DOE/MC/31114 -- 5186
(DE96004463)

Natural Gas Storage -- End User Interaction
Task 2

Topical Report

January 1996

Work Performed Under Contract No.: DE-AC21-94MC31114

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
ICF Resources Incorporated
Fairfax, Virginia

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NATURAL GAS STORAGE – END USER INTERACTION
TASK 2

DOE

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For
U.S. Department of Energy
Office of Fossil Energy
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January 1996

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Executive Summary

New opportunities have been created for underground gas storage as a result of recent regulatory developments in the energy industry. The Federal Energy Regulatory Commission (FERC) Order 636 directly changed the economics of gas storage nationwide. Pipelines have been required to "unbundle" their various services so that pipeline users can select only what they need from among the transportation, storage, balancing and the other traditional pipeline services. At the same time, the shift from Modified Fixed Variable (MFV) rate design to Straight Fixed Variable (SFV) rate design has increased the costs of pipeline capacity relative to underground storage and other supply options. Finally, the ability of parties that have contracted for pipeline and storage services to resell their surplus capacities created by Order 636 gives potential gas users more flexibility in assembling combinations of gas delivery services to create reliable gas deliverability. In response to Order 636, the last two years have seen an explosion in proposals for gas storage projects.

Another major development affecting the demand for storage is the restructuring of the electric power industry. This trend began with the passage of the Public Utilities Regulatory Policies Act (PURPA) which allowed non-utility electric generators, or qualifying facilities, to provide electric power to electric utilities. Since 1978, substantial amounts of cogeneration and independent power capacity have come on line. Repeal of the Fuel Use Act enabled this capacity to be built with efficient gas-fired turbine technologies. The Energy Policy Act of 1992 and newly proposed FERC regulations will further the break-up of the electric power industry into independent generators, transmission companies, and distribution utilities. The fuel of choice for most cogeneration and independent power has been, and probably will continue to be, natural gas. Since many of these units are not the lowest cost generation sources available to a utility, they may not be operated full time. Thus, they use gas unevenly over time and may increase the need for storage.

A. Project Purpose

The primary purpose of this project is to develop an understanding of the market for natural gas storage that will provide for rigorous evaluation of federal R&D opportunities in storage technologies.

B. Project Objectives

The primary objectives of this project are:

1. To identify market areas and end use sectors where new natural gas underground storage capacity can be economically employed;

2. To develop a storage evaluation system that will provide an analytical tool to evaluate storage requirements under alternative economic, technology, and market conditions; and

3. To analyze the economic and technical feasibility of alternatives to conventional underground gas storage.

C. Project Analytical Approach

To meet the foregoing objectives, an analytical approach was designed to follow the decision making process used by storage developers in deciding where, how much, when, and what type of storage facility would be economic. Initially, it was thought that these decisions could be made based on the concept that gas demands of various types of end users within a given region could be satisfied by storage capacities within that region. As described below, this initial approach had to be modified to examine storage needs and economics on a total U.S. gas system basis, and to recognize that in today's gas markets storage is of interest to many more parties than just the end users.

Both the initial and final approaches to determining the need for storage in a region recognize that there are two primary conditions that must exist to make storage economic. The first condition is that there must be seasonal or shorter-term changes in gas demands of end users each year. If all consumers used constant amounts of gas all year long, there would be no economic justification for storage. This occurs because pipeline transportation rates are less expensive than storage rates, if the pipeline capacity is near fully utilized. Secondly, there must be differences in the cost of gas and/or the cost of gas delivery during the year. If the price of gas and its transportation costs did not vary over the course of a year, storage would simply be an additional cost to add to the total cost of delivered gas.

This project has been divided into six tasks. Tasks 1, 3, and 5 are the analytical assignments that respond to the three primary objectives listed above. Tasks 2, 4, and 6 are the written reports for the three analytical tasks. Task 1 defines the storage market, including identification of existing and proposed storage facilities and their costs, development of an analytical basis for comparing the economics of gas storage with its competitors, and preliminary identification of where additional storage may be required. Task 3 requires development of a data base and screening criteria for existing and potential storage reservoirs and modification of the GSAM model to evaluate the effects of technology changes on storage reservoirs in which the same way as on production reservoirs. Task 5 will be used to evaluate a wide range of alternative storage technologies under varying market conditions.

The primary work items involved in completion of Task 1 of this gas storage analysis project are:

- Characterize current and forecast market demands for gas that may affect the economic need for storage and identify regions where gas demands may require additional storage capacity;
- Identify existing storage facilities, their locations, and their working gas and deliverability capacities;
- Develop similar information for proposed new and expanded storage facilities;
- Determine regional costs for existing gas storage services and predicted costs for proposed new storage facilities;
- Develop an analytical basis for comparing the economics of gas storage versus its principal alternatives -- pipeline capacity and peak shaving supplies; and
- Develop preliminary indications of where additional gas storage capacity may be needed and what type of storage is required at this location to meet potential consumer needs.

These work items have been completed and a brief summary of the Task 1 findings is provided in the following section.

D. Major Findings of Task 1

1. Identifying gas storage needs from a strictly end user perspective and on a region-by-region basis is infeasible. Numerous parties are involved in the development and use of storage now and storage services are often provided by capacity in distant regions.

2. The gas storage market, along with the entire gas industry, is undergoing major changes that affect investment decisions. Examples of these changes include:

   - pipeline rate design changes that have raised fixed costs, making storage generally more attractive than in the past;
   - pipeline rate design changes, rate discounting, and excess capacity in some regions have made summer transportation rates less expensive;
   - gas pipeline companies are no longer the primary sources of storage services since LDCs and gas marketers control much of the storage capacity now; and
   - surplus storage capacity is currently available in the East North Central region.

3. The value of storage depends on the way it is used and the gas supply alternatives against which storage competes. Storage use varies from the conventional seasonal cycle of withdrawal during cold weather and refill during warmer months, to the intra-daily cycles that an electric utility may need during summer and winter. The gaseous supply alternatives to storage are pipeline capacity and peak shaving supplies (liquefied natural gas and propane mixed with air). Gas also competes with fuel oils in the industrial and electric generation sectors where some facilities are dual-fueled.

4. The costs of the gas supply alternatives depend primarily on the number of days per year the gas delivery is needed. For periods well over half of a year, pipeline capacity will be the least costly choice. For the very short term--roughly one to ten days per year--peak shaving supplies will typically be the least expensive in areas distant from gas production. The costs of storage fall between those of pipeline capacity and peak shaving -- from a few days to possibly 150 days in areas distant from gas production.

5. Existing gas storage service cost varies widely, depending on both the type of storage and when the facility was completed. Typically, the least cost storage is that developed in depleted gas and oil reservoirs, where some existing subsurface and surface facilities may be used and pipeline connections may be available. The highest cost facilities are mined caverns in salt formations, where deliverabilities are highest and cycling times are lowest. In between these cost levels are those for storage facilities using aquifers. Under cost of service rate regulations, the storage charges for older, largely amortized storage facilities of the same type are always much less costly than for newer facilities. This historical downward trend in rates for storage will probably not be seen for those storage facilities that are now being allowed by the Federal Energy Regulatory Commission to charge "market based" rates.

6. Gas demand growth forecasts and recent regulatory changes have appeared to increase the demand for storage in several regions of the U.S. The growth in unbalanced seasonal demand from the residential and commercial sectors is expected to be greatest in the South Atlantic, West South Central, California, and combined Middle Atlantic/New England regions. A sample of the complications that prevent these areas from having obvious needs for more storage are: 1) except for West Virginia, the South Atlantic has no known storage reservoir sites near the major population areas and the transportation distance from storage in Louisiana and Mississippi to this region typically makes storage an uneconomic alternative to pipeline capacity; 2) the short distances from gas production to demand areas makes pipeline capacity a tough competitor for storage in the West South Central region; 3) California has a surplus of pipeline capacity from Canadian and U.S. supply areas that should compete favorably with any new storage capacity for California; and 4) the lack of geology favorable to gas storage in New England makes this region dependent on other regions, such as the Middle Atlantic, for storage service.

7. Existing and potential market area gas storage capacity in the East North Central, Middle Atlantic, and the South Atlantic (West Virginia) regions is capable of meeting storage needs in several other market regions. The location of economic gas storage capacity for use in a given demand region will depend on the cost of the storage service, the costs of gas transportation to the storage region, and the cost of gas transportation from the storage region to the demand region, compared with these same costs for storage in another region.

8. In 1994 there were 375 gas storage facilities in the U.S., with working gas capacities totaling 3,695 billion cubic feet and deliverability rates totaling nearly 68 billion cubic feet per day. These facilities included depleted gas and oil reservoirs, aquifers, and salt caverns. Proposed new facilities of the same three types total 81 projects with 495 billion cubic feet of working gas capacity and about 21 billion cubic feet per day of deliverability.

9. As indicated by the capacities stated in item 6, above, the deliverability of the proposed storage projects will be substantially higher than for the existing facilities. The planned projects would add about 13 percent to working gas capacity and nearly 31 percent to deliverability. This increased deliverability trend is in response to higher values being placed on high deliverability storage to take advantage of gas price volatility (attempts to buy low and sell high) and to be more competitive with peak shaving supplies.

10. In addition to conventional seasonal storage for reducing the cost of winter supplies, gas is stored today for short-term peak supplies (in high deliverability facilities), to balance gas volumes that shippers place into pipelines with the amounts they take out (to avoid paying imbalance penalties), to hedge against price changes, to speculate on price changes, and to provide emergency supply services (by marketers and pipelines).

11. In the past, the principal investors in storage facilities were the gas companies -- mostly pipelines (or their subsidiaries) and LDCs. The primary subscribers to the storage service were the LDCs which needed storage to minimize their costs of winter supplies for serving the temperature sensitive loads of residential and commercial customers. Today, investors in new storage facilities are more apt to be gas marketers who are expanding

the supply services they offer and entrepreneurs who develop storage to sell the service. In addition to the LDCs, storage service subscribers are now more likely to include industrial consumers and gas marketers.

12. The new players in gas storage and their varying reasons for investing and using this service tend to complicate simulation of the decision making process that is required for developing the economics of storage compared to its alternatives.

These findings, along with the storage capacity and cost data bases developed for both the existing and planned storage facilities, directly support planned efforts for Task 3 effort under way now. The primary work items for Task 3 are:

- development of the storage reservoir technical and economic screening criteria for identifying reservoirs that have potential for gas storage;
- modification of the GSAM upstream models as required to predict reservoir performance under conditions of gas injection and withdrawal cycles;
- testing the modified GSAM performance in identification of reservoirs with storage potential against known storage reservoirs; and
- development of regional storage potential through identification of target storage reservoirs.

I. Introduction

This report analyzes both seasonal and quick response storage within the context of end use markets for gas. Further, gas markets and the economics of storage serving those markets are examined in the context of new storage opportunities. The report describes the economic alternatives to underground storage, including pipeline capacity, liquified natural gas, propane, and fuel oil. The results of this analysis provide the bases for evaluating the need for advances in storage technology in the context of a competitive market.

Natural gas storage facilities can be divided into two types according to the way they are used — seasonal and short term. The former type of facility was typical of those built prior to 1980, although many large seasonal storage reservoirs are still being developed today. Short-term storage facilities have become popular with natural gas deregulation, as their rapid injection and withdrawal capabilities allow quick response to market changes.

According to the U.S. Department of Energy, Energy Information Administration (DOE/EIA)[1] there were 375 underground gas storage facilities operating in the United States during 1993. These storage fields were located in 27 states with a total working gas capacity of about 3.7 trillion cubic feet (Tcf) and a peak day deliverability of 68 billion cubic feet (Bcf) per day. Approximately 60 percent of the storage facilities are concentrated in the northeastern quadrant of the country (Exhibit I-1), where gas is typically stored in depleted oil and gas reservoirs. The only other regional concentration of storage is in the West South Central Region where 19 percent of the facilities are located. Interstate gas pipeline companies own about 49 percent of the facilities and local gas distribution companies (LDCs) hold 42 percent. Independent storage operators and intrastate gas pipeline companies have the balance of the facilities.

A. Industry Developments

New opportunities have been created for underground gas storage as a result of recent regulatory developments in the energy industry. The Federal Energy Regulatory Commission (FERC) Order 636 directly changed the economics of gas storage nationwide. Pipelines have been required to "unbundle" their various services so that pipeline users can select only what they need from among the transportation, storage, balancing and the other traditional pipeline services. At the same time, the shift from Modified Fixed Variable (MFV) rate design to Straight Fixed Variable (SFV) rate design has increased the costs of pipeline capacity relative to underground storage and peak shaving[2] options. Finally, the secondary

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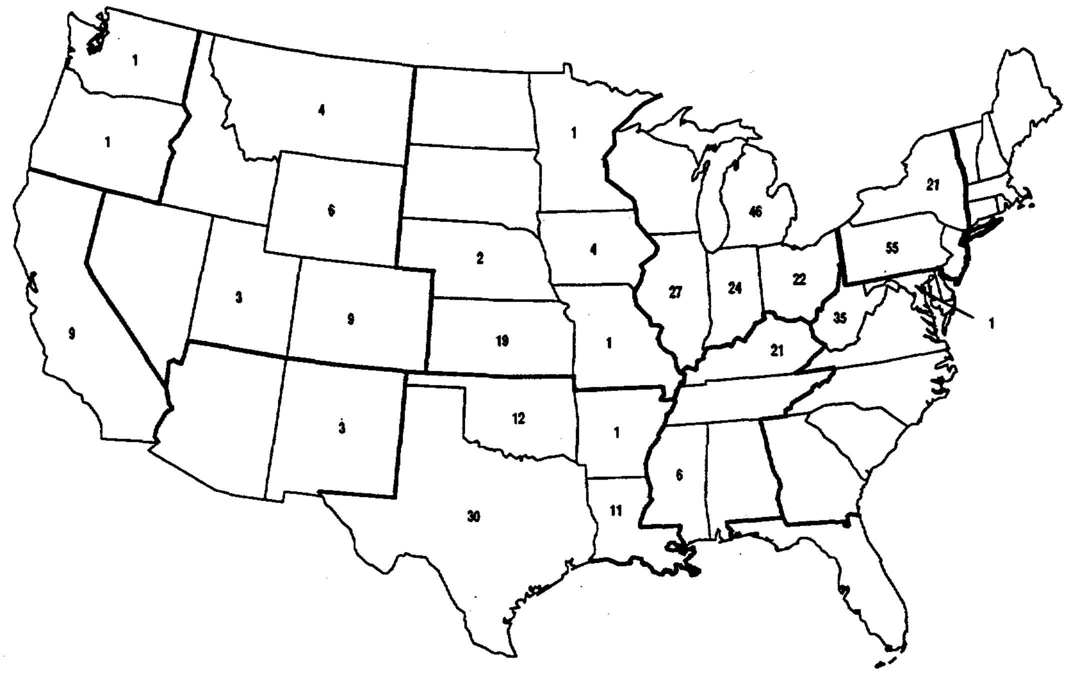
1) U.S. Department of Energy, Energy Information Administration (DOE/EIA). "The Value of Underground Storage in Today's Natural Gas Industry", March 1995, pages 45-46.

2) The two primary peak shaving options are liquefied natural gas (LNG) and propane and air mixtures. LNG supplies can be from imports and by liquefaction of pipeline gas during warmer months. Peak shaving operations are typically performed by local gas distribution companies (LDCs).

EXHIBIT I-1
Existing Underground Gas Storage Facilities—
Number of Facilities by State



Source: DOE-EIA, Value of Underground Storage in Today's Natural Gas Industry

market[3] in pipeline and storage services created by Order 636 gives potential gas users more flexibility in assembling combinations of gas delivery services to create reliable gas deliverability. In response to Order 636, the last two years have seen an explosion in proposals for gas storage projects.

Another major development affecting the demand for storage is the restructuring of the electric power industry. This trend began with the passage of the Public Utilities Regulatory Policies Act (PURPA) which allowed non-utility electric generators, or qualifying facilities, to provide electric power to electric utilities. Since 1978, substantial amounts of cogeneration and independent power capacity have come on line. Repeal of the Fuel Use Act enabled this capacity to be built with efficient gas-fired turbine technologies. The Energy Policy Act of 1992 and newly proposed FERC regulations will further the break-up of the electric power industry into independent generators, transmission companies, and distribution utilities. The fuel of choice for most cogeneration and independent power has been, and probably will continue to be, natural gas. Since many of these units are not the lowest cost generation sources available to a utility, they may not be operated full time. Thus, they use gas unevenly over time.

3) Secondary markets for pipeline and storage services were created when Order 636 allowed the parties that have contracted for those services to resell their surplus capacities.

B. Project Objective and Analytic Approach

The primary objectives of this project are: 1) to identify U.S. market areas and end use sectors where new natural gas underground storage capacity can be economically employed, 2) to provide the Morgantown Energy Technology Center (METC) with a storage evaluation system that will provide the analytical tools necessary for METC to evaluate storage requirements under alternate economic, technology, and market conditions in the future, and 3) to analyze the feasibility of alternatives to conventional gas storage methods.

In order to meet these objectives, an analytic approach was developed to determine the critical decision parameters used by new storage field developers in deciding to develop a new storage project. These decisions focused on two areas:

- Technical Issues: What is the technical capability of the site including working gas capacity, deliverability and injection rates, investment and operating costs, pipeline access, and siting problems?

- Market Issues: Is there a market for the storage, considering the alternatives available in energy markets, including potential advancements in underground storage technology?

C. The Uses of Underground Gas Storage and Its Operational Aspects

In general, the operation of an underground gas storage facility typically involves: 1) injecting the desired volume of pipeline gas into the reservoir using pipeline pressure and onsite compressors to augment the pipeline pressure, if necessary, as reservoir pressure builds up during injection, 2) monitoring storage pressure during static periods to determine leakage rates, 3) withdrawing gas from the reservoir when it is needed, using reservoir pressure initially, 4) processing the stored gas to remove water, liquid hydrocarbons, and any other impurities, and 5) compressing the stored gas to pipeline pressure whenever the reservoir pressure is inadequate.

In the past, when most gas storage was used to supplement pipeline gas supply during the winter season when gas demand was highest, the operations described above were essentially a seasonal, one cycle per year, task. Gas was withdrawn during cold weather and reinjected during the warmer months — with some injection during winter months, if temperatures moderated. With the restructuring of the gas industry under FERC Order 636 and rapid increases in high deliverability, salt cavern storage, new forces are at work shaping the way storage is used. The pipelines no longer control how most of the storage capacity is used. The downstream gas shippers, LDCs, and large consumers that have contracted for the storage make the decisions on when and how much to inject and withdraw. The pipelines have retained just enough storage capacity to manage their own operations. Pipeline company use of storage now is very like a surge drum to handle short-term differences in the amount of gas being placed into and taken from the line.

Although most shippers still use much of their storage capacity in the traditional way, to augment pipeline capacity in times of heavy seasonal demands, the following newer uses have gained importance in recent years.

1. Balancing Supply with Demand

Because a typical gas shipper cannot accurately estimate the amount of gas it will need every day, there will be daily imbalances between the gas the shipper places into the pipeline and takes from the pipeline. Some will take more gas than they placed into the pipeline and others will leave gas in the line. The pipeline can usually manage the net daily imbalance with its load management storage. If individual shippers have a substantial daily imbalance they can be charged a penalty amount for causing pipeline load management problems. More typically, the daily imbalances are acceptable and a monthly imbalance penalty is of more concern. Because monthly imbalance penalties charged by pipelines can be sizable, shippers frequently use storage to balance their gas supplies and demands.

2. Emergency Supply

In the past, when the gas pipelines were fully responsible for serving the contracted demands of their customers, problems with gas supply at the producer level were typically solved by the pipeline. The pipeline customers might have peak shaving supplies that would serve as emergency supplies for a few hours or days. When a pipeline had a supply problem, it used gas from its storage or obtained gas from other suppliers and/or pipelines. As common carriers, pipelines no longer have this supply responsibility, except for small portions of their throughput that is sold to very small consumers that cannot find and purchase their own gas and contract for transportation. Thus, shippers now need to have their own methods of handling supply emergencies. For supply problems that affect major percentages of their total supply or last for several days, gas storage is an obvious solution for shippers.

3. No-Notice Service

A relatively new service offered by gas pipelines that can provide shippers a substitute for having their own storage is no-notice service. If a shipper (that has contracted with a pipeline for no-notice service) experiences gas demand in excess of the pipeline transportation volume nominated for a day, the shipper can call on its pipeline to transport the deficit up to the maximum daily quantity of the no-notice contract. The pipeline has no obligation to provide the gas transported under no-notice service, however. The storage that the pipeline may need to supply this no-notice service can be a part of the operational storage capacity that FERC Order 636 allows interstate gas pipelines to retain.

4. Gas Marketer Operations

The unbundling of gas service by interstate gas pipelines, as required by FERC Order 636, combined with the desire of many past pipeline customers to retain a bundled supply and delivery service, has prompted gas marketers to offer this comprehensive service. To help balance their supply and delivery volumes and meet emergencies, many of the marketers have contracted for or purchased storage capacity.

5. Gas Producer Storage

Gas producers are using field area storage to help maintain a constant flow of gas from their wells and to back up their production in case of field equipment problems. Both conventional depleted reservoir and salt cavern storage are used for these purposes.

6. Gas Market Hubs

FERC Order 636 encourages the development of market centers or hubs at locations where several interconnected gas pipelines can facilitate physical gas trades among multiple sellers and buyers. The need for storage to balance these physical trades on a day-to-day basis has led to many hubs being located where storage is available or is being developed.

7. Price Hedging and Speculation

Because of the fairly regular seasonal cycles in gas prices and the more general price volatility that exists since gas prices were decontrolled, there are opportunities for those who have storage capacity to buy gas when prices are at the lower end of the seasonal swings. LDCs and marketers that have storage capacity try to take advantage of these opportunities to minimize their gas costs. The challenge in this practice is to find a combination of a lower gas price plus a storage cost that is lower than the higher price of gas in the season of higher demand. These hedging operations use conventional gas storage. Operators and users of high deliverability storage, which is several times as costly as conventional storage, can speculate on the rise and fall of gas prices -- cycling their capacity several times each year in some cases. The ability to cycle several times per year can offset the additional costs of high deliverability storage, if the speculator anticipates price swings accurately most of the time.

8. Injection/Withdrawal Patterns

An informative measure of average operations for gas storage facilities is their patterns of gas injections and withdrawals over a period of time. The DOE/EIA publishes monthly data on gas storage injections and withdrawals by states which show general patterns of gas flows in and out of storage.

In late 1993, the American Gas Association (AGA) began publishing weekly reports of estimates of the working gas in storage, regionally and nationally. These reports for the first time give weekly data on net storage injection and withdrawal volumes. Since the AGA data do not show separate volumes for injections and withdrawals, the total in and out movements are missed. This omission is most critical in locations such as California, where high deliverability reservoirs and the lack of a severe winter season allow substantial short-term cycling of storage all year.

AGA collects the statistical information on underground storage from more than 35 companies which account for about 85 percent of total working gas capacity. The report covers three regions (the producing area, the east consuming region, and the west consuming region) as well as national totals. AGA's regions are shown in Exhibit I-2. AGA calculates the percent of the total working gas remaining in storage for the reporting companies and extrapolates this percentage to all of the U.S. storage facilities. So far, there appears to be a reasonable correlation between these reports and those of the DOE/EIA. The DOE/EIA monthly data are reported from a larger sample of storage operators.

Exhibit I-3 provides a summary of AGA weekly working gas volumes in storage for the three AGA regions and the U.S. total. Although the working gas volumes did not bottom out and peak in exactly the same week during 1994, the regional patterns are very similar. Storage gas reaches a minimum volume in March or early April when withdrawals are ending and peaks in November before the winter season withdrawal begins.

EXHIBIT I-2
AGA Underground Gas Storage Regions

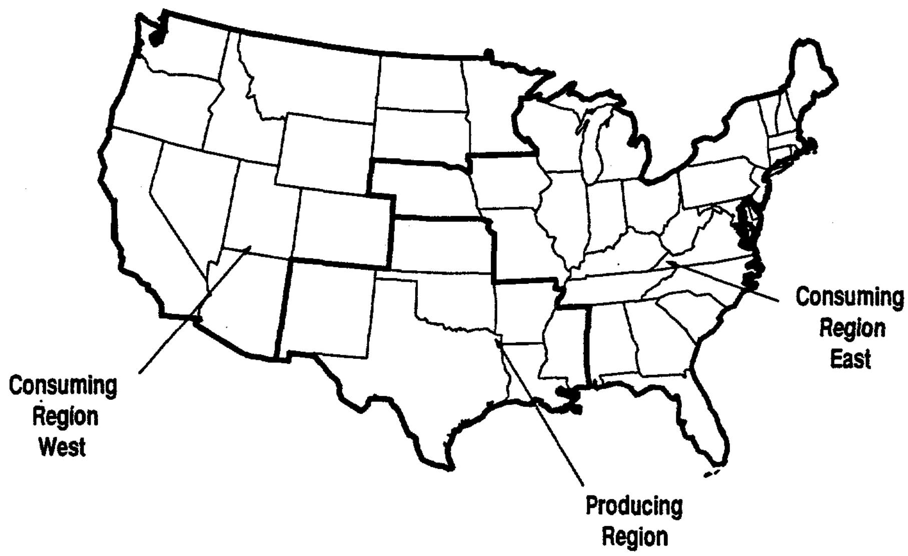
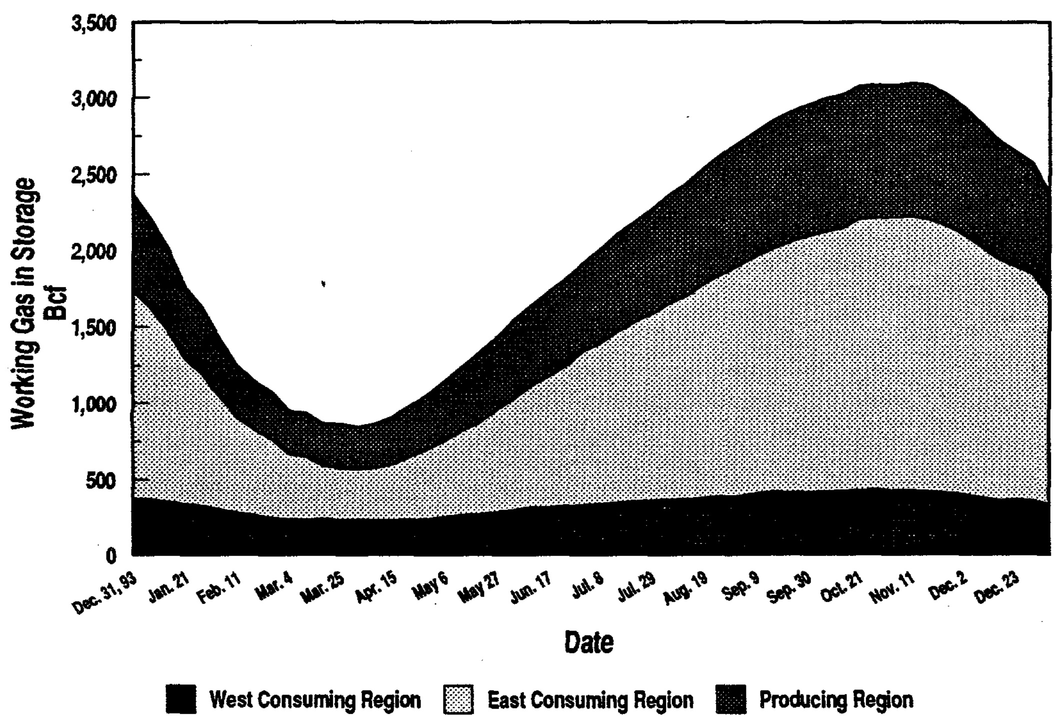


EXHIBIT I-3
Estimated Working Gas in Storage Over Time, 1994



Source: Pasha Publications, Gas Storage Report

D. Regulatory Issues

1. Regulatory Jurisdiction

Most storage facilities have to comply with both FERC and state regulations. In those cases where the stored gas is involved in interstate commerce, FERC certification of the project prior to its development and FERC approval of the tariff is mandatory. In these cases, state and local authority will be limited to such items as approval of the site, environmental controls, safety requirements, and public health considerations. In those cases where gas storage will not be involved in interstate commerce, the state and local authorities would have complete jurisdiction at the level they deem necessary.

2. Tariff Rates

Typical rates for gas storage will include both fixed and variable charges that are based on costs of constructing, operating, and maintaining the facility. The fixed monthly charges are normally applied to the total volume of gas storage space reserved and the delivery rate required for gas withdrawals. The variable charges are applied to the volumes of gas injected and withdrawn. Recently, the FERC has approved "market based" rates for a few storage facilities that are considered to be subject to sufficient competition from other storage facilities. Although tariff rates for storage are being discounted now by operators in areas where surplus capacity exists, the tariffs remain the best data source for existing storage service costs.

Regional gas storage tariff rates are currently being updated for the GSAM data base. Weighted averages of the storage rates for one or more storage operators in each region will be used by GSAM in making economic decisions on whether to use storage service or an alternative to meet gas demands.

3. FERC Order 636

In April 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636, "Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 184 of the Commission's Regulations". This order marked the culmination of the restructuring of the natural gas industry.

To summarize the impact of the order, FERC determined that the traditional role of pipelines as gas merchants, purchasing gas at the wellhead and selling it to LDCs at the city-gate, was a hindrance to the development of a competitive gas market. FERC intended to make comparable the transportation of gas sold by pipelines and non-pipelines while maintaining the reliability of service.

Within this initiative, FERC unbundled storage from the sales and transportation functions of the pipeline. Pipelines with downstream storage could keep it "only to fulfill their obligations with respect to system storage management (load balancing) and 'no-notice' transportation." The rule intended for access to facilities be on an "even, nondiscriminatory basis among all shippers." DOE/EIA has estimated that 80 to 90 percent of interstate working gas capacity will become available to previous pipeline customers under Order 636.[4)]

4) EIA. "The Expanding Role of Underground Storage", Natural Gas Monthly, October 1993.

In addition, the FERC encouraged the development of market centers as meeting places for gas purchasers and sellers. As a consequence, pipeline storage took on a new role within the industry. Without storage, the seller needs to find a buyer to receive his supply or else there is no sale. Storage allows market centers to provide intertemporal transportation between buyers and sellers. Some storage was transferred or leased to LDCs, some was leased to end-users who wished to insure an uninterruptible gas supply, and some was purchased by brokers, marketers or others with the intention to capitalize on the changes in market prices.

Under Order 636, pipelines were allowed significant latitude in penalizing shippers whose accounts were out of balance. In many cases, shippers experiencing fluctuating demand can use short-term storage to maintain balance, and thus avoid penalty.

Order 636 also raised the cost of pipeline transportation for consumers and resellers that do not have a steady demand for gas by mandating the straight fixed-variable (SFV) rate design. SFV shifts essentially all the fixed costs of gas transmission to the monthly demand charge for the pipeline capacity reserved. Now the only significant variable cost of transmission service is the compressor fuel used by the pipeline. This cost is typically a small fraction of the total transmission cost. Since the demand charge must be paid every month, regardless of the gas volume transported, shippers with low load factors (with wide variations in gas use) now pay more for gas delivery than when part of the fixed costs were included in the changes for gas actually delivered. This change to SFV rates for pipeline capacity has increased the economic attractiveness of storage use for some shippers — compared to paying the higher demand charges of pipelines. Thus, some shippers have increased their storage capacity to offset reductions in pipeline capacity reservations.

E. Organization of the Report

Following this introductory section, the report next presents forecasts of end-use requirements for gas by regions and consuming sectors. This is followed by descriptions of the existing and planned new storage facilities in each state by their capacities, reservoir types, and ownership. Estimated costs for the new facilities are provided where this information has been made public. Next, descriptions of the seasonal and peak shaving alternatives to underground storage are provided. This is followed with discussion of the economics of gas storage and its alternatives and a description of the methodology designed for preliminary determinations of the economic need for regional storage. Finally, preliminary observations are provided on where additional storage may be needed, based on forecast gas requirements by consuming sectors.

II. Natural Gas Demand Forecasts

A. Introduction

The regional demand for gas storage in coming years will be a function of seasonal gas demand patterns, the costs and operating characteristics of gas storage, and the costs of alternatives to gas storage.

The purpose of this chapter is to develop initial forecasts of regional gas demand by sector, characterizing the seasonal patterns of this demand. These preliminary forecasts are used in determining regions where and how much additional storage may be needed in the future, and for comparisons with later GSAM forecasts during model calibration exercises.

The process of developing these initial forecasts involves review of three public sources for gas demand forecasts and selection of one as best for this use. The annual demand forecasts from the selected source were then converted to monthly forecasts by applying the monthly gas consumption patterns reported by the DOE/EIA. Forecasts are detailed by four consuming sectors and 12 consuming regions. The detailed forecasts are presented in Appendices A, B, C, and D of this report.

B. Publicly Available Forecasts

1. Description of Forecasts

There are three principal, public sources for gas demand forecasts. Each year, the U.S. Department of Energy's Energy Information Administration (DOE/EIA) issues an *Annual Energy Outlook* (AEO) which forecasts developments in the U.S. energy sector. Because the AEO develops forecasts of the entire energy sector, nuances of specific sectors may be omitted or minimized.

The American Gas Association (AGA) also issues annual gas supply and demand forecasts. The AGA is a trade association whose membership consists primarily of local distribution companies and pipelines. AGA's mission is to promote the expanding use of natural gas. Because of a perceived bias, the AGA forecast is often considered less credible than others, despite the fact that it may not have the lowest prices and highest demands.

The Gas Research Institute developed its annual *Baseline Gas Projection* as part of its effort to measure the needs and benefits of GRI-sponsored research. The baseline projection is meant to represent what the world would look like without GRI intervention in technology development. As such, it may tend to understate the affect of new technologies on the gas market. Because the GRI forecast tends to have the greatest acceptance in the gas industry and because regional detail is available from GRI, we used the 1995 GRI forecast as the baseline for this analysis.

The three forecasts described here[1] are generally in agreement in regards to forecasted trends in gas demand among end-use sectors, with any differences being matters of degree. There are certain assumptions that lie at the heart of each forecast, and ultimately the differences between the forecasts are the result of minor variations of those assumptions.

Among the major assumptions driving recent issues of the three forecasts (all published in 1995) are lower crude oil prices than previously forecast. These range from a crude oil price forecast that is essentially flat in real terms (GRI), to forecasts of a small but rising oil price (DOE/EIA and AGA). In every case the crude oil price forecast is substantially lower than that of previous years. Other energy prices, including gas prices, are expected to come down to remain competitive.

A second major assumption concerns the future development and use of improved gas technologies. End use technologies are expected to enter the market at a rate that will encourage additional gas use, due to increased efficiencies and environmental mandates. At the same time, supply technologies are expected to make gas production economical enough to meet gas demand at competitive prices. A substantial amount of this increased production is expected to come from sources such as tight formations, coal seams, and deep water in the Gulf of Mexico — parts of which are economically infeasible under current technologies.

A third assumption common to all three forecasts is that primary energy consumption will continue to grow, despite moves toward conservation. This growth is expected to increase demand for gas, oil, and other energy sources.

The residential and commercial sectors are dominated by the theory that increased use of newer gas technologies and increased heating conversions to gas will be mitigated by improved appliance and equipment efficiencies, resulting in only a slight demand growth. One interesting difference among the forecasts is that GRI and AGA predict increasing penetration of the space cooling market by gas technologies, while DOE/EIA sees gas remaining primarily in space heating and water heating.

Industrial and electric generation consumption are expected to be the primary growth sectors for natural gas. Historical trends toward increased gas use in the industrial sector, due in part to oil's replacement by gas as the primary boiler fuel, are expected to continue. New end use technologies are also expected to spur demand growth in the industrial sector. All three forecasts expect that roughly 60% of all new electric generation capacity will be gas-fired. Expectations as to the type of that capacity vary; GRI sees it coming predominantly from combined-cycle generators, while DOE/EIA has much of that capacity in the form of combustion turbine generation. There is also some difference in the manner that the forecasts apply the expected increase in cogeneration projects. The DOE/EIA and AGA include this in the industrial sector demand, while GRI forecasts separate gas demands for cogenerated electricity and cogenerated thermal energy.

None of these forecasts provides seasonal detail for the natural gas market. Seasonal detail is a critical element in determining demand for storage (primarily depleted reservoir and aquifer storage) over the long term. Moreover, seasonal detail is critical in understanding how demand for gas in the electric generation sector will be served and whether storage will be needed to serve that market.

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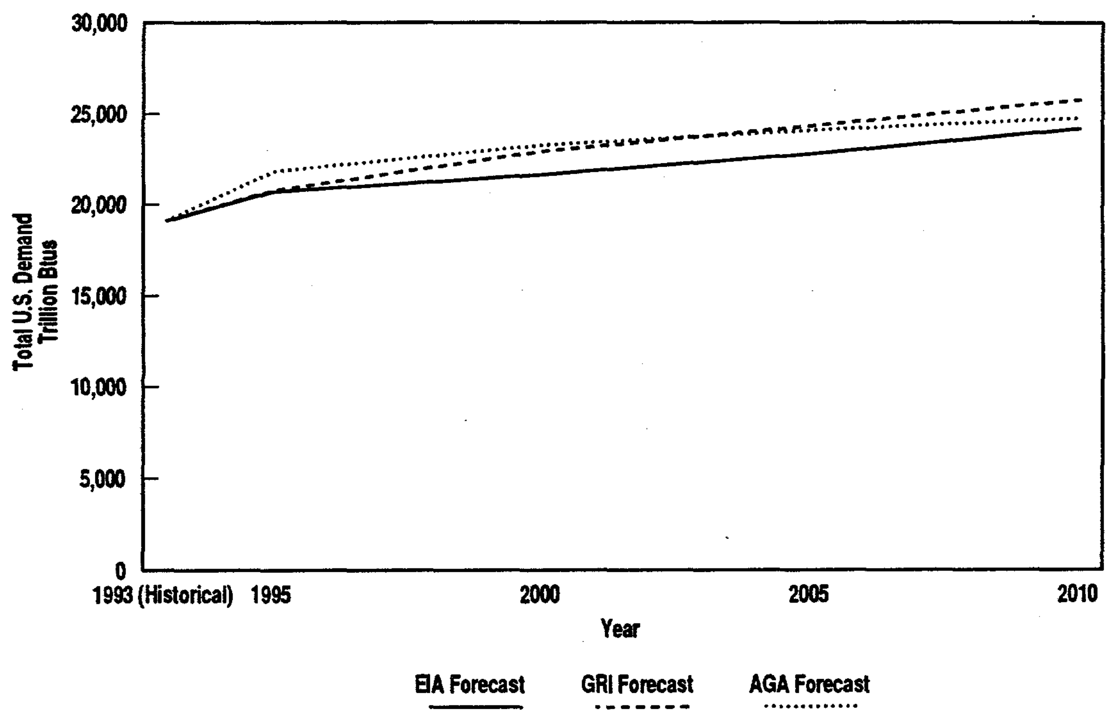
1) GRI, "Baseline Projection Data Book," 1995 Edition. DOE/EIA, "Annual Energy Outlook," 1995. AGA, "The Gas Energy Supply and Demand Outlook, 1995-2010," 2/95.

An initial estimate of seasonal demand has been forecast by using DOE/EIA, "Natural Gas Monthly," historical consumption factors for each sector by region and applying these monthly factors to the GRI forecasts of consumption by sector to create forecasted regional load shapes. Forecast demands using GSAM will recognize two seasons--a 151-day winter and 214-day summer.

2. Comparison of Gas Market Forecasts

Exhibit II-1 compares the three gas demand forecasts through the year 2010. DOE/EIA's forecast is the least aggressive regarding growth with a 1.4 percent annual growth rate. GRI and AGA both forecast a greater rate of growth, at 1.8 and 1.6 percent, respectively. In all three cases, the most rapid growth rate occurs before the year 2000. Despite some differences, the forecasts do not differ dramatically. At their greatest differential in the year 2003, the AGA and GRI forecasts for gas demand are only 6.4 percent greater than the DOE/EIA forecast.

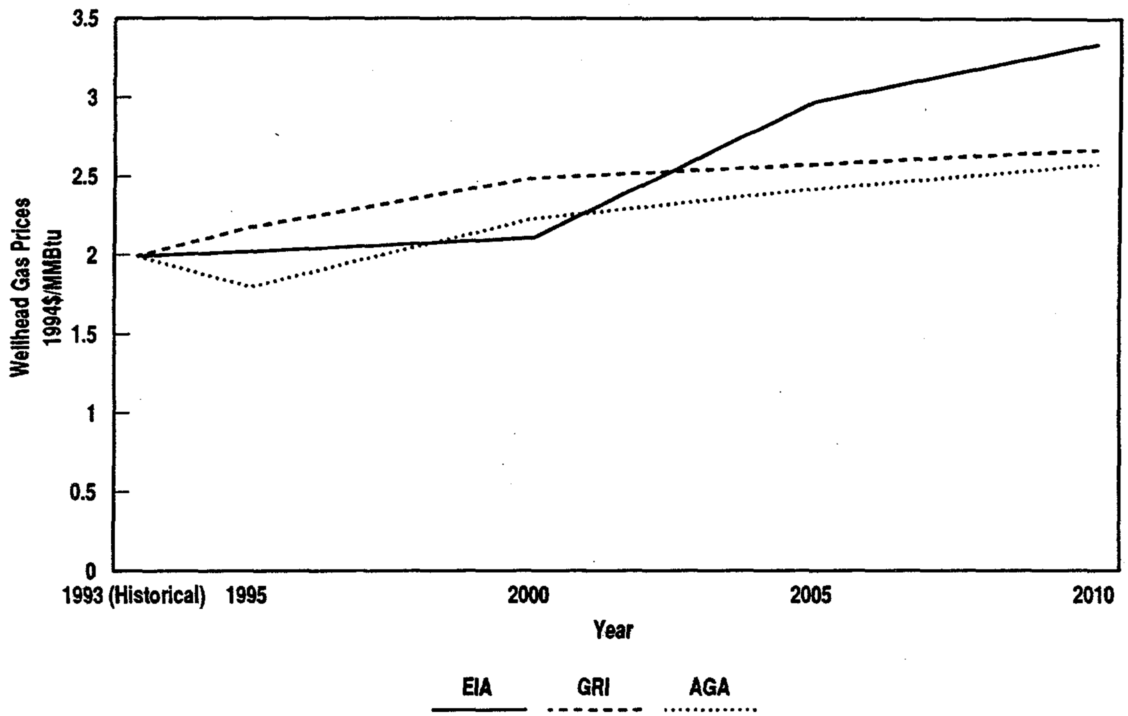
EXHIBIT II-1
Comparison of Gas Market Forecasts
Total U.S. Demand, 1993 - 2010



Note: All forecasts were published in 1995.

One major reason for the decline in the rate of gas demand growth consistent in all forecasts after 2000 is the forecast of an increasing real price of gas (Exhibit II-2). All three price forecasts expect significant price increases by 2010; 2 percent per year in the GRI forecast, 3.7 percent per year in AGA and 5.1 percent per year in DOE/EIA. Gas prices are expected to rise as a result of diminishing deliverability from existing reserves and the need to exploit increasingly costly sources of supply. Another major affect on gas demand is the assumptions made regarding the prices of other fuels, since gas competes with fuel oil and coal in the industrial and power generation sectors.

EXHIBIT II-2
Comparison of Forecasts of Gas Wellhead Price

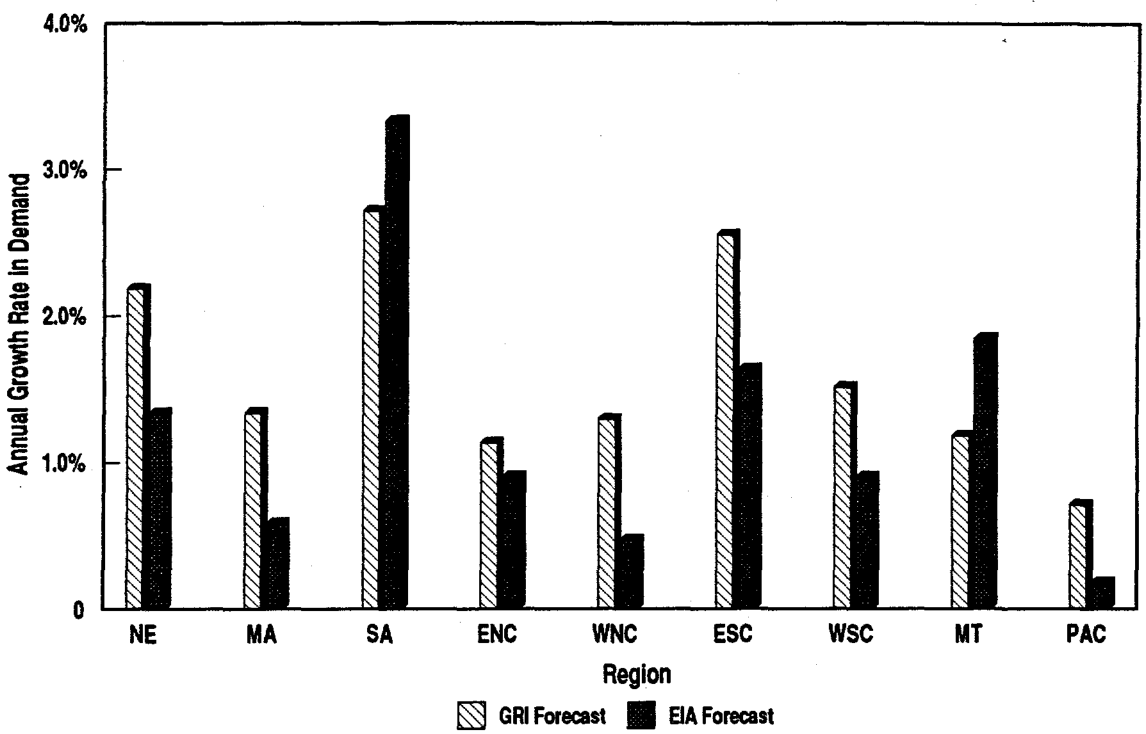


Note: All forecasts were published in 1995.

GRI and DOE/EIA provide forecasted regional detail in demand growth (Exhibit II-3). The greatest growth is expected by both forecasts to be in the South Atlantic region, at near three percent per year. GRI forecasts the East South Central and New England regions to be next in growth rates, at between two and three percent per year. DOE/EIA forecasts the Mountain States, East South Central, and New England regions growth rates lag behind South Atlantic growth, at less than two percent per year.

In all three forecasts, the expected demand growth comes largely from the electric generation sector. Industrial demand is also expected to increase. Residential and commercial demand are forecast to remain relatively constant. The following discussion reviews each of the four sectors.

EXHIBIT II-3
Regional Demand Growth Rates
GRI and EIA Forecasts for 1993 - 2010



Note: MT and PAC represent combined sub-regions in the GRI forecast.

C. Electric Generation Sector

A number of factors will determine how much gas is needed in the electric generation sector. The most significant of these are:

(1) Electricity demand
(2) Fuel prices
(3) Capital costs of generation technology
(4) Environmental policy

1. Electricity Demand

The growth in electric generation sector demand for gas is heavily dependent on overall growth in electricity demand. In the current generation stock, gas fired generation is usually a high-cost option that is used only after lower variable cost options (e.g., hydro, nuclear and coal) are exhausted. Gas generation options are often the marginal power supply. Where growing demand shifts the marginal generation supply to higher cost options, gas-fired facilities will run more often.

In the newly competitive world of electricity generation, however, increasing the use of existing facilities will be more desirable than building new ones. Electricity trades among utilities will become more frequent. While this will mean increased use of existing gas-fired plants, it will also reduce the demand for new plants that might have used gas. The resulting changes in gas demand for power generation are, therefore, not obvious and will likely vary among regions.

2. Fuel Prices

Gas must compete with other fuels in many electric generation applications. Most existing fossil fuel plants that use gas can also use residual fuel oil (resid). Although (qualitatively) gas enjoys some advantages over resid (e.g., lower emissions, easier to handle), gas must still be priced competitively to capture this market. On the other hand, many new gas-fired plants use highly-efficient, combined cycle generation technology. Because combined cycle plants require cleaner fuels than boilers, gas competes with distillate fuel oil in this market. Another factor in fuel choice is that the higher efficiency of combined cycle plants, relative to other fossil fueled plants, can make gas the economic fuel choice even when gas is somewhat more costly than resid on a Btu purchased basis.

3. Capital Costs of Generation Technologies

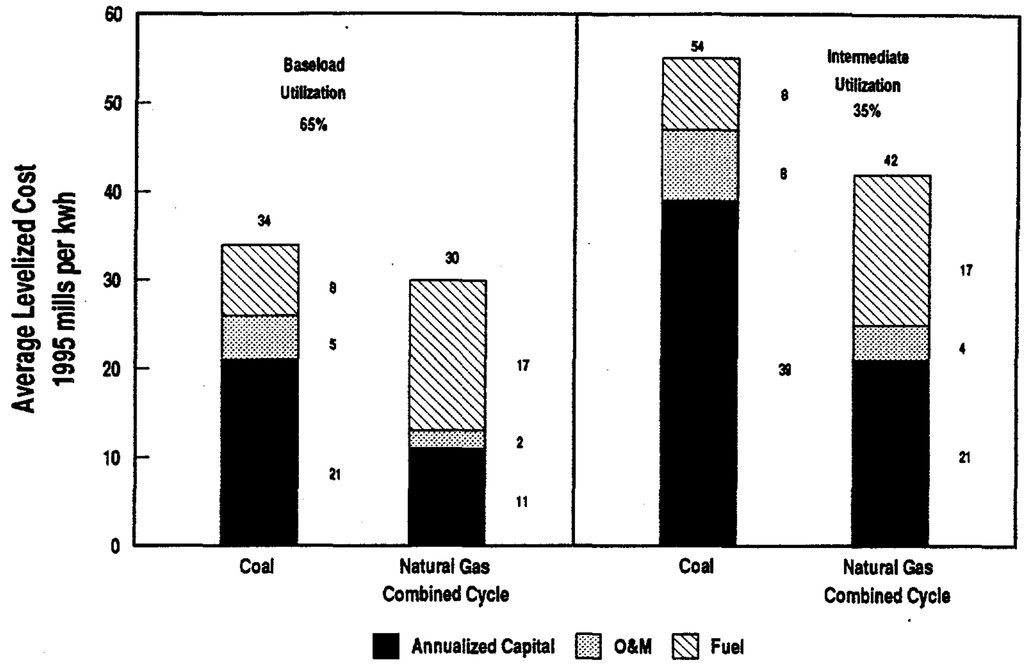
Combustion turbines that burn gas or fuel oil tend to be relatively inefficient, yet inexpensive to build. These facilities are often used to meet electricity peaking needs. Combined cycle generating plants, on the other hand, are more efficient than other fossil fueled plants and, although more costly than simple combustion turbine plants, they are still considerably less expensive than coal plants. Because of their higher efficiency and lower capital costs, combined cycle gas-fired plants have become more competitive with coal for baseload and intermediate uses in terms of capital costs. While gas generally has a higher variable cost than coal, gas-fired facilities tend to be competitive with coal when the full cost of generation is considered. Exhibit II-4 shows the relative capital costs associated with the two types of plants. Gas plants can also be smaller, requiring easier adaptation to the incremental capacity needs of a utility. As a result, when new, high utilization generation is considered on a full cost basis, gas plants may be considered the most cost effective option. However, clean coal technologies and increased gas costs after the turn of the century could change the relative economics of coal and gas for baseload and intermediate uses.

4. Environmental Issues

Gas burns cleaner than coal or oil. Gas consumption produces no SO_2, the leading cause of acid rain. Several utilities will help meet their atmospheric emissions allowables under the Clean Air Act Amendments of 1990 by increasing their use of gas. Clean coal technologies available in the next decade may reduce the environmental incentives to switch to gas, however.

Gas can also be used to reduce greenhouse gas emissions. Gas produces half the CO_2 of coal and two-thirds that of oil when burned. However, if natural gas is emitted to the atmosphere, it constitutes a much greater potential greenhouse gas threat than comparable amounts of CO_2. Therefore, the incentive is not only to burn more gas but also to develop ways to make better use of the gas that is currently emitted to the atmosphere, such as coal mine methane and landfill gas.

EXHIBIT II-4
Relative Capital Costs for Coal vs. Natural Gas



Source: ICF Kaiser, "ICF Energy Service 1995-A"

5. Regional Distribution of Gas Demand for Power Generation

Increasing demand for gas for electricity generation will vary regionally. Because the availability of underground storage is somewhat region-specific, the applicability of storage advances to improved gas marketability will also be a function of whether the geology and pipeline access available to a consuming region provides storage opportunities consistent with growing demand. According to the 1995 GRI baseline forecast, the bulk of electric generation demand growth for gas will occur in the South Atlantic, East North Central, and West South Central regions (Exhibit II-5).

Exhibit II-6 shows how gas/oil demand for power generation is forecast by GRI to be split between utility and non-utility generators by region.

6. Electric Generation and Gas Storage

The characteristics of demand for gas and gas storage in the power generation sector will also depend on the type of power plants built and how they will be used. Combined cycle power plants can be used as baseload or intermediate capacity. If they are used as baseload facilities, they will likely use firm pipeline capacity to meet a relatively constant daily demand and will not need much storage. If they are used as intermediate load, they may turn on and off, perhaps for the weekend or parts of every day. The operators of the plant may need intra-daily flexibility in their gas takes to meet electricity demand surges and declines. High deliverability storage combined with firm pipeline capacity may be the most cost effective way to meet those demand characteristics.

EXHIBIT II-5
Forecasts of Electrical Generation Gas Demand by Region

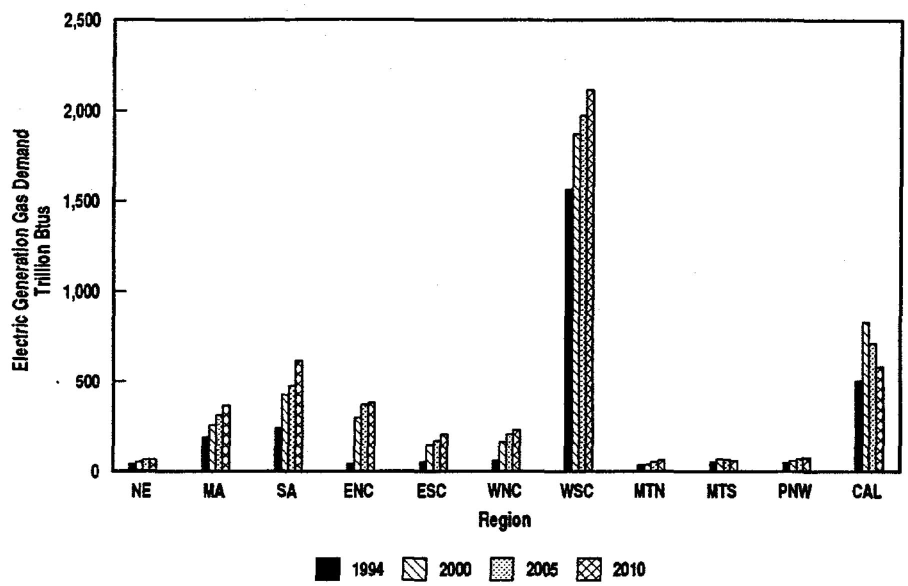
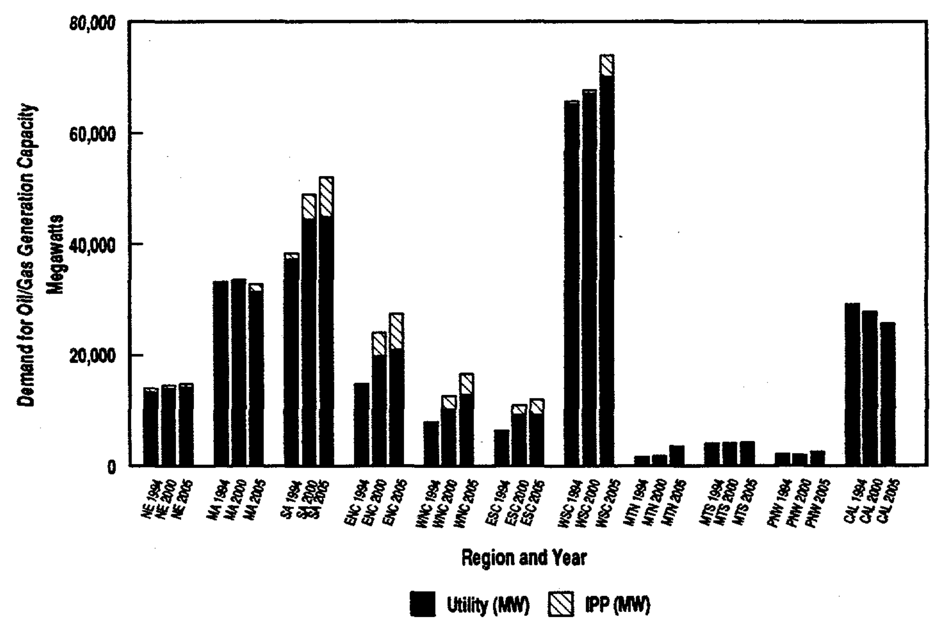


EXHIBIT II-6
Forecasts of Demand for Oil/Gas Generation Capacity by Region



Gas fired peaking units are likely to continue to use gas when it is available, either through interruptible or released firm transportation. These plants will continue to have dual fuel capabilities. Exhibit II-7 provides the GRI forecasted U.S. gas-fired generation capacity by capacity type. Combined cycle generation is growing at the fastest rate, implying that increased gas demand will occur for base load and intermediate and peak electricity demand. Some increase in gas turbine capacity indicates more use of gas for peaking units. The use of gas-fired steam units is forecast to remain predominant, but decline over time.

