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Natural Gas Storage - End User Interaction

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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 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 storage and peak shaving options. Finally, the secondary market 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-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 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 load following units (peaking or intermediate), as opposed to baseload units, they use gas unevenly over time. In regions where electric power demand is greatest in the summer for air conditioning, this uneven usage could eventually decrease 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 the analytical tool to evaluate storage requirements under alternate economic, technology, and market conditions; and
3. To analyze the economic and technical feasibility of alternatives to conventional gas storage.

C. Project Analytic 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 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 need 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 the 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 a difference in the cost of gas and/or the cost of gas delivery during the year. If the price of gas and its transportation cost 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 required 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 much the same way as on production reservoirs. Task 5 evaluated a range of alternative storage technologies under varying market conditions.

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

Task 1:

- 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 my be needed.

Task 3:

- Development of the storage reservoir technical and economic screening criteria for identifying reservoirs that have potential for gas storage;
- Modification of the GSAM upstream modules as required to predict reservoir performance under conditions of gas injection and withdrawal cycles;
- Testing the modified GSAM performance in identifying reservoirs with storage potential against known storage reservoirs; and

characterization of regional storage potential through identification of target storage reservoirs.

Task 5:

- Testing the effects of aggressive reservoir development technology application on the need for storage;
- Testing the effects of aggressive reservoir development technology application on the cost and performance of potential new storage reservoirs;
- Testing the effects that the addition of the gas storage model has on the gas supply, demand, and price projections of GSAM under various economic and technology assumptions;
- Summarizing the lessons learned from both Task 3 and Task 5, regarding the demand for storage in the consuming regions under various economic and technology scenarios; and
- Describing the recommended additional tasks that are needed to improve the quantitative results of model tests on the demand for storage under various economic and technology scenarios.

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

D. Major Findings

Task 1:

1. Identifying gas storage needs for 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 pipeline 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 Local Distribution Companies (LDCs) and gas marketers now control much of the storage capacity; and
   - surplus storage capacity appears to be 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 costs vary widely, depending on both the type of storage and when the facility was completed. Typically, the least costly 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 shortest. In between these cost levels are those for storage facilities using aquifers. Under cost of service rate regulation, 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 for 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. Examples of the complications that prevent these areas from increasing storage capacity 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 and 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; 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 gas storage capacities in the East North Central, Middle Atlantic, and the South Atlantic (West Virginia) regions are 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 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.

Task 3:

The gas storage module for GSAM was tested in four supply/demand and technology scenarios that provided insights on how economic and technological changes will affect the demand for gas storage capacity. In other words, an attempt was made to examine potential requirements for gas storage that account for several possible futures in the North American gas market. A Base Case, that represents essentially the status quo, was used as a benchmark against the other three cases. The Low Demand and High Demand Cases differ from the Base Case in the amount of gas demand growth they experience for fueling electric power generation. In the Low Demand Case, coal wins the competition with gas for this growth sector. In the High Demand Case, gas wins the competition for power generation fuel. In the Technology Case aggressive advancements are assumed in technology for both exploration and production and for storage reservoirs. The major findings from testing these four scenarios are listed below.

1. Among the four scenarios tested, the greatest use of storage as measured by annual gas extraction rates occurs in the Technology Case, wherein total U.S. gas extraction declines from 1,185 Bcf in the year 2000 to 854 Bcf in 2010. The Base Case uses the least amount of storage of 1,077 to 765 Bcf between the years 2000 and 2010. The following table summarizes the total U.S. forecast gas extraction rates for each of the four cases. In all cases, the use of storage declines by 26 to 29 percent between 2000 and 2010. This decline in storage utilization occurs because most of the growth in gas demand is for power generation rather than for the temperature-sensitive residential and commercial loads that improve the economics for gas storage.

Extraction Rates for Storage Gas, Bcf

	2000	2005	2010
Base Case	1,077	905	765
Low Demand Case	1,144	1,013	843
High Demand Case*	1,098	931	776
Technology Case	1,185	1,050	854

*High Demand requires less storage capacity. See item 5 below.

2. The number of new gas storage reservoirs developed varies from four in the Base Case to 11 in the Technology Case. Only four demand regions are projected to add new storage capacity in any of the cases analyzed, the East North Central, West South Central, Mountain South, and California. In the Low Demand Case, eight new storage facilities are forecast as required in the U.S., while in the High Demand Case, the projection is for development of six new storage facilities.

3. In addition to selecting reservoirs for development as new storage facilities, the integration module also selects which of the existing storage facilities are economic to use. Annual utilization of existing storage capacity varied widely among the regions and the scenarios tested. The higher utilization rates are in the Middle Atlantic, South Atlantic, East South Central and California regions. These rates varied from 90 to 100 percent utilization. The lower utilization rates appeared in the East North Central, West North Central, and Pacific Northwest regions. The utilization rates among these latter four regions varied from zero to 60 percent. These results indicate that in the Middle Atlantic, South Atlantic, East South Central, and California regions the reservoir deliverability received per unit of service cost is better with most of the existing storage facilities that it would be with new facilities. On the other hand, these results indicate that the East North Central, West North Central, and Pacific Northwest regions, probably have more storage capacity than the market demands. In the case of the East North Central region and California, these results indicate that some existing storage facilities are not as economic as new facilities, because these two regions are among the four regions where new facilities are forecast to be developed.

4. The existing storage facilities selected for use by the storage module also change with the scenario analyzed. For example, in the Base Case, 13 of the 23 existing storage facilities in the Mountain North region were selected for use. In the Low Demand Case, one additional storage facility was selected for use, bringing the total to 14 active storage facilities in the Mountain North region. Considering all regions, the Low Demand Case had 10 existing storage reservoirs scattered among four regions added to the Base Case total. In the High Demand and Technology Cases, several existing storage facilities were added to the Base Case roster and several were deleted. In the High Demand Case, the larger decline in storage demand resulted in deletion of three storage reservoirs that were used in the Base Case. In the Technology Case, the single reservoir deletion from the list of existing storage reservoirs used in the Base Case indicates that the more aggressive technology advancements assumed for this scenario has improved the economics of using some reservoirs relative to others. In other words, some of the idle reservoirs of the Base Case are more susceptible to technology improvements than those used in the Base Case.

5. The High Demand Case requires less gas storage capacity because essentially all of the gas demand increase over the Base Case occurs in the power generation sector. This added load takes the place of storage because gas use for generation is typically a summer load that reduces the seasonality of demand, making better year-round use of pipeline capacity. The

Low Demand Case has less electric generation demand and has greater seasonal swings in gas demand, improving the economics for storage.

6. Substantial pipeline capacity is added to transport gas from the Gulf of Mexico West to Texas Gulf Coast and from the Mid-Continent to Mountain North regions in all four scenarios. Other significant pipeline capacity additions are projected from the San Juan to Mountain North and from the Permian to San Juan. The regions receiving gas through these expansions are not included in regions projected to need gas storage because in these instances pipeline capacity was determined to be more economic than storage.

7. Prices for the gas storage service used in the four scenarios vary widely within each storage region and among the four scenarios tested. Prices, based on company tariff rates for existing facilities and reservoir development cost estimates for new storage facilities, vary from as little as $0.17 to $1.63 per Mcf stored. The lower prices are typically for older facilities that had lower investments for facility development and for the base gas.

8. Because GSAM is structured to recognize only two seasons and the winter season is 151 days long, the economic advantage of gas storage is understated in this study. Since there is no recognition of the higher winter demand that typically occur for shorter periods, the full advantage of both peak shaving and shorter-cycle storage cannot be determined. As structured now, gas pipeline capacity is justified over 151 days of constant demand. This constant demand can be an average of 151 days that have peak gas demands several times the average demand. Since pipeline capacity rarely can be justified for the gas demands of the coldest ten to 30 days of winter, this average winter load is unrealistic.

9. Despite the understatement of the demand for gas storage, this study does support anecdotal information from the trade press and from contacts with storage operators that storage capacity is overbuilt in several regions. Regions where additional storage capacity will be required are identified. The differences in the need for storage have been determined, depending on whether or not gas wins in the competition with coal for the power generation market and on the level of technology advancement assumed.

10. The storage module of GSAM has been prepared to incorporate aquifer and salt cavern storage facilities whenever data bases for these formations are developed.

Task 5:

The gas storage module for GSAM was used to test two comparison cases involving four supply/demand and technology scenarios. These cases provided insights on how economic and technological changes will affect the demand, cost and performance of gas storage capacity. In other words, an attempt was made to examine future requirements for gas storage to balance the gas market in North America.

In the first comparison, aggressive technology advancement assumptions were added to a Base Case, creating a Technology Case. The Base Case represents essentially the status quo in gas markets and evolutionary technology advancement. In this comparison, the Technology Case resulted in more use of storage, lower cost storage, and improved storage performance. In the second comparison, the same aggressive technology advancement assumptions were added to a High Demand Case, creating a High Demand Technology Case. The High Demand Case differs from the Base Case in the amount of gas demand growth experienced, primarily for fueling electric power generation. In the High Demand Case, gas wins the future competition with coal for increasing shares of power generation fuel. As in the first comparison, the addition of improved technology results in more use of storage, lower cost storage, and improved storage performance. In both of the higher technology cases, aggressive advancements are assumed in technology for both exploration and production and for storage reservoirs. The major findings from testing these four scenarios are listed below.

1. Among the four scenarios tested, the larger use of storage as measured by annual gas extraction rates occurs in the Technology Case, wherein total U.S. gas extraction declines from 1,185 Bcf in the year 2000 to 854 Bcf in 2010. The Base Case uses the least amount of storage at 1,077 to 765 Bcf between the years 2000 and 2010. In both of the case comparisons, the addition of aggressive technology increases the need for storage, as shown in the following table.

Extraction Rates for Storage Gas, Bcf

Comparison Cases	2000	2005	2010
Base Case	1,077	905	765
Technology Case	1,185	1,050	854
High Demand Case	1,098	931	776
High Demand/Tech Case	1,173	1,021	831

In all four cases, the use of storage declines by 28 to 29 percent between 2000 and 2010. There are two reasons for this decline in storage utilization: 1) most of the growth in gas demand is for power generation rather than for the temperature-sensitive residential and commercial loads that improve the economics for gas storage and 2) gas deliverability from storage reservoirs is assumed to decline at five percent per year.

2. The number of new gas storage reservoirs developed varies from four in the Base Case to 11 in the Technology Case. Only four demand regions are projected to add new storage capacity in any of the cases analyzed, the East North Central, West South Central, Mountain South, and California. As in the case of total storage capacity utilized, the two higher technology cases resulted in more demand for new storage capacity. The following table summarizes the numbers of new storage facilities selected for the two comparisons.

Summary Of New Storage Facilities
Case

Region	Base Case	Technology	High Demand Case	High Demand Tech Case
East North Central	1	2	1	1
West South Central	1	2	3	2
Mountain South	0	5	0	3
California	2	2	2	2
Totals	4	11	6	8

3. The High Demand Technology Case shows the combined effects of the High Demand and Technology Cases. The number of new storage facilities added in the High Demand Technology Case are lower than in the Technology Case because of the increased power generation load that goes with the High Demand assumptions. This added load takes the place of storage because gas use for generation is typically a summer load that reduces the seasonality of demand, making better year-round use of pipeline capacity. However, two

more new storage facilities are added in the High Demand Technology Case compared to the High Demand Case.

4. Typically, the impact on a potential storage reservoir from adding aggressive technology advancement to a given scenario: 1) raises the volume of working gas available in the reservoir, 2) increases reservoir deliverability, 3) raises the levelized investment cost, and 4) lowers the total fixed costs. These changes are observed in both of the comparisons made wherein improved technology assumptions were added to the Base and High Demand Cases.

5. Substantial pipeline capacity is added to transport gas from the Mountain North to Mid-Continent, Gulf of Mexico West to Texas Gulf Coast, and from the Mountain North to San Juan regions in all four scenarios. Other significant pipeline capacity additions are projected from Alberta to Canada East and into the U.S. Northeast in all four scenarios and from the San Juan to the Permian in the two higher technology cases. Significantly, the two higher technology cases projected less demand for additional capacity on TransCanada Pipelines than the Base and High Demand Cases. This increased U.S. gas supply at lower prices, reducing dependence on Canadian imports. The regions receiving gas through these pipeline expansions are not included in regions projected to need gas storage because in these instances pipeline capacity was determined to be more economic than storage.

6. Prices for the gas storage service used in the four scenarios vary widely within each storage region and among the four scenarios tested. Prices, based on company tariff rates for existing facilities and reservoir development cost estimates for new storage facilities, vary from as little as $0.11 to $1.63 per Mcf stored. The lower prices are typically for older facilities that had lower investments for facility development and for the cushion gas.

7. Because GSAM is structured to recognize only two seasons and the winter season is 151 days long, the economic advantage of gas storage is very likely understated in this study. Since there is no recognition of the higher winter demands that typically occur for shorter periods, the full advantage of both peak shaving and shorter-cycle storage cannot be determined. As structured now, gas pipeline capacity is justified over 151 days of constant demand. This constant demand can be an average of 151 days that have peak gas demands several times the average demand. Since pipeline capacity rarely can be justified for the gas demands of the coldest ten to 30 days of winter, this average winter load is unrealistic.

I. INTRODUCTION

The Task 2 report for this project, completed in January 1996, focused primarily on describing the types, capacities, and costs of natural gas storage facilities that are available and the markets that gas storage is required to serve. The Task 4 report, completed in February 1997, described the modifications that have been made to the Gas Systems Analysis Model (GSAM) for evaluating prospective storage projects under varying technical, economic, and regulatory conditions. Initial tests of the modified model selected regional lists of existing storage facilities that are forecast to be utilized and of potential new storage reservoirs, including their costs of service. The Task 6 report, completed in March 1997, provided the results of additional model tests under varying scenarios and additional analysis of Task 4 model runs — emphasizing the effects that improved technology will have on comparison cases with similar economic parameters. This final technical report combines the results of the work performed in Tasks 1, 3, and 5 and the reports of Tasks 2, 4, and 6.

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[1] options. Finally, the secondary market[2] 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 facilitate 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 only intermittently over time.

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[1] 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).

[2] 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 capacity.

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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 Federal Energy Technology Center (FETC) with a storage evaluation system that will provide the analytical tools necessary for FETC to evaluate storage requirements under alternate economic, technology, and market conditions, 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, and location?
- 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, 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 task (one cycle per year). 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 contractual 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 commitments 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 pattern 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 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 in the U.S. 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-1. 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-1
AGA Underground Gas Storage Regions

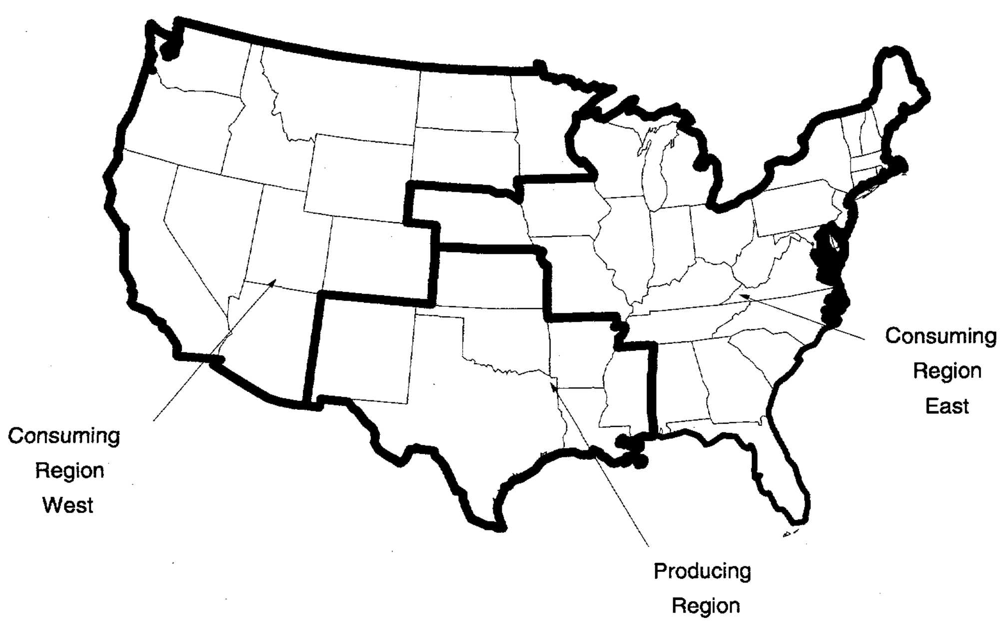
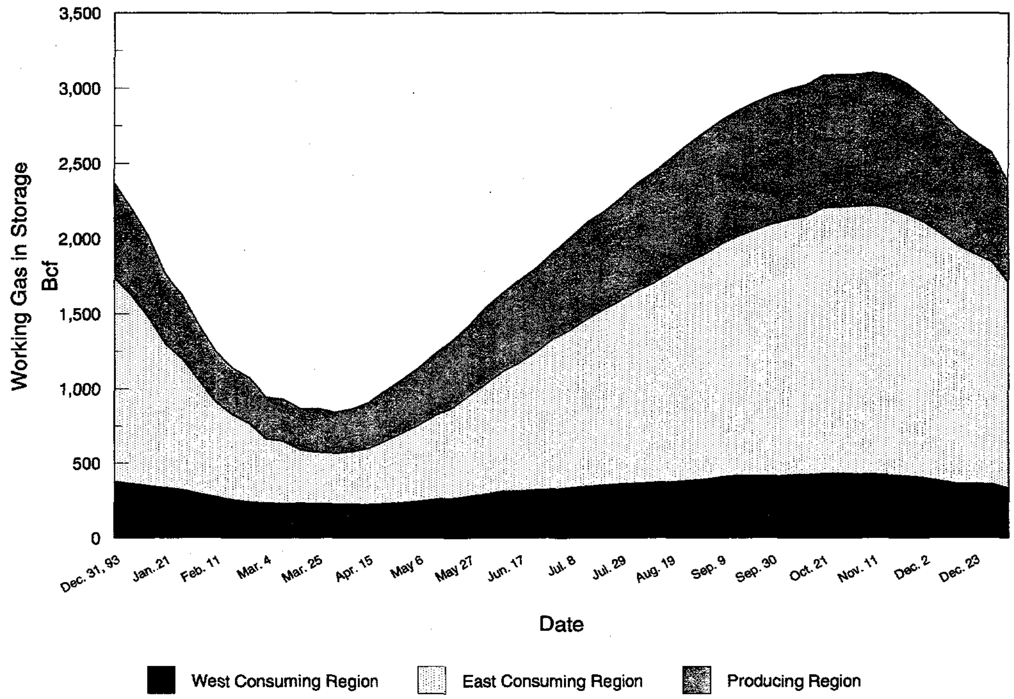


Exhibit I-2 provides a summary of AGA weekly working gas volumes in storage for the three AGA regions and the U.S. total. Although the working gas volumes did not bottom out and peak in exactly the same weeks during 1994, the regional patterns are very similar. Storage gas reaches a minimum volume in March or early April when withdrawals are ending and peaks in November before the winter season withdrawal begins.

Exhibit I-2
Estimated Working Gas in Storage over Time, 1994



Source: Pasha Publications, Gas Storage Report

D. *Modeling of Peak Shaving Gas Supplies*

1. Regional Economics of Peak Shaving

As described in Chapter IV of this project, peak shaving gas supplies are not the economic choice for incremental capacity to meet peak day gas demand in most regions of the U.S., when compared to underground gas storage. Only the New England, Florida, California, and the Pacific Northwest regions currently show an economic advantage for peak shaving over underground storage. However, peak shaving is used and is being expanded in some regions for reasons that are apparently outside of simple economic comparisons. Several definitions of terms should be clarified before proceeding with this discussion of peak shaving.

2. Definition of Peak Shaving

A common definition of peak shaving supplies is a supply of gas that an LDC or an end user can access without depending on a delivery system outside of its own facilities. Thus, a major liquefied natural gas (LNG) storage and regasification facility used to enhance a gas pipeline's delivery capability does not qualify as peak shaving. The only peak shaving supplies of significance in the U.S. are LNG and mixtures of propane and air. Peak shaving supplies are usually expected to last for only three to ten days as supplements to other larger supply sources during periods of peak demand.

