completions do not continue to exceed the 1996 low case level.

Texas (Excluding Gulf of Mexico OCS)

For many years Texas has been the largest natural gas producing State. In 1993, Texas produced more than a quarter of the total dry gas in the lower 48 States, about the same as the Gulf of Mexico OCS. {12} Gas producing zones range from high permeability, water-drive formations to low permeability "Tight Gas" reservoirs. The two largest gas producing areas in 1993 in the State were the Carthage and the Panhandle West fields.

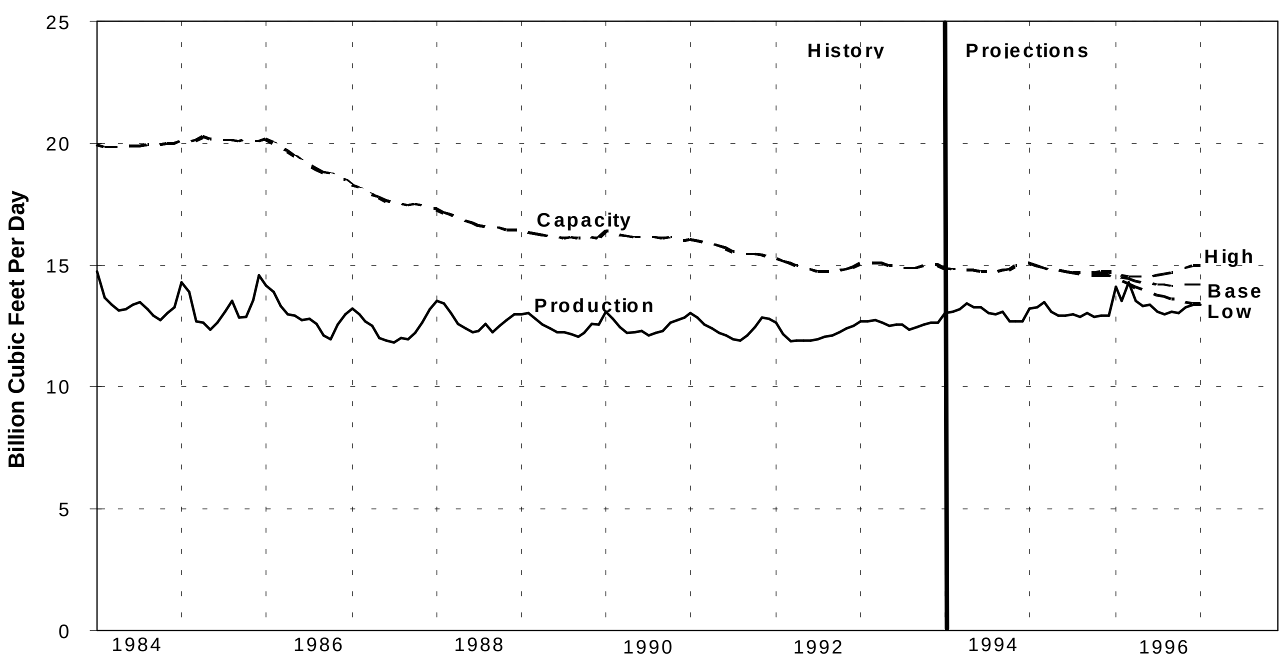
Figure 14 shows the dry gas production rate and wellhead productive capacity from 1984 through 1993 with projections through 1996. The January, June, and December production rates and capacities are presented in Tables 5 and 6. Productive capacity began a very pronounced downturn beginning in 1986. After 1986, surplus capacity began to diminish (Figure 14). Consequently, capacity utilization increased from 1986 through 1993 (Table 5). The surplus capacity is projected to continue to decrease through 1996 for the *low* and *base* cases. There is no surplus capacity for the *low* case in December 1996. Compared with the OCS, surplus capacities have not shown large increases in June. This reflects the fact that production requirement for Texas gas are less seasonal than for the Gulf of Mexico OCS.

Figure 15 shows the number of gas-well completions "added during the year and producing in December" from 1984 through 1993 with projections through 1996. The number of gas-well completions declined sharply in 1986.

Initial flow rates for Texas wells range from high to relatively low. The average initial flow rate per well in Texas has been about 1 million cubic feet per day for over the last few years (Table D1).

Figure 16 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 1993.

Figure 14. Texas (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Enrgy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 5. Texas (Excluding Gulf of Mexico) Dry Gas Production and Wellhead Productive Capacity, 1984-1993 (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-84	14,737	16,474	3,488	19,962	5,225	73.8
Jun-84	13,363	16,499	3,401	19,900	6,537	67.2
Dec-84	13,298	16,618	3,393	20,011	6,713	66.5
Jan-85	14,287	16,690	3,398	20,088	5,801	71.1
Jun-85	12,657	16,702	3,398	20,100	7,443	63.0
Dec-85	14,589	16,676	3,421	20,097	5,508	72.6
Jan-86	14,148	16,663	3,509	20,172	6,024	70.1
Jun-86	12,749	16,018	3,267	19,285	6,536	66.1
Dec-86	13,007	15,395	3,146	18,541	5,534	70.2
Jan-87	13,217	15,137	3,140	18,277	5,060	72.3
Jun-87	11,918	14,631	3,033	17,664	5,746	67.5
Dec-87	13,196	14,348	3,025	17,373	4,177	76.0
Jan-88	13,542	14,160	3,150	17,310	3,768	78.2
Jun-88	12,233	13,676	3,074	16,750	4,517	73.0
Dec-88	13,001	13,435	2,993	16,428	3,427	79.1
Jan-89	12,969	13,377	3,080	16,457	3,488	78.8
Jun-89	12,247	13,200	2,954	16,154	3,907	75.8
Dec-89	12,564	13,262	2,833	16,095	3,531	78.1
Jan-90	13,095	13,414	2,963	16,377	3,282	80.0
Jun-90	12,292	13,250	2,888	16,138	3,846	76.2
Dec-90	12,836	13,036	2,982	16,018	3,182	80.1
Jan-91	13,040	13,104	2,951	16,055	3,015	81.2
Jun-91	12,105	12,850	2,839	15,689	3,584	77.2
Dec-91	12,778	12,543	2,809	15,352	2,574	83.2
Jan-92	12,667	12,390	2,925	15,315	2,648	82.7
Jun-92	11,912	11,994	2,826	14,820	2,908	80.4
Dec-92	12,483	12,127	2,818	14,945	2,462	83.5
Jan-93	12,679	12,051	3,042	15,093	2,414	84.0
Jun-93	12,562	11,982	2,945	14,927	2,365	84.2
Dec-93	12,654	12,114	2,896	15,010	2,356	84.3

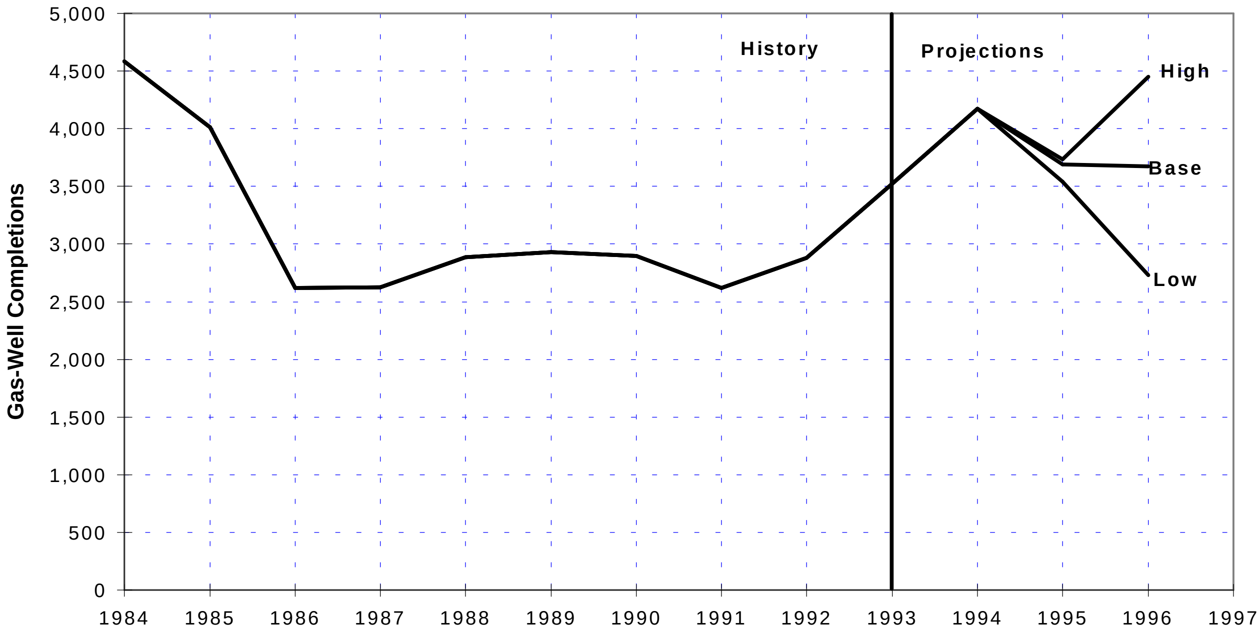
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 6. Texas (Excluding Gulf of Mexico) Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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 Projections				
Jan-94	13,018	11,964	2,907	14,871	1,853	87.5
Jun-94	13,268	11,931	2,805	14,736	1,468	90.0
Dec-94	12,697	12,301	2,777	15,078	2,381	84.2
Jan-95	13,248	12,308	2,768	15,076	1,828	87.9
Jun-95	12,944	12,004	2,724	14,728	1,784	87.9
Dec-95	12,956	11,901	2,691	14,592	1,636	88.8
Jan-96	14,110	11,822	2,693	14,515	405	97.2
Jun-96	13,366	11,192	2,700	13,892	526	96.2
Dec-96	13,428	10,750	2,678	13,428	0	100.0
		Base Case Projection				
Jan-94	13,018	11,964	2,907	14,871	1,853	87.5
Jun-94	13,268	11,931	2,805	14,736	1,468	90.0
Dec-94	12,697	12,301	2,777	15,078	2,381	84.2
Jan-95	13,248	12,308	2,768	15,076	1,828	87.9
Jun-95	12,944	12,011	2,724	14,735	1,791	87.8
Dec-95	12,943	12,018	2,664	14,682	1,739	88.2
Jan-96	14,090	11,972	2,664	14,636	546	96.3
Jun-96	13,365	11,595	2,651	14,246	881	93.8
Dec-96	13,380	11,603	2,605	14,208	828	94.2
		High Case Projection				
Jan-94	13,018	11,964	2,907	14,871	1,853	87.5
Jun-94	13,268	11,931	2,805	14,736	1,468	90.0
Dec-94	12,697	12,301	2,777	15,078	2,381	84.2
Jan-95	13,248	12,308	2,768	15,076	1,828	87.9
Jun-95	12,944	12,013	2,724	14,737	1,793	87.8
Dec-95	12,935	12,056	2,691	14,747	1,812	87.7
Jan-96	14,081	12,023	2,693	14,716	635	95.7
Jun-96	13,362	11,866	2,700	14,566	1,204	91.7
Dec-96	13,220	12,296	2,678	14,974	1,754	88.3

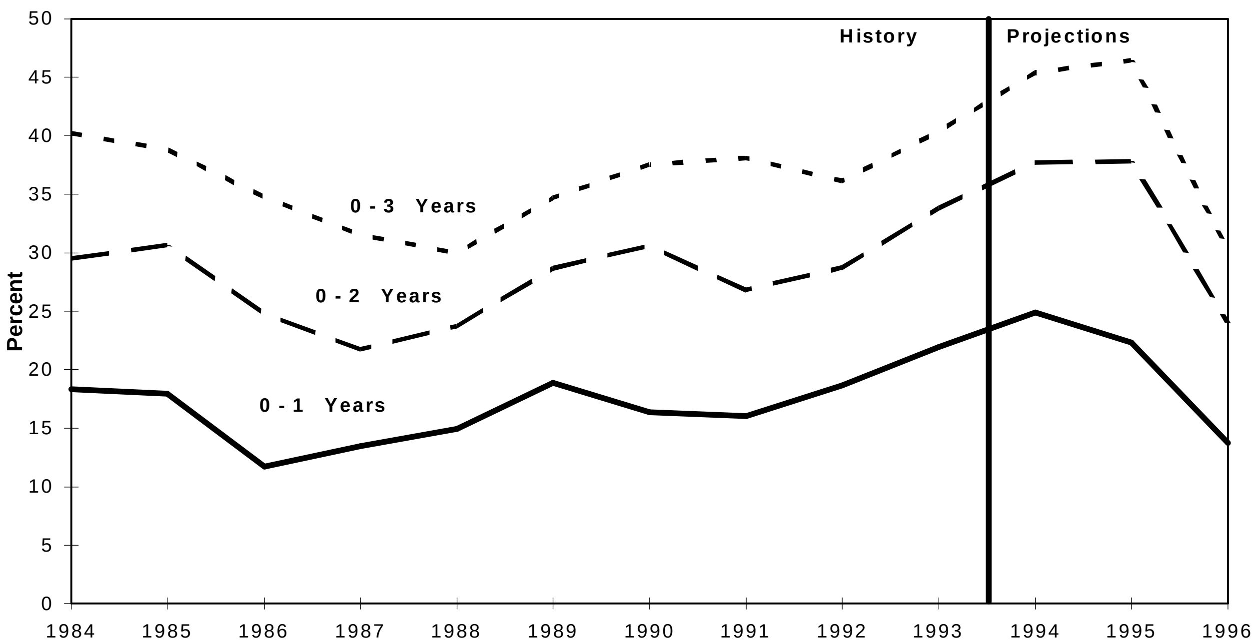
Sources: •Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. •Productive Capacity Projections: GASCAP94 C051995.

Figure 15. Texas (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP94 C051995.

Figure 16. Percent of Total Wellhead Productive Capacity of Texas (Excluding Gulf of Mexico OCS) Gas Wells, by Age, 1984-1996 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP94 C051995.

Figure 17 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. 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.

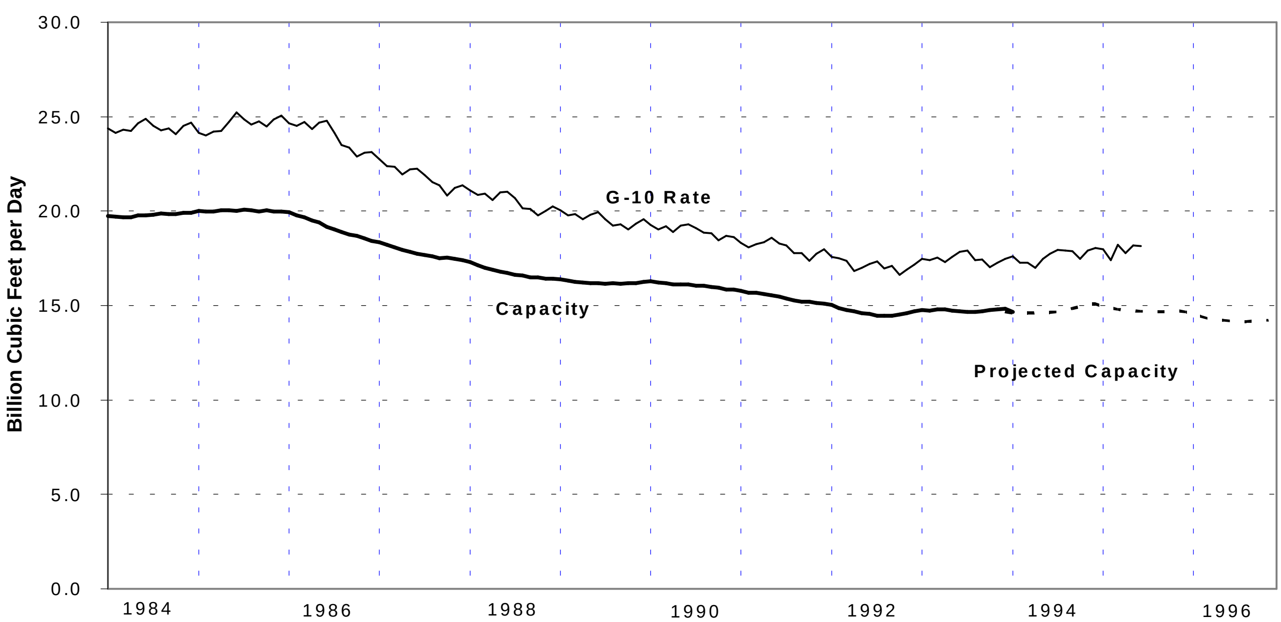
Operators of Texas gas wells are required to make a production test of each gas well semi-annually and report the test on Form G-10 unless the well is exempt from testing. All gas wells producing less than 100 thousand cubic feet per day are automatically exempt. Each month, the TRC determines statewide 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. 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.

Capacity estimated in this report is the daily rate that can be sustained for a month. Rates reported on the G-10 tests are required to be sustainable for only 72 hours.

Both, however, exhibit a similar downward trend, indicating a diminishing surplus capacity.

Figure 17. Texas (Excluding Gulf of Mexico OCS) Monthly Gross Gas-Well Gas Productive Capacity and G-10 Rate, 1984-1996



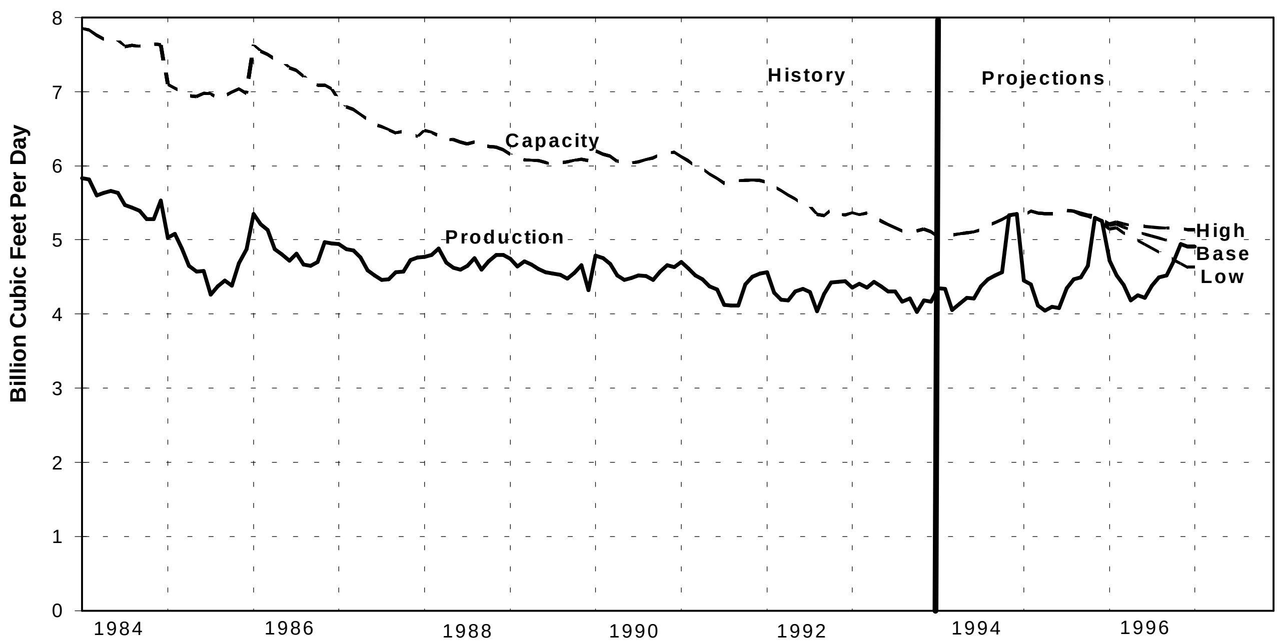
Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Railroad Commission of Texas. Projections: Model GASCAP94 C051995.

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-pressured formations on the Gulf Coast as well as from low permeability and relatively shallow reservoirs in North Louisiana. In 1993, the two fields producing the largest volume of natural gas in the State were the Chalkey and Lake Arthur South fields, according to Dwight's data. In 1993, 10 percent of the total dry gas production of the lower 48 States came from Louisiana. {12}

The following pages include Tables 7 and 8 and Figures 18 through 20, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age. These data exclude the OCS.