EXHIBIT II-7
Forecasts of Total U.S. Gas-Fired Generating Capacity By Type and Year

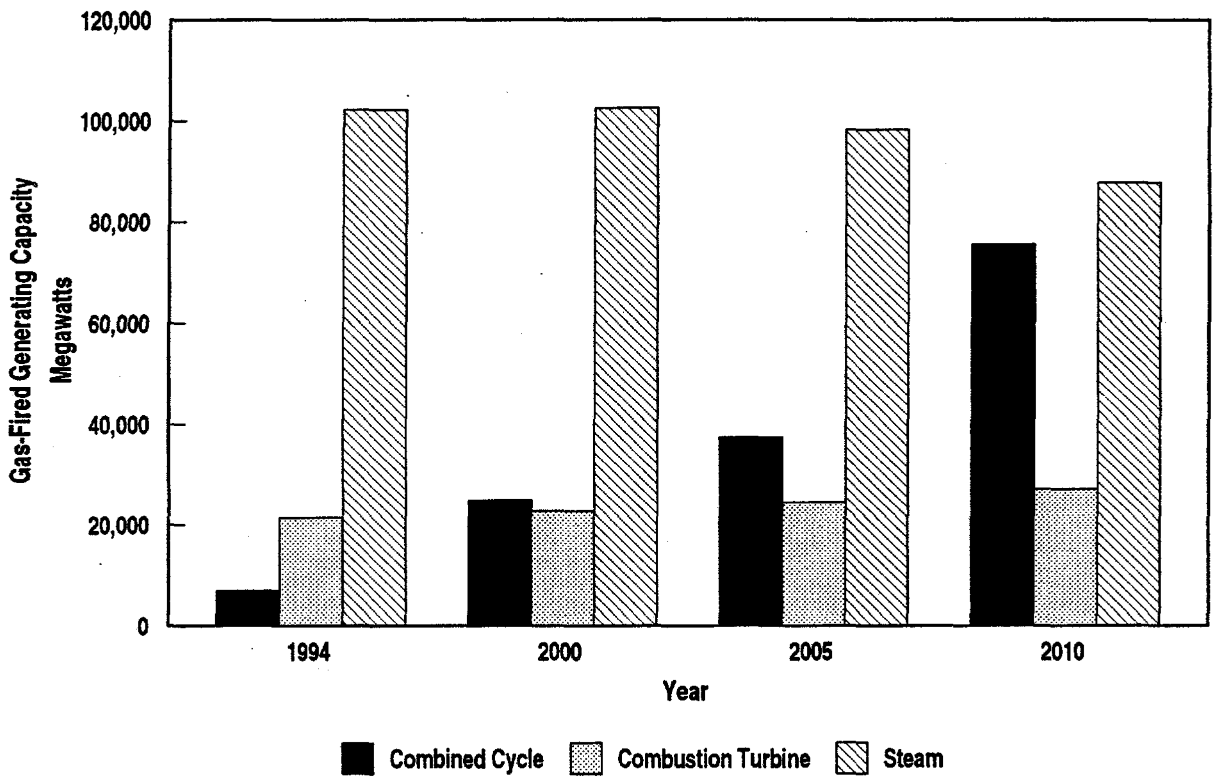
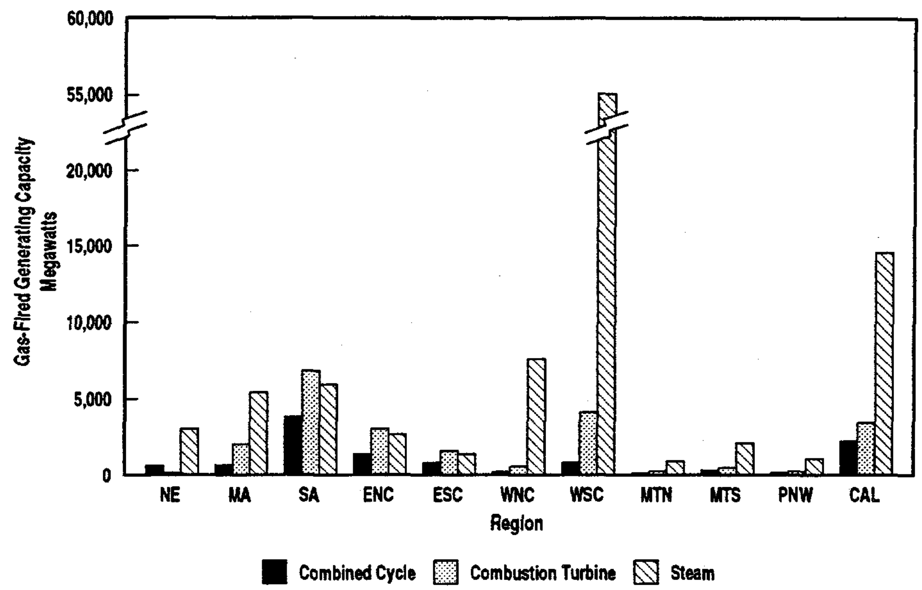


Exhibit II-8 provides a regional breakdown of existing gas-fired generating capacity by type of unit, demonstrating the current predominance of steam generating capacity. This is especially true of the West South Central region, due to that region's historically inexpensive and readily available gas supply. More important for the purposes of this project are the expected additions to capacity. In those regions that expect the greatest increase in gas-fired capacity, the predominant type of unit providing that capacity is a combined cycle generator (Exhibit II-9). The South Atlantic (SA) region has the largest absolute growth in capacity, and is growing at an annual rate of 7 percent. Next in absolute growth are the East

North Central (ENC) and West South Central (WSC) regions, at about 11,000 megawatts each. Annual growth rates for these two regions are 9 percent for the ENC and 1 percent for the WSC.

EXHIBIT II-8
Existing Gas-Fired Generating Capacity By Type and Region (1994)

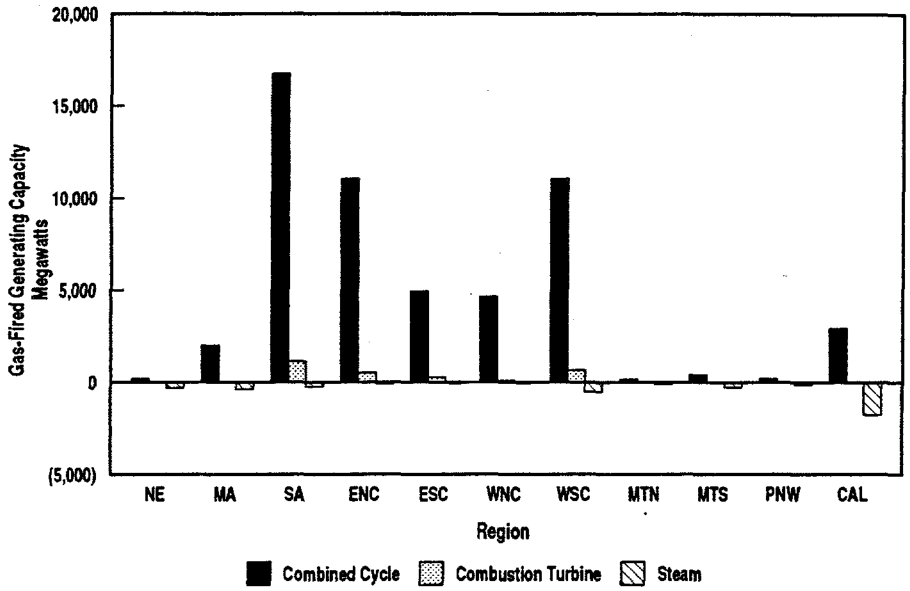


To obtain preliminary insights on where additional gas storage might be required, monthly gas demand forecasts have been developed for each of the four consuming sectors in each of the 12 market regions. These forecasts are presented in Appendices A, B, C, and D. Appendix A provides the monthly forecasts for the electric power generation sector. The monthly forecasts have been developed by applying DOE/EIA, "Natural Gas Monthly" demand patterns during 1993 and 1994 to the annual gas demand forecasts of GRI.

Review of the charts in Appendix A indicates that the highest electric generation demands will continue to occur in summer months when demands of the other three sectors are relatively low and gas supply and transportation costs are low. Thus, conventional seasonal storage will not be needed for the power generation sector. The only exception to this pattern is in the Pacific Northwest region which has peaks in gas use in both the summer and winter.

Because of the rapid changes in fuel demands experienced in the power generation sector (on both intra- and inter-day bases), high deliverability salt cavern storage is expected to be more suitable for this sector in cases where plants cannot use an alternate fuel.

EXHIBIT II-9
Forecast Changes in Gas-Fired Generating Capacity
By Type and Region, 1994 - 2005



D. Industrial Demand

Industrial demand is generally split into three categories: boiler fuel, process use, and non-process use. Boiler and non-process uses of gas are usually switchable to some type of fuel oil, usually a low sulfur resid, but such switching is subject to environmental constraints. Process gas uses, such as for feedstock for fertilizer or for clean product drying methods, are not readily switchable. As shown in Exhibit II-10, slightly less than half of all industrial gas use falls into the non-switchable process use category.

1. Industrial Demand For Gas

The two principal reasons for using storage are to meet short-term variations in demand and to more efficiently serve seasonal demand fluctuations. The traditional model for industrial demand places a premium on neither. Industrial demand for energy is generally characterized as relatively constant over the year (Exhibit II-11). The seasonal requirements for industrial gas use (i.e., space heating) are generally overwhelmed by day-to-day energy intensive operations that characterize many industrial applications. Exceptions may exist to the extent that industrial operations follow some exogenous seasonal schedule (e.g., industrial operations associated with processing agricultural products). Monthly load shapes for industrial gas demand are provided in Appendix B.

EXHIBIT II-10
U.S. Industrial Natural Gas Consumption by End Use, 1991

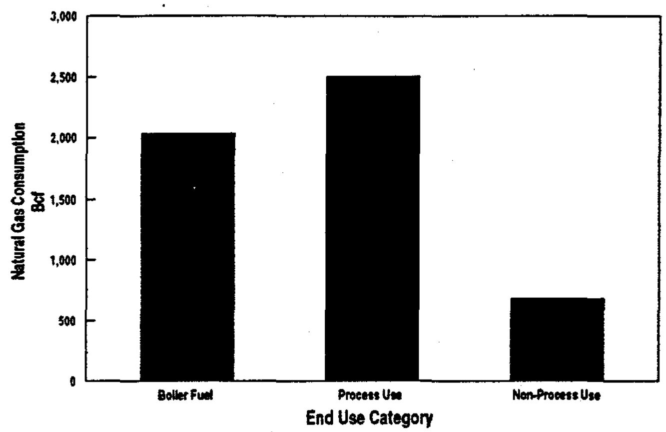
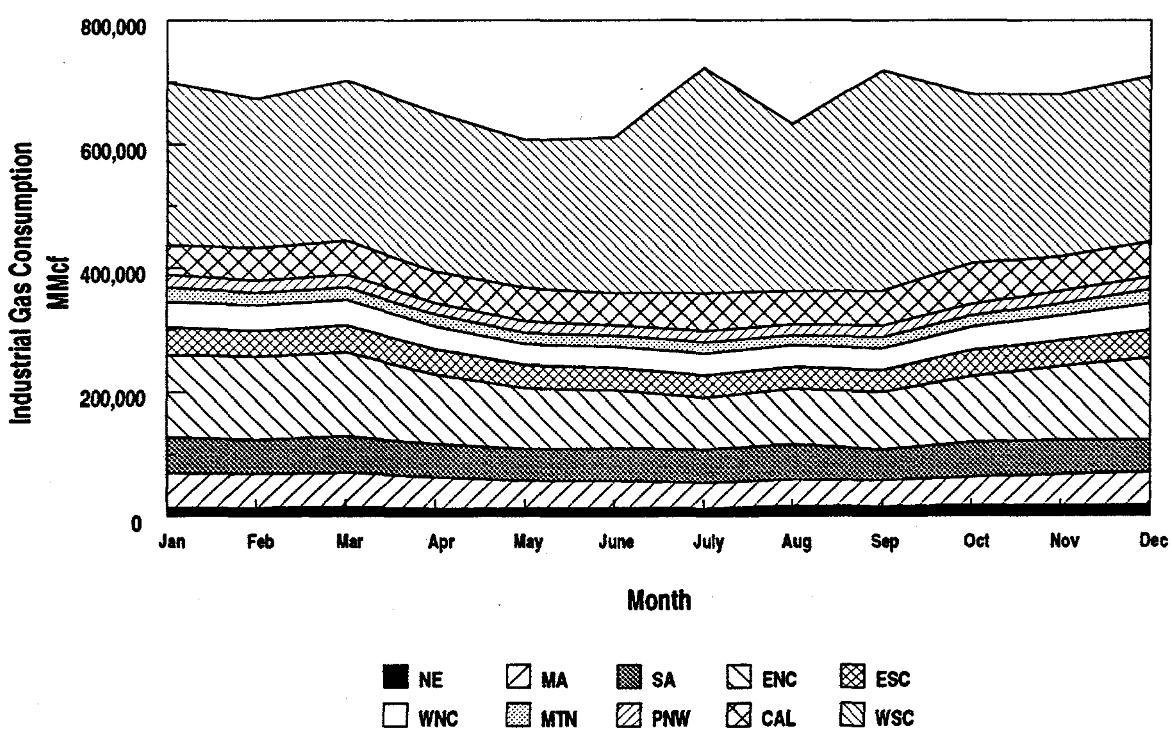


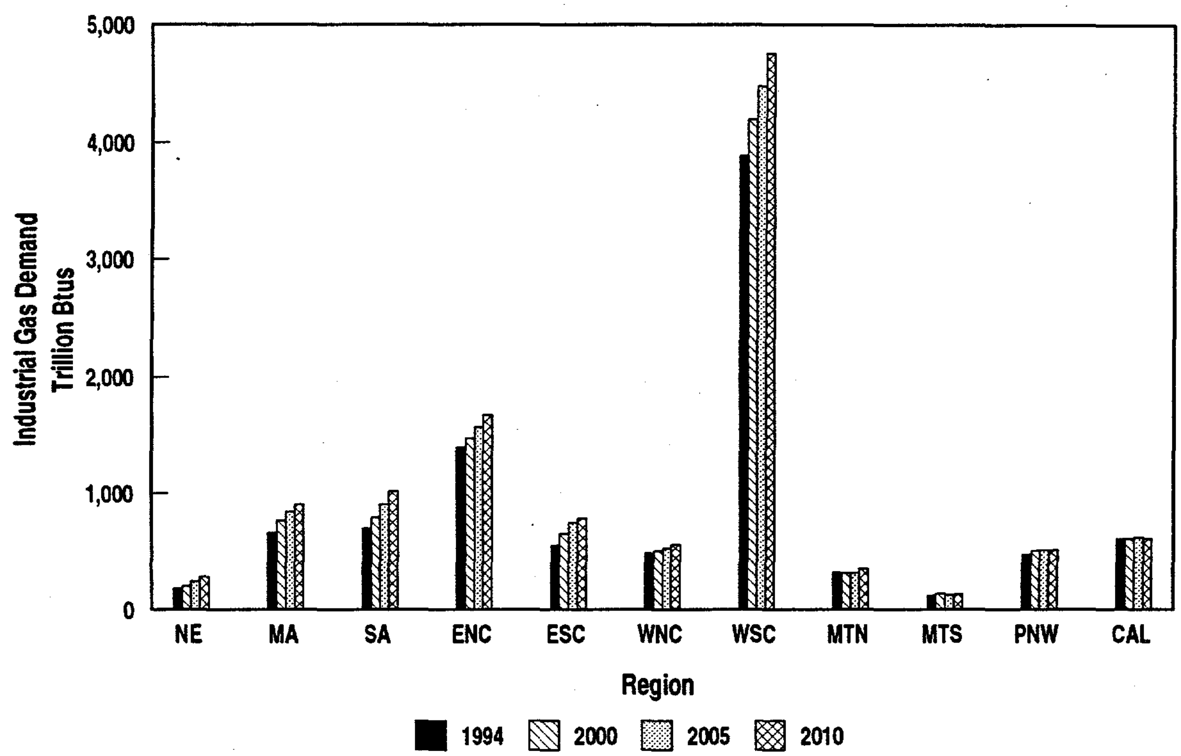
EXHIBIT II-11
Industrial Demand for Gas by Region, 1995



Demand in Florida and Mountain South is too small to appear on this graph.

Exhibit II-12 shows the GRI regional forecasts for total industrial gas demand. In absolute terms, the West South Central region continues to be the major growth area for industrial demand, while the Mid-Atlantic, South Atlantic, East North Central, and East South Central are expected to have substantial percentage increases. Except for the West South Central region, the western states are forecast to have very little growth in industrial gas use between 1994 and 2010.

EXHIBIT II-12
Forecasts of Industrial Gas Demand by Region



2. Industrial Demand for Storage

Large future demands for additional storage for the industrial sector seems unlikely for two reasons. First, industrial energy consumption is relatively constant during the year. Where demand is near constant, pipeline capacity is cheaper than storage. (The effects of fixed and variable costs on the economics of gas pipelines are explained more fully in Chapter VI.) Second, a significant part of industrial gas demand is from plants that can use an alternate fuel--typically a fuel oil. Frequently, heavy fuel oils are cheaper than gas in winter, making gas storage an unnecessary added cost. The ability to switch fuels also allows many industrial consumer to buy gas on the spot market and use interruptible transportation services--further saving costs.

Review of the charts in Appendix B shows that there is some seasonality in the industrial gas demands of the more northern consuming regions. This is most noticeable in the East North Central region where the winter industrial demand is expected to be about 60 percent higher than summer demand. This industrial demand seasonability along with the much greater commercial and residential seasonality in the East North Central and the availability of both depleted reservoir and aquifer storage sites have caused the development of the huge storage capacities in this region.

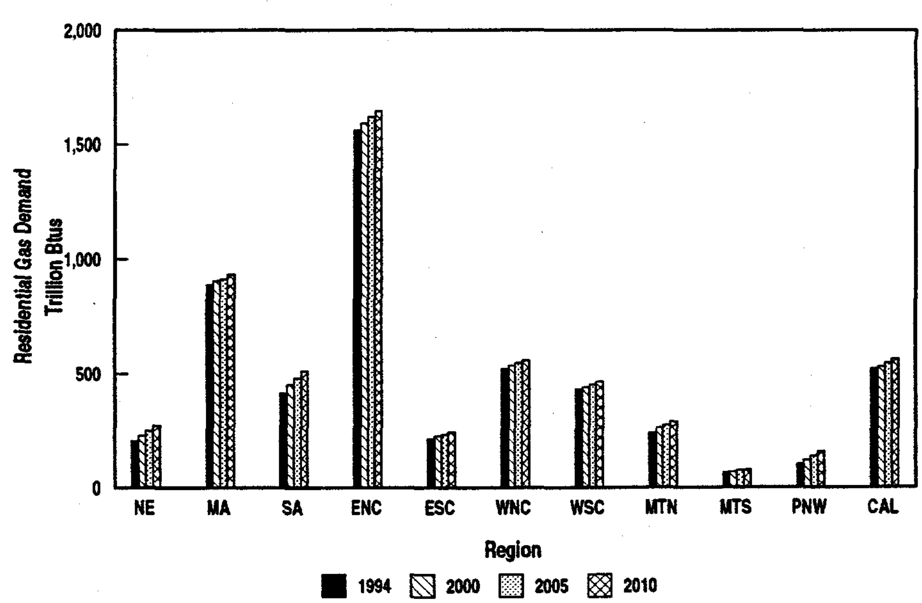
E. Residential Demand

1. Residential Demand for Gas

Residential demand for gas is expected to increase slightly in the future. Because decisions associated with gas use in homes constitute significant investments in technologies dedicated to a single energy source (e.g., electric heat pump versus gas furnace) underlying trends in unit installation usually rely on long-term expectations for energy costs as well as the relative costs of the technologies.

Generally, increases in the number of households using gas are expected to offset gains in the efficiency of gas appliances to hold demand relatively steady. Differences in population growth and market penetration may create regional variations in demand growth (Exhibit II-13). For example, in New England, where oil heats a relatively high percentage of the existing residential stock, residential gas demand will grow as a greater percentage of homes connect to gas.

EXHIBIT II-13
Forecasts of Residential Gas Demand by Region



2. Residential Demand for Storage

The character of residential demand tends to match well with the injection/withdrawal characteristics of traditional reservoir storage. Seasonality of demand in the residential sector has been the single greatest reason for creating underground gas storage capacity. Appendix C contains forecasts of monthly regional gas demand for the residential sector, based on the GRI forecast.

Review of Appendix C (and Appendix D for commercial demand) shows the great differences in forecast summer and winter gas demands in the residential sector. By way of comparison, the East North Central region residential gas demand is expected to rise by 730 percent from summer to winter while the industrial demand rises by 60 percent, as described earlier. In the more southerly regions, the differences in summer and winter demands are somewhat less dramatic.

Increases in residential demand tend to decrease the load factor for capacity utilization as each new customer adds more demand at the peak than at the off-peak period. LDCs may be able to meet this changing profile of demand through more storage capacity and/or more extensive and efficient use of existing storage capacity, instead of by purchasing additional pipeline capacity. Technologies that increase the capacity or decrease the cost of conventional reservoir use are expected to be helpful in regions with growing residential markets.

F. Commercial Demand

1. Commercial Demand For Gas

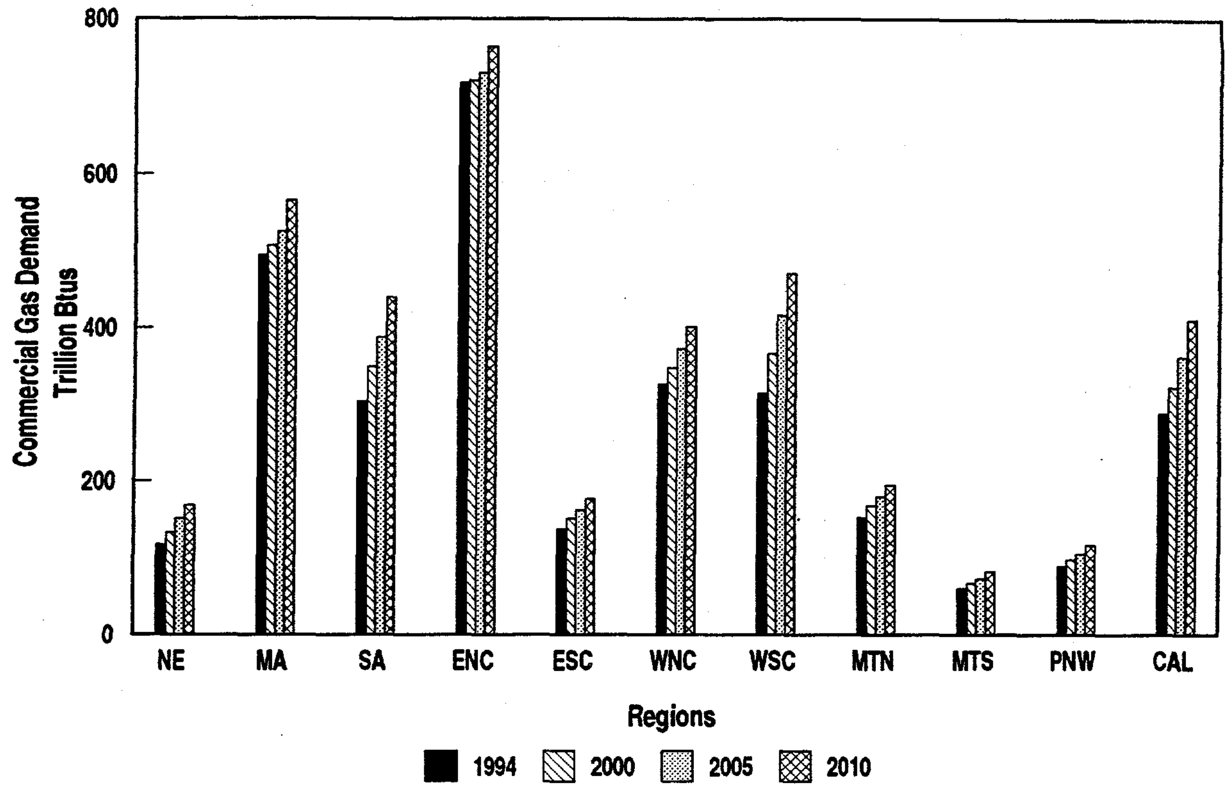
The commercial sector consists of establishments or agencies engaged primarily in the sale of goods or services. Exhibit II-14 provides GRI's forecast of regional demand through 2010. Commercial demand is generally driven by population and economic growth. New business developments are expected to expand the commercial sector over the forecast period, and new, more efficient gas technologies are expected to expand the role of gas in the commercial sector. However, improved efficiencies will keep actual gas demand growth relatively low. Also, there is some uncertainty about the likelihood of gas expanding from its traditional commercial markets of space heating and water heating to penetrate the space cooling market as well. Failure to make significant headway in the space cooling market could cause an even slower growth in demand than otherwise predicted. Commercial sector demand is generally considered similar to, albeit somewhat less peaky than, residential demand. Appendix D provides monthly estimates of regional gas demand.

Using the East North Central region as an example again, the increase in commercial gas demand from summer to winter is forecast to be about 520 percent. This is less seasonality than in the residential sector, but still much higher than the industrial sector in this region.

2. Commercial Demand for Storage

Storage that serves the commercial sector will likely resemble the kind of storage used for residential customers. As with residential demand for gas, more storage capacity or more efficient use of existing capacity would appear to be a more economical way to meet greater peak demand than using additional pipeline capacity.

EXHIBIT II-14
Forecasts of Commercial Gas Demand by Region



G. Summary — Need for Storage

After examining the GRI, EIA, and AGA forecasts of gas demand, the GRI forecast was chosen to represent the preliminary baseline for this project. Exhibit II-15 provides a summary of the GRI demand projections. The higher growth rates for total demand in all consuming sectors, at between two and three percent per year, are anticipated in the South Atlantic, East South Central, and New England regions. Among the various consuming sectors, demand in the industrial and power generation sectors are expected to grow the fastest, increasing by nearly two trillion cubic feet each between 1994 and 2010. Starting from a lower base, the rise in electric demand averages 3.3 percent per year while the industrial demand annual growth rate is 1.3 percent. Total residential demand is expected to grow by about half a trillion cubic feet between 1994 and 2010 with commercial sector demand growing by three-fourths of a trillion cubic feet over the same time period.

EXHIBIT II-15
Forecast of Total U.S. Gas Demand by Sectors
(Billion Cubic Feet per Year)

Year	Residential	Commercial	Industrial	Electric Generation	Total
1994	5,161	3,006	9,344	2,839	20,350
2000	5,350	3,231	10,109	4,233	22,923
2005	5,519	3,466	10,849	4,492	24,326
2010	5,703	3,790	11,549	4,777	25,819
Source: GRI Baseline Projection Data Book, 1995					

Differing from the other consuming sectors, the relatively constant seasonal gas demand of the industrial sector requires little storage. Residential and commercial loads, which are forecast to grow more slowly, provide the major demand for seasonal storage while the rapid cycling of power plants demands high deliverability storage which can be cycled several times each year.

Review of the charts in Appendices A, B, C, and D provides some preliminary insights on where additional gas storage may be needed in the future. Substantial projected growth in short-term summer gas use by the electric generation sector in the Middle Atlantic, South Atlantic, East South Central, and West North Central regions suggests a potential need for high deliverability storage there. Increasing winter demand in the residential and commercial sectors, with relatively little growth in summer demand, in the New England and South Atlantic regions indicate a future need for additional seasonal storage may develop in these regions. However, these forecasts of regional gas demand patterns alone are not enough to determine where and how much storage will be economic. Other important factors in determining storage needs are the capacities of existing storage facilities, costs of storage capacity additions, and the economics of storage compared to its alternatives. These topics are discussed in the following chapters.

III. Existing Gas Storage Facilities in the U.S.

Traditionally, underground natural gas storage facilities in the United States have served the needs of gas utilities. The network is largely seasonal in its operation, augmenting the ability to meet gas demand during peak winter periods. The system began operation early in this century and continues to grow today.

The deregulation of natural gas prices and the restructuring of the gas industry in the 1980s has created opportunities for radically different kinds of storage service. Some new customers are looking for the ability to adjust to rapidly changing market conditions, prices and demand. Modern short-term storage facilities stress rapid cycling capabilities with high deliverability rates, even at the expense of reduced capacity in some cases.

Traditionally, natural gas storage facilities used depleted hydrocarbon reservoirs with injection and withdrawal rates appropriate for seasonal cycling. Even so, a few rapid cycling facilities have been in use in the U.S. since the 1960s. The major distinction between the new storage facilities being built today and those built earlier is one of emphasis. In the past, the emphasis was on the ability to provide reliable gas supply to high priority, low load factor customers (such as homes, schools and hospitals) during seasonal periods of peak demand. Today, more storage facilities are being built that serve short-term fluctuations in market demand that may last only a few days.

This section describes traditional underground storage capacity in the United States. It reviews the historical background behind storage development and provides the magnitude of capacity and deliverability. This section also describes the kinds of facilities currently available and where they are located. Additionally, descriptions are provided on how these facilities operate and how they are regulated.

A. Background

Since the late 1940s, market area storage facilities have allowed temperature sensitive gas demands to be supplied by pipeline systems that are not sized to meet peak demands. In the 1970s, storage was also added in the producing regions as supply-constrained transmission systems supplemented their uncertain gas flow from producers. The uncertainty in the 1970s was due to a combination of supply inadequacy and the potential for gas well and gas processing facility freeze up in extreme cold weather.

Traditionally, interstate gas transmission systems have owned more than two-thirds of the storage capacity in the U.S. (Exhibit III-1). Slightly more than a quarter of the capacity is controlled by gas resellers such as LDCs or by intrastate pipelines. Until recently, gas was sold in the interstate market under strict price regulation. Producers sold their gas to the transmission companies under long-term "take-or-pay" contracts. The responsibility for securing supplies, for serving the market, and for meeting fluctuations in demand rested with the transmission companies. Because interstate pipelines were practically the sole merchants of interstate gas to LDCs and most gas users outside of the gas-producing regions of the United States, the pipelines built storage facilities for seasonal sales peaks, peak day surges and operational pipeline balancing. These activities were usually needed to support the pipelines' obligation to serve their customers. Less than five percent of current storage capacity is owned or operated by producers.

EXHIBIT III-1
Storage Sites, Working Gas, and Deliverability of Existing Gas Storage by Operator Class (as of 1992)

	Interstate Pipelines	LDCs	Intrastate Pipelines	Others	Totals
Sites	184	156	11	24	375
Working Gas (Bcf)	2,160	1,123	137	275	3,695
Deliverability (Bcfd)	34.1	25.3	3.6	4.8	67.7
Source: EIA, "The Value of Underground Storage in Today's Natural Gas Industry", March 1995.					

For many years, the LDCs have seen significant economic benefits to using storage for reducing their peak purchases from the pipelines. Storage could also serve as a partial guarantee of gas supply even under the most severe conditions. When they could, LDCs sought to create local storage, and state regulators encouraged storage construction by LDCs in their market areas. Further, as additions to storage were included in the LDCs' gas plant, the LDCs were rewarded during the ratemaking process with return on their increased investment. Regulators, end users, politicians and gas industry officials often agreed that local area storage projects would benefit the end users with increased reliability of gas supply.

B. Gas Storage Volumes and Capacities

Approximately 8 Tcf of storage capacity exists in the United States today. However, only 3.7 Tcf of the total is working gas that can be withdrawn for use. The other 4.3 Tcf is base gas which serves as a permanent part of the storage field that maintains the pressure required to deliver the working gas and cannot be recovered while the field is operational.[2] The cost of base gas generally represents one of the greatest capital costs in developing a storage reservoir. For example, if a storage field has 5 Bcf of base gas and the base gas costs $1.50 per Mcf, the cost of the base gas alone would be $7.5 million.

Since 1987, from 1.8 to 2.8 Tcf of working gas has been withdrawn from storage each year. In the past, this withdrawal volume was largely dependent upon the severity of the winter. More recently, storage is being used more frequently to respond to volatility in gas prices.

2) U.S. Department of Energy, Energy Information Administration (DOE/EIA). "The Value of Underground Storage in Today's natural Gas Industry", March 1995, pages 45-46.

Storage withdrawals occur according to a repetitive annual cycle on a national basis. About 85 percent of the total withdrawals occur between October and March. Injections from April through September account for about 70 percent of the annual injections. Injections tend to occur over a longer time period for several reasons. Injection levels are dictated by the cost of gas, the opportunity to inject gas, the need to optimize compression capacity, and the need to have the storage facility full at the beginning of the winter heating season. Withdrawals, in contrast, are market-driven, and demand typically fluctuates with temperature.

C. Types of Storage Facilities

There are many ways in which natural gas can be stored. The three primary types of underground storage facilities considered in this study are depleted reservoirs, aquifers and salt caverns. Other types of gas storage include liquified natural gas (LNG), propane, above ground tanks and abandoned underground cavities (e.g., iron mines and coal mines). These other types of gas storage are described in a later section of this report.

1. Depleted Oil and Gas Reservoirs

Depleted reservoirs are by far the most common type of gas storage facility, with 316 facilities in operation in 1993. Depleted reservoir storage exists in every GSAM region[3] except New England and Florida, but is concentrated in the Middle Atlantic, East North Central, and West South Central regions (Exhibit III-2). The base gas requirement for these reservoirs averages about 50 percent of the total capacity. Working gas in such reservoirs typically ranges from 1 to 40 Bcf. The maximum daily deliverability of these fields varies greatly, ranging from 0.2 to 33 percent of working gas capacity. However, the typical range is 1 to 4 percent of working gas capacity. Higher maximum withdrawal rates tend to be associated with high permeability fields. Generally, depleted gas/oil reservoir facilities are designed to be cycled once a year, but typically are not fully cycled.

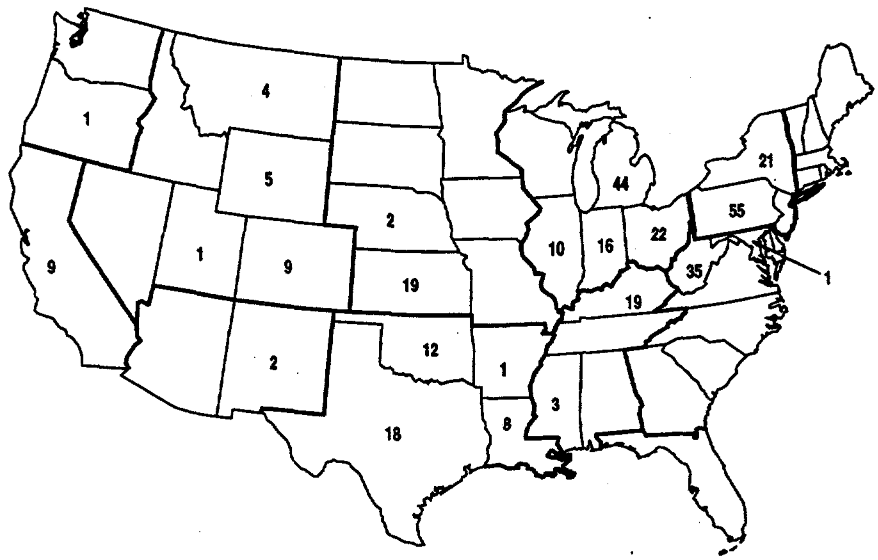
Depleted reservoir storage facilities are typically the least expensive and quickest to develop. The reasons for this are that technical information on reservoir characteristics is available from previous development and production operations, some wells are available for injection and withdrawal, some cushion gas will be available in depleted gas reservoirs, and gas retention is highest of the three primary underground storage types.

2. Aquifers

Aquifer storage is used in limited geographic areas (Exhibit III-3). Aquifer storage is most common in the East North Central (Illinois, Indiana) and West North Central regions (Iowa) where 29 of the 38 U.S. facilities are located.

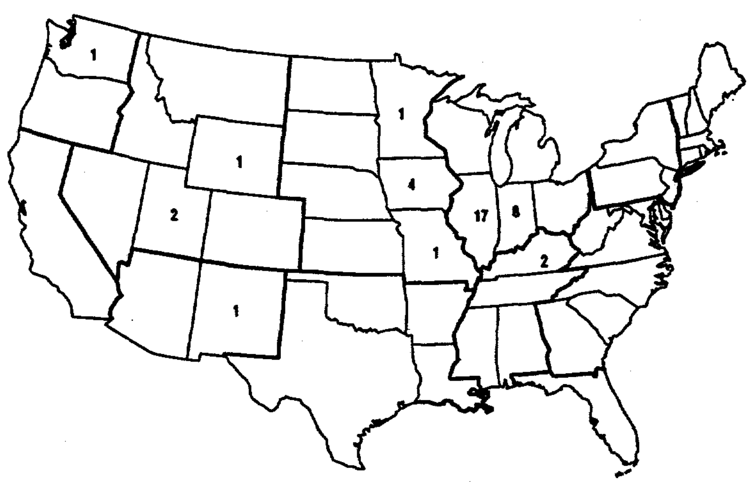
3) GSAM regions are the U.S. regions used in the Gas Systems Analysis Model (GSAM) currently being developed under sponsorship of METC. GSAM regions are the same as U.S. census regions, except that Florida is separate from other South Atlantic states, the Rocky Mountain region is divided into northern and southern areas, and California is separate from the Pacific region.

EXHIBIT III-2
Existing Depleted Reservoir Storage Facilities—Number of Facilities by State



Source: DOE-EIA, "Value of Underground Storage in Today's Natural Gas Industry"

EXHIBIT III-3
Existing Aquifer Storage Facilities—Number of Facilities by State



Source: DOE-EIA, "Value of Underground Storage in Today's Natural Gas Industry"

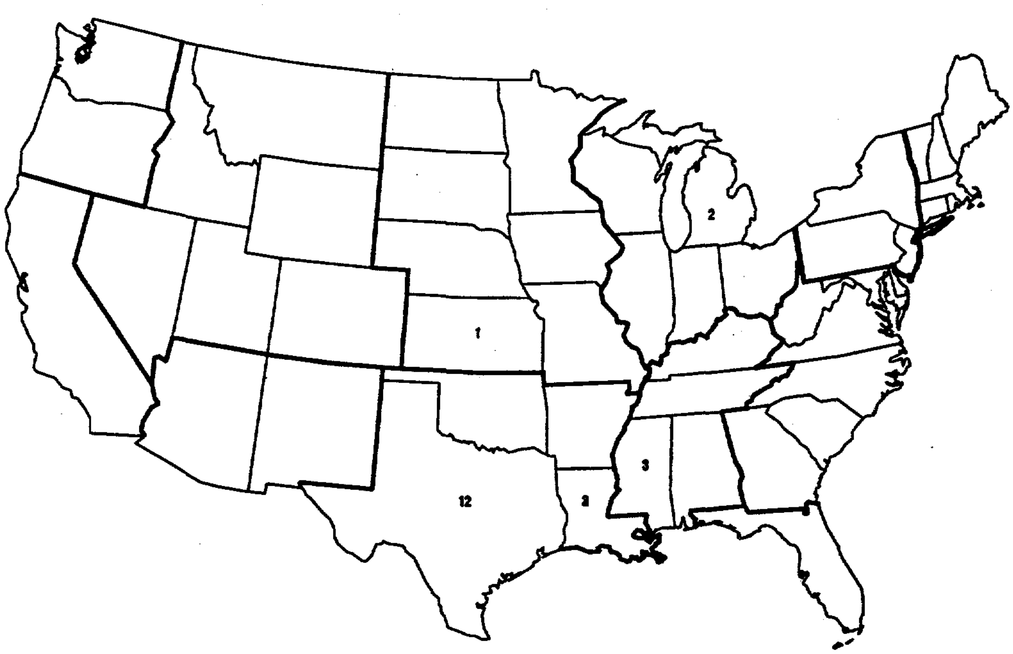
Typically, natural gas is injected into a water bearing reservoir so that a gas bubble can be kept in place by the geometry of the structural closure and the water pressure. Extensive instrumentation and multiple injection and withdrawal wells are generally used to monitor and control the gas movement. Water coning[4] or gas migration sometimes can create problems in the aquifer storage facilities.

The volume of working gas in aquifers averages 7.5 Bcf per reservoir. However, aquifers also require a relatively high ratio of base gas to working gas, as high as 70 percent of the total gas in the reservoir. Aquifers are often the most expensive type of storage facility to operate. An indication of aquifer costs can be found in the FERC application of Midwest Gas Storage, where operation and maintenance costs are 17 to 24 cents per Mcf a year, and gas injection and withdrawal costs 1 to 2 cents per Mcf. Generally speaking, an aquifer cannot be cycled more than once each year.

3. Salt Dome Caverns

Underground salt caverns are increasingly being used for natural gas storage because of their high injection and withdrawal rates. Starting with the first salt dome caverns at Eminence, Mississippi built by Transco in 1970, today there are 20 that store 82 Bcf of working gas (Exhibit III-4).

EXHIBIT III-4
Existing Salt Cavern Storage Facilities—
Number of Facilities by State



Source: DOE-EIA, "Value of Underground Storage in Today's Natural Gas Industry"

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4) Water coning occurs when localized low pressure space adjacent to the gas well bore allows water below the bore to move upward in a cone shape toward or into the well bore.

Salt caverns are typically two to three times more expensive than other storage reservoirs, but this cost tends to be offset somewhat by the relatively high deliverability and low base gas requirement (about 25 percent of total capacity) of the caverns. Salt caverns must be leached from underground salt formations to create the gas pressure vessels. Withdrawals rates of 10 percent of the total gas per day are not uncommon compared to the 1 to 4 percent typical of depleted reservoirs described above.

Possibly the most attractive feature of salt caverns from an economic viewpoint is their ability to be cycled several times per year. Physically, the complete cycle from full to empty and refilling again requires only about thirty days. Withdrawal rates for salt caverns are usually limited only by the dehydration capability of the gas-handling equipment in place. Another measure of this salt cavern flexibility in operation is the ability to switch a cavern from the injection cycle to the withdrawal cycle in 15 minutes and reverse the flow of gas back to injection again in another 30 minutes.

Exhibit III-5 provides a summary of gas storage sites, working gas capacities, and deliverabilities for existing storage by the types of reservoirs described above.

EXHIBIT III-5
Storage Sites, Working Gas, and Deliverability of Existing Gas Storage by Type of Reservoir (as of 1993)

	Type of Reservoir			
	Depleted Gas/Oil	Aquifers	Salt Caverns	Totals
Sites	316	38	21	375
Working Gas (Bcf)	3,170	443	82	3,695
Deliverability (Bcfd)	53.4	7.3	7.0	67.7
Source:	EIA, "The Value of Underground Storage in Today's Natural Gas Industry", March 1995.			

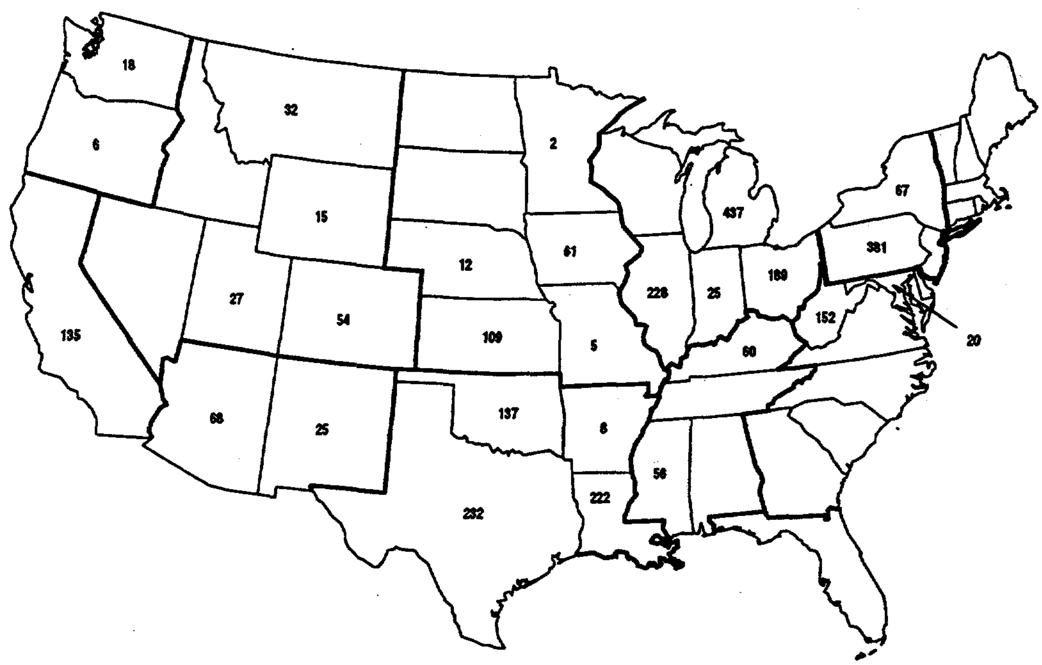
4. Other Storage

Recently, there has been a steadily increasing interest in developing underground cavities in other strata than salt. Such caverns are practical if a reasonable gas seal can be created. Coal or other mines must be sealed to prevent the migration of gas out of the storage cavern. This isolation of the stored gas is particularly important with the extremely high pressures sought for a storage application. Although some special cases appear very promising, there has been no widespread application of these techniques as yet.

D. Geographic Distribution of Underground Gas Storage

Since the location of underground gas storage is heavily influenced by market needs and the availability of suitable reservoirs, it is not surprising that most of the facilities are found in gas and oil producing states near large gas markets. As shown in Exhibit III-6, larger gas withdrawals from storage in 1993 were from Pennsylvania, Ohio, Michigan, West Virginia, Louisiana, and Texas, all of which have depleted gas and oil fields. The substantial withdrawals shown for Illinois were primarily from the aquifer storage available there.

EXHIBIT III-6
Total Storage Withdrawals by State in 1993
(Bcf)



Source: EIA, Natural Gas Annual 1993

All of New England and most of the Southeastern states do not have storage facilities that are nearly proportional to their population. Generally speaking, these areas lack the depleted gas and oil reservoirs, aquifers or salt deposits to provide for underground storage. Storage substitutes (such as propane, LNG, and pipeline capacity) have ameliorated this deficiency to some extent. In the Southeast, the lack of traditional storage facilities is largely offset by the geography of the transmission network. Historically, the states closest to production areas have been upstream of pipeline bottlenecks in times of heavy demand. Because the Southeast is so close to the production areas of the Gulf Coast, and because southern weather tends to be relatively mild, the lack of storage has not been critical to distribution of gas in the Southeast.

New gas supply routes from Canada, the LNG import terminal at Everrett, Massachusetts, LNG storage facilities throughout New England, propane/air facilities, and increased domestic pipeline capacity have all substituted for underground storage in New England.

Exhibit III-7 provides a summary of storage deliverability by region in 1993. Examination of Exhibit III-6 and III-7 shows that the East North Central and West South Central regions have and use the greatest storage deliverabilities in the U.S.

EXHIBIT III-7
Storage Deliverability by Region in 1993

Region	Deliverability (MMcf/d)
New England	0
Middle Atlantic	8,570
South Atlantic	3,272
Florida	0
East North Central	18,538
East South Central	3,322
West North Central	4,206
West South Central	16,194
Mountain North	1,791
Mountain South	100
Pacific Northwest	550
California	4,003

E. Summary

Although the share of gas storage operated by interstate gas pipelines is declining, they still represent about half of the storage sites, working gas capacity and deliverability in the U.S. Traditional, seasonal storage using depleted gas and oil reservoirs represented 86 percent of the existing working gas capacity, and 79 percent of the existing deliverability in 1993. Aquifers represented 12 percent of the working gas capacity. Aquifers and salt caverns each represented about seven percent of the total U.S. deliverability from storage. Most of the storage facilities are located in the Middle-Atlantic, East North Central, and West South Central regions adjacent to large gas markets and oil and gas producing areas. Regions where little or no storage capacity exists indicate that favorable geologic structures have not been located or that the economics of storage are unfavorable. The major changes occurring in gas storage recently has been the increase in share of high deliverability storage capacity in salt dome caverns — mostly in Texas and Louisiana.

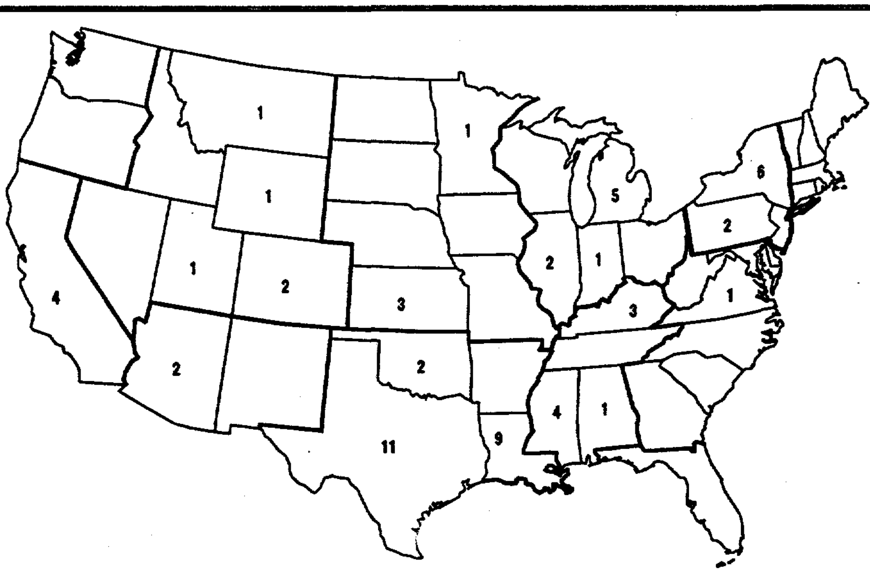
The regional working gas and deliverability capacities developed for this chapter will be among the key data inputs to the GSAM gas storage module. When storage demand reaches these capacity limits, GSAM will make investment decisions on whether to add storage capacity or to add an alternative to storage. The alternatives will be additional pipeline capacity or peak shaving capacity. These capacity data will be used in conjunction with the tariff rates for storage that are currently being updated in the GSAM data base.

IV. Proposed New Gas Storage Facilities in the U.S.

The new dynamics of the natural gas market have created significant additional interest in construction of new storage facilities. In the past five years, a number of developers have announced plans to build storage facilities around the United States. Exhibit IV-1 shows the location of new proposed projects listed by DOE/EIA in 1995.[1] Not all of the proposed facilities will be built. The announcement of plans is usually an early step in the long process of developing a capital intensive storage project. Additional steps include identifying and negotiating with potential customers, finalizing engineering studies, filing for and receiving regulatory approvals, and obtaining financing. Over time, the economics of competitive proposals and the interest of potential customers will pare down the number of proposed sites.

This chapter reviews the types and sizes of storage projects being proposed and the estimated cost of building them. Because of the low investment threshold for announcing storage plans, the projects reviewed represent a snapshot of those under consideration at a given moment in time. This review is not intended to provide insight into which proposed facilities will actually be built. Rather, it provides an indication of potential sites and types of storage that facility developers consider most attractive and worthy of investment consideration.

EXHIBIT IV-1
Total Proposed Storage Facilities—
Number of Facilities by State



Source: DOE/EIA, "Value of Underground Storage in Today's Natural Gas Industry"

1) DOE/EIA, "The Value of Underground Storage in Today's Natural Gas", March 1995.

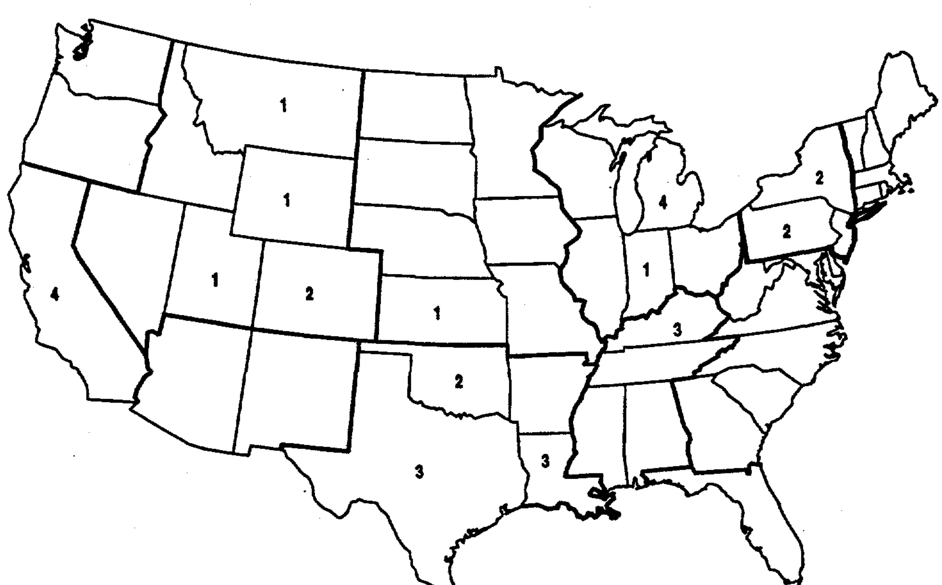
Because several of the new storage facilities have proposed using market-based rates, their sponsors may never need to file the detailed cost information traditionally required in FERC rate regulation. Therefore, even though the total estimated cost of building proposed projects is likely to be publicly available, the data available on cost categorization and allocation are from a limited number of projects. Nonetheless, it can be assumed that new facilities will require cost recovery to ensure success. Further, even within a competitive market, rates will vary within a fixed-variable allocation regime similar to existing SFV rate design.

A. New Depleted Reservoirs

About two thirds of the proposed 495 Bcf of new storage working capacity will be in depleted reservoirs. However, only 31 percent of the new deliverability will be in proposed projects in depleted reservoirs. As shown in Exhibit IV-2, these facilities would be located primarily in the West South Central, East North Central, Middle Atlantic, and California regions. Other facilities are proposed for the Mountain North, West North Central, and East South Central regions.

The proposed projects in depleted reservoirs vary greatly by capacity and the proposed facilities are generally larger than existing ones (Exhibit IV-3). The proposals range from the 250 MMcf New Hope reservoir in Kentucky to the 46 Bcf project at Cotton Plant, Louisiana. The larger proposed facilities tend to be in the major gas producing areas, such as the West South Central region, although there are some large facilities in the East North Central region (Michigan) and California.

EXHIBIT IV-2
Proposed Depleted Reservoir Storage Facilities—
Number of Facilities by State



Source: DOE/EIA, "Value of Underground Storage in Today's Natural Gas Industry"

EXHIBIT IV-3
Capacity of Gas Storage Projects in Depleted Reservoirs

Region		Number of Projects	Total Gas Range (MMcf)	Average Total Gas (MMcf)	Working Gas Range (MMcf)	Average Working Gas (MMcf)
Middle Atlantic	Existing	73	17 - 108,002	11,902	5 - 57,001	5,576
	Proposed	4	5,640 - 24,900	13,385	3,100 - 12,100	6,550
East North Central	Existing	99	93 - 107,644	16,071	32 - 41,073	6,747
	Proposed	5	800 - 42,000	11,800	800 - 17,000	9,000
East South Central	Existing	24	60 - 126,971	15,686	19 - 62,497	6,940
	Proposed	3	1,400 - 29,500	14,630	700 - 14,750	7,320
West North Central	Existing	21	198 - 493,79	19,279	34 - 34,536	6,001
	Proposed	1	8,000	8,000	5,000	5,000
West South Central	Existing	50	63 - 51,831	30,059	295 - 112,491	13,914
	Proposed	8	4,800 - 46,000	32,300	3,000 - 30,000	19,833
Mountain North	Existing	20	264 - 202,528	24,764	226 - 78,436	8,739
	Proposed	5	10,000 - 26,300	17,766	5,300 - 15,200	10,167
California	Existing	10	835 - 119,447	42,145	410 - 58,841	15,524
	Proposed	4	9,000 - 65,000	30,250	6,000 - 40,000	17,250
Source: DOE/EIA, "The Value of Underground Storage in Today's Natural Gas Industry,"						

As with most traditional depleted reservoir storage fields, the proposed storage facilities offer deliverability on a seasonal basis (Exhibit IV-4). Deliverability at maximum withdrawal rates tends to range from 70 to 100 days. This would tend to overstate deliverability somewhat, because in traditional fields, deliverability declines as working gas (and reservoir pressures) decline. These deliverability rates are consistent with many of the existing depleted reservoir fields.

Exhibit IV-5 provides cost estimates for the proposed facilities. The unit costs of these facilities provide a measure of the value of the facilities relative to each other and relative to other options. To build an additional MMcf of depleted reservoir storage capacity in the U.S. costs, on average, $3,319 per MMcf, using the regional working gas capacities of Exhibit IV-4 as weightings for the average regional costs of Exhibit IV-5. Similarly, to add peak storage deliverability of an Mcf per day, construction of a new storage reservoir facility averages $185/Mcfd. The Mid-Atlantic facilities tend to reflect much higher expected construction costs on a per unit basis (for both capacity and deliverability) than the other regions. Task 3 of this project will determine the reasons for this and other storage cost differences among the various regions.

EXHIBIT IV-4
Deliverability of Gas Storage Projects in Depleted Reservoirs

Region		Number of Projects	Average Working Gas(MMcf)	Average Deliverability (MMcf/day)
Middle Atlantic	Existing	73	5,576	117
	Proposed	4	6,550	72
East North Central	Existing	99	6,747	134
	Proposed	5	9,000	105
East South Central	Existing	24	6,940	117
	Proposed	3	7,320	59
West North Central	Existing	21	6,001	129
	Proposed	1	5,000	80
West South Central	Existing	50	13,914	222
	Proposed	8	18,825	385
Mountain North	Existing	20	8,739	71
	Proposed	5	10,167	219
California	Existing	10	15,524	400
	Proposed	4	17,250	366

EXHIBIT IV-5
Estimated Costs of Gas Storage Projects in Depleted Reservoirs

Region	Estimated Project Cost ($ million)			Average Cost ($/MMcf) Working Gas	Average Cost ($/Mcfd) Deliverability
	Maximum	Minimum	Average		
Middle Atlantic	76	24	44	6,740	613
East North Central	120	1	26	2,922	250
East South Central	51	3	28	3,111	388
West North Central	12	12	12	2,400	150
West South Central	100	15	53	2,672	138
Mountain North	50	4	27	4,065	188
California	90	25	53	3,043	143

In order to estimate the effect of cost changes on storage decisions, it is helpful to understand that the price charged to a customer to use the facility will be based on the costs of the storage service -- both fixed and variable. The fixed components of the storage costs consist of capital depreciation and amortization, property taxes, return on equity, income taxes, and fixed operations and maintenance costs. The variable part of the storage charges are from the variable operations and maintenance costs, which include items such as compressor fuel and lubricants and compressor overhauls.

Depreciation, amortization, return, and property taxes will be a function of the cost of acquiring the site and building the storage facility. Exhibit IV-6 provides additional detail on construction costs associated with several of the proposed new storage facilities.[2] Surface facilities and well costs tend to be the costliest part of construction. These elements, in addition to Administrative and General costs, are likely to vary with the size of the facility. Base gas costs, which appear to range from one-seventh to one quarter of construction costs, are a function of the initial cost of gas for the facility and the amount of base gas required. Property acquisition costs (including rights of way) vary by location and facility size.

EXHIBIT IV-6
Detailed Construction Cost Estimates for
Selected Gas Storage Projects in Depleted Reservoirs
($000)

	Facility Location		
Cost Category	Riverside New York	Blue Lake Michigan	Richfield Kansas
Total Cost	24,251	132,723	11,820
Property Acquisition	372	1,220	710
Compression, Regulation and Metering	8,314	64,820	275
Wells and Piping	8,890	30,416	7,535
Base Gas	3,800	18,750	2,800
Administrative & Other	3,055	17,517	500

Operations and maintenance costs are roughly a function of the field capacity and deliverability. Exhibit IV-7 provides estimated operations and maintenance costs for the Riverside Storage Project. Most of these costs are also fixed, roughly as a function of field size. Compressor station, measuring, and regulating station materials and expenses are generally classified as variable costs and allocated to the commodity portion of the storage tariff.

2) Detailed cost data are not available for most of the proposed facilities because (1) they are still in the development stage or (2) they have filed for market-based rates at FERC, which allows them to avoid submitting cost data.

EXHIBIT IV-7
Estimated O&M Costs for Riverside Gas Storage Project

Cost Category		First Year Costs ($)	Fixed or Variable (F,V)
Operations			
Supervision & Engineering	Labor	36,900	F
	Supplies	35,000	F
Wells	Labor	2,700	F
	Supplies	3,500	F
Lines	Labor	7,900	F
	Supplies	3,600	F
Compressor Station	Labor	300,000	V
	Supplies	21,500	V
Station Field and Power	Labor	0	F
	Supplies	298,271	F
Measuring and Regulating Station	Labor	7,900	V
	Supplies	3,000	V
Total Operations		720,271	
Maintenance			
Supervision & Engineering	Labor	10,100	F
	Supplies	0	F
Structures and Improvements	Labor	1,700	F
	Supplies	3,000	F
Wells	Labor	2,700	F
	Supplies	11,000	F
Lines	Labor	2,700	F
	Supplies	1,500	F
Compressor Station	Labor	139,200	V
	Supplies	81,000	V
Measuring and Regulating Station	Labor	2,600	V
	Supplies	0	V
Total Maintenance		255,500	
Administration & General		164,608	
Total Operation & Maintenance		1,140,379	

Source: Riverside Gas Storage Co., Application for Certificate of Public Convenience and Necessity, before the U.S. Federal Energy Regulatory Commission, CP94-292-000, March 17, 1994.