In recent years LNG has been the favored peak shaving gas supply as its costs have declined with improved refrigeration processes and equipment efficiencies. Propane/air mixtures have been in declining use for peak shaving and some facilities were being abandoned until the frigid eastern U.S. weather of January 1994 caused some rethinking of the value of these plants. One of the reasons for the decreasing popularity of propane/air is the incompatibility of propane in some uses of natural gas. For example, any significant propane contamination of compressed natural gas (CNG) used for vehicle fuel can result in gradual loss of tank capacity as propane condenses in the tank. In addition, propane/air must be diluted with large amounts of natural gas to be suitable for most gas burners, while LNG can be used undiluted. Despite this trend toward LNG in the selection of peak shaving supplies, those LDCs that have major propane/air facilities are expected to continue using them. A major advantage of propane/air peak shaving is the potential for resupply of propane during the winter, while only the LNG storage supplied by LNG imports can be recharged in winter.

3. Justification of Peak Shaving Investments

Despite the fact that current comparisons show peak shaving to be economically inferior to underground storage in all but four demand regions of the U.S., existing peak shaving facilities continue to be used each winter and additional capacity is being constructed in the eastern U.S. A very large part of the justification of peak shaving for LDCs has to be the added confidence obtained by having what amounts to an emergency supply of gas within their own control. Peak shaving supplies represent an insurance policy for the coldest winter nights. This policy is important because interruption of supply to residential and commercial customers is taken as a very serious failure of a gas utility's obligation to serve, by their public service commissions, as well as the affected customers. The public relations costs and renewal of service costs for interrupted customers are not included in the economic comparisons made here for peak shaving vs. underground storage.

4. Model Assumptions for Peak Shaving Supplies

Peak shaving supplies are not modeled as variables in the gas storage module of GSAM for two reasons. First, GSAM is currently not structured to include a peak period of three to ten days duration (a third season) that is necessary to perform the economic evaluation of peaking versus other supply alternatives. This short season is necessary for evaluation of peak shaving economics because the relatively low investment cost and higher operating costs of peak shaving typically provide lower cost gas than storage does for only a few days of each winter. The second reason is that, in most consuming regions, peak shaving does not appear to be economically superior to storage, even for short time periods.

To account for the fact that both LNG and propane/air peak shaving is practiced for small volumes of gas supply in several consuming regions, the integrating module of GSAM has been designed to include the use of peak shaving gas volumes each winter. Only those regions that currently have peak shaving facilities are forecast to have peaking capacity in the future, and the only regions that are forecast to have peaking growth are those with announced projects. Since the use of peak shaving capacity can vary from zero to 100 percent from year to year, the annual use of peak shaving gas in each region is assumed to be 50 percent of the peaking capacity in the region. The Middle Atlantic region, which has the greatest peak shaving capacity of the 15 consuming regions, can store only 1.3 percent of its current gas demand for residential, commercial, and industrial customers. The highest percentage of supply represented by peaking capacity is in New England, at 1.8 percent of gas demand, for these same three consuming sectors. Thus, peaking supplies are not a large part of total North American gas supply and should not be expected to have much influence on the use of underground gas storage. A summary of the peaking volumes used in the model is provided in Exhibit I-3.

The forecast costs of peak shaving supplies used by LDCs in all consuming regions that have these facilities are provided in Exhibit I-4.

Exhibit I-3
Peak Shaving Gas Use Assumptions
(MMcf per Year)

LNG WINTER USE				
REGION	1995	2000	2005	2010
New England	4,050	5,050	5,050	5,050
Middle Atlantic	13,811	13,811	15,811	15,811
South Atlantic	6,558	8,558	8,558	8,558
Florida	-	-	-	-
East South Central	2,566	2,566	2,566	2,566
East North Central	4,975	4,975	4,975	4,975
West South Central	-	-	-	-
West North Central	4,312	4,312	4,312	4,312
Mountain 1	-	-	-	-
Mountain 2	913	913	913	913
California	-	-	-	-
Pacific Northwest	1,349	1,349	1,349	1,349
Canada-East	1,142	1,142	1,142	1,142
Canada-West	300	300	300	300
Northern Mexico	-	-	-	-
PROPANE/AIR WINTER USE				
REGION	1995	2000	2005	2010
New England	664	664	664	664
Middle Atlantic	453	453	453	453
South Atlantic	2,368	2,368	2,368	2,368
Florida	38	38	38	38
East South Central	547	547	547	547
East North Central	1,873	1,873	1,873	1,873
West South Central	-	-	-	-
West North Central	2,229	2,229	2,229	2,229
Mountain 1	11	11	11	11
Mountain 2	56	56	56	56
California	60	60	60	60
Pacific Northwest	56	56	56	56
Canada-East	-	-	-	-
Canada-West	-	-	-	-
Northern Mexico	-	-	-	-

Exhibit I-4
Peak Shaving Gas Cost Assumptions
($/Mcf)

	1995	2000	2005	2010
LNG	5.84	6.67	6.53	6.40
Propane/Air	6.93	7.91	7.75	7.59

E. 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 this 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.

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 to 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.[3]

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 charges 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.

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[3] EIA. "The Expanding Role of Underground Storage," *Natural Gas Monthly*, October 1993.

F. *Organization of the Report*

Following this introductory section is a compilation of the findings reported in Tasks 2, 4, and 6 of this project. These findings include descriptions of the types, capacities, and costs of natural gas storage facilities that are available and the markets that gas storage is required to serve as reported in Task 2. This is followed with the results of Task 4, which described the modifications that have been made to the Gas Systems Analysis Model (GSAM) for evaluating prospective storage projects under varying technical, economic, and regulatory conditions. Initial tests of the modified model selected regional lists of existing storage facilities that are forecast to be utilized and of potential new storage reservoirs, including their costs of service. Finally, results are presented from the additional model runs of Task 6 scenarios which compare cases with and without major technology improvements. The report concludes with a discussion of the GSAM modifications that are recommended to provide a more robust tool for evaluating the need for gas storage and the impacts that the application of technology advancements can have on storage performance.

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[4] 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).

[5] 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 capacity.

[6] EIA. "The Expanding Role of Underground Storage," *Natural Gas Monthly*, October 1993.

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 cost 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 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 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 need 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 effect 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[7] are generally in agreement in regards to forecasted trends in gas demand among end users 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.

[7] GRI, *Baseline Projection Data Book*, 1995 Edition. DOE/EIA, *Annual Energy Outlook*, 1995. AGA, *The Gas Energy Supply and Demand Outlook, 1995-2010*, February, 1995.

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 congeneration projects. DOE/EIA and AGA include this in the industrial sector demand, while GRI forecasts separate gas demands for congenerated electricity and congenerated thermal energy.

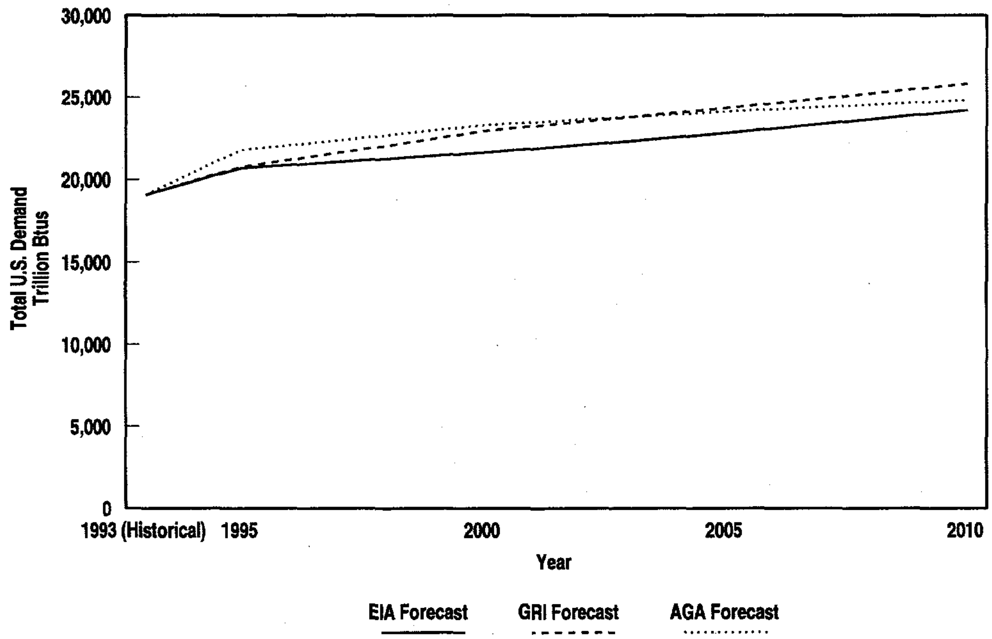
None of these forecasts provides seasonal demand detail for the natural gas market. Seasonal detail is a critical element in determining demand for storage (primarily depleted reservoir and aquifer storage) over the long term. Moreover, seasonal demand detail is critical in understanding how demand for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

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

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



Note: All forecasts were published in 1995.

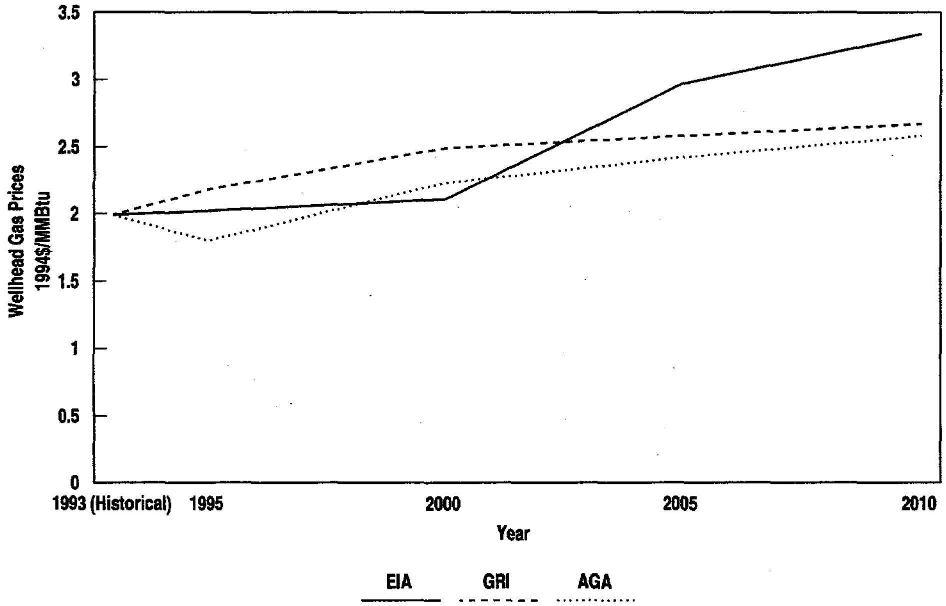
greatest differential in the year 2003, the AGA and GRI forecasts for gas demand are only 6.4 percent greater that the DOE/EIA forecast.

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: two 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 effect 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.

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.

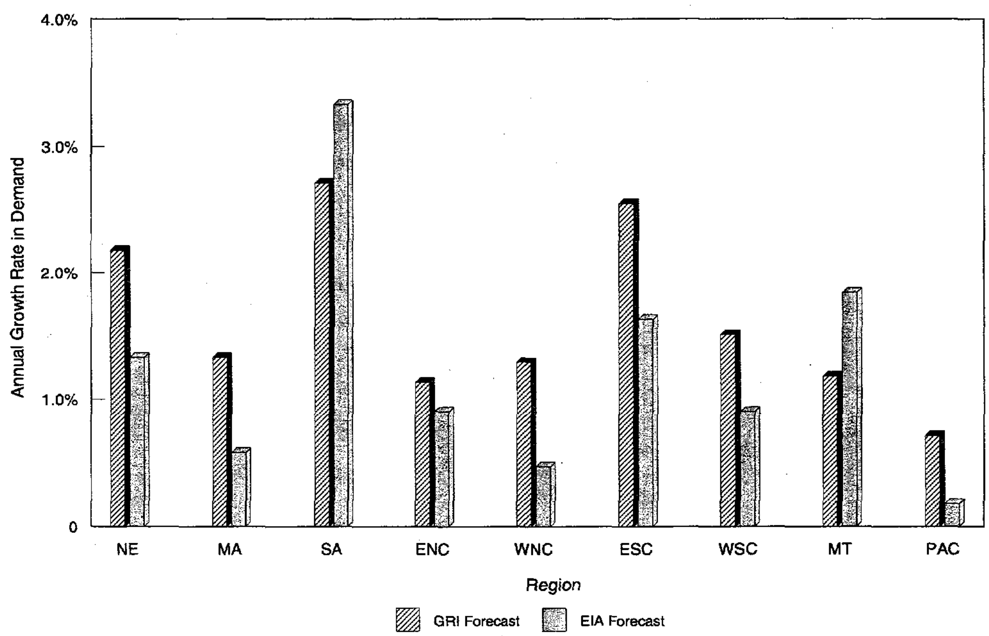
In all three forecast, the expected demand growth comes largely from the electric generation sector. Industrial demand is also expected to increase. Residential and commercial demand are forecast to remain relatively constant. The following discussion reviews each of the four sectors.

Exhibit II-2
Comparison of Forecasts of Gas Wellhead Price



Note: All forecasts were published in 1995.

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.

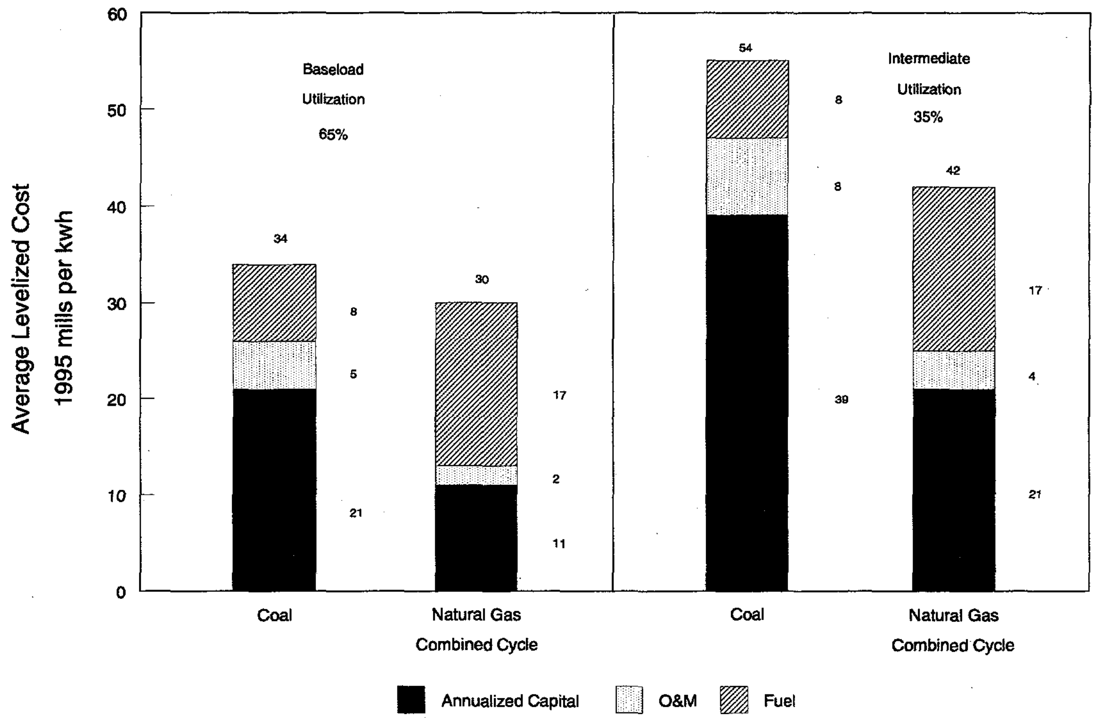
2. Fuel Prices

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 be 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 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.

Exhibit II-4
Relative Capital for Costs vs. Natural Gas



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

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 Amendment 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.

5. Regional Distribution of Gas Demand for Power Generation

Increasing demand 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.

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

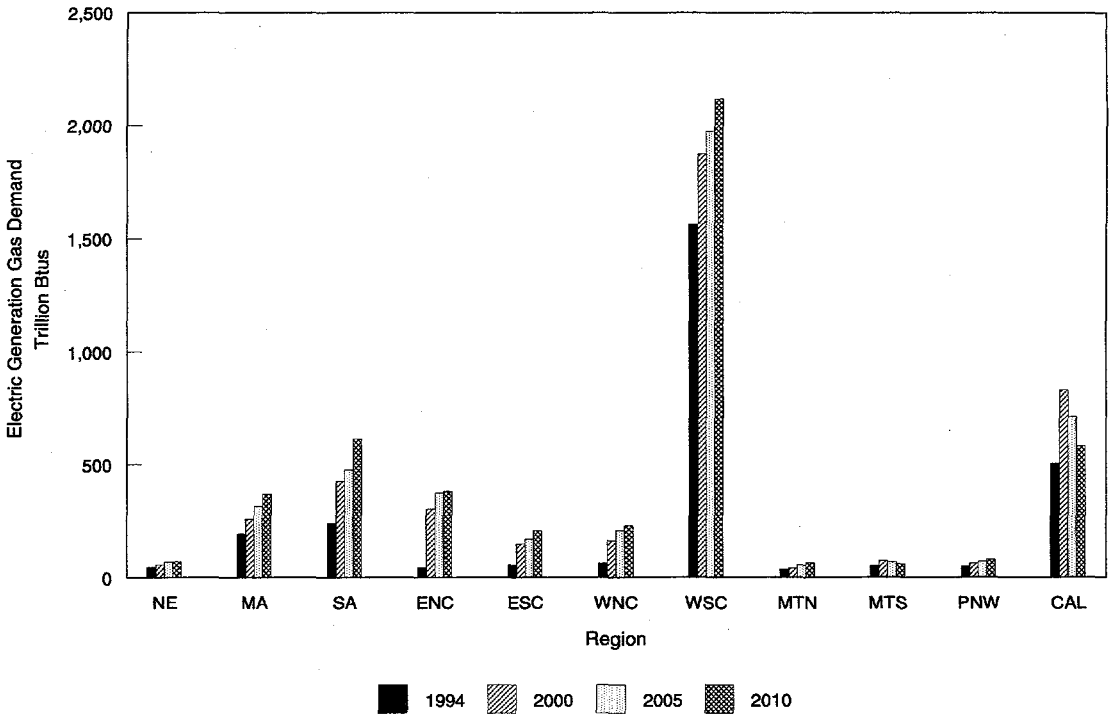
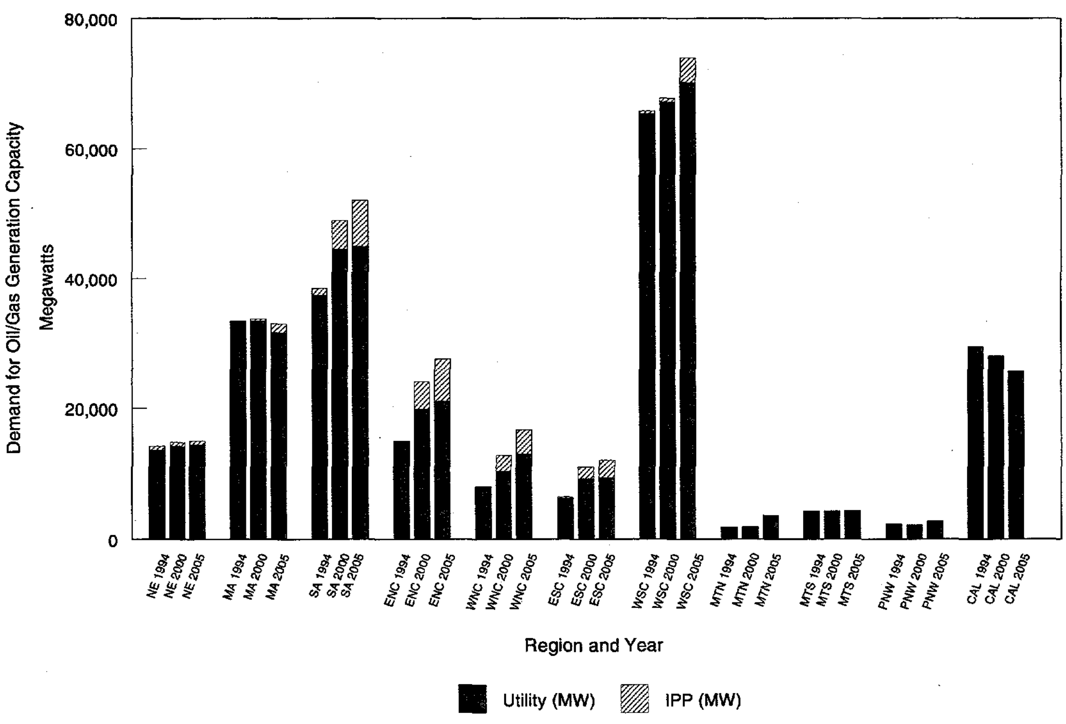


Exhibit II-6
Forecasts of Demand for Oil/Gas Generation Capacity by Region



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.