Figure 18. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 7. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1984-1993 (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-84	5,838	7,262	591	7,853	2,015	74.3
Jun-84	5,631	7,069	619	7,688	2,057	73.2
Dec-84	5,536	7,017	614	7,631	2,095	72.5
Jan-85	5,030	6,574	525	7,099	2,069	70.9
Jun-85	4,581	6,440	539	6,979	2,398	65.6
Dec-85	4,876	6,460	516	6,976	2,100	69.9
Jan-86	5,353	7,047	585	7,632	2,279	70.1
Jun-86	4,724	6,787	538	7,325	2,601	64.5
Dec-86	4,950	6,456	579	7,035	2,085	70.4
Jan-87	4,940	6,296	583	6,879	1,939	71.8
Jun-87	4,523	5,986	570	6,556	2,033	69.0
Dec-87	4,764	5,822	573	6,395	1,631	74.5
Jan-88	4,772	5,907	569	6,476	1,704	73.7
Jun-88	4,599	5,778	546	6,324	1,725	72.7
Dec-88	4,796	5,677	540	6,217	1,421	77.1
Jan-89	4,740	5,660	502	6,162	1,422	76.9
Jun-89	4,567	5,559	483	6,042	1,475	75.6
Dec-89	4,320	5,644	420	6,064	1,744	71.2
Jan-90	4,785	5,761	440	6,201	1,416	77.2
Jun-90	4,486	5,604	432	6,036	1,550	74.3
Dec-90	4,635	5,743	443	6,186	1,551	74.9
Jan-91	4,703	5,704	419	6,123	1,420	76.8
Jun-91	4,332	5,413	415	5,828	1,496	74.3
Dec-91	4,544	5,382	422	5,804	1,260	78.3
Jan-92	4,560	5,269	512	5,781	1,221	78.9
Jun-92	4,342	4,978	504	5,482	1,140	79.2
Dec-92	4,447	4,837	497	5,334	887	83.4
Jan-93	4,359	4,969	397	5,366	1,007	81.2
Jun-93	4,302	4,813	400	5,213	911	82.5
Dec-93	4,163	4,725	389	5,114	951	81.4

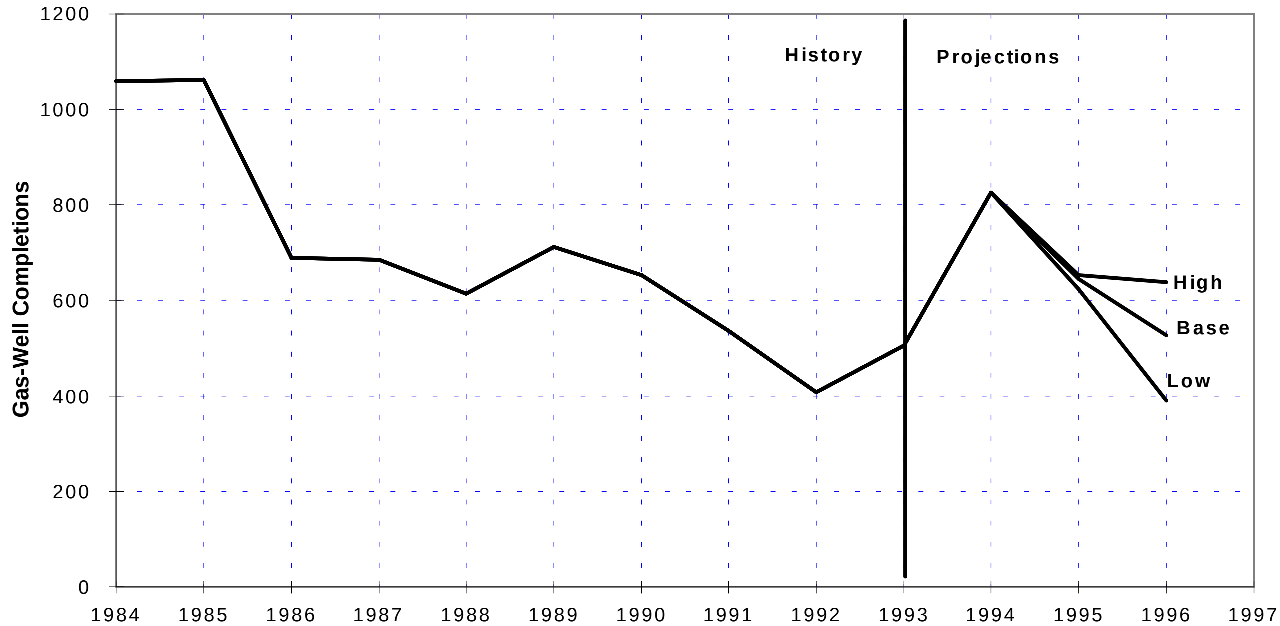
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995.

Table 8. Louisiana (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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-94	4,351	4,671	369	5,040	689	86.3
Jun-94	4,205	4,750	358	5,108	903	82.3
Dec-94	5,354	4,996	358	5,354	0	100.0
Jan-95	4,448	4,967	361	5,328	880	83.5
Jun-95	4,081	5,030	344	5,374	1,293	75.9
Dec-95	5,225	4,884	341	5,225	0	100.0
Jan-96	4,731	4,807	341	5,148	417	91.9
Jun-96	4,218	4,602	342	4,944	726	85.3
Dec-96	4,634	4,294	340	4,634	0	100.0
Base Case Projection						
Jan-94	4,351	4,671	369	5,040	689	86.3
Jun-94	4,205	4,750	358	5,108	903	82.3
Dec-94	5,354	4,996	358	5,354	0	100.0
Jan-95	4,448	4,967	361	5,328	880	83.5
Jun-95	4,081	5,032	344	5,376	1,295	75.9
Dec-95	5,259	4,922	337	5,259	0	100.0
Jan-96	4,724	4,857	337	5,194	470	91.0
Jun-96	4,218	4,744	336	5,080	862	83.0
Dec-96	4,910	4,580	330	4,910	0	100.0
High Case Projection						
Jan-94	4,351	4,671	369	5,040	689	86.3
Jun-94	4,205	4,750	358	5,108	903	82.3
Dec-94	5,354	4,996	358	5,354	0	100.0
Jan-95	4,448	4,967	361	5,328	880	83.5
Jun-95	4,081	5,033	344	5,377	1,296	75.9
Dec-95	5,277	4,936	341	5,277	0	100.0
Jan-96	4,721	4,875	341	5,216	495	90.5
Jun-96	4,217	4,839	342	5,181	964	81.4
Dec-96	5,141	4,801	340	5,141	0	100.0

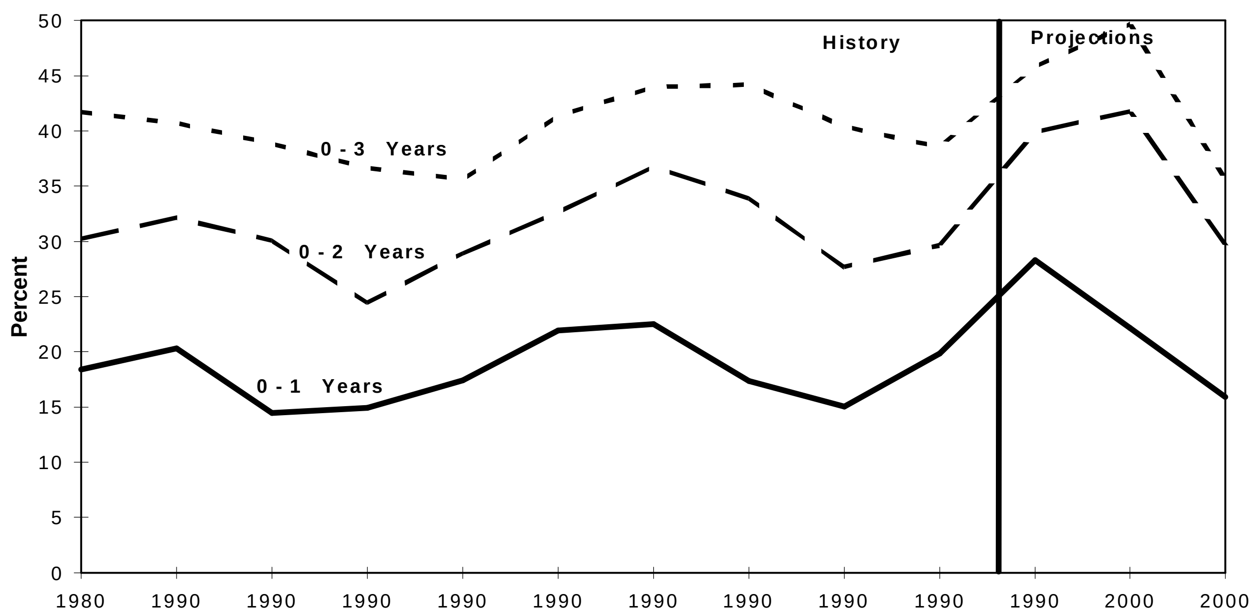
Sources: Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 19. Louisiana (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 20. Percent of Total Wellhead Productive Capacity of Louisiana (Exlcuding Gulf of Mexico OCS) Gas Wells, by Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

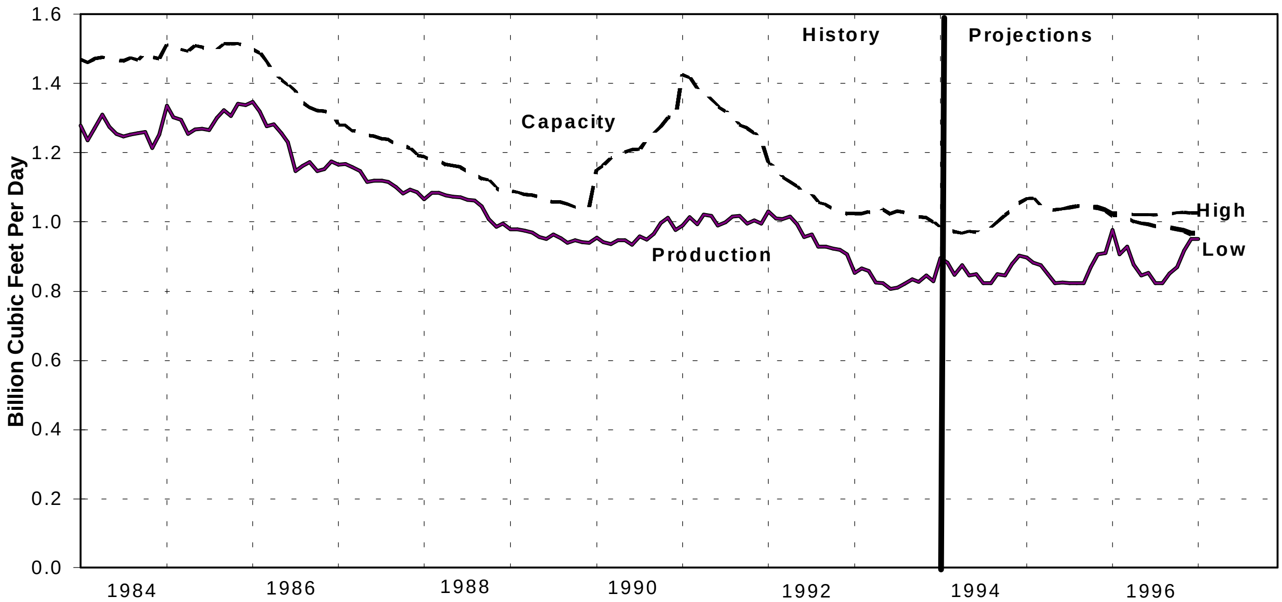
California (Including Pacific OCS)

California is a net importer of natural gas. All California gas produced is used within the State. In 1993, more than half the total gas produced in California and the Pacific OCS was oil-well gas. {12}

In 1993, Elk Hills and Lost Hills oil fields were the two largest producers of natural gas. The two largest gas fields were Rio Vista and Pitas Point; the latter is in the Pacific OCS. This information was obtained from the California Department of Conservation.

The following pages include Tables 9 and 10 and Figures 21 through 23, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age. These data include the OCS.

Figure 21. California (Including Pacific OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



Note: Production projection plotted for base case only. Base case capacity projection is nearly the same as low case projection.

Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 9. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity, 1984-1993 (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-84	1,279	735	735	1,470	191	87.0
Jun-84	1,254	738	729	1,467	213	85.5
Dec-84	1,253	725	747	1,472	219	85.1
Jan-85	1,335	761	751	1,512	177	88.3
Jun-85	1,269	736	770	1,506	237	84.3
Dec-85	1,337	725	786	1,511	174	88.5
Jan-86	1,347	725	775	1,500	153	89.8
Jun-86	1,231	663	734	1,397	166	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	535	714	1,249	129	89.7
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	467	692	1,159	88	92.4
Dec-88	996	430	655	1,085	89	91.8
Jan-89	979	431	659	1,090	111	89.8
Jun-89	951	403	658	1,061	110	89.6
Dec-89	940	392	648	1,040	100	90.4
Jan-90	954	499	652	1,151	197	82.9
Jun-90	933	571	638	1,209	276	77.2
Dec-90	976	664	637	1,301	325	75.0
Jan-91	990	801	625	1,426	436	69.4
Jun-91	991	706	628	1,334	343	74.3
Dec-91	996	598	635	1,233	237	80.8
Jan-92	1,030	540	632	1,172	142	87.9
Jun-92	956	450	630	1,080	124	88.5
Dec-92	907	395	628	1,023	116	88.7
Jan-93	852	449	575	1,024	172	83.2
Jun-93	806	444	579	1,023	217	78.8
Dec-93	828	412	588	1,000	172	82.8

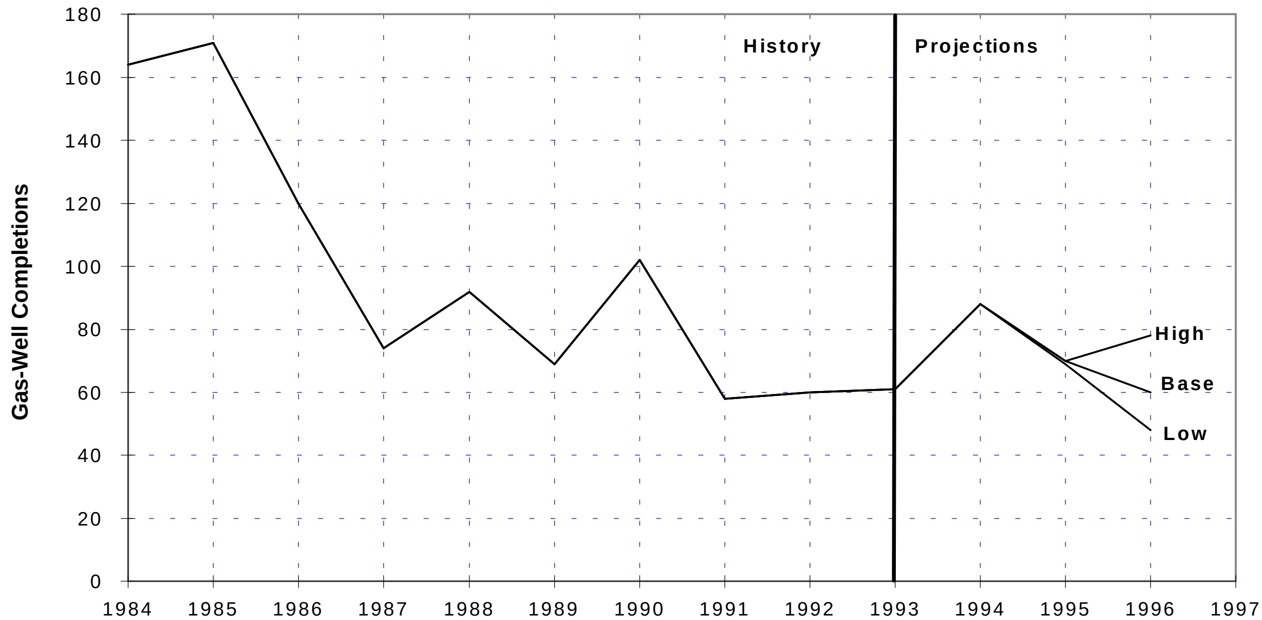
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 10. California (Including Pacific OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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 Projections				
Jan-94	896	406	577	983	87	91.1
Jun-94	849	392	579	971	122	87.4
Dec-94	903	451	604	1,055	152	85.6
Jan-95	897	456	611	1,067	170	84.1
Jun-95	825	445	593	1,038	213	79.5
Dec-95	910	450	587	1,037	127	87.8
Jan-96	977	438	584	1,022	45	95.6
Jun-96	852	406	586	992	140	85.9
Dec-96	964	383	581	964	0	100.0
		Base Case Projections				
Jan-94	896	406	577	983	87	91.1
Jun-94	849	392	579	971	122	87.4
Dec-94	903	451	604	1,055	152	85.6
Jan-95	897	456	611	1,067	170	84.1
Jun-95	825	445	593	1,038	213	79.5
Dec-95	909	450	582	1,032	123	88.1
Jan-96	976	439	579	1,018	42	95.9
Jun-96	852	418	576	994	142	85.7
Dec-96	951	402	568	970	19	98.0
		High Case Projections				
Jan-94	896	406	577	983	87	91.1
Jun-94	849	392	579	971	122	87.4
Dec-94	903	451	604	1,055	152	85.6
Jan-95	897	456	611	1,067	170	84.1
Jun-95	825	445	593	1,038	213	79.5
Dec-95	909	451	587	1,038	129	87.6
Jan-96	975	442	584	1,026	51	95.0
Jun-96	852	435	586	1,021	169	83.4
Dec-96	940	445	581	1,026	86	91.6

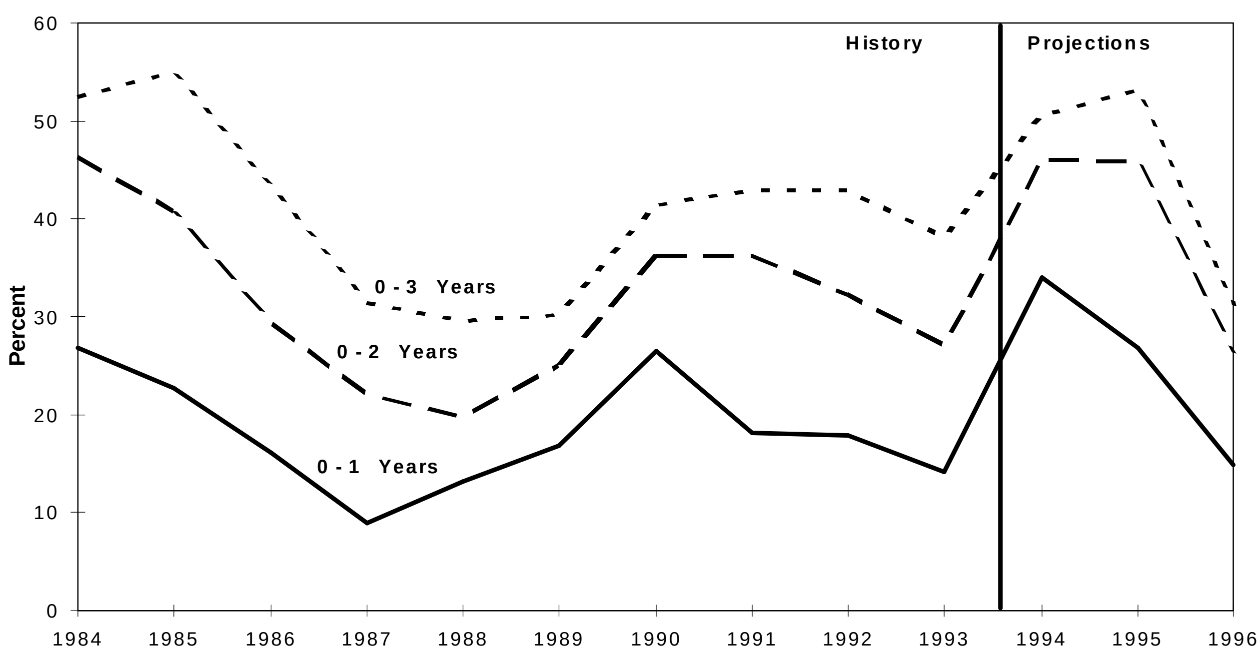
Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 22. California (Including Pacific OCS) Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP94 C051995.

Figure 23. Percent of Total Wellhead Productive Capacity of California (Including Pacific OCS) Gas Wells, by Age, 1984-1996 (Base Case)



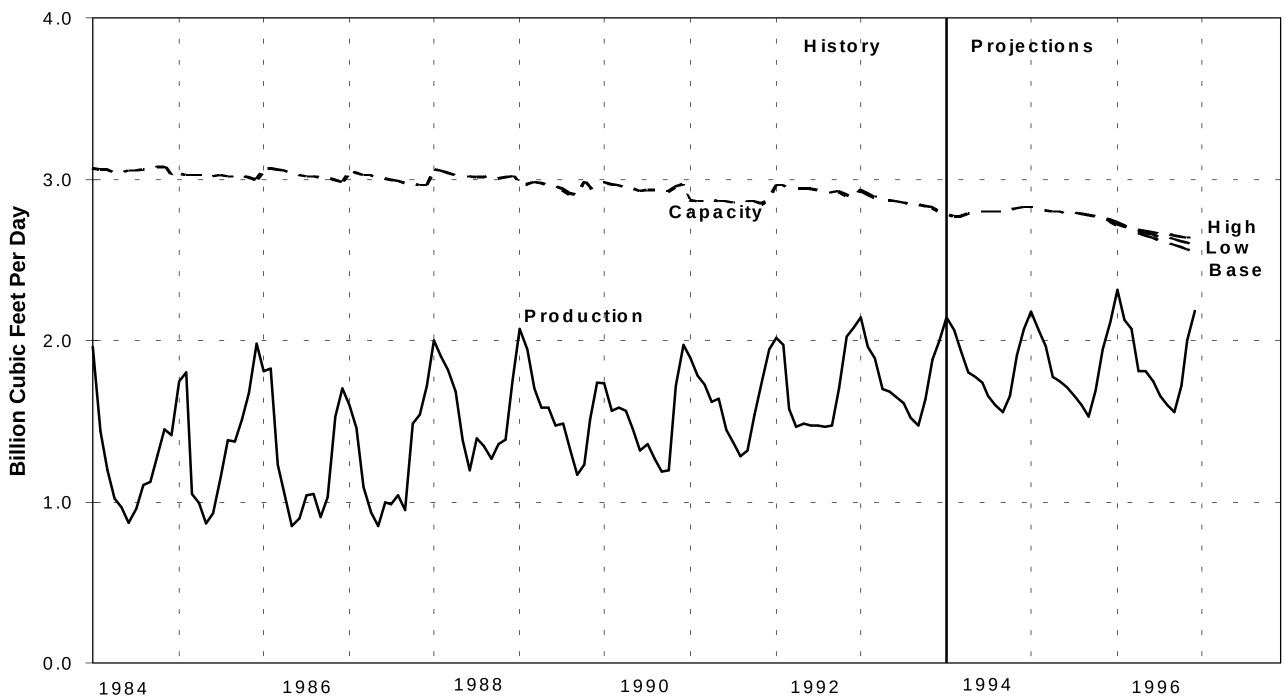
Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP94 C051995.