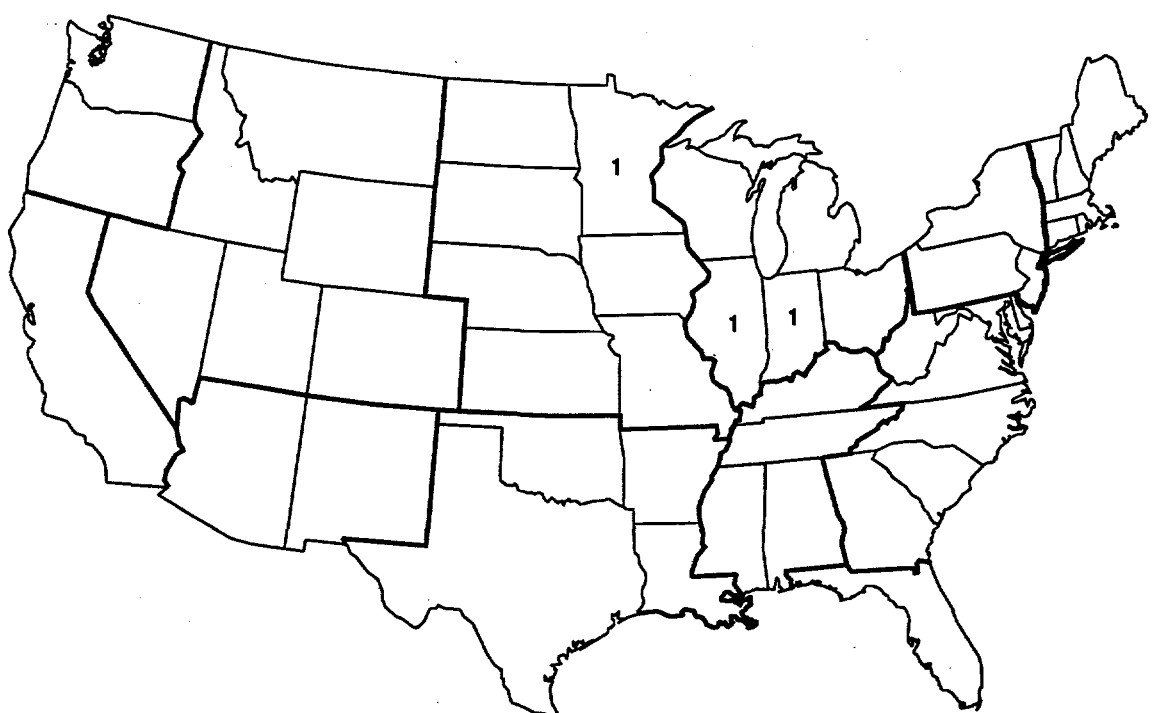
Traditionally, in creating rates for storage capacity and deliverability for depleted reservoir storage facilities, fixed costs have been allocated arbitrarily between capacity and deliverability components in rate design. In the rate designs reviewed for this study, 50 percent of the fixed costs were usually allocated to each. All variable costs are traditionally associated with the charges for actual deliveries in and out of storage.

B. New Aquifers

Two of the proposed new storage facilities use aquifers. They are Hillsboro in Illinois (East North Central) and Calcutta-Carbon in Indiana (East North Central). A third, existing, aquifer storage facility, Waterville in Minnesota, has proposed a capacity expansion (Exhibit IV-8).

The number of proposed aquifers relative to other proposed storage is somewhat less than the proportion of the existing population. Aquifers represent 5 percent of the 62 announced storage projects versus 10 percent of the 375 existing storage facilities. The geographical concentration of the proposed facilities is consistent with the existing stock, however. Currently, aquifers storage facilities are being operated predominantly in Illinois (17 facilities), Indiana (8 facilities), and Iowa (4 facilities) (Exhibit IV-9).

EXHIBIT IV-8
Proposed Aquifer Storage Facilities—
Number of Facilities by State



Source: DOE/EIA, "Value of Underground Storage in Today's Natural Gas Industry"

EXHIBIT IV-9
Proposed and Existing Gas Storage Projects in Aquifers

Proposed Project	State	Region	Working Gas Capacity (MMcf)	Deliverability (MMcf/d)	Cycling (Days)
Hillsboro	Illinois	East North Central	4,500	75	60
Calcutta-Carbon	Indiana	East North Central	3900	35	111
Waterville-Waseca	Minnesota	West North Central	1200	--	--
Region	**Number of Existing Projects**	**Average Working Gas Capacity (MMcf)**	**Average Deliverability (MMcf/d)**	**Average Cycling (Days)**	
East North Central	30	8,547	189	48	
East South Central	2	3,977	60	66	
West North Central	10	8,071	137	59	
Pacific Northwest	1	15,100	450	34	
Mountain North	2	743	73	10	
Mountain South	1	7,242	50	145	

In general, the aquifer storage facilities are about the same size as the proposed salt cavern facilities, but they offer deliverability features comparable to depleted reservoirs. As providers of storage capacity they are generally more expensive than depleted reservoirs (Exhibit IV-10).

No detailed cost information was available for any of the three new aquifer projects. However, allocation of costs to capacity and deliverability were available from Natural Gas Pipe Line Company of America (NGPL), which currently owns 9 aquifer storage fields in Illinois and Iowa. NGPL's fixed costs are allocated to capacity/deliverability on a 50/50 basis, similar to depleted reservoirs.

C. New Salt Caverns

Nearly half of the total number of proposed new storage facilities listed by the DOE/EIA would use salt caverns. By comparison, less than six percent of the current facilities are salt caverns. The new salt cavern storage facilities comprise one-third of the new working capacity and over two-thirds of the deliverability of all new storage projects. Many of the proposed facilities are in or near major production areas, namely Texas and Louisiana in the West South Central region, Alabama and Mississippi in the East South Central region and Kansas in the West North Central region. Although the Mountain South region is a significant producer of gas, the proposed salt cavern storage there is likely to serve a specific market, California. Additional salt cavern storage is proposed in the Mid-Atlantic region in New York (Exhibit IV-11).

The 29 proposed storage facilities would add 164 Bcf of working gas capacity, or about 5,700 MMcf per facility (Exhibit IV-12). If all the proposed capacity were built, it would increase the stock of salt cavern storage capacity by 200 percent. The proposed fields tend to be larger than existing facilities, albeit generally still smaller than depleted reservoirs.

Many of the larger proposed projects are expected to be built in phases (Exhibit IV-13). Phased construction enables a developer to begin realizing revenue as later stages are completed. It also reduces utilization risks by allowing the pace of construction to follow more closely customers' contractual commitments. Salt cavern facilities can be phased because the reservoir is created in the process of construction (i.e., the reservoir does not exist prior to construction as it does in a depleted reservoir).

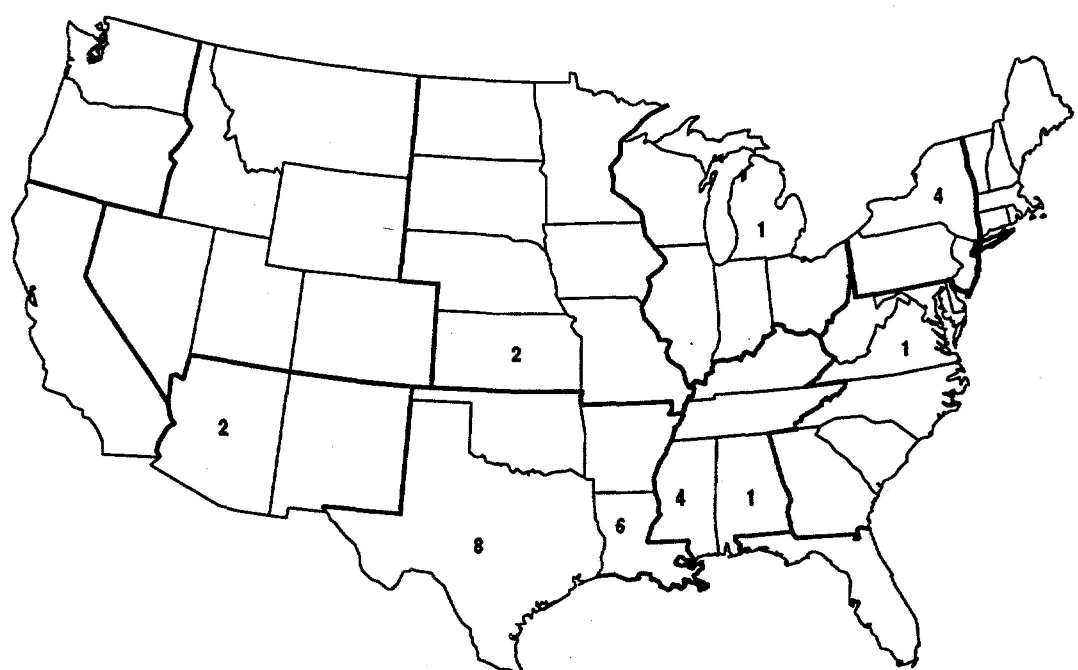
Most of the proposed salt cavern storage facilities will be able to cycle their gas over a 10 to 12 day period, compared to over 100 days for a depleted reservoir (Exhibit IV-14). This means the average new salt cavern storage facility would provide 526 MMcf per day of deliverability. The proposed Red Lake project is an exception, with a cycling capability of 24 days.

Exhibit IV-15 provides cost estimates for the proposed salt cavern facilities. On a per unit of capacity basis, these facilities average $6,500 per MMcf, almost double the construction cost of a depleted reservoir. A more appropriate measure of the relative value of salt cavern storage, however, is based on the cost per Mcf per day of deliverability. The new salt cavern facilities are expected to average $78 per Mcf per day of deliverability, 40% of the costs of deliverability associated with depleted reservoir storage facilities.

EXHIBIT IV-10
Costs of Proposed Gas Storage Projects in Aquifers

Facility	Region	Working Gas (MMcf)	Deliverability (MMcf/d)	Cost ($000s)	Capacity Cost-Average ($/MMcf)	Deliverability Cost-Average ($/Mcfd)
Hillsboro	ENC	4,500	75	36,600	8,133	488
Calcutta-Carbon	ENC	3,900	35	12,275	3,147	351
Waterville-Waseca	WNC	1,200	--	2,000	1,667	--
Aquifer Avg.		4,200	55	24,437	5,818	444
Depleted Reservoir Avg. (for comparison)					3,319	185

EXHIBIT IV-11
Proposed Salt Cavern Storage Facilities— Number of Facilities by State



Source: DOE/EIA, "Value of Underground Storage in Today's Natural Gas Industry"

EXHIBIT IV-12
Capacity of Gas Storage Projects in Salt Domes

Region		Number of Projects	Total Gas Range (MMcf)	Average Total Gas (MMcf)	Working Gas Range (MMcf)	Average Working Gas (MMcf)
Middle Atlantic	Existing	0	--	--	--	--
	Proposed	4	800 - 7,800	7,150	800 - 6,200	5,600
East North Central	Existing	4	238 - 4,540	2,048	186 - 2,940	1,375
	Proposed	1	3,000	3,000	3,000	3,000
East South Central	Existing	1	6,350	6,350	4,448	4,448
	Proposed	5	3,160 - 12,600	6,808	2,200 - 9,000	4,588
West North Central	Existing	1	2,500	2,500	2,000	2,000
	Proposed	2	7,500 - 7,600	7,550	5,000	5,000
West South Central	Existing	11	2,086 - 12,551	7,838	1,357 - 8,762	5,033
	Proposed	14	3,000 - 20,400	9,579	2,000 - 16,000	6,342
Mountain North	Existing	2	1,148 - 2,792	1,970	222 - 2,002	1,112
	Proposed	0	--	--	--	--
Mountain South	Existing	0	--	--	--	--
	Proposed	2	18,000 - 20,000	19,000	12,000 - 20,000	16,000

EXHIBIT IV-13
Proposed Gas Storage Projects in Salt Caverns to be Built in Phases

Project	Region	Working Gas Capacity MMcf	Phases	Construction Years
Cayuta	Middle Atlantic	6,200	3	3
Avoca	Middle Atlantic	5,000	3	3
Mid-Continent	West North Central	5,000	4	4
Red Lake	Mountain South	20,000	2	4
Pataya	Mountain South	12,000	2	3
MS-1	East South Central	9,000	5	3
Eminence	East South Central	5,840	2	2
LA-1	West South Central	8,000	4	3
Moss Bluff	West South Central	4,000	2	2
Napoleonville	West South Central	11,600	2	4
Spindletop	West South Central	16,000	2	1
Loop	West South Central	2,000	2	3

EXHIBIT IV-14
Deliverability of Gas Storage Projects in Salt Caverns

Region		Number of Projects	Average Working Gas (MMcf)	Average Deliverability (MMcf/d)	Cycling Maximum (Days)	Cycling Minimum (Days)	Cycling Average (Days)
Middle Atlantic	Existing	0	--	--	--	--	--
	Proposed	4	5,600	500	12	10	11
East North Central	Existing	4	1,375	104	36	3	13
	Proposed	0	3,000	150	20	20	20
East South Central	Existing	1	4,448	320	14	14	14
	Proposed	5	4,588	348	29	10	14
West North Central	Existing	1	2,000	120	17	17	17
	Proposed	3	5,000	450	13	10	11
West South Central	Existing	11	5,028	483	39	3	10
	Proposed	14	6,342	580	20	4	11
Mountain South	Existing	0	--	--	--	--	--
	Proposed	2	16,000	1250	24	10	13
Mountain North	Existing	2	1,112	113	11	6	10
	Proposed	0	--	--	--	--	--

EXHIBIT IV-15
Costs of Proposed Gas Storage Projects in Salt Caverns

Region	ESTIMATED PROJECT COST ($millions)			Cost-Average ($/MMcf of Working Gas)	Cost-Average ($/Mcfd)
	Maximum	Minimum	Average		
Middle Atlantic	59.2	55.2	57.8	16,514	181
East South Central	100.0	20.0	40.1	8,732	115
West North Central	53.0	40.0	46.5	9,300	103
West South Central	78.8	5.0	33.1	5,213	57
Mountain South	59.0	59.0	59.0	3,687	47
Salt Cavern Average				6,529	78
Depleted Reservoir Average (for comparison)				3,319	185

Salt dome and bedded salt facilities tend to be more expensive than depleted reservoirs in the initial construction stages because the latter already have the necessary infrastructure in place to withdraw gas and they may also have their base gas in place. Little data are available concerning new salt cavern facilities. Exhibit IV-16 compares detailed cost data for the Eminence Salt Storage project with the proposed Riverside depleted reservoir facility. As evidenced in the comparison, cavern costs (actual construction of the reservoir) and base gas costs are much greater for Eminence, while property acquisition costs are generally consistent.

The same general ratemaking principles used for depleted reservoirs would also apply to salt cavern storage. The principle difference is in the allocation of fixed costs between capacity and deliverability charges. High deliverability is a significant motivating factor in building new salt cavern storage. In our research, we have discovered allocation factors (i.e., shares of fixed costs allocated to deliverability versus capacity) from 80/20 to 90/10, versus 50/50 or 40/60 for depleted reservoirs.

Exhibit IV-17 summarizes gas storage projects, working gas capacities, and deliverabilities for proposed storage by the types of reservoirs described above.

D. Summary

The recent trend of newer storage capacity going to high deliverability salt caverns is being reinforced with the proposals for additional storage. Although a tightening market will probably reduce the number of facilities actually built in the next few years, 58 percent of the announced projects are in salt. They would have 33 percent of the new working gas capacity and 68 percent of the new deliverability. Depleted reservoirs would have 65 percent of the working gas capacity and 31 percent of the deliverability.

Exhibit IV-18 provides a summary of estimated unit costs for new storage by type of reservoir. The higher cost of salt cavern working gas capacity is at least partially offset by the ability to cycle gas in and out several times per year, whereas other reservoir types are typically good for only one cycle each year. In addition, the higher delivery rates of salt cavern storage provide the lowest unit costs for deliverability (in \$/Mcfd). Aquifer storage, on the other hand, has by far the highest unit costs for deliverability of the three storage types and working gas capacity unit costs at a level between those of depleted reservoirs and salt caverns.

The unit capacity and deliverability costs presented in Exhibits IV-5, IV-10, and IV-15, along with additional cost data that becomes available, will be used in the GSAM investment decision process. GSAM will determine whether additional storage or another alternative is economic whenever gas demands exceed gas delivery capacities.

EXHIBIT IV-16
Detailed Cost Comparisons for Eminence Salt Cavern and Riverside Depleted Reservoir Gas Storage Projects

Cost Category	Eminence Louisiana	Percentage of Total	Riverside New York	Percentage of Total
Total Cost ($000s)	60,883	100	24,251	100
Property Acquisition	45	0	787	3
Site Preparation	11,697	19	9,980	41
Cavern Costs	30,170	50	--	--
Well Costs	--	--	6,939	29
Base Gas	14,277	23	3,800	16
Administrative & Other	4,694	8	2,745	11

EXHIBIT IV-17
Storage Projects, Working Gas Capacity, and Deliverability of Proposed Gas Storage by Type of Reservoir (as of 1993)

	Depleted Gas/Oil	Aquifer	Salt Caverns	Totals
Projects	30	3	29	81
Working Gas (Bcf)	322	9	164	495
Deliverability (Bcfd)	6.5	0.1	14.1	20.7
Source: EIA, "The Value of Underground Storage in Today's Natural Gas Industry", March 1995				

EXHIBIT IV-18
Average Unit Costs of New Storage Facilities by Type of Reservoir (as of 1993)

Unit Costs	Depleted Gas/Oil	Aquifer	Salt Caverns
$/Mcf of Working Capacity	$3.32	$5.82	$6.53
$/Mcfd of Deliverability	$185.00	$444.00	$78.00

V. Alternatives to Storage

The economics of storage cannot be assessed by looking at storage alone. Certainly, storage fields compete with one another in terms of cost and service. However, parts of the service provided by storage facilities may also be provided by substitutes. Research that decreases the costs of storage would likely improve storage's competitive position relative to those alternatives. This section reviews the costs of storage substitutes, relative to the value of storage.

A. Background

Storage competes with several alternatives based on its intended use. Depleted reservoirs and aquifers typically meet seasonal increases in demand such as residential customers' demand for increased heating during the winter. Substitutes for this type of storage must provide the customer with increased deliverability over an extended period. Because of the duration and daily volume of winter space heating demand, fixed costs can be spread over a larger gas volume, making capital intensive alternatives attractive. Possible substitutes for seasonal storage include pipeline capacity and liquefied natural gas (LNG) imports.

Salt cavern storage can meet peaking and cycling demands where numerous short-term demand variations exceed the average. Substitutes for this type of storage afford customers the opportunity to operate at times of supply scarcity (due to capacity constraints and/or high value demand). The more random timing of the demand places high value on having the substitute available at the time it is needed. Typically, these substitutes have consisted of interruption (for alternative fuel-capable customers) and peak shaving with mixtures of propane gas (LPG) and air or LNG.

There is also a geographic element to the competitive value of storage relative to its alternatives. In some regions, the construction of underground storage facilities is not possible for geological reasons. In some areas, there are no depleted gas/oil fields, no suitable aquifers nor salt strata appropriate for salt cavern storage facilities. Yet, these regions may have equal or greater demand for the seasonal or peaking capabilities that storage affords. New England is an excellent example of a region that has little geological support for underground gas storage despite a large need for seasonal supplies.

Further, the price of gas tends to be geographically differentiated due to transportation costs. A storage alternative that may be economical in New England may not be attractive on the Gulf Coast near gas supply sources. These factors together argue for a regional consideration of gas storage costs versus alternatives.

B. Pipeline Capacity

Pipeline capacity is the most significant competitor to gas storage. Traditionally, pipelines provided storage as an integral part of their contract demand service. Customers paid for their contract quantities to be delivered without consideration of the combination of pipeline and storage reservoir capacity needed to meet their demand. Storage service could be included in the pipeline general firm service contract and/or in a winter service contract.

When Order 636 required the "unbundling" of pipeline services, pipeline customers were allowed to make explicit decisions on the amount of storage they purchased from the pipeline. Customers may also purchase more expensive no-notice service that provides rebundled security. Order 636 also increased the cost of reserving pipeline capacity, the major alternative to purchasing storage capacity. Pipelines are now required to allocate all their fixed costs to their demand charges. With higher fixed charges, the cost penalty for over nominating pipeline capacity is higher.

GSAM already considers the cost of additions to pipeline capacity in meeting increased demand. Exhibit V-1 provides the fixed (at 100% load factor) and variable pipeline transportation costs for selected routes included in GSAM. The model adds pipeline capacity only when demand merits adding to the fixed costs of the pipeline.

EXHIBIT V-1
Estimated Gas Pipeline Transportation Costs in GSAM

Source-Destination	Fixed Cost ($/MMBtu/d)	Variable Cost ($/MMBtu)	Fuel Percentage
Alberta-California	0.30	0.020	5.70%
Alberta-Middle Atlantic	0.64	0.042	10.42%
Rockies Foreland-California	0.67	0.002	4.54%
So Louisiana-Middle Atlantic	0.49	0.030	6.08%
So Louisiana-South Atlantic	0.26	0.018	3.79%
Permian-California	0.44	0.048	9.87%
Texas Gulf Coast-West South Central	0.05	0.050	2.00%
Mid-Continent-West North Central	0.27	0.027	3.03%

C. LNG

There are four LNG import terminals in the United States.[1)] They are located at Everett, Massachusetts; Lake Charles, Louisiana; Elba Island, Georgia; and Cove Point, Maryland. Exhibit V-2 provides the storage capacity and deliverability for each of the terminals.

These import terminals were built to provide supplemental base load gas to the United States at a time when domestic supplies were inadequate to meet demand and resources were perceived to be dwindling. Each terminal was designed to receive LNG by tankers from abroad (initially Algeria), and regasify it for introduction into the transmission system. Depending on the number of tankers in use and their round-trip times, the terminal tankage could be refilled several times a year. The average storage

1) An LNG plant and terminal at Cook Inlet, Alaska exports natural gas produced in southern Alaska to Japan.

EXHIBIT V-2
LNG Import Terminals

Terminal	Site	State	Storage Capacity (Bcf)	Deliverability (MMcf/d)
Columbia LNG	Cove Point	Maryland	5.90	1,000
Distrigas	Everett	Massachusetts	3.8	267
Southern Energy	Elba Island	Georgia	4.6	540
Trunkline LNG	Lake Charles	Louisiana	7.0	699

Source: LNG Observer, July 1992.

capacity of the four terminals was 5.3 Bcf and average deliverability was 438 MMcfd. These average capacities are just slightly larger than those of existing salt cavern storage facilities.

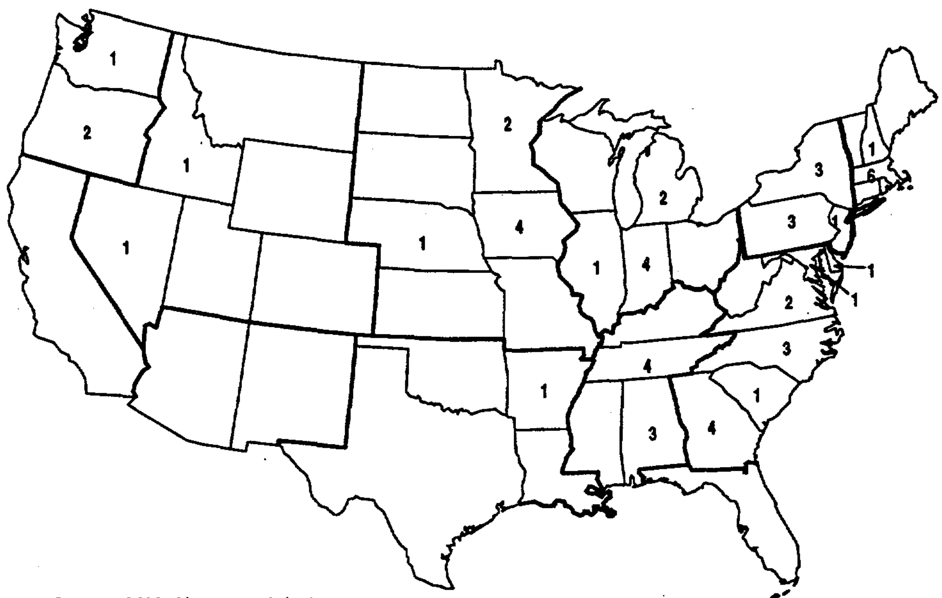
Changes in the natural gas market have made the LNG import terminals less practical. The lifting of wellhead price regulation and the unexpected increase in low-price North American gas supplies have made LNG from overseas less competitive against domestic and imported Canadian supplies. Currently, only the Lake Charles and Everett terminals receive LNG shipments from abroad and those supplies are at prices substantially below the original contract. In fact, Everett gas is priced to be competitive with pipeline gas delivered to New England. This arrangement is not as likely to be economical for potential suppliers to the other import sites where competitive gas prices tend to be lower because they are located closer to U.S. gas production areas.

If gas is not delivered to a terminal as LNG by ship, then a capability to liquefy pipeline gas must be added to make the LNG storage option feasible. Liquefaction facilities are relatively expensive, so a high level of utilization of the facility is a prerequisite for the economics to be even minimally attractive. Further, a significant amount of energy must be expended to liquefy natural gas. As much as 20 percent of the gas meant for storage may be used in the liquefaction process. In an LNG exporting country, the energy cost associated with liquefaction may not be significant due to a low local value for the natural gas. However, in the United States, that energy use imposes relatively high variable costs on the operation of an LNG facility.

Columbia Gas is currently adapting Cove Point for such use. The Cove Point facility will incorporate a 15 MMcf per day liquefier at an estimated cost of $15.5 million. Columbia's pro forma tariff estimates a fuel cost of 20.5 percent for volumes delivered under its firm storage rate schedule.

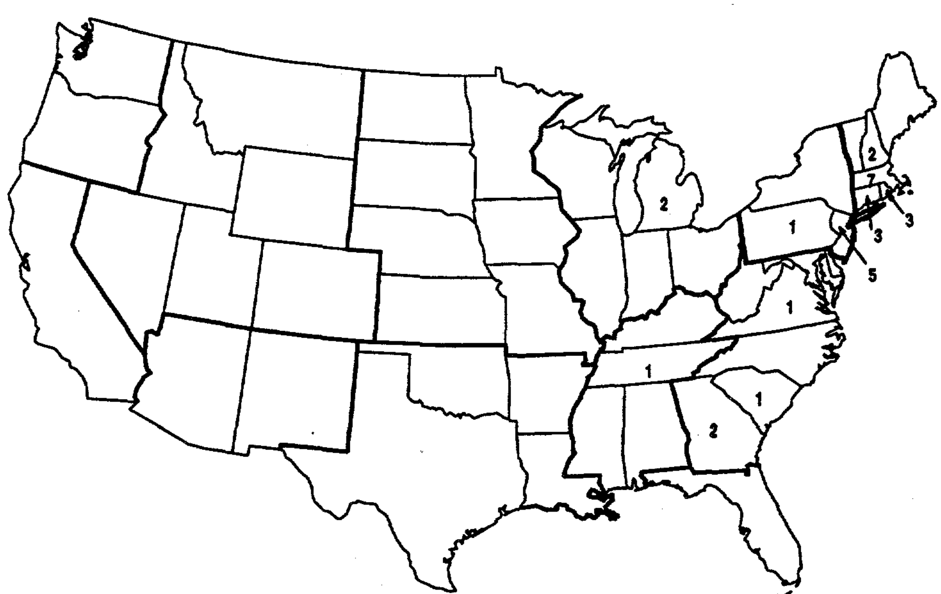
In contrast to the LNG import terminals, there are many smaller LNG storage facilities operational throughout the nation. The majority of these are peak shaving facilities, capable of liquefying, storing, and regasifying natural gas as necessary (Exhibit V-3). Some are satellite storage facilities, which receive their gas from an outside supplier already in its liquid state. These satellite facilities can store and regasify the LNG they receive. Exhibit V-4 shows the distribution of these facilities.

EXHIBIT V-3
LNG Peak Shaving Facilities



Source: LNG Observer, July 1992

EXHIBIT V-4
LNG Satellite Storage Facilities



Source: LNG Observer, July 1992

The liquefaction facilities that refrigerate this gas to a liquid state for storage constitute a significant part of the cost of the overall operations of peak shaving projects. The liquefaction process is rather slow and energy consuming compared to regasification for peak deliverability. Typically, these facilities receive pipeline gas ten months of the year, liquefy it, and store the LNG until the peak winter heating season, and then regasify the LNG at a very high rate to satisfy peak demand. Typical plant designs provide for regasifying 10 percent of the stored gas per day. Partial cycling is possible to the extent that the low capacity liquefaction equipment can start to operate again as soon as LNG storage capacity and pipeline gas are available.

In contrast, many of the LNG satellite facilities in New England purchase supplies from the Distragas Everett terminal via tank truck. This allows them to refill quicker, enabling greater cycling capability.

A new LNG storage facility has been proposed by Cabot and Granite State Transmission. This facility, to be built in southern Maine, would have a 2 Bcf/year capacity in 1997 for Northern Utilities and other gas utilities and shippers. The storage facility would receive LNG by truck from the Everett import terminal and deliver gas to Portland Natural Gas Pipeline and Tennessee Gas Pipeline for transmission throughout New England. Since the LNG tanks can be refilled during the winter, the capacity is expected to be cycled more than once per year. Withdrawal volume is estimated to be 1.83 times the 2 Bcf capacity, or 3,660 Bil Btu per year. Gas deliverability will be 54,640 MMBtu per day. The capital cost of this facility is estimated at $44.2 million.

A typical cost to store LNG over the year and then regasify it during the winter heating season is approximately $6 per Mcf, not including the cost of gas. Exhibit V-5 provides a detailed breakdown of the derivation of rates at the proposed Granite State Transmission LNG facility. The gas price will be a function of the cost of LNG plus the cost of truck transportation from Everett to the new storage facility.

EXHIBIT V-5
Representative Costs and Rates for a 2 Bcf LNG Storage Facility
($000)

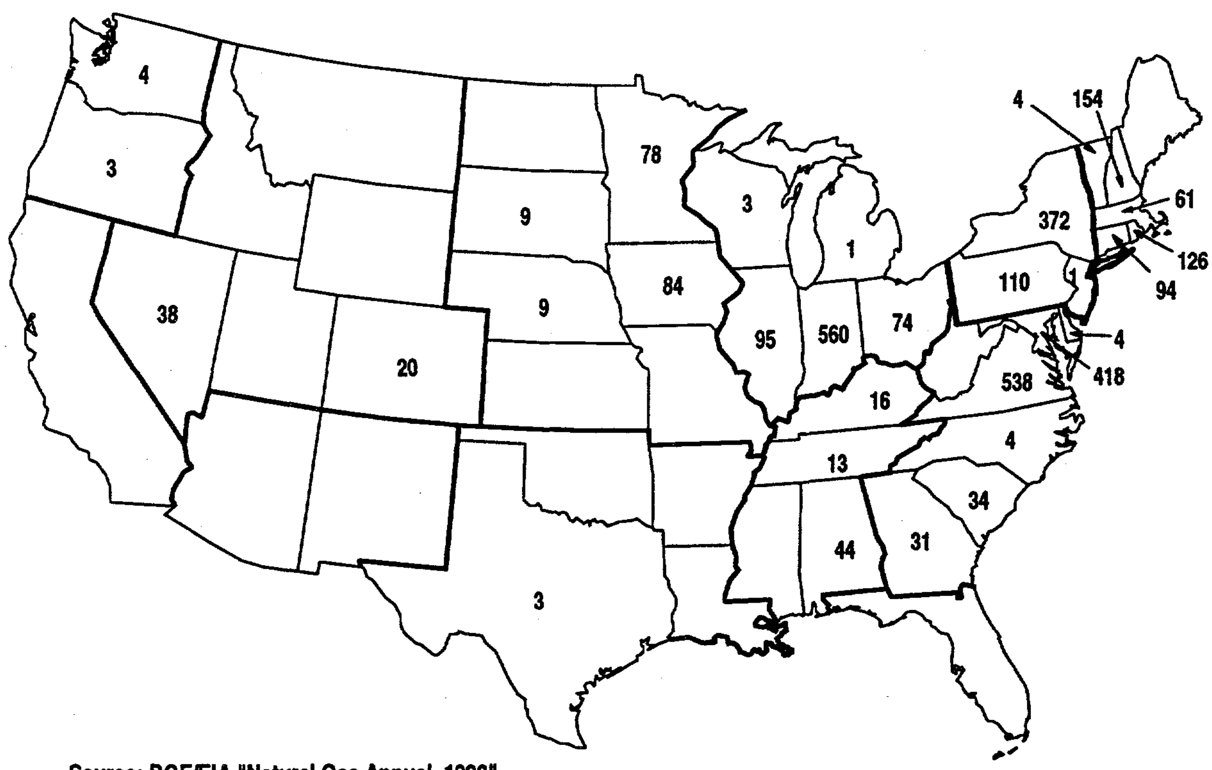
Cost Category	Total Cost	Fixed Cost	Variable Cost	Deliverability Cost	Capacity Cost	Withdrawal Cost
O&M Expense	$2,699	$2,499	$200	$1,030	$1,469	$200
Administrative & General	$619	$619	$0	$205	$414	$0
Taxes (excluding income tax)	$410	$410	$0	$136	$274	$0
Depreciation	$1,434	$1,434	$0	$489	$945	$0
Interest Cost	$1,836	$1,836	$0	$608	$1,226	$0
Return on Equity	$2,727	$2,727	$0	$903	$1,824	$0
Federal Taxes	$1,468	$1,468	$0	$486	$982	$0
State Taxes	$358	$358	$0	$118	$239	$0
Total Cost of Service	$11,551	$11,351	$200	$3,976	$7,375	$200
Gas Volume				54,640 (MMBtu/day)	2,000,000 MMBtu	3,660,158 MMBtu
Tariff Rates				$6.063/MMBtu/Mo.	$0.3073/MMBtu/Mo.	$0.0546/MMBtu

D. Propane/Air

Gas utilities also use a mixture of propane and air as a low volume substitute for storage. Propane is similar to methane chemically except that it has more carbon in each molecule. It is heavier, has a higher Btu content per cubic foot, and can easily be liquefied by increasing its pressure or decreasing its temperature. The last characteristic makes propane especially well suited for storage. Propane can be stored in conventional pressure containers, above or below ground. When needed, the propane is gasified by heating and mixed with air to reduce its Btu content. This blend of gases directly enters the distribution mains. The mixture is a substitute for natural gas and within some practical operational limits can be used without harm in most end use equipment.

About 3 Bcf per year (natural gas equivalent) of propane/air is used by the U.S. gas utility system. Exhibit V-6 shows gas equivalent volumes used in each state during 1993. Indiana, Virginia, Maryland, and New York are the principal users of propane/air. Because propane can be stored in tanks, propane/air facilities may be built practically anywhere that a site can be approved, given an adequate supply of propane.

EXHIBIT V-6
Propane/Air Use by State, 1993
(MMcf)



Source: DOE/EIA "Natural Gas Annual, 1993"

Both the Avoca bedded salt reservoir and Columbia LNG applications for FERC certificates provide cost estimates for a propane/air facility (Exhibit V-7) to illustrate the competitiveness of their storage projects.[2] Columbia's analysis of the competitive storage market estimates that a new 10 billion Btu/day propane/air facility costs between $1.2 million and $1.8 million. If the facility were to operate 10 days per year, the fixed costs would equal approximately $3.80 per MMBtu (about $2.40 for an existing facility), and non-gas operating costs would be between $0.25 to $0.75 per MMBtu. These cost estimates are consistent with the Avoca estimate of between $2.50 and $3.50 per MMBtu. The average price of propane varies regionally, as shown in Exhibit V-8.

E. Fuel Oil

The use of fuel oil also constitutes another alternative to gas storage. By interrupting the use of gas by fuel switchable customers, an LDC or pipeline can use that part of its existing pipeline capacity to meet seasonal changes in demand.

Traditionally, this option has been exercised by LDC's interrupting fuel switchable customers that are on interruptible (lower cost) tariffs. Recently, as alternative fuel-capable customers have begun purchasing their own firm gas delivery capacity, LDCs are making peak shaving agreements that allow use of the customers' capacity for a set period of the year in return for the LDC paying the additional cost of the alternative fuel and an "administrative" fee.

Decisions between fuel oils and gas are already modeled in GSAM and will not be included in the gas storage module. Exhibit V-9 provides the 1994 GRI forecasts of regional fuel oil costs for the electric utility industry that are used by GSAM.

F. Fuel Cost Comparison

Appendix E provides 1995 cost comparisons between storage and its alternatives based on the analysis contained in this and previous chapters. These comparisons are meant to demonstrate an initial snapshot of the decision factors relevant to end use determinations of gas storage versus alternatives. Many of the fuel prices used can and will be changing during the operation of the model. Propane/air use is also limited due to detrimental end user system effects of extensive propane use. Because of the declining use of propane/air for peak shaving and increasing use of LNG, the costs of peak shaving used in the gas storage module are being represented by LNG costs.

The charts shown in Appendix E represent the way unit costs of pipeline, storage and peak shaving services vary depending on the number of days per year they are used. Because of the fixed costs, which must be paid for firm service whether or not the service is used, unit costs (per Mcf of use) rise dramatically when usage declines to a few days per year.

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2) Cove Point LNG Company, L.P., Abbreviated Certificate Application, Docket No. CP94-59-000; Avoca Natural Gas Storage, Certificate Application, Docket No. CP94-161-000.

EXHIBIT V-7
Propane/Air Peak Shaving Cost Estimates
($/Dth)

Columbia LNG Estimates:		
Existing Facility Costs	High	Low
Average Unit Cost of Service	3.43	2.25
Cost of Propane	4.45	4.45
Total Average Cost	7.88	6.70
New Facility Costs	High	Low
Average Unit Cost	4.30	3.00
Cost of Propane	4.45	4.45
Total Average Cost	8.75	7.45
Avoca Estimates:		
Existing Facility Costs	High	Low
Average Unit Cost of Service	3.50	2.50
Cost of Propane	5.26	5.26
Total Average Cost	8.76	7.76

EXHIBIT V-8
1994 Average Regional Propane Costs

Region	$/MMBtu
New England	4.43
Middle Atlantic	4.24
South Atlantic	4.26
East North Central	4.19
East South Central	3.82
West North Central	4.00
West South Central	3.51
Mountain North	4.31
Mountain South	3.79
Pacific Northwest	3.81
California	4.58

Source: ICF Projections of 1993, Petroleum Marketing Annual Data

EXHIBIT V-9
1994 Regional Fuel Oil Costs
($/MMBtu)

	Distillate Fuel Oil	Residual Fuel Oil
Region		
New England	4.36	2.51
Middle Atlantic	4.36	2.64
South Atlantic	4.45	2.27
East North Central	4.38	2.80
East South Central	4.59	1.77
West North Central	4.31	1.67
West South Central	4.38	2.21
Mountain North	5.03	3.58
Mountain South	5.27	4.15
Pacific Northwest	4.81	3.12
California	4.22	3.11

Source: Gas Research Institute, Baseline Projection Databook, 1995

Because pipelines have high fixed costs and very low variable costs, they provide the least cost gas delivery service for large parts of a year. Peak shaving services are just the opposite--their fixed costs are relatively low and variable costs are substantially higher than those of pipelines. Thus, peak shaving operations are the economic choice for only one to ten days per year, and only in some regions. Storage services are typically the economic choice for one to five months of the year because storage fixed costs are lower than pipeline fixed costs.

Each of the curves in the charts of Appendix E includes the variable operating and maintenance costs, the fixed costs (divided by the gas volume that would use the facilities represented by the fixed costs), and the cost of gas transportation to and from underground storage and peak shaving. Note that in most cases, storage becomes less expensive than pipeline services at between 50 and 100 days per year.

The curves of Appendix E also show that under current market conditions for gas transportation, storage, and peak shaving, LNG is the short-term economic choice over storage only in New England, Florida, California, and the Pacific Northwest. For New England, Florida, and the Pacific Northwest, LNG is the lower cost short-term gas source because of the high transportation costs to move gas from storage in other regions where storage facilities are available. LNG is economic in California because of the high tariff rates for storage.

Despite the lack of clear economic justification for LNG peak shaving in some regions, these supplies are desired by LDCs for insurance purposes. Typically, LNG facilities are located within an LDC's system so it has complete control (without dependence on others for delivery) of this emergency gas supply. In general, LNG peak shaving facilities rarely utilize their full storage capacities in a winter.

The charts of Appendix E will be used in the GSAM storage module to obtain an initial indication of the number of days per year that each region will find storage to be less costly than pipeline capacity. As explained in the next chapter, the number of days storage service is economic in each region will be converted to the amount of storage needed by relating days per year to the monthly gas demand patterns of each region. For future years, the GSAM storage module will determine the economic use of storage.

G. Summary

The two natural gas alternatives to underground storage are pipeline capacity and imported LNG. Two other alternatives are propane/air mixtures and fuel oils that substitute for natural gas. For traditional winter season load increases, the significant choices in competition with underground storage are: 1) reserving more pipeline capacity, 2) purchasing imported LNG, and 3) using residual fuel or distillate fuel oil in place of gas. The short term alternatives, for peak shaving periods of roughly one to ten days per year, are propane storage for eventual mixing with air and storage of LNG that has been liquefied from pipeline gas during off-peak periods. A summary of regional peak shaving capacity and deliverability is provided in Exhibit V-10.

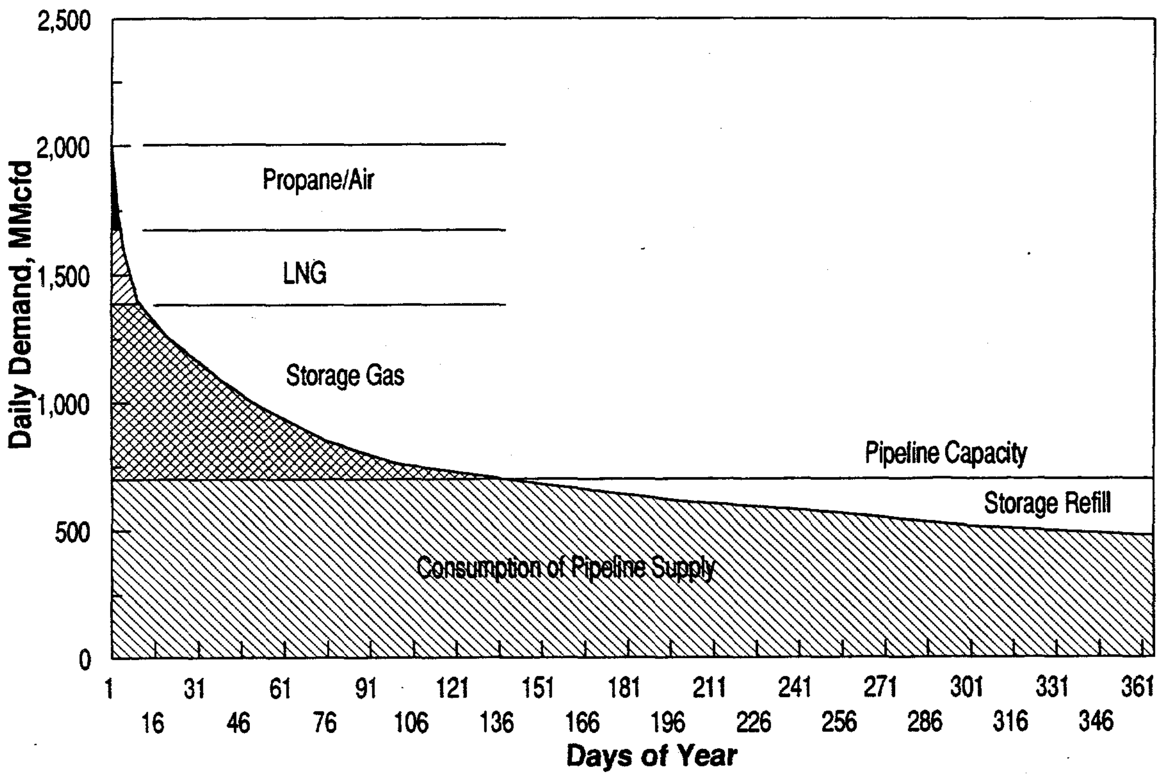
Decisions on the use of underground storage or the alternatives have historically been based on the costs of the higher volumes of gas required for space heating in winter months. The growth of underground storage occurred because it was less expensive for incremental winter supply than reserving pipeline capacity. For those consumers that could afford to invest in a backup or competing fuel such as fuel oils, gas was purchased at cheaper "interruptible" and (more recently) "spot" prices during the warmer months.

EXHIBIT V-10
Regional Peak Shaving Capacities and Deliverabilities

Region	Propane/Air		LNG						Peakshaving Total	
			Peakshaving		Satellite		Total			
	Capacity (MMcf)	Deliv. (MMcf/d)	Capacity (MMcf)	Deliv. (MMcf/d)	Capacity (MMcf)	Deliv. (MMcf/d)	Capacity (MMcf)	Deliv. (MMcf/d)	Capacity (MMcf)	Deliv. (MMcf/d)
New England	1,327	552	1,358	57	6,742	372	8,100	429	9,427	981
Middle Atlantic	906	399	25,257	1,096	2,365	252	27,622	1,348	28,528	1,747
South Atlantic	4,735	987	12,288	1,606	828	72	13,116	1,678	17,851	2,665
Florida	76	27	0	0	0	0	0	0	76	27
East North Central	3,746	850	9,782	1,180	168	30	9,950	1,210	13,696	2,060
East South Central	1,094	249	5,126	711	5	5	5,131	716	6,225	965
West North Central	4,458	877	8,624	815	0	0	8,624	815	13,082	1,692
West South Central	0	0	0	0	0	0	0	0	0	0
Mountain North	111	21	1,825	165	0	0	1,825	165	1,936	186
Mountain South	22	1	0	0	0	0	0	0	22	1
Pacific Northwest	112	71	2,698	300	0	0	2,698	300	2,810	371
California	119	42	0	0	0	0	0	0	119	42
Total	16,705	4,076	66,958	5,930	10,108	731	77,066	6,661	93,771	10,737

For the few coldest days of winter, when higher variable costs can be tolerated, the lower fixed costs of propane/air and LNG storage become more economic for those who must use a gaseous fuel. Exhibit V-11 provides an example of how an LDC might plan its supplies over a year to use the least expensive supply for each day of the year. This "load duration" curve moves from the peak day to the year-round base load of warmer months. It should be noted that in areas where air conditioning loads of gas-burning electric utilities are high in summer months, the peak day for gas use or some of the higher load days may be caused by the power generation loads.

EXHIBIT V-11
Representation of a Typical LDC Load Duration Curve



VI. Storage Demand Methodology Proposed for GSAM

The ultimate objective of this gas storage study project is to provide GSAM with a submodel which more accurately simulates the roles that storage plays in balancing North American gas supplies and demands through a market clearing price mechanism. This submodel, or module, will act as another source of gas supply to the gas consuming regions during periods of high gas demand, and will behave as another demand sector during gas reinjection periods when other market demands are low.

Since GSAM will make the decisions regarding use of gas or other fuels in the industrial and power generation sectors where dual fuel capabilities reside, the gas supply decisions of gas distributors and marketers as modeled in the gas storage module of GSAM need choose among only the gaseous alternatives. Thus the alternatives that will be modeled in the storage module will be underground storage, pipeline capacity, and peak shaving. Selecting the optimum mixture of these alternatives to minimize gas costs while maintaining high levels of supply dependability is a complex problem for any major purchaser of natural gas. Modeling this procedure is even more complex, considering the various regions of the U.S. and their differences in climate, distances from supply and storage, costs of storage and peak shaving, and gas usage patterns. This section describes the factors that must be considered in modeling storage economics and the modeling methodology that has been developed.

A. Economics of Gas Storage and Its Alternatives

The basic reason behind the use of market area storage and peak shaving for higher demand periods in a year is the high unit cost of reserving pipeline capacity that will be used for only parts of each year. Gas pipelines have high capital costs and very low operating costs, so once pipeline capacity is in place, the incremental cost of its use is very low. These economics argue for keeping pipeline throughputs near capacity all year long. The measure of pipeline use is called "load factor". A high load factor is attained when the average use of a pipeline approaches the pipeline capacity. For example, if a line is designed to transport 500 MMcf per day (MMcfd) and its average use through the year is 400 MMcfd, the load factor would be 80 percent.

The concept of a load factor can be applied to various capacities other than those of pipelines as a measure of how fully they are utilized, such as for gas storage and for the portion of pipeline capacity a shipper may have under contract. For example, if a shipper reserves 50 MMcfd of capacity on a pipeline and ships a daily average of 30 MMcf, the shipper is using only 60 percent of the capacity reserved and paying about 65 percent more for transportation than if only 30 MMcfd of pipeline capacity were reserved. If the 50 MMcfd was reserved because demand rises to that level on a few days each year, one or more less expensive alternatives to supplement the average need for 30 MMcfd are probably available. Exhibit VI-1 shows how the unit costs of the gas supply alternatives vary with their use (load factor) each year.

Compared to pipeline capacity, underground storage has lower capital (fixed) costs and higher operating (variable) costs. Because of this difference in fixed and variable costs, there will be periods each year when increments of underground storage service have lower unit costs than a similar increment of pipeline capacity. Depending on the market area climate and distance from gas sources, the duration

EXHIBIT VI-1
Examples of Load Factor Effects on Average Gas Supply Costs

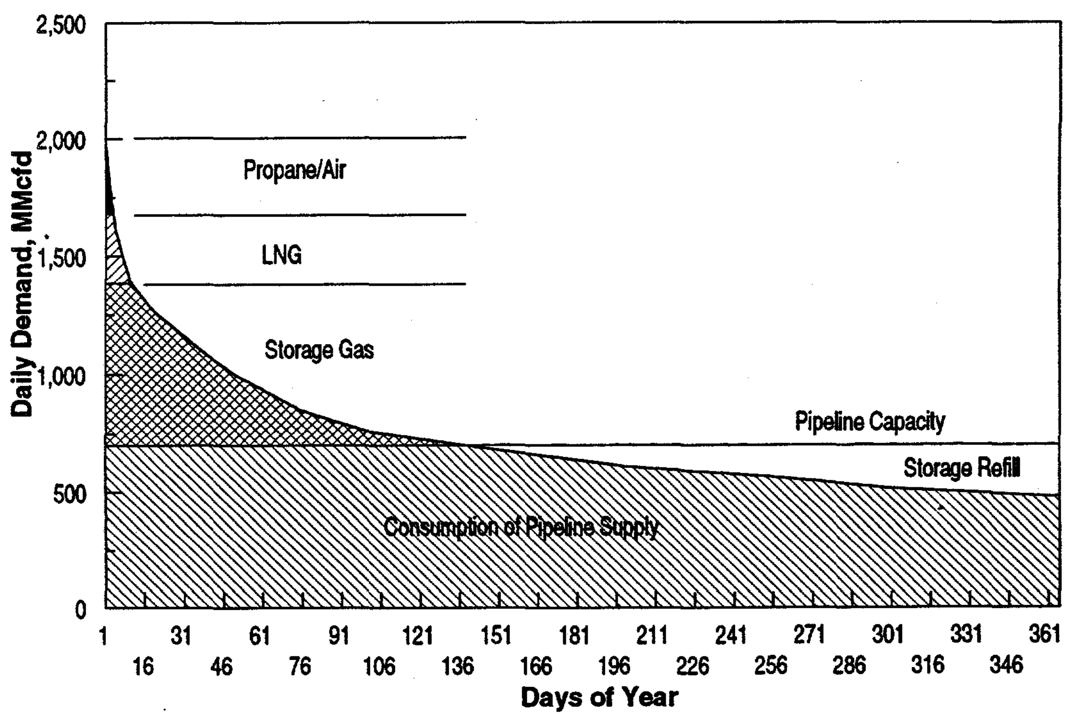
Gas Supply Alternative	Fixed Monthly Capacity Reservation Cost	Unit Reservation Rate					Variable Usage Rate	Gas Field Price	Total Unit Rate, $/Mcf				
	$/Mcf	@100% Load Factor	@30% Load Factor	@8% Load Factor	@0.8% Load Factor	@0.3% Load Factor	$/Mcf	$/Mcf	@80% Load Factor	@30% Load Factor	@8% Load Factor	@0.8% Load Factor	@0.3% Load Factor
		(365 days/yr)	(110 days/yr)	(30 days/yr)	(3 days/yr)	(1 day/yr)			(292 days/yr)	(110 days/yr)	(30 days/yr)	(3 days/yr)	(1 day/yr)
Pipeline Capacity Alternative (1)	$16.00	$0.53	$1.75	$6.58	$65.75	$175.34	$0.22	$2.00	$2.75	$3.97	$8.80	$67.97	$177.56
Storage Alternative (2)		N.A.	$1.22	$3.48	$31.22	$82.59	$0.36	$2.00	N.A.	$3.58	$5.84	$33.58	$84.95
Pipeline to storage	$12.00	$0.39	$0.39	$0.39	$0.39	$0.39	$0.12		$0.51	$0.51	$0.51	$0.51	$0.51
(@ 100% load factor)													
Pipeline to market	$5.50	$0.18	$0.60	$2.26	$22.60	$60.27	$0.05		$0.23	$0.65	$2.31	$22.65	$60.32
(from storage)													
Storage	$2.00	N.A.	$0.22	$0.82	$8.22	$21.92	$0.05		N.A.	$0.27	$0.87	$8.27	$21.97
LNG Alternative		N.A.	N.A.	$3.12	$25.32	$66.41	$0.92	$2.00	N.A.	N.A.	$6.04	$28.24	$69.33
LNG	$6.00	N.A.	N.A.	$2.47	$24.66	$65.75	$0.80		N.A.	N.A.	$3.27	$25.46	$66.55
Pipeline to LNG	$16.00	$0.66	$0.66	$0.66	$0.66	$0.66	$0.12		N.A.	N.A.	$0.78	$0.78	$0.78
(@ 80% load factor)													
Propane/Air Alternative	$4.00	N.A.	N.A.	$1.64	$16.44	$43.84	$10.00	N.A.	N.A.	N.A.	$11.64	$26.44	$53.84

Notes:
1. Pipeline capacity alternative is direct route to market from gas supply source.
2. Storage alternative is sum of storage rate, pipeline rate to storage at a high load factor (100% in this example) plus pipeline rate from storage to market at lower load factors.
3. LNG alternative is sum of LNG rate and pipeline rate to the LNG facility at a high load factor (80% in this case).

of these periods when storage is economic can vary from a few weeks to months. In colder climates, the higher gas demands occur in winter months for space heating and in some warmer climates the higher demands can be in winter for heating and in summer when air conditioning requires greater use of gas-fired electric power generation. The examples of Exhibit VI-1 show that the cost of storage becomes less than the cost of pipeline capacity when the pipeline load factor falls to about 30 percent. Stated another way, it would not be economic to reserve pipeline capacity for the coldest 110 days of the year when underground storage plus the gas transportation it requires would cost less than pipeline capacity.

For the few coldest days in northern areas of the U.S., peak shaving supplies of LNG and propane/air mixtures can be less expensive sources of gas to supplement the pipeline capacity and underground storage that cost less for most of each year. LNG may be the lowest cost supply alternative for supplementing the reserved pipeline and storage capacity during the highest two to ten days of gas demand. For the peak day or peak three-day demand, propane/air may be the least cost supplement to the other alternatives. Exhibit VI-1 shows LNG lowest for more than three days and propane/air lowest for the highest one- to three-day demand increments. Exhibit VI-2 provides an example of how a northeastern U.S. LDC might plan to meet its demands from the coldest to warmest day of a year.

EXHIBIT VI-2
Example of Gas Supplies Planned for Design Year Demand
(Load Duration Curve)



As demonstrated in Exhibit VI-1, there is no simple set of prices for underground storage and its alternatives. All have annual fixed costs for capacity reservation or plant investment that do not vary with the amount of use. As use of the capacity or facility goes down, the fixed unit costs, in dollars per Mcf, rise. Buying pipeline capacity to meet gas demand for 11 months of the year would raise the average cost of pipeline service from $2.75 per Mcf to $8.80 per Mcf in the example of Exhibit VI-1. Using underground storage for supply during the period from the coldest 110 days up to the coldest 30 days would cost from $3.58 to $5.84 per Mcf — less expensive than pipeline capacity during this period. In addition to the cost variations from the levels of use of gas storage and its alternatives, Exhibit VI-1 also shows that the distances from supply to storage and from storage to the shipper have major effects on the costs of the alternatives through their pipeline delivery costs.

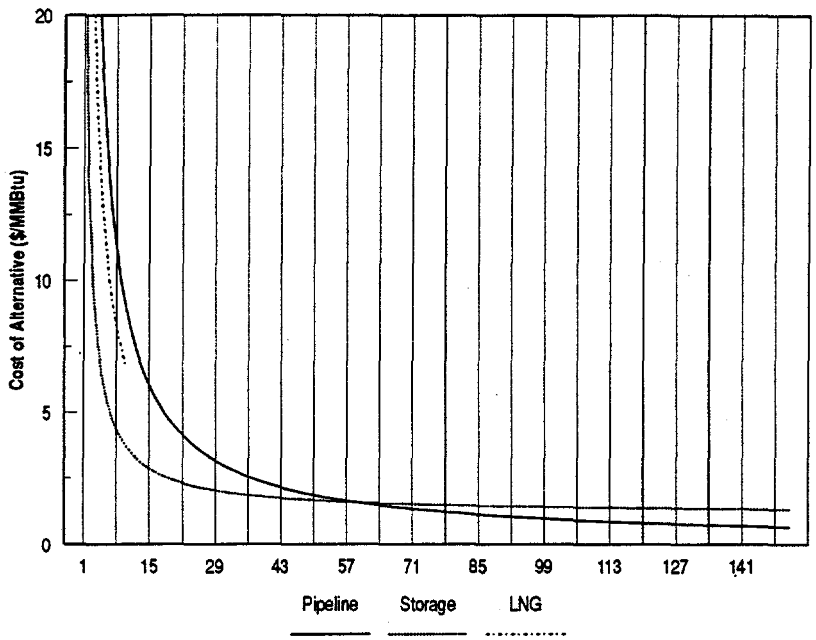
In recent years, two significant changes have occurred in natural gas markets that reduced the need for storage in some regions. The first change was the initiation of contract terms whereby developers of cogeneration plants that are dual-fueled by gas and distillate fuel oil agree to burn oil for a month or more and divert their firm gas supply to the LDC during the LDC's high demand periods each year. The price paid by the LDC for this peaking supply is typically related to the cost of the alternate fuel the cogenerator has to burn. Payment for the gas may be made through a discount in the LDC's charges for gas deliveries to the cogenerator during the remainder of the year, or a credit against regular delivery charges. If the cost of this arrangement is less than the cost of an increment of delivered storage gas, the LDC can elect to reduce its reservation for storage service and storage gas delivery capacity.

The second change results from the "no-notice" service that most pipelines must offer, according to FERC Order 636. Under no-notice service, shippers can reserve firm pipeline transportation service for specified daily capacities. This is similar to pipeline firm transportation service, except that any storage capacity used to supply the gas may belong to the shipper, and there are no penalties for unscheduled deliveries up to the level reserved by the shipper. A pipeline can provide this service by using gas in its own operational storage capacity, borrowing gas from contract storage, or diverting gas deliveries scheduled for interruptible shippers. In all cases, however, the shipper with no-notice service must ultimately furnish the gas that is delivered by the pipeline.