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 the gas-fired steam units is forecast to remain predominant, but decline over time.

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

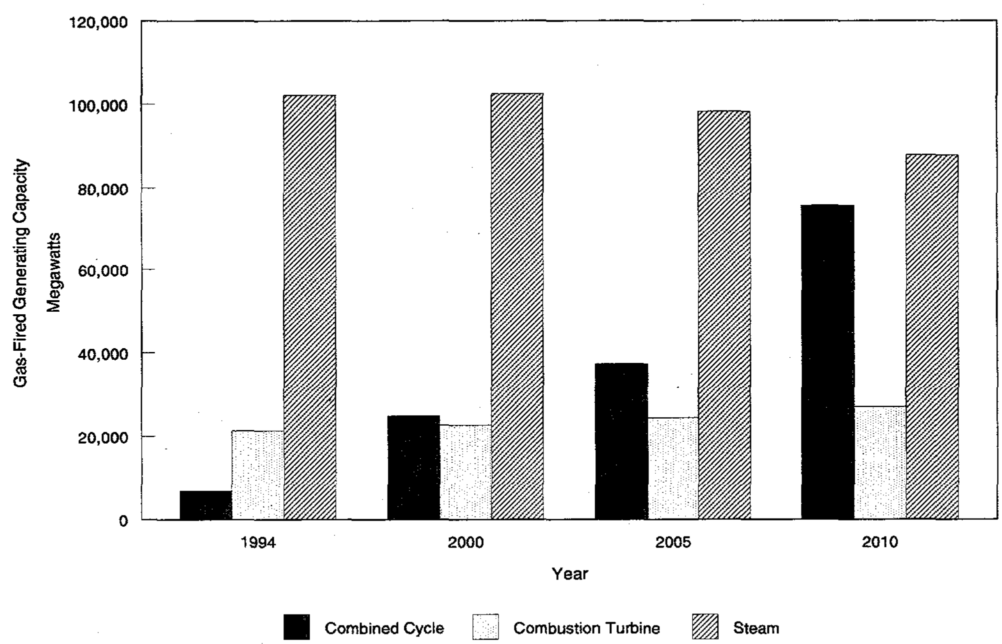


Exhibit II-8
Existing Gas-Fired Generating Capacity By Type and Region (1994)

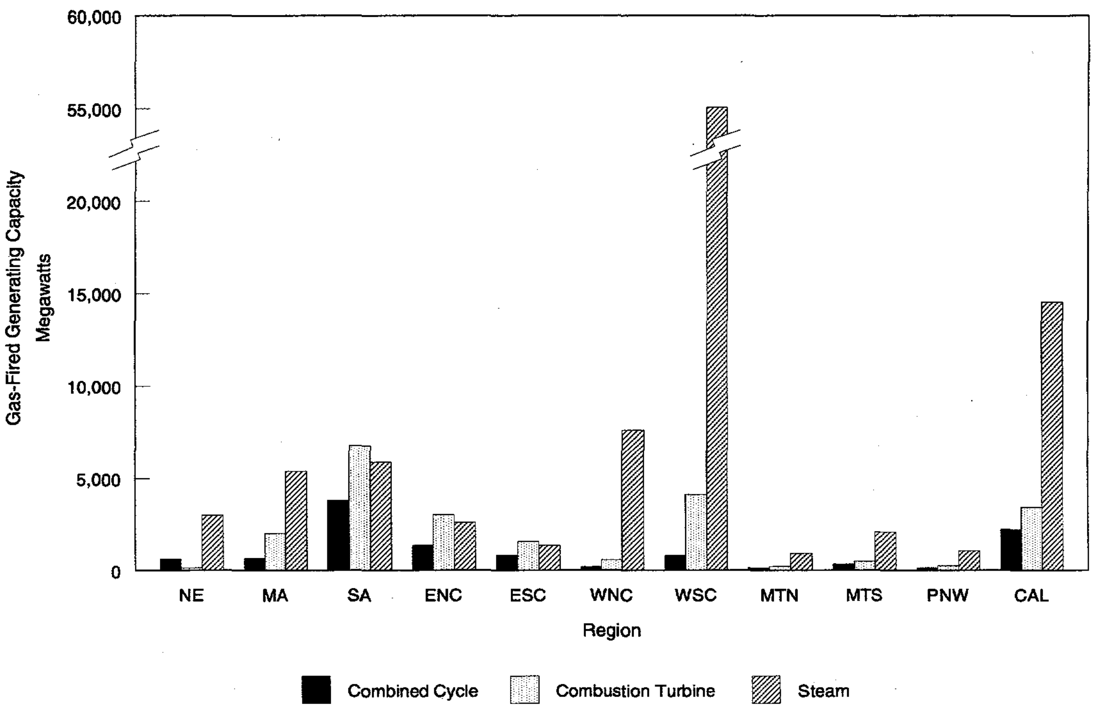
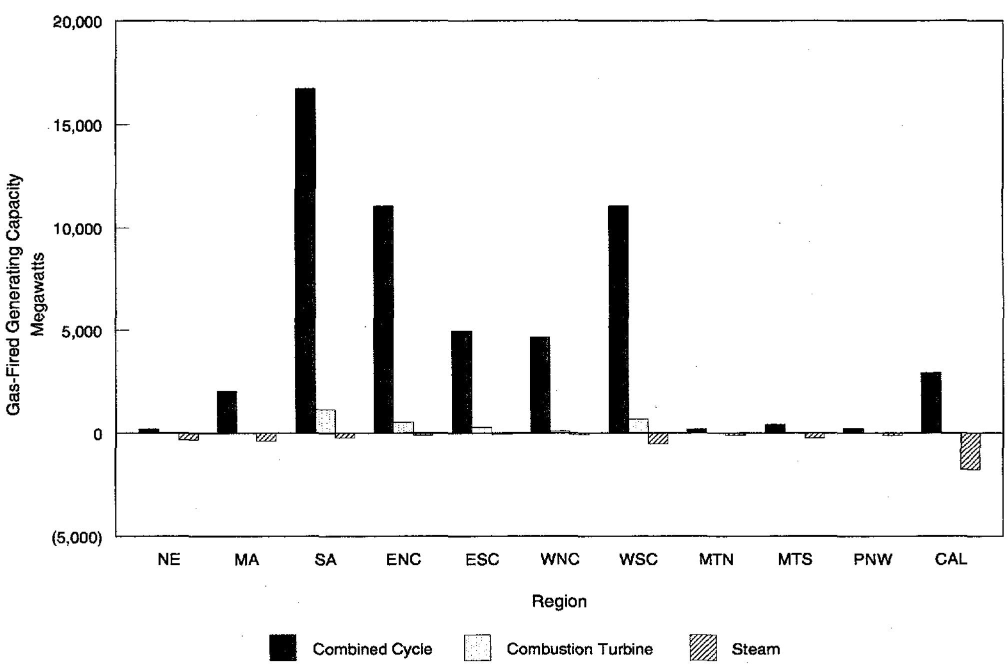


Exhibit II-9
Forecasts Changes in Gas-Fired Generating Capacity By Type and Region, 1994-2005



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.

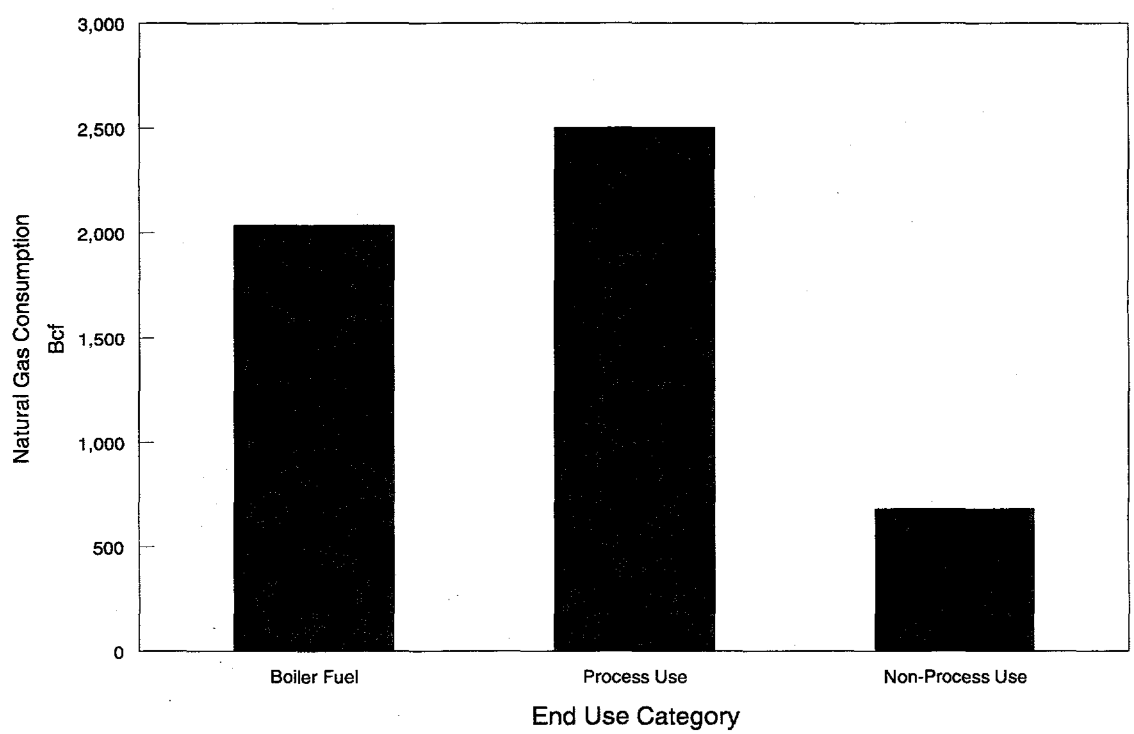
Review of the charts in Appendix A indicates that the highest electric generation demands will continue to occur in summer months when demands of the other three sectors are relatively low and gas supply and transportation costs are low. Thus, conventional seasonal storage will not be needed for the 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.

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 dying 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.

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



1. Industrial Demand For Gas

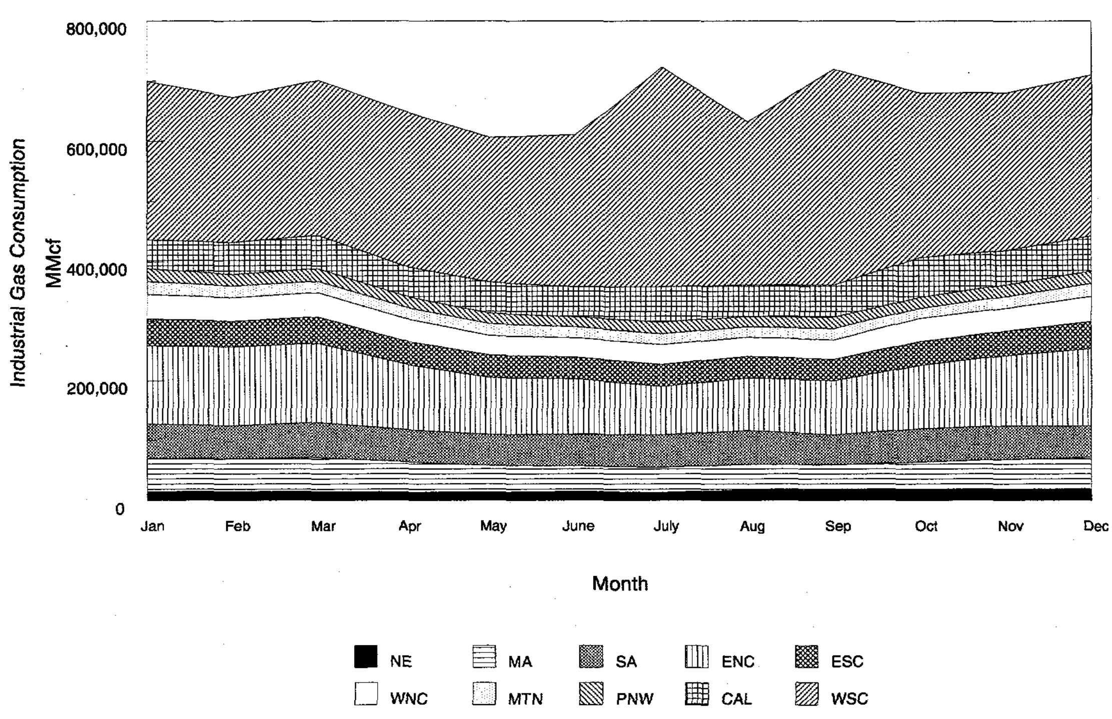
The two principal reasons for using storage are to meet short-term variations in demand and to more efficiently serve seasonal demand fluctuations. The traditional model for industrial demand places a premium on neither. Industrial demand for energy is generally characterized as relatively constant over the year (Exhibit II-11). The seasonal requirements for industrial gas use (i.e., space heating) are generally overwhelmed by day-today 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-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.

2. Industrial Demand for Storage

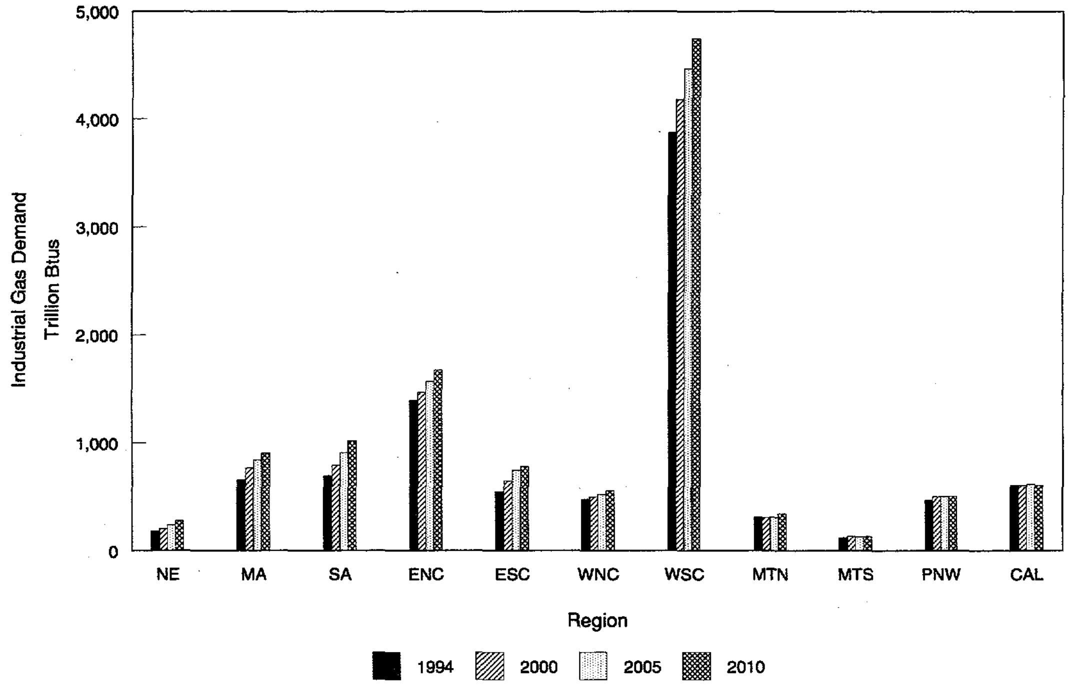
Large future demands for additional storage for the industrial sector seems unlikely for two reasons. First, industrial energy consumption is relatively constant during the year. Where demand is near constant, pipeline capacity is cheaper than storage. (The effects of fixed and variable cost on the economics 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

Exhibit II-11
Industrial Demand for Gas Region, 1995



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

Exhibit II-12
Forecasts of Industrial Gas Demand by Region



gas in winter, making gas storage an unnecessary added cost. The ability to switch fuels also allows many industrial consumers 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.

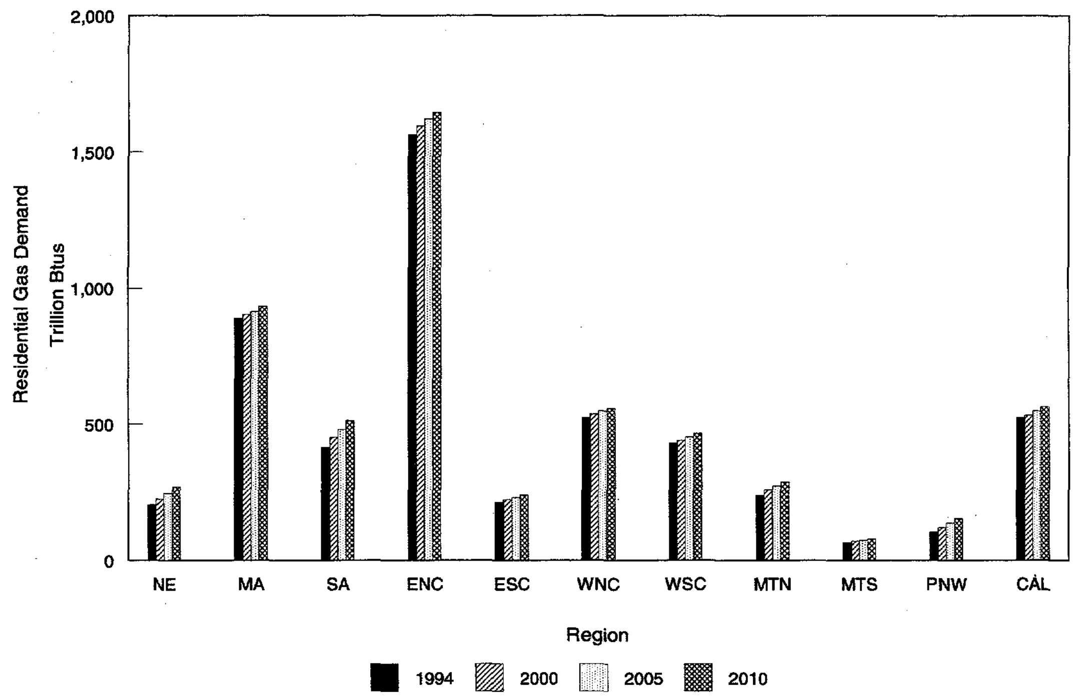
E. Residential Demand

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 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 difference 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 storage reservoir use are expected to be helpful in regions with growing residential markets.