Kansas

In 1993 over half the gas produced in the State of Kansas came from the giant Hugoton field. Hugoton field production of 405 billion cubic feet of gas was 3 percent more than in 1992 and over 15 percent more than 5 years earlier in 1989. This information was obtained from Dwight's. Hugoton field occupies almost all of the western half of Kansas and extends south into Oklahoma and the northern part of the Texas Panhandle. Production from this field generally comes from low permeability sandy carbonate reservoir rocks.

The following pages include Tables 11, 12, and Figures 24 through 26. This data provides historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 24. Kansas Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 11. Kansas Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	1,960	2,864	202	3,066	1,106	63.9
Jun-84	868	2,830	220	3,050	2,182	28.5
Dec-84	1,413	2,807	212	3,019	1,606	46.8
Jan-85	1,749	2,812	227	3,039	1,290	57.6
Jun-85	928	2,785	233	3,018	2,090	30.7
Dec-85	1,981	2,755	241	2,996	1,015	66.1
Jan-86	1,806	2,783	287	3,070	1,264	58.8
Jun-86	897	2,783	245	3,028	2,131	29.6
Dec-86	1,702	2,757	226	2,983	1,281	57.1
Jan-87	1,597	2,805	251	3,056	1,459	52.3
Jun-87	994	2,750	252	3,002	2,008	33.1
Dec-87	1,720	2,710	248	2,958	1,238	58.1
Jan-88	2,002	2,776	281	3,057	1,055	65.5
Jun-88	1,197	2,716	302	3,018	1,821	39.7
Dec-88	1,753	2,740	279	3,019	1,266	58.1
Jan-89	2,071	2,719	248	2,967	896	69.8
Jun-89	1,472	2,710	244	2,954	1,482	49.8
Dec-89	1,736	2,752	218	2,970	1,234	58.5
Jan-90	1,729	2,701	279	2,980	1,251	58.0
Jun-90	1,316	2,654	275	2,929	1,613	44.9
Dec-90	1,970	2,698	268	2,966	996	66.4
Jan-91	1,888	2,671	200	2,871	983	65.8
Jun-91	1,442	2,663	202	2,865	1,423	50.3
Dec-91	1,940	2,673	193	2,866	926	67.7
Jan-92	2,014	2,745	215	2,960	946	68.0
Jun-92	1,472	2,733	205	2,938	1,466	50.1
Dec-92	2,079	2,682	201	2,883	804	72.1
Jan-93	2,142	2,730	204	2,934	792	73.0
Jun-93	1,647	2,646	217	2,863	1,216	57.5
Dec-93	1,999	2,594	203	2,797	798	71.5

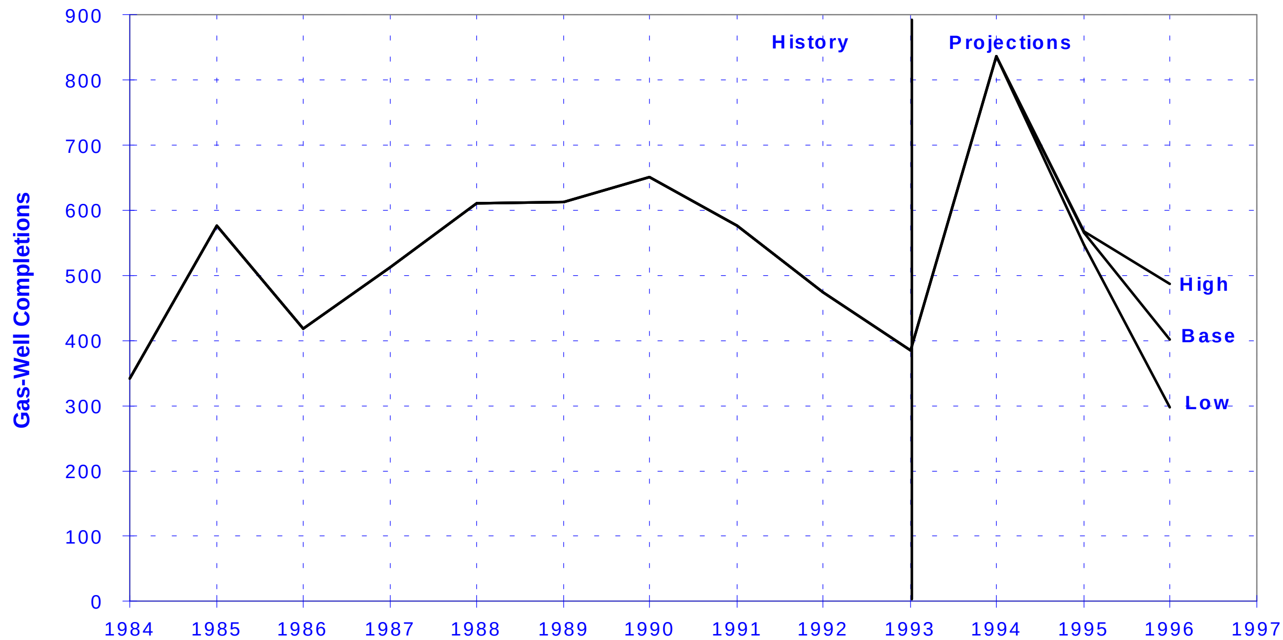
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 12. Kansas Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996
(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-94	2,141	2,578	196	2,774	633	77.2
Jun-94	1,742	2,595	202	2,797	1,055	62.3
Dec-94	2,068	2,630	197	2,827	759	73.2
Jan-95	2,174	2,636	189	2,825	651	77.0
Jun-95	1,712	2,607	187	2,794	1,082	61.3
Dec-95	2,114	2,559	184	2,743	629	77.1
Jan-96	2,313	2,538	184	2,722	409	85.0
Jun-96	1,748	2,449	184	2,633	885	66.4
Dec-96	2,231	2,369	181	2,550	319	87.5
	Base Case Projection					
Jan-94	2,141	2,578	196	2,774	633	77.2
Jun-94	1,742	2,595	202	2,797	1,055	62.3
Dec-94	2,068	2,630	197	2,827	759	73.2
Jan-95	2,174	2,636	189	2,825	651	77.0
Jun-95	1,712	2,607	187	2,794	1,082	61.3
Dec-95	2,112	2,567	182	2,749	637	76.8
Jan-96	2,309	2,548	182	2,730	421	84.6
Jun-96	1,748	2,475	180	2,655	907	65.8
Dec-96	2,183	2,420	176	2,596	413	84.1
	High Case Projections					
Jan-94	2,141	2,578	196	2,774	633	77.2
Jun-94	1,742	2,595	202	2,797	1,055	62.3
Dec-94	2,068	2,630	197	2,827	759	73.2
Jan-95	2,174	2,636	189	2,825	651	77.0
Jun-95	1,712	2,607	187	2,794	1,082	61.3
Dec-95	2,111	2,566	184	2,750	639	76.8
Jan-96	2,308	2,548	184	2,732	424	84.5
Jun-96	1,747	2,485	184	2,669	922	65.5
Dec-96	2,157	2,449	181	2,630	473	82.0

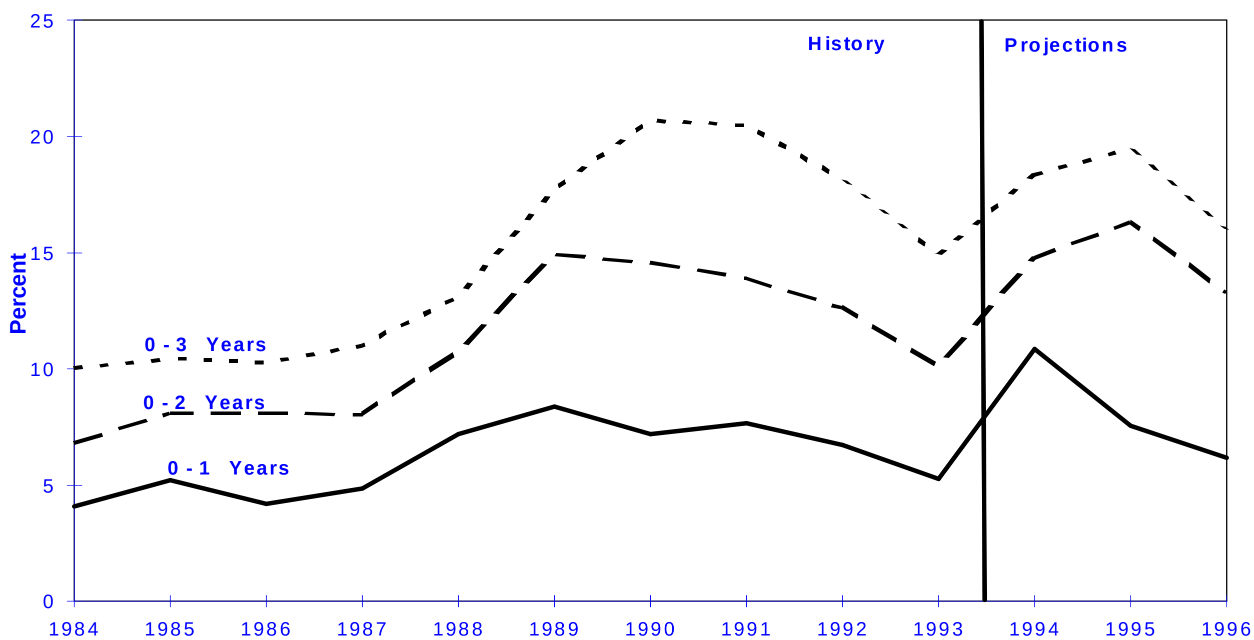
Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 25. Kansas Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 26. Percent of Total Wellhead Productive Capacity of Kansas Gas Wells, by Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

New Mexico

Most of this State's natural gas is produced from fields in northwestern New Mexico from the San Juan Basin. San Juan Basin gas production increased from 434 billion cubic feet in 1989 to 1,030 billion in 1993. Practically all of the oil-well gas production comes from the Permian Basin of southeast New Mexico.

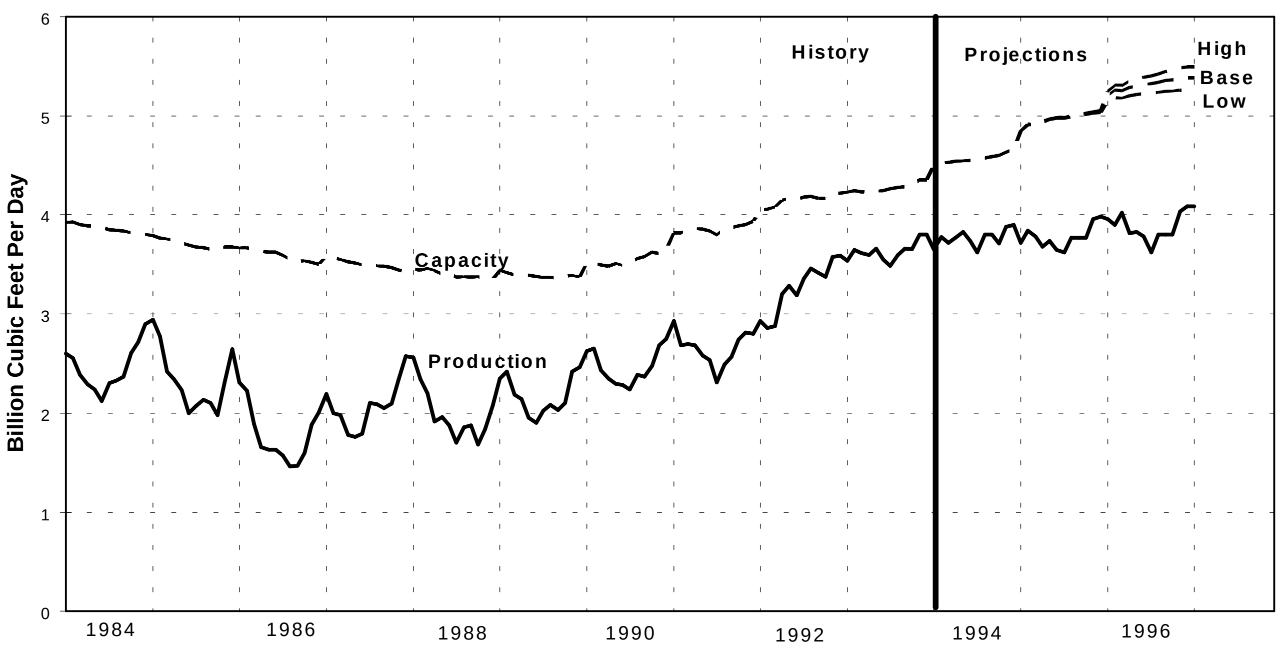
Basin field, the largest gas field in the State, produced 589 billion cubic feet of mixed gas-well conventional and coalbed gas during 1993. This was an increase of 127 billion cubic feet over 1992. New Mexico has been an area of intense drilling for coalbed gas since 1989. Coalbed gas production from this field increased 260 percent from 1989 through 1993.

It is expected that, with the current reduction in new well completions, gas production from this area is near its peak. Drilling dramatically decreased in 1993 after the Section 29 gas tax credit expired.

Coalbed gas production in New Mexico was about 15 percent of the State's total dry gas production in 1990, 23 percent in 1991, 31 percent in 1992, and 36 percent in 1993.{11} Coalbed gas-well completions were treated separately from the conventional gas-well completions in this report. Coalbed gas wells are predicted to have very low decline rates and therefore very long lives. Coalbed gas capacity has shown an increase the last few years (Figure 28).

The following pages include Tables 13, 14, and Figures 27 through 30, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 27. New Mexico Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 13. New Mexico Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	2,600	3,390	535	3,925	1,325	66.2
Jun-84	2,125	3,329	549	3,878	1,753	54.8
Dec-84	2,900	3,240	562	3,802	902	76.3
Jan-85	2,945	3,232	561	3,793	848	77.6
Jun-85	2,002	3,150	548	3,698	1,696	54.1
Dec-85	2,645	3,122	554	3,676	1,031	72.0
Jan-86	2,306	3,092	574	3,666	1,360	62.9
Jun-86	1,628	3,072	551	3,623	1,995	44.9
Dec-86	2,004	2,982	521	3,503	1,499	57.2
Jan-87	2,192	3,043	536	3,579	1,387	61.2
Jun-87	1,794	2,971	525	3,496	1,702	51.3
Dec-87	2,572	2,883	539	3,422	850	75.2
Jan-88	2,562	2,927	524	3,451	889	74.2
Jun-88	1,880	2,888	512	3,400	1,520	55.3
Dec-88	2,079	2,847	503	3,350	1,271	62.1
Jan-89	2,351	2,939	501	3,440	1,089	68.3
Jun-89	1,904	2,905	472	3,377	1,473	56.4
Dec-89	2,464	2,917	458	3,375	911	73.0
Jan-90	2,629	3,006	508	3,514	885	74.8
Jun-90	2,286	3,000	491	3,491	1,205	65.5
Dec-90	2,750	3,133	504	3,637	887	75.6
Jan-91	2,927	3,265	551	3,816	889	76.7
Jun-91	2,533	3,300	539	3,839	1,306	66.0
Dec-91	2,800	3,388	547	3,935	1,135	71.2
Jan-92	2,929	3,490	560	4,050	1,121	72.3
Jun-92	3,190	3,593	563	4,156	966	76.8
Dec-92	3,586	3,668	553	4,221	635	85.0
Jan-93	3,539	3,662	566	4,228	689	83.7
Jun-93	3,549	3,686	557	4,243	694	83.6
Dec-93	3,799	3,774	579	4,353	554	87.3

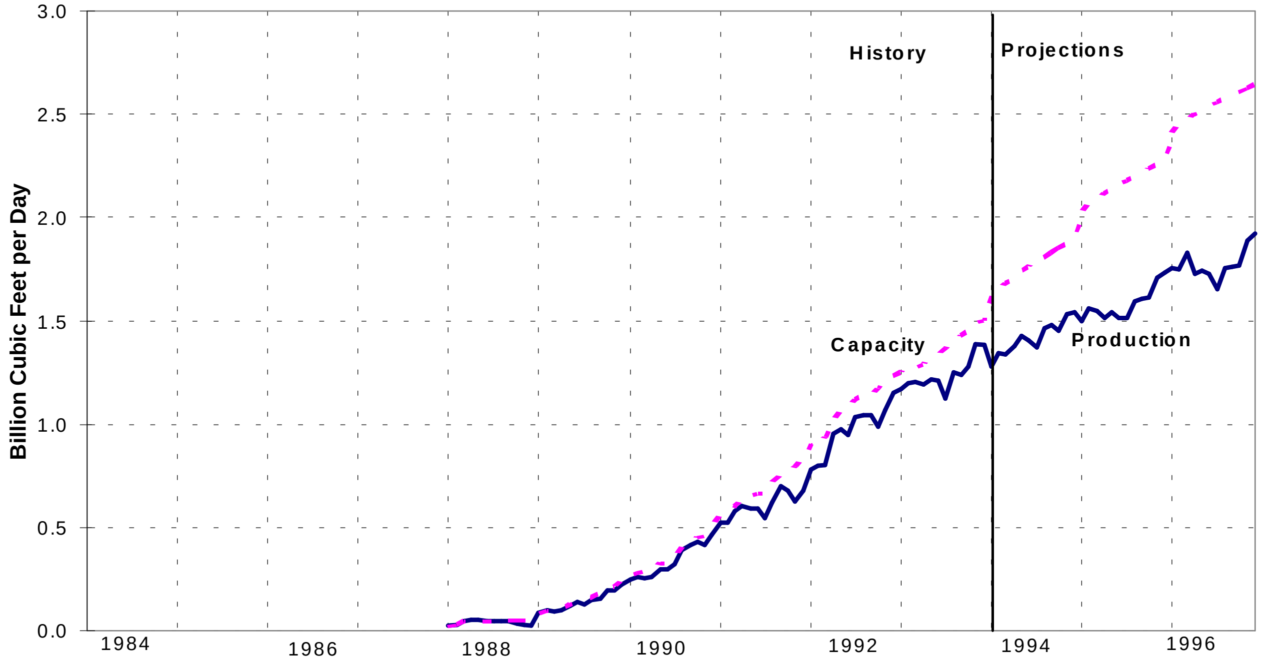
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 14. New Mexico Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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-94	3,654	3,939	562	4,501	847	81.2
Jun-94	3,740	4,015	533	4,548	808	82.2
Dec-94	3,897	4,124	540	4,664	767	83.6
Jan-95	3,718	4,308	534	4,842	1,124	76.8
Jun-95	3,649	4,416	556	4,972	1,323	73.4
Dec-95	3,987	4,484	546	5,030	1,043	79.3
Jan-96	3,960	4,599	546	5,145	1,185	77.0
Jun-96	3,783	4,678	545	5,223	1,440	72.4
Dec-96	4,179	4,725	537	5,262	1,083	79.4
		Base Case Projection				
Jan-94	3,654	3,939	562	4,501	847	81.2
Jun-94	3,740	4,015	533	4,548	808	82.2
Dec-94	3,897	4,124	540	4,664	767	83.6
Jan-95	3,718	4,313	534	4,847	1,129	76.7
Jun-95	3,649	4,424	556	4,980	1,331	73.3
Dec-95	3,983	4,499	541	5,040	1,057	79.0
Jan-96	3,954	4,667	540	5,207	1,253	75.9
Jun-96	3,783	4,781	535	5,316	1,533	71.2
Dec-96	4,089	4,861	523	5,384	1,295	75.9
		High Case Projection				
Jan-94	3,654	3,939	562	4,501	847	81.2
Jun-94	3,740	4,015	533	4,548	808	82.2
Dec-94	3,897	4,124	540	4,664	767	83.6
Jan-95	3,718	4,315	534	4,849	1,131	76.7
Jun-95	3,649	4,427	556	4,983	1,334	73.2
Dec-95	3,981	4,505	546	5,051	1,070	78.8
Jan-96	3,951	4,704	546	5,250	1,299	75.3
Jun-96	3,782	4,843	545	5,388	1,606	70.2
Dec-96	4,040	4,955	537	5,492	1,452	73.6

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

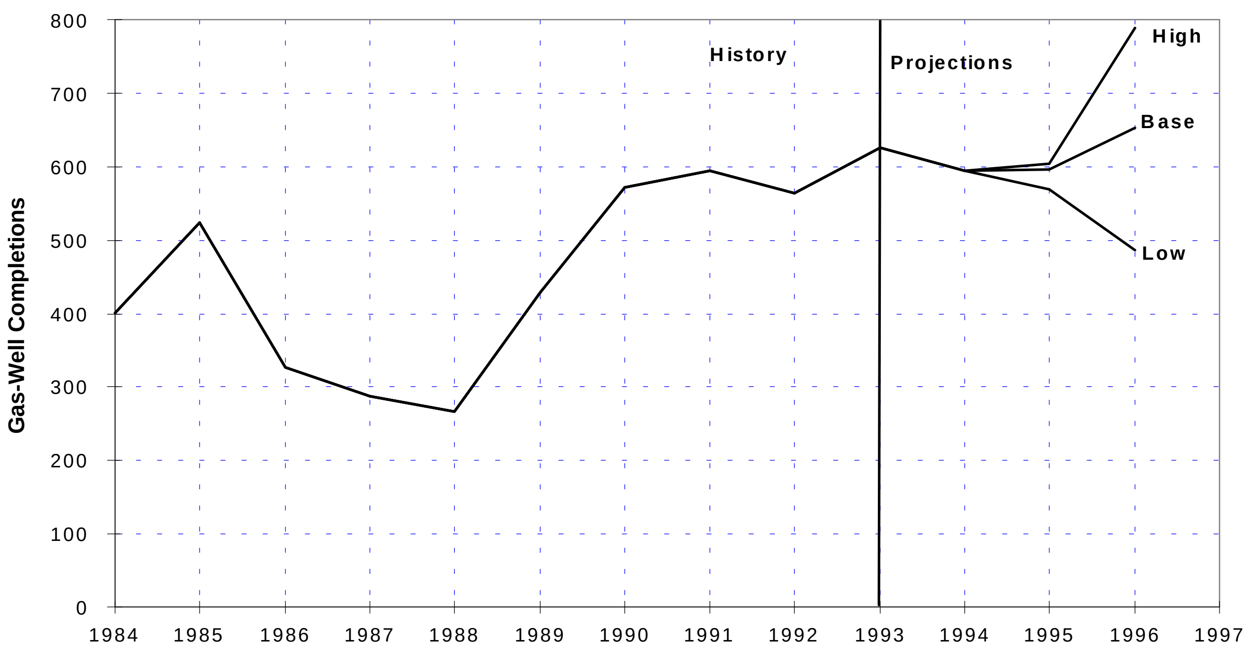
Figure 28. New Mexico Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



Note: Production projection plotted for base case only.