B. GSAM Methodology for Assessing the Need for Storage

The initial step in analyzing the need for storage and/or its alternatives in a northern region is to develop the prices for these services from the warmest (least gas demand) day to the coldest (highest gas demand) day of each year being forecast. Exhibit VI-3 provides an example of how the prices of each supply alternative vary with changes in daily gas demand. This example, for the East North Central (ENC) region in 1995, shows that pipeline capacity is less expensive than storage for most of the year, but is more costly than storage during the 60 days of highest demand. (The pipeline price curve crosses over to higher than the storage price curve at about the 60th day.) This means that the optimum time period for storage to begin supplementing pipeline deliveries is when pipeline deliveries have supplied all of the gas for 305 days (365 less 60). Further, the curves show that LNG is never less expensive than storage under the economic conditions of 1995, in this region. A set of these price curves for each region is provided in Appendix E. In addition to the price of the storage alternative, the prices that are presented in these regional curves include the costs of gas transportation to storage and from storage to the consuming region.

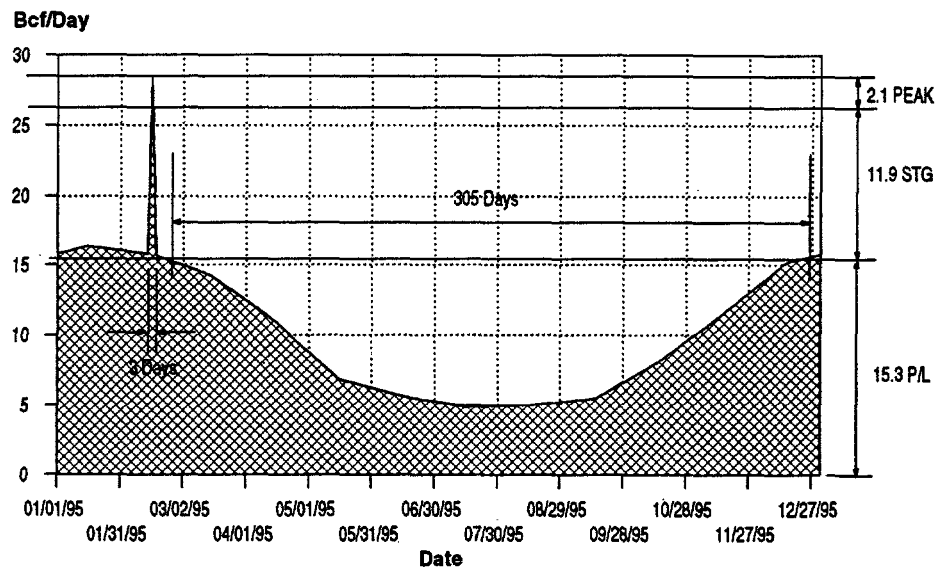
EXHIBIT VI-3
Projected Price Curves, 1995
East North Central



The next step is to compile the total gas demand for all consuming sectors in each region for all years being forecast. These compilations will include the average monthly demands and an estimated peak day demand based on historical peak day data from each region. It should be understood that these demand graphs are not supposed to show the actual demand over the course of a year, but rather develop an average level of demand for the year, with a peak day "spike" to indicate the maximum level to which demand is expected to rise during the year. Exhibit VI-4 provides an example of these demands for the East North Central region in 1995. Appendix F provides similar charts for each of the 12 regions described here. The charts clearly show that peak demands for gas for the various regions do not all occur in the same month. In colder climates, the peak month is typically January or February. In warmer climates there may be a peak demand in summer when air conditioning loads require electric utilities to burn more gas in peaking turbines.

By combining the daily price data illustrated in Exhibit VI-3 with the demand data of Exhibit VI-4, the periods during a year when pipeline capacity should be used alone can be measured. Starting with the days of least demand and working upscale to higher daily demands, the 305 days of optimum pipeline deliveries can be identified. Continuing this process, the days in which storage should be the economic choice can also be identified. Exhibit VI-5 illustrates the optimum amounts and times of use for each supply alternative for the East North Central region in 1995.

EXHIBIT VI-5
Projected Gas Storage Demand Curve, 1995
East North Central Region



Peak Day volume is included for illustrative purposes.

Wherever storage capacity is developed, there must be enough pipeline capacity available in the off-peak periods of each year to refill the storage. When part of the storage capacity in a region is reserved for use in another region, the pipeline capacity to the storage region must be secured by the users in the other region. In addition, shippers in the using region must also reserve peak-period pipeline capacity from the storage region to the using region.

C. Methodology Refinements

Some refinements to this process will have to be made in Phase II of the project. Because of limitations in the data that are available to the public, there are at least two areas where other data sources and reasoned assumptions will be needed regarding gas flows and prices for the various regions. Among the refinements expected to be required are:

1. Since gas stored in one region is frequently transported to another region for consumption, estimates must be made for the interstate flows of gas withdrawn from storage. A prime example of this complication exists in analyzing winter gas supplies for the New England region. Although there is no underground storage in New England, a large part of winter gas supply to that region comes from storage in other regions, such as the Middle Atlantic, East South Central, and East North Central. Thus there must be a surplus of storage capacity in these three regions compared to their combined need for storage.

2. Allowances should be made for the seasonal variations that occur in gas transportation rates. Rate discounting is common now in periods of the year when pipeline capacity utilization is low. Relationships between pipeline capacity utilization (which GSAM models) and transport rates are being developed to provide seasonal differences in rates for gas transport to and from gas storage facilities.

VII. Regional Storage Needs

Using the methodology described in Section VI, the currently optimum underground gas storage capacities can be developed for each region, considering the demand pattern of the region and the costs of storage and the other supply alternatives that are available. However, the economically optimum capacity for a region cannot be directly compared with the existing capacity in the region to determine the need for more or less storage capacity. There are several reasons why these direct comparisons cannot be made:

1. Storage needs of one region are frequently supplied by storage capacity in another region.

2. Some existing storage may not be economic compared to new storage that has higher gas injection and withdrawal rates or new, less costly storage that is developed with improved technology.

3. Storage capacity in a distant region plus transportation to market may in some cases be less expensive than local storage in the market area.

4. Even if existing storage supply exceeds demand on a national basis, economics may dictate the addition of new capacity in specific areas or of special characteristics. Some storage capacity could become stranded because it is uneconomic compared to other capacity.

Thus the balance of storage need and availability at any time in the future needs to be analyzed on an inter-regional basis rather than an intra-regional basis, which argues for using a tool like GSAM to undertake such an analysis.

The methodology developed for determining the need for storage capacity in the various regions will be to find the least costly gas storage price plus gas transportation rate combination to provide storage service to regions with too little or too costly storage capacity. In regions where geology is favorable for developing additional storage capacity, the combination of distant storage plus transportation will have to compete with new or expanded storage capacity in the region that needs more capacity. In New England and Florida, where geology has been considered unfavorable for developing storage, the least costly distant capacity will be chosen or storage may prove to be uneconomic.

The storage characteristic of primary importance to storage users is its daily deliverability and the number of days that this deliverability is available. Although the product of these two characteristics is a volume of gas, the gas volume or storage capacity contracted for is not the important characteristic. A volume of storage gas that requires 90 days to recover is not nearly as valuable as a similar storage volume that can be recovered in 10 or 30 days. Thus high deliverability storage may be more economic in many circumstances, even though its first costs are substantially higher than a competing low deliverability storage facility.

Because of the inter-regional scope of balancing storage demand and supply, and the implications of potential newer technology, the more definitive identification of regional storage needs must await development of the storage module and its integration with GSAM. However, based on GRI forecasts of gas demand, some preliminary observations can be made regarding potential storage needs.

A. Residential/Commercial Needs

Review of Exhibit VII-1 shows that the amount of growth in the temperature sensitive residential and commercial consuming sectors may indicate that three regions could be candidates for additional gas storage between now and the year 2010. These regions are the South Atlantic, West South Central, and California. Each of these regions is forecast to have a combined residential and commercial demand increase of near 200 Bcf by 2010. However, for three different reasons none of these three regions is an obvious candidate for more storage.

The South Atlantic region, which is forecast to have the largest growth in the residential and commercial sectors, has few areas near population centers that have known reservoirs. Only West Virginia with 35 existing facilities has the geology for substantial storage capacity. Maryland, with one existing depleted reservoir facility, and Virginia, with one planned salt cavern facility, are the only other states in the South Atlantic region with recognized storage possibilities. These three states, located at the northern end of the region, will have to compete with potential sites in the adjacent major storage states of Pennsylvania, Ohio, and Kentucky. Florida and Georgia, which are closer to major gas producing states, may find that storage in a distant state and transportation from storage are more expensive than direct pipeline capacity -- particularly for those shippers that have invested in large peak shaving facilities for peak load periods.

Gas consumers in the West South Central region, where about 70 percent of U.S. natural gas is produced, do not have to pay for long, costly pipelines to deliver their gas. Consequently, storage in these four states is primarily for supplementing gas production activities at any time of year rather than for cold weather demand. As discussed later, peak demands in this region occur in both winter and summer for space heating and cooling. Much of the electric power generated for air conditioning in summer is gas fueled.

California has both a substantial forecast of growth in gas demand and the geology for high quality storage. Four projects are planned which would nearly double the deliverability of the nine existing storage facilities there. The need for these new projects is not obvious, however, because there is substantial surplus pipeline capacity into California. Increments of storage capacity will have to compete with the reduced gas transportation rates that result from the surplus pipeline capacity available.

A more likely scenario for a regional storage capacity increase would be in the Mid Atlantic region to satisfy the residential and commercial demand growth of both the Mid Atlantic and New England regions. Combined, these two regions are expected to have the same level of growth as the South Atlantic region, and there are eight storage projects planned for Pennsylvania and New York.

Although having a smaller rise in residential and commercial demand, the East North Central region presents a more straight-forward case for added storage capacity. The eight new facilities planned for Michigan, Indiana, and Illinois indicate the region's suitability for added storage capacity. Some of the Michigan storage potential might be economic for use in the Mid Atlantic and New England regions -- particularly if the stored gas is from Canada and less expensive than U.S. production.

EXHIBIT VII-1
GRI Regional Gas Consumption Forecast by Sectors
(TrBtu/yr)

Power Generation	1993	2000	2005	2010	Growth 1993-2010	
					TrBtu/yr	Percent
New England	50	55	67	69	19	38%
Mid Atlantic	225	259	314	369	144	64%
South Atlantic	227	426	477	615	388	171%
East North Central	37	301	374	382	345	932%
East South Central	47	149	170	208	161	343%
West North Central	42	162	208	229	187	445%
West South Central	1517	1873	1975	2116	599	39%
Mountain North	34	41	55	65	31	91%
Mountain South	47	73	69	61	14	30%
Pacific Northwest	46	62	71	79	33	72%
California	468	832	712	584	116	25%
Industrial	**1993**	**2000**	**2005**	**2010**	**Growth 1993-2010**	
					TrBtu/yr	**Percent**
New England	179	204	241	279	100	56%
Mid Atlantic	610	764	839	904	294	48%
South Atlantic	701	790	906	1018	317	45%
East North Central	1376	1468	1569	1671	295	21%
East South Central	515	647	744	777	262	51%
West North Central	509	500	524	557	48	9%
West South Central	3794	4186	4468	4753	959	25%
Mountain North	348	309	313	346	-2	-1%
Mountain South	89	134	127	133	44	49%
Pacific Northwest	467	503	505	506	39	8%
California	710	604	613	605	-105	-15%

EXHIBIT VII-1
GRI Regional Gas Consumption Forecast by Sectors
(TrBtu/yr) (continued)

Commercial	1993	2000	2005	2010	Growth 1993-2010	
					TrBtu/yr	Percent
New England	117	133	151	168	51	44%
Mid Atlantic	496	508	526	566	70	14%
South Atlantic	302	349	387	439	137	45%
East North Central	725	721	730	764	39	5%
East South Central	139	151	162	176	37	27%
West North Central	332	347	372	401	69	21%
West South Central	313	366	416	471	158	50%
Mountain North	149	168	180	195	46	31%
Mountain South	58	67	73	82	24	41%
Pacific Northwest	90	98	106	117	27	30%
California	278	323	363	411	133	48%
Residential	**1993**	**2000**	**2005**	**2010**	**Growth 1993-2010**	
					TrBtu/yr	**Percent**
New England	199	226	246	269	70	35%
Mid Atlantic	881	904	914	932	51	6%
South Atlantic	409	451	480	512	103	25%
East North Central	1550	1593	1620	1644	94	6%
East South Central	211	222	230	239	28	13%
West North Central	521	536	548	558	37	7%
West South Central	426	439	451	465	39	9%
Mountain North	232	258	272	286	54	23%
Mountain South	63	69	73	78	15	24%
Pacific Northwest	100	121	137	156	56	56%
California	519	531	548	564	45	9%

EXHIBIT VII-1
GRI Regional Gas Consumption Forecast by Sectors
(TrBtu/yr) (continued)

Commercial and Residential	1993	2000	2005	2010	Growth 1993-2010	
					TrBtu/yr	Percent
New England	316	359	397	437	121	38%
Mid Atlantic	1377	1412	1440	1498	121	9%
South Atlantic	711	800	867	951	240	34%
East North Central	2275	2314	2350	2408	133	6%
East South Central	350	373	392	415	65	19%
West North Central	853	883	920	959	106	12%
West South Central	739	805	867	936	197	27%
Mountain North	381	426	452	481	100	26%
Mountain South	121	136	146	160	39	32%
Pacific Northwest	190	219	243	273	83	44%
California	797	854	911	975	178	22%

B. Industrial Needs

Because of the relatively flat demand for gas that the industrial sector exhibits, there is little or no demand for gas storage by industry. Some exceptions to this conclusion may occur in cases where large industrial consumers choose to use storage as a tool in attempting to reduce gas costs. By purchasing gas on the spot market when prices are thought to be low, relative to the future, and withdrawing stored gas at other times, perceptive industrial gas consumers may be able to obtain lower cost gas than through a long term fixed price contract.

C. Electric Power Needs

In all regions, the demand for gas by power plants peaks in the summer months when electric air conditioning loads are heaviest. However, in most regions this summer load simply fills part of the load valley that occurs in the warmer months, thereby improving the annual load factor but not affecting the winter peak load. The most obvious exception to this load pattern occurs in Florida where gas is a major power generation fuel and space heating requirements are relatively small compared to other regions. Since the more populous areas of Florida have no storage potential and gas transportation is much less costly in summer months, there is little chance that this demand will result in a need for storage. A similar situation exists in the West South Central (WSC) region where the monthly average total load is about equal in cold and hot weather periods. Although storage sites are available in the WSC region, local gas availability and low delivery costs in the warmer months argue for direct deliveries of gas for power generation. As with some industrial loads, there may be a more speculative use of storage by some electric power plants to take advantage of lower gas prices in the warmer months and take gas from storage in the winter months when field prices are typically higher.

D. Potential For Storage Use By Producers

Although gas producer use of storage is outside the scope of this study, it does potentially add another demand for storage facilities. More producers are considering the possibility of using gas storage to offset the financial effects of gas price volatility. Rather than shut-in gas production when demand and prices are low, producers can inject gas into storage, thereby saving it for periods when demand and prices are higher. If the cost of storage is less than the price differentials that occur, this scheme could be profitable. Success would likely depend on how many times gas prices cycle with the required price amplitude to make a profit. This process is similar to that used by some gas marketers, LDCs, industrial consumers, and electric utilities which use storage to attempt "buy low, sell high."

Other alternatives that producers have to choose from for minimizing the effects of price volatility are the acceptance of long-term contracts at fixed or regularly escalated prices and the use of financial instruments for hedging gas revenues.

E. Storage Design and Operating Criteria

In addition to the regional gas demand patterns and costs of alternatives to storage, there are certain storage design and operating criteria that will be important to the identification of regional storage needs in the subsequent tasks of this project. These criteria are:

- Gas deliverability rate over time
- Gas reinjection rate over time
- Total working capacity of storage facility
- Location of storage facility relative to market served
- Estimated capital, operating, and maintenance costs

F. Summary

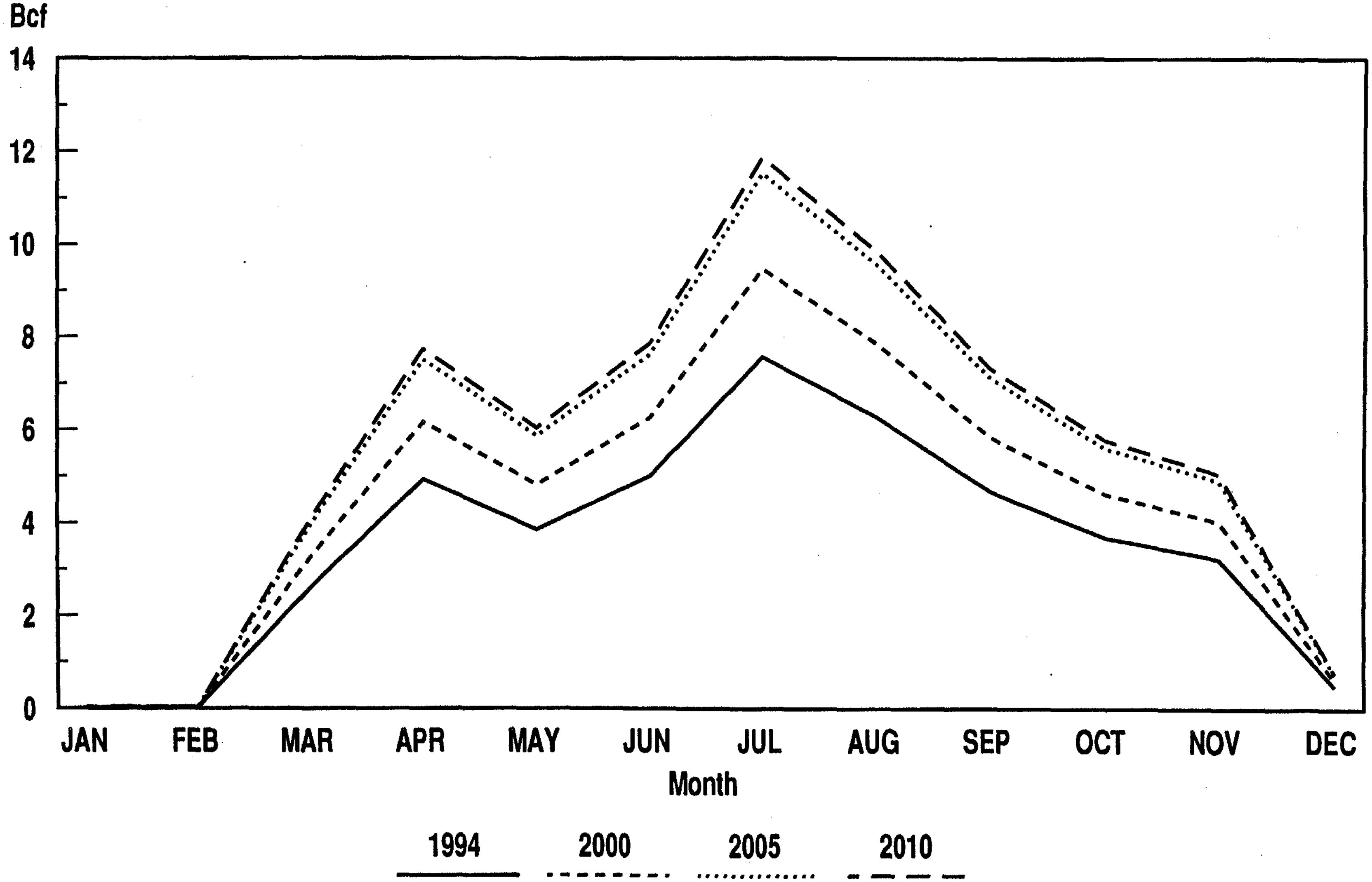
Although there are regions where seasonal gas demands are expected to grow and possibly make additional storage capacity economically attractive, there also are a large number of additional considerations that complicate the decision making process for adding storage. These complications include the inter-regional availability of storage, the increasing value of high deliverability storage, the impacts of new technology on storage capacities and costs, and the variations that exist in the monthly gas demand patterns of the consuming regions.

Final conclusions on where and how much additional storage capacity will be needed between now and the year 2010 will have to come from the sophisticated market balancing operations of GSAM. This will occur with the completion of Tasks 3 and 5.

Appendix A

New England

Monthly Electrical Generation Gas Demand Curve



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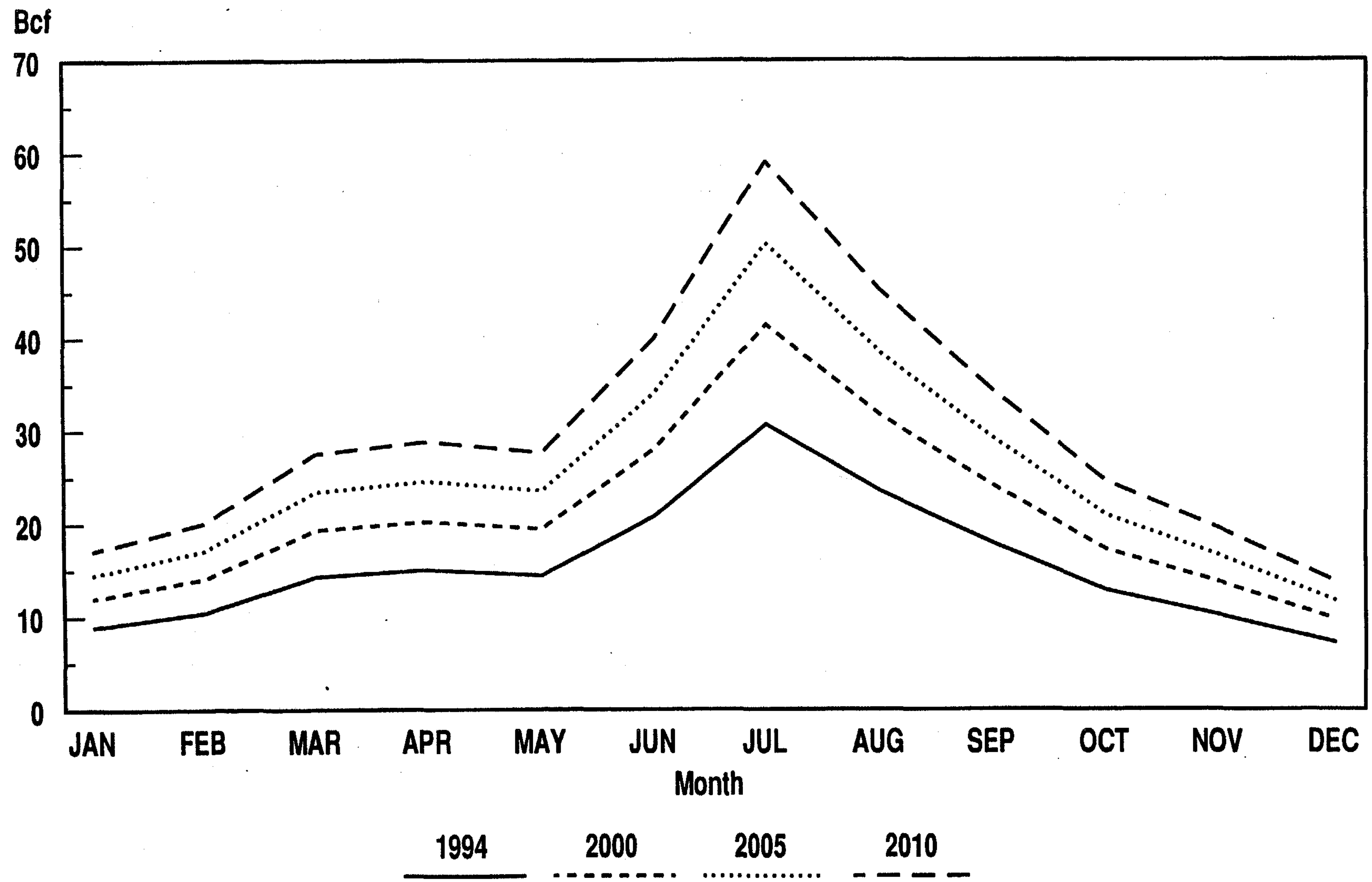
A-2

Middle Atlantic

Monthly Electric Generation Gas Demand Curve



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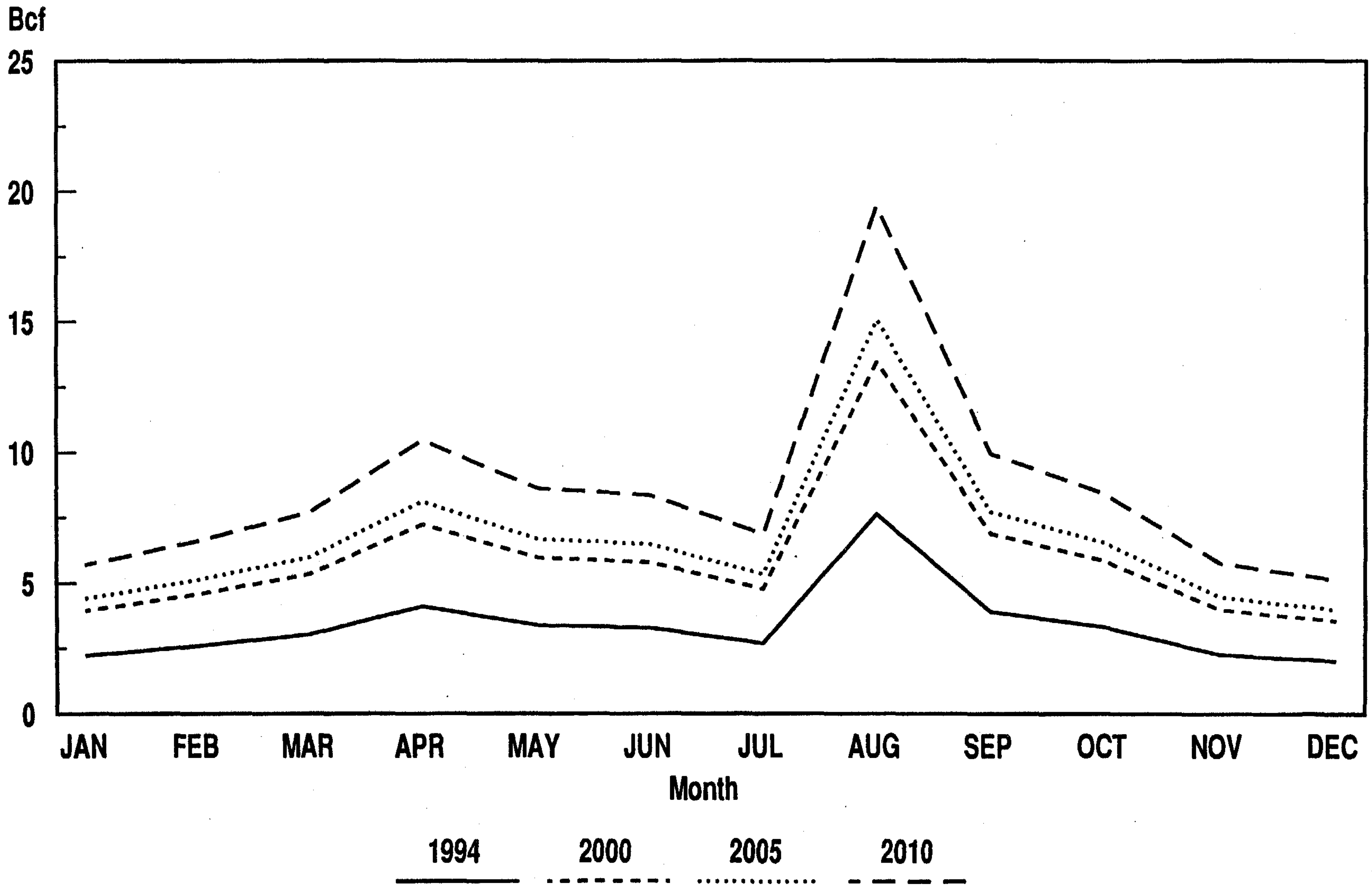
A-3

South Atlantic

Monthly Electric Generation Gas Demand Curve



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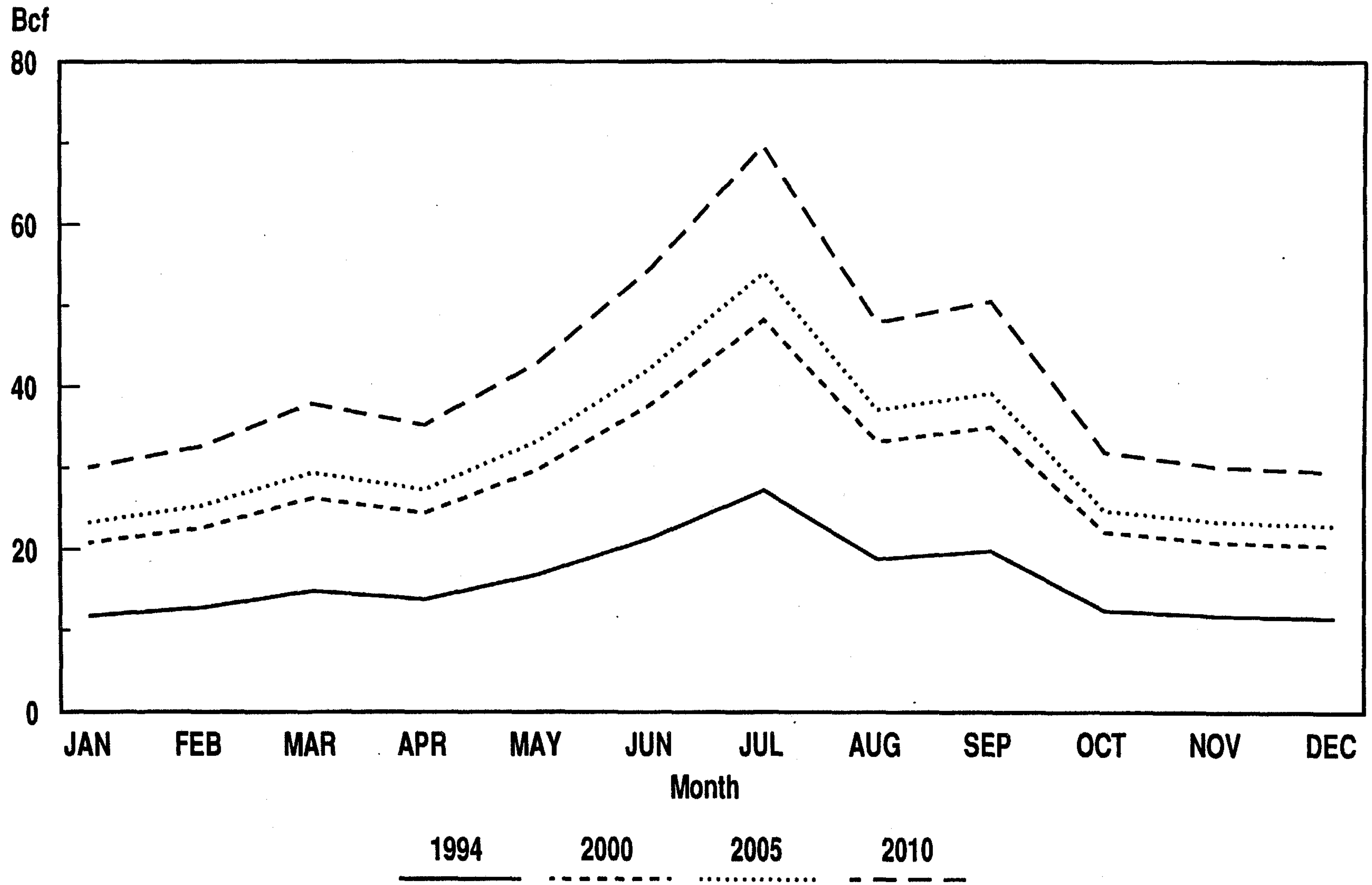
Florida

Monthly Electric Generation Gas Demand Curve



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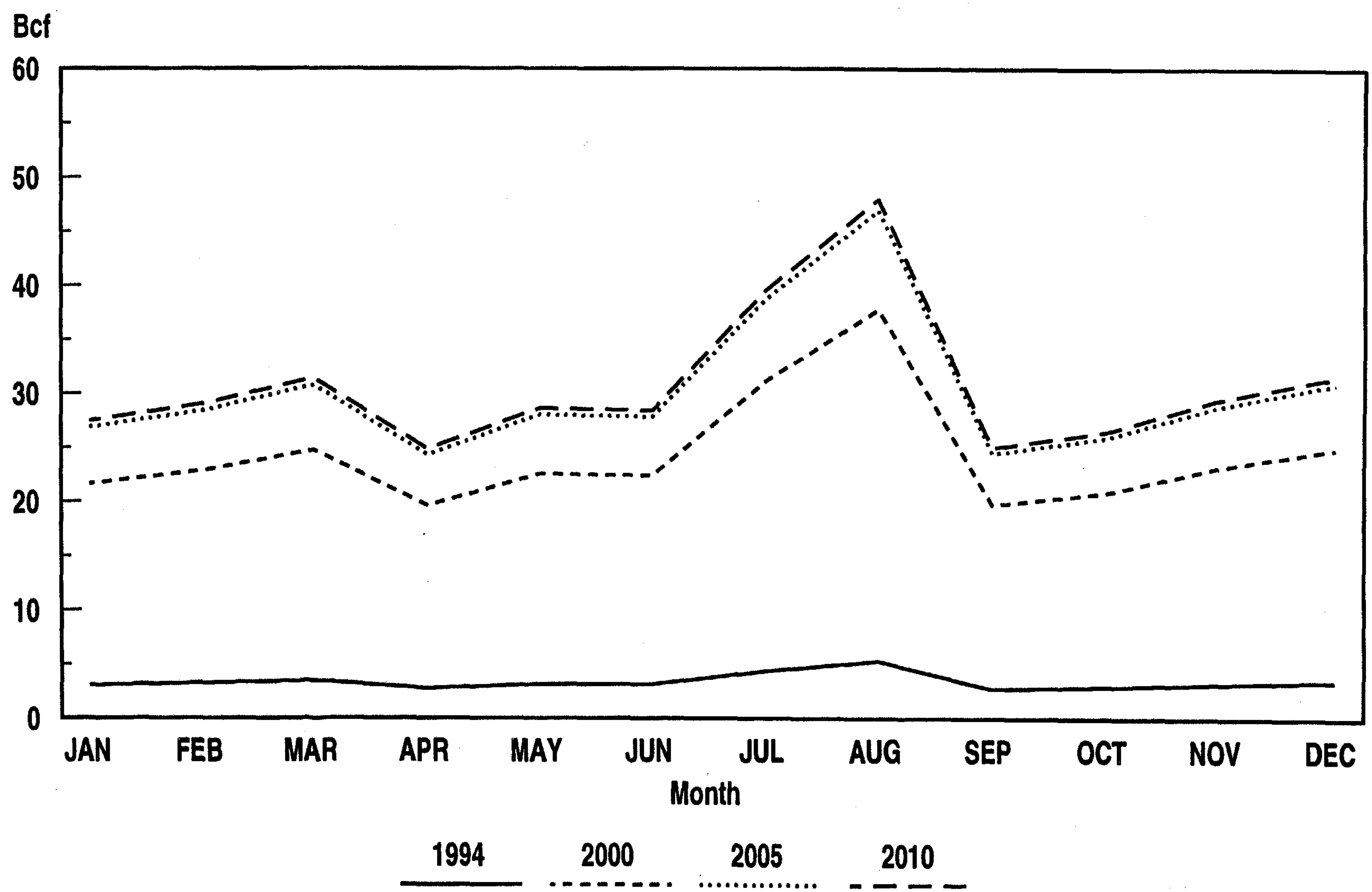
A-5

East North Central

Monthly Electric Generation Gas Demand Curve



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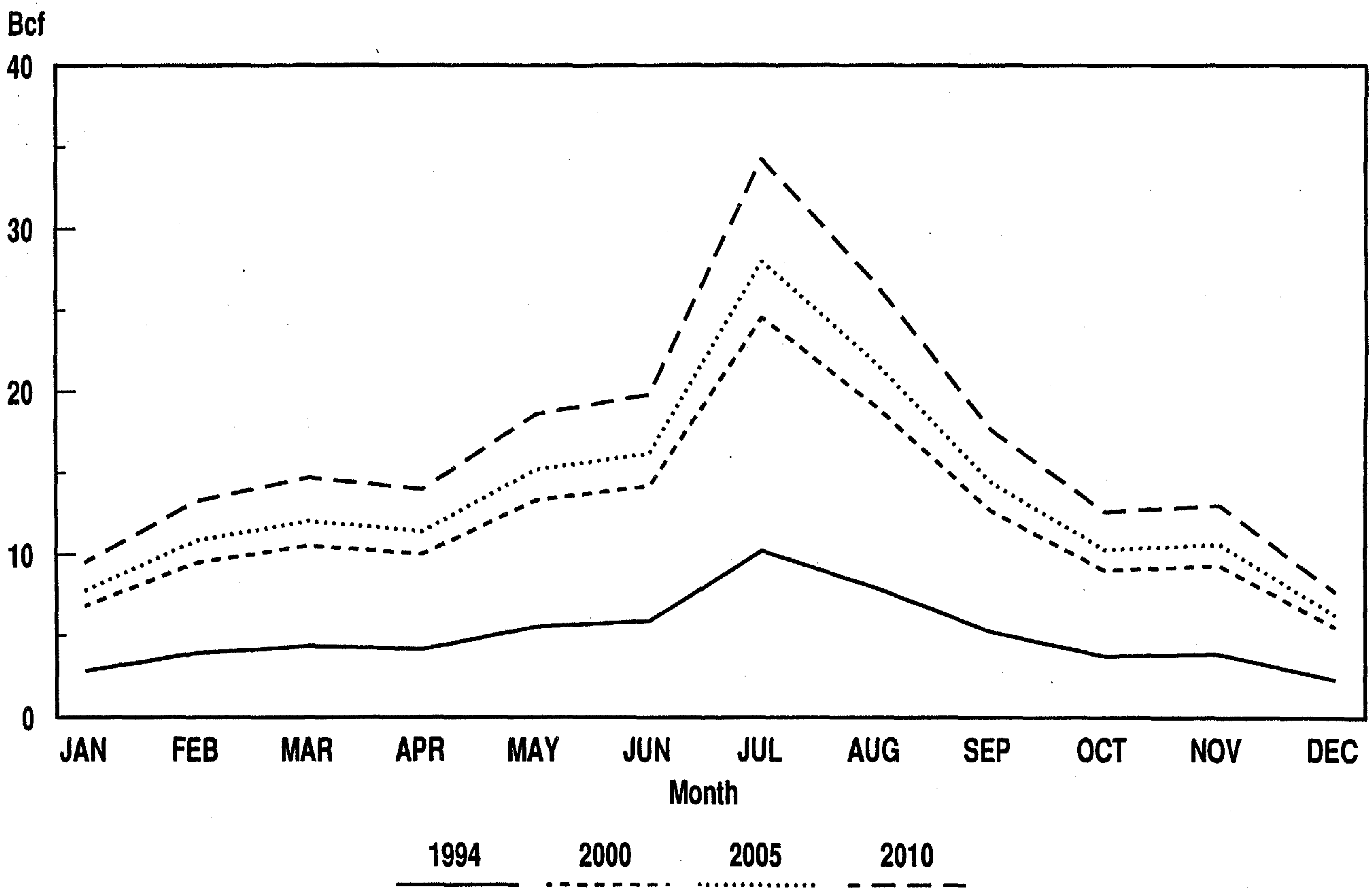
East South Central

Monthly Electric Generation Gas Demand Curve



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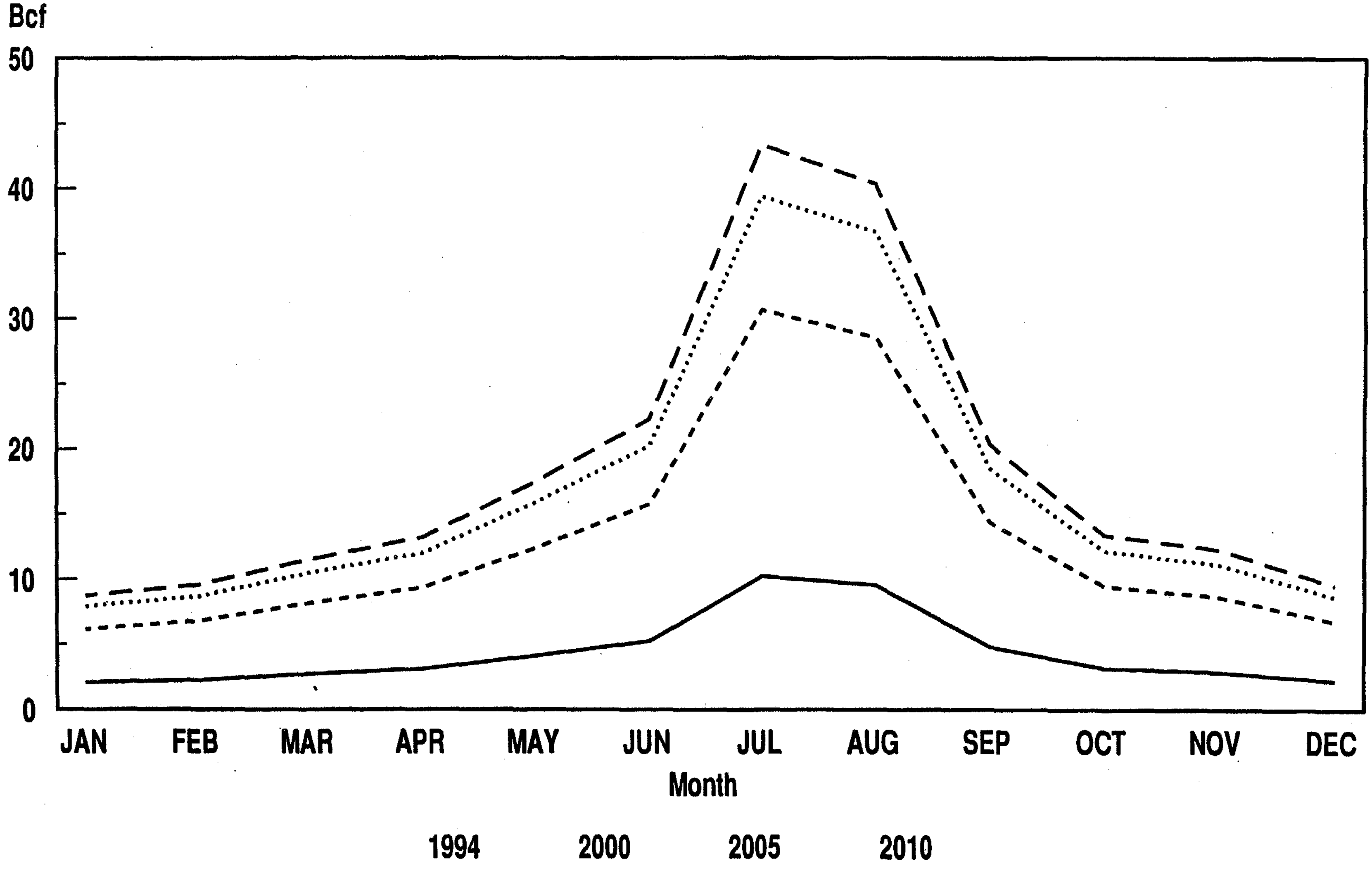
West North Central

Monthly Electrical Generation Gas Demand Curve



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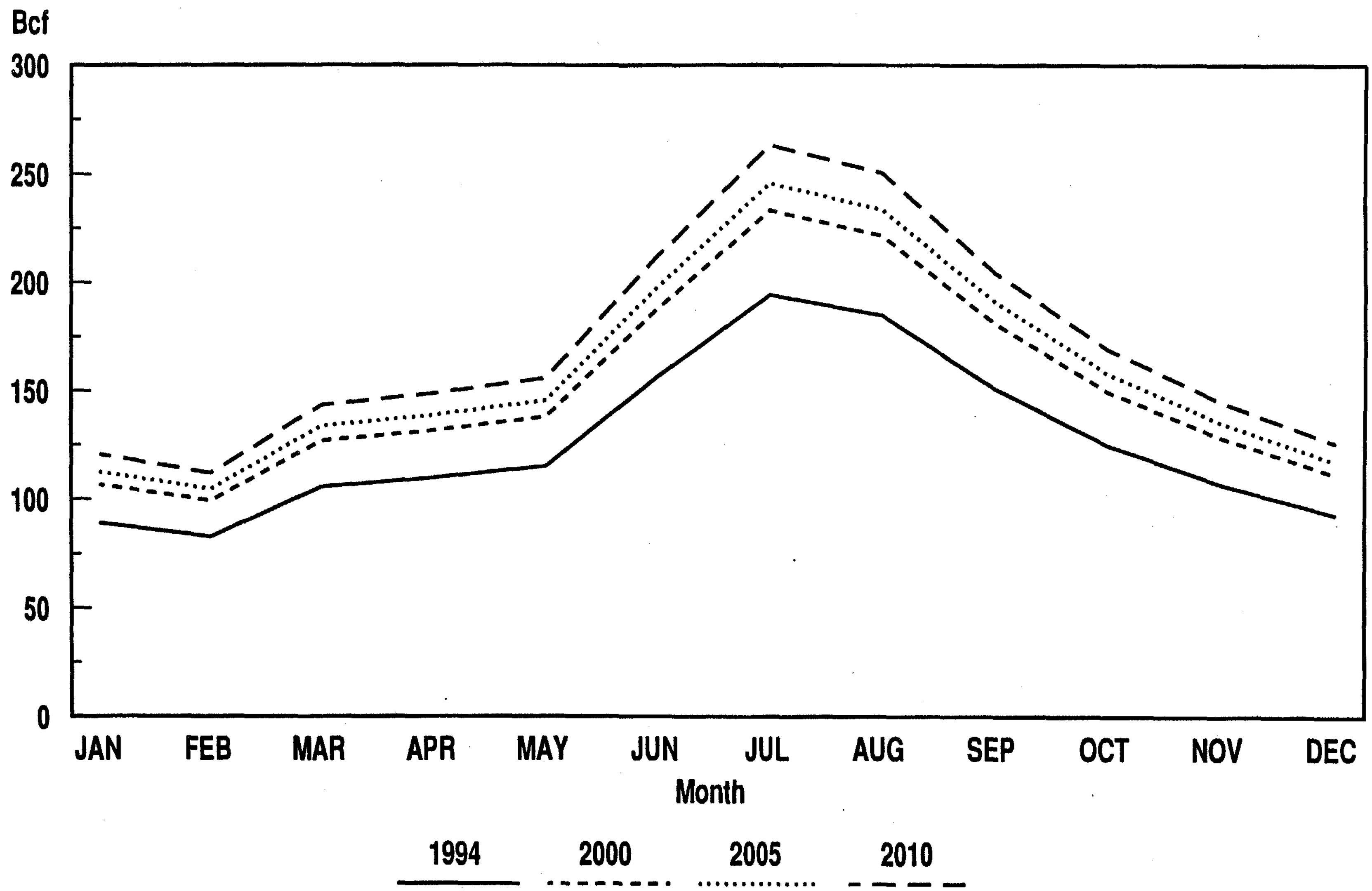
West South Central

Monthly Electric Generation Gas Demand Curve



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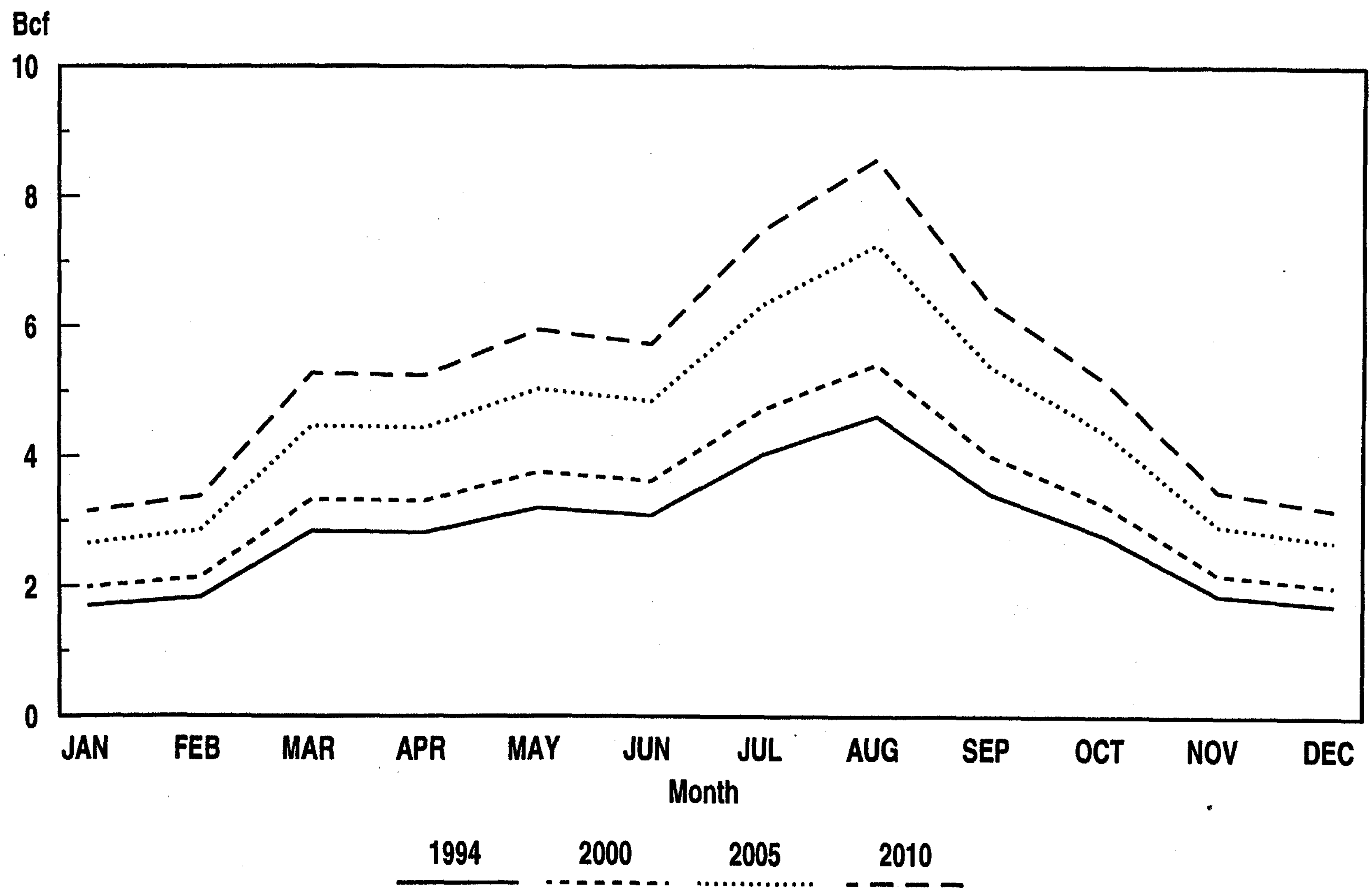
Mountain North

Monthly Electric Generation Gas Demand Curve



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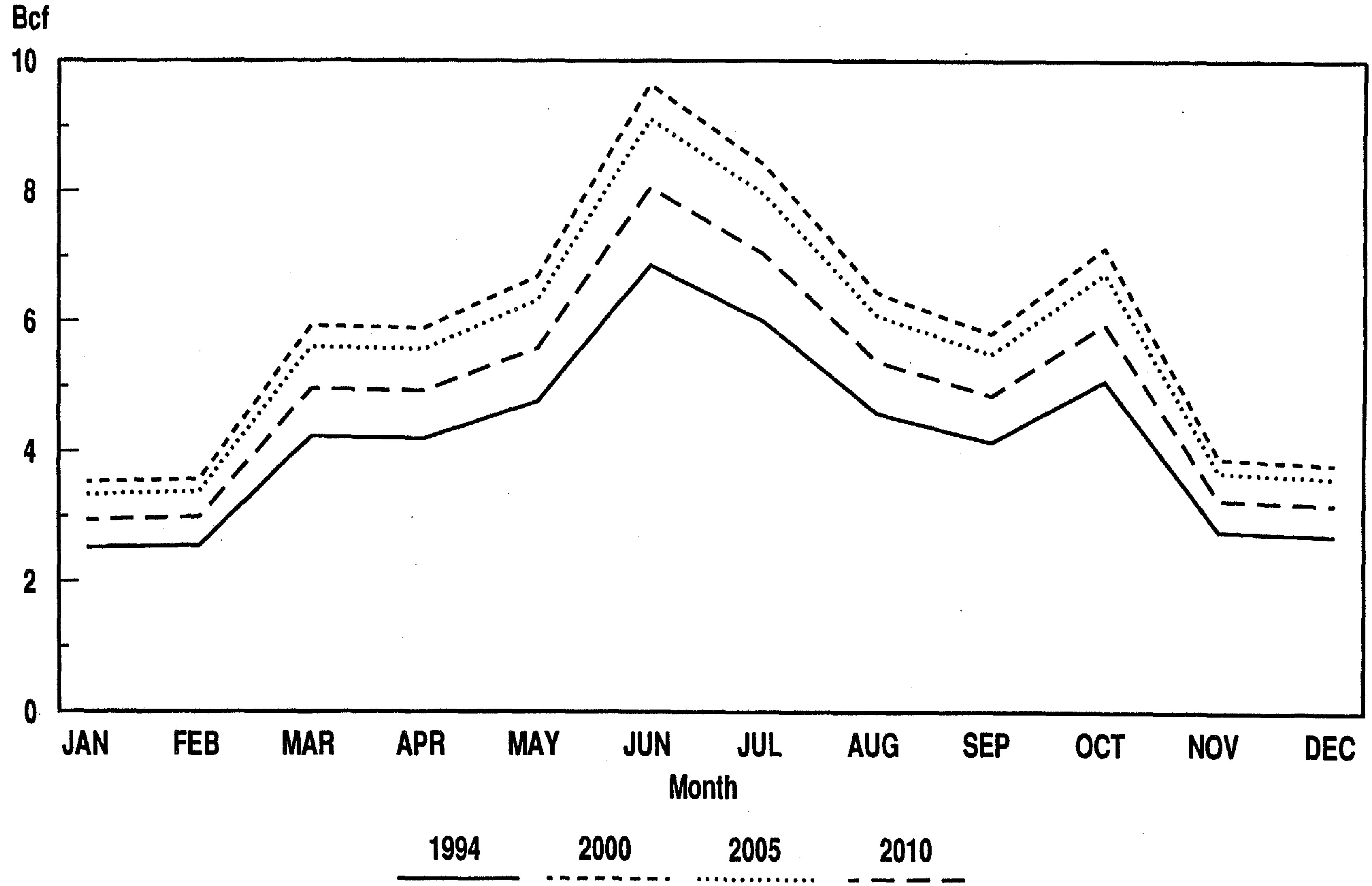
Mountain South