F. Commercial Demand

1. Commercial Demand For Gas

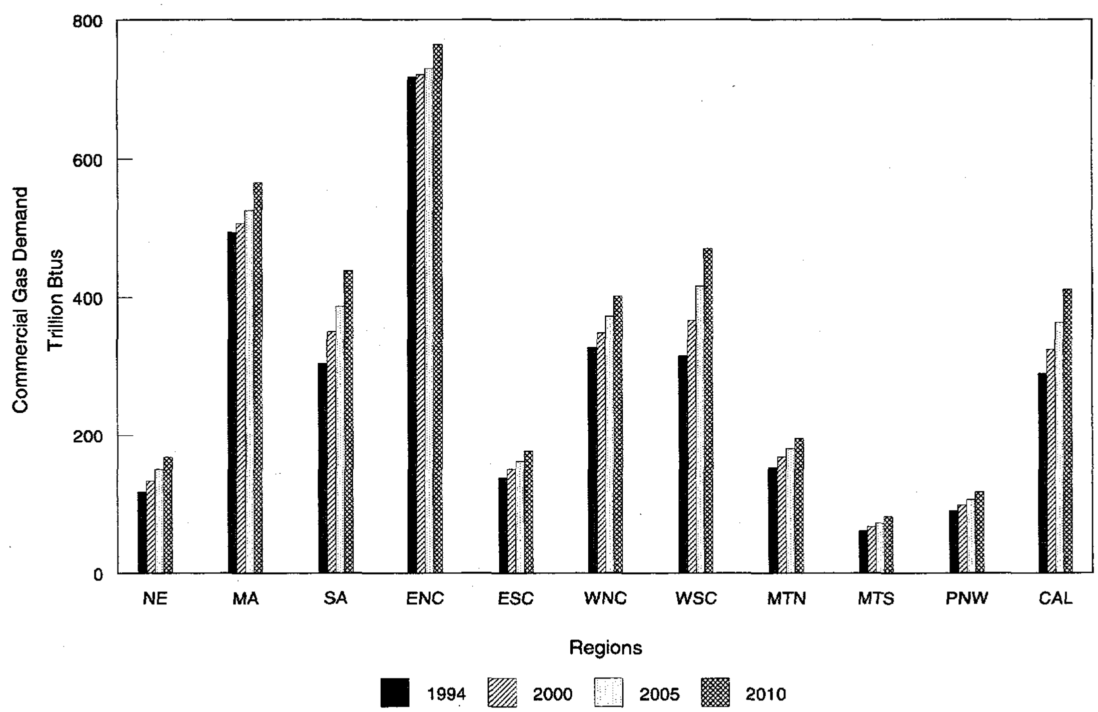
The commercial sector consists of establishments or agencies engaged primarily in the sale of goods or services. Exhibit II-14 provides GRI's forecast of regional demand through 2010. Commercial demand is generally driven by population and economic growth. New business developments are expected to expand 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	10,350
2000	5,350	3,231	10109	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 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 Untied 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)	24.1	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.[8] 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. The cost of base gas generally represents one of the greatest capital costs in developing a storage reservoirs. 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.

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 rate of which the reservoir can be filled without gas loss, 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.

[8] 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.

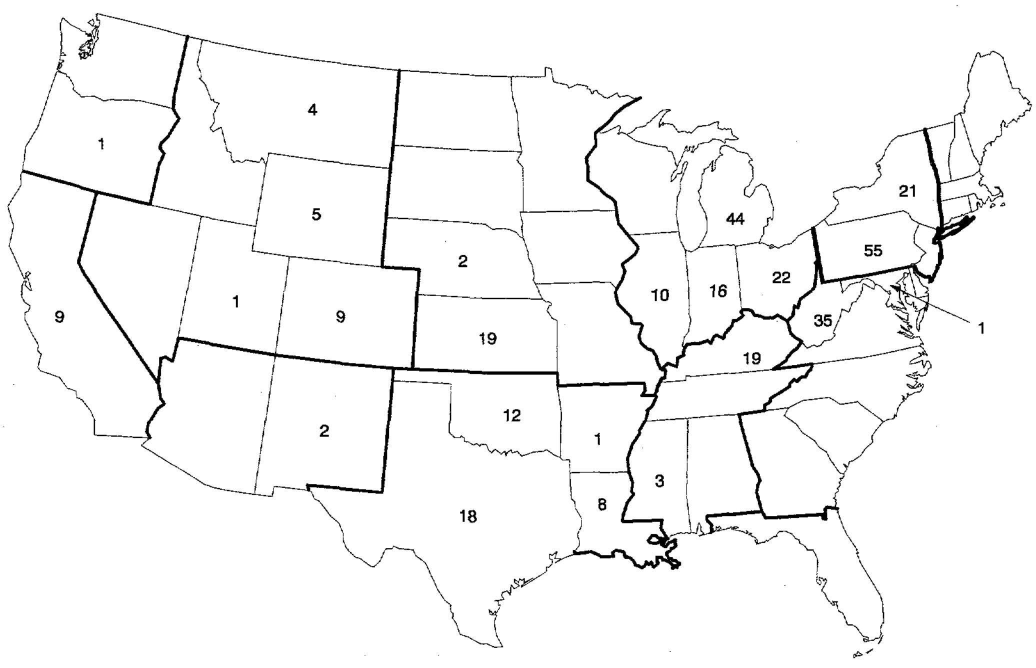
C. *Types of Storage Facilities*

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 liquefied 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[9] 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 reservoirs 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 they typically are not fully cycled.

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"

[9] GSAM regions are the U.S. regions used in the Gas Systems Analysis Model (GSAM currently being developed under sponsorship of FETC. 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.

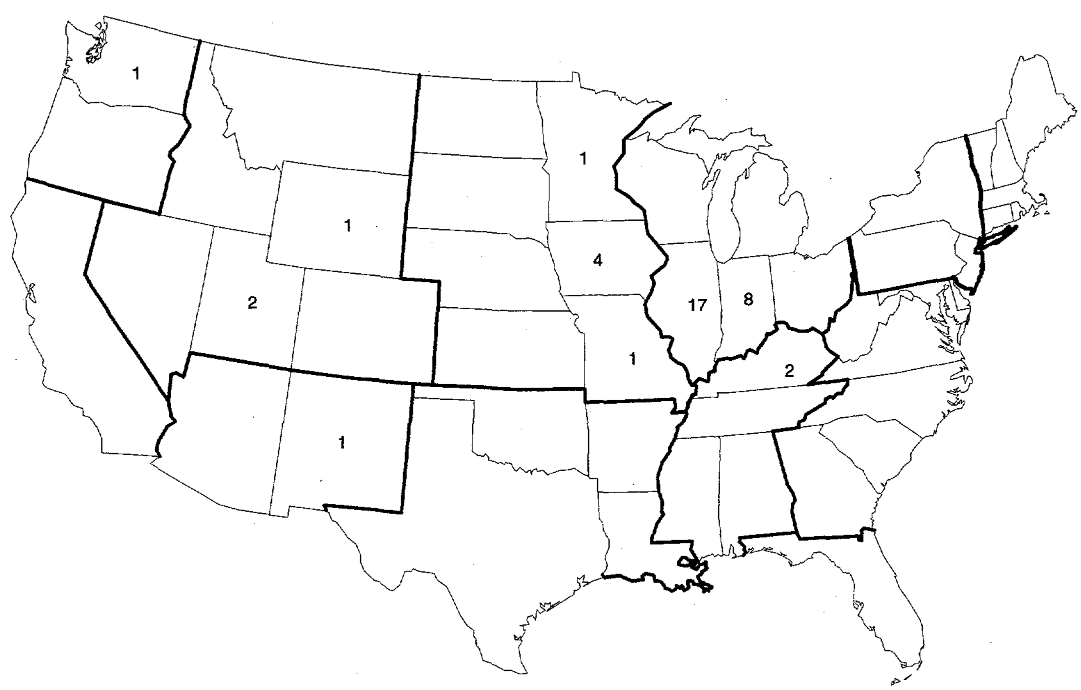
Depleted reservoir storage facilities are typically the least expensive and quickest to develop. The reasons for this are that technical information on reservoir characteristics is available from previous development and production operations, some wells are available for injection and withdrawal, some 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.

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[10] or gas migration sometimes can create problems in the aquifer storage facilities.

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"

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

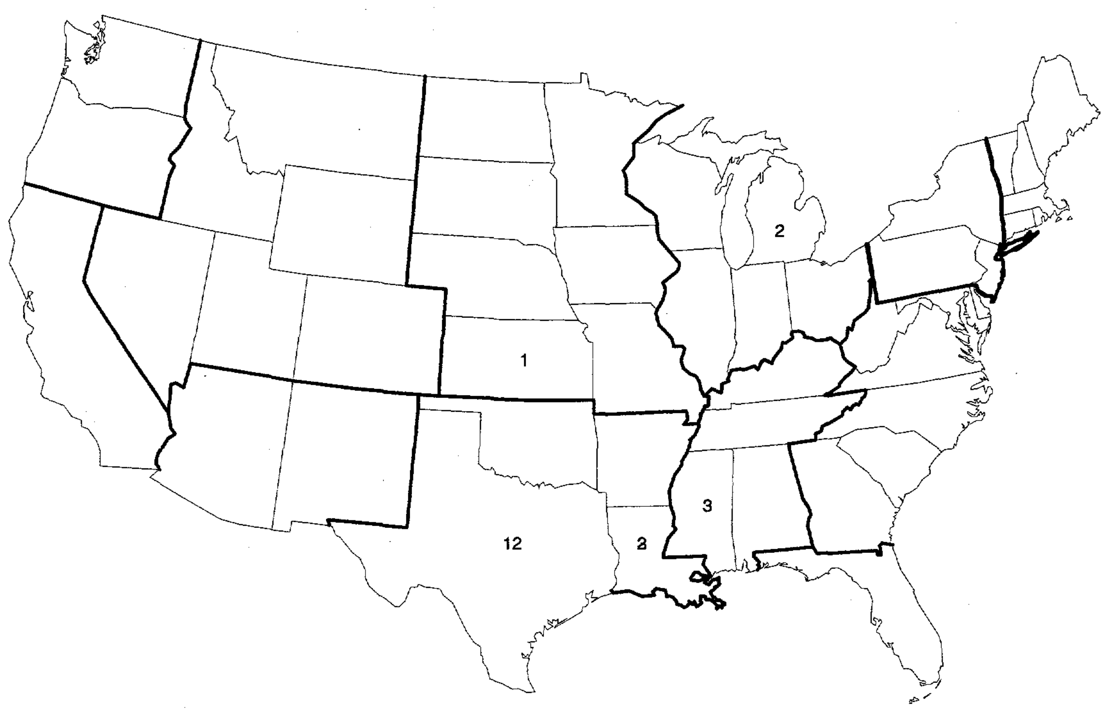
The volume of working gas in aquifers averages 7.5 Bcf per reservoir. However, aquifers also require a relatively high ratio of base gas to working gas, as high as 70 percent of the total gas in the reservoir. Aquifers are often the most expensive type of storage facility to operate. An indication of 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 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 21 that store 82 Bcf of working gas (Exhibit III-4).

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.

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"

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.

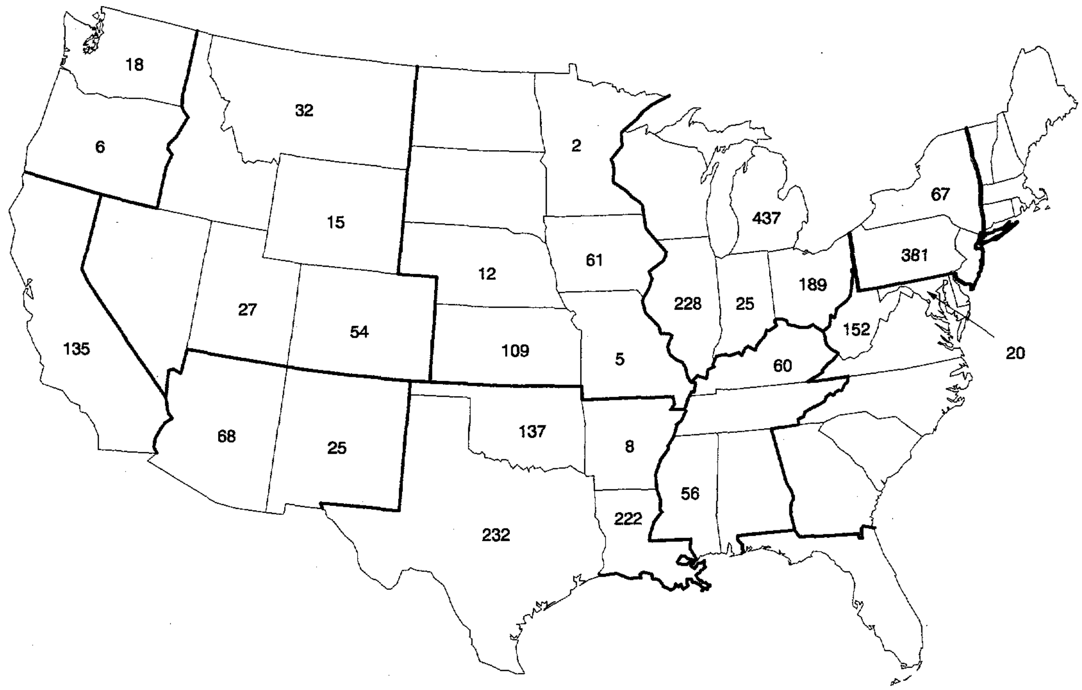
4. Other Storage

Recently, there has been 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, the 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 Everett, 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
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

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 region have and use the greatest storage deliverabilities in the U.S.

E. Summary

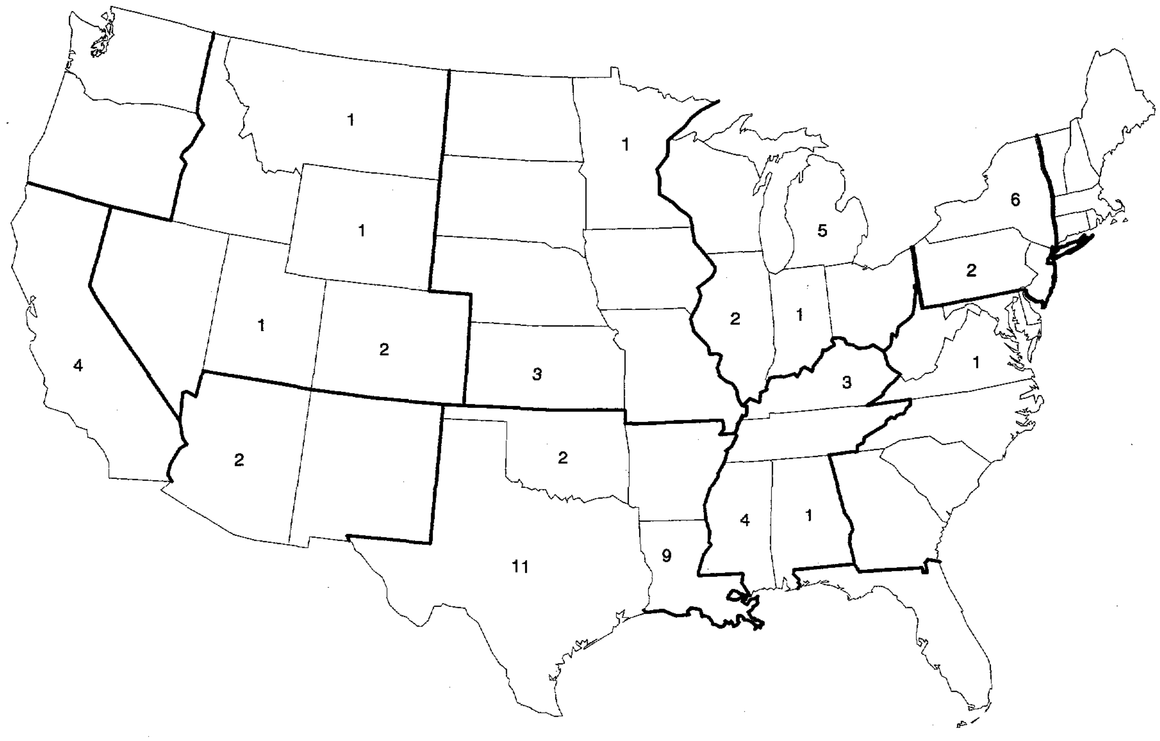
Although the share of gas storage operated by interstate gas pipelines is declining, they still represent about half of the storage sites, working gas capacity and deliverability in the U.S. Traditional, seasonal storage using depleted gas and oil reservoirs represented 86 percent of the existing working 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 the gas storage recently has been the increase in share of high deliverability storage capacity in salt dome caverns — mostly in Texas and Louisiana.

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.[11] 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"

[11] DOE/EIA, *The Value of Underground Storage in Today's Natural Gas*, March 1995.

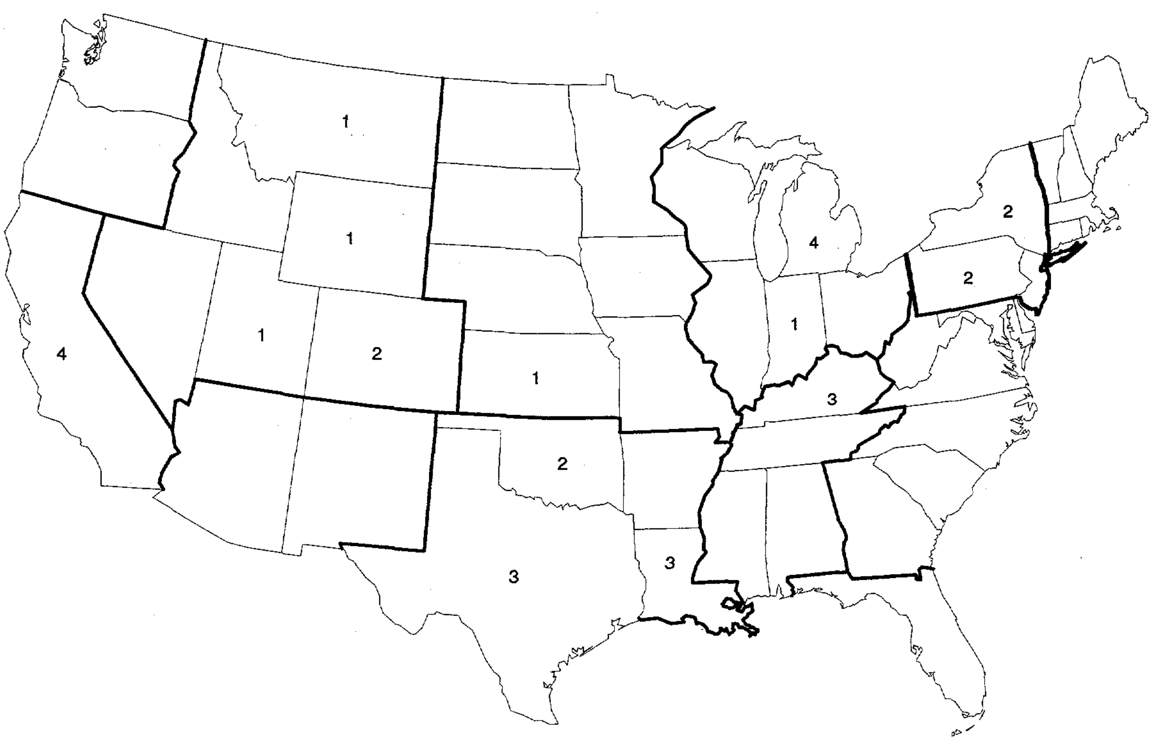
Because several of the new storage facilities have proposed using market-based rates, their sponsors may never need to file the detailed cost information traditionally required in FERC rate regulation. Therefore, even though the total estimated cost of building proposed projects is likely to be publicly 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 is 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, and California regions. Other facilities are proposed for the Mountain North, West North Central, East South Central, and Mid-Atlantic 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, 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 - 49,379	19,279	34 - 34,356	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 one 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.

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	19,833	385
Mountain North	Existing	20	8,739	71
	Proposed	5	10,167	219
California	Existing	10	15,524	400
	Proposed	4	17,250	366

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

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 and 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.[12] 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.

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.