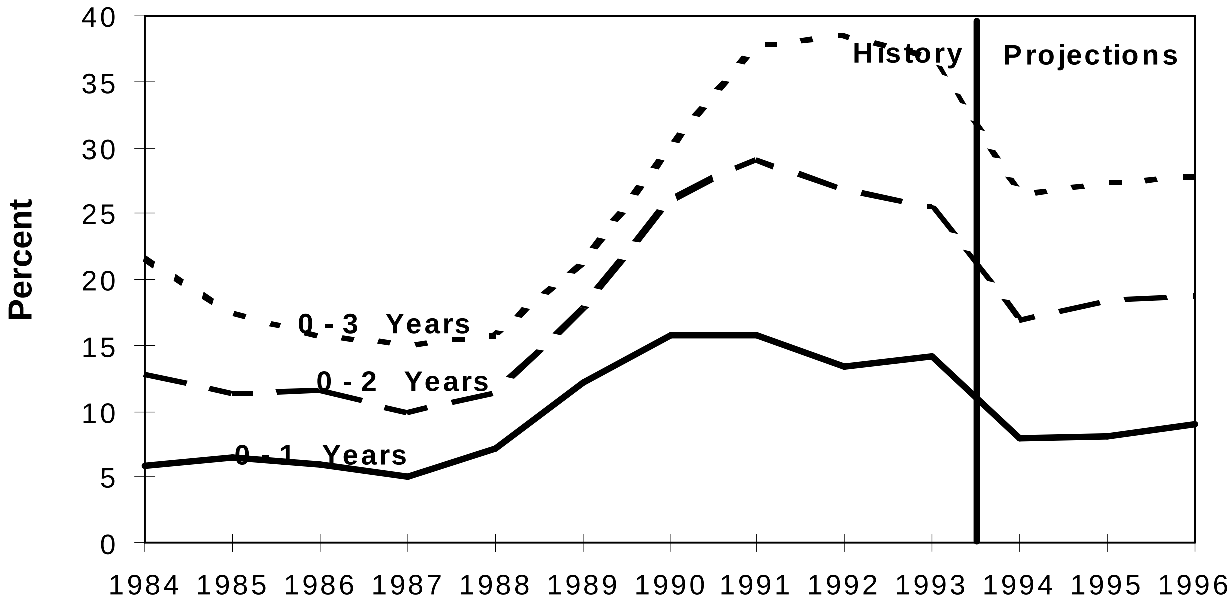
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Figure 29. New Mexico Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 30. Percent of Total Wellhead Productive Capacity of New Mexico Gas Wells, by Age, 1984-1996 (Base Case)



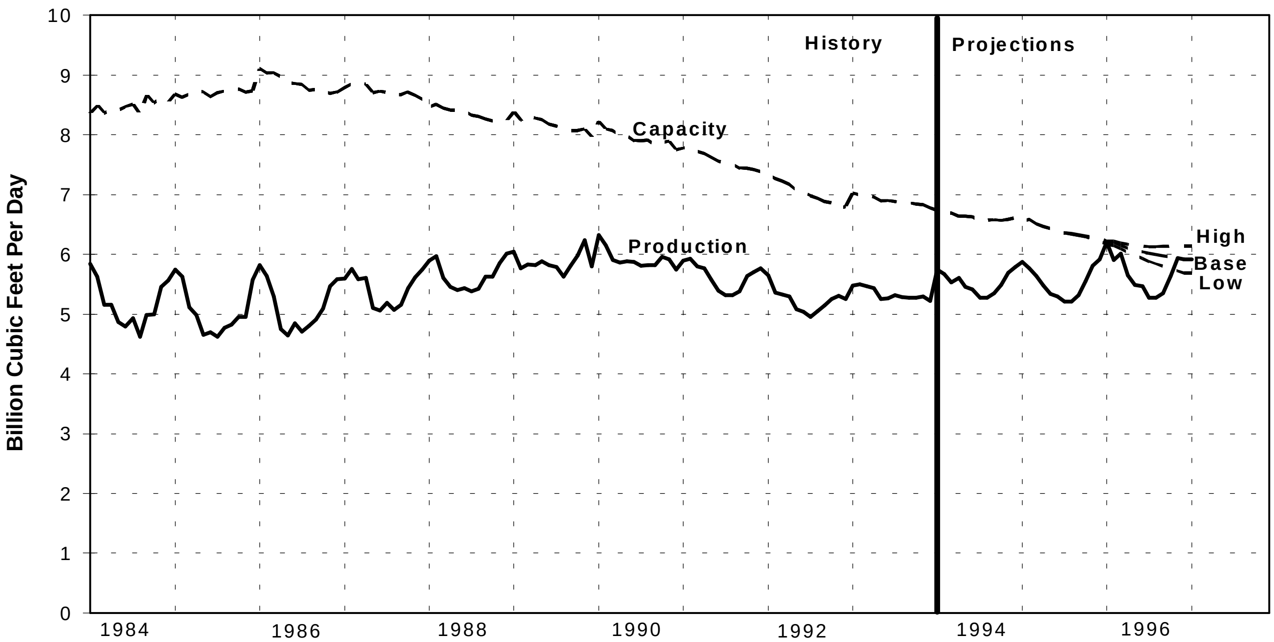
Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP94 C051995.

Oklahoma

Oklahoma is among 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 located generally in central Oklahoma. In 1993, 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 consists of more than 70 fields.

The following pages include Tables 15 and 16 and Figures 31 through 33, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 31. Oklahoma Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 15. Oklahoma Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	5,839	7,262	1,107	8,369	2,530	69.8
Jun-84	4,794	7,327	1,146	8,473	3,679	56.6
Dec-84	5,562	7,448	1,104	8,552	2,990	65.0
Jan-85	5,744	7,500	1,187	8,687	2,943	66.1
Jun-85	4,693	7,506	1,138	8,644	3,951	54.3
Dec-85	5,579	7,533	1,207	8,740	3,161	63.8
Jan-86	5,821	7,602	1,507	9,109	3,288	63.9
Jun-86	4,844	7,566	1,295	8,861	4,017	54.7
Dec-86	5,583	7,456	1,264	8,720	3,137	64.0
Jan-87	5,594	7,563	1,228	8,791	3,197	63.6
Jun-87	5,062	7,435	1,296	8,731	3,669	58.0
Dec-87	5,749	7,393	1,211	8,604	2,855	66.8
Jan-88	5,891	7,259	1,202	8,461	2,570	69.6
Jun-88	5,440	7,176	1,222	8,398	2,958	64.8
Dec-88	6,008	7,058	1,183	8,241	2,233	72.9
Jan-89	6,048	7,168	1,222	8,390	2,342	72.1
Jun-89	5,825	7,041	1,141	8,182	2,357	71.2
Dec-89	5,802	6,939	1,033	7,972	2,170	72.8
Jan-90	6,325	7,003	1,224	8,227	1,902	76.9
Jun-90	5,879	6,816	1,094	7,910	2,031	74.3
Dec-90	5,748	6,740	1,010	7,750	2,002	74.2
Jan-91	5,896	6,839	940	7,779	1,883	75.8
Jun-91	5,396	6,615	941	7,556	2,160	71.4
Dec-91	5,766	6,497	892	7,389	1,623	78.0
Jan-92	5,647	6,432	903	7,335	1,688	77.0
Jun-92	5,042	6,142	894	7,036	1,994	71.7
Dec-92	5,250	5,914	886	6,800	1,550	77.2
Jan-93	5,476	6,206	825	7,031	1,555	77.9
Jun-93	5,266	6,054	847	6,901	1,635	76.3
Dec-93	5,217	6,009	772	6,781	1,564	76.9

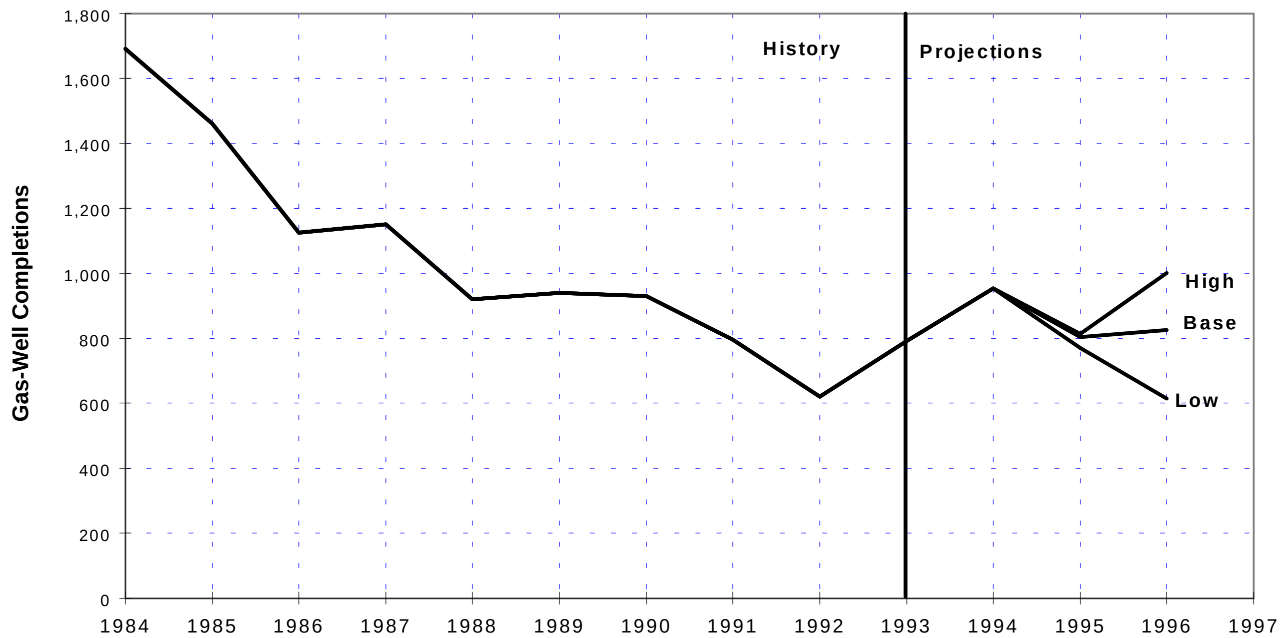
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 16. Oklahoma Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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-94	5,740	5,935	796	6,731	991	85.3
Jun-94	5,416	5,829	797	6,626	1,210	81.7
Dec-94	5,789	5,834	779	6,613	824	87.5
Jan-95	5,870	5,807	745	6,552	682	89.6
Jun-95	5,293	5,642	750	6,392	1,099	82.8
Dec-95	5,926	5,485	738	6,223	297	95.2
Jan-96	6,167	5,429	738	6,167	0	100.0
Jun-96	5,466	5,197	737	5,934	468	92.1
Dec-96	5,683	4,954	729	5,683	0	100.0
			Base Case Projection			
Jan-94	5,740	5,935	796	6,731	991	85.3
Jun-94	5,416	5,829	797	6,626	1,210	81.7
Dec-94	5,789	5,834	779	6,613	824	87.5
Jan-95	5,870	5,807	745	6,552	682	89.6
Jun-95	5,293	5,644	750	6,394	1,101	82.8
Dec-95	5,920	5,521	730	6,251	331	94.7
Jan-96	6,204	5,474	730	6,204	0	100.0
Jun-96	5,465	5,322	724	6,046	581	90.4
Dec-96	5,911	5,202	709	5,911	0	100.0
			High Case Projection			
Jan-94	5,740	5,935	796	6,731	991	85.3
Jun-94	5,416	5,829	797	6,626	1,210	81.7
Dec-94	5,789	5,834	779	6,613	824	87.5
Jan-95	5,870	5,807	745	6,552	682	89.6
Jun-95	5,293	5,644	750	6,394	1,101	82.8
Dec-95	5,917	5,532	738	6,270	353	94.4
Jan-96	6,213	5,489	738	6,227	14	99.8
Jun-96	5,464	5,405	737	6,142	678	89.0
Dec-96	6,054	5,406	729	6,135	81	98.7

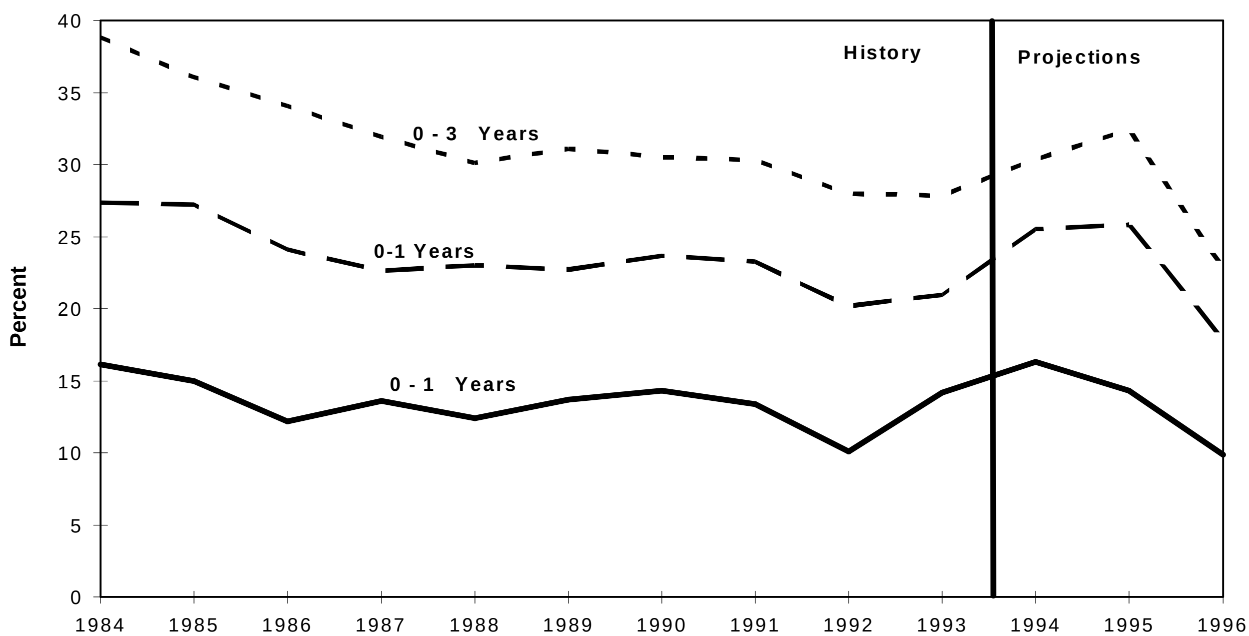
Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995

Figure 32. Oklahoma Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: • History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. • Projections: Model GASCAP94 C051995.

Figure 33. Percent of Total Wellhead Productive Capacity of Oklahoma Gas Wells, by Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

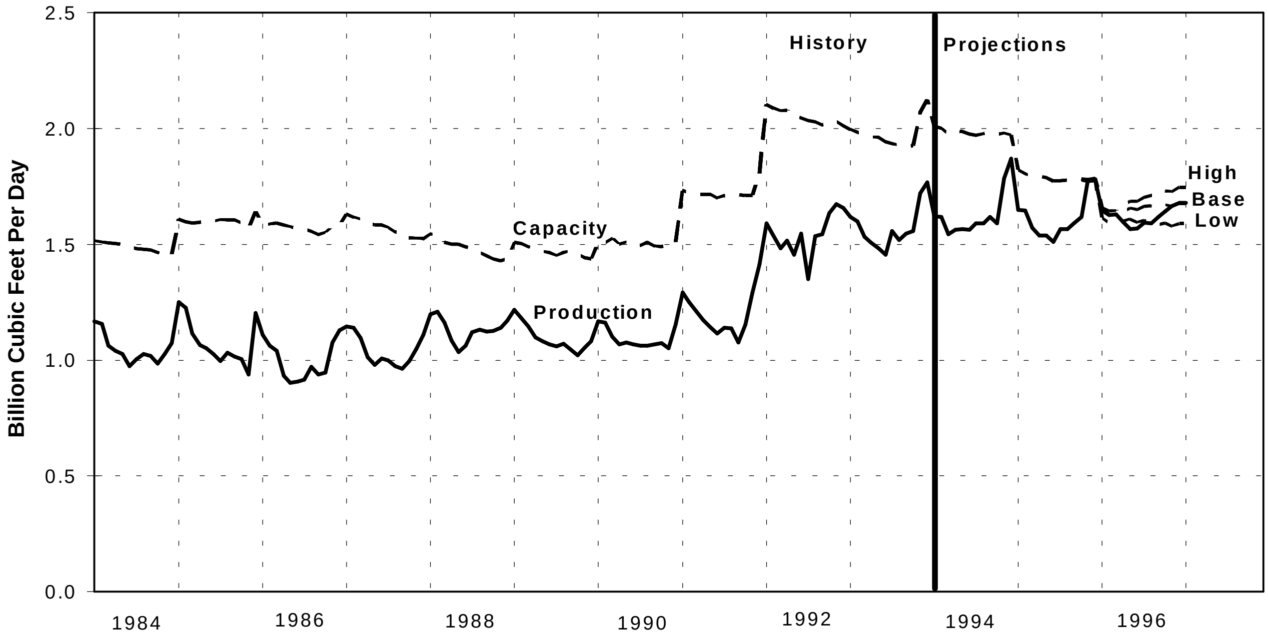
Southeast (Excluding Gulf of Mexico OCS)

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

Coalbed gas production in Alabama was 35 percent of the State's total dry gas production in 1990, 47 percent in 1991, 35 percent in 1992, and 37 percent in 1993. {11} Coalbed gas-well completions in Alabama were treated separately from conventional gas-well completions in this report. Coalbed gas capacity has shown an increase the last few years (Figure 35).

The following pages include Tables 17 and 18 and Figures 34 through 37, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 34. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 17. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity, 1984-1993 (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-84	1,166	1,383	133	1,516	350	76.9
Jun-84	973	1,354	134	1,488	515	65.4
Dec-84	1,073	1,316	135	1,451	378	73.9
Jan-85	1,251	1,468	141	1,609	358	77.8
Jun-85	1,025	1,452	147	1,599	574	64.1
Dec-85	1,204	1,492	150	1,642	438	73.3
Jan-86	1,110	1,440	146	1,586	476	70.0
Jun-86	909	1,429	137	1,566	657	58.0
Dec-86	1,128	1,454	131	1,585	457	71.2
Jan-87	1,146	1,503	128	1,631	485	70.3
Jun-87	1,008	1,455	130	1,585	577	63.6
Dec-87	1,109	1,398	127	1,525	416	72.7
Jan-88	1,197	1,422	124	1,546	349	77.4
Jun-88	1,062	1,369	121	1,490	428	71.3
Dec-88	1,171	1,317	119	1,436	265	81.5
Jan-89	1,216	1,382	126	1,508	292	80.6
Jun-89	1,067	1,337	127	1,464	397	72.9
Dec-89	1,082	1,323	115	1,438	356	75.2
Jan-90	1,168	1,403	109	1,512	344	77.2
Jun-90	1,068	1,405	110	1,515	447	70.5
Dec-90	1,152	1,390	112	1,502	350	76.7
Jan-91	1,293	1,638	94	1,732	439	74.7
Jun-91	1,114	1,609	92	1,701	587	65.5
Dec-91	1,413	1,706	93	1,799	386	78.5
Jan-92	1,592	1,949	156	2,105	513	75.6
Jun-92	1,547	1,896	150	2,046	499	75.6
Dec-92	1,658	1,862	152	2,014	356	82.3
Jan-93	1,618	1,847	150	1,997	379	81.0
Jun-93	1,456	1,804	140	1,944	488	74.9
Dec-93	1,768	1,985	141	2,126	358	83.2

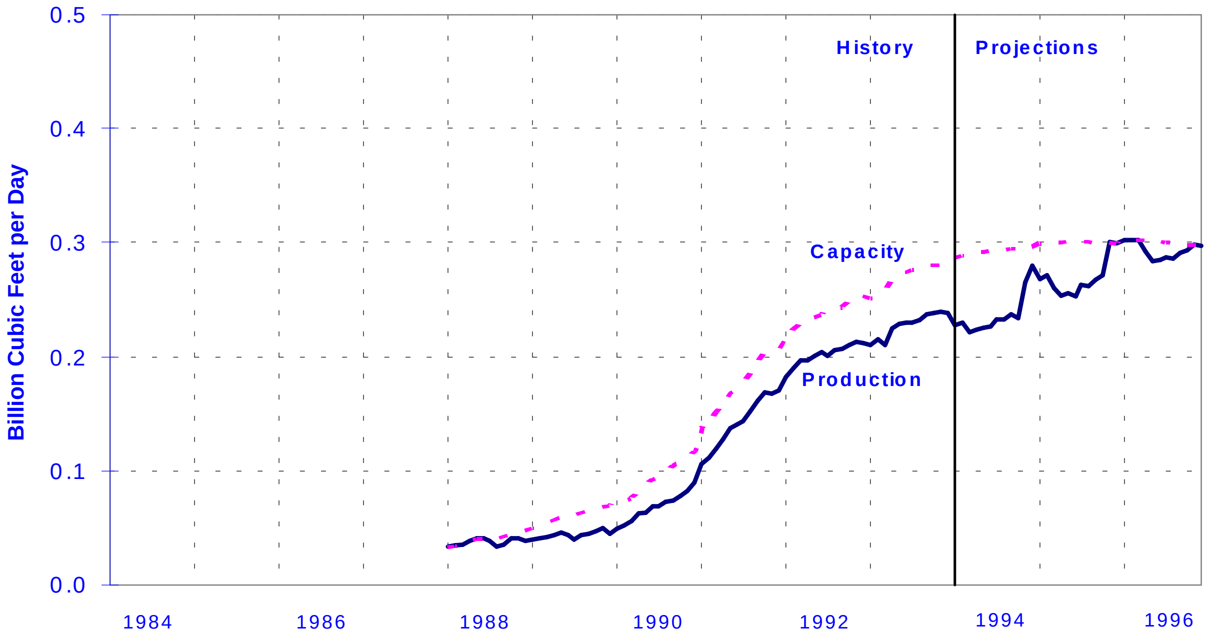
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995.