Monthly Electric Generation Gas Demand Curve

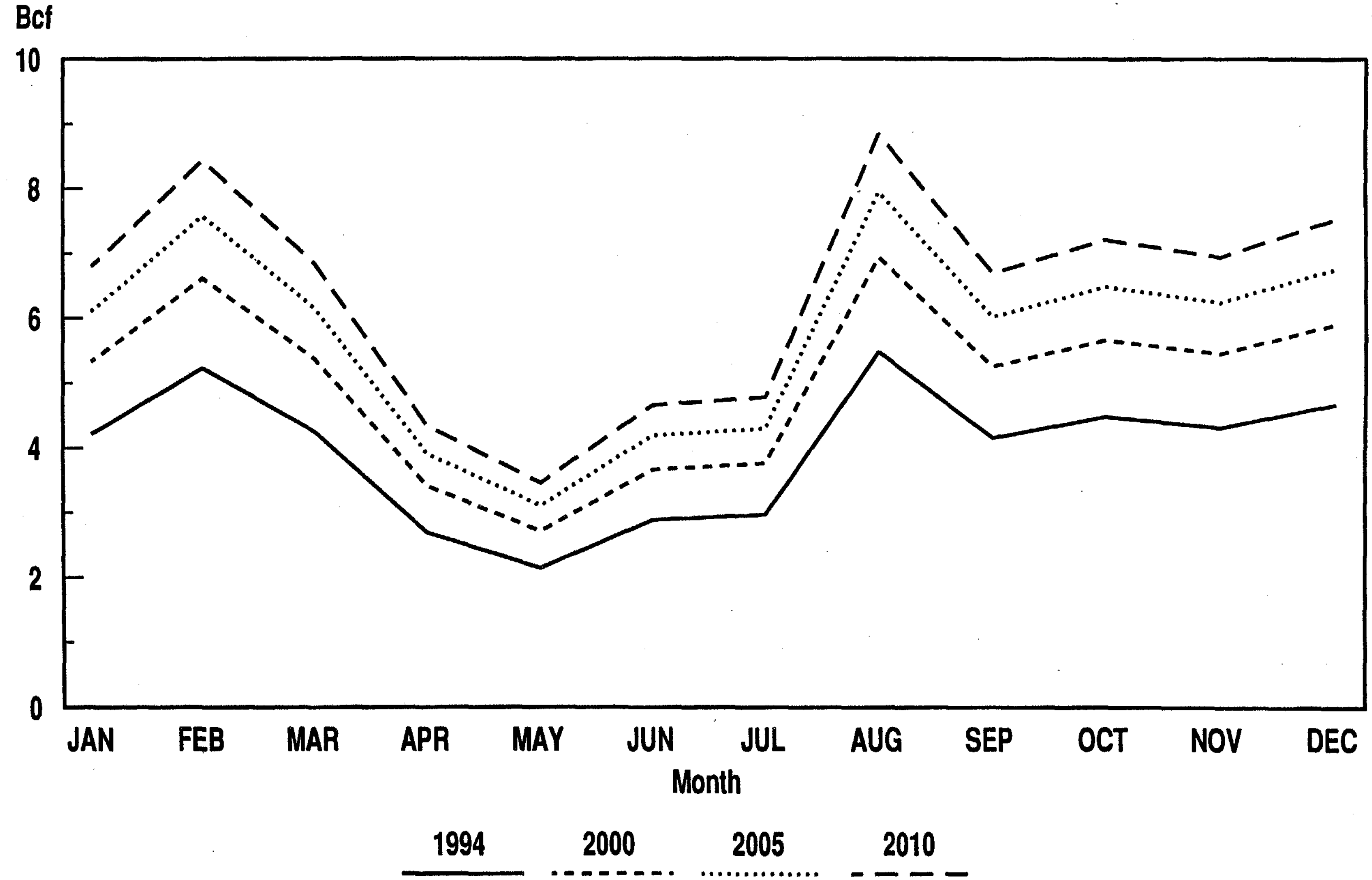


db\graphs\m2elec

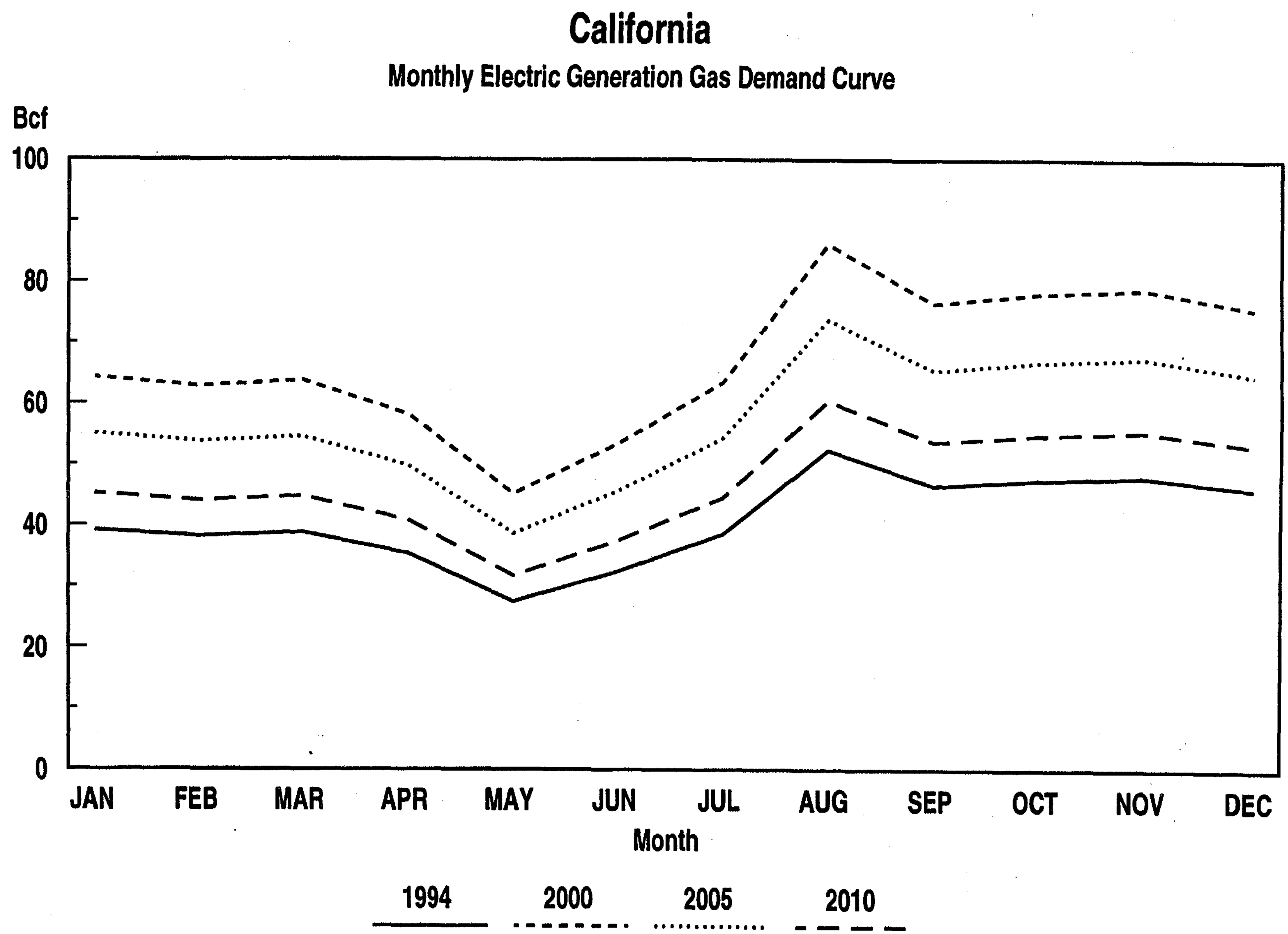
A-11

Pacific Northwest

Monthly Electric Generation Gas Demand Curve



db\graphs\pnelec



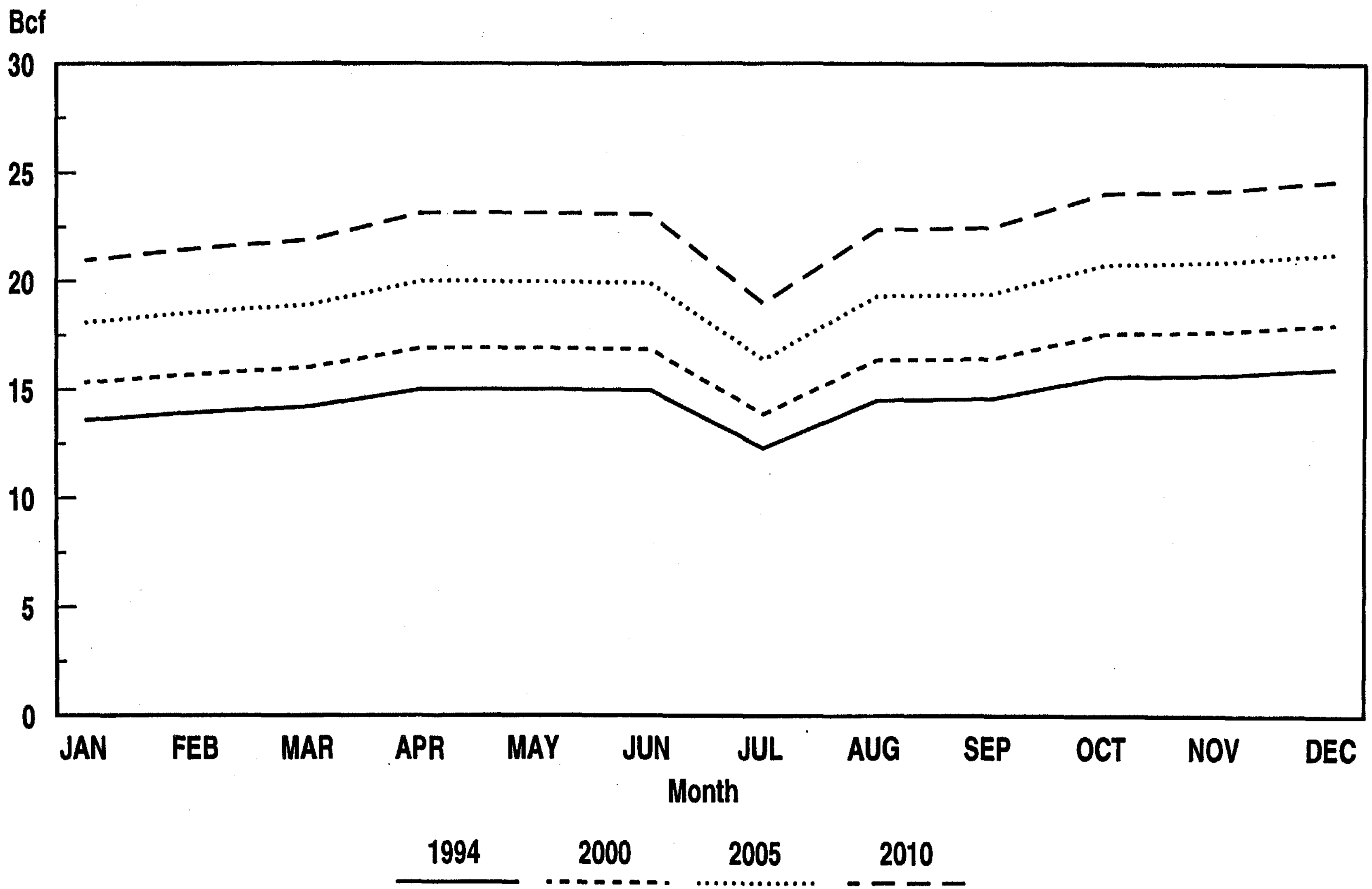
db\graphs\caelec

A-13

Appendix B

New England

Monthly Industrial Gas Demand Curve

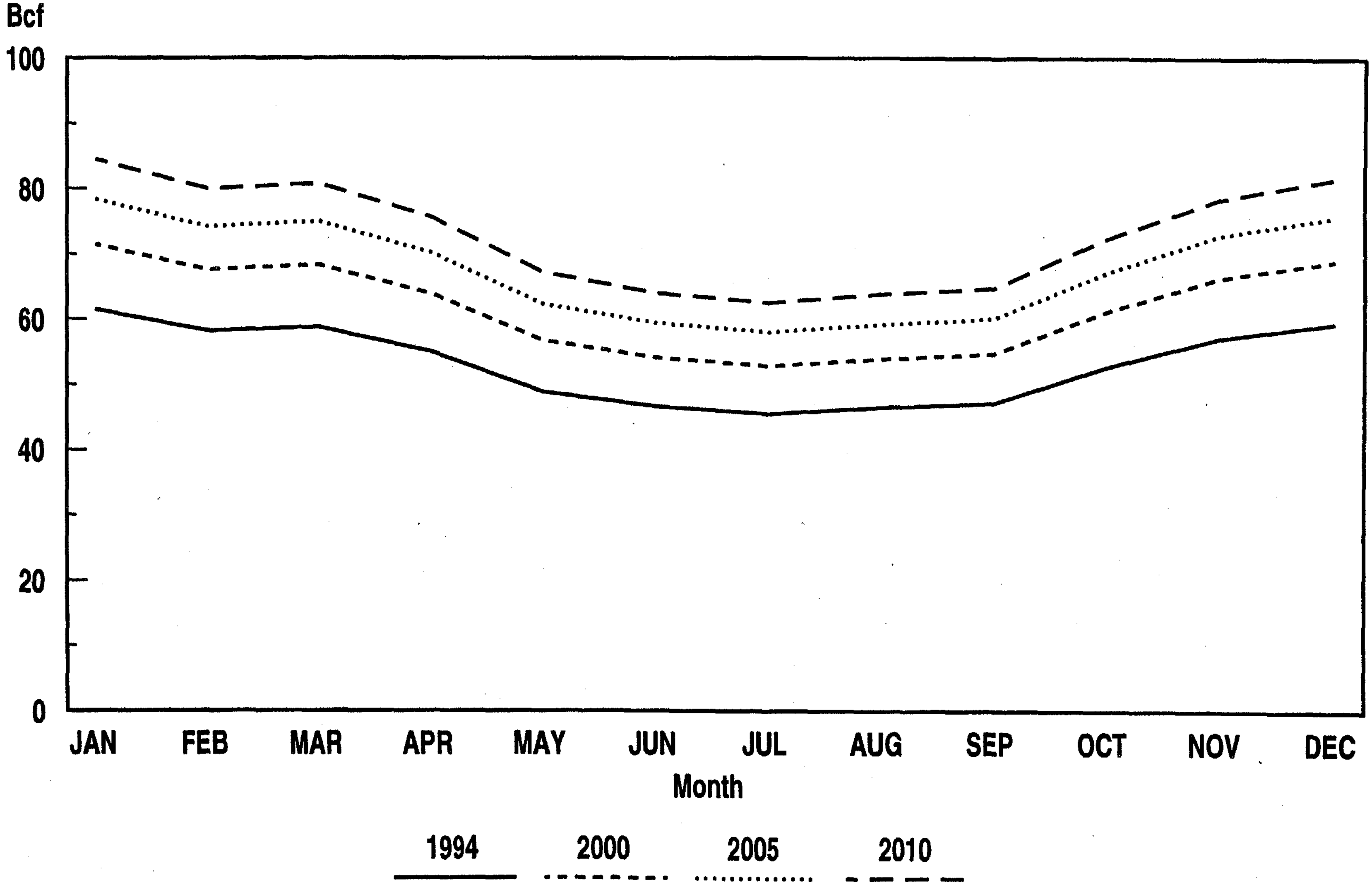


db\graphs\neind

B-2

Middle Atlantic

Monthly Industrial Gas Demand Curve

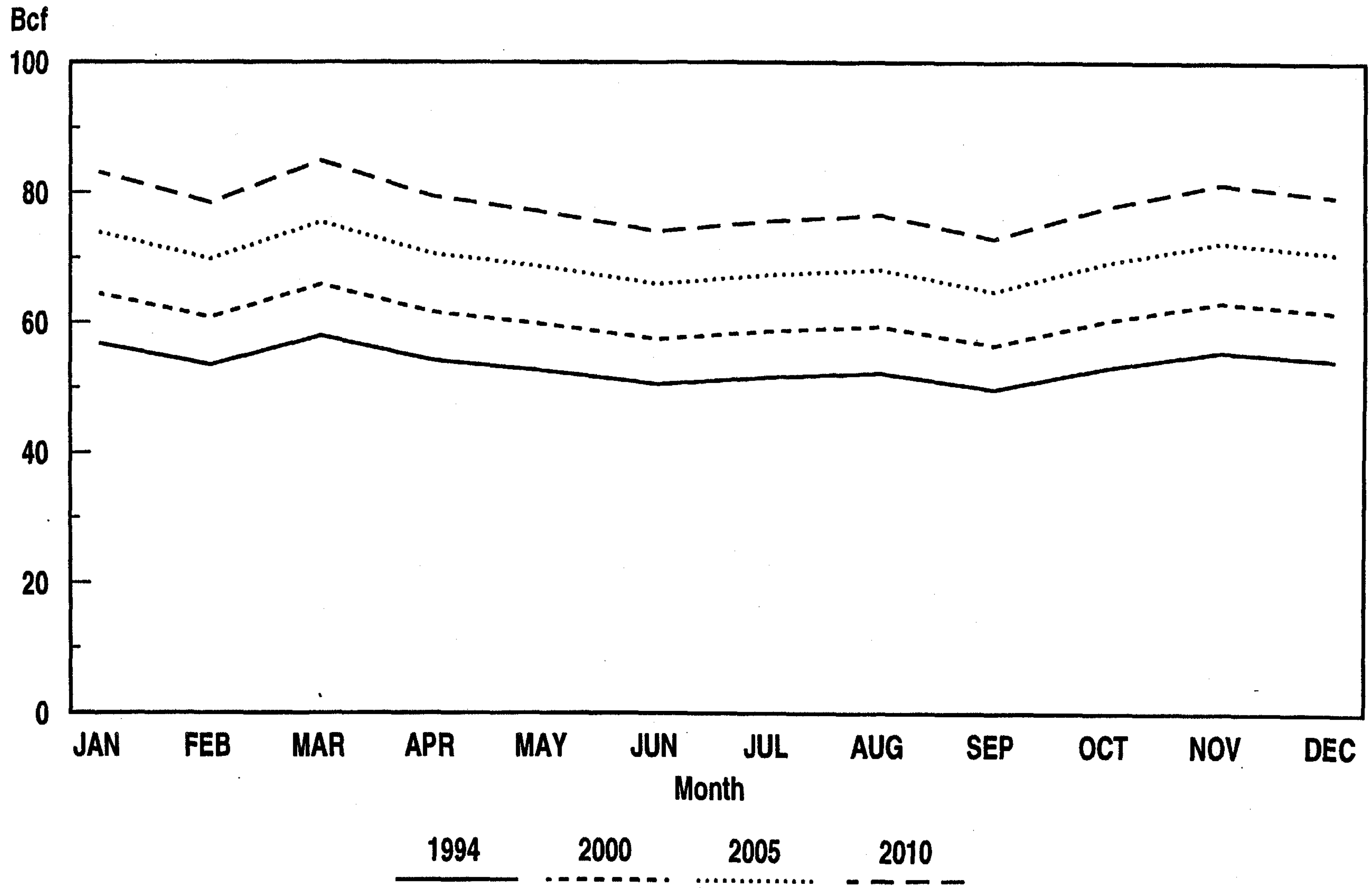


db\graphs\maind

B-3

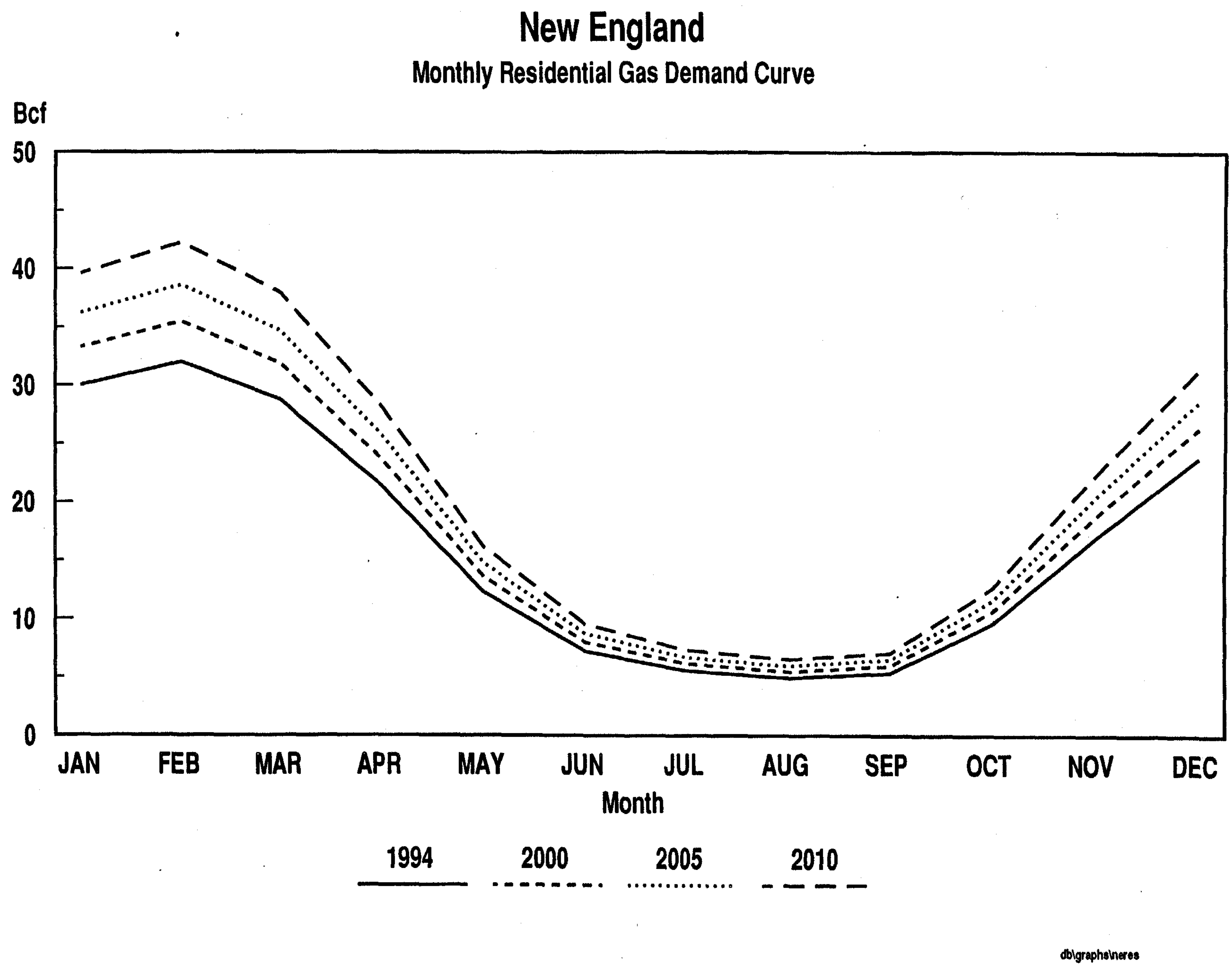
South Atlantic

Monthly Industrial Gas Demand Curve



db\graphs\saind

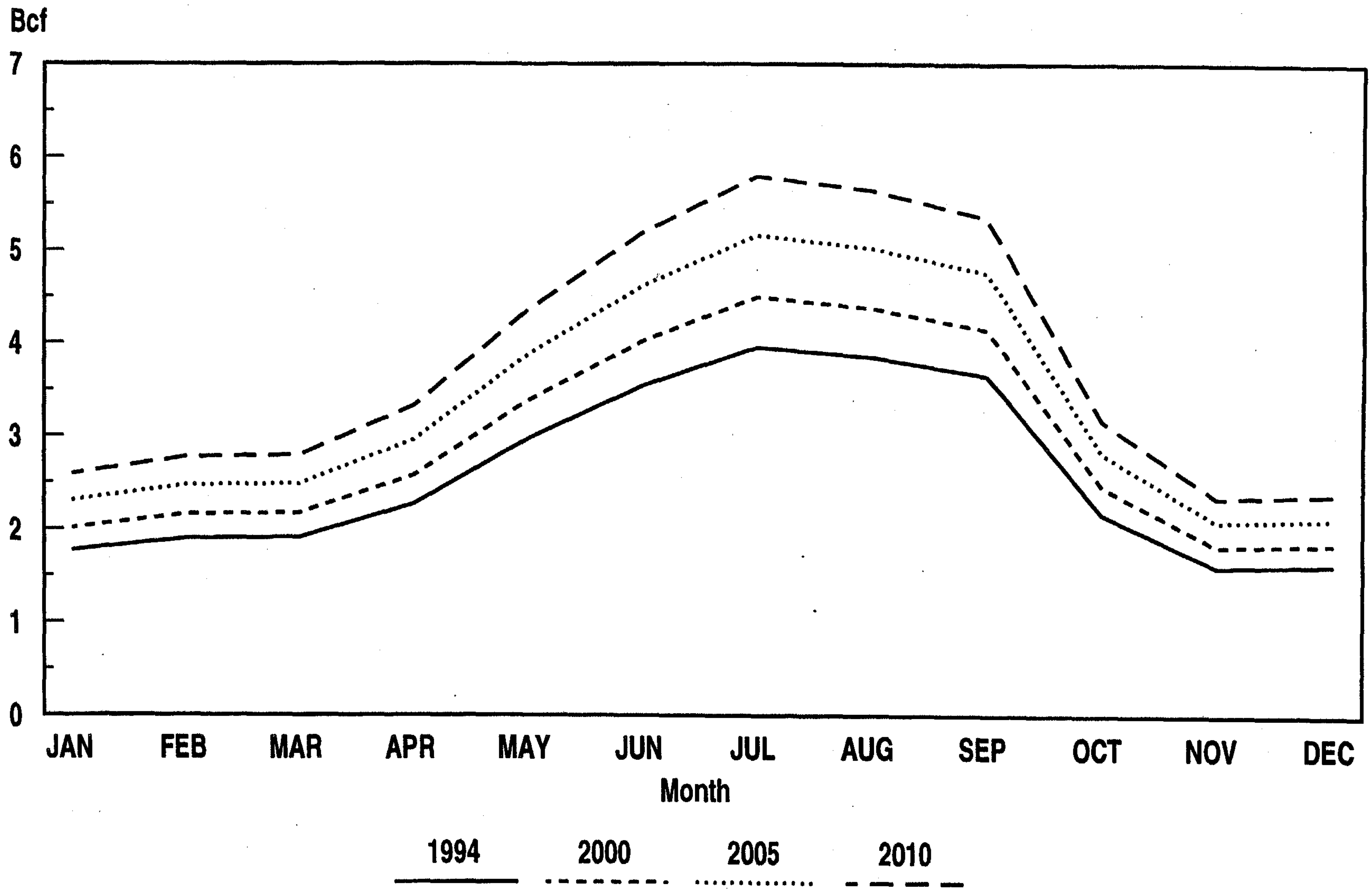
B-4


New England
Monthly Residential Gas Demand Curve
Bcf
50
40
30
20
10
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Month
1994
2000
2005
2010
db\graphs\neres