[12] 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

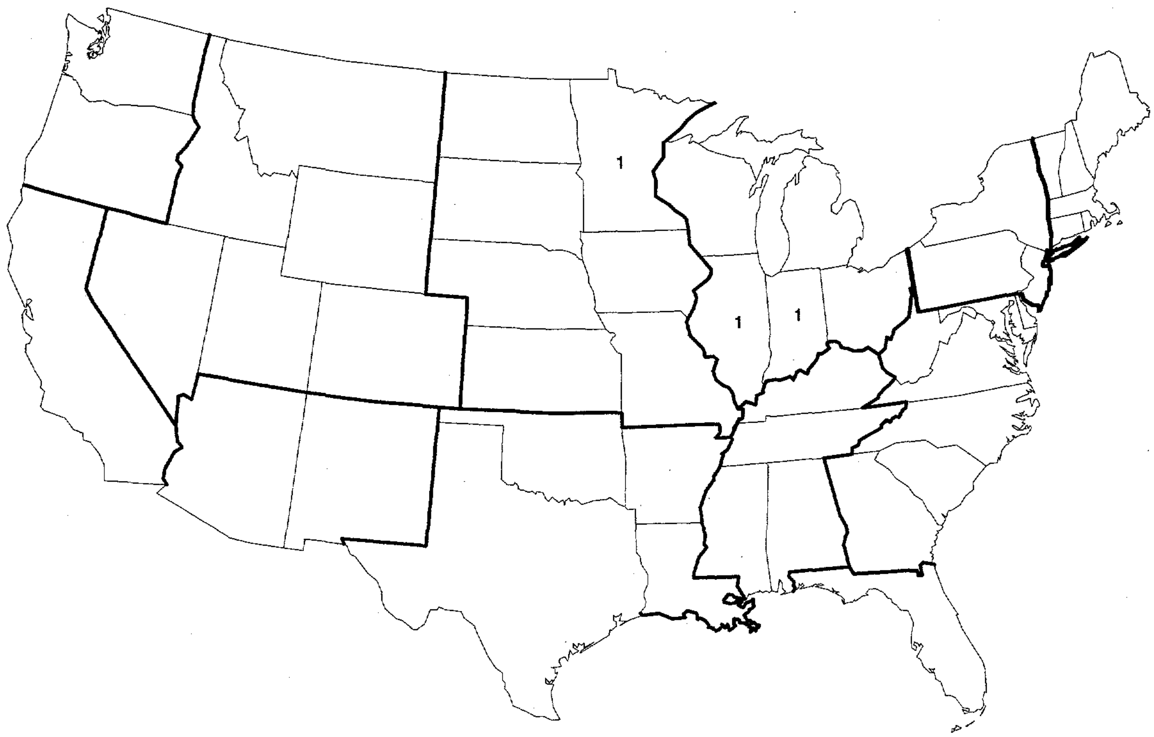
Cost Category		First Year Costs ($)	Fixed or Variable (F,V)
Operations			
Supervision & Engineering	Labor	36,900	F
	Supplies	35,000	F
Wells	Labor	2,700	F
	Supplies	3,500	F
Lines	Labor	7,900	F
	Supplies	3,600	F
Compressor Station	Labor	300,000	V
	Supplies	21,500	V
Station Field and Power	Labor	0	F
	Supplies	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
Wells	Labor	1,700	F
	Supplies	3,000	F
Lines	Labor	2,700	F
	Supplies	11,000	F
Compressor Station	Labor	2,700	F
	Supplies	1,500	F
Station Field and Power	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 Operations & 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

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).

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"

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).

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 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.

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	3,900	35	111
Waterville-Waseca	Minnesota	West North Central	1,200	--	--
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	

Exhibit IV-10
Cost 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

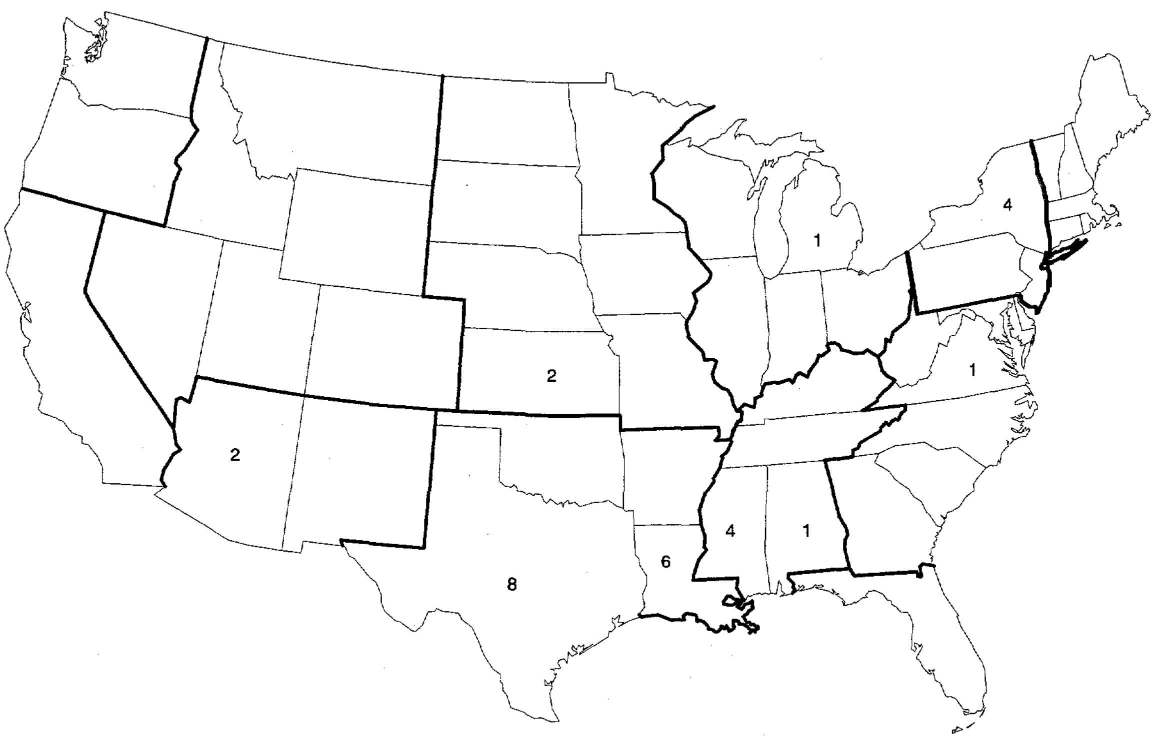
C. New Salt Caverns

Nearly half of the total number of proposed 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 the 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 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).

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

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

Project	Region	Working Gas Capacity MMcf	Phases	Construction
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-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, or 40% of the costs of deliverability associated with depleted reservoir storage facilities.

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 is 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-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 North	Existing	0	--	--	--	--	--
	Proposed	2	16,000	1250	24	10	13
Mountain South	Existing	2	1,112	113	11	6	10
	Proposed	0	--	--	--	--	--

Exhibit IV-15
Costs of Proposed Gas Storage 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 South 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

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-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. New 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 are at a level between those of depleted reservoirs and salt caverns.

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.[13] They are located in 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

[13] 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.

their round-trip times, the terminal tankage could be refilled several times a year. The average storage 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.

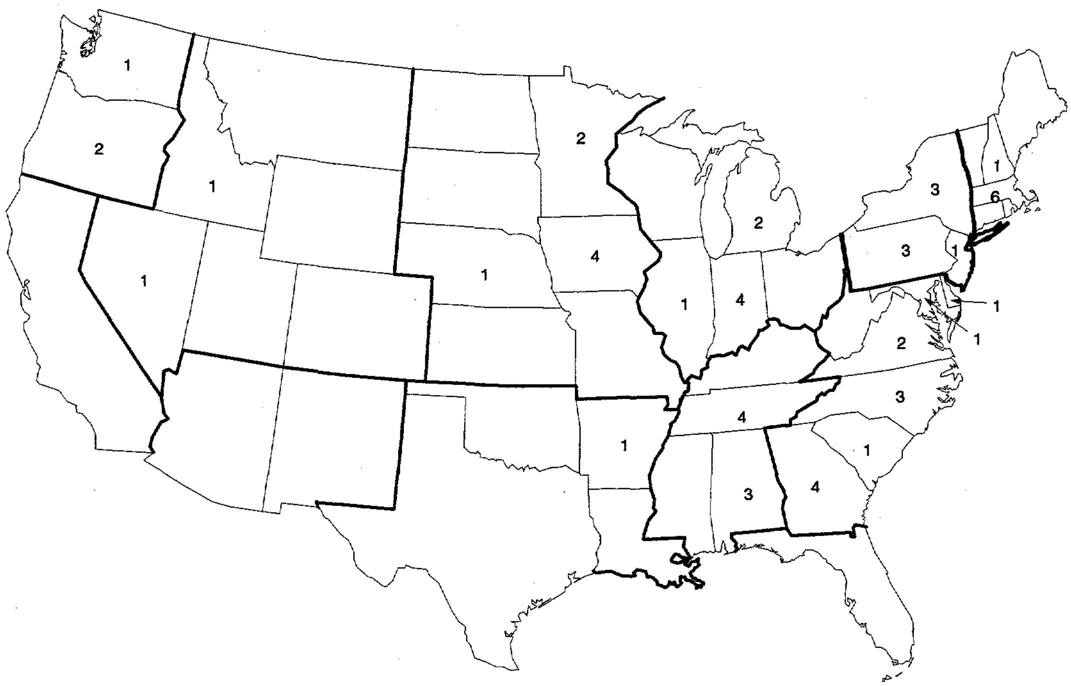
Changes in the natural gas market have made the LNG import terminals less practical. The lifting of wellhead price regulation and the unexpected increase in low-price North American gas supplies have made LNG from overseas less competitive against domestic and imported Canadian supplies. Currently, only 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.

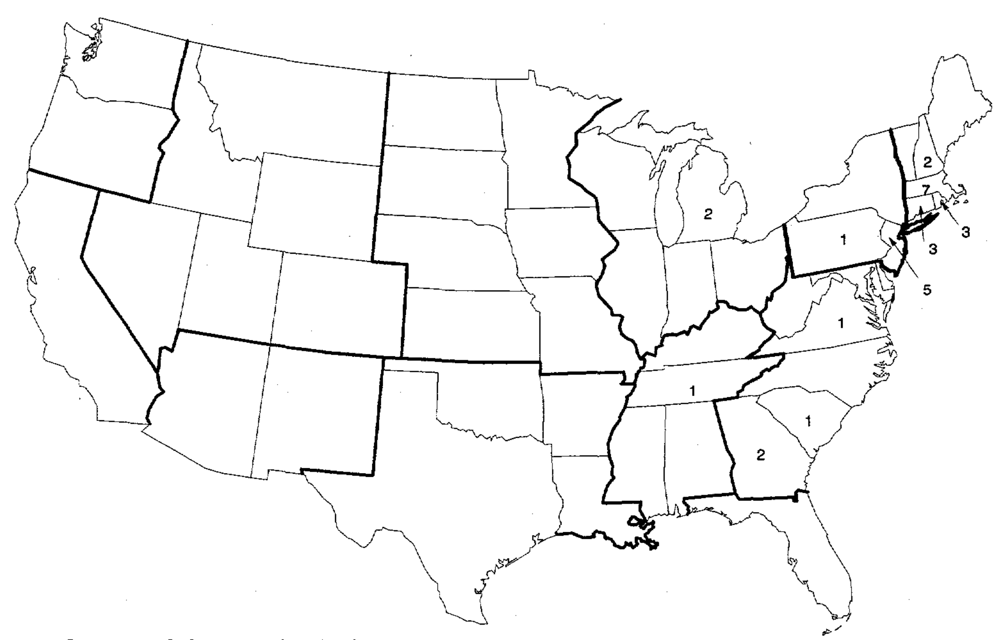
In contrast to the LNG import terminals, there are many smaller LNG storage facilities operational throughout the nation. The majority of these are peak shaving facilities, capable of liquefying, storing, and regasifying natural gas as necessary (Exhibit V-3). Some are satellite storage facilities, which 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 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 54,6400 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.

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 to most end use equipment.

About 3 Bcf per year (natural gas equivalent) of propane/air is used by the U.S. gas utility systems. 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.

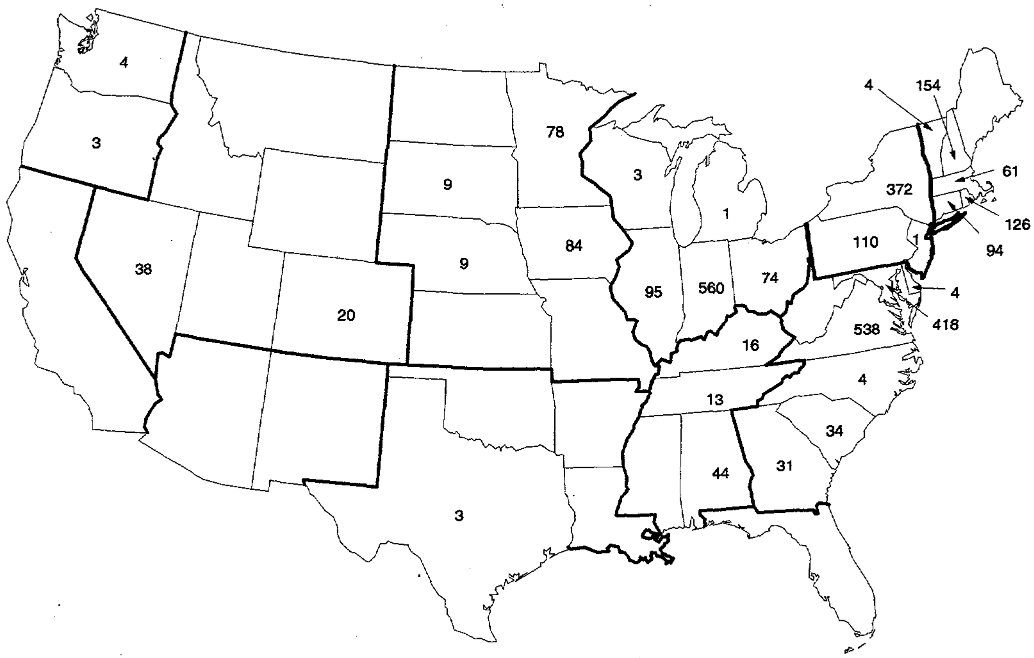
Exhibit V-5
Representative Costs and Rates for a 2 Bcf LNG Storage Facility
($000)

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 Services	$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.	$0.0549/MMBtu

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.[14] 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 MMBtu. The average price of propane varies regionally as shown in Exhibit V-8.

[14] Cove Point LNG Company, L.P., Abbreviated Certificate Application, Docket No. CP94-59-000; Avoca Natural Gas Storage, Certificate Application, Docket No. CP94-161-00.

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



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

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 a token "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 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.

Exhibit V-7
Propane/Air Peak Shaving Costs 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 Cost	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 Costs of Service	3.50	2.50
Costs 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 Kaiser Projections of 1993, Petroleum Marketing Annual Data

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

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

Region	Distillate Fuel Oil	Residual Fuel Oil
New England	4.36	2.51
Middle Atlantic	4.36	2.64
South Atlantic	4.45	2.27
East South 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

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 cost (divided by the gas volume that would use the facilities represented by the fixed costs), and the costs 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.

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.

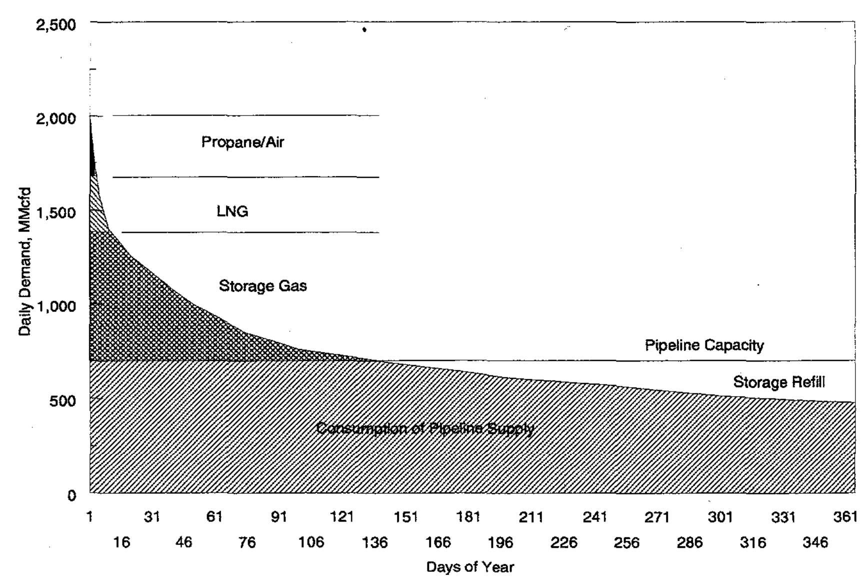
Decisions on the use of underground storage or the alternatives have historically been based on the costs of the higher volumes of gas required for space heating in winter months. The growth of underground storage occurred because it was less expensive for incremental winter supply than reserving pipeline capacity. For those consumers that could afford to invest in a backup or competing fuel such as fuel oil, 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	11	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 and 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 difference 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 for use of storage and peak shaving during the higher demand periods in a year is the high unit cost of reserving pipeline capacity that will be used for only short periods 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, 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 load factors 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 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. In 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 pipeline capacity when the pipeline load factor falls to about 30 percent. Stated another way, it would not

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

Gas Supply Alternative	Fixed Monthly Capacity Reservation Cost $/Mcf	Unit Reservation Rate @100% Load Factor (365 days/year)	@30% Load Factor (110 days/year)	@8% Load Factor (30 days/year)	@.8% Load Factor (3 days/year)	@.3% Load Factor (1 day/year)	Variable Usage Rate $/Mcf	Gas Field Price $/Mcf	Total Unit Rate, $/MCF @80% Load Factor (292 days/year)	@30% Load Factor (110 days/year)	@8% Load Factor (30 days/year)	@.8% Load Factor (3 days/year)	@.3% Load Factor (1 day/year)
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.	N.A.	$26.44	$53.84

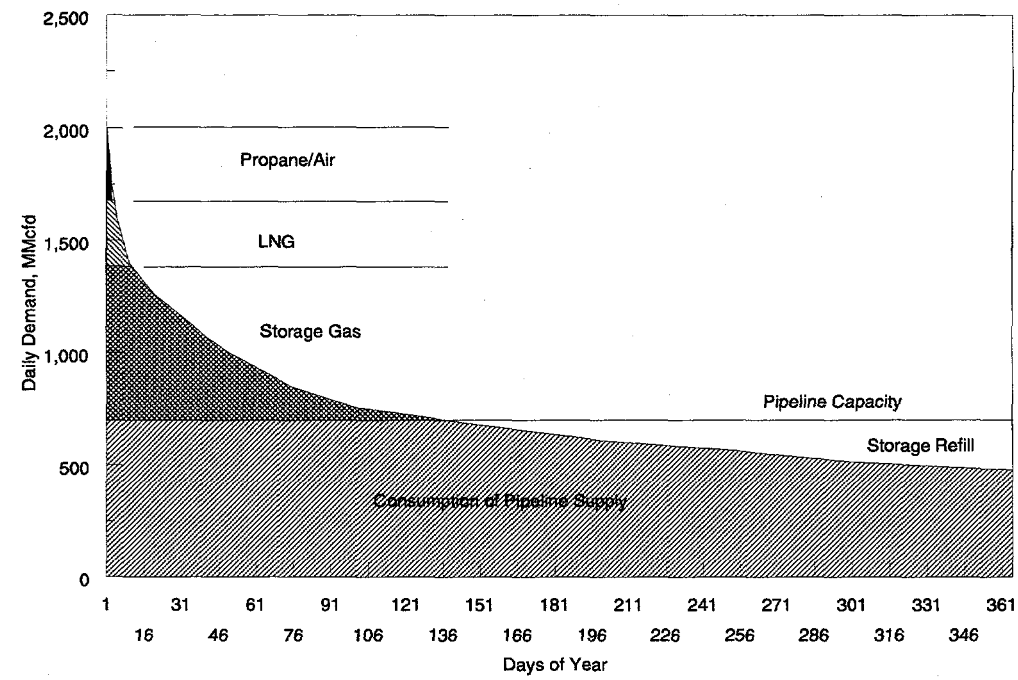
Notes: 1. Pipeline capacity alternative is direct route to market form gas supply source.
2. Storage alternative is sum of storage rate, pipeline rate to storage at a high load factor (100% in this example) plus pipeline rate from storage to market at lower factors.
3. LNG alternative is sum of LNG rate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

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 costs less for the remainder of the year. LNG may be the lowest cost supply alternative for supplementing the reserved pipeline and storage capacity during the two to ten days of peak 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.