Table 18. Southeast (Excluding Gulf of Mexico OCS) Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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 Projections				
Jan-94	1,620	1,870	140	2,010	390	80.6
Jun-94	1,564	1,843	134	1,977	413	79.1
Dec-94	1,871	1,838	135	1,973	102	94.8
Jan-95	1,648	1,687	135	1,822	174	90.5
Jun-95	1,511	1,639	134	1,773	262	85.2
Dec-95	1,773	1,641	132	1,773	0	100.0
Jan-96	1,615	1,483	132	1,615	0	100.0
Jun-96	1,569	1,464	132	1,596	27	98.3
Dec-96	1,589	1,458	131	1,589	0	100.0
		Base Case Projection				
Jan-94	1,620	1,870	140	2,010	390	80.6
Jun-94	1,564	1,843	134	1,977	413	79.1
Dec-94	1,871	1,838	135	1,973	102	94.8
Jan-95	1,648	1,687	135	1,822	174	90.5
Jun-95	1,511	1,640	134	1,774	263	85.2
Dec-95	1,782	1,651	131	1,782	0	100.0
Jan-96	1,646	1,515	131	1,646	0	100.0
Jun-96	1,569	1,521	130	1,651	82	95.0
Dec-96	1,678	1,550	128	1,678	0	100.0
		High Case Projection				
Jan-94	1,620	1,870	140	2,010	390	80.6
Jun-94	1,564	1,843	134	1,977	413	79.1
Dec-94	1,871	1,838	135	1,973	102	94.8
Jan-95	1,648	1,687	135	1,822	174	90.5
Jun-95	1,511	1,640	134	1,774	263	85.2
Dec-95	1,787	1,655	132	1,787	0	100.0
Jan-96	1,660	1,528	132	1,660	0	100.0
Jun-96	1,568	1,554	132	1,686	118	93.0
Dec-96	1,748	1,617	131	1,748	0	100.0

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

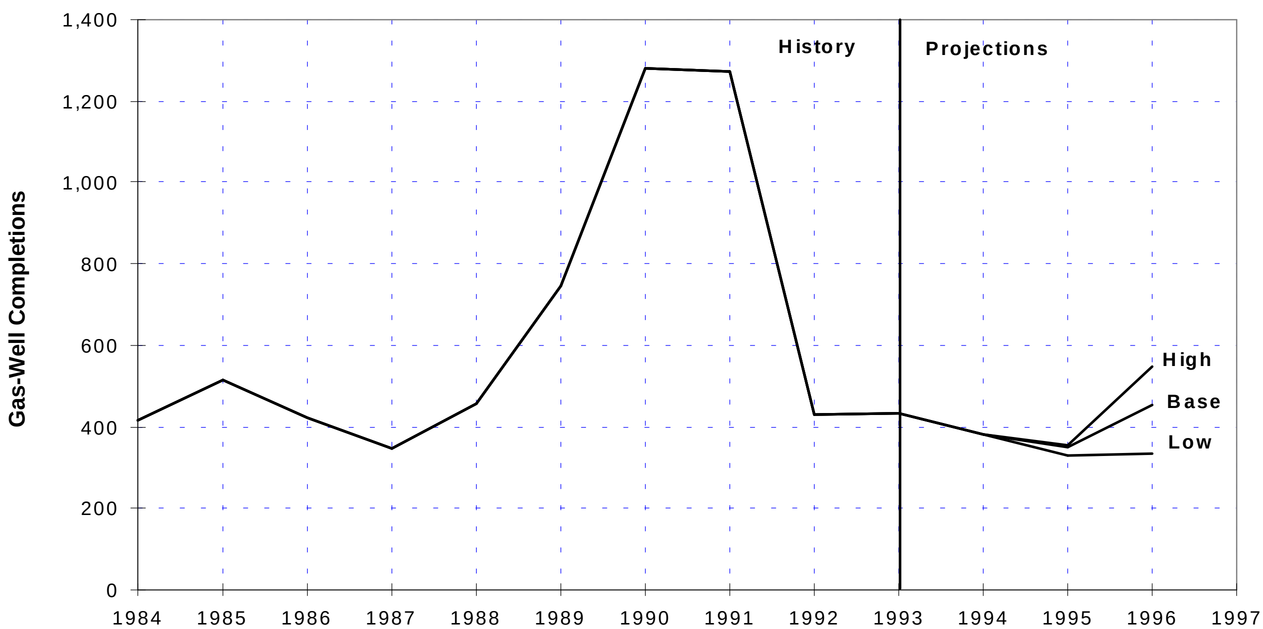
Figure 35. Southeast (Excluding Gulf of Mexico OCS) Dry Coalbed Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



Note: Production projection plotted for base case only.

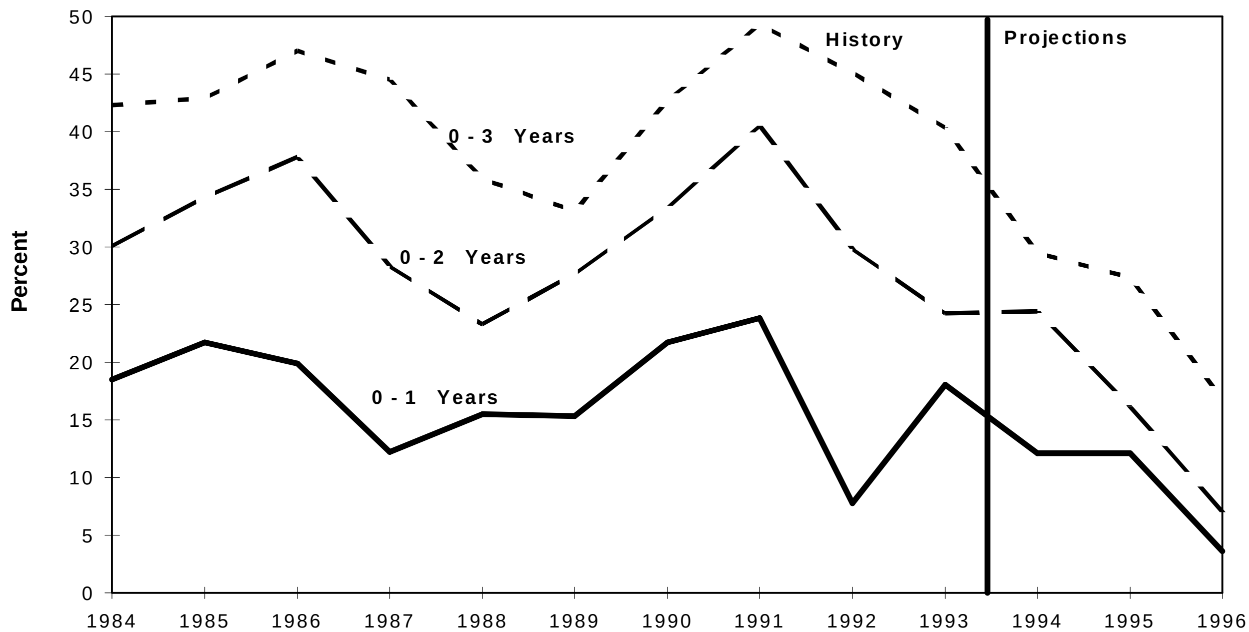
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Figure 36. Southeast (Excluding Gulf of Mexico OCS) Gas-Well Completions Added During Year and Producing as of December, 1984-1996



Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP94 C051995.

Figure 37. Percent of Total Wellhead Productive Capacity of Southeast (Excluding Gulf of Mexico OCS) Gas Wells, by Age, 1984-1996 (Base Case)



Sources: • History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; • Projections: Model GASCAP94 C051995.

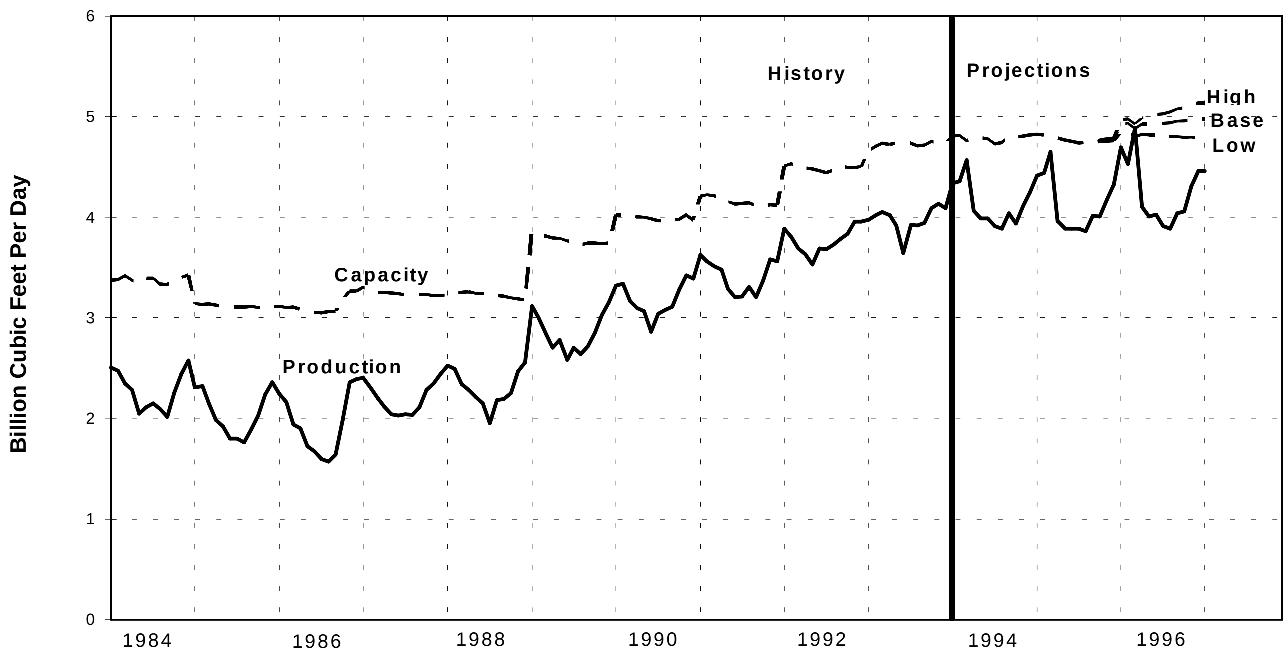
Rocky Mountains

The Rocky Mountains area includes Colorado, Montana, North Dakota, Utah, and Wyoming. The area is diverse and geologically complex with many low permeability formations.

Coalbed gas production in Colorado was about 11 percent of the State's total dry gas production in 1990, 17 percent in 1991, 26 percent in 1992, and 32 percent in 1993. {11} Coalbed gas-well completions in Colorado and Wyoming were treated separately from conventional gas-well completions in this report. Coalbed gas capacity has shown an increase the last few years (Figure 39).

The following pages include Tables 19 and 20 and Figures 38 through 41, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age.

Figure 38. Rocky Mountains Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



Note: Production projection plotted for base case only.

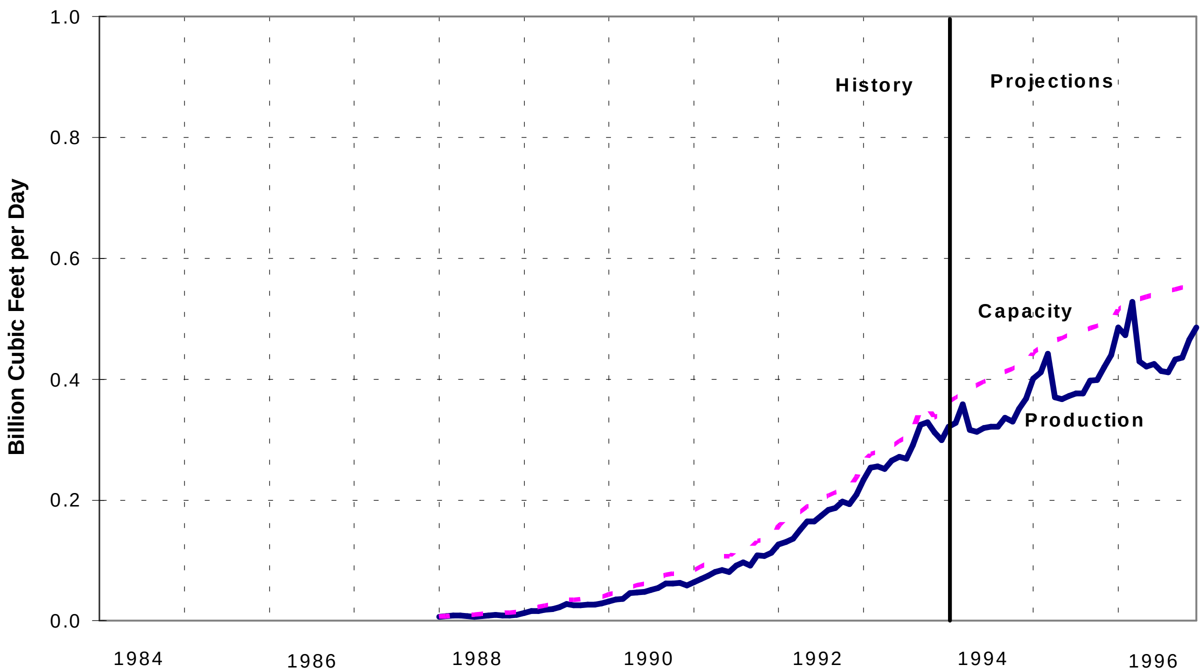
Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995. • Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 19. Rocky Moutains Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	2,507	2,907	468	3,375	868	74.3
Jun-84	2,112	2,886	508	3,394	1,282	62.2
Dec-84	2,573	2,943	478	3,421	848	75.2
Jan-85	2,306	2,506	634	3,140	834	73.4
Jun-85	1,802	2,471	636	3,107	1,305	58.0
Dec-85	2,355	2,496	609	3,105	750	75.8
Jan-86	2,240	2,465	650	3,115	875	71.9
Jun-86	1,671	2,452	600	3,052	1,381	54.8
Dec-86	2,390	2,701	562	3,263	873	73.2
Jan-87	2,402	2,516	785	3,301	899	72.8
Jun-87	2,025	2,478	761	3,239	1,214	62.5
Dec-87	2,439	2,456	763	3,219	780	75.8
Jan-88	2,524	2,424	802	3,226	702	78.2
Jun-88	2,147	2,438	804	3,242	1,095	66.2
Dec-88	2,553	2,423	754	3,177	624	80.4
Jan-89	3,117	2,935	909	3,844	727	81.1
Jun-89	2,580	2,892	873	3,765	1,185	68.5
Dec-89	3,155	2,881	861	3,742	587	84.3
Jan-90	3,318	2,963	1,061	4,024	706	82.5
Jun-90	2,861	2,940	1,045	3,985	1,124	71.8
Dec-90	3,390	2,957	1,015	3,972	582	85.3
Jan-91	3,626	3,104	1,102	4,206	580	86.2
Jun-91	3,207	3,051	1,077	4,128	921	77.7
Dec-91	3,558	3,069	1,048	4,117	559	86.4
Jan-92	3,883	3,444	1,064	4,508	625	86.1
Jun-92	3,688	3,407	1,054	4,461	773	82.7
Dec-92	3,956	3,494	1,009	4,503	547	87.9
Jan-93	3,975	3,897	769	4,666	691	85.2
Jun-93	3,644	3,971	766	4,737	1,093	76.9
Dec-93	4,089	4,000	741	4,741	652	86.2

Sources: • Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. • Productive Capacity: GASCAP94 C051995

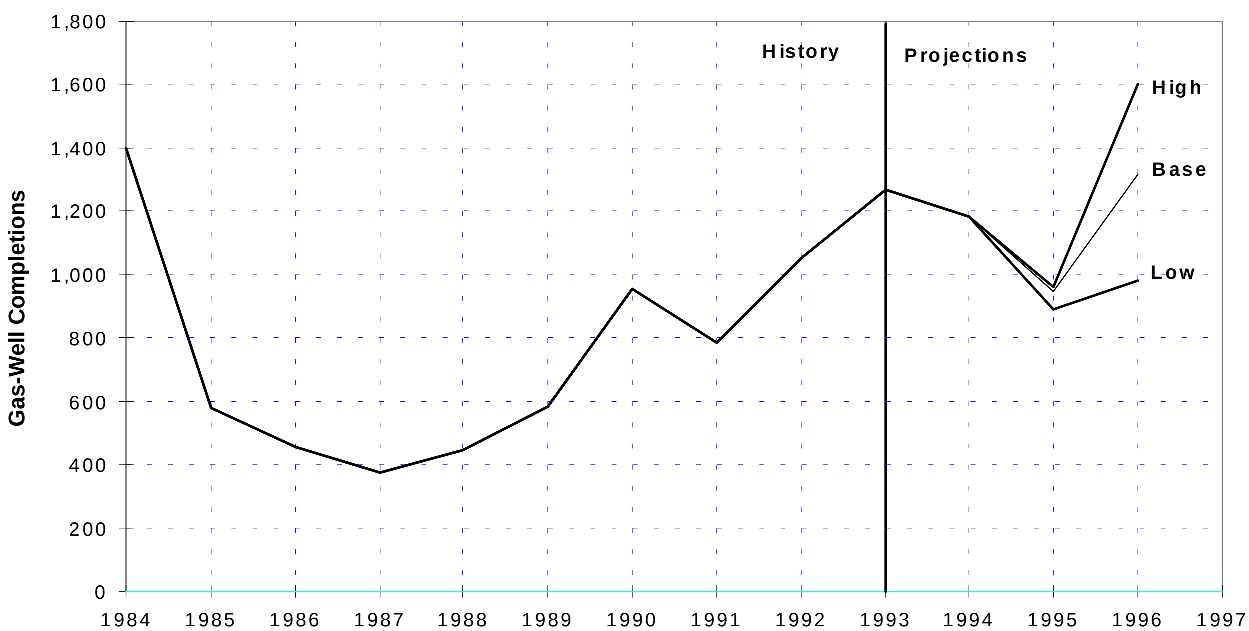
Figure 39. Rocky Mountains Dry Coalbed Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Figure 40. Rocky Mountains Gas-Well Completions Added During Year and Producing as of December, 1984-1996



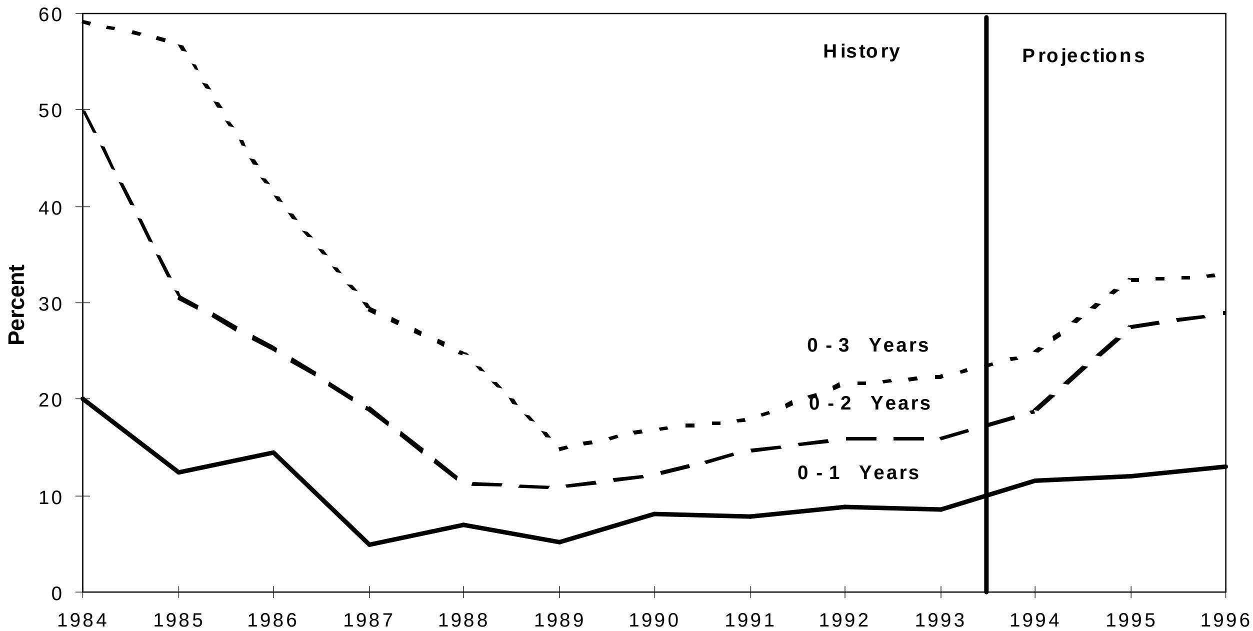
Sources: •History: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Completions include recompletions in new producing zones. •Projections: Model GASCAP94 C051995.