B-5

Florida

Monthly Industrial Gas Demand Curve

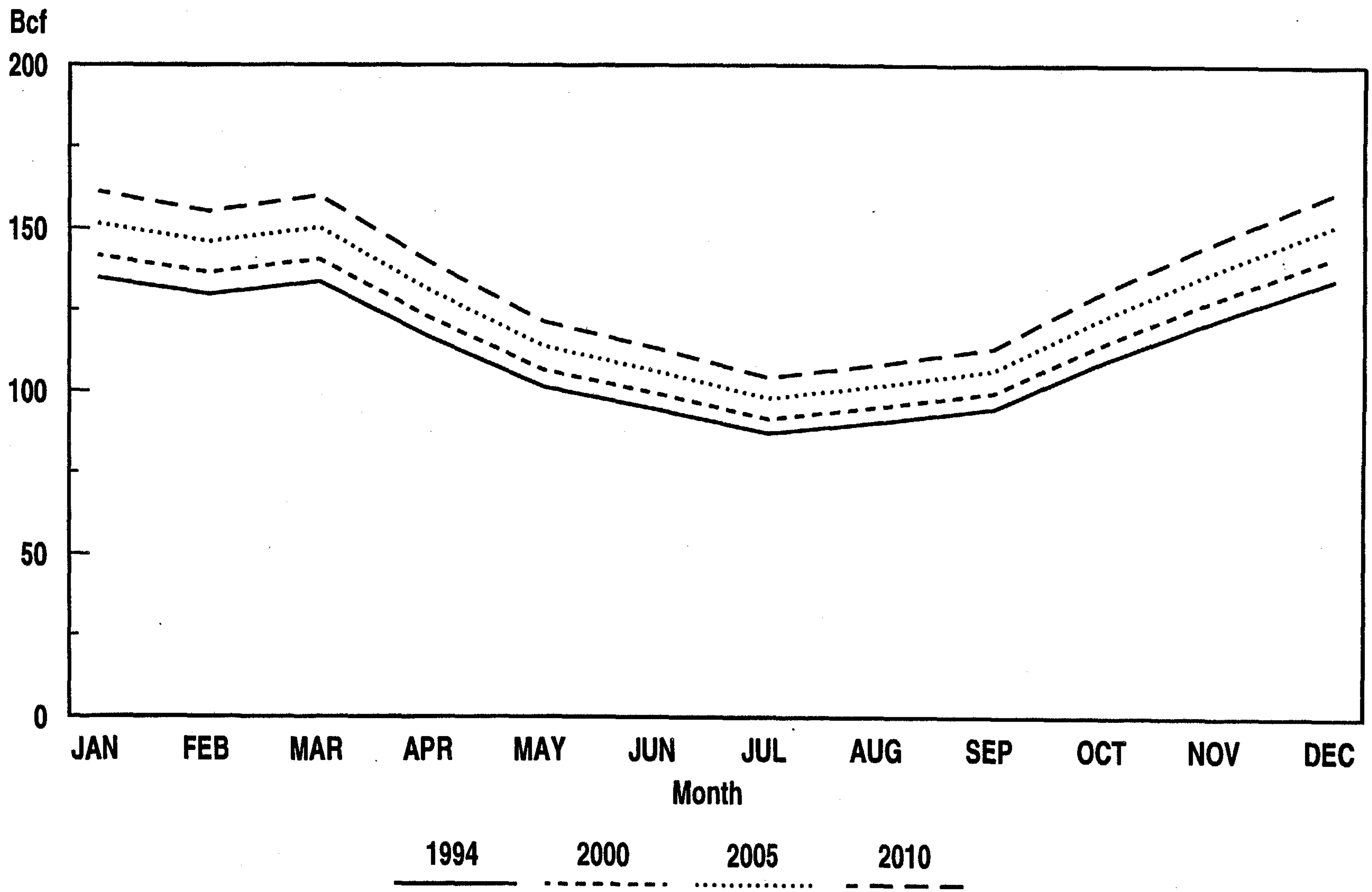


db\graphs\flind

B-6

East North Central

Monthly Industrial Gas Demand Curve

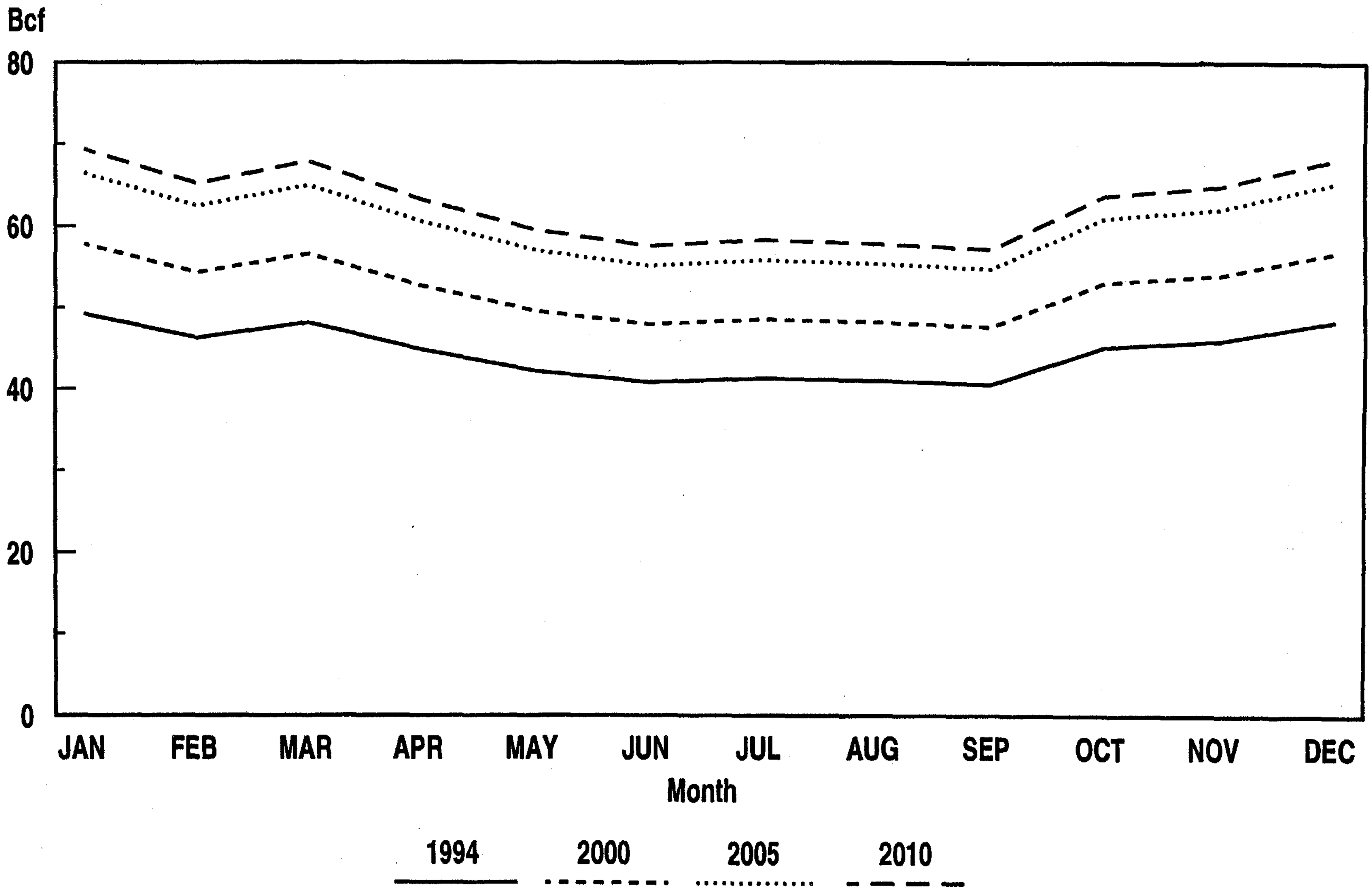


db\graphs\encind

B-7

East South Central

Monthly Industrial Gas Demand Curve

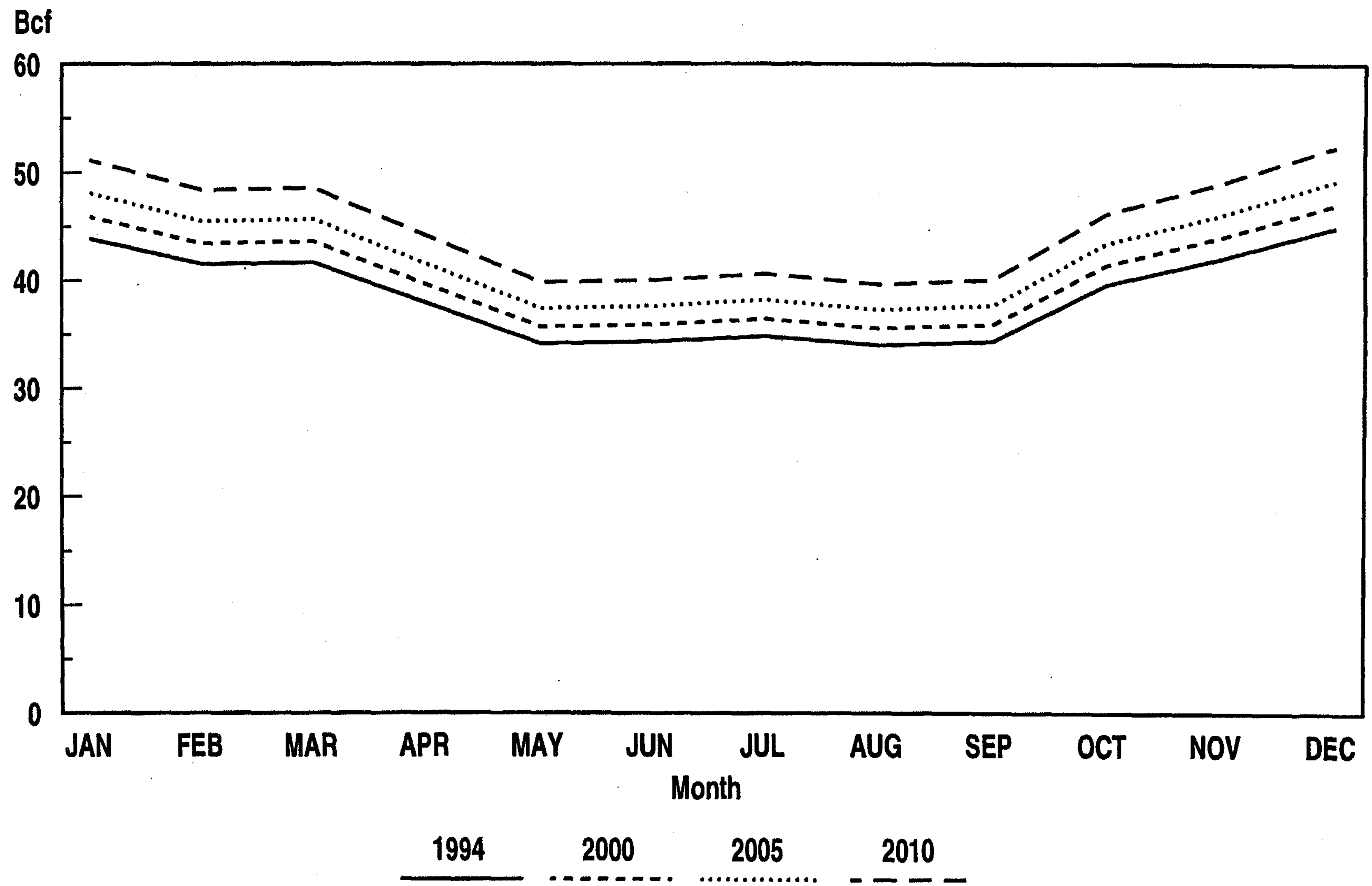


db\graphs\escind

B-8

West North Central

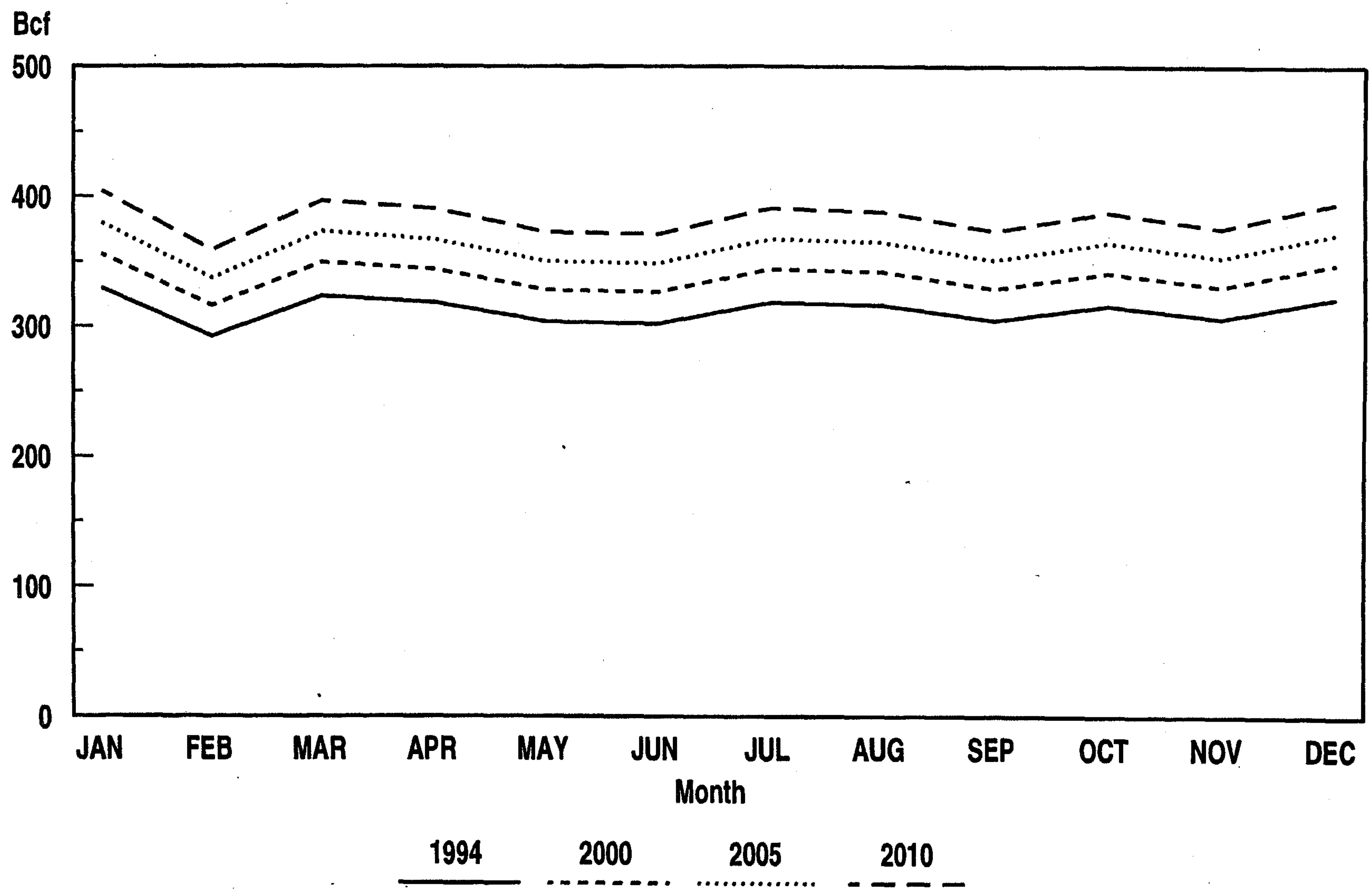
Monthly Industrial Gas Demand Curve



db\graphs\wncind

West South Central

Monthly Industrial Gas Demand Curve

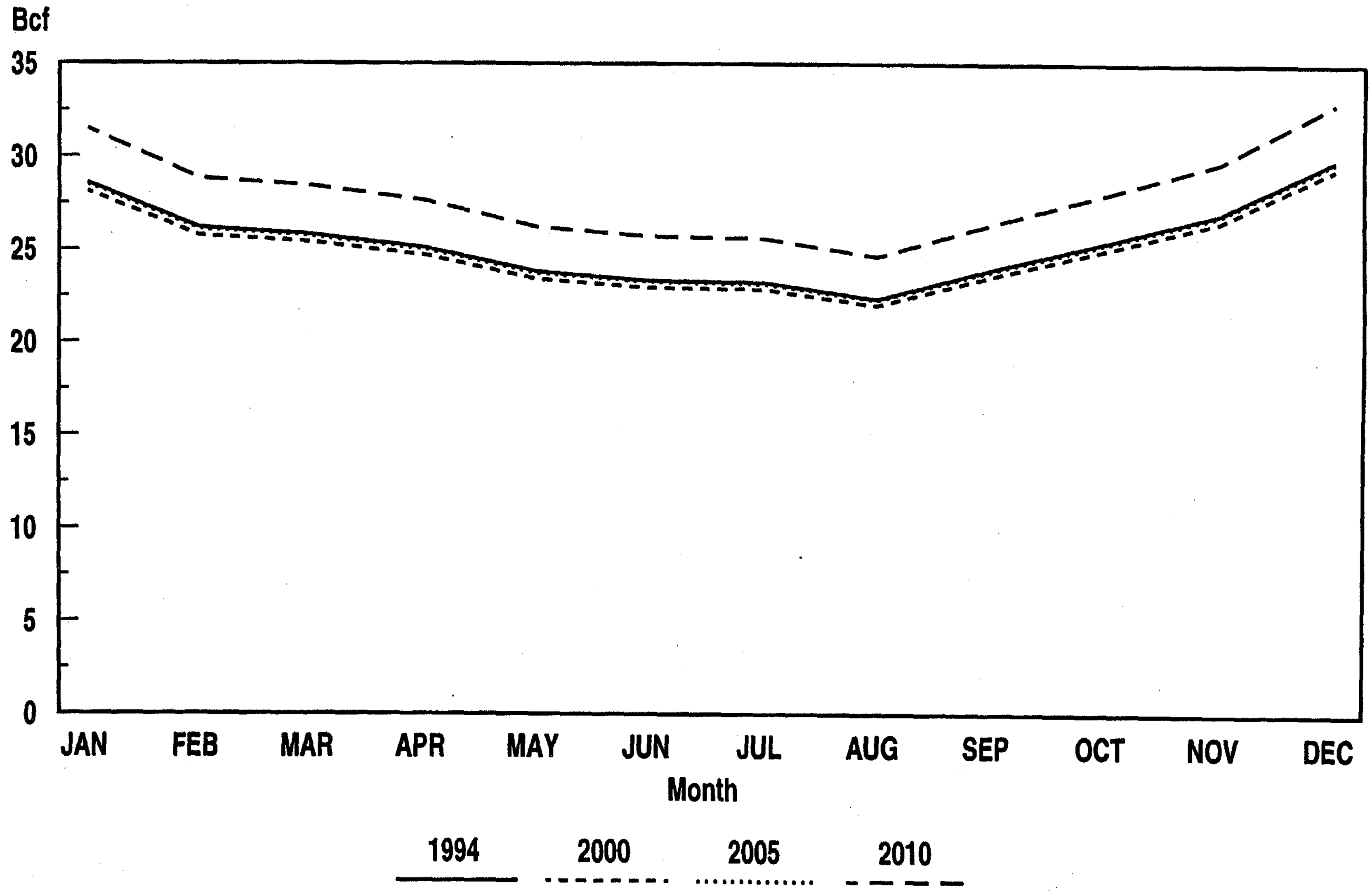


db\graphs\wscind

B-10

Mountain North

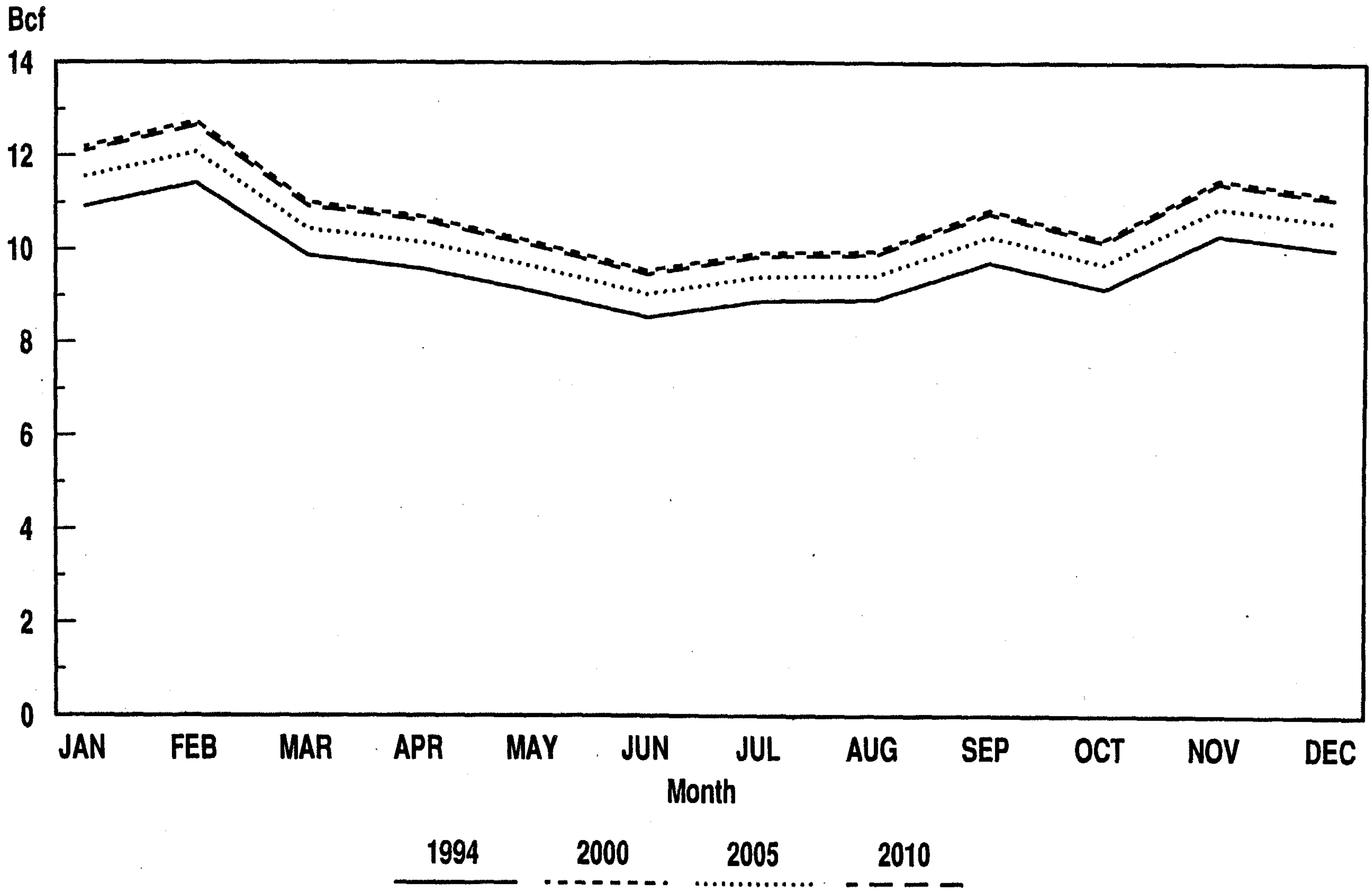
Monthly Industrial Gas Demand Curve



db\graphs\m1ind

Mountain South

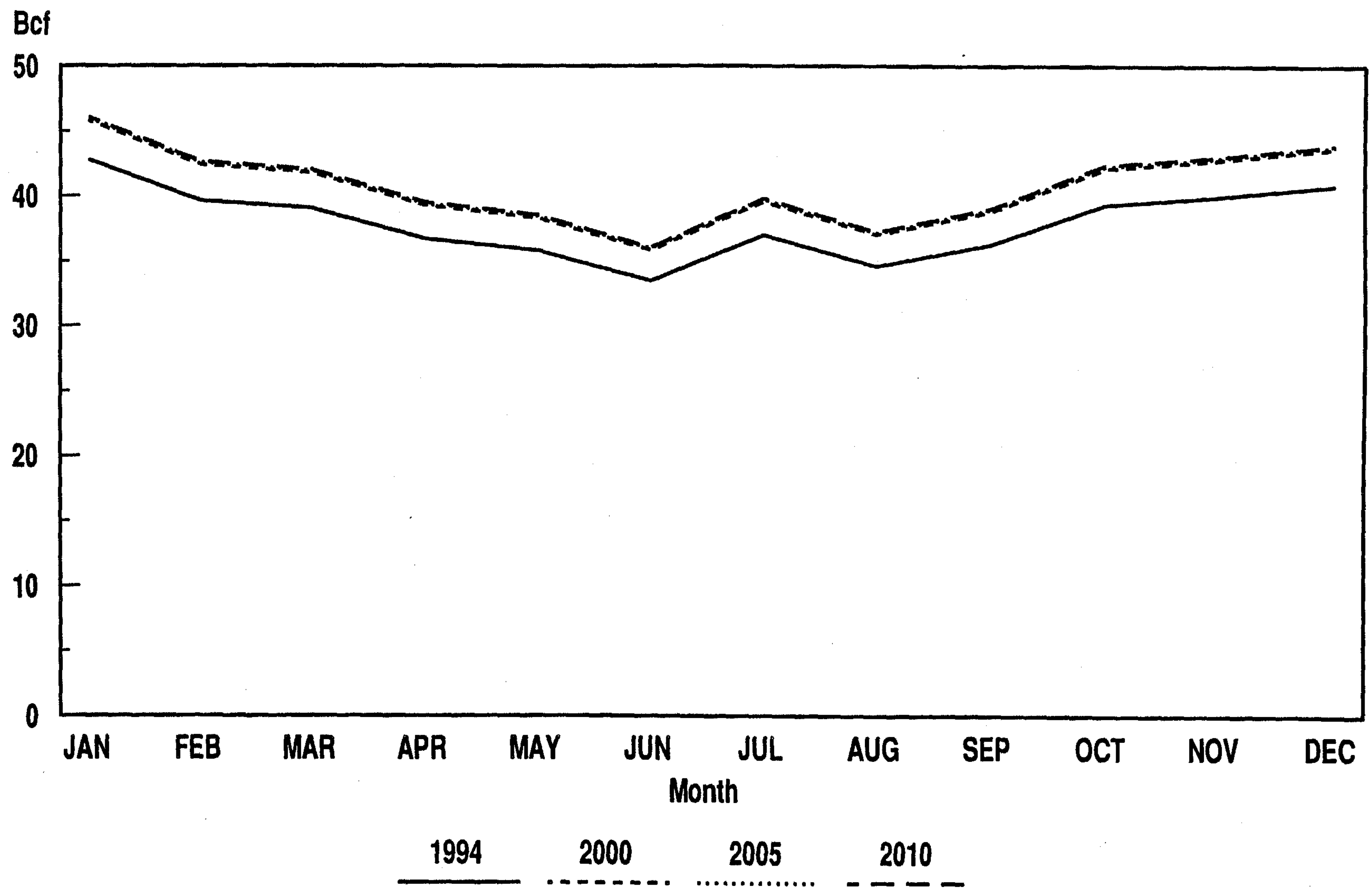
Monthly Industrial Gas Demand Curve



db\graphs\m2ind

Pacific Northwest

Monthly Industrial Gas Demand Curve

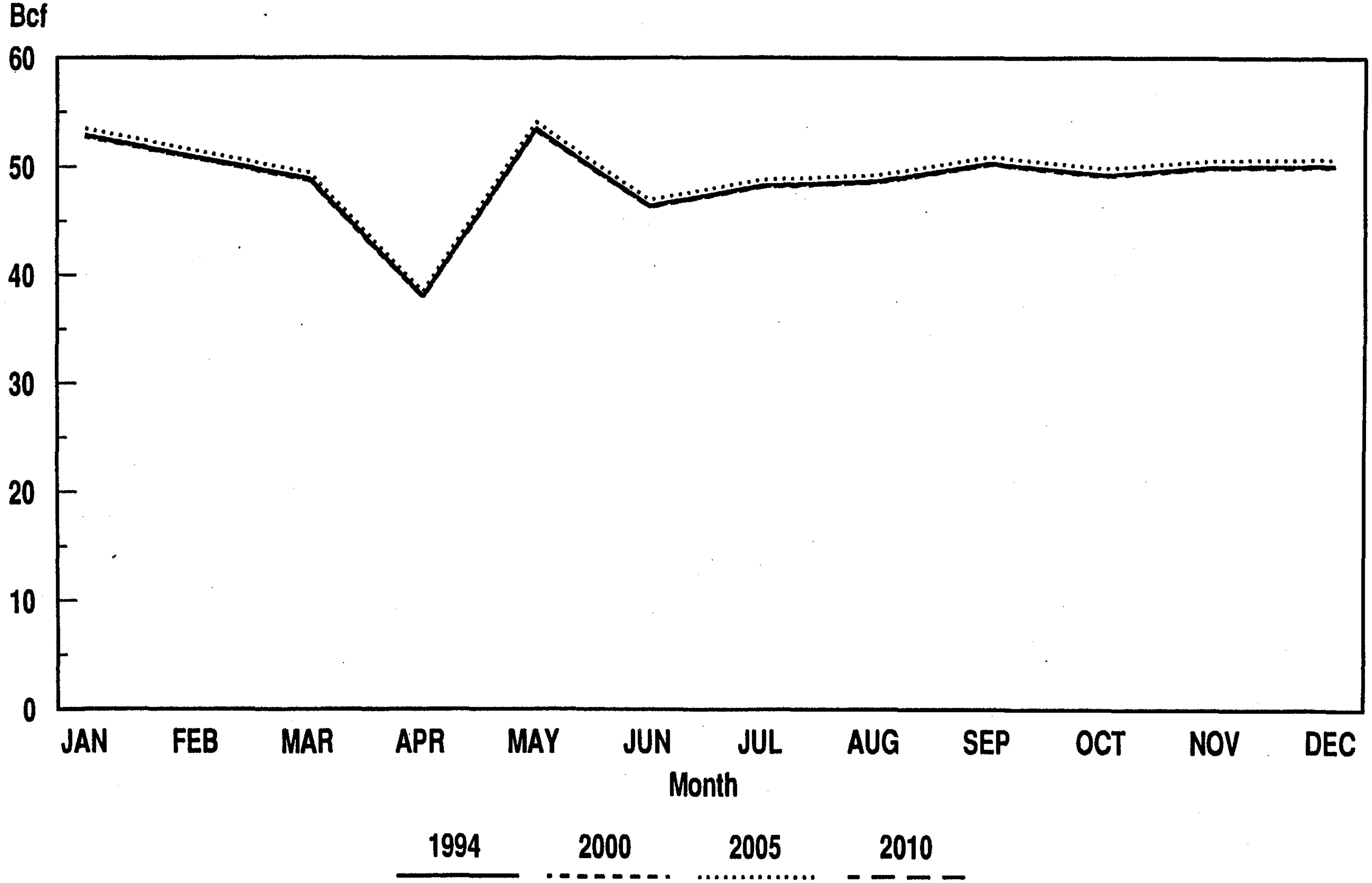


db\graphs\pnind

B-13

California

Monthly Industrial Gas Demand Curve



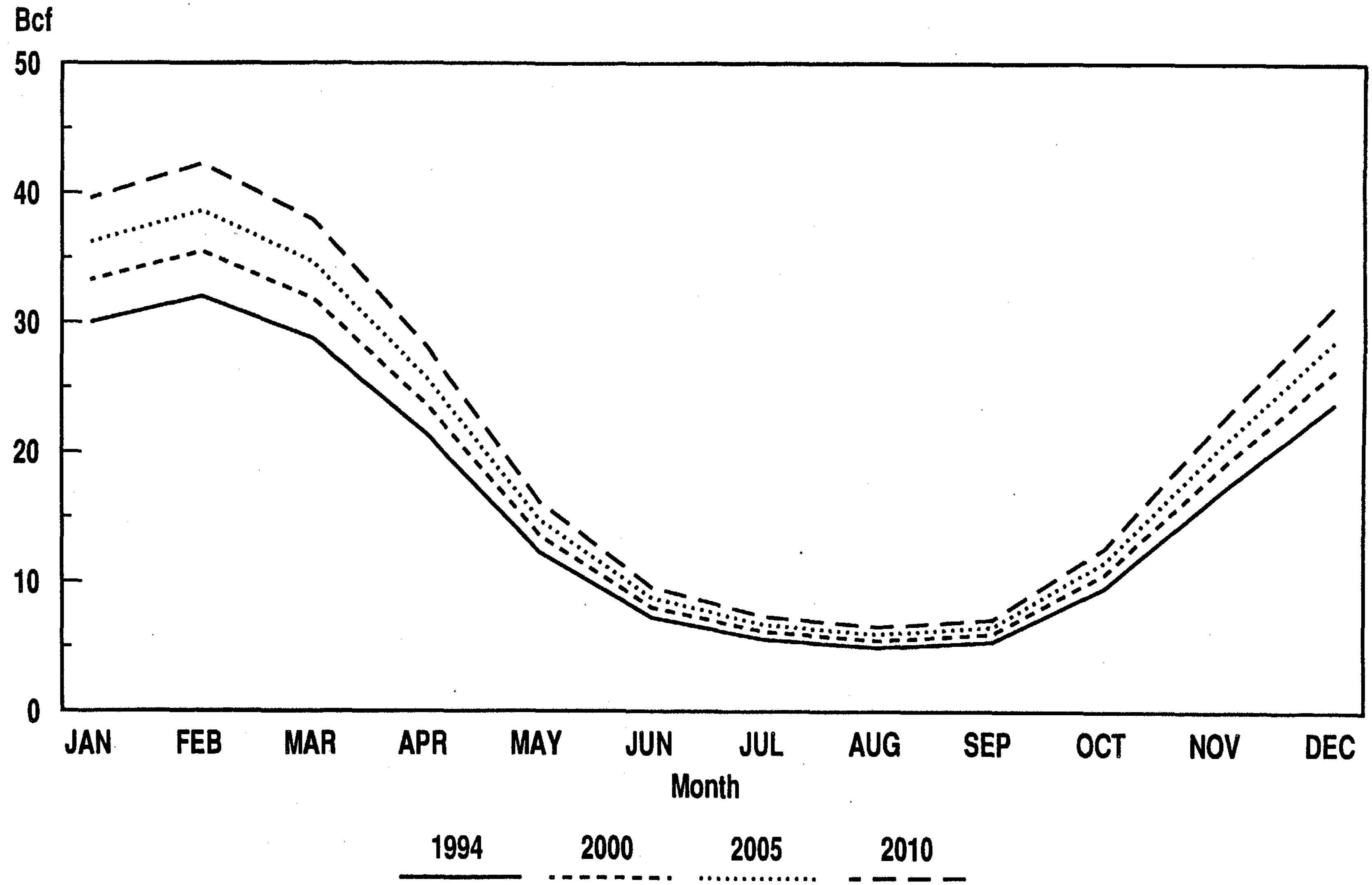
db\graphs\caind

B-14

Appendix C

New England

Monthly Residential Gas Demand Curve

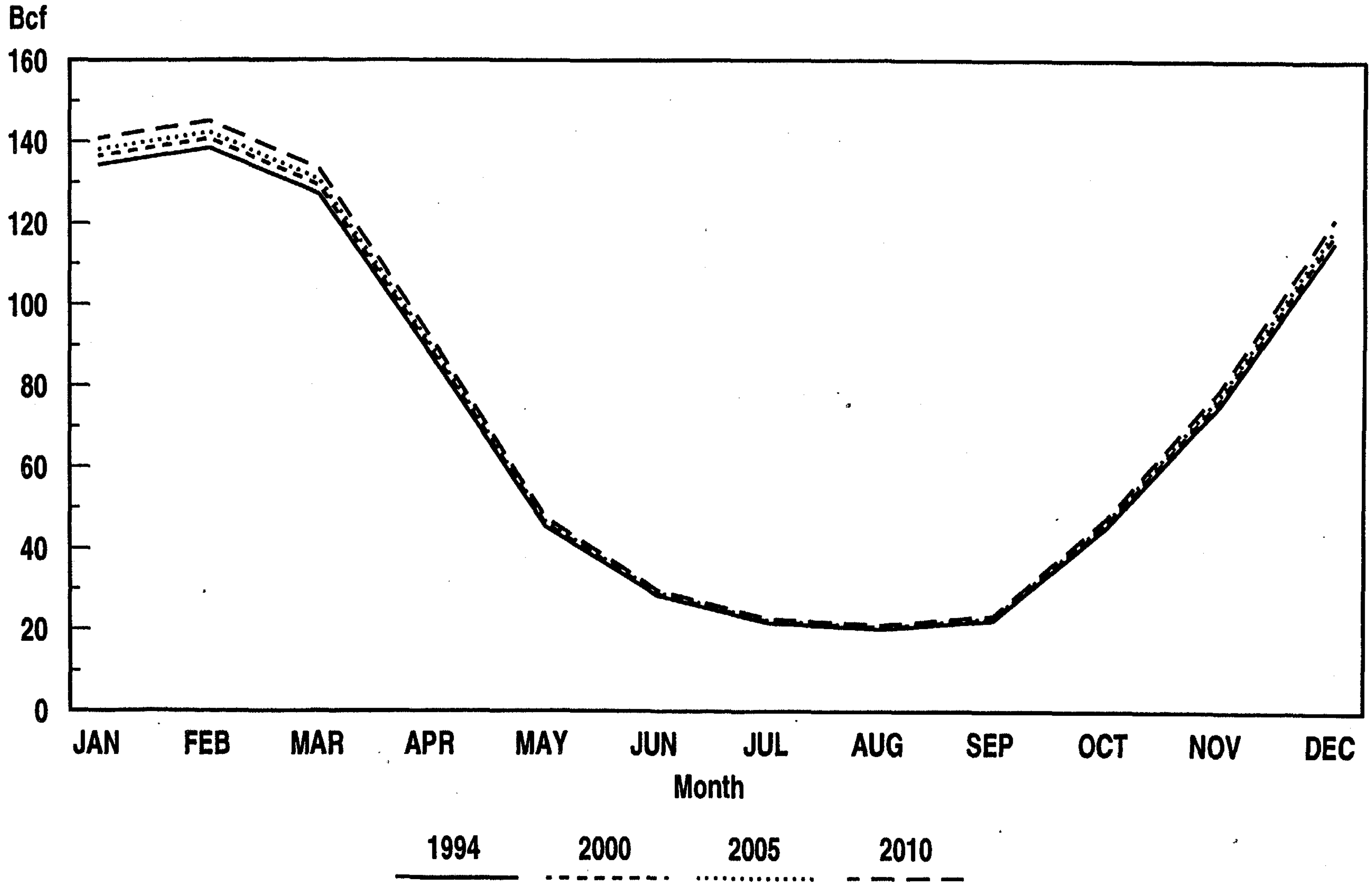


db\graphs\neres

C-2

Middle Atlantic

Monthly Residential Gas Demand Curve

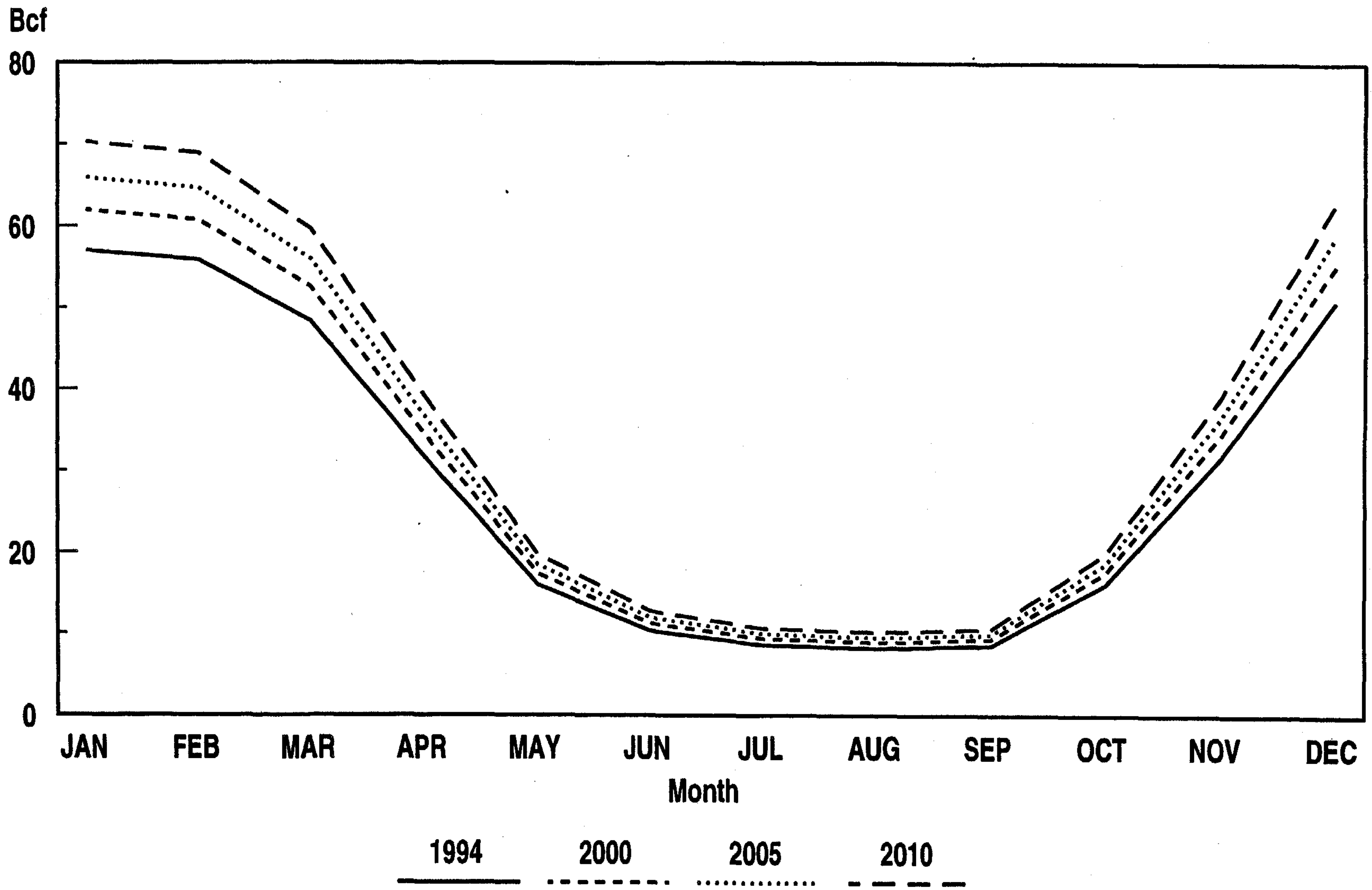


db\graphs\mares

C-3

South Atlantic

Monthly Residential Gas Demand Curve

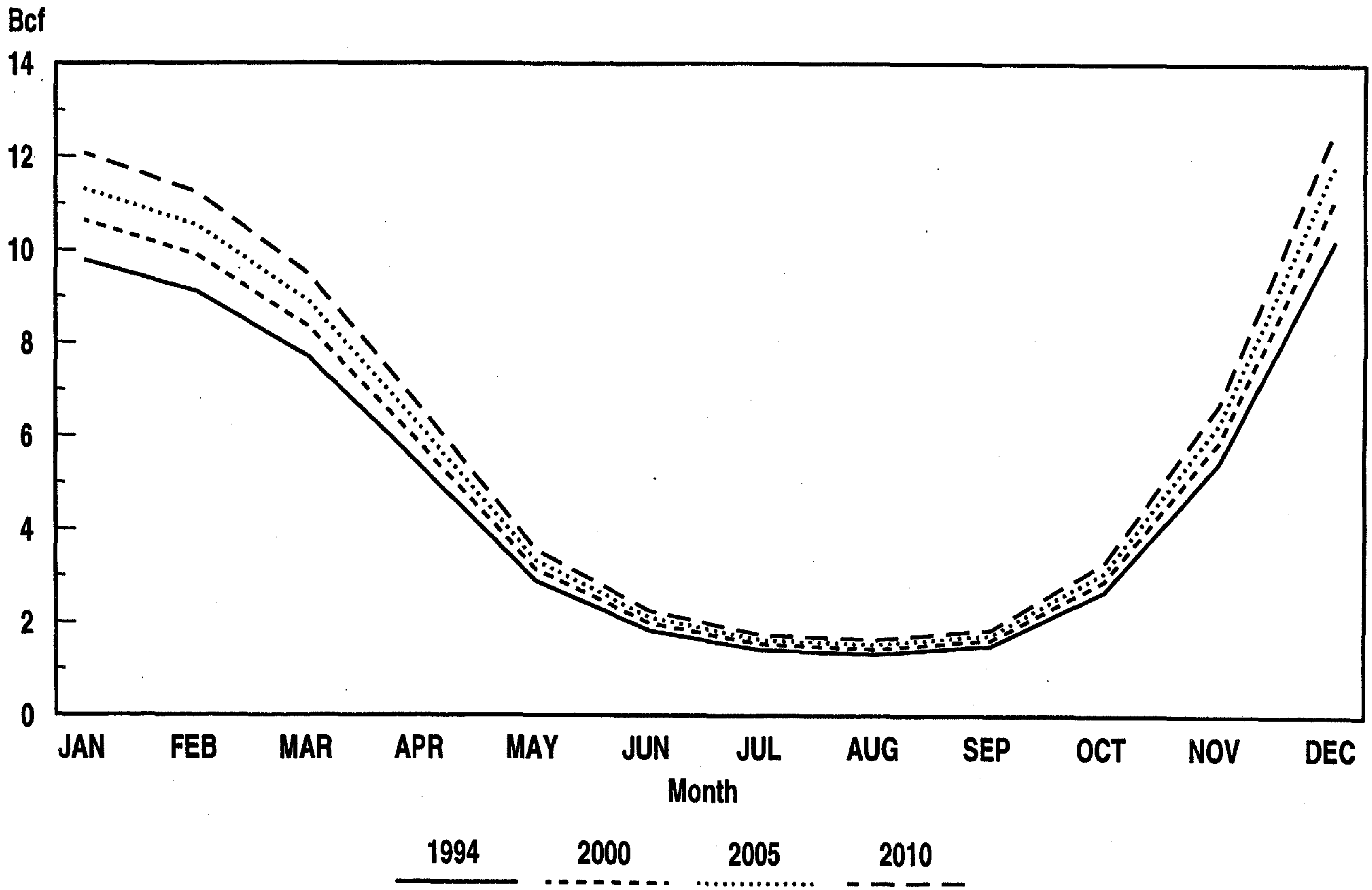


db\graphs\sares

C-4

Florida

Monthly Residential Gas Demand Curve

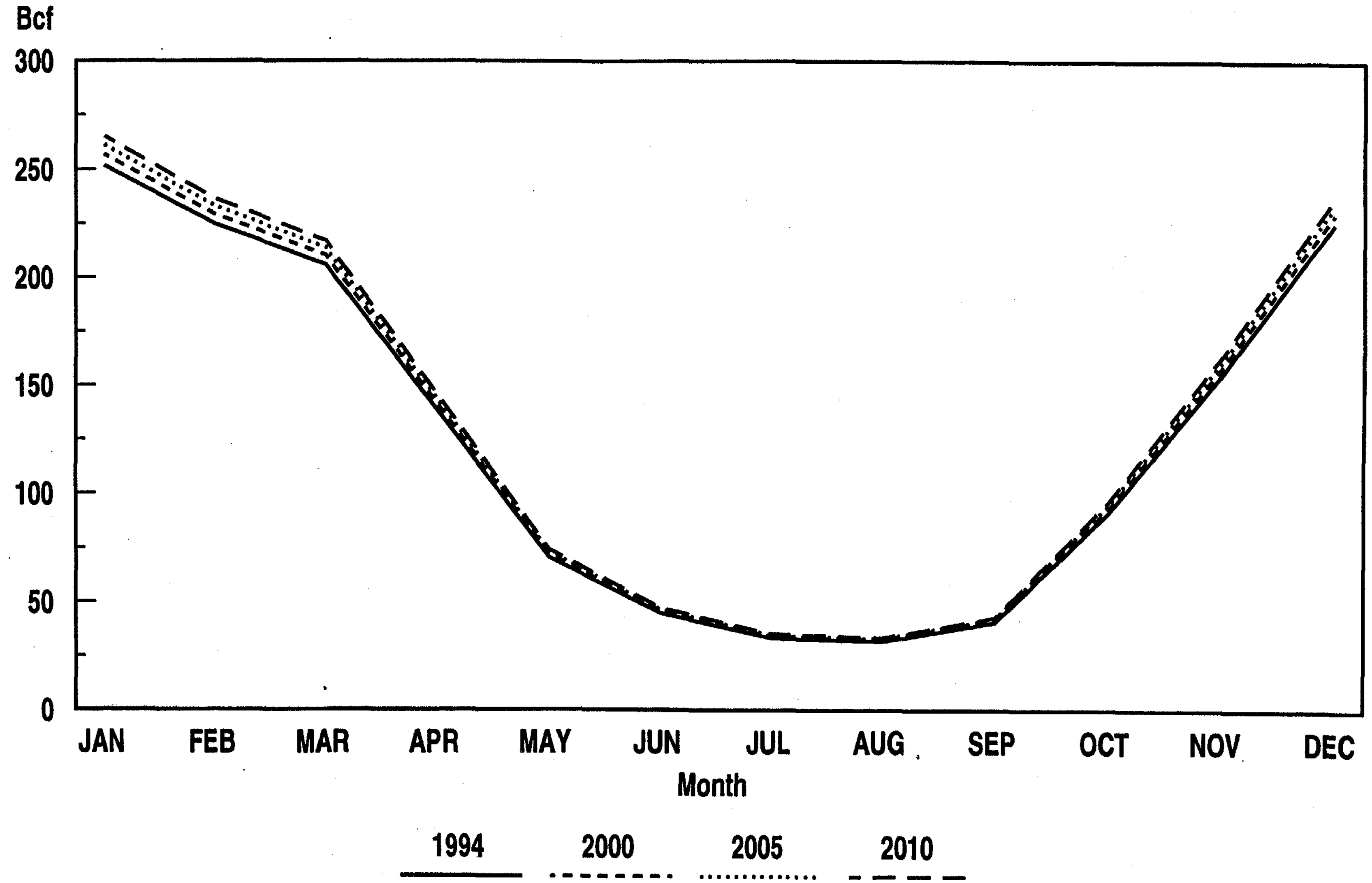


db\graphs\fires

C-5

East North Central

Monthly Residential Gas Demand Curve

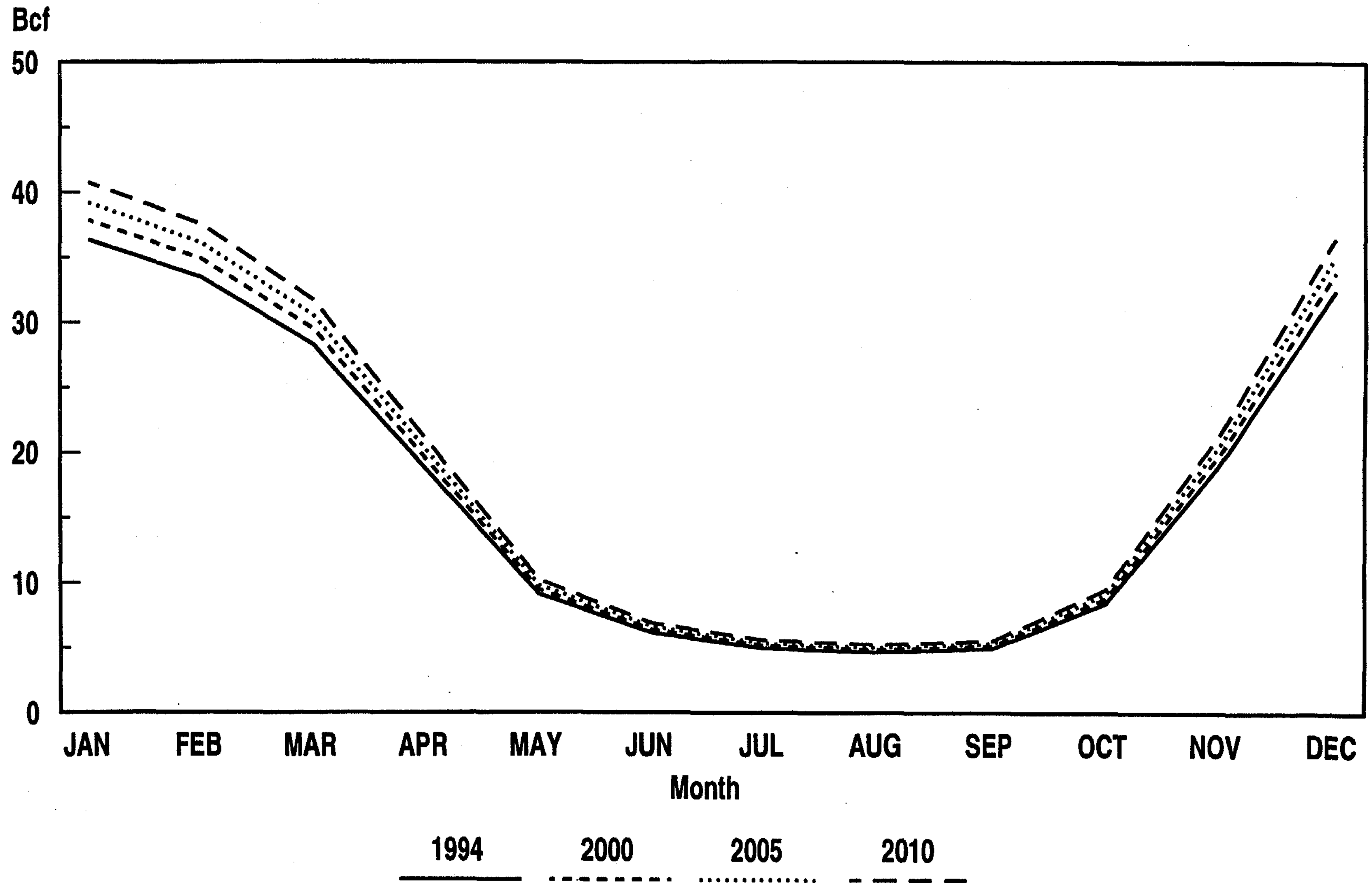


db\graphs\encres

C-6

East South Central

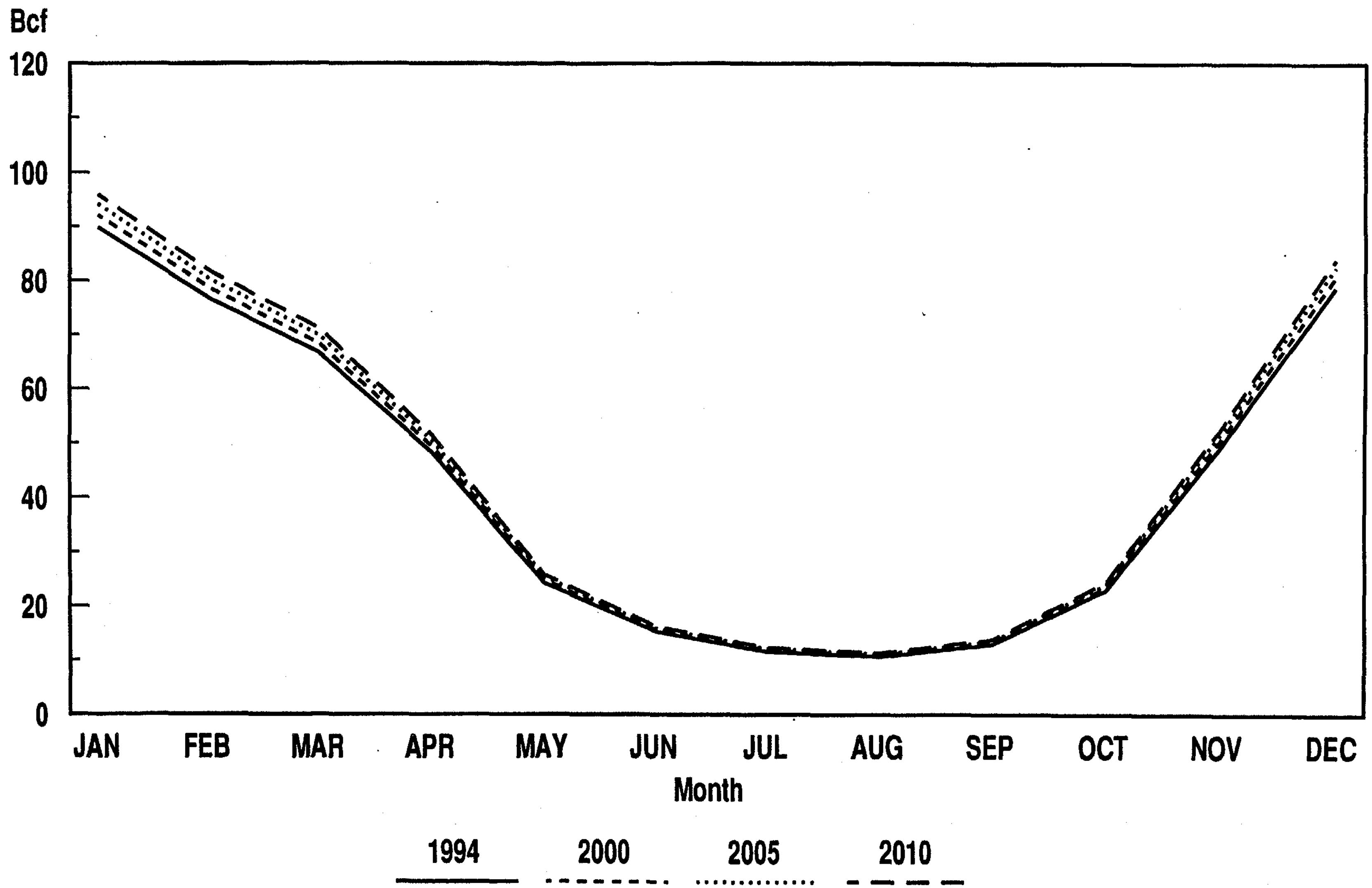
Monthly Residential Gas Demand Curve



db\graphs\escres

West North Central

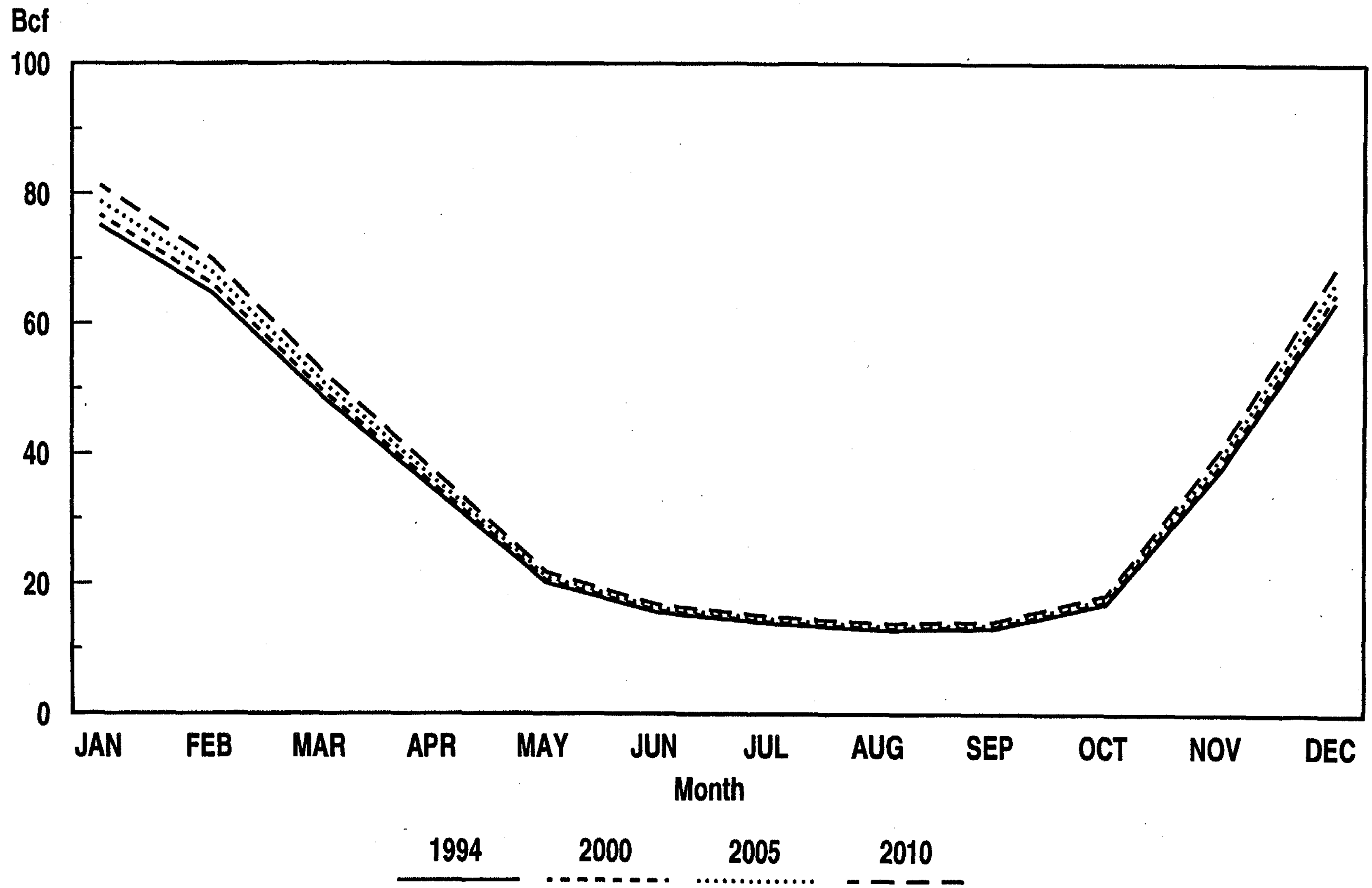
Monthly Residential Gas Demand Curve



db\graphs\wncres

West South Central

Monthly Residential Gas Demand Curve

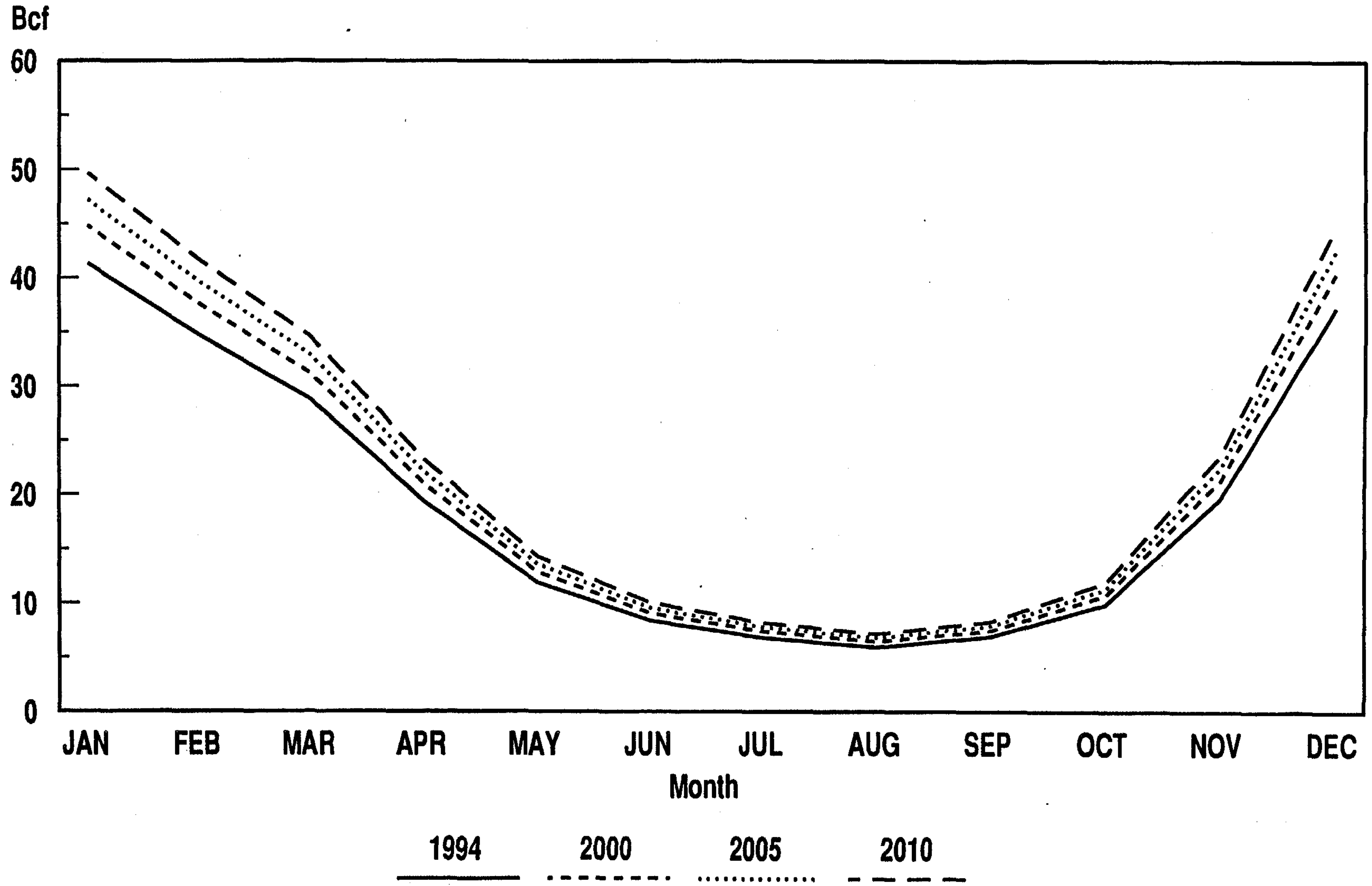


db\graphs\wscres

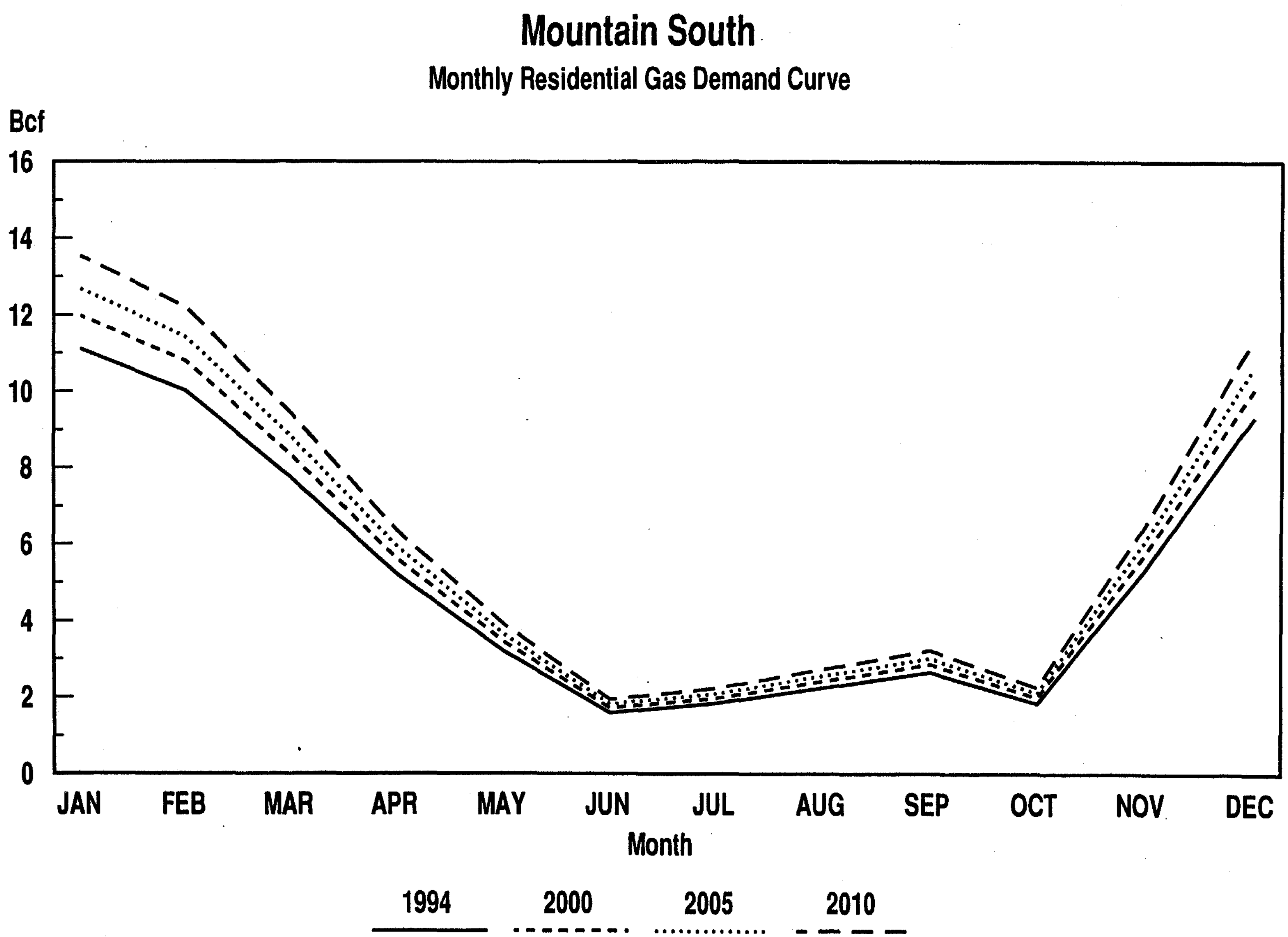
C-9

Mountain North

Monthly Residential Gas Demand Curve