As demonstrated in Exhibit VI-1, there is not 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 costs 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.

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



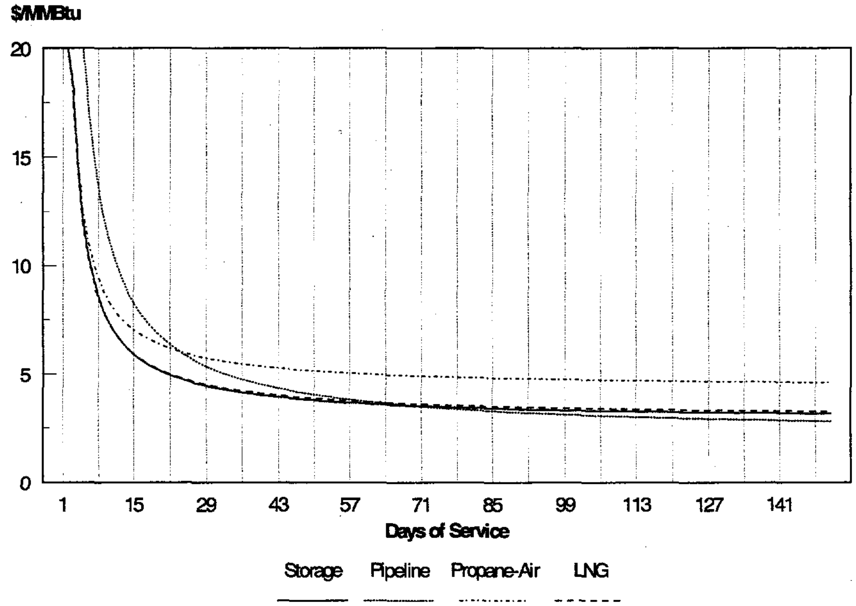
In recent years, two significant changes have occurred in natural gas markets that reduced the need for storage in some regions. The first change was the initiation of contract terms whereby developers of congeneration plants that are dual-fueled by gas and distillate fuel oil agree to burn oil for a 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 LCD's charges for gas deliveries to the congenerator 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 LCD 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)

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

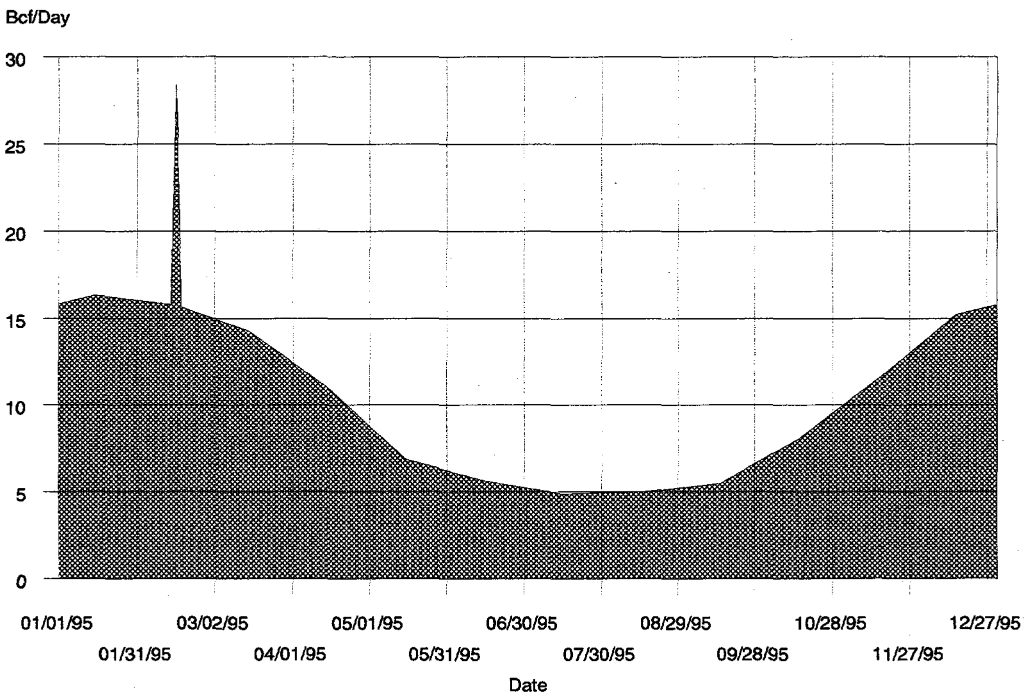


region in 1995, shows that pipeline capacity is less expensive than storage for most of the year, but is more costly than storage during the 60 days of highest demand. (The pipeline price curve crosses over to higher than the storage price curve at about the 60th day.) This means that the optimum time 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 the 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 cost of gas transportation to storage and from storage to the consuming region.

The next step is to compile the total gas demand for all consuming sectors in each region for all years being forecast. Theses 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 pipelines 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-4
Projected Total Gas Demand Curve, 1995
East North Central Region



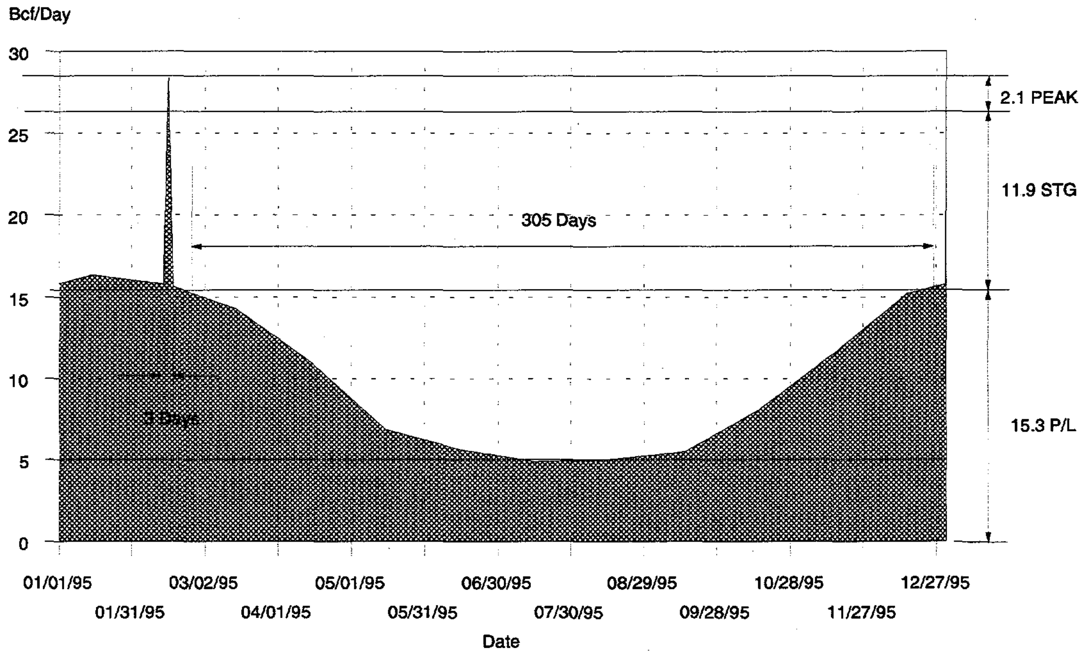
Peak Day volume is included for illustrative purposes.

One way to visualize this process of optimizing the costs of supply alternatives and their timing is to assume that the demand chart is a cross section of a lake bed. The lake is first partially filled with gas delivered by pipeline, until the lake is deep enough to cover 305 days of the lake bottom. This will leave exposed shorelines and possibly island in the lake that will, in turn, be partially submerged by the addition of gas from storage. When the lake level reaches the point where the optimum number of days of storage days are covered, LNG and/or propane/air will be used to submerge the remaining peak demands.

Exhibit VI-5 shows that using pipeline capacity for the 305 days of lowest demand between early March and late December results in a need for 15.3 Bcfd of pipeline capacity. Assuming that the LDCs in the East North Central region will use their 2.1 Bcf per day of peak shaving capacity during peak demand periods each winter, there will be an optimum storage deliverability need of 11.9 Bcfd for January, February, and part of December. Peak shaving supplies will be needed for the peak shown in February.

Additional review of Exhibit VI-5 indicates that the East North Central region has substantially more pipeline capacity available in the warmer months than is needed to refill storage for winter use in the East North Central region. This imbalance between the need for storage in the region and the refill capacity is understandable when you consider that this region provides storage gas in the winter for may of the states along the east coast that are not in the East North Central region, and that there is surplus pipeline capacity serving the region.

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.

VII. Regional Storage Needs

Using the methodology described in Section VI, optimum underground gas storage capacities can be modeled 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 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 storage capacity in specific areas or storage with special characteristics. Some storage capacity could become stranded because it is uneconomic compared to other capacity.

Thus the balance of storage need and availability in the future needs to be analyzed on an inter-regional basis rather than in 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 characteristics of primary importance to 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 some 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 be provided by the storage module of 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 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 condition 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 South Central	42	162	208	229	187	445%
West North 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 North 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 (cont'd)
GRI Regional Gas Consumption Forecast by Sectors
(TrBtu/yr)

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	378	439	197	45%
East North Central	725	721	730	764	39	27%
East South Central	139	151	162	176	37	27%
West South Central	332	347	372	401	69	21%
West North 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	8914	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	558	37	7%
West North Central	521	536	548	465	39	9%
West North 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 (cont'd)
GRI Regional Gas Consumption Forecast by Sectors
(TrBtu/yr)

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 South Central	853	883	920	959	106	12%
West North 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 the 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 producers 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. 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. These operations are discussed in following chapters.

VIII. Reservoir Database Development

The development of an underground gas storage facility is dependent on the characteristics of the reservoir in which the gas is to be stored, particularly the porosity, permeability, depth, thickness and aerial extent of the reservoir. Normally, a reservoir which is chosen for storage is one that has demonstrated the ability to contain and flow gas at high rates. The reservoir's geology will set the limits on the maximum field capacity, but can be designed and engineered to produce a specific capacity and deliverability performance from the reservoir. There are three parameters which will dictate the economic and operational development of a storage field for a specified performance: 1) the volume of base (or cushion) gas, 2) the number of wells in the field, and 3) the amount of horsepower needed to drive the compressors for storage gas injection and withdrawal. The Storage Reservoir Performance Module currently uses *The Significant Oil and Gas Fields of the United States* and *The Significant Oil and Gas Pools of Canada* databases developed by NRG Associates for the discovered U.S. and Canadian gas reservoirs. In addition, United States Geologic Survey (USGS), AGA, Hart publications and other published data are used in creating the storage reservoir database.

The Storage Reservoir Performance Module (SRPM) requires certain key reservoir-specific rock and fluid properties in order to predict deliverability, working gas volumes and cost factors depending upon various technology and costing algorithms. It handles reservoir properties by utilizing pay grades within the reservoir, which take into account the heterogeneity present. These values, in addition to other key parameters (e.g. base gas requirements, location, injection and extraction rates, projected life of the storage reservoir etc.), are sent to the GSAM Demand and Integrating (D&I) Module. The D&I module is a linear programming (LP) model which selects the most economical existing and potential new storage reservoirs to meet the gas demand in the electric power generation, industrial, commercial and residential sectors for specified market condition[15].

The storage database development was divided into two separate subtasks, addressing: a) existing storage facilities, and b) new/potential storage facilities in depleted gas reservoirs.

A. *Database For Existing Gas Storage Reservoirs*

There are two reasons why a comprehensive, reservoir-based database was developed for the existing gas storage reservoirs of the U.S. Most importantly, the database was used to screen storage reservoirs for the improvements in performance and economics that could result from technology advancements. Overall increases in reservoir deliverability in coming years, for example, will come from improvements to existing reservoirs as well as from the development of new storage facilities. GSAM compares the costs and benefits of expanding existing storage with those of new storage in the process of selecting the more economic storage capacity additions. The second need for this database was for use in validating the model. The model was tested by simulating the performance of several existing gas storage reservoirs of each type and adjusting reservoir parameters until the model reasonably predicted the actual performance of these reservoirs.

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[15] The integrating LP is based on the concept of maximizing producer plus consumer surplus to create estimates of market equilibrium prices and quantities of gas.

1. The Important Reservoir Parameters

For evaluation of storage prospects, the storage performance module requires the following 12 data elements for each reservoir examined.

1. Field and Formation Name
2. Location of Field: State and Region code (see Exhibit VIII-1)
3. Geologic trap type and play code in United States
4. U.S. Geological Survey (USGS) play notations
5. Reservoir/Volumetric Data
   a) Average net pay (ft),
   b) Reservoir area (acres),
   c) Porosity (fraction),
   d) Permeability (md),
   e) Initial gas and water saturations,
   f) Gas gravity,
   g) Depth of formation (ft),
   h) Original reservoir pressure (psia).
6. Storage Specific data (if available for existing fields)
   a) Working gas (MMCF),
   b) Base gas (MMCF),
   c) Ultimate storage capacity (MMCF),
   d) Designed maximum deliverability (MMCF),
   e) Horsepower requirements (HP).
7. Well data
   a) Number of existing injection/withdrawal (I/W) wells,
   b) Number of pressure control/observation wells,
   c) Well radius (ft).
8. Other data
   a) Type of water influx (strong/medium/weak),
   b) Aquifer pressure, where data exists,
   c) Fracture matrix permeability (where different from reservoir permeability),
   d) Estimated length of fractures.

Exhibit VIII-1
GSAM/SRPM Region Identification

GSAM/SRPM Region Code	GSAM/SRPM Region Name
01	New England
02	Middle Atlantic
03	South Atlantic
04	Florida
05	East South Central
06	East North Central
07	West South Central
08	West North Central
09	Mountain 1 (South)
10	Mountain 2 (North)
11	California
12	Pacific Northwest
13	Canada-East
14	Canada-West
15	Mexico-Demand

2. Acquisition of Reservoir Data

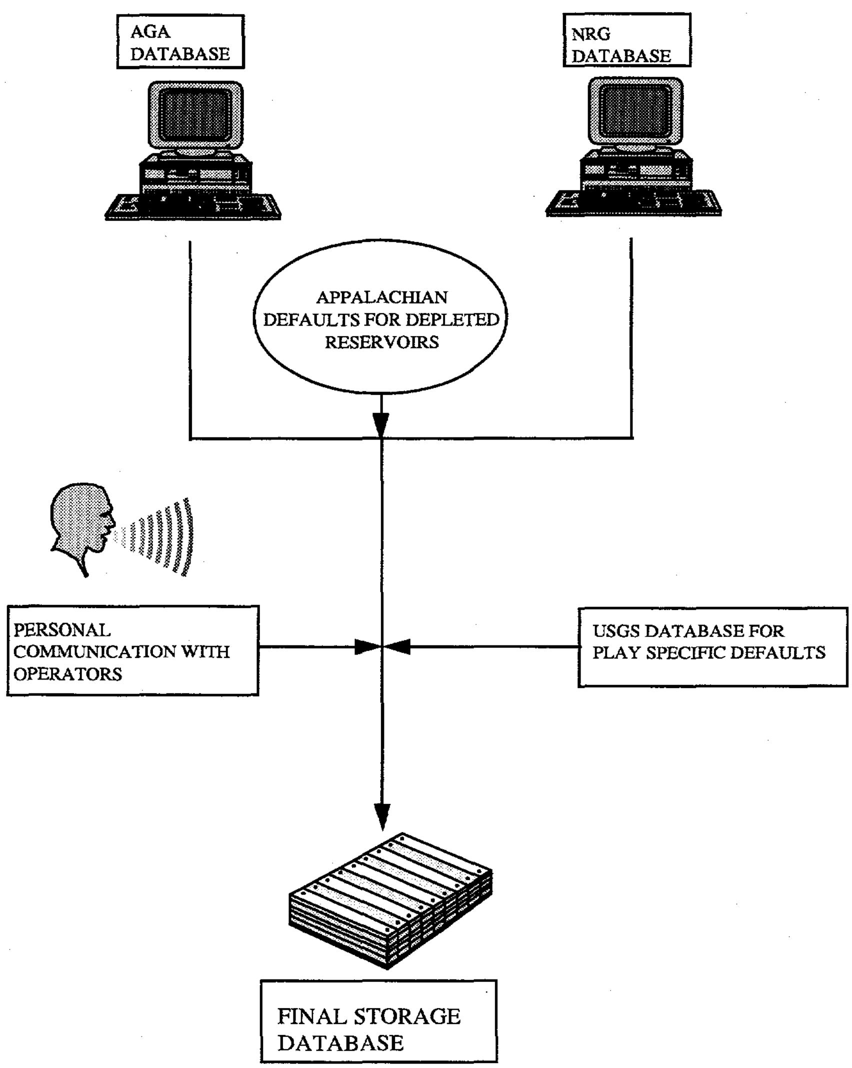
Exhibit VIII-2 describes the procedure for developing the reservoir specific data on storage prospects used in SRPM. The major source of the data was the AGA database of storage fields which was last updated in 1993.[16] This AGA database contains certain storage specific information (e.g. working gas, base gas, and deliverability values etc.) but does not contain the detailed reservoir properties in order to predict the future development of the project based on advanced technologies and future expansion using SRPM. In order to achieve this goal, AGA database was cross-walked with the reservoirs identified as existing storage reservoirs by *NRG Associates* in *The Significant Oil and Gas Fields of the United States.* The NRG database was used to extract detailed reservoir properties required to solve fluid flow equations in SRPM. Of the 388 reservoirs in AGA database, only 42 reservoirs were found in the NRG database and relevant data was extracted for these reservoirs.

Most of the existing gas storage reservoirs were not included in the NRG database, because they were not producing reservoirs when this database was compiled. Consequently, many of the database elements for existing storage reservoirs had to be developed by questioning operating company representatives for these storage facilities and by using reservoir parameters from appropriately selected nearby producing reservoirs that are included in the NRG database. In developing the appropriate parameters for existing storage reservoirs, data provided in the 1993 AGA report on underground gas storage were used to select comparable reservoirs located nearby. Characteristics of the comparable reservoirs were used as proxies for the required data not provided by AGA. The useful data elements listed (but not always provided) in the AGA report are shown below:

[16] American Gas Association, Operating Section Report, "1993 Survey of Underground Gas Storage Facilities in the United States and Canada."

- Reservoir name
- County and state location
- Reservoir discovery year
- Formation name
- Average reservoir pay thickness
- Type of geologic trap
- Reservoir maximum and minimum depths
- Original reservoir pressure
- Reservoir acreage
- Number of output/input wells
- Original reserves
- Developed storage capacity
- Undeveloped storage capacity
- Designed maximum deliverability
- Maximum storage pressure

Exhibit VIII-2
Development Procedure for the Reservoir Database



In another exercise, each existing storage reservoir was assigned a USGS geologic play code based on its geology, rock type and location. This code was helpful in assigning play-specific average properties to all reservoirs within the same geologic play. Each reservoir in the storage database was assigned a 11 digit code (defined as Storage ID) based on its regional location, reservoir type, play code and unique AGA identification number. This NRG proxy data approach and the USGS play approach was not possible for existing aquifer and salt cavern storage facilities nor for depleted reservoirs in the Appalachian basin, because they are not included in the NRG databases for gas and oil reservoirs. For these three cases, data sources were limited to the AGA report, contacts with storage facility operators, internal knowledge at ICF Resources, and other published materials.

B. Database For New/Potential Storage Reservoirs

The new dynamics of the natural gas market has created significant additional interest in construction of new storage facilities. Substantial projected growth in short-term summer gas use by the electric generation sector in the Mid-Atlantic, South Atlantic, East South Central and West North Central regions suggests a potential need for high deliverability storage in these regions. Most of the potential storage projects would be depleted gas reservoirs located near to the demand regions. In this exercise, therefore, the depleted gas reservoirs were considered for database development.