Table 20. Rocky Moutains Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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-94	4,335	4,077	726	4,803	468	90.3
Jun-94	3,988	4,071	706	4,777	789	83.5
Dec-94	4,247	4,134	683	4,817	570	88.2
Jan-95	4,415	4,149	674	4,823	408	91.5
Jun-95	3,888	4,066	686	4,752	864	81.8
Dec-95	4,330	4,083	675	4,758	428	91.0
Jan-96	4,700	4,175	675	4,850	150	96.9
Jun-96	4,026	4,141	674	4,815	789	83.6
Dec-96	4,557	4,121	666	4,787	230	95.2
		Base Case Projection				
Jan-94	4,335	4,077	726	4,803	468	90.3
Jun-94	3,988	4,071	706	4,777	789	83.5
Dec-94	4,247	4,134	683	4,817	570	88.2
Jan-95	4,415	4,150	674	4,824	409	91.5
Jun-95	3,888	4,068	686	4,754	866	81.8
Dec-95	4,325	4,106	668	4,774	449	90.6
Jan-96	4,693	4,258	667	4,925	232	95.3
Jun-96	4,026	4,273	662	4,935	909	81.6
Dec-96	4,458	4,326	648	4,974	516	89.6
		High Case Projection				
Jan-94	4,335	4,077	726	4,803	468	90.3
Jun-94	3,988	4,071	706	4,777	789	83.5
Dec-94	4,247	4,134	683	4,817	570	88.2
Jan-95	4,415	4,150	674	4,824	409	91.5
Jun-95	3,888	4,069	686	4,755	867	81.8
Dec-95	4,323	4,113	675	4,788	465	90.3
Jan-96	4,690	4,287	675	4,962	272	94.5
Jun-96	4,025	4,345	674	5,019	994	80.2
Dec-96	4,405	4,469	666	5,135	730	85.8

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. Productive Capacity Projections: GASCAP94 C051995.

Figure 41. Percent of Total Wellhead Productive Capacity of Rocky Mountain Gas Wells, by Age, 1984-1996 (Base Case)



Sources: •History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; •Projections: Model GASCAP94 C051995.

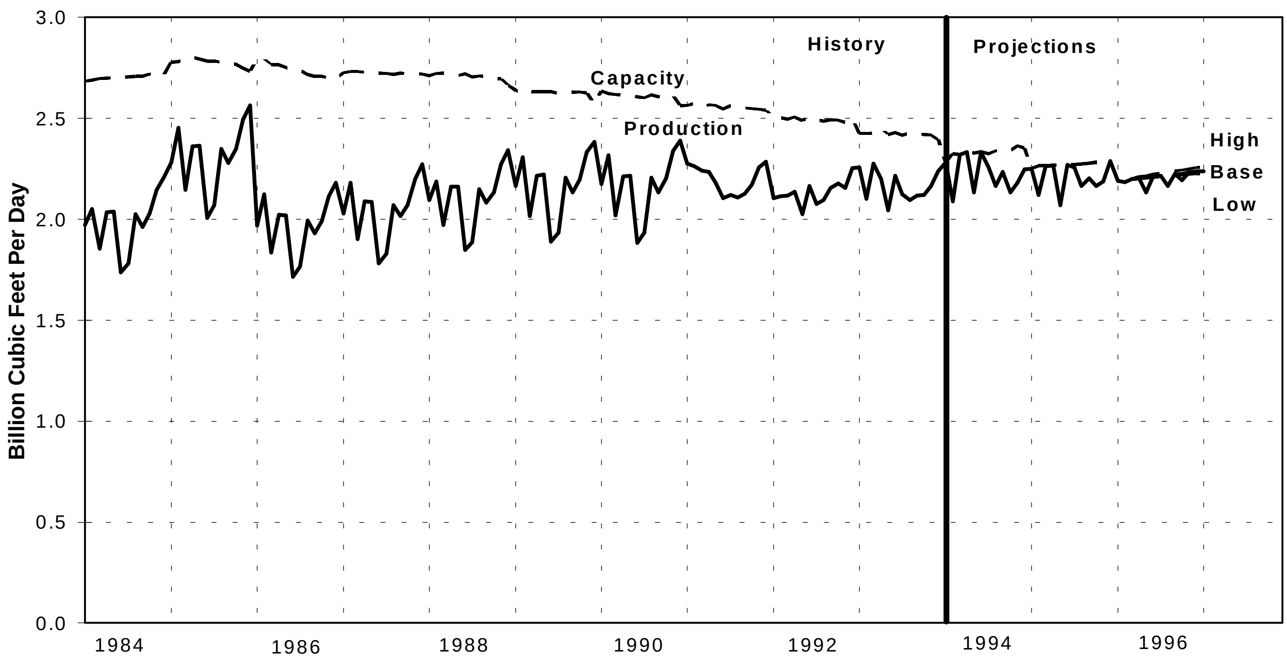
Eighteen States

The remaining producing 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; 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

The following pages include Tables 21 and 22 and Figures 42 and 43, which provide historical and projected production and productive capacity, gas-well completions added, and percent of capacity by well age. Production and productive capacity are equal with no surplus in 1995 and 1996.

Figure 42. Eighteen States Dry Gas Monthly Production Rate and Wellhead Productive Capacity, 1984-1996



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 GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995. •Production Projections: Energy Information Administration. *Short-Term Energy Outlook Quarterly Projections* Third Quarter 1995 and Model GASCAP94 C051995.

Table 21. Eighteen States Dry Gas Production and Wellhead Productive Capacity, 1984-1993
(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-84	1,972	2,453	231	2,684	712	73.5
Jun-84	1,738	2,468	238	2,706	968	64.2
Dec-84	2,206	2,481	232	2,713	507	81.3
Jan-85	2,281	2,575	203	2,778	497	82.1
Jun-85	2,007	2,568	216	2,784	777	72.1
Dec-85	2,565	2,527	208	2,735	170	93.8
Jan-86	1,970	2,577	213	2,790	820	70.6
Jun-86	1,716	2,541	201	2,742	1,026	62.6
Dec-86	2,182	2,511	189	2,700	518	80.8
Jan-87	2,029	2,508	218	2,726	697	74.4
Jun-87	1,781	2,504	221	2,725	944	65.4
Dec-87	2,272	2,500	219	2,719	447	83.6
Jan-88	2,095	2,498	214	2,712	617	77.2
Jun-88	1,848	2,493	227	2,720	872	67.9
Dec-88	2,341	2,457	207	2,664	323	87.9
Jan-89	2,166	2,403	237	2,640	474	82.0
Jun-89	1,890	2,405	228	2,633	743	71.8
Dec-89	2,382	2,380	194	2,574	192	92.5
Jan-90	2,173	2,371	264	2,635	462	82.5
Jun-90	1,883	2,368	239	2,607	724	72.2
Dec-90	2,390	2,336	226	2,562	172	93.3
Jan-91	2,275	2,311	253	2,564	289	88.7
Jun-91	2,105	2,308	239	2,547	442	82.6
Dec-91	2,285	2,296	244	2,540	255	90.0
Jan-92	2,104	2,248	256	2,504	400	84.0
Jun-92	2,165	2,240	259	2,499	334	86.6
Dec-92	2,254	2,241	257	2,498	244	90.2
Jan-93	2,255	2,156	268	2,424	169	93.0
Jun-93	2,216	2,162	268	2,430	214	91.2
Dec-93	2,236	2,153	243	2,396	160	93.3

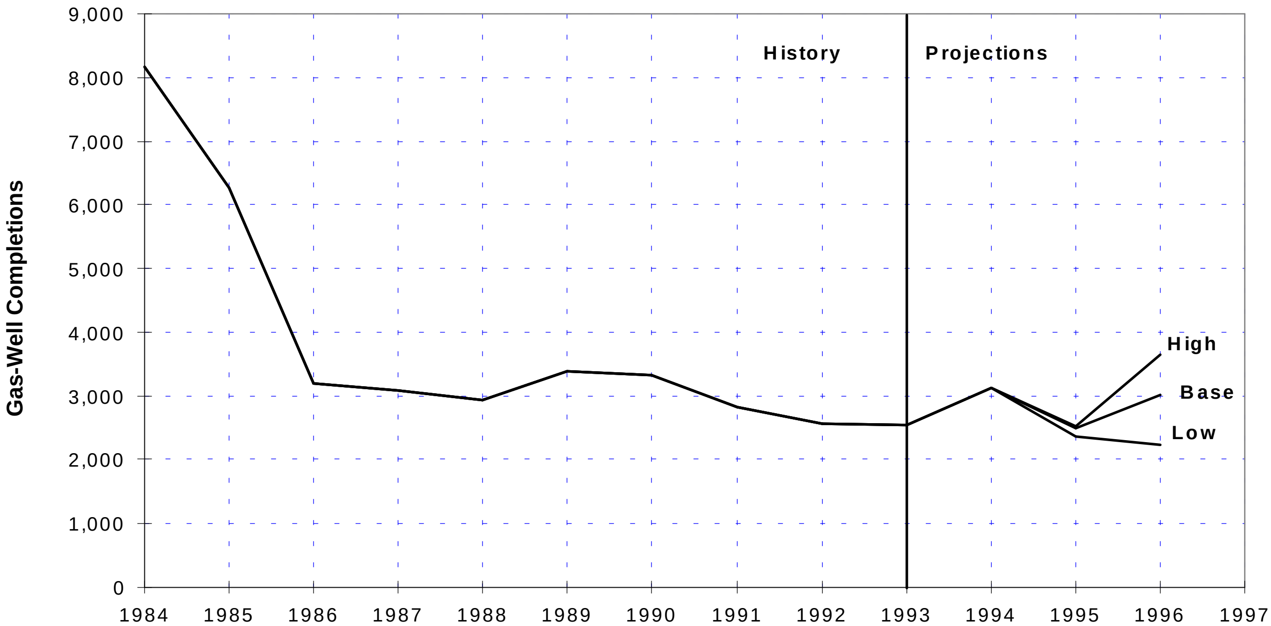
Sources: •Production History: Energy Information Administration, Office of Oil and Gas; Dwight's Energydata, Inc.; and Model GASCAP94 C051995. •Productive Capacity: GASCAP94 C051995.

Table 22. Eighteen States Dry Gas Production and Wellhead Productive Capacity Projections, 1994-1996 (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-94	2,281	2,052	229	2,281	0	100.0
Jun-94	2,331	2,072	262	2,334	3	99.9
Dec-94	2,247	2,109	244	2,353	106	95.5
Jan-95	2,251	2,008	243	2,251	0	100.0
Jun-95	2,270	2,027	243	2,270	0	100.0
Dec-95	2,289	2,050	239	2,289	0	100.0
Jan-96	2,189	1,950	239	2,189	0	100.0
Jun-96	2,208	1,970	238	2,208	0	100.0
Dec-96	2,225	1,990	235	2,225	0	100.0
		Base Case Projection				
Jan-94	2,281	2,052	229	2,281	0	100.0
Jun-94	2,331	2,072	262	2,334	3	99.9
Dec-94	2,247	2,109	244	2,353	106	95.5
Jan-95	2,251	2,008	243	2,251	0	100.0
Jun-95	2,270	2,027	243	2,270	0	100.0
Dec-95	2,288	2,052	236	2,288	0	100.0
Jan-96	2,189	1,953	236	2,189	0	100.0
Jun-96	2,212	1,978	234	2,212	0	100.0
Dec-96	2,236	2,008	228	2,236	0	100.0
		High Case Projection				
Jan-94	2,281	2,052	229	2,281	0	100.0
Jun-94	2,331	2,072	262	2,334	3	99.9
Dec-94	2,247	2,109	244	2,353	106	95.5
Jan-95	2,251	2,008	243	2,251	0	100.0
Jun-95	2,270	2,027	243	2,270	0	100.0
Dec-95	2,291	2,052	239	2,291	0	100.0
Jan-96	2,192	1,953	239	2,192	0	100.0
Jun-96	2,222	1,984	238	2,222	0	100.0
Dec-96	2,256	2,021	235	2,256	0	100.0

Sources: • Production Projections: Energy Information Administration. *Short-Term Energy Outlook* Quarterly Projections Third Quarter 1995, DOE/EIA-0202(95/3Q) and Model GASCAP94 C051995. • Productive Capacity Projections: GASCAP94 C051995.

Figure 43. Eighteen States Gas-Well Completions Added During Year, 1984-1996



Sources: •History: Energy Information Administration, Office of Oil and Gas. Estimates of gas-well completions based on API well completion data. •Projections: Model GASCAP94 C051995.

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Appendix A

Methodology

Appendix A
Methodology

This appendix generally describes the methodology used to estimate the gas productive capacity of conventional and coalbed gas wells and oil wells for each State or area through 1996. For more detail, see Appendix B or the *Wellhead Gas Productive Capacity (GASCAP) Model Documentation*. {16} Lack of back-pressure test data and gas-in-place estimates by reservoir for a sizeable portion of the lower 48 States precluded doing conventional kinds of gas-well productive capacity studies that have been done in the past for specific States and areas. Because only production data were available for the lower 48 States, another technique had to be used. The lower 48 States were divided into States and multi-States for which production data by well is listed by Dwight's EnergyData, Inc. (Dwight's). 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 areas: Colorado, Montana, North Dakota, Utah, and Wyoming. A Southeast area consisted of Alabama, Arkansas, and Mississippi. An additional 18 States were studied as a group using aggregate EIA monthly production data and API drilling statistics. They 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 is to obtain the production for each gas-well completion in every State or multi-State 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 are then established and projected using the estimated number of monthly new wells going on production. The projected 1994, 1995 and 1996 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 is tabulated and plotted versus 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 is 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 annual peak rates are determined, they are screened (Figure A1) to eliminate those that are not 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 annual 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 connected by the fourth and last points is 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 due to reasons other than physical limitations of the wells--for example, low demand, proration, or temporary mechanical problems.

The next step is to fit the remaining points with a hyperbolic curve. A hyperbolic curve fit is chosen because it is the decline curve most often encountered. For example, Figure A2 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; the Y - intercept), and ultimate recovery (G_{ul}; the X - intercept). Although this curve might appear to be exponential, there is a slight curvature. The exponent B is close to one (1), indicating that the curve comes close to being an exponential curve.

The rate versus cumulative production relationship {17} for the hyperbolic decline is:

$$G_p = \frac{q_i^{\,b}}{D_i(1-b)} \left(q_i^{\,1-b} - q^{\,1-b}\right). \qquad \text{(A1)}$$

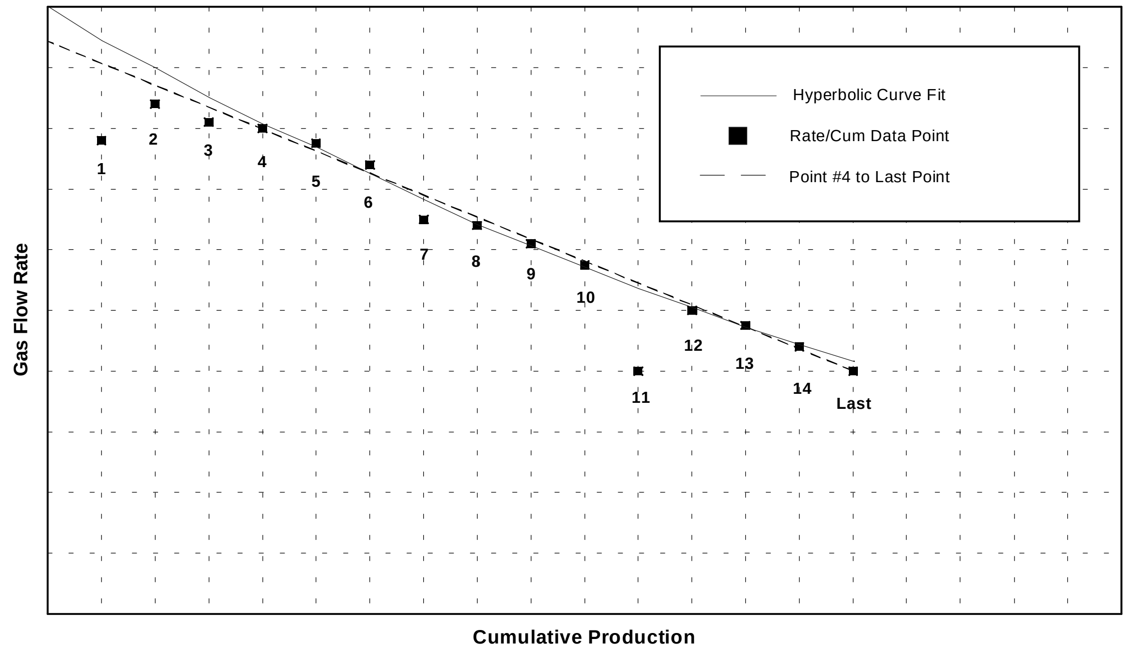
where

G_p	=	cumulative gas produced, thousand cubic feet
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.

In equation (A1), 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, q, at abandonment conditions is zero, equation (A1) becomes:

$$G_{ul} = \frac{q_i}{D_i(1-b)}. \qquad \text{(A2)}$$

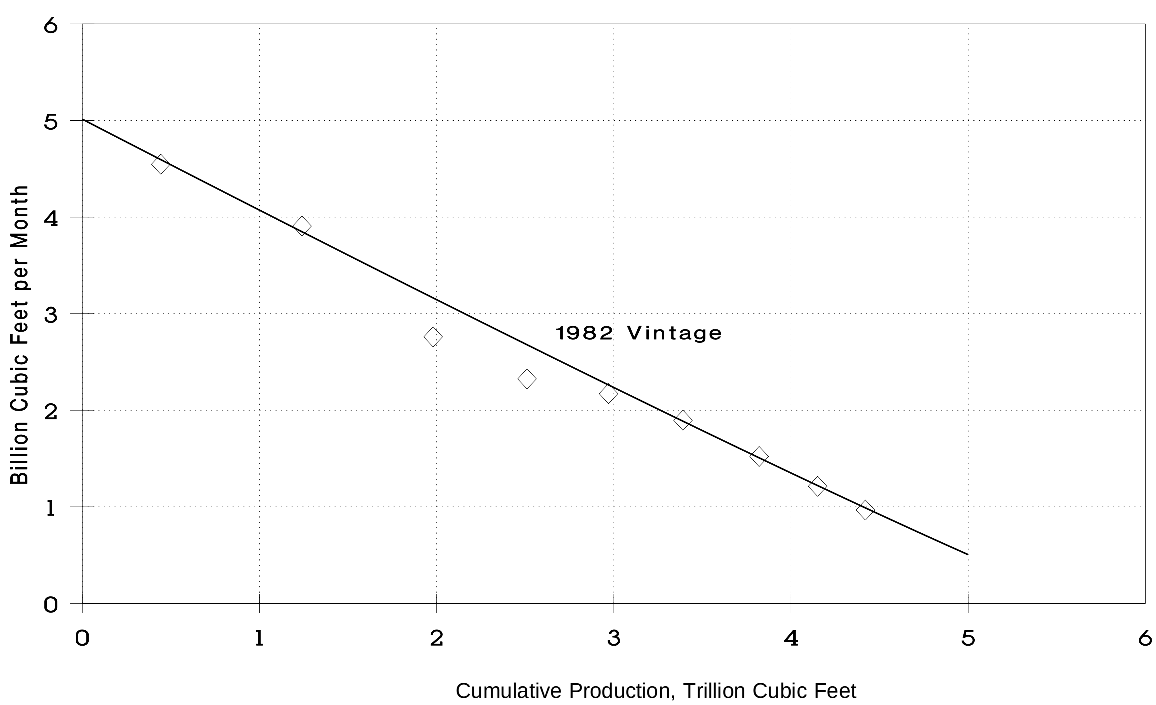
Figure A1. Screening Process



Note:	Point	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.

Figure A2. Gross Gas-Well Gas Productive Capacity for the Gulf of Mexico OCS 1982 Vintage



Source: Energy Information Administration Model GASCAP C051995, based on production data from Dwight's Energydata, Inc.

Rearranging (A1),

$$q = \left(q_i^{\,1-b} - \frac{D_i\ (1-b)}{q_i^{\,b}}\ G_p \right)^{\frac{1}{1-b}}. \quad \text{(A3)}$$

Simplifying (A3),

$$q = q_i \left(1 - \frac{D_i (1-b)}{q_i} G_p \right)^{\frac{1}{1-b}}. \quad \text{(A4)}$$

Substituting (A2) in (A4),

$$q = q_i \left(1 - \frac{G_p}{G_{ul}} \right)^{\frac{1}{1-b}}. \quad \text{(A5)}$$

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

$$q = q_i \left(1 - \frac{G_p}{G_{ul}} \right)^{B}. \quad \text{(A6)}$$

Equation (A6) is 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*{17}, 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{18} 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 falling 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 (A9) would result in division by 0, a forbidden operation. Values of B greater than 3.0 tend to give unrealistically large values of G_{ul}. Also, the raw production data is often distorted by low gas demand. This causes an apparent very rapid production rate decline and an accompanying large B that is 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 is 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. 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 is 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 3 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 2 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 are taken for the 7 years prior to the last 3 years, and are multiplied by the peak rate in the second year of production to provide a fixed q_i.