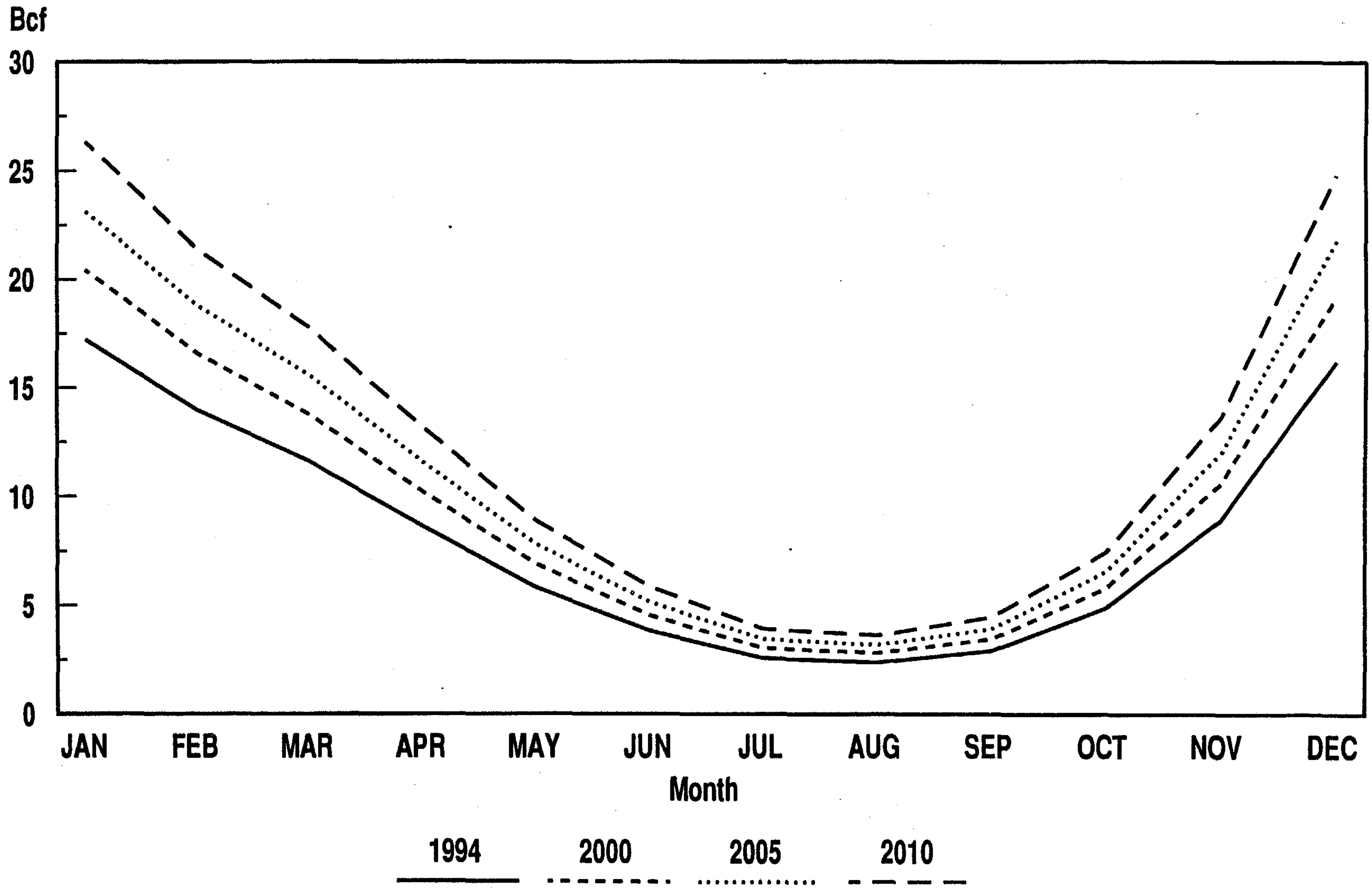
db\graphs\m1res



db\graphs\m2res

Pacific Northwest

Monthly Residential Gas Demand Curve

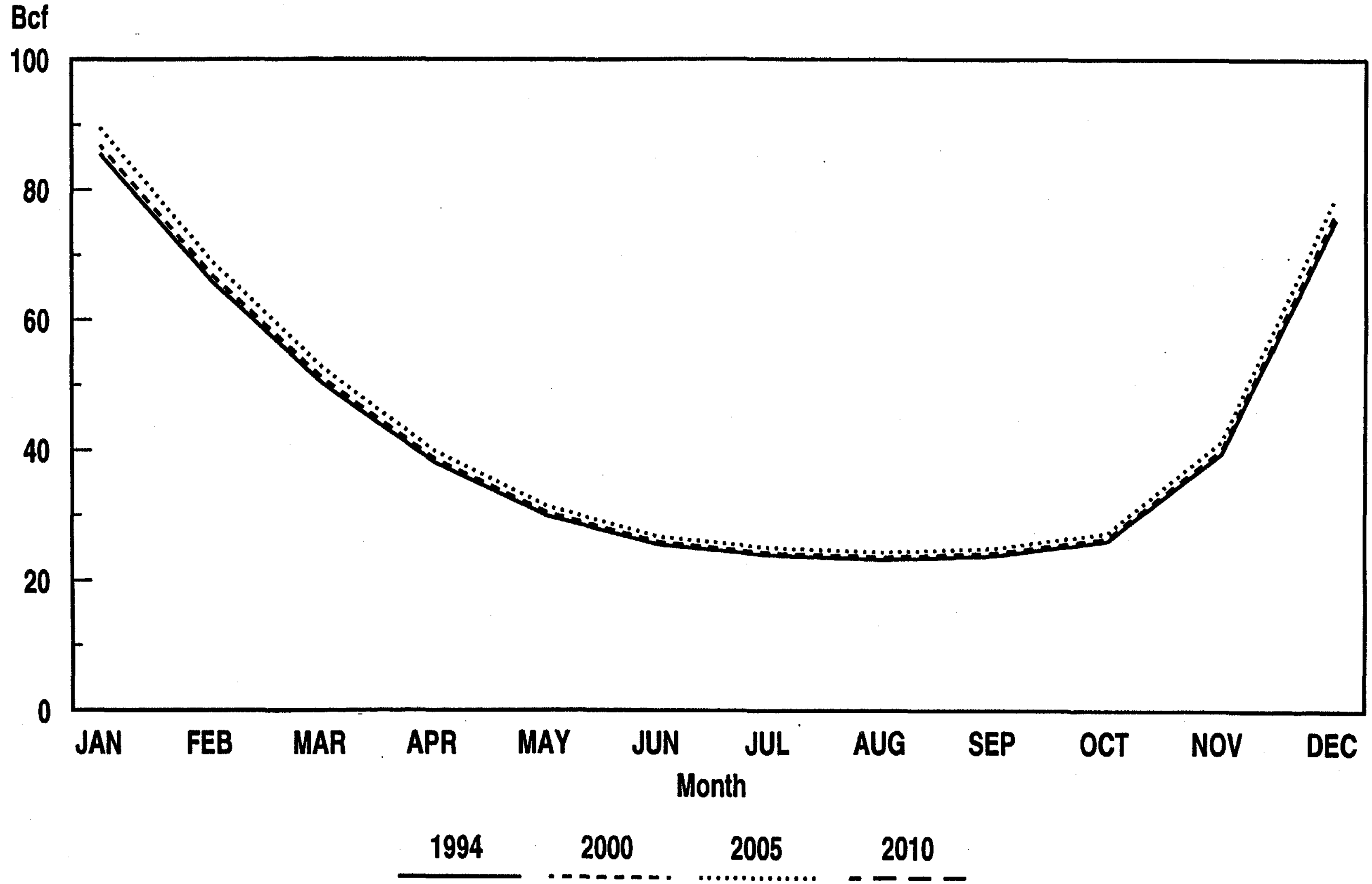


db\graphs\pnres

C-12

California

Monthly Residential Gas Demand Curve



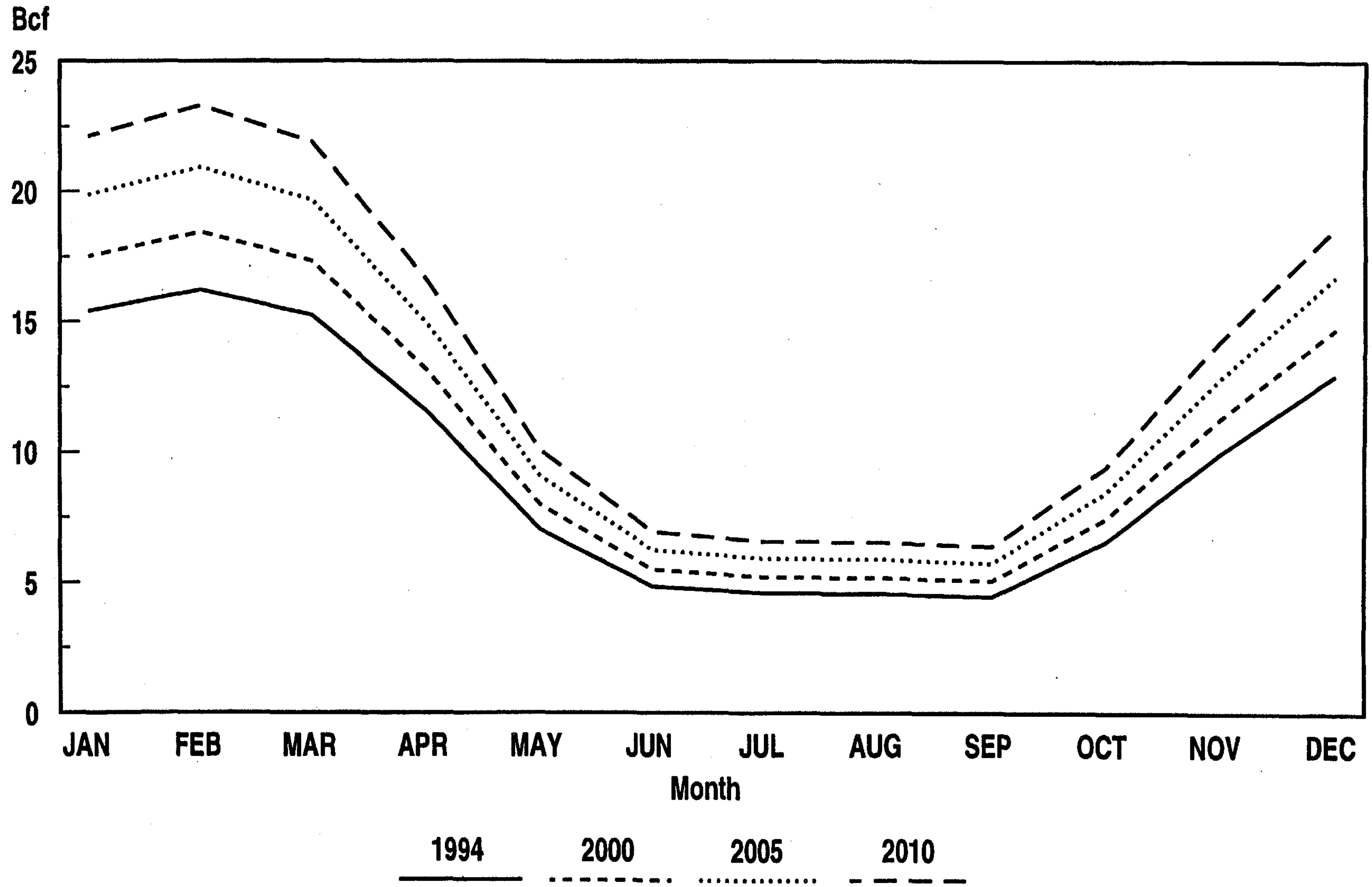
db\graphs\cares

C-13

Appendix D

New England

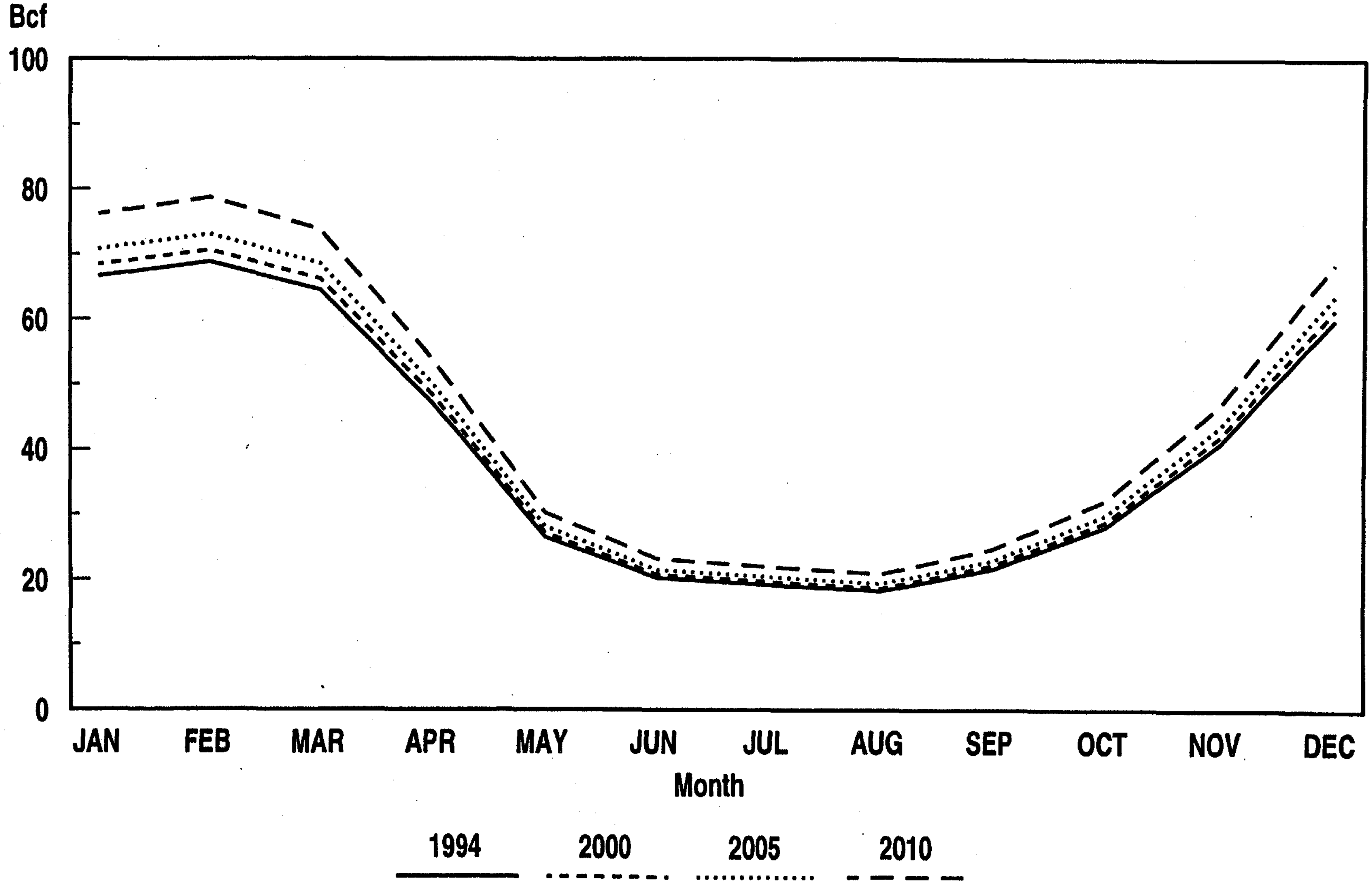
Monthly Commercial Gas Demand Curve



db\graphs\necom

Middle Atlantic

Monthly Commercial Gas Demand Curve

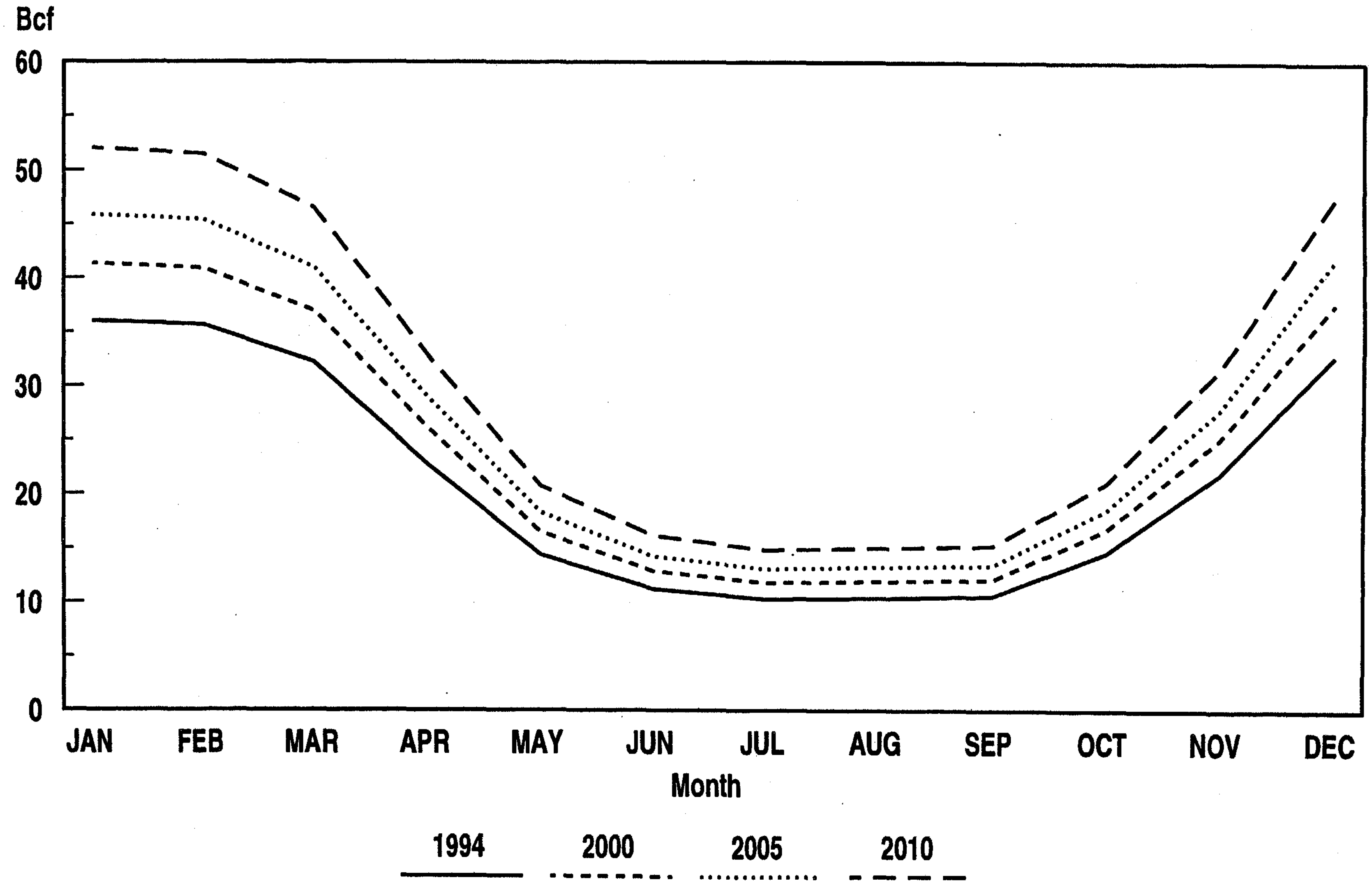


db\graphs\macom

D-3

South Atlantic

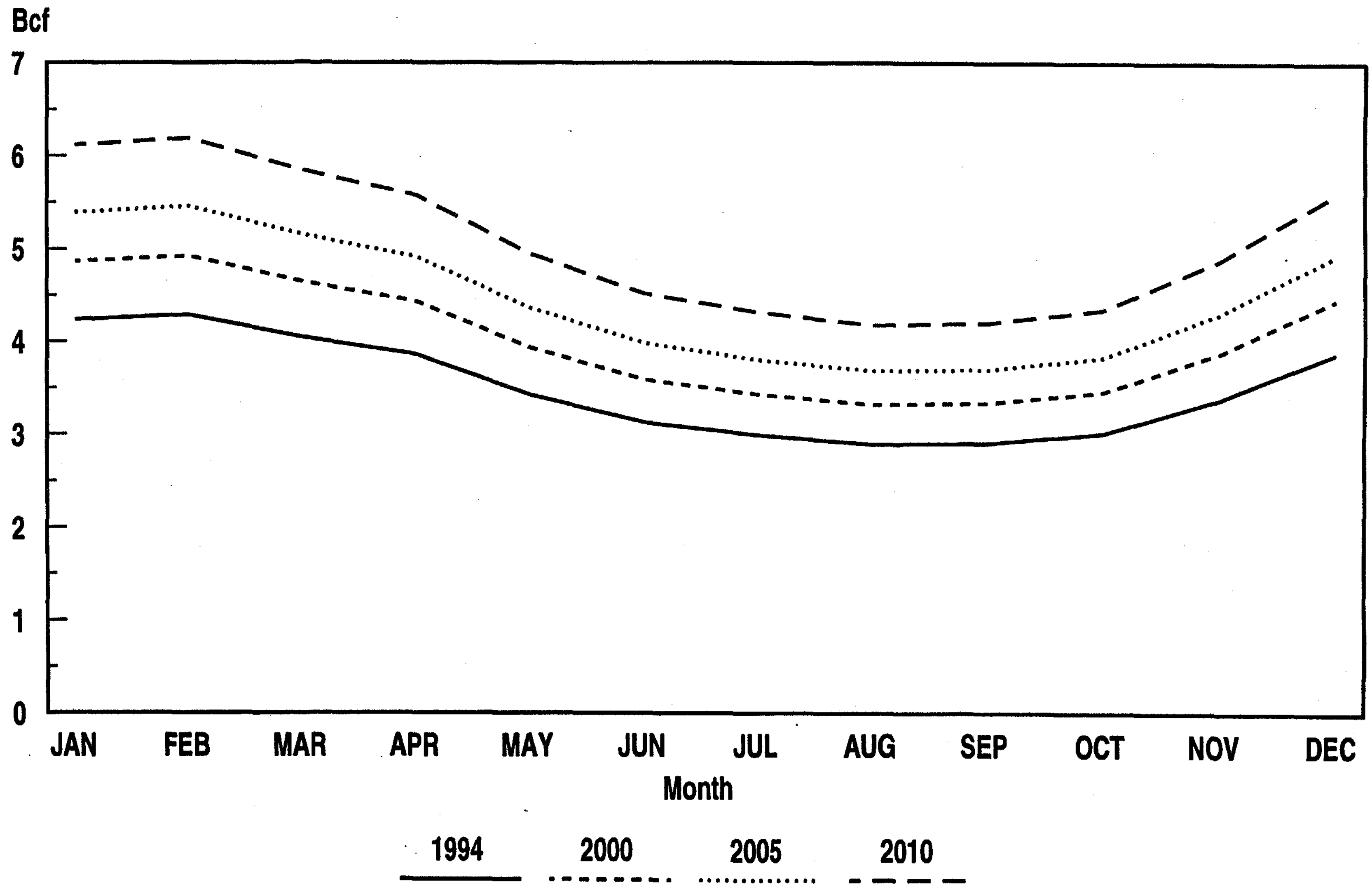
Monthly Commercial Gas Demand Curve



db\graphs\sacom

Florida

Monthly Commercial Gas Demand Curve

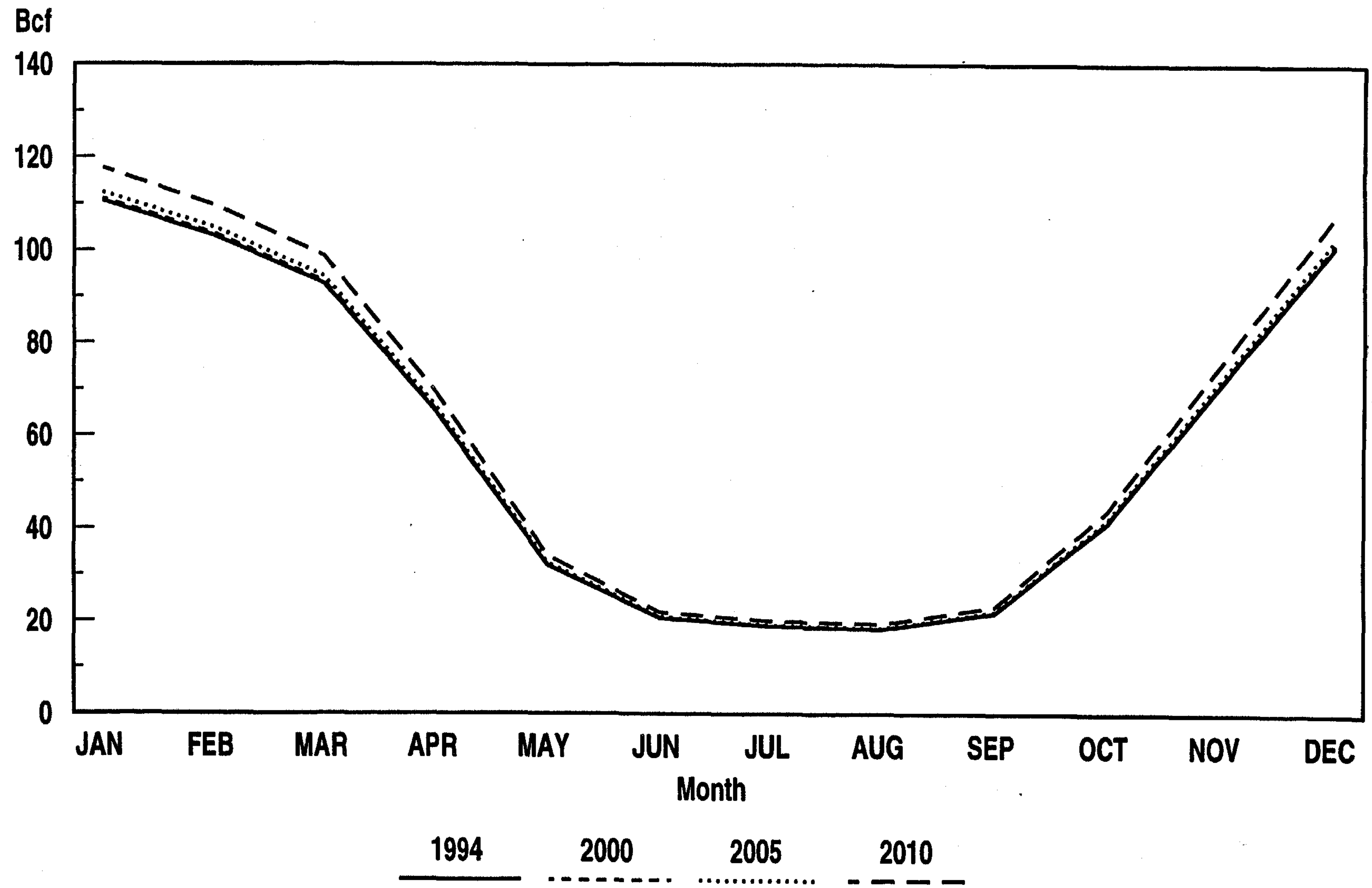


db\graphs\flcom

D-5

East North Central

Monthly Commercial Gas Demand Curve

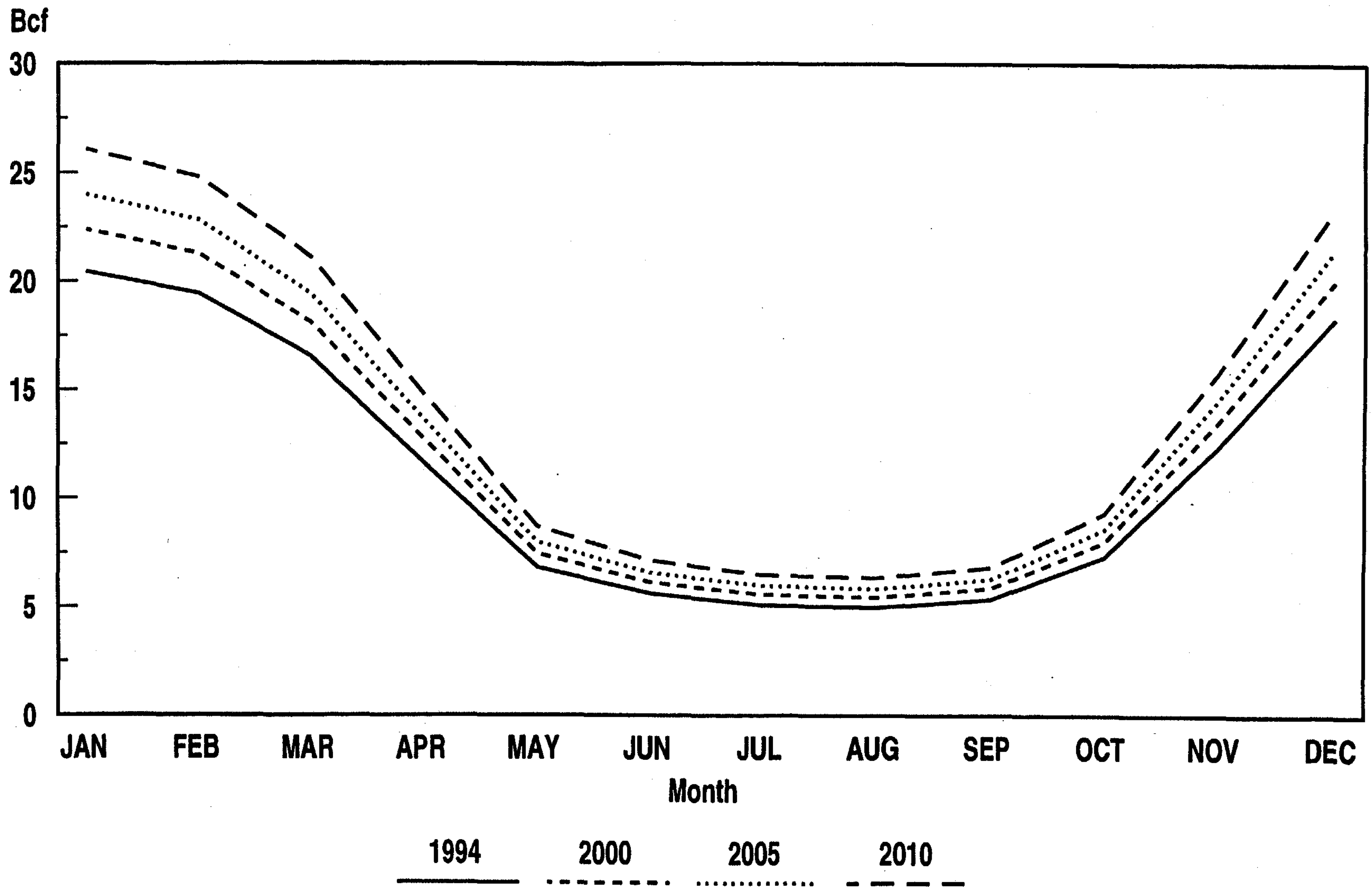


db\graphs\enccom

D-6

East South Central

Monthly Commercial Gas Demand Curve

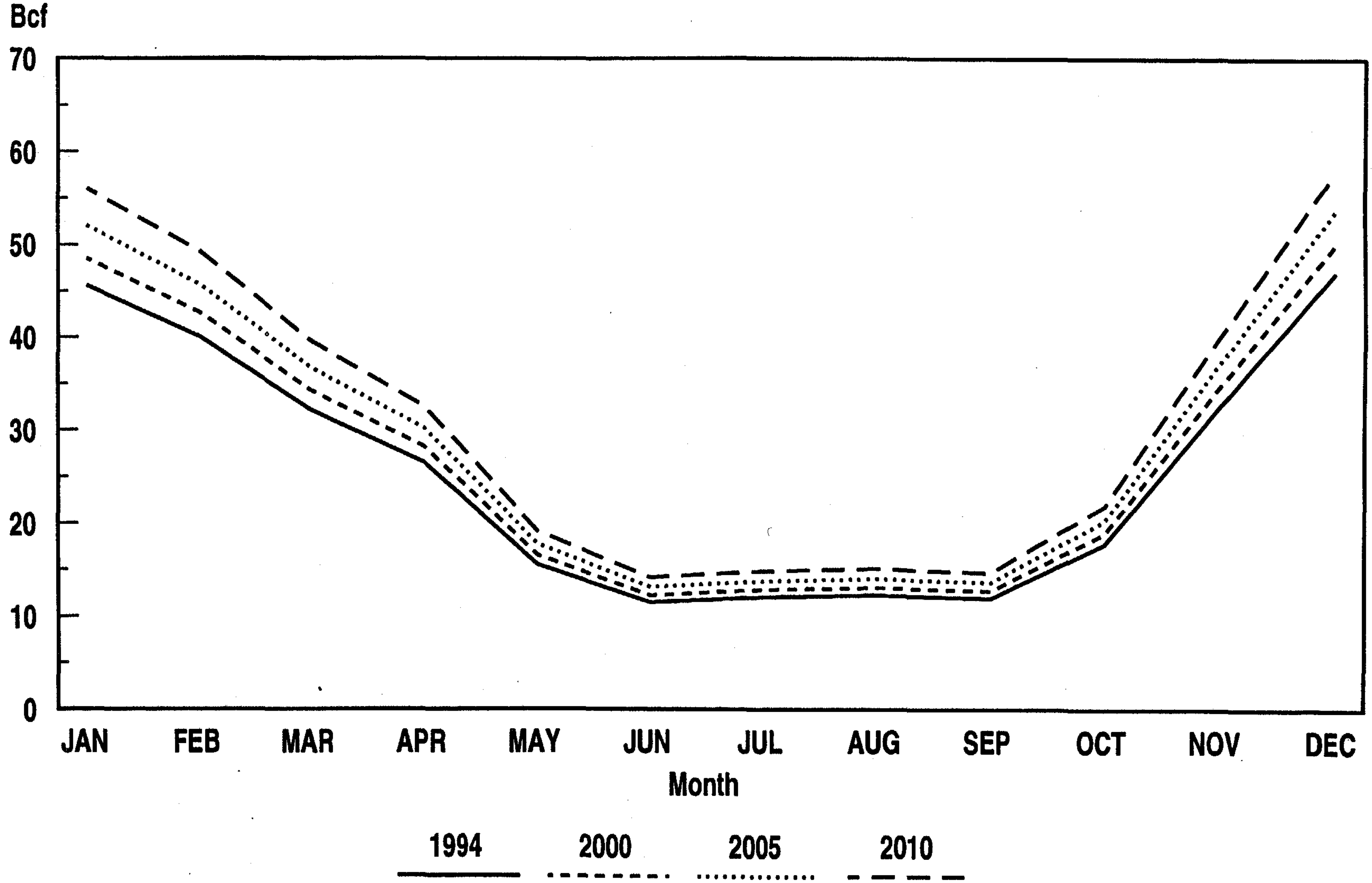


db\graphs\esccom

D-7

West North Central

Monthly Commercial Gas Demand Curve

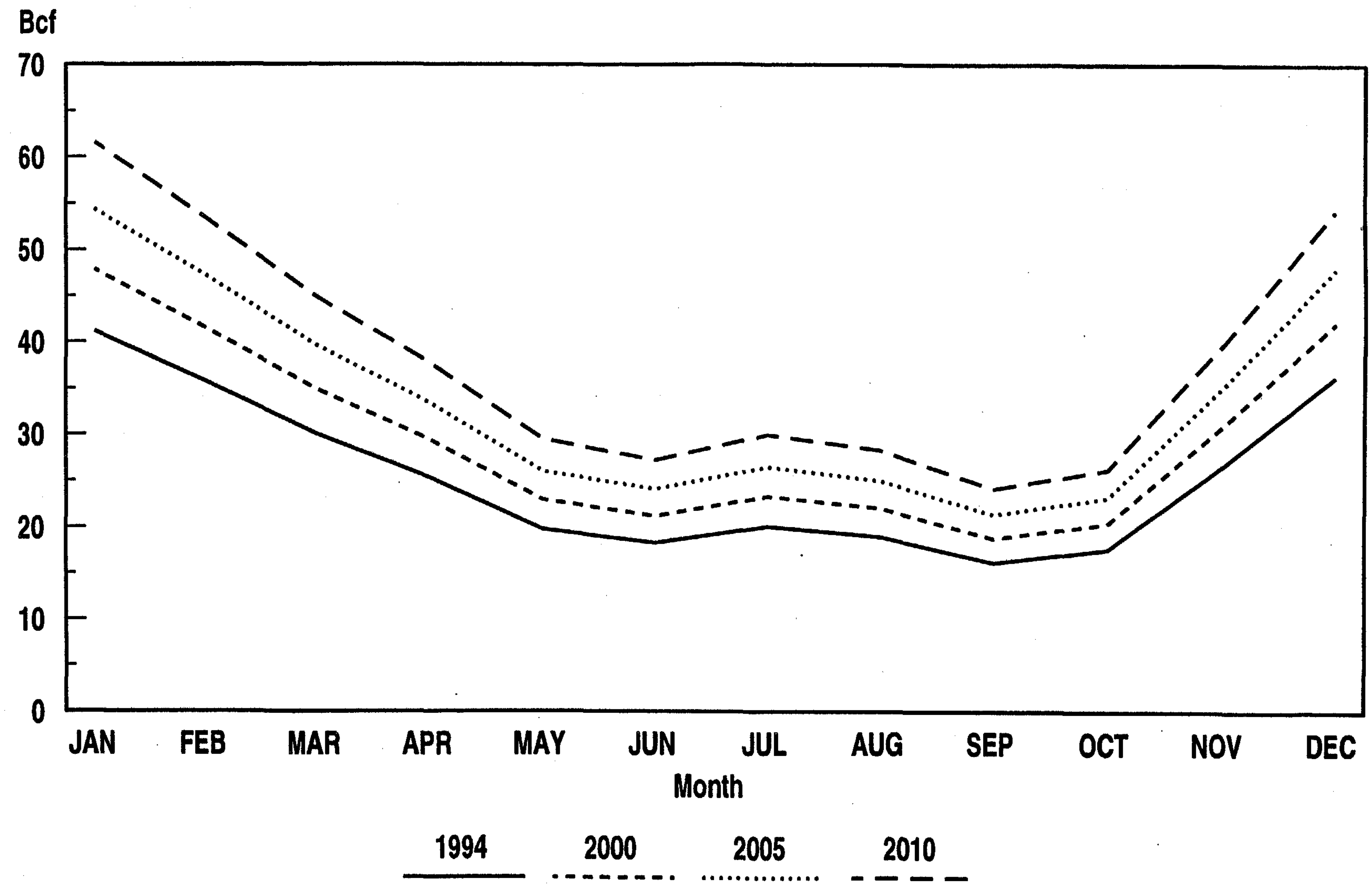


D-8

db\graphs\wnccom

West South Central

Monthly Commercial Gas Demand Curve

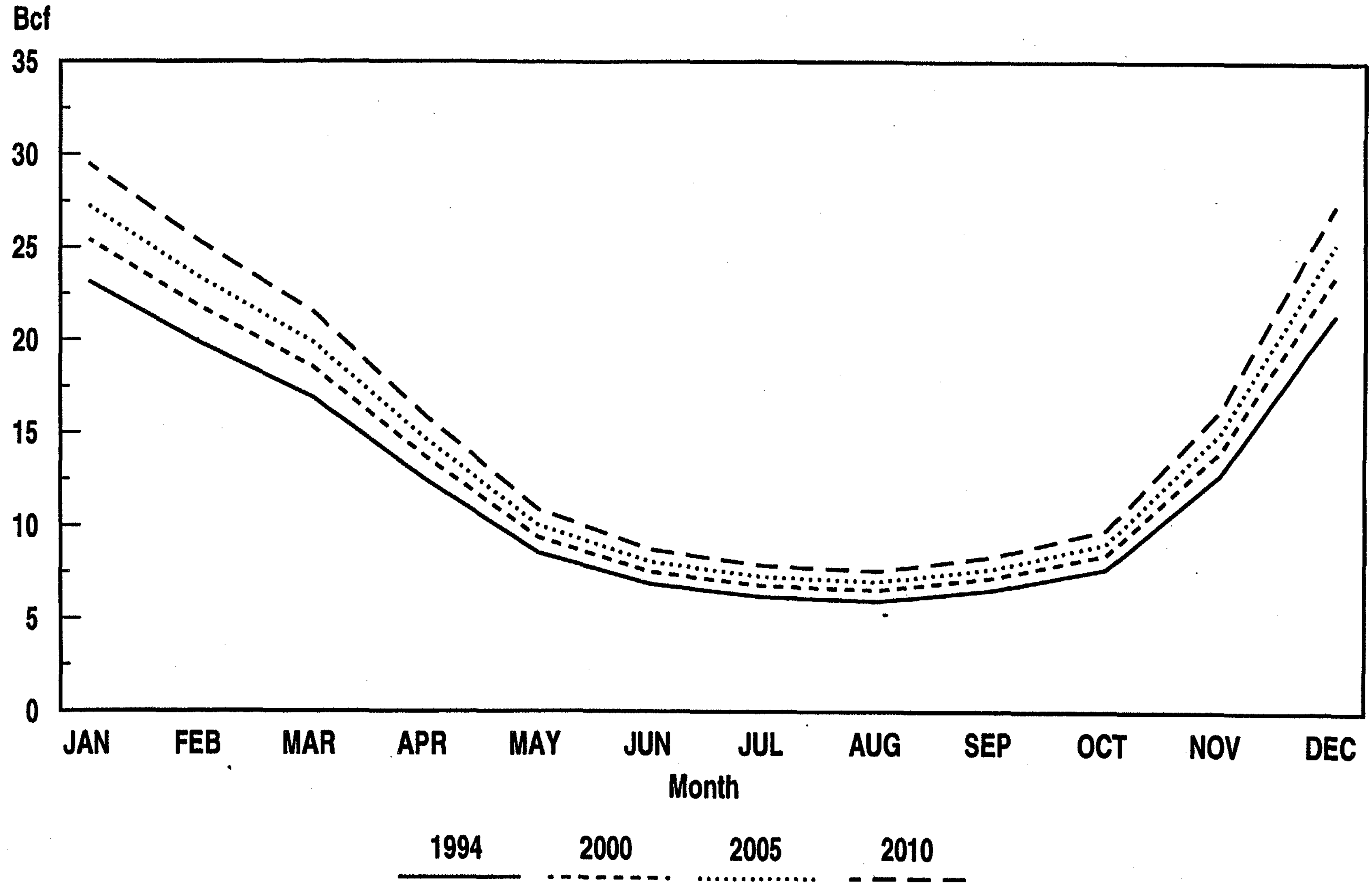


db\graphs\wsccom

D-9

Mountain North

Monthly Commercial Gas Demand Curve

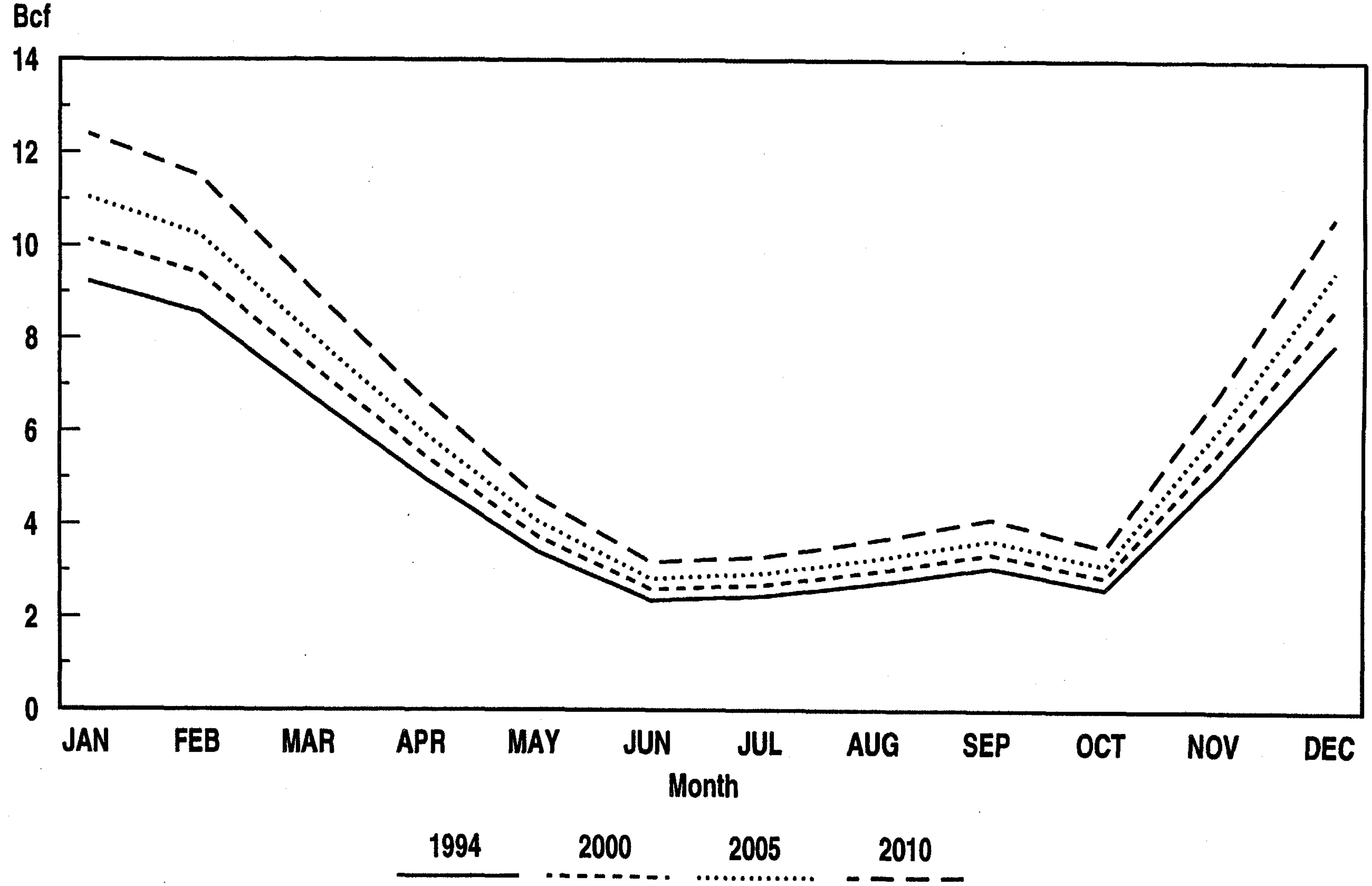


db\graphs\m1com

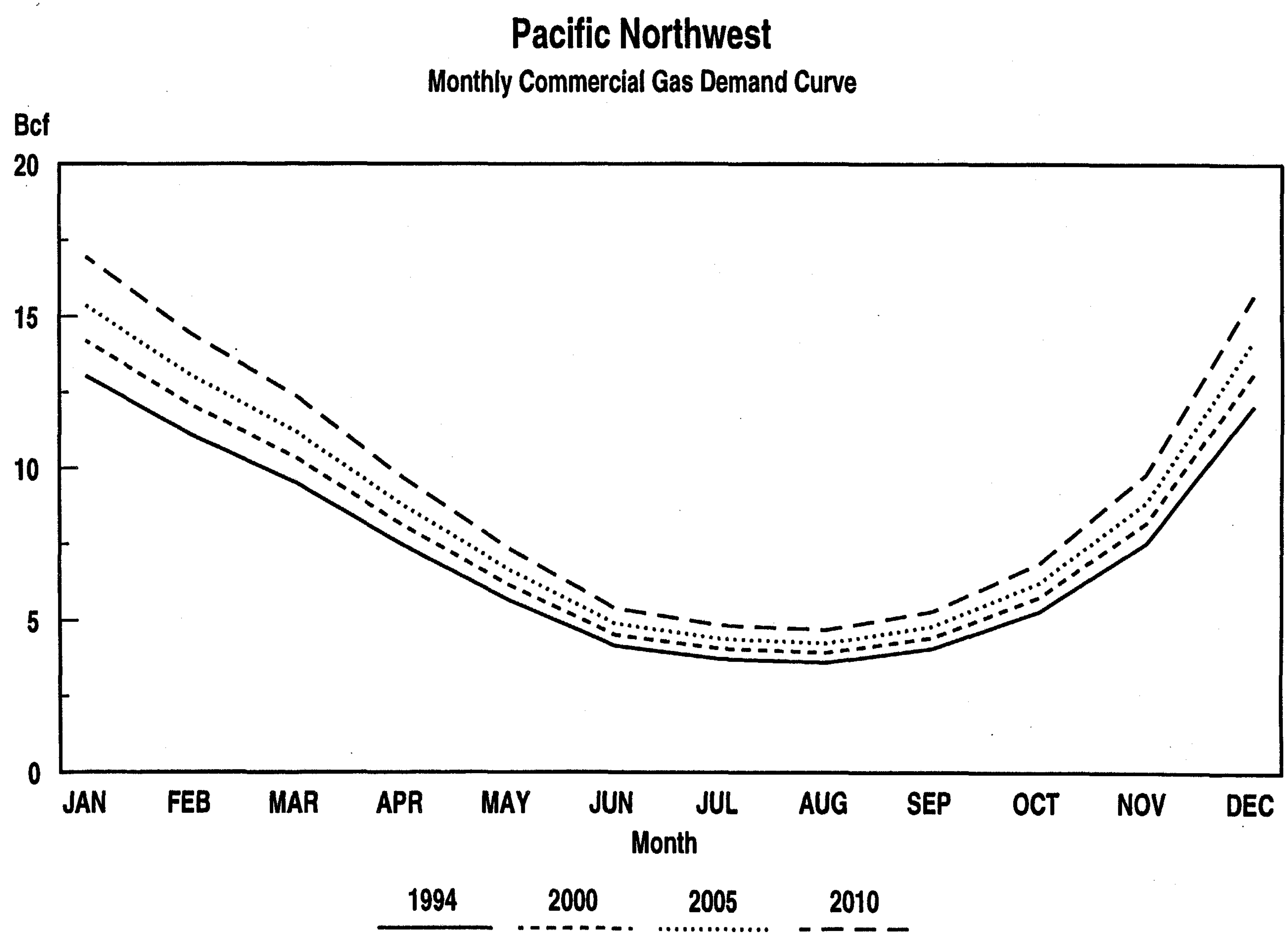
D-10

Mountain South

Monthly Commercial Gas Demand Curve



db\graphs\m2com

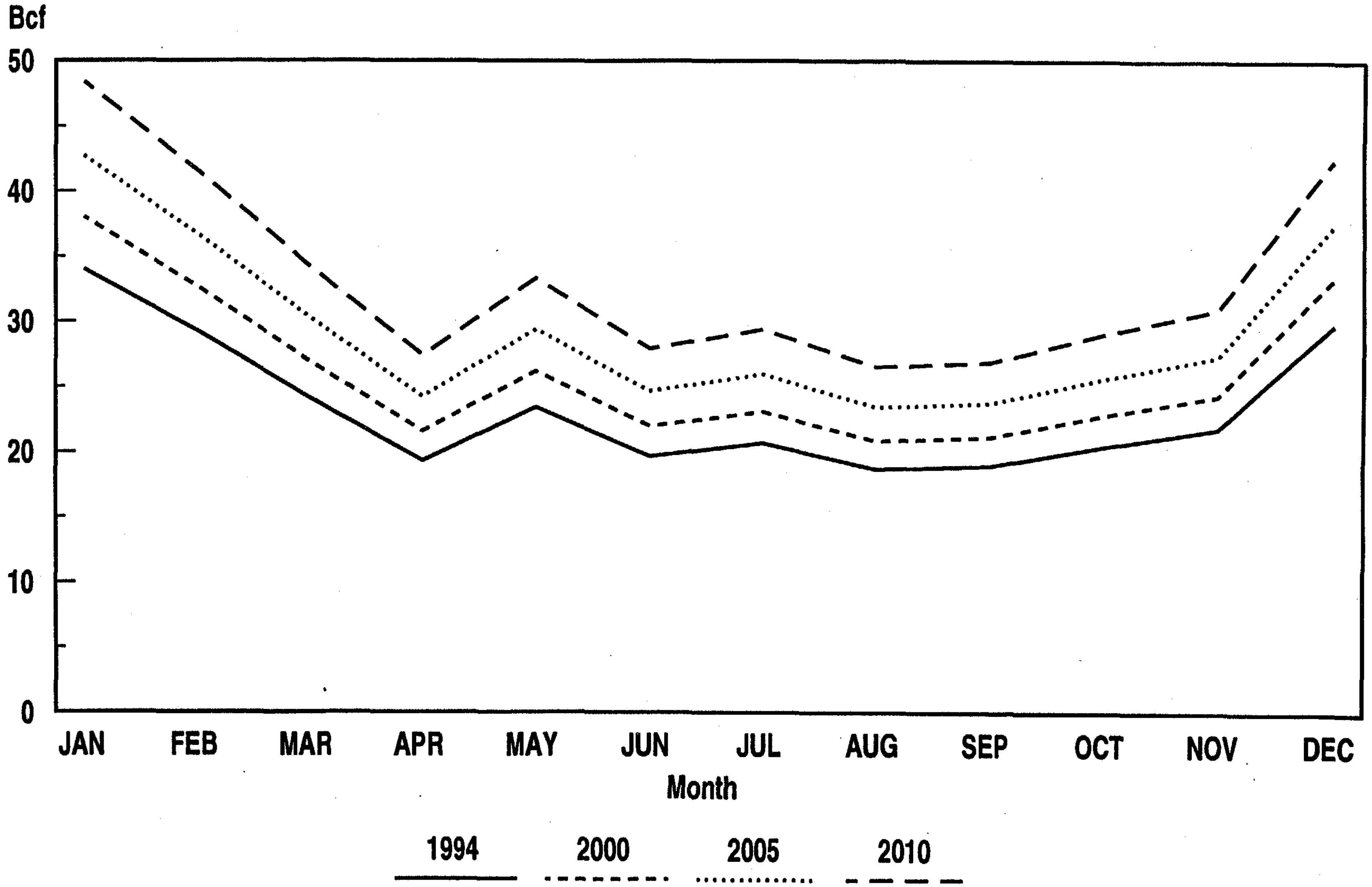


dblgraphs\pncom

D-12

California

Monthly Commercial Gas Demand Curve



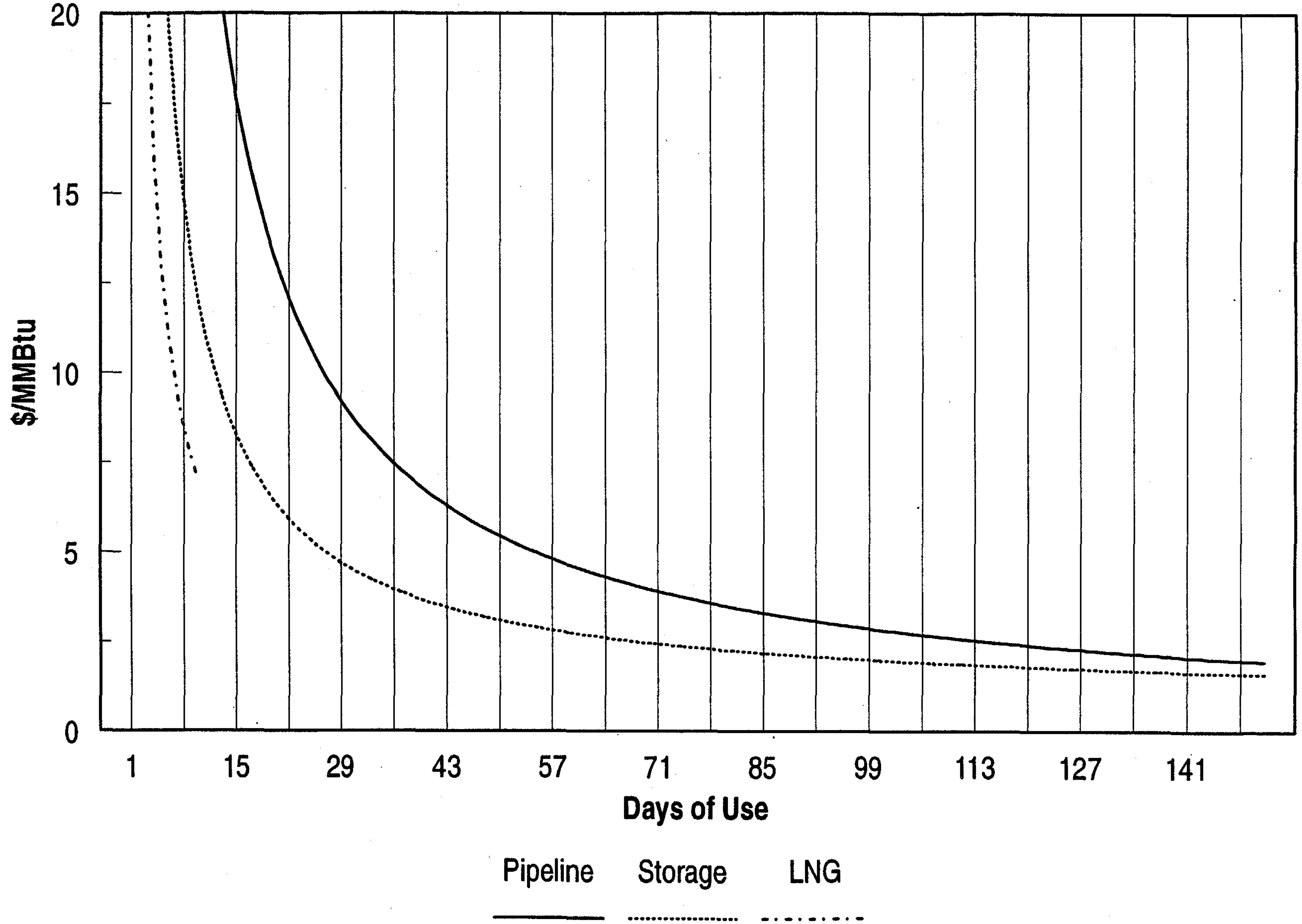
db\graphs\cacom

D-13

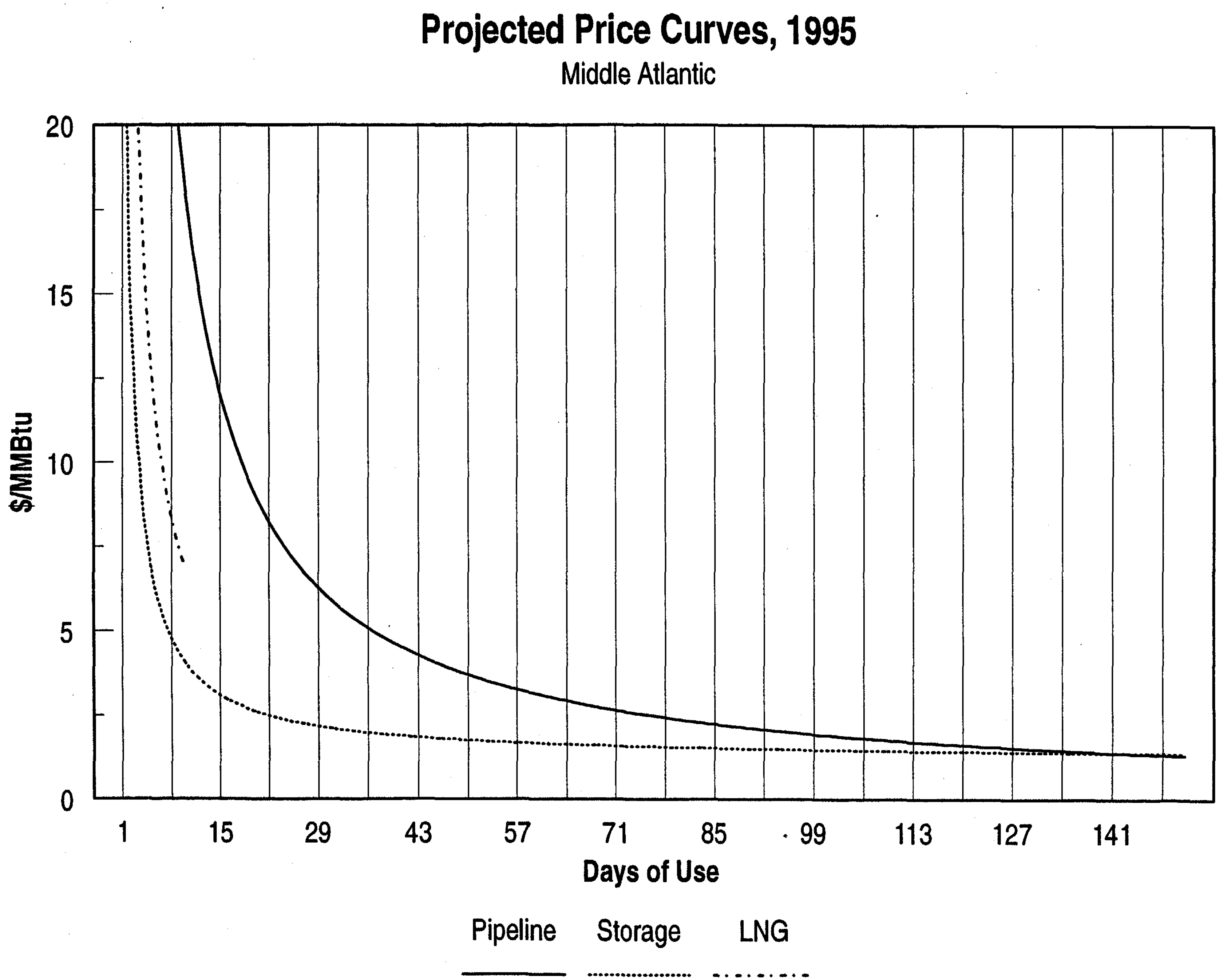
Appendix E

Projected Price Curves, 1995

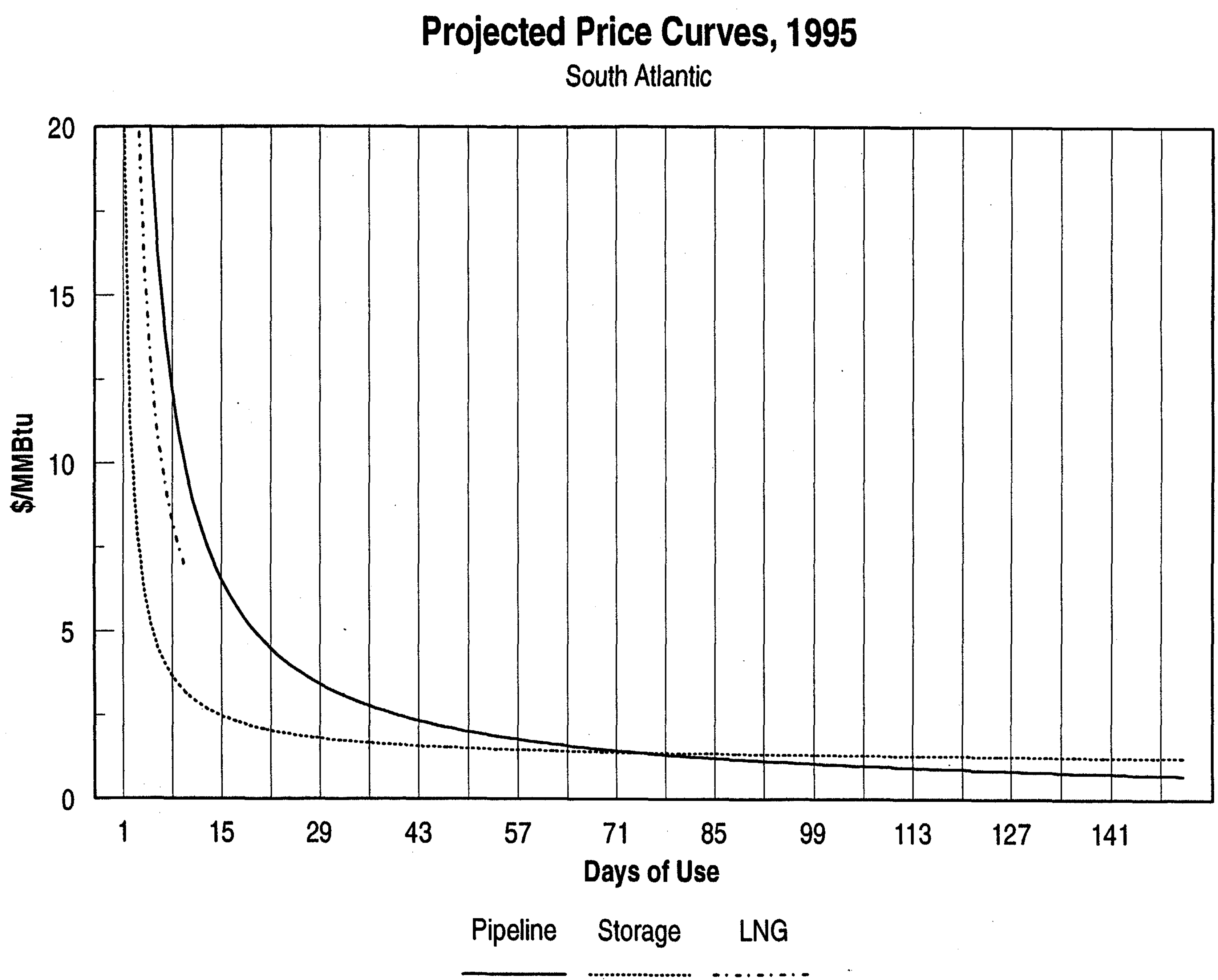
New England



E-2


Projected Price Curves, 1995
Middle Atlantic
$/MMBtu
20
15
10
5
0
1
15
29
43
57
71
85
99
113
127
141
Days of Use
Pipeline
Storage
LNG

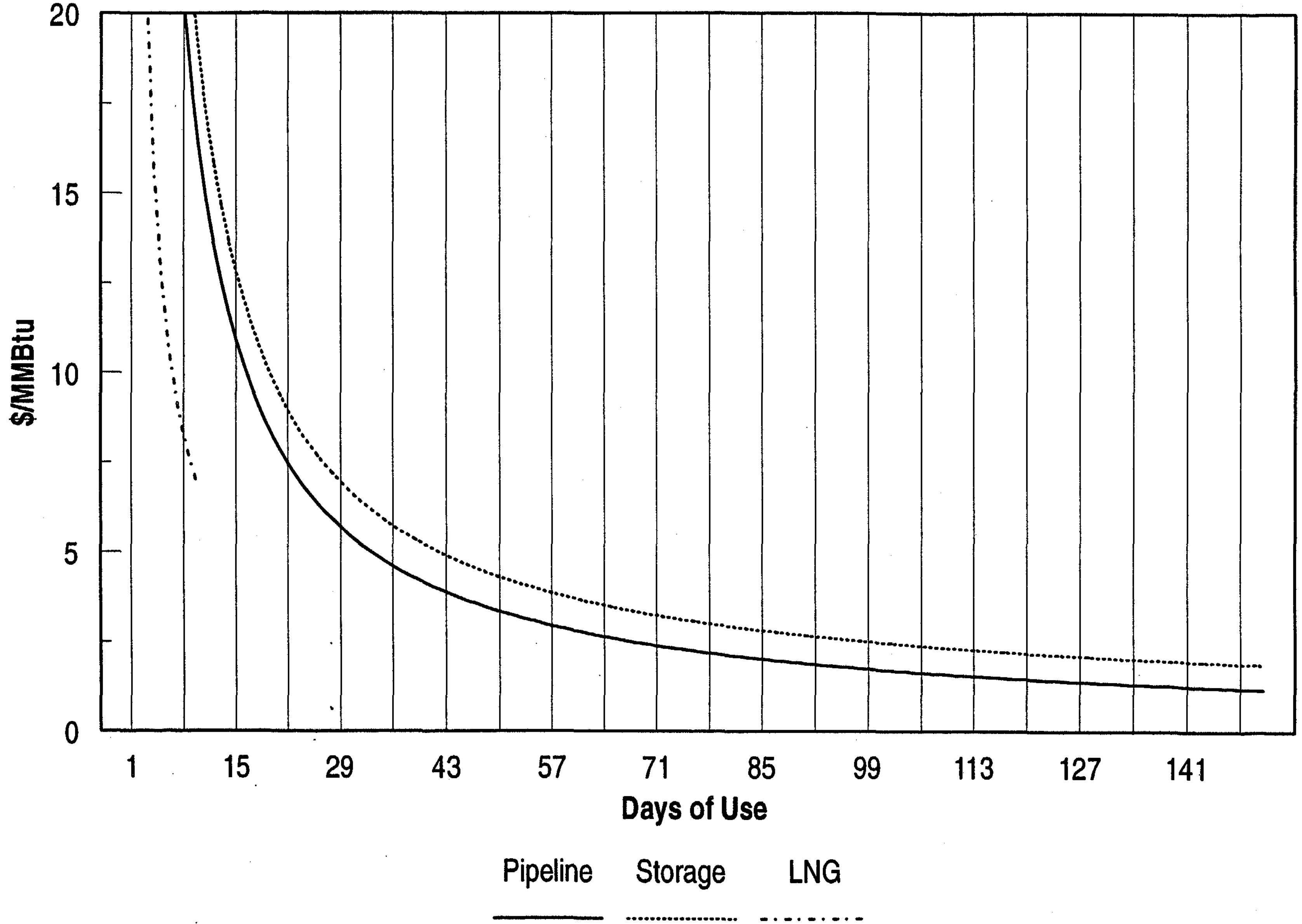
E-3


Projected Price Curves, 1995
South Atlantic
$/MMBtu
20
15
10
5
0
1
15
29
43
57
71
85
99
113
127
141
Days of Use
Pipeline
Storage
LNG