1. The NRG Reservoir Database

Since the NRG database for gas and oil reservoirs already resided in GSAM, much of the data required for evaluating gas and oil reservoirs for suitability as future gas storage reservoirs were readily available. The NRG database contains over 180 elements of data for each reservoir in its database. The data elements included in this database are reservoir properties, location, production histories etc. among other items. In those cases where critical data elements were missing for a reservoir, default values were estimated either by developing default equations or by selecting data through comparisons with appropriately similar nearby reservoirs. The NRG database consists of several thousand gas reservoirs which could be candidate for storage. Various screening criteria were utilized to select the ideal candidate for storage reservoirs. Altogether around 140 potentially new storage reservoirs were included in the database.

2. The Appalachian Reservoir Database

The Appalachian atlas of oil and gas reservoirs that was originally scheduled to be available for use in the selection of new storage reservoirs was delayed and was unavailable for use in this project. Since no other comprehensive data source was made available, the characteristics of potential storage reservoirs for the eastern U.S. was generated from a cross-section of the eastern U.S. existing storage reservoirs. Many of the Appalachian storage prospects have been studied for several years and their characteristics are well known among geologists and petroleum engineers who have specialized in gas storage in the eastern states. Without this approach, no GSAM analysis of storage prospects in Appalachia could be made.[17]

The database developed for the eastern U.S. includes around 10 reservoirs for most of the Appalachian states including Ohio, West Virginia, Pennsylvania, and New York. Reservoirs located in USGS plays 6719, 6720, 6721, 6725, 6732, 6737 were selected as potential storage sites based on their

[17] And in our opinion, this approach was the only viable one for completing the Appalachian database.

reservoir properties, location, and deliverability estimates. Potential storage reservoirs such as two new fields in south central New York (Steuben County), Adrian and Thomas Corners were represented in the database. The potential for new storage reservoirs in north central Appalachia lies within the area of the basin which lies west of the line that extends from Syracuse, NY to Hagerstown, MD. Geology to the east of this boundary is mostly Cambrian and granite type rocks that don't have the reservoir characteristics of porosity and permeability for good storage. Altogether 50 storage reservoirs were found to be potential storage sites based on the selection criteria as described in Section III of this report.

IX. Reservoir Screening for Storage Use

A. *Technical Screening Criteria for Storage*

Reservoirs in the GSAM database contain significant data on the rock and gas properties for producing reservoirs nationwide. This information, including appropriate defaults to account for missing elements, can be used to screen and evaluate reservoirs for future storage use. This section describes the screening criteria developed based on evaluation of active storage projects. In addition, values for key storage project properties not available from the GSAM database can be estimated based on available data. The procedure described here provides all the necessary information for use in the reservoir performance model described in the next section.

The procedures developed to screen projects and default missing data were developed based on analysis of AGA data on storage projects. Information available on existing projects in this data set were evaluated to determine critical limits to the use of reservoirs of various types as storage projects. Existing storage reservoirs were matched, where possible, to the reservoirs described in the GSAM database. This allowed evaluation of data for a variety of properties and cross checking of entries to ensure consistency. Where data for similar elements did not agree, the data in the AGA data set was assumed to be more accurate for the storage projects.

The critical properties impacting storage project description include permeability, depth, working pressures, and drive mechanisms. Most of this information is contained in the GSAM database for non-associated gas reservoirs. To determine missing properties from the database or elements not included in the data, several screening procedures and defaults were developed.

The first priority was to eliminate reservoirs that did not have suitable geology or volumes for use as storage sites. For this procedure, information in the GSAM data on Resource Type, Drive Type, and Field Type was used. Only sandstone, limestone, dolomite, and chalk reservoirs were evaluated for storage potential. Strong water drives, where abandonment pressure was more than 75% of original, were eliminated from consideration as storage candidates. Reservoirs with complex settings, as demonstrated by poor recovery (less than 50% of original gas in place), were dropped as well.

For depleted non-associated gas reservoirs with suitable rock types and recovery history, those with less than 5 BCF original gas in place (OGIP) were eliminated as candidate storage sites. Depleted oil reservoirs where the total original gas and oil in place was less than the equivalent of 5 BCF were also dropped. The original oil in place (OOIP) was converted to equivalent gas in place using the following formula:

$$\begin{aligned} \text{OGIP (equivalent)} &= \text{OOIP} * \text{Boi} * 0.199 * \text{Pressure/ Temperature or} \\ &= \text{OOIP} * \text{Boi/Bgi if known} \end{aligned}$$

where Boi is the original oil formation volume factor in cubic feet per stock tank barrel and Bgi is the gas formation volume factor in cubic feet per billion standard cubic feet.

Deep reservoirs were selected in such a manner that they were large enough to support the additional costs associated with development and operation of the project. Exhibit IX-1 represents minimum reservoir volume by depth criteria used in this study.

Exhibit IX-1
Minimum Reservoir Volume
by Depth Criteria

Depth Range	Minimum Volume
7000-7500	15 BCF
7501-8000	32 BCF
8001-9000	72 BCF
9001-10000	120 BCF
10001-11000	176 BCF
11001-12000	240 BCF

Note: Reservoirs deeper than 10,000 feet were eliminated.

In addition to small reservoirs, immature reservoirs, such as those with less than 80% cumulative recovery of their estimated ultimate reserves, were dropped from the database.

Reservoirs with unacceptable levels of impurities were also eliminated. Based on AGA data, no reservoirs were considered for storage sites if they had H_2S in excess of 0.3%, CO_2 in excess of 6%, N_2 in excess of 10%, or total non-hydrocarbon gases in excess of 20%. These limits were used to screen reservoirs and eliminate projects with excessive impurities. Also, the original gas volume limits described above were expanded to account for additional volumes required for the non-hydrocarbon concentrations of each reservoir, including changes in average gas compressibility.

B. Estimation of Missing Storage Reservoir Properties

Values for storage project for volumetrics, porosity, permeability, depth, and gas characteristics were available from the GSAM database. Where data was not available, GSAM's Resource Modules estimated the missing value based on the geologic play, using engineering calculations. Estimating the volume of working gas and base gas for a reservoir involves determining the storage reservoir working pressure and the volume available for storage. The working pressure was assumed to be the original reservoir pressure. When this was not available, the pressure was estimated based on the reservoir depth using a pressure gradient consistent with the geologic play. Two areas were adjusted to reflect unique pressure relationships. In the Upper Midwest (Michigan, Illinois, Indiana, etc.) for reservoir less than 5000 feet deep the maximum storage pressure was assumed to be calculated as follows:

Storage Pressure = Pressure Original * (1.5-3.33*(Pressure Original/Depth-0.35))

Similarly, in Eastern Canada:

Storage Pressure = Pressure Original * (1.5-2.67*(Pressure Original/Depth-0.35))

The calculated storage working pressure was set to a limit of 110% of original pressure for all reservoirs. This is the highest reported value for any project in the AGA database.

Based on the storage working pressure, reservoir volume, and gas characteristics, the total amount of storage capacity, working gas plus base gas, was estimated. The standard volumetric formula as shown below was used to calculate storage capacity:

$$\text{Storage Capacity} = 43560 * \text{Area} * \text{Thickness} * \text{Porosity} * \text{Gas Saturation} / \text{Gas Formation Volume Factor}$$

The gas formation volume factor (Bg) was determined based on the temperature, pressure, gas gravity, and concentration of impurities. This value was estimated based on the storage gas and reservoir conditions as well as the original reservoir gas and other reservoir properties.

C. Acceptable Ranges for Screening Criteria

The new/potential storage candidates were selected based on various selection criteria. The NRG database contains several thousand depleted gas reservoirs, which could be candidates for storage facilities. This extensive list was narrowed to 2403 prospects based on total reserves (reservoirs with reserves less than 5 BCF, and original gas in place estimates higher than 100 BCF, were not selected), depth (reservoirs with depth greater than 10,000 ft were not selected), and location (Alaska and Offshore reservoirs were not selected). Once this list was formed, it was run through various screening criteria (for example: the initial gas saturation value should always be higher than 0.65, porosity value should be higher than 10%, permeability value should be higher than 100 md. etc.) based on location and size of the reservoir. In addition, separate screening criteria were used for each state to account for their storage needs and availability. Engineering judgment was utilized in some cases to by-pass these screening criteria to accurately represent the potential of future storage reservoirs. One of the most important requirements in selecting a new/potential reservoir was the availability of data for at least 6 to 7 of the identified critical reservoir parameters. These parameters are required to predict deliverability, working gas and base gas value for the storage reservoir. In selection of potential storage facilities, emphasis was given to those fields which were geographically near to the demand regions and therefore would not incur high pipeline transportation costs.

X. GSAM MODIFICATIONS

Gas Systems Analysis Model (GSAM) was developed as a comprehensive, non-proprietary PC-based model with a primary purpose of assessing the impact of supply technology developments on U.S. natural gas supply, and a secondary purpose of assessing various impacts of policy/regulatory initiatives, on U.S. gas markets.

An important aspect of the current GSAM approach is the Reservoir Performance Module, which involves prediction of the technical and economic performance of producing gas reservoirs under various completion and production configurations. It estimates the ultimate recovery and production rates based upon explicit, geologic conditions at the reservoir level, and fundamental reservoir engineering principles using a suite of type curves. It can also assess the impact of alternative technologies on ultimate gas recovery, production, and extraction costs by representing advanced technology practices as explicit user-controlled changes in the reservoir model or economic parameters. This approach incorporates substantial improvements over traditional approaches to characterizations involving a "percentage increase" in recovery or simplified proxies for technology performance that ignore the variation in impact across the resource base. Costs for each reservoir are estimated at the same level of detail considered by an operator. Capital, operating and environmental compliance costs are calculated based on region, resource type, regulatory conditions, depth, production rates, and technology characteristics.

However, in its current configuration, GSAM uses an aggregated approach to characterize and predict the performance of gas storage facilities. GSAM represents storage of gas in material balance constraints that balance the supply and demand of gas for each region, time, and season. The various storage costs and other parameters are, however, at the regional level.

In the current task, ICF Resources modified GSAM to allow for a more rigorous modeling of gas storage. The storage data was built from a database of actual storage sites. In particular, a Storage Performance Module was developed to predict the performance and costs of each individual gas storage reservoir. These data are then passed on to the Demand and Integrating Module, which incorporates these disaggregated results in balancing supply and demand for gas, and for determining market equilibrium prices and quantities of gas. The enhancements also included the capability to calculate the changing cost of additional storage capacity as new storage demands are realized and as new technologies reduce costs or improve capacity or deliverability.

A. Purpose of GSAM Modifications

In modifying GSAM for this project, the goal was to clearly identify storage facility types and specific, concrete technology improvements that DOE could consider in developing its gas storage R&D. The current task aims to incorporate a first-level geologic model with a fairly comprehensive "cost-to-develop" analysis to determine the suitability of each candidate as a storage reservoir. The model will do this within the context of the entire gas market system, recognizing the potential for alternatives to storage to become more attractive if storage costs rise. The following enhancements to the capabilities of GSAM have been made as a result of this research through modifications to its existing features:

- Screen economically depleted gas and oil reservoirs for technical, environmental and gross economic suitability as storage reservoirs.
- Screen existing storage reservoirs for their suitability for expansion in size or deliverability.

- Determine the cost of storage development for a given economic and technology scenario, the expected performance of the project, and the resulting cost of service to storage customers.

B. Individual Modifications to GSAM

Modifications to GSAM focused on the following changes:

- Modify the gas reservoir production and ultimate recovery routines to predict both gas injectivity and deliverability in storage reservoirs.
- Modify the operating cost algorithms to predict compression, injection, production and processing costs over time in gas storage projects.
- Modify the reservoir performance type curves to allow for prediction of injection into and flow from depleted gas and oil reservoirs, and aquifers.
- Add injection and production performance relationships for salt caverns.
- Develop new technology/performance/cost relationships for technologies with the highest potential impact on storage reservoir development.
- Modify the economics module to permit the evaluation of gas storage capital costs and injection/production costs, as well as an income stream based on service charges related to storage. Also, modify the income and severance tax treatments accordingly.
- Modify the Demand and Integrating (D&I) Module of GSAM to incorporate storage reservoir level data in balancing supply and demand of gas.

C. Modeling Methodology of Storage Reservoir Performance Module (SRPM)

The Storage Reservoir Performance Module was derived from the Reservoir Performance Module of GSAM, which estimates production rate and ultimate recovery of gas as a function of reservoir characteristics and technology assumptions. It utilizes a suite of engineering type curves, modified from evaluation methods used in classical well test analysis, that can handle conventional, aquifers, and salt dome cavern reservoirs. SRPM has been developed to predict both gas injectivity and deliverability from storage reservoirs, and hence the type curves have been modified accordingly. To explain the workings of the type curves in SRPM, the following radial flow equation (Darcy's law), and the mass balance equation are shown which provide an idea into the calculations such as the injection/withdrawal rate, and the working and base gas estimates (technically recoverable reserves) from the storage reservoir:

(1) $$Q = \frac{0.703\, kh\left(p_c^{\,2} - p_{wf}^{\,2}\right)}{T\mu Z\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + D_{q_s}\right]}$$

where,

Q = the flow rate in MMCF/Day,
k = the permeability of the reservoir in md,
h = the reservoir thickness in ft,
P_c = the average reservoir pressure in psia,
p_{wf} = the bottom-hole sandface pressure in psia,

T	= the reservoir temperature in °R,
Z	= the gas deviation factor,
μ	= the viscosity of gas in cp,
r_e	= the effective drainage radius in ft,
r_w	= the well radius in ft,
s	= the skin factor, and
D_{qs}	= the rate dependent skin factor.

The flow equation (1) predicts the gas flow rate such that the mass balance in the reservoir is satisfied. The following mass balance equation is used in SRPM:

$$(2)\quad G_p B_{gf} = G(B_{gf} - B_{gi}) + W_e - B_w W_p$$

where, G_p is the cumulative gas produced in BCF, B_{gf} is the gas formation volume factor (bbl/SCF) at the end of the time step, G is the original gas in place in BCF, B_{gi} is the gas formation volume factor (bbl/SCF) at start of the time step, W_e is water influx during the time step in bbl, B_w is water formation volume factor in bbl/STB, and W_p is water produced during the time step in STB. The flow equation (1) and the mass balance equation (2) form the iterative loop and a solution is found when pressures and flow rates converge for all the time steps.

As explained earlier, the Reservoir Performance Module of GSAM was developed with the purpose of estimating production rate and ultimate recovery for a gas reservoir produced to its economic limit. Storage facilities, on the contrary, go through alternating production (withdrawal) and injection (refill) periods. Thus, one storage cycle consists of a production phase where gas is withdrawn to meet the demand, and an injection phase where the reservoir is refilled. At the end of each complete cycle, the reservoir is restored to its original condition in terms of reservoir pressure and gas-in-place. This can only be achieved by designing the injection phase in each cycle based on the production (withdrawal) phase performance.

D. Modification of GSAM's Operating Routines to Allow Gas Withdrawal/Injection

The following key modifications/additions were implemented to adapt the GSAM Reservoir Performance Module to evaluate storage reservoirs:

1. Different and variable time step sizes were implemented for the withdrawal and injection periods;
2. Type-curve analysis routines were tailored to calculate injection rate requirements at succeeding time steps based on the total gas withdrawn during the preceding time step;
3. As each complete storage cycle (withdrawal + injection) involves two time steps, a routine was added to convert performance in each time step to an annualized basis for economic calculations; and
4. Assumptions/enhancements specific to the type of reservoir, i.e., depleted gas reservoir, aquifer or salt dome cavern, were incorporated.

A detailed description of each of these additions and modifications follows.

1. Time Step Sizes

The time step sizes for the withdrawal and injection phases in a storage cycle are equal to the actual withdrawal and injection times respectively. Industry standard factors were used to determine the injection time requirement based on the withdrawal time. For example, if the withdrawal time was 3 months and a factor of 1.5 was used, the injection time would be 4.5 months. In actual computations, 100 days of withdrawal and 265 days of injection were assumed simulating base load storage facilities. These values were used because SRPM primarily provides input to the Demand and Integrating (D&I) module of GSAM where storage is competing with pipeline construction for transporting gas and thus storage is considered a base load option. Hence, for the purpose of the integrating linear program the D&I module searches for the least costly alternative. SRPM is designed, however, to analyze all alternative development profiles including peaking for a particular storage facility whenever not running in an integrated manner.

2. Injection Calculations

The injection rate was calculated for each alternating time step corresponding to the injection phase of the storage cycle using the following equation:

$$\textit{Injection Rate}\,(t) \quad = \quad \frac{\textit{Total Gas Withdrawal}\ (t-1)}{\textit{Injection Cycle Time Step Size}}$$

Where t is the index for the time step.

The steps involved in the rate/pressure calculations were also modified to enable calculation in SRPM. The modified calculation procedure was as follows:

1. Calculate the withdrawal rate and pressure for a given production time step.
2. Calculate the average reservoir pressure at the end of the time step.
3. Calculate the total gas produced during the withdrawal cycle.
4. Calculate the injection rate based on the total gas produced during the production cycle.
5. Calculate the reservoir pressure after the injection period using dimensionless type curves.
6. Repeat steps 1 through 5 for the number of storage cycles in each analysis.

3. Conversion of Time Step Sizes to an Annual Basis

SRPM calculates production and injection quantities for each storage reservoir based on production and injection cycle times. These times are not necessarily expressed on an annual basis and therefore must be converted appropriately for annual accounting and calculations. SRPM was adjusted to convert production and injection cycles into discrete calendar timesteps. The model then converted the timesteps into annual values for use in costing, economics and discounted cash flow evaluations. To clarify this point consider the following illustrative example for three years, with the production (withdrawal) cycle equal to 0.1 years and the injection cycle equal to 1.0 year (10 times the production cycle). Note that the following pattern of production and injection cycles are maintained:

1. Production cycle #1, Followed by Injection cycle #1;
2. Production cycle #2, Followed by Injection cycle #2;
3. Production cycle #3, Followed by Injection cycle #3.

Time (Year)	Withdrawal Activity	Injection Activity
0.0	Production cycle #1 ***Started***	
0.1	Production cycle #1 ***Completed***	Inj. cycle #1 ***Started***
1.0		0.9 Injection cycle #1 ***Completed***
1.1	Production cycle #2 ***Started***	0.1 Injection cycle #1 ***Completed***
1.2	Production cycle #2 ***Completed***	Inj. cycle #2 ***Started***
2.0		0.8 Injection cycle #2 ***Completed***
2.2	Production cycle #3 ***Started***	0.2 Inj. cycle #2 ***Completed***
2.3	Production cycle #3 ***Completed***	Injection cycle #3 ***Started***
3.0		0.7 Injection cycle #3 ***Completed***

From the above table we can see that the annual amounts are as follows:

Time (Year)	Withdrawal Activity	Injection Activity
1.0	100% of Production cycle #1	90% of Injection cycle #1
2.0	100% of Production cycle #2	10% of Injection cycle #1 + 80% of Injection cycle #2
3.0	100% of Production cycle #3	20% of Injection cycle #2 + 70% of Injection cycle #3

SRPM was developed to allow the withdrawal and injection cycles to take values greater than, less than, or equal to one year. Hence, SRPM can be run in full production mode or in storage (withdrawal + injection) mode depending upon the time steps designed.

E. Modification of the Reservoir Performance Module of GSAM

Some key assumptions and reservoir type specific modifications were also incorporated into the model to address differing input requirements and technology specific information. These changes were determined by calibrating and testing the model for different reservoir types.

Depleted Gas Reservoirs:

- the reservoir when filled was assumed to be at its initial conditions of pressure and gas saturation;
- 20% of the wells located in the reservoir were stimulated every year to maintain constant deliverability;
- an injection efficiency of 95% was used to account for leakage and injection losses;
- the variation of permeability among different pay grades was kept within ±25%;
- a tubing size of 5 inches was used for deliverability and injectivity calculations.

Aquifers (Water Drive Reservoirs):

- the aquifer underlying the storage reservoir was assumed to be five times larger than the storage reservoir volume;
- the reservoir when filled was assumed to be at its initial conditions for pressure and gas saturation;
- 20% of the wells located in the reservoir were stimulated every year to maintain constant deliverability;
- an injection efficiency of 95% was used to account for leakage and injection losses;
- the variation of permeability among different pay grades was kept within ± 25%;
- a tubing size of 5 inches was used for deliverability and injectivity calculations.

Salt Cavern Reservoirs:

- the salt cavern was modeled as a depleted gas reservoir with very high permeability and porosity;
- the cavern was assumed to be at its initial conditions;
- the cavern was reworked every alternate year;
- an injection efficiency of 95% was used to account for leakage and injection losses;
- a tubing size of 6.5 inches was used for deliverability and injectivity calculations.

F. New Technology Performance and Cost Relationships

1. Storage Cost Evaluation

The modification of the GSAM gas reservoir type curve modules provided estimates of withdrawal and injection volumes, number of wells in storage service, operating pressures, and other storage performance parameters. In addition, economic analysis subroutines were updated and modified to conform to storage investment decision criteria. These modules use input data on specific regional and national costs to generate discounted cash flow (DCF) assessments of specific projects. The costs are tied to selected performance characteristics and can be varied based on the technologies being employed.

Initial estimates of costs for drilling investments, completion costs, workovers, fixed and variable operating costs, and compression installation, maintenance, and operation were first developed. As explained earlier, the Storage Reservoir Performance Module uses a slightly modified approach from GSAM. The input costs for regional drilling and completion are the same. Operating costs can be varied regionally and are based on the depth, injection and withdrawal rates, and operating conditions. Compression requirements are determined based on the brake-horsepower requirements to meet pipeline pressure requirements during storage withdrawal and to sustain adequate injection during the summer.

Based on the estimates developed for specific investments and costs, expenditures over time were determined based on the development/conversion phasing of the project. Also, future annual investments and maintenance requirements were determined for specific periods of service. These annual costs were computed based on the estimated storage performance determined in the type curve routines. Based on the fully developed project timing, the DCF for the project was determined based on the revenues generated from gas sales and rents. These estimates were developed using detailed project cash flow analysis, with contemporary, specific state and federal tax rates and deductions.

The Storage Reservoir Performance Module also does a series of DCF calculations to determine the sensitivity of the potential storage projects to changes in economics. The evaluations consider the impact of changes in gas prices, drilling costs, other required investments, taxes, and other costs. This series of analytical results provide a range of economic outcomes that can be tailored to estimate results under varying future market conditions. This provides details needed in the GSAM Demand and Integrating Module for individual project decisions. The process of selecting projects based on their economic attractiveness is described below.

2. Technology Evaluations

Changes in a variety of development and operating practices can be modeled for storage projects. The Storage Reservoir Performance Module provides the capability to independently assess the impacts of performance enhancements and cost savings on the overall project economics for individual storage sites. This analysis can provide a wide variety of results for R&D analysis.

Direct storage performance improvements can be modeled by changing the completion design and gathering system pressure. Improvements in operating practices and workover designs can dramatically improve the near wellbore damage associated with storage operations. This is modeled by changes in the skin factor restricting or enhancing flow in the near wellbore region. Horizontal wells with varying lateral lengths can also be directly modeled for storage applications. Technology improvements in well design, using improved tubing and completion practices can also be modeled by changing the production tubing diameter and/or the well bore radius. This reflects the improved flow capacity from larger radius drilling and completion technology. In addition, the flowing tubing pressure is directly determined based on the roughness associated with various materials. The system pressure to which the well produces can also be altered to reflect expanded or improved compressor design.

Economic impacts of storage technology improvements can be modeled through the detailed variation of individual project costs. Investments, remediation costs, and standard operating expenditures can be impacted directly or indirectly by technology changes. The Storage Performance Module independently assesses the changes in costs associated with the application of new technologies. For example, horizontal drilling will improve storage injectivity and possibly reduce the number of wells required for many storage sites, however, individual horizontal wells will cost 40 to 100% more than conventional, vertical wells with standard completions. Improved monitoring of storage pressures could ultimately reduce operating costs and reduce losses. This type of technology improvement can also be directly assessed.

The greatest value of the newly designed system is the capability of evaluating multiple technology improvements consistently and simultaneously. This provides the ability to evaluate the relative value of various technology improvements and to assess the synergistic impact of application of two or more technologies in combination. For example, the development of storage with horizontal wells combined with the improved compressor efficiency to lower producing pressures and costs could have a larger impact than either application alone. Further, because reservoirs are uniquely described based on their storage project properties, analysis can focus on the resources with the greatest potential for future success. The evaluation of storage in a market dynamic model assures that R&D planning evaluations will provide meaningful, market-required information.

3. Technology Evaluation Suggestions

The initial evaluation of storage technology should reflect changes that could result from FETC and industry R&D. Based on evaluations using GSAM, technologies that reduce drilling costs, utilize horizontal wells, decrease wellbore damage (skin), and optimize compression should have the largest impact in the future, market-driven natural gas system. The analysis here will focus on these technologies.

Consistent with emerging technologies, horizontal wells will be used in candidate storage reservoirs where the thickness and overall size are sufficient to allow their drilling. With advances in technology, horizontal wells with lateral of 3000 feet should be possible at a cost of 20% more than vertical wells. In addition, improved drilling muds and bits will allow completions with less formation damage, reducing skin factors by 50%.

Compressor efficiency should improve allowing smaller more efficient compressors to move gas to and from storage. The reduction in required brake-horsepower will be evaluated on a reservoir specific basis. The average operating cost of storage will also decline over time with advances in metering and computer-aided production systems. This will reduce variable and fixed operating costs by up to 20%.

Combinations of drilling, completion, compression, and operating costs will be evaluated to determine their combined impacts. Further, the relative impacts of technology advances by industry, GRI, and FETC will be estimated. Based on the findings, key shortcomings of storage availability will be determined.

G. Modifications to Cost Routines

After the type curve analysis has been completed, SRPM calls for various programs to perform a detailed cash flow analysis. The purpose of this calculation is to evaluate production and operating costs under all reasonable economic conditions. The process of detailed cost and economic analysis as done in SRPM is as follows:

(1) **Unit Cost Calculations:** Compute stimulation cost, development drilling costs, facilities cost, fixed and variable O&M costs. All values are calculated on a unit cost basis ($/well, $/Mcf, etc).

(2) **Costing Algorithms:** Calculate total cost based on the number of wells available for gas storage and production rate. The costs calculated include total drilling cost, total stimulation cost, total compressor cost, total facilities cost, and total fixed and variable operating costs. The algorithm also evaluates the total levelized investment cost, fixed operating cost and variable operating cost for every unit of gas produced during a year cycle. The output serves as a input for GSAM's DRI module.

(3) **Final Cash Flow Algorithm:** This section computes the detailed pro-forma cash flow for each reservoir, including full cost accounting and tax calculations for further studies. Based on the results of this section, a discounted cash flow analysis is conducted to calculate the cost of service for a new storage field.

For existing storage reservoirs the costs of service for storage reservoirs is based on the tariff rates of the company that operates the reservoir. Various independent surveys and informal discussions with gas storage operators were conducted to determine the levelized, operating and fuel costs and were incorporated in SRPM.

Most of the modifications made to the GSAM economic module were incorporated in the above routines to reflect storage costs and other economic parameters. The costing algorithms were derived from various sources and are widely used in industry for designing new storage facilities.

H. *Working of SRPM*

SRPM includes reservoir data for both existing and undeveloped storage facilities. Since it has reservoir specific entries for each of its 388 existing and around 140 potential storage sites, it is capable of performing assessments of the technical and economic potential of numerous storage prospects rapidly. Effects of better fractures, horizontal wells, better drilling fluids, environmental regulations etc. can be characterized using SRPM since it operates on the reservoir level. Hence, this is an effective planning tool for the FETC in deciding its research and development needs for gas storage.

SRPM evaluates the existing and undeveloped storage reservoirs differently because of the availability of data.

1. Existing Storage Facilities

For existing storage sites the AGA database provides the working gas, base gas, and deliverability values. The AGA database, however, doesn't include the reservoir rock and fluid properties. SRPM performs history check calculations as shown in Exhibit X-1, and adjusts the skin factor and permeability values so that the calculated deliverability is close to the reported deliverability. This is required for technology modeling of existing reservoirs. In this way SRPM computes the permeability and skin factors for all 388 existing storage reservoirs having reported deliverability values from AGA. SRPM then performs economic calculations and performs an after-tax pro-forma cash flow analysis for every reservoir analyzed. The modified economic module of SRPM provides levelized investment costs, fixed and variable O&M and fuel usage values for GSAM's Demand and Integrating Module to incorporate into the linear program for storage applicability and expansion efforts in a full market context.

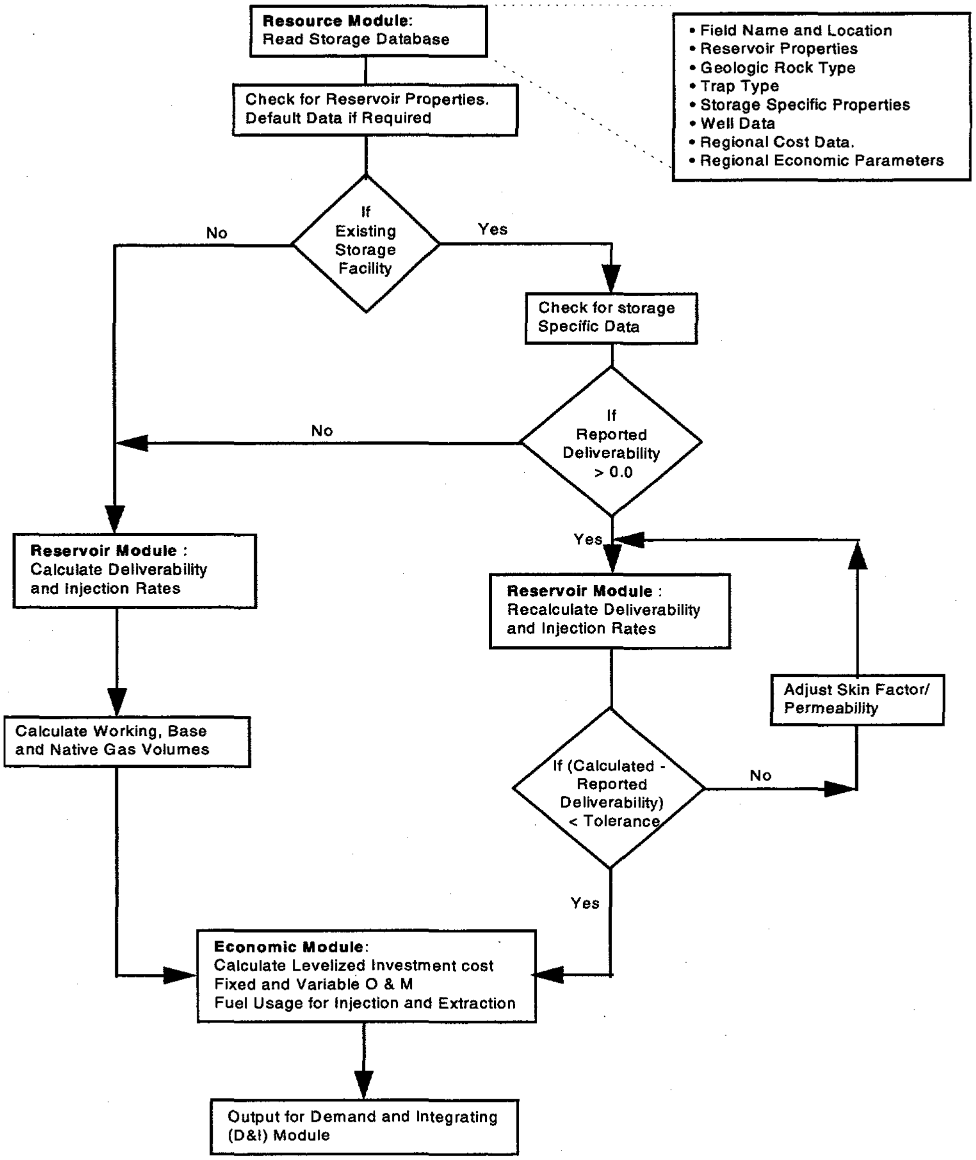
2. Potential New Storage Facilities

SRPM evaluates the undeveloped storage facilities in a different manner than from what was explained earlier. Here, all the reservoir properties are available from NRG, and USGS databases and hence no history check is performed. Based on the screening criteria developed, around 140 depleted gas reservoirs have been selected as potential storage candidates in this category.

For these reservoirs, values for base gas, working gas and deliverability have to be calculated. The type curve approach utilized in SRPM provides the capability of designing the storage facility based on the economics and particular storage needs.

Exhibit X-2 shows the model workings in calculating the deliverability. Since storage is designed for deliverability of the last MCF of working gas needed, it is essential to determine the maximum withdrawal rate that can be achieved at the end of the withdrawal cycle. In SRPM, gas is withdrawn from the reservoir at a defined proration and a design minimum flowing wellhead surface pressure for the full withdrawal cycle. In most cases, SRPM utilizes a design minimum flowing wellhead pressure of 100 psia and 100 days for withdrawal cycle. As shown in Exhibit X-2, at first the gas is withdrawn at a rate of R1 MCF/Day. During the withdrawal cycle of 100 days, the rate declines as indicated. At the end of 100 days, the withdrawal rate R1' is obtained which is considerably lower than R1. This reservoir can be designed for a deliverability of R1', however, it is capable of producing at a higher rate than R1' for its entire withdrawal cycle. Hence, a design deliverability of R1' for this particular reservoir would not be prudent. In case gas is withdrawn from the reservoir at R2 MCF/Day (R1>R2), the reservoir will sustain a constant rate of R2 for a longer time compared to R1 as shown, and would produce at a higher rate than R1' (R1'<R2') at the end of 100 days. SRPM, continues with this exercise until it obtains a constant withdrawal rate of R4 MCF/Day

Exhibit X-1
Flow Chart of SRPM Process

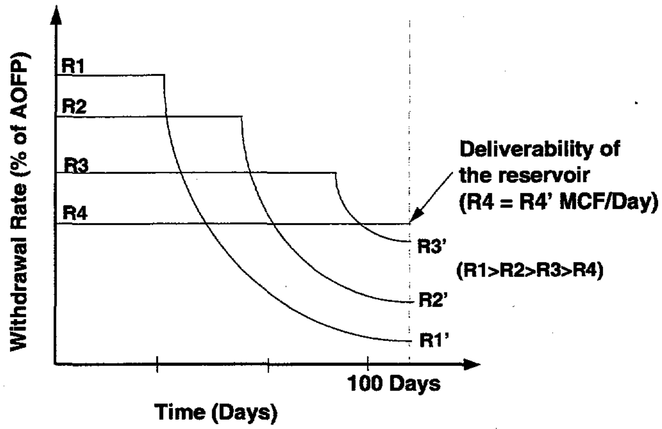


which doesn't make the rate decline during the entire 100 day period. SRPM, does an internal check to ensure that total gas withdrawal during the 100 day period doesn't exceed the working gas.

In calculating the base gas and working gas for the reservoir, SRPM is run in full production (withdrawal) mode, at the design minimum flowing wellhead pressure. This provides the total technically recoverable gas production from the reservoir under a defined set of technology conditions. Working gas volume is assumed to be 90% of this technically recoverable number. Finally, the difference between original gas in place (OGIP) and this working gas volume provides the base and native cushion gas volumes for the reservoir.

The type curve approach utilized in SRPM helps in designing the storage facility to meet specific deliverability needs. Exhibit X-3 indicates a potential application of SRPM for such designs. This figure

Exhibit X-2
Illustration Of SRPM Process In Calculating Deliverability



shows graphically how the wellhead pressure and the amount of working gas may be used to tailor a storage reservoir for a base load facility. This graph is for a reservoir that has a total OGIP of 22 BCF. Initial reservoir pressure is 1285 psia. Various minimum wellhead flowing pressures were assumed (1000, 800, 600, 400, 250 and 100 psia), and SRPM was run in full production (withdrawal) mode to create the working gas amount versus the deliverability, with flowing wellhead surface pressure as the changing parameter. Lines of constant time for emptying the reservoir at the rated deliverability are also drawn. For a base load storage facility design various choices are available. A base load unit with a working gas capacity of 2.7 BCF could be developed with a flowing wellhead surface pressure of 1000 psia and a rated deliverability of 27 MMCF/Day. This would require a certain amount of compressor horsepower and would require 100 days to empty at the rated deliverability.

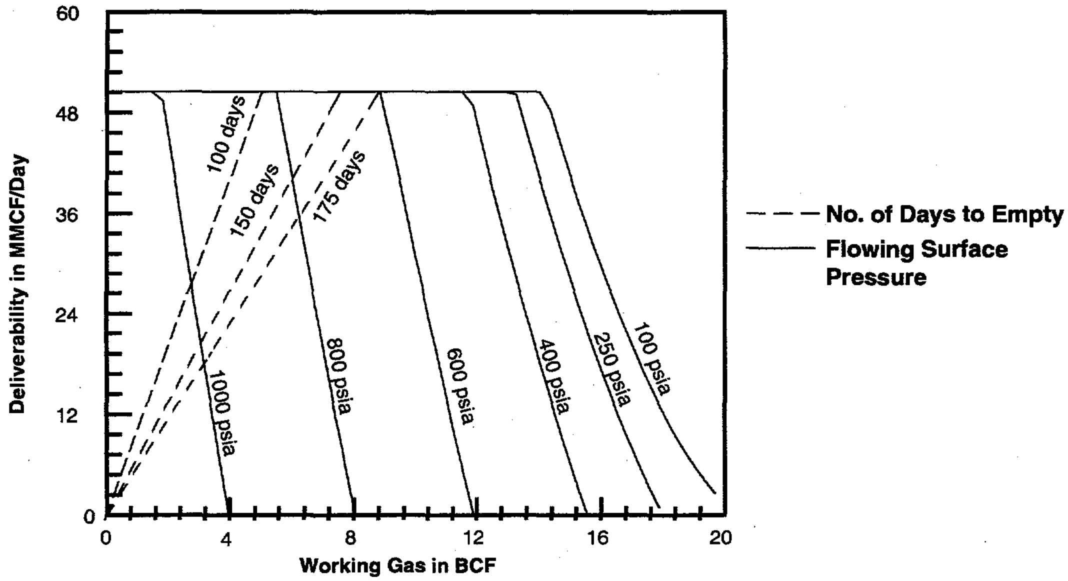
A second choice of working gas of 5 BCF with a flowing wellhead pressure of 800 psia would give a rated deliverability of 50 MMCF/Day and would require less compressor horsepower. The time to employ would still be 100 days.

If the storage reservoir were to be developed as a base load facility for 175 days, a similar set of choices are available. Using 175 days to empty as a guide, some alternatives are available. The facility could be developed having 8.75 BCF of working gas with a rated deliverability of 50 MMCF/Day. The flowing wellhead pressure would be 600 psia. Another choice would be a facility with 6.3 BCF of working gas, a rated deliverability of 36 MMCF/Day, and a flowing wellhead pressure of 800 psia.

This particular analysis indicates that for a 100 day withdrawal cycle, the rated deliverability of the reservoir cannot exceed 50 MMCF/Day for a minimum flowing wellhead pressure design of 800 psia or less. In other words, the design minimum flowing wellhead pressure can be anywhere between 100 psia and 800 psia for a maximum deliverability of 50 MMCF/Day for 100 day withdrawal. A maximum working gas of 5 BCF would be available from this reservoir in such cases.

The above example shows that considerable options are available in designing a storage facility by using various parameters to tailor a reservoir to a particular need. The choices are governed mostly by the economics and the particular storage needs.

Exhibit X-3
SRPM Storage Design



- **SRPM is Capable of Designing a Storage Facility Based on Particular Storage Needs and Economics.**

I. Modification of the Demand and Integrating Module

The Demand