For the projections of 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 is 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 (A6) after dividing each term by the number of gas-well completions, v,

$$G_{ulv} = \frac{G_{pv}}{1 - \left({}^{q_v}/_{q_{iv}}\right)^{1/B}}. \tag{A7}$$

The q_i and G_{ul} on a per-well completion basis are 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 are developed through the last historical data year, they are projected for 3 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 is 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 in each month for the first time) are used for the current vintage capacity calculations.

All old vintages are projected for 3 years. The production rate as a function of cumulative production, G_p, is given by equation (A6). The production rate can also be written as a function of time, t, as described by Arps, although in his formulation, $B = \dfrac{1}{1-b}$:

$$q = q_i \left(1 + \frac{q_i \,(B - 1)\, t}{G_{ul}} \right)^{\frac{B}{1 - B}} . \quad \text{(A8)}$$

Equation (A8) is the hyperbolic equation that describes production rate decline as a hyperbolic function of time.

The time, t, that corresponds to the vintage productive capacity at the beginning of the month is calculated by solving equation (A8):

$$t = \frac{G_{ul} \left[\left({}^{q}/_{qi} \right)^{\frac{1-B}{B}} - 1 \right]}{(B-1) q_i} . \quad \text{(A9)}$$

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 and 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 using following equation, which is a rearrangement of equation (A6):

$$G_p = G_{ul} \left[1 - \left({}^{q}/_{q_i} \right)^{1/B} \right] . \quad \text{(A10)}$$

Furthermore, the productive capacities for the nine areas are multiplied by load factors. The load factors are applied because gas-well completions are frequently shut-in because of mechanical problems. In the 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 a 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 area is obtained by taking an average of the 10 annual load factors.

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 yield maximum productive capacity for the month for each vintage.

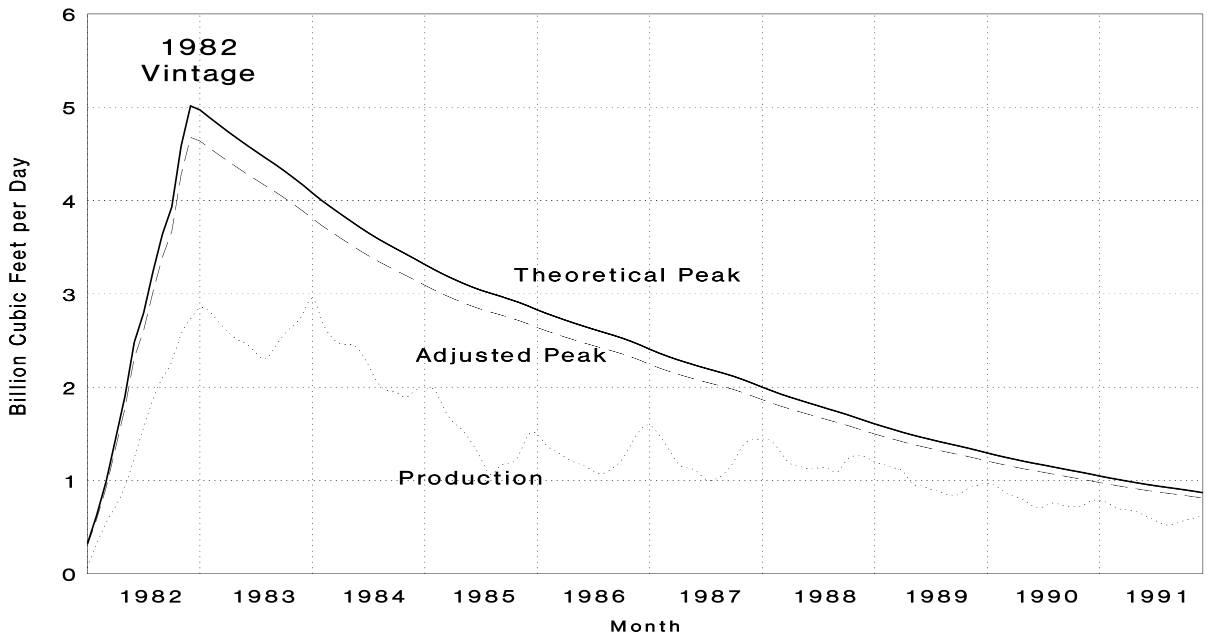
The productive capacities for each vintage year are summed and the demand is allocated to each vintage by its percentage of the total capacity. Next, the allocated production is added to the cumulative production at the beginning of a specific month for each vintage, and the process is repeated starting with the calculation of time (t) in equation (A9).

Figure A3 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.

Projected Productive Capacity of New Vintage Wells

Demand is defined for this model to be the volume of gas required from gas-well completions. Productive capacity is defined to be the maximum volume of gas a gas-well can produce for a month.

Figure A3. Capacity and Production Rates for the Gulf of Mexico OCS 1982 Vintage Year

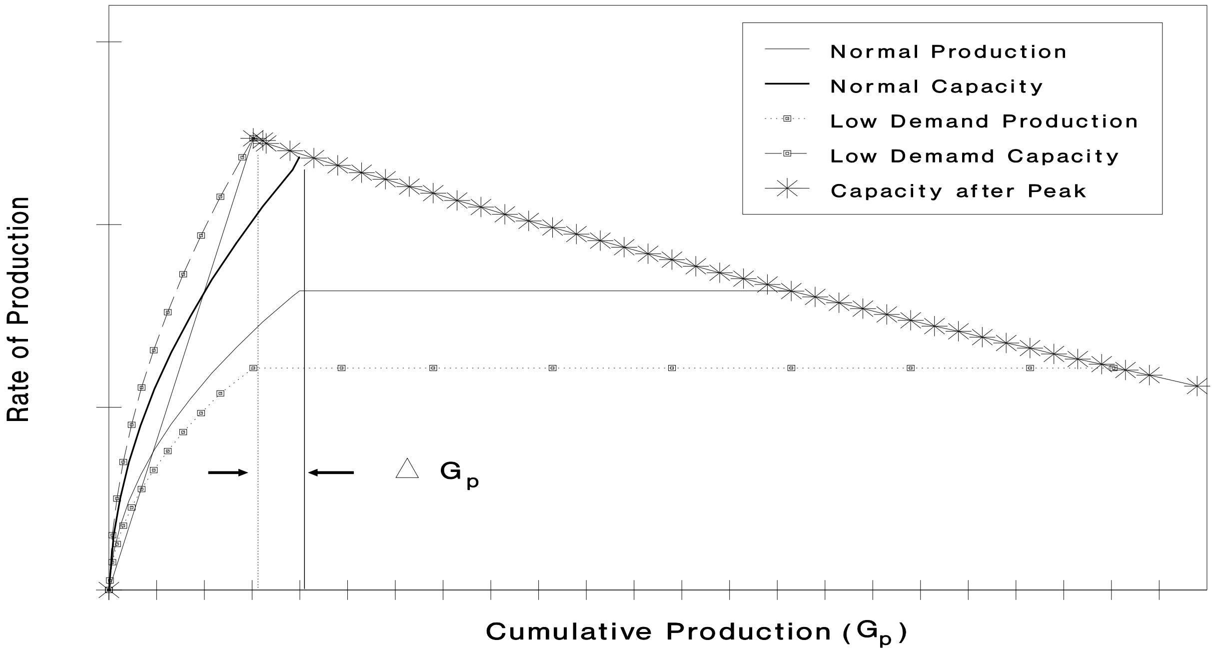


Sources: Production: Energy Information Administration, Office of Oil and Gas and Dwight's Energydata, Inc. Theoretical and adjusted peaks: Model GASCAP93 C060194.

If demand approaches the productive capacity of the old wells, the new wells (i.e., wells with near original capacity) will be called upon to produce at higher daily rates. This will cause the capacities of wells brought on in January to begin a higher rate of decline than normal (what usually happens in the historical data). Therefore, the productive capacity of wells brought on in January will be significantly less than their initial capacity, and the cumulative production (G_p) will be higher at the end of the year. If, however, demand decreases as a percentage of productive capacity, the new wells will not be required to produce at as high a rate as is normal. Their productive capacity will be greater than normal, and their corresponding cumulative production will be less at the end of the first year (Figure A4). A theoretical hyperbolic type curve, illustrates this discussion. The difference in the cumulative production (ΔG_p) is the difference between the annual production under normal demand (Case 1) and low demand (Case 2) at the end of the first year. Since capacity has been defined as a function of cumulative production, the difference in cumulative production for a low demand year or a high demand year can be determined by subtracting the actual cumulative production from the historical normal cumulative production (mean production rates for all previous vintage years per well completion). The capacity can be adjusted to account for low (or high) demands during the first year. This is done on a monthly basis for the first year of production for each new vintage year. The difference in cumulative production at the end of the first year is also used to adjust the cumulative production and, therefore, the capacity in all subsequent years.

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. For 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 is 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.

Figure A4. Theoretical Hyberbolic Type Curve for Production and Capacity



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

The equation is as follows:

$$q_k = \left(\tfrac{1}{2} \nu_k + \sum_{j=0}^{k-1} \nu_j \right) \left(\frac{q_i}{\nu} \right) \left[1 - \frac{\sum_{j=0}^{k-1} \Delta G_{p_j}}{\left(\frac{G_{ul}}{\nu} \right) \sum_{j=0}^{k-1} \nu_j} \right]^B . \qquad \text{(A11)}$$

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 historical cumulative production per well 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 approach is taken for this group of States. Monthly peak rates are determined from monthly gas-well production data obtained from the *Natural Gas Monthly*, and 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.

$$q_{pk(m)} = q_{pk(m-1)} \exp^{D(G_{p\nu\ (m-1)})} + q_{gi}\ \nu_{m-1}. \qquad (A12)$$

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:

$$q_{pk(m,n)} = q_{pk(m,1)} \exp^{D(G_{p\nu(m,n-1)})} + q_{gi}\ \nu_{m,n-1}. \qquad (A13)$$

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 is estimated for the same States and areas as gas-well gas productive capacity. Oil wells are 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.

Gross gas production from oil wells for each State is available on an annual basis only. Therefore, monthly gross gas production from oil wells from 1984 through 1993 was calculated. The annual GOR is calculated by dividing the annual gross oil-well gas production {12} by the annual oil production.{19} Then the monthly oil production is multiplied by the appropriate GOR. The monthly oil production estimates for each State and area for 1994, 1995, and 1996 were multiplied by the corresponding 1993 GOR to yield the forecast of the monthly oil-well gas productive capacity for 1994, 1995, and 1996.

Coalbed Gas Productive Capacity

Coalbed gas-well completion productive capacity is estimated using the same basic method as for a conventional gas-well completion. The coalbed gas-well completions were grouped in vintage years for New Mexico and the Rocky Mountains, and Southeast areas. All completions commencing production prior to the beginning of 1989 were included in the 1988 vintage to facilitate handling of the projections of older completions producing at low rates scattered over many years. Table A1 shows the vintage years for each area, along with the cumulative production and the number of wells included in the vintage year.

Table A1. Coalbed Gas Cumulative Production and Number of Completions by Area for Vintage Years 1988 - 1993

	NEW MEXICO		ROCKY MOUNTAINS		SOUTHEAST	
Vintage Year	Cumulative Production Mcf	Number of Completions	Cumulative Production Mcf	Number of Completions	Cumulative Production Mcf	Number of Completions
1988	146,178,016	97	70,904,366	171	91,978,971	484
1989	325,153,987	246	59,061,348	140	54,880,691	408
1990	391,944,440	370	66,267,233	201	110,683,127	961
1991	319,820,330	495	71,155,094	164	70,003,987	1031
1992	125,573,111	378	26,608,641	141	7,328,619	197
1993	22,933,962	425	11,205,760	230	5,502,818	140

Note: Vintage 88 includes all previous completed coalbed gas-wells.
Sources: Energy Information Administration, Office of Oil and Gas and Dwight's EnergyData, Inc.

The problem with projecting coalbed gas production is that it increases the first few years as gas desorbs from the coal. Production can peak five years after initial production before starting to decline. Traditional decline curve analysis methods do not accommodate inclining production. To project coalbed gas production a curve was developed to describe the life cycle of a typical coalbed gas-well completion (Figure A5). The annual peak production rate per completion was plotted for a representative vintage for each area. The vintage was chosen so that the later peak production rates would show a decline . Since most of the initial production from these completions occurred less than 10 years ago, there is very little decline data available. After the maximum peak rate occurred, the peak rates were projected exponentially. A decline rate was determined from a review of the historical data for older coalbed gas completions in each area because there were not enough declining points. Data were then simulated from a rate versus time curve based on the peak rates for each year for that vintage. The simulated data for rate (q) from the exponential decline curve and corresponding cumulative production (G_p) data were then used to solve for constants A and B in equation (A14), the rate versus cumulative production relationship:

$$q = -G_p/B(-\ln A + \ln G_p)^2. \qquad \text{(A14)}$$

The EXCEL 5.0 SOLVER routine was used to force the curve generated by equation (A14) track the simulated data curve. The value of A and B calculated from equation (A14) was then substituted into equation (A15) the time versus cumulative production relationship:

$$C = -t + [B/(\ln A + \ln G_p)]. \qquad \text{(A15)}$$

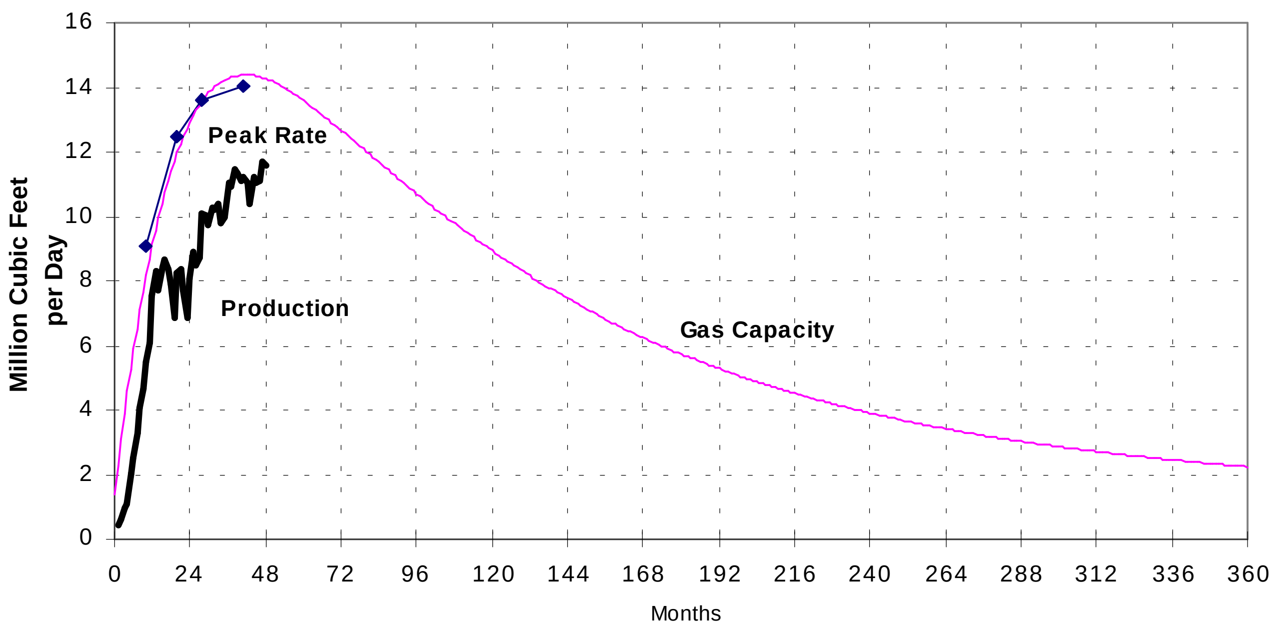
The value of C was calculated using equation (A15). Using this solution for C the EXCEL 5.0 SOLVER routine was again used to find the value of A and B in equation (A16) that generated a curve similar to the simulated data.

Equation (A16) for the rate versus time relationship is:

$$q = A[\exp^{B/(C+t)}][-B/(C+t)^2]. \qquad \text{(A16)}$$

Figure A5. New Mexico Coalbed Gas-Well Completion Production and Peak Production Rate

Source: Energy Information Administration, Office of Oil and Gas and Dwight's EnergyData, Inc.



Iterations of the above process are run solving for values of A, B, and C until curves generated by the simulated data, rate versus cumulative production data, and the rate versus time data matched as close as possible. Figure A5 shows the final peak rate curve generated by this technique.

Gas Demand

The forecast of the gas demand that will be met by domestic production is available on a quarterly basis for the United States for 1994, 1995, and 1996 in Table 10 of the *Third Quarter 1995 Short-Term Energy Outlook* (STEO).{10} 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 A2), and was distributed to each State or area. Since dry gas data are not available on a quarterly basis, but marketed production data are for each State or area (Table A3), the latter are converted to quarterly dry gas (Table A4). For example in Texas (excluding Gulf of Mexico OCS), the first quarter's marketed production of 1,235,840 million cubic feet (Table A3) is multiplied by .92382 (Table A3) to obtain the dry gas production of 1,141,691 million cubic feet (Table A4). Then the quarterly dry gas production is added for all the areas for each quarter (Table A6). The quarterly dry gas is divided by total dry gas for that quarter and is expressed as a fraction (Table A5). 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 for conversion of demand from dry gas to gross gas basis is that the gas production data from Dwight's are on a gross gas basis.

The quarterly gross gas (gas-well gas plus oil-well gas) is then distributed on a monthly basis for each State or area based upon its monthly marketed production for 1993. The monthly gross oil-well gas production was determined by multiplying the 1993 annual GOR by the monthly historic oil production for each State or area from 1984 through 1993. Monthly gas production from oil wells was then 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 then 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.

Table A3. Marketed, Dry, and Gross Gas Production for 1993
(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	1,166,090	1,154,297	1,162,469	1,196,470	4,679,326	4,607,407	0.98463	4,713,715	1.02307
Texas[c]	1,235,840	1,245,093	1,247,054	1,245,538	4,973,525	4,594,632	0.92382	5,540,828	1.20594
Louisiana[c]	385,529	376,565	409,882	502,450	1,674,426	1,608,168	0.96043	1,695,522	1.05432
California (Incl. Pacific OCS)	79,687	76,850	76,157	83,158	315,852	303,798	0.96184	405,367	1.33433
Kansas	189,260	163,973	151,439	181,675	686,347	642,333	0.93587	688,157	1.07134
New Mexico	344,187	346,805	350,601	367,836	1,409,429	1,326,236	0.94097	1,430,331	1.07849
Oklahoma	519,196	499,005	491,897	539,842	2,049,940	1,947,980	0.95026	2,049,942	1.05234
Southeast									
Alabama[c]	69,081	68,016	74,044	90,368	--	297,591	--	359,806	--
Arkansas	49,255	47,788	47,786	51,540	--	195,863	--	204,552	--
Mississippi	22,144	20,689	19,891	17,971	--	80,300	--	145,026	--
Total Southeast	**140,480**	**136,493**	**141,721**	**159,879**	**578,573**	**573,754**	**0.99167**	**709,384**	**1.23639**
Rocky Mountains									
Colorado	92,362	101,888	98,584	108,151	--	382,327	--	414,004	--
Montana	15,026	13,292	11,309	14,901	--	53,787	--	55,517	--
North Dakota	14,579	15,107	15,172	14,993	--	53,927	--	64,951	--
Utah	61,630	54,990	47,872	60,910	--	212,101	--	336,183	--
Wyoming	220,332	177,582	191,292	189,750	--	749,838	--	1,022,602	--
Total Rocky Mountains	**403,929**	**362,859**	**364,229**	**388,705**	**1,519,722**	**1,451,980**	**0.95542**	**1,893,257**	**1.30391**
18 States	**206,450**	**201,201**	**201,871**	**203,218**	**812,740**	**789,396**	**0.97128**	**824,115**	**1.04398**
Lower-48	**4,670,648**	**4,563,141**	**4,597,320**	**4,868,771**	**18,699,880**	**17,845,684**	**--**	**19,950,618**	**--**

[a]Dry gas divided by marketed gas.
[b]Gross gas divided by dry gas.
[c]Excludes Gulf of Mexico OCS.
--=Not Applicable.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Adminitration, corrected data from *Natural Gas Monthly* and *Natural Gas Annual,* 1993.

Table A4. Quarterly Dry Gas Production by State and Area for 1993
(Million Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Gulf of Mexico OCS	1,148,168	1,136,556	1,144,602	1,178,081	4,607,407
Texas	1,141,691	1,150,239	1,152,051	1,150,650	4,594,631
Louisiana	370,273	361,664	393,663	482,568	1,608,168
California (Incl. Pacific OCS)	76,646	73,917	73,251	79,984	303,798
Kansas	177,123	153,458	141,728	170,025	642,334
New Mexico	323,871	326,334	329,906	346,124	1,326,235
Oklahoma	493,372	474,185	467,431	512,991	1,947,979
Southeast	139,310	135,356	140,541	158,547	573,754
Rocky Mountain	385,924	346,684	347,993	371,378	1,451,979
18 States	200,520	195,422	196,073	197,381	789,396
Lower-48 Total	4,456,898	4,353,815	4,387,239	4,647,729	17,845,681

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

Table A5. Quarterly Dry Gas Fraction by State and Area for 1993

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Gulf of Mexico OCS	0.25762	0.26105	0.26089	0.25347
Texas (Excl. Gulf of Mexico OCS)	0.25616	0.26419	0.26259	0.24757
Louisiana (Excl. Gulf of Mexico OCS)	0.08308	0.08307	0.08973	0.10383
California (Incl. Pacific OCS)	0.01720	0.01698	0.01670	0.01721
Kansas	0.03974	0.03525	0.03230	0.03658
New Mexico	0.07267	0.07495	0.07520	0.07447
Oklahoma	0.11070	0.10891	0.10654	0.11037
Southeast	0.03126	0.03109	0.03203	0.03411
Rocky Mountains	0.08659	0.07963	0.07932	0.07991
18 States	0.04499	0.04489	0.04469	0.04247
Lower-48 Total	**1.00000**	**1.00000**	**1.00000**	**1.00000**

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

Table A6. Quarterly Gross Gas Demand by State and Area for 1994, 1996, and 1995
(Trillion Cubic Feet)

State/Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			1994		
Gulf of Mexico OCS	1.211	1.225	1.220	1.218	4.873
Texas(Excl. Gulf of Mexico OCS)	1.419	1.461	1.447	1.402	5.730
Louisiana (Excl. Gulf of Mexico OCS)	0.402	0.402	0.432	0.514	1.751
California (Incl. Pacific OCS)	0.105	0.104	0.102	0.108	0.419
Kansas	0.196	0.173	0.158	0.184	0.711
New Mexico	0.360	0.371	0.371	0.377	1.479
Oklahoma	0.535	0.526	0.513	0.545	2.119
Southeast	0.178	0.176	0.181	0.198	0.733
Rocky Mountains	0.519	0.476	0.473	0.489	1.957
18 States	0.216	0.215	0.213	0.208	0.852
Lower-48 Total	**5.141**	**5.129**	**5.110**	**5.243**	**20.623**
			1995		
Gulf of Mexico OCS	1.231	1.195	1.213	1.235	4.874
Texas(Excl. Gulf of Mexico OCS)	1.443	1.425	1.439	1.422	5.729
Louisiana(Excl. Gulf of Mexico OCS)	0.409	0.392	0.430	0.522	1.752
California (Incl. Pacific OCS)	0.107	0.101	0.101	0.109	0.419
Kansas	0.199	0.169	0.157	0.187	0.712
New Mexico	0.366	0.362	0.369	0.383	1.479
Oklahoma	0.544	0.513	0.509	0.553	2.120
Southeast	0.180	0.172	0.180	0.201	0.733
Rocky Mountains	0.527	0.464	0.470	0.496	1.958
18 States	0.219	0.210	0.212	0.211	0.852
Lower-48 Total	**5.226**	**5.002**	**5.080**	**5.320**	**20.627**
			1996		
Gulf of Mexico OCS	1.300	1.231	1.221	1.252	5.003
Texas(Excl. Gulf of Mexico OCS)	1.524	1.469	1.448	1.441	5.882
Louisiana(Excl. Gulf of Mexico OCS)	0.432	0.404	0.433	0.528	1.797
California (Incl. Pacific OCS)	0.113	0.104	0.102	0.111	0.430
Kansas	0.210	0.174	0.158	0.189	0.732
New Mexico	0.387	0.373	0.371	0.388	1.518
Oklahoma	0.575	0.528	0.513	0.561	2.176
Southeast	0.191	0.177	0.181	0.204	0.753
Rocky Mountains	0.557	0.479	0.473	0.503	2.011
18 States	0.232	0.216	0.213	0.214	0.875
Lower-48 Total	**5.519**	**5.155**	**5.113**	**5.390**	**21.177**

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

For States or areas where monthly gross gas-well gas productive capacity was less than the gross gas-well gas demand, 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 1994, 1995, and 1996.

The monthly gross gas-well gas productive capacity and oil-well gas production for each State or area were then added to obtain the total monthly gross gas productive capacity and 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

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 inputs to the Drilling Rig Model are provided by 3 submodels: the Gas Rig Model, the Percentage Gas Rigs Model, and the Rig Efficiency Model. The number of rigs drilling for gas is of particular importance in this study, and the Percentage 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 an input to 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 . The Excel Solver routine is used to fit and calibrate each model to historical data and minimize the sum of the squared differences in fitting model output to actual historical data.

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 do this. The number of rigs drilling for gas prior to August 1987 was modeled to provide a 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 1993. The number of active rigs comes from Baker Hughes Incorporated Market Research, and well completion data are obtained from the American Petroleum Institute (API). The Gas Rig Model equation is as follows:

$$GR_i = 59.2401 + 1.105796 * \left(\frac{SGW_i}{STW_i} \right) * SRig3_i + 63. \qquad \text{(A17)}$$

[1]Baker Hughes Incorporated, Marketed Research.
[2]Model GASCAP94 C051995.

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)
59.2401	=	model calibration coefficient
1.105796	=	model calibration coefficient
0.429062	=	*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 modeled gas rig counts and the post-August 1987 actual gas rig counts are used as input for the Percentage Gas Rigs Model.

Percentage Gas Rigs Model

The Percentage Gas Rigs Model estimates 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 gas 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 gas adjustment coincides with the evolution and impact of the tax credits. The Percentage Gas Rigs Model equation is as follows:

$$GRR3_i = a * \left(1 + e * SOI_i + \left(d * \left(\frac{\sum_{i-12}^{i-23} GI_i}{12} \right) * \left(\frac{SGI_i}{SGI_{i-12}} \right) * (1 + CB) \right) \right) * 100. \tag{A18}$$

where

$GRR3_i$	=	percentage gas rigs (gas rig ratio) with 3-month exponential smoothing (exponential smoothing coefficient = 0.5)
a	=	0.531312, model calibration coefficient
e	=	-0.00454, model calibration coefficient
d	=	0.003637, model calibration coefficient
SOI	=	smoothed oil income
GI	=	gas income
SGI	=	smoothed gas income
CB	=	coalbed gas adjustment factor
0.072477	=	*SOI* exponential smoothing coefficient
0.066675	=	*SGI* exponential smoothing coefficient.

The coalbed gas adjustment factor is as follows:

$$CB = 0.172189 * \left(1 + 0.146276 * \left[X\right]_{-5}^{5}\right) * \left[Y\right]_{1/24}^{1} * \langle f, i, j \rangle. \tag{A19}$$

where

CB	=	coalbed gas adjustment factor
0.172189	=	model calibration coefficient
0.146276	=	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	=	1.835148, model calibration coefficient used only for 1 month, January 1993
i	=	1.273358, model calibration coefficient used only for 1 month, February 1993
j	=	0.377529, model calibration coefficient beginning in March 1993 and held constant thereafter.

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

Rig Efficiency Model

The Rig Efficiency Model provides an adjustment of drilling efficiencies as a function of the number of working rigs. It also provides for long term gradual improvements in efficiency due to 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:

$$RWI_i = c * \left(\exp^{-b * \left(\frac{CumRig_{i-1}}{500{,}000}\right)} \right) * \left(1 + d * \left(\frac{SSRig_{i-1} - SSRig_{i-13}}{LSRig_{i-25}} \right) \right). \tag{A20}$$

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	=	1.131632, model calibration coefficient
b	=	0.284094, model calibration coefficient
d	=	0.999782, model calibration coefficient
0.052582	=	*SSRig* exponential smoothing coefficient
0.054654	=	*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 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, 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. The 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:

$$Rigs_i = b * \left((1+k) * SI_i\right)^d * RWI_i * ASn_i. \tag{A21}$$

where

Rigs	=	number of active drilling rigs
b	=	2.60603, model calibration coefficient
k	=	-0.07069, model calibration coefficient for AMT (used from January 1987 through November 1993 only)
SI	=	smoothed income term (equation A22)
d	=	1.195676, model calibration coefficient
RWI	=	modeled Rig per Well Index (equation A20)
ASn	=	adjusted seasonality (equations A26 and A27).

The smoothed income term is as follows:

$$SI_i = SOI_i^V + \left(\frac{\left(\frac{GRR3_i}{100}\right)}{\left(\frac{SGI_i^C}{SGI_i^C + SOI_i^C}\right)} \right) * SGI_i^V. \tag{A22}$$

where

SI	=	smoothed income
SOI^V	=	smoothed Oil Income with a variable exponential smoothing coefficient (equation A23)
$GRR3_i$	=	modeled Percentage Gas Rigs (equation A18)
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 A24)
0.3779	=	SOI^c and SGI^c constant exponential smoothing coefficient.

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

$$\propto_{SOI_i^V} = \frac{2}{2 + \left[\left(\frac{SRig12_{i-1}}{SRig_{i-1}^V} \right) * h * \exp^{c*((SOI6_i - SOI6_{i-2}) - |SOI6_i - SOI6_{i-2}|)} \right]}. \tag{A23}$$

where

$\propto_{SOI_i^V}$	=	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 A25)
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:

$$\propto_{SGI_i^V} = \frac{2}{2 + \left[\left(\frac{SRig12_{i-1}}{SRig_{i-1}^V} \right) * h * \exp^{f*((SGI12_i - SGI12_{i-2}) - |SGI12_i - SGI12_{i-2}|)} \right]}. \tag{A24}$$

where

$\propto_{SGI_i^V}$	=	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 A25)
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:

$$\propto_{SRig_i}{}^V = \frac{2}{2 + \left[\dfrac{e}{\exp^{0.2 * ((SRig48_i - SRig48_{i-12}) + |SRig48_i - SRig48_{i-12}|)}} \right]}. \qquad \text{(A25)}$$

where

$\propto_{SRig_i}{}^V$	=	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 are 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 is then run again holding fixed everything other than the seasonality parameters to calibrate only the seasonality coefficients. The seasonality is then held fixed while the nonseasonality parameters were recalibrated in a third fit of the model.

Seasonality is determined by the following equations:

$$\begin{aligned}
&Sn_{i=1} = f \quad for\ January \\
&Sn_{i=2} = f + \frac{l}{2^{i-1}} \quad for\ February \\
&Sn_{i=3} = f + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}} \quad for\ March \\
&Sn_{i=4} = f + \frac{l}{2^{i-3}} + \frac{l}{2^{i-2}} + \frac{l}{2^{i-1}} \quad for\ April \\
&Sn_{i=5,11} = Sn_{i=4} + j*(i-4) \quad for\ May\ thru\ November \\
&Sn_{i=12} = Sn_{i=11} + \frac{j}{3} \quad for\ December
\end{aligned} \qquad \text{(A26)}$$

where

Sn	=	the 12 different seasonality factors for January through December
i	=	1 through 12 for the corresponding months January through December
f	=	1.057304, model calibration coefficient
l	=	-0.13275, model calibration coefficient
j	=	0.014638, model calibration coefficient.

Next, the seasonality is adjusted according to the trend direction as seasonality has less impact when rig counts are increasing than when rig counts are falling. Therefore, adjusted seasonality factors replace the regular seasonality factors as 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:

$$ASn_i = 1 + \frac{(Sn_i - 1) * (0.5 + 0.5 * \exp^{a})}{0.5 + 0.5 * \exp^{\left(a * \frac{SRig_{i-1}}{SRig_{i-13}}\right)}}. \tag{A27}$$

where

ASn	=	adjusted seasonality factors
Sn	=	the 12 different seasonality factors for January through December (equation A26)
a	=	3.60894, 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 is then run one last time to determine the value for k in equation (A21) (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, at the ratio of actual to predicted rigs calculated for the last month of real data.

Exponential Smoothing

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

$$SI_i = I_i * \alpha + SI_{i-1} * (1 - \alpha). \tag{A28}$$

where

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

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: 1995

Part of Another Model: No

References to Any Other Models: None

Documentation reference: Wellhead Gas Productive Capacity Model (GASCAP) Documentation DOE/EIA-M052 March 1995.

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, Velton T. Funk, John B. Arkenberg.

•**Telephone:** 214-767-2200

Archive Media and Installation Guides: Cartridge tape available from NEIC for GASCAP94, for the report Natural Gas Productive Capacity for the Lower 48 States 1984 through 1996, DOE/EIA-0542(95), published October 1995.

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

Coverage:

•**Geographic:** Lower-48 natural gas producing States

•**Time Unit/Frequency:** Evaluates 13 years of historical data and project productive capacity for **3 years**.

•**Products:** Natural gas

•**Economic Sectors:** Not applicable

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**: Estimates conventional and coalbed gas-well gas productive capacity separately.

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

- Drilling statistics monthly tapes

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

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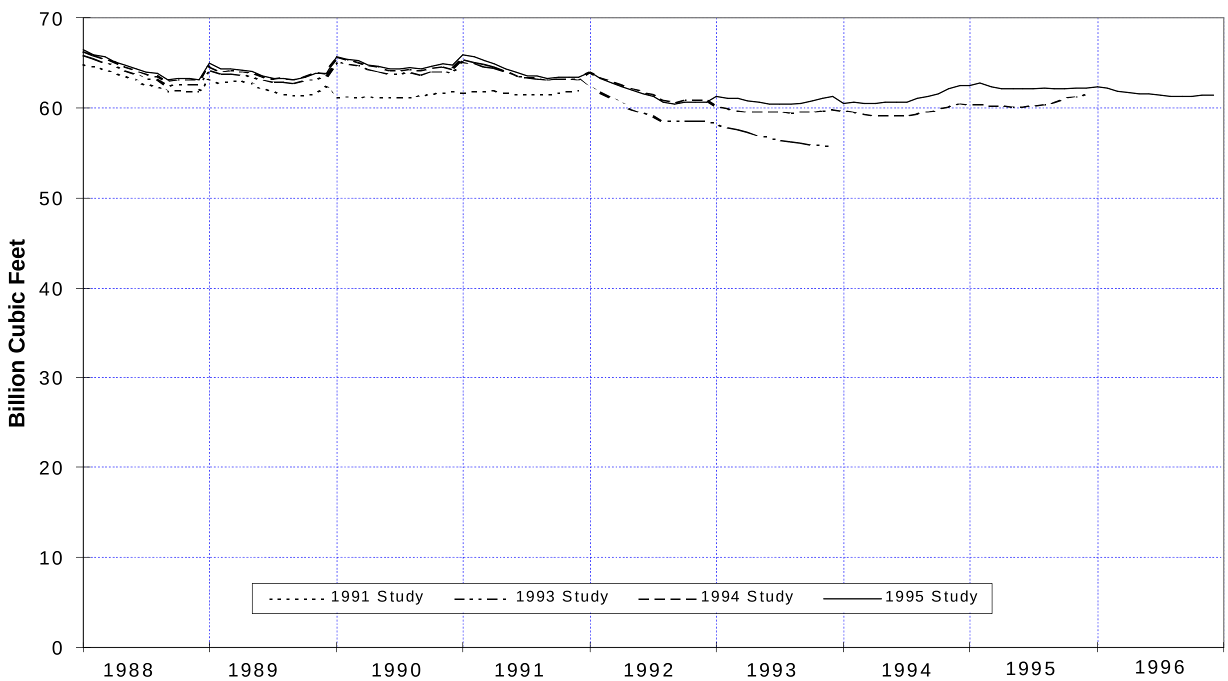
Comparison of Productive Capacity

Comparisons for the period 1988 through 1995, between the current base case productive capacities and those from the previous studies, appear in Figure C1. In nearly all cases values the for the 1995 study are higher than those found in the earlier studies.

Figure C1. Comparisons of Dry Gas Productive Capacity for the 1991, 1993, 1994, and 1995 Studies, 1988- 1996



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: *Natural Gas Productive Capacity for the Lower 48 States 1980 through 1995*. DOE/EIA-0542 (Washington, DC, July 14, 1994). •1995 Study: Model GASCAP94 C051995.

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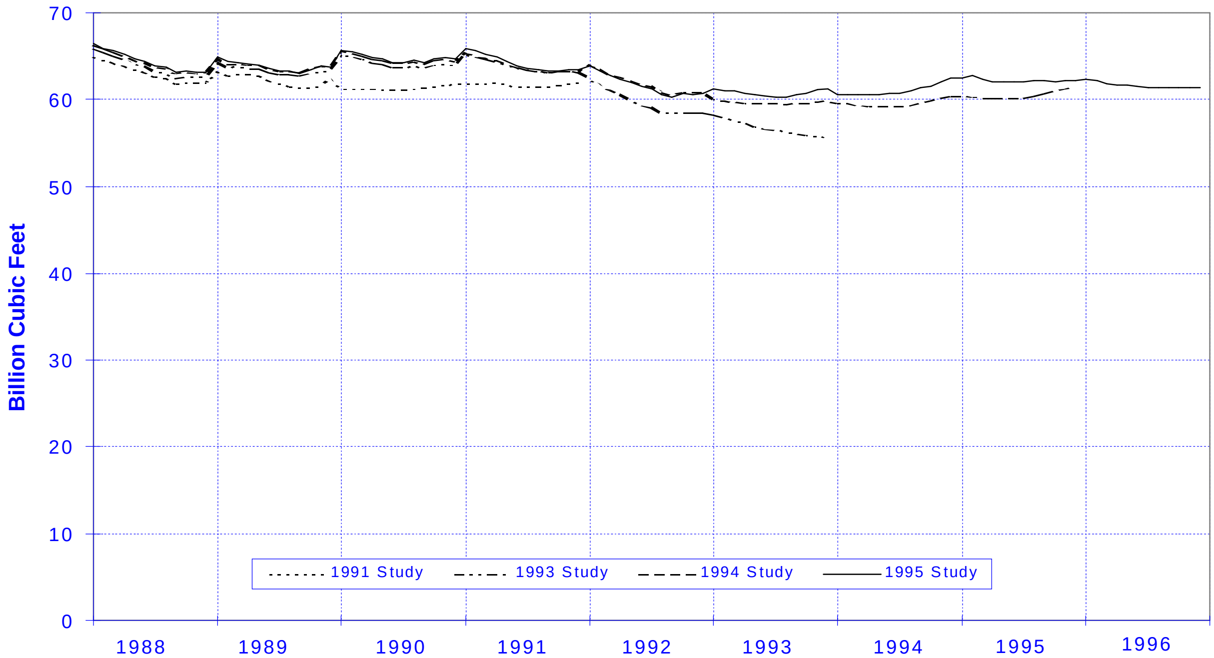

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Appendix D

Dry Gas-Well Capacity per New Gas-Well Completion

Dry Gas-Well Capacity per New Gas-Well Completion

Dry gas-well gas productive capacity of about 1 billion cubic feet per day is added per 1,000 new gas-well gas completions. This is the difference between the dry gas-well productive capacity change for the *high* case and the *base* case during 1996 divided by the difference in gas-well completions between the *high* and *base* case during 1996. For productive capacity, the period of change is from December 1995 to December 1996 (Table 2). The well completions for the *base* and *high* cases are those added during 1996 (Figure 9). Capacity is in billion cubic feet per day (Bcf/day) and the number of completions are in thousands.

The calculation follows:

$$\frac{\text{(Difference in dry gas-well gas capacity change during 1996 for the } \textit{high} \text{ and } \textit{base} \text{ case)}}{\text{(Difference in gas-well completions between the } \textit{high} \text{ and } \textit{base} \text{ case during 1996)}}$$

$$= \frac{\text{(56.1 Bcf/day - 54.4 Bcf/day) - (53.4 Bcf/day - 54.3 Bcf/day)}}{\text{14.1 thousand completions - 11.6 thousand completions}}$$

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

$$\cong 1 \ \frac{\text{MMcf/day}}{\text{gas-well completion}}$$

Table D1. Average Initial Flow Rates, Ultimate Recovery, and Decline Exponent on a Conventional Gas-Well Completion Basis for 1990-1992 (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	7.6	4,997	1.1
Texas (Excluding Gulf of Mexico OCS)	1.0	1,010	2.2
Louisiana (Excluding Gulf of Mexico)	2.1	1,979	1.8
California (Including Pacific OCS)	2.4	1,052	1.7
Kansas	0.4	718	2.5
New Mexico	0.8	2,262	2.8
Oklahoma	1.1	1,398	2.4
Southeast	1.1	2,179	1.9
Rocky Mountains	0.6	1,042	2.7

Source: Energy Information Administration Model GASCAP94 C051995.

The estimate of dry gas-well capacity per new gas-well completion depends on three parameters: initial flow rate (q_i); ultimate recovery (G_{ul}); and the decline exponent (B) (Table D1). These parameters are an average of the parameters obtained from nonlinear regressions of equation (A6) over the data for each area.

Glossary

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Annual Average-Day Demand: Annual demand divided by the number of days in the year.

Associated Gas: Natural gas, commonly known as gas-cap gas, 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.

Coalbed Gas: Natural gas that is produced from coalbeds. Methane is the principal component. It is commonly referred to as coalbed methane.

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 natural 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 natural 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.

Demand: U.S. requirement for dry gas from all sources -- production, storage withdrawals, supplemental gaseous fuels, and imports.

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 gas volume, including all natural gas plant liquids and nonhydrocarbon gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.

G-10 Rate : Daily gas well production rate calculated as specified on the Railroad Commission of Texas Oil and Gas Division form G-10 and Rule 28.

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 natural 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: Natural gas produced from well completions classified as oil-well completions by a regulatory body.

Peak-Day Demand: Highest daily demand that occurred on any one day during the year.

Peak-Month Average-Day Demand: Highest of the 12 monthly demands for the year divided by the number of days in the month.

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 natural 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.

Water-Drive Reservoir: A reservoir in which the rate of water intrusion into the pay substantially equals the volumetric net rate of oil and gas withdrawal.

Well: A hole made by drilling through strata.

Well Completion: A flow string in a well used to conduct fluids to the surface from one reservoir or zone. A producing well may contain one or more well completions.