E-4

Projected Price Curves, 1995

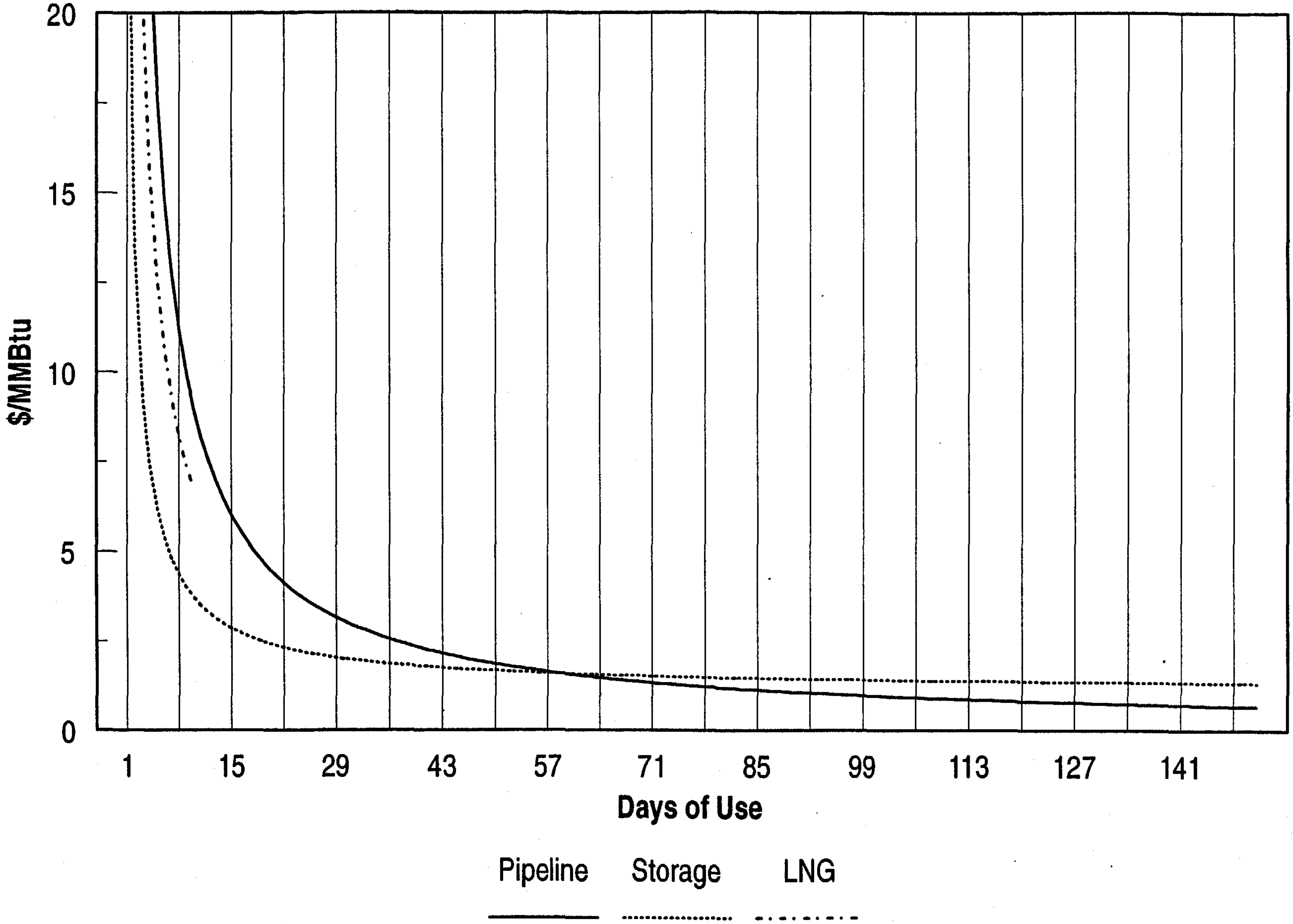
Florida



E-5

Projected Price Curves, 1995

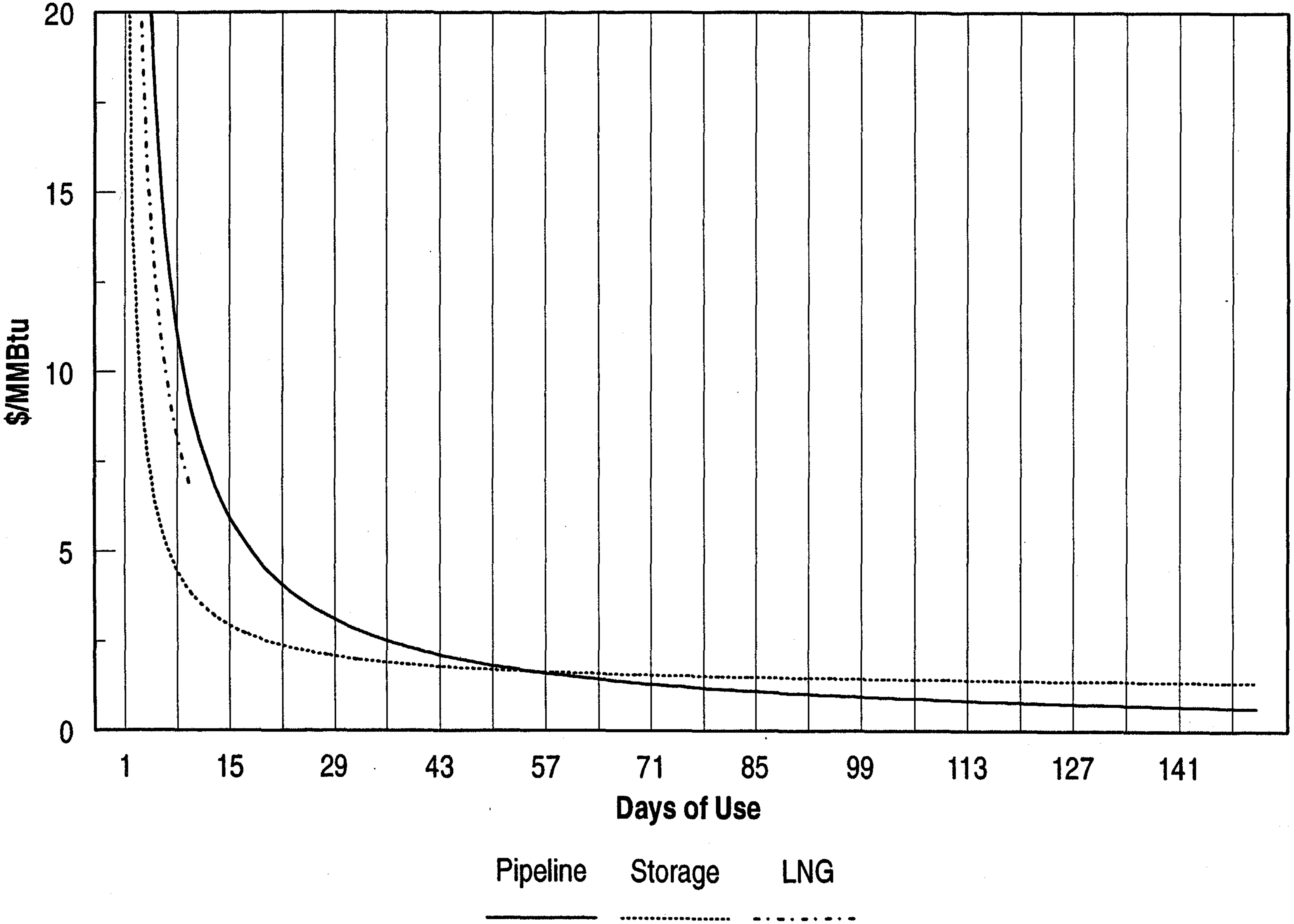
East North Central



E-6

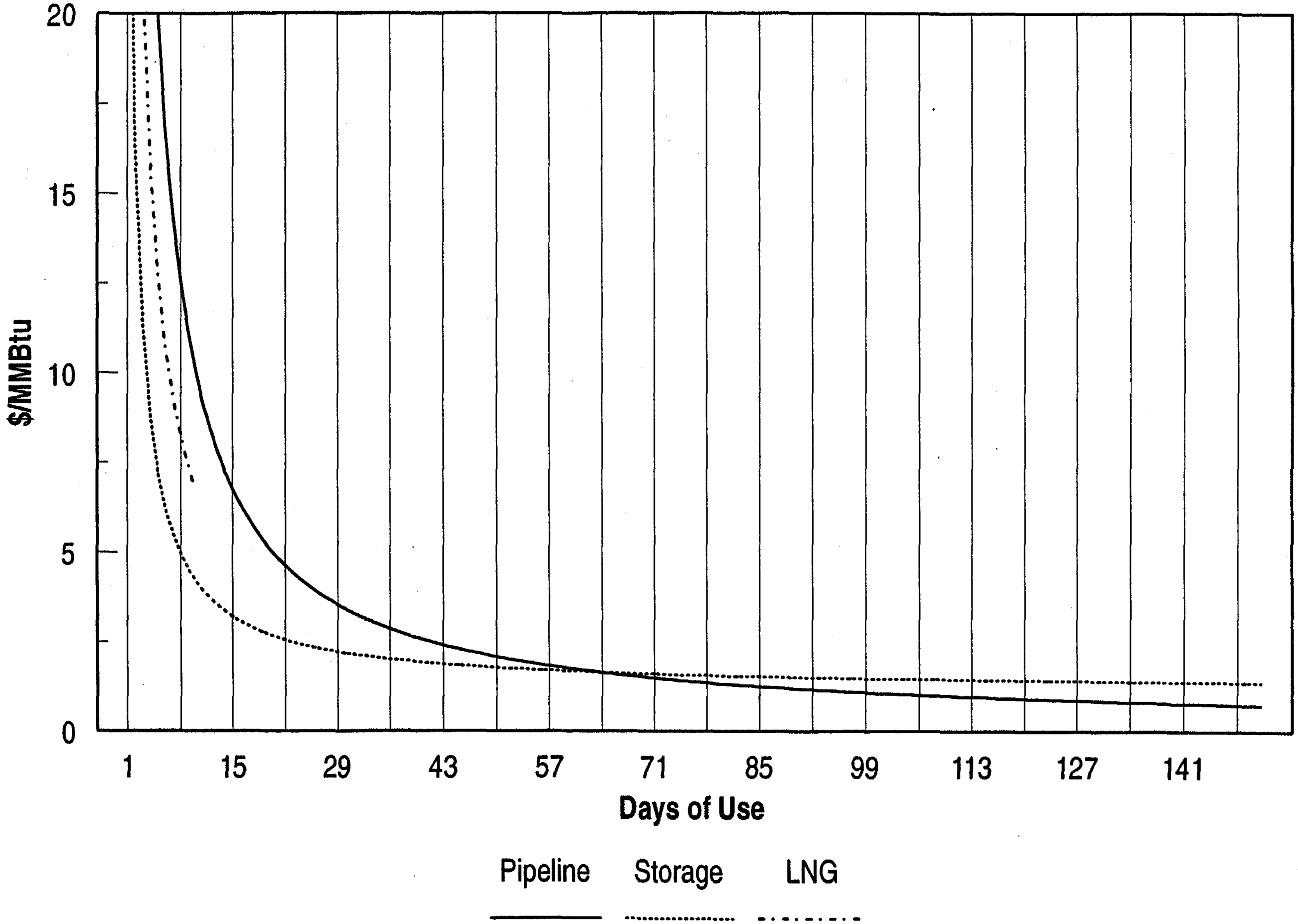
Projected Price Curves, 1995

East South Central



Projected Price Curves, 1995

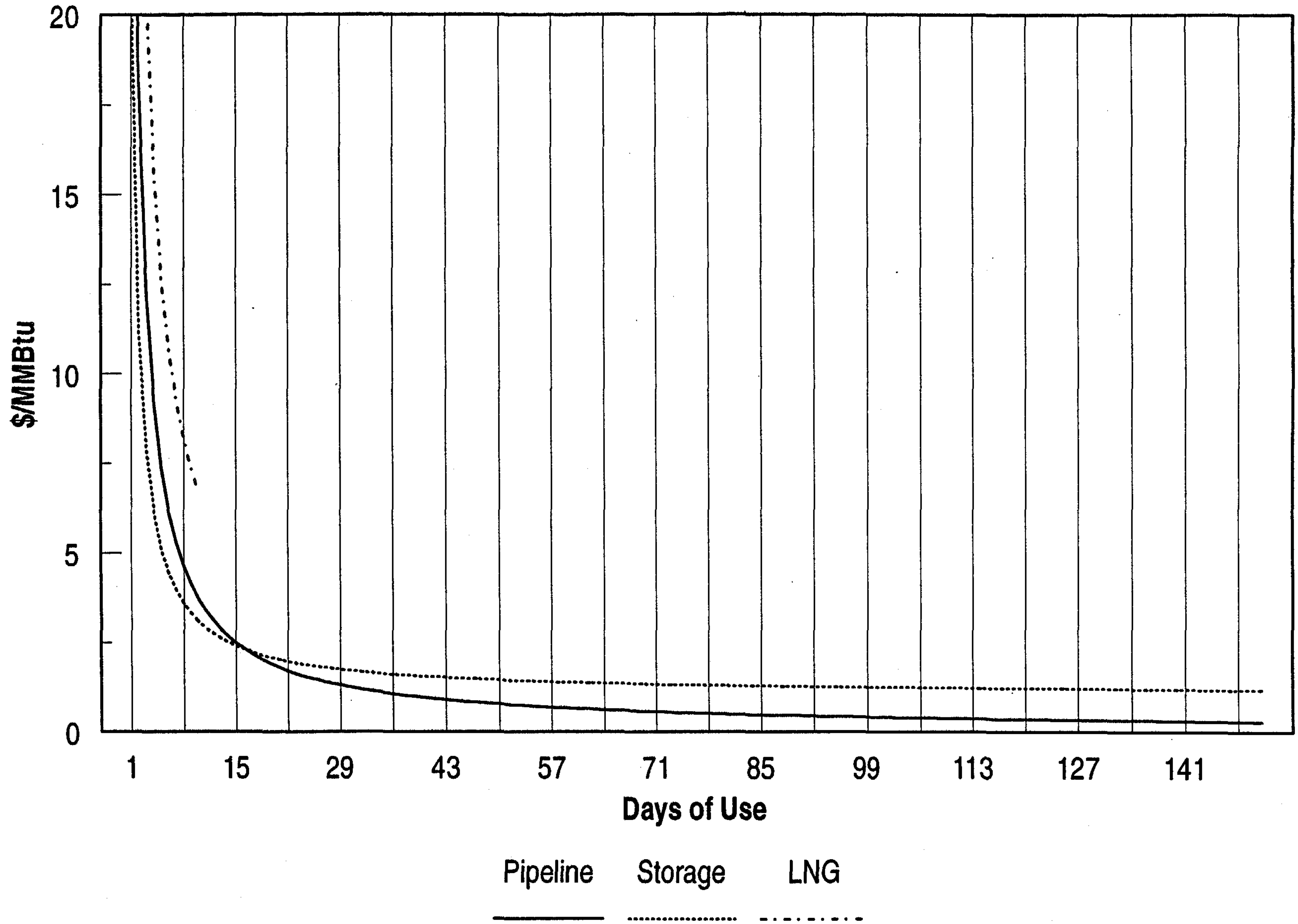
West North Central



E-8

Projected Price Curves, 1995

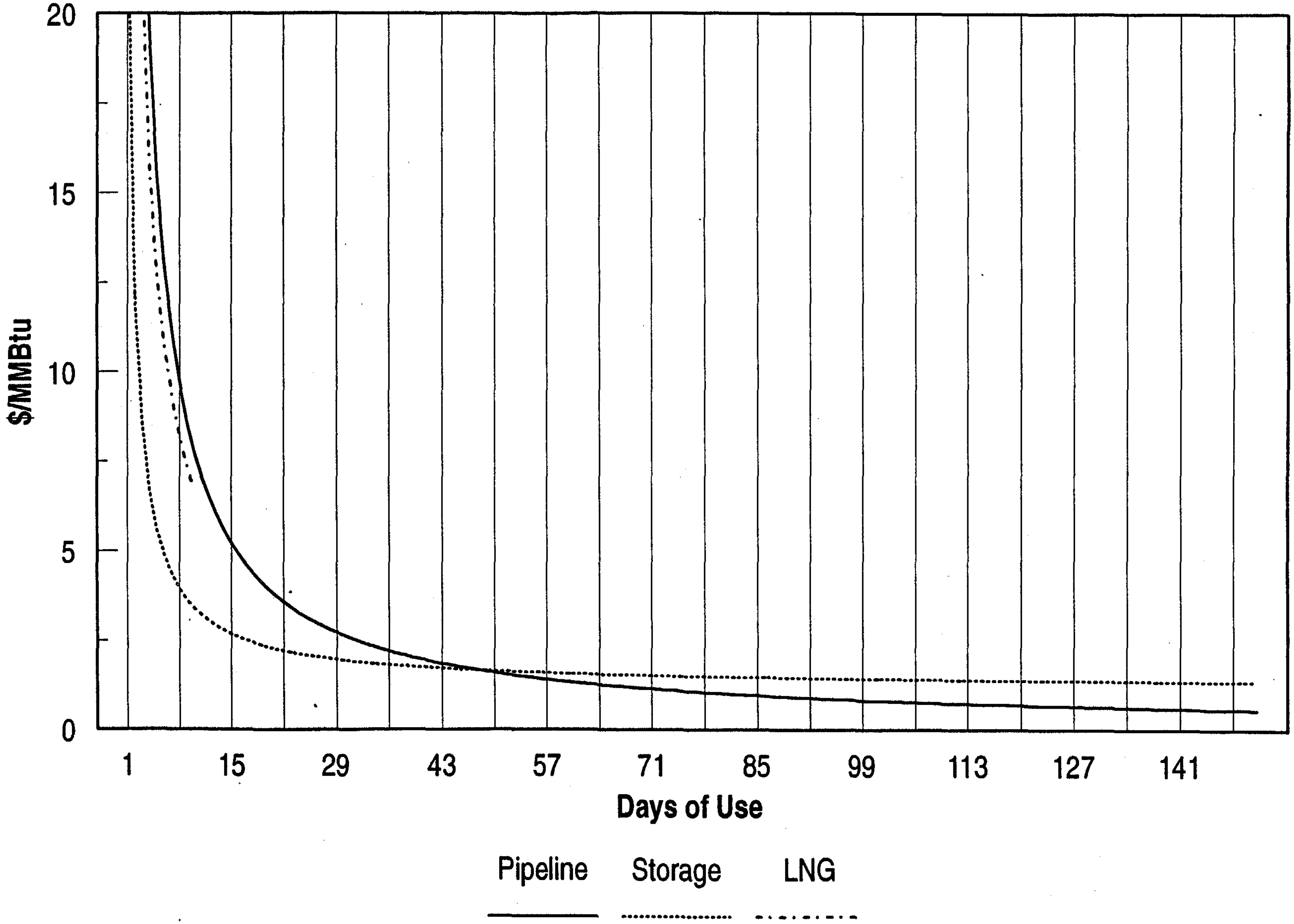
West South Central



E-9

Projected Price Curves, 1995

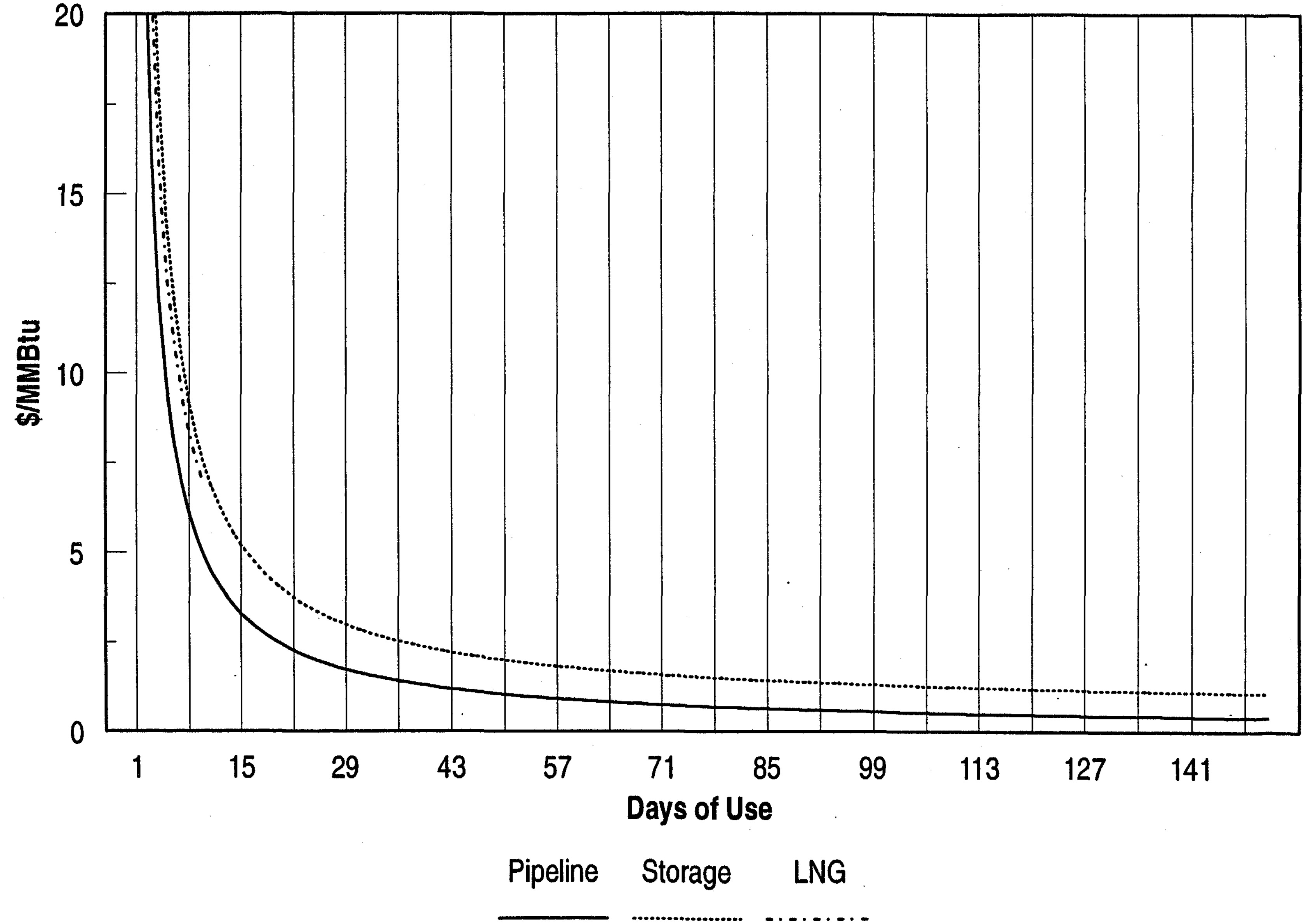
Mountain North



E-10

Projected Price Curves, 1995

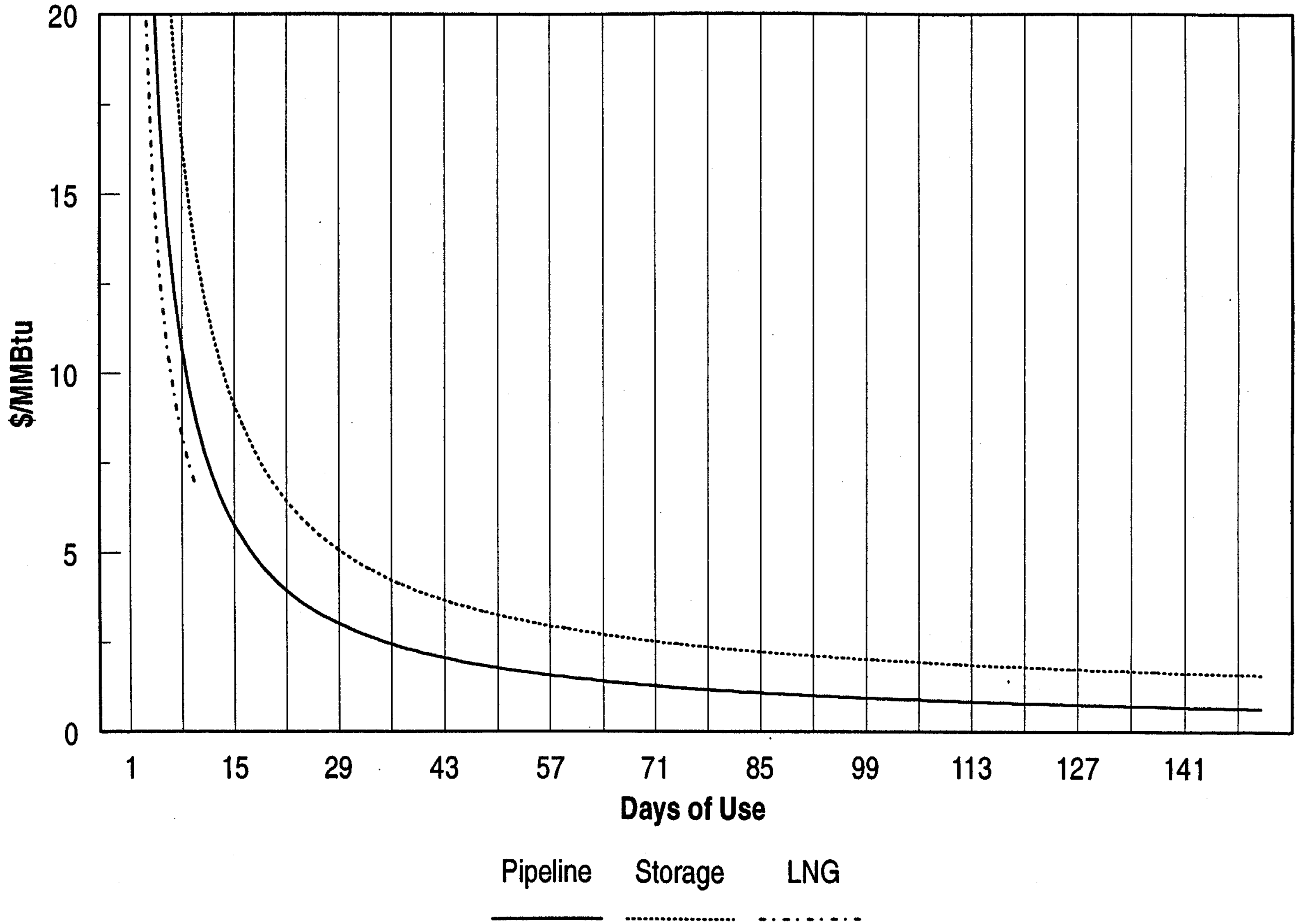
Mountain South



E-11

Projected Price Curves, 1995

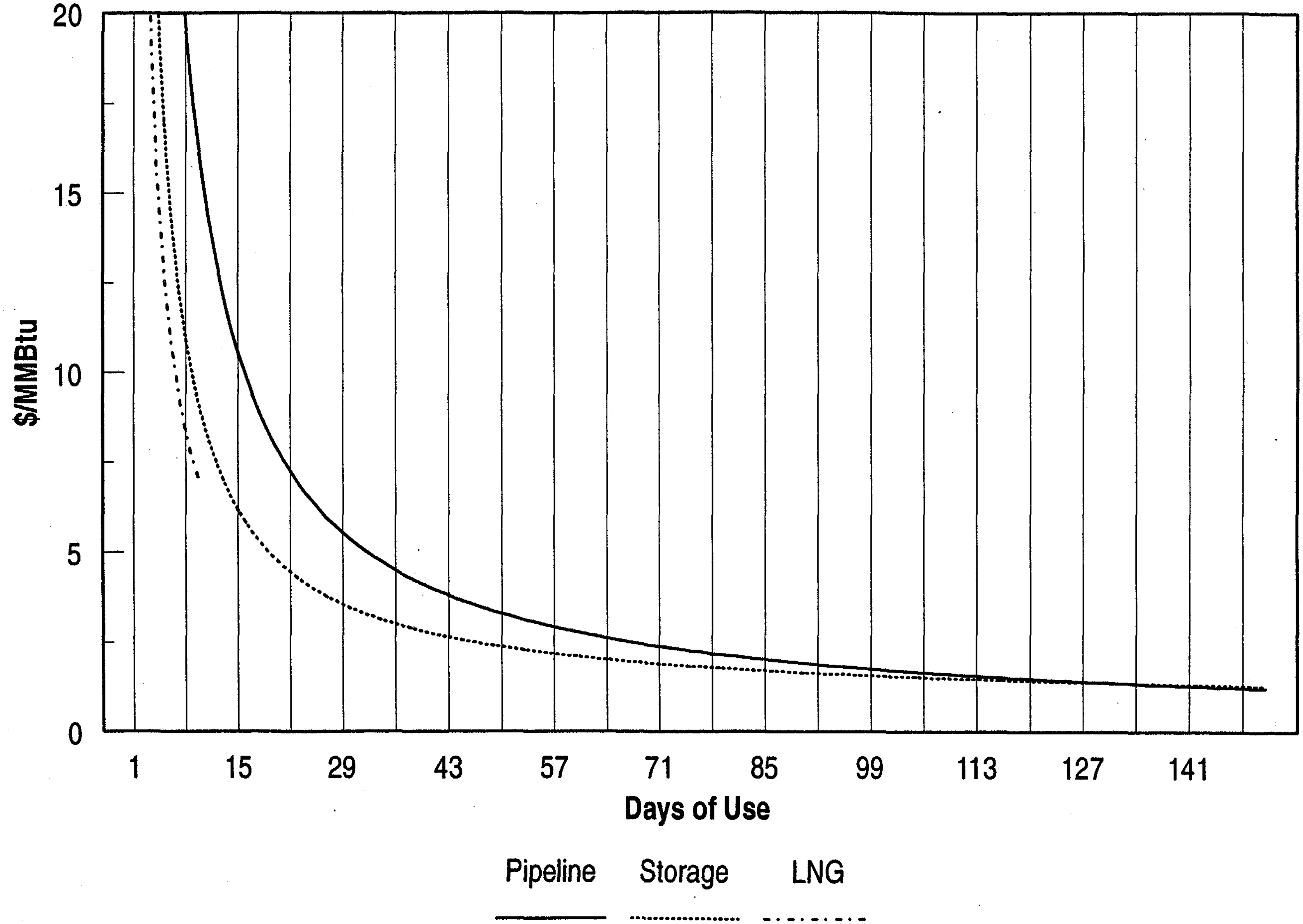
Pacific Northwest



E-12

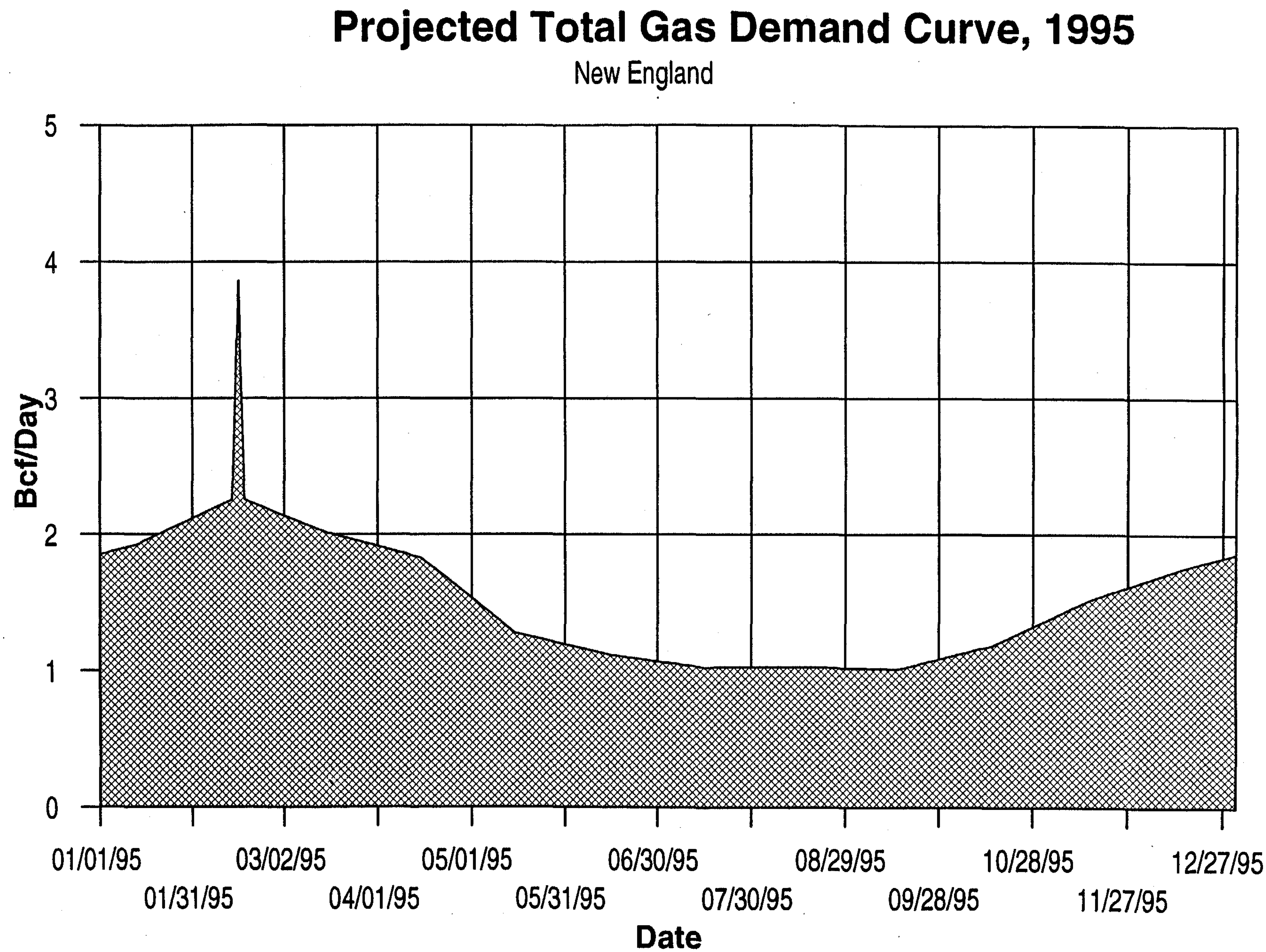
Projected Price Curves, 1995

California



E-13

Appendix F

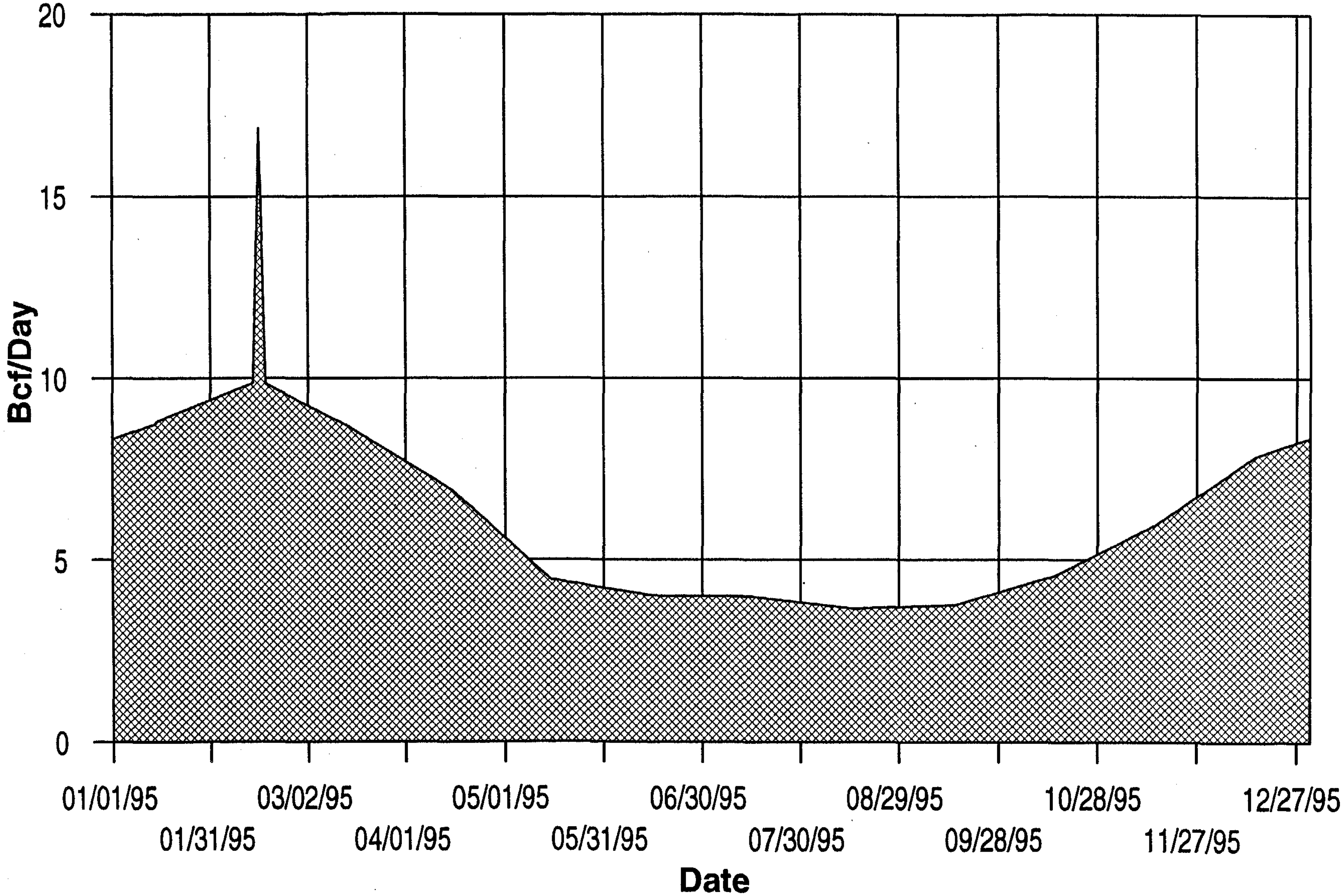


Peak Day volume is included for illustrative purposes.

F-2

Projected Total Gas Demand Curve, 1995

Middle Atlantic

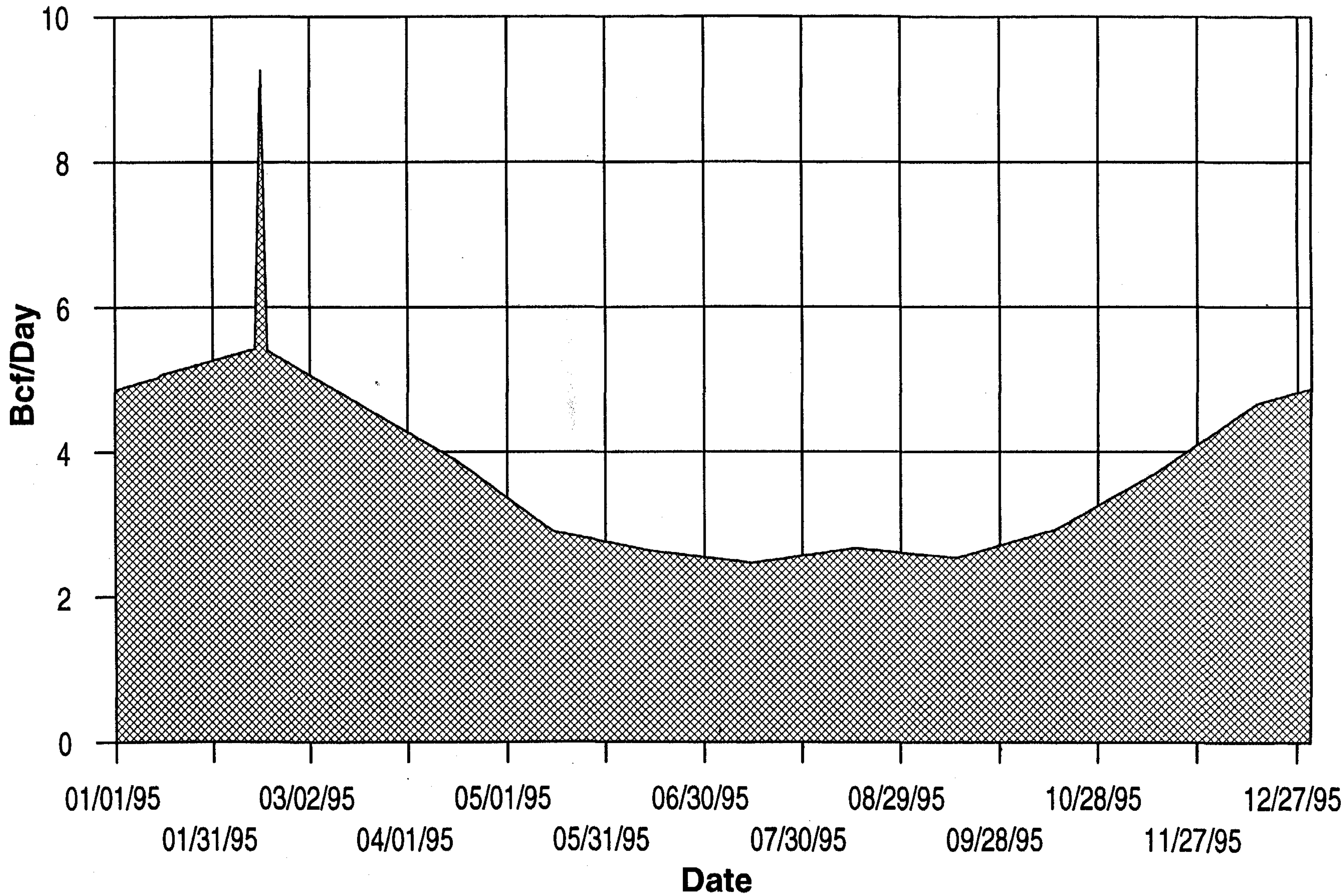


Peak Day volume is included for illustrative purposes.

F-3

Projected Total Gas Demand Curve, 1995

South Atlantic

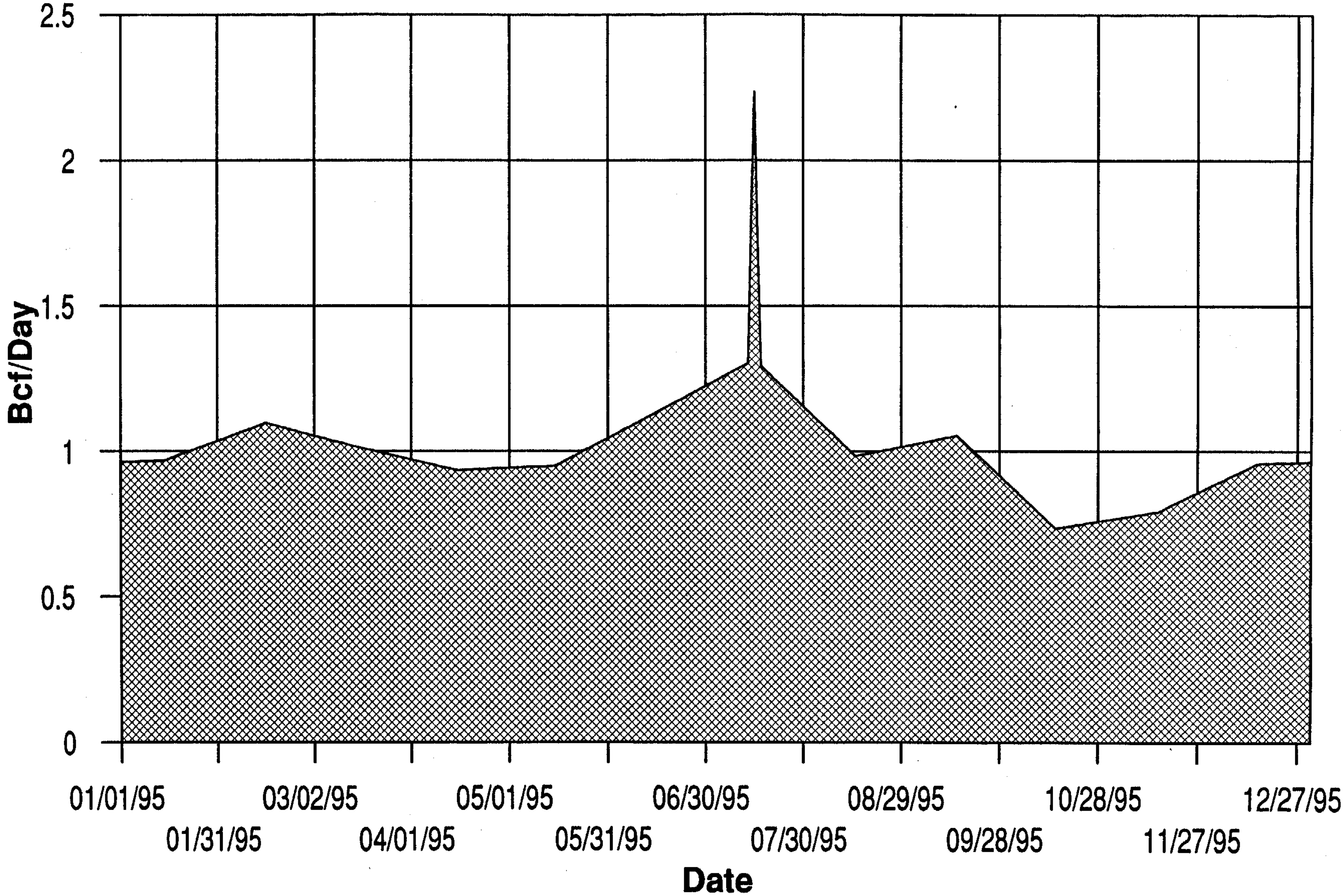


Peak Day volume is included for illustrative purposes.

F-4

Projected Total Gas Demand Curve, 1995

Florida

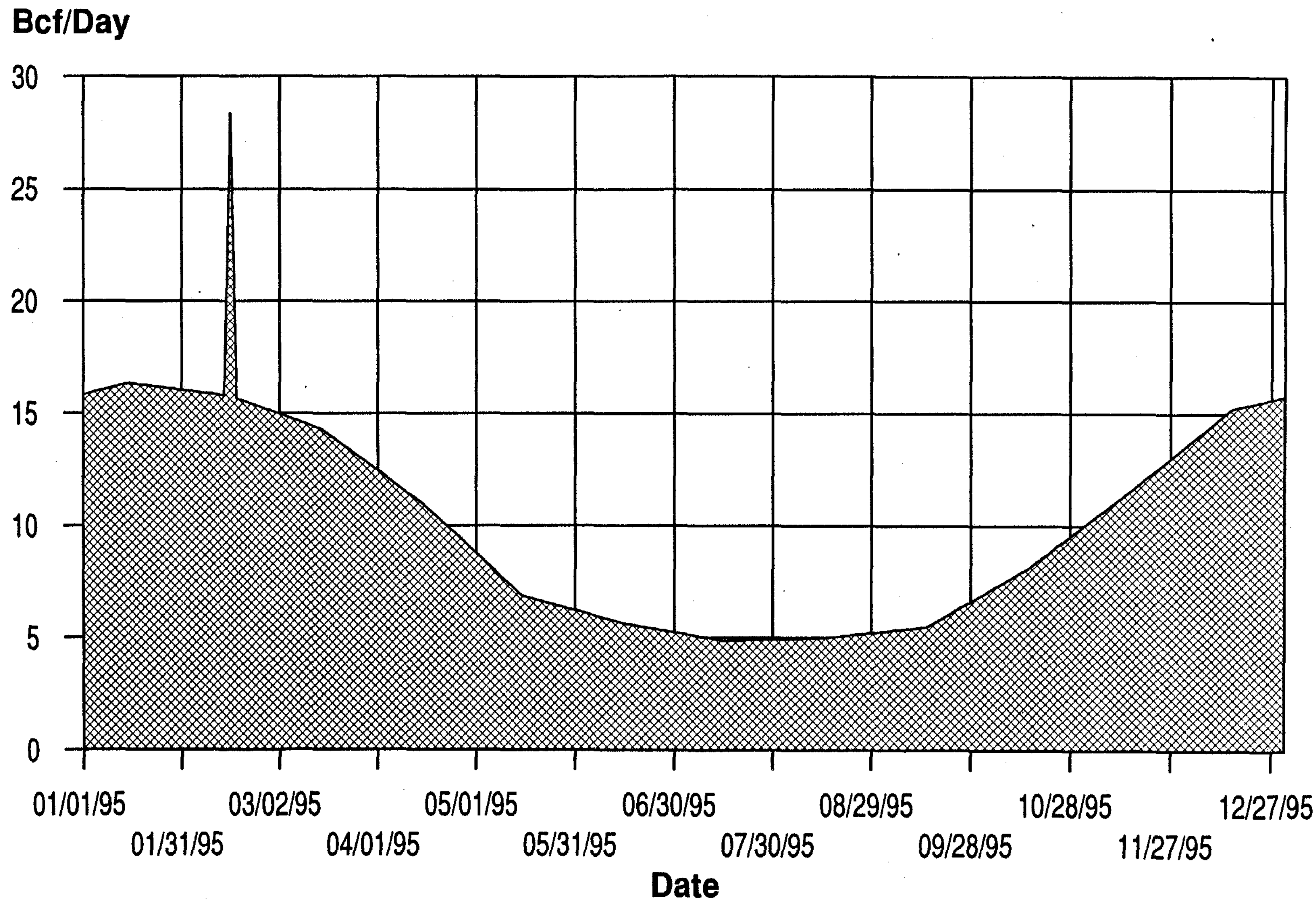


Peak Day volume is included for illustrative purposes.

F-5

Projected Total Gas Demand Curve, 1995

East North Central

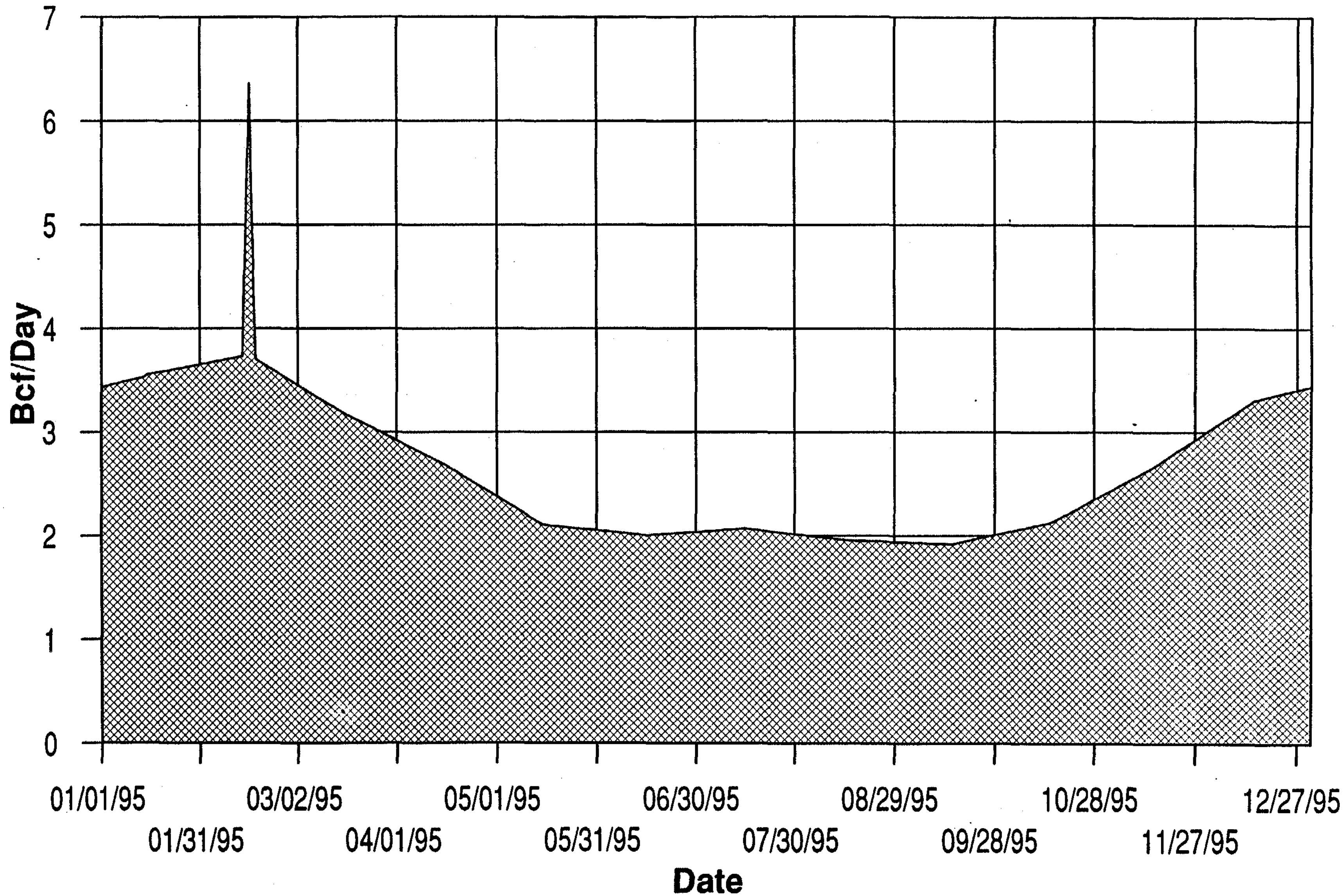


Peak Day volume is included for illustrative purposes.

F-6

Projected Total Gas Demand Curve, 1995

East South Central

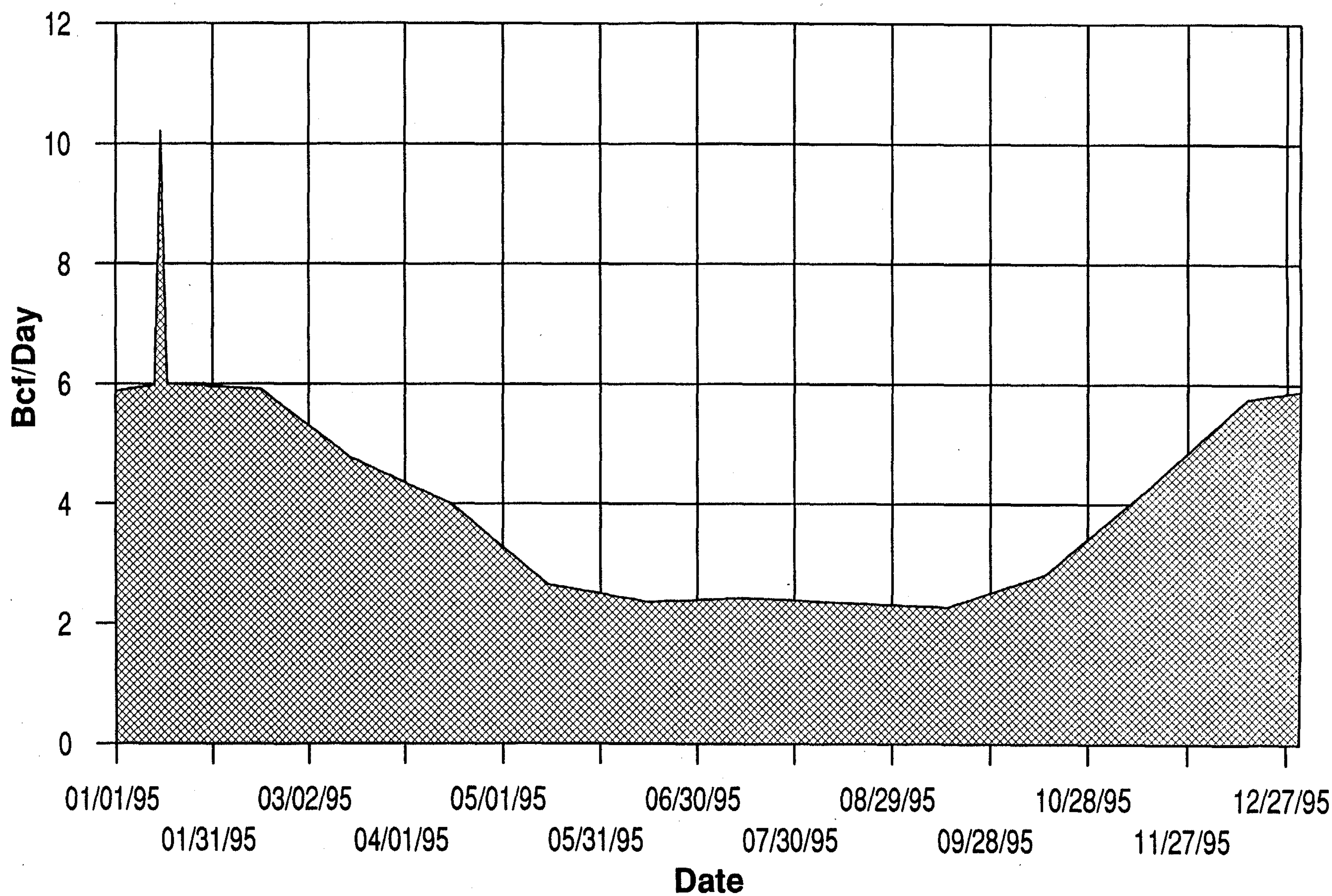


Peak Day volume is included for illustrative purposes.

F-7

Projected Total Gas Demand Curve, 1995

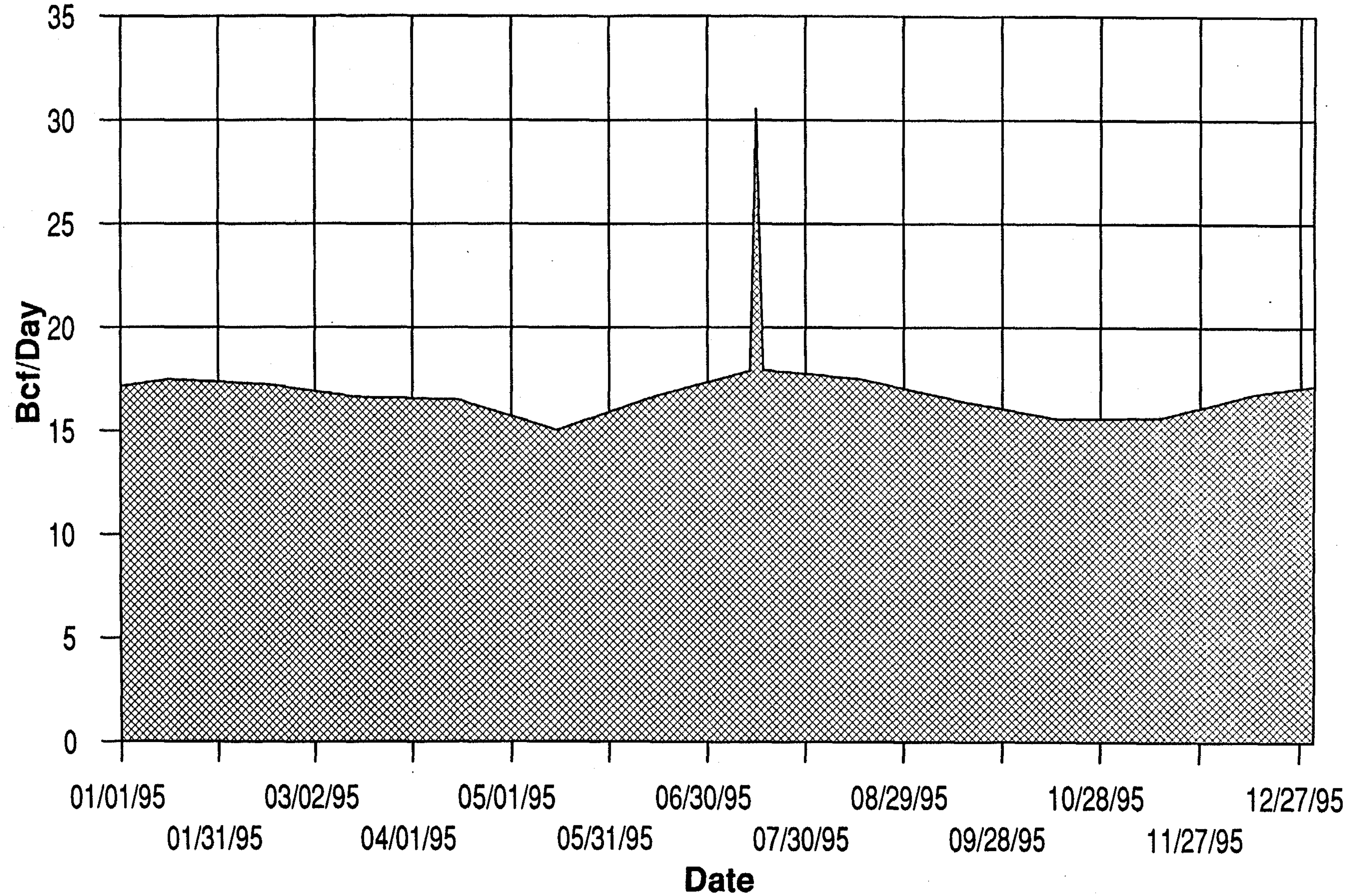
West North Central



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

West South Central

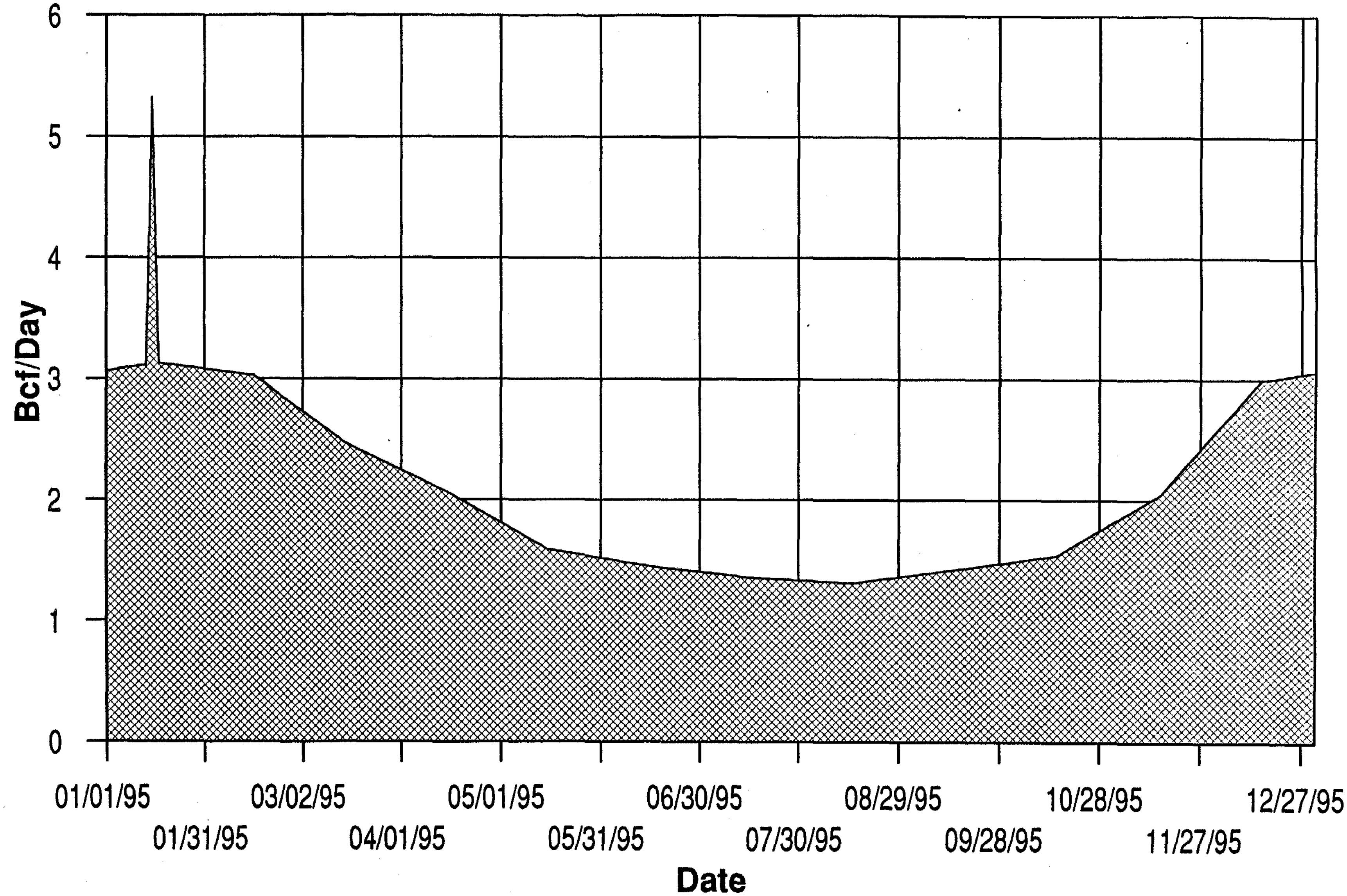


Peak Day volume is included for illustrative purposes.

F-9

Projected Total Gas Demand Curve, 1995

Mountain North

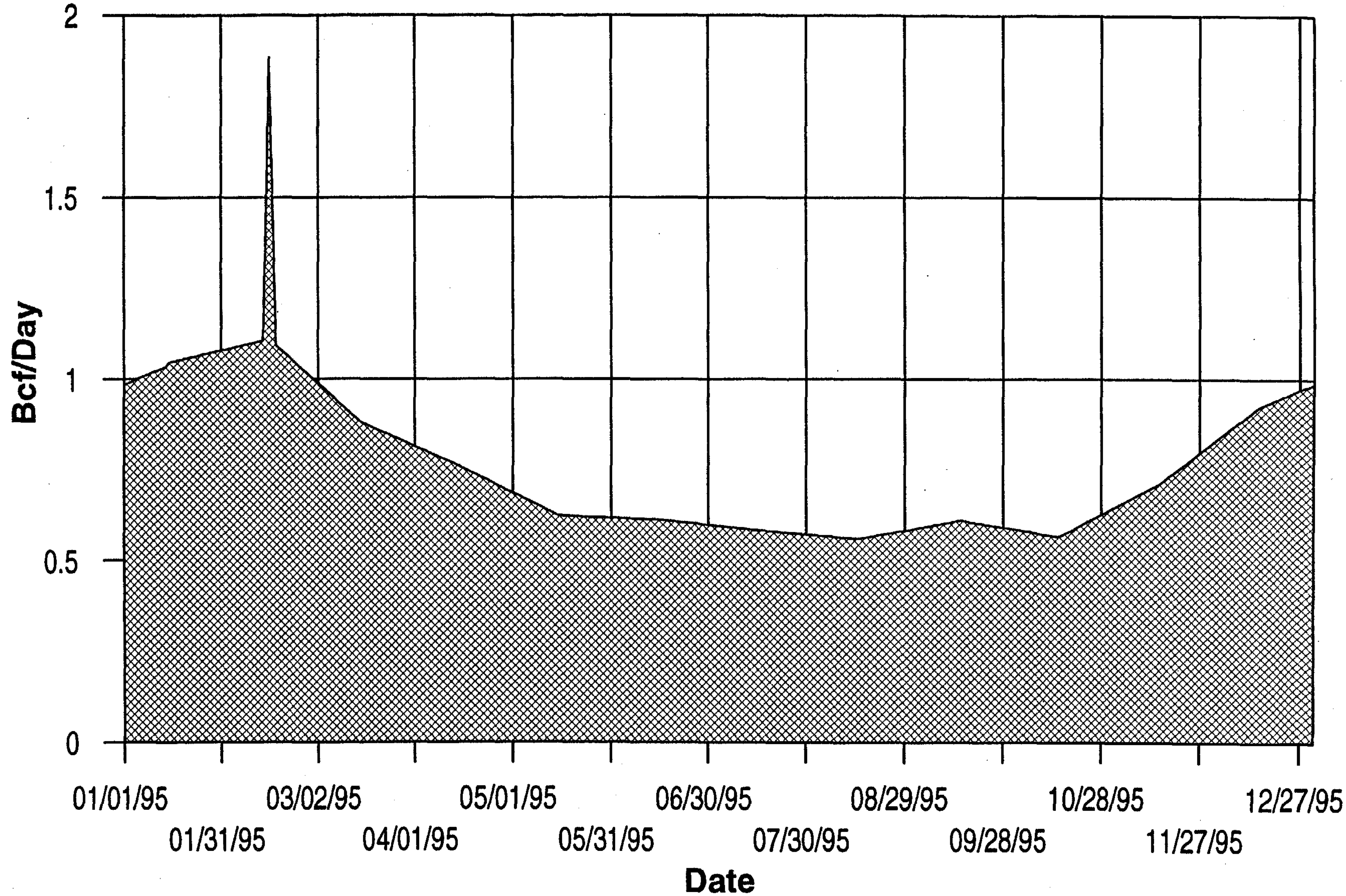


Peak Day volume is included for illustrative purposes.

F-10

Projected Total Gas Demand Curve, 1995

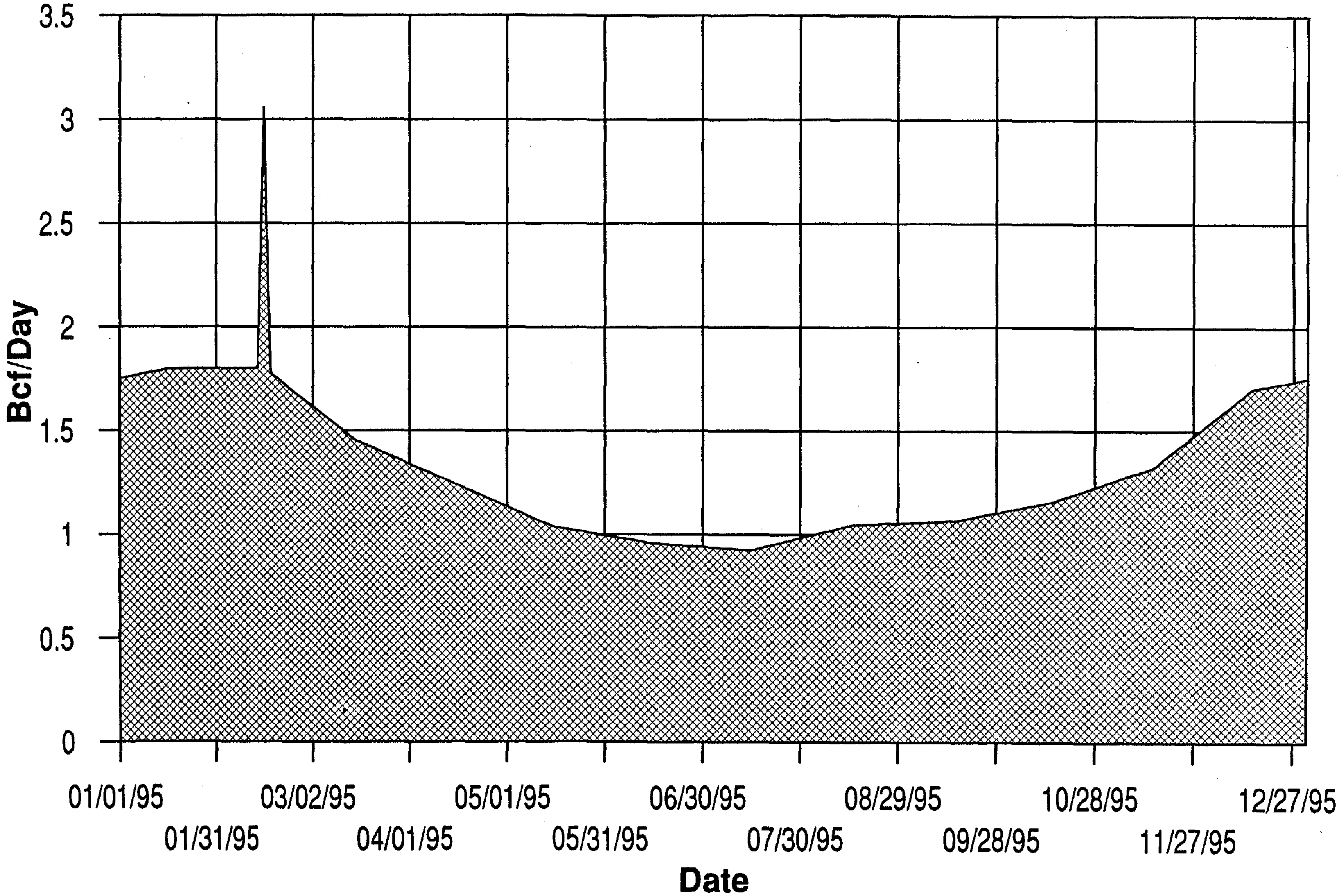
Mountain South



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

Pacific Northwest



Peak Day volume is included for illustrative purposes.

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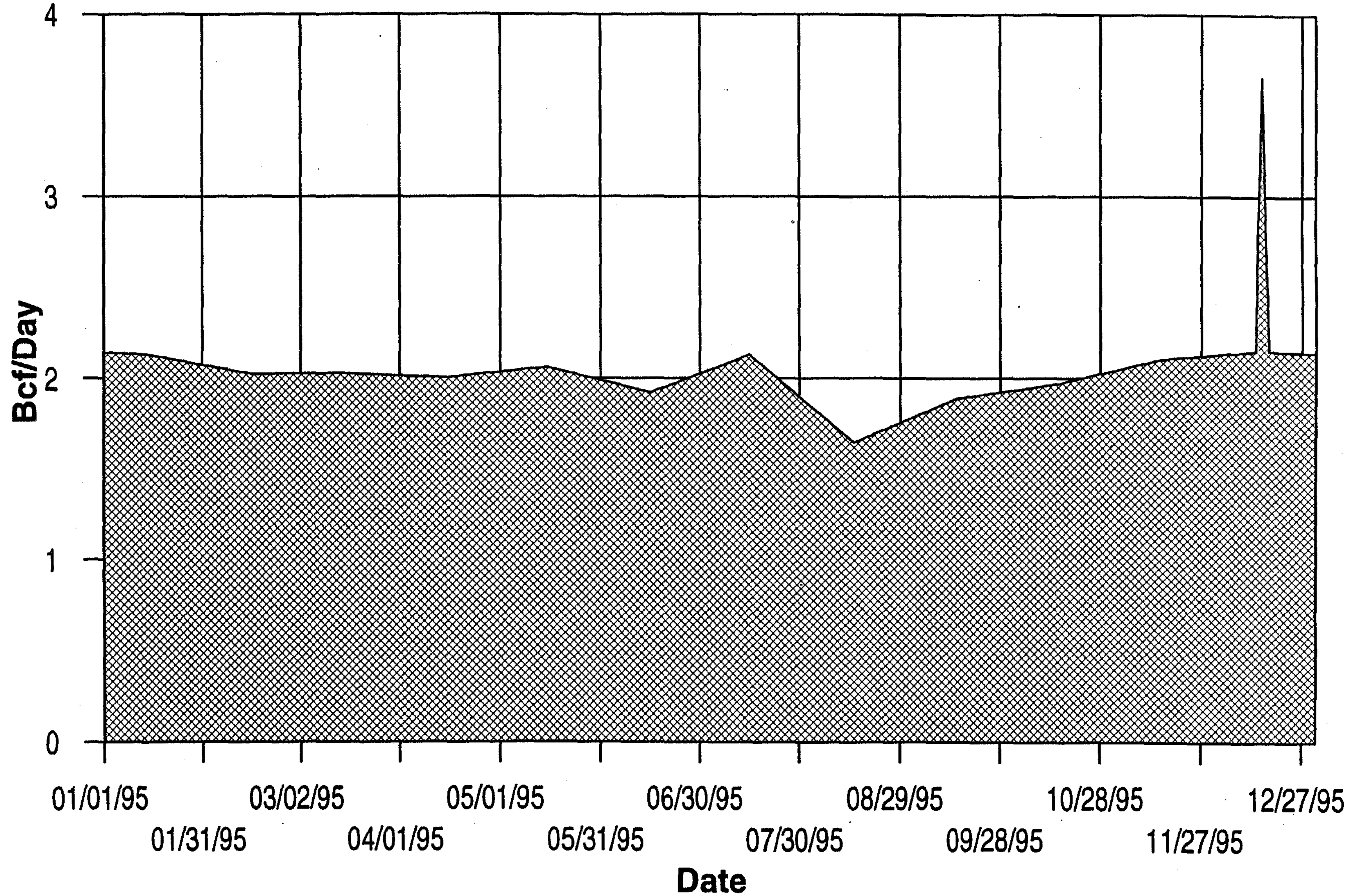
Projected Total Gas Demand Curve, 1995

California



Peak Day volume is included for illustrative purposes.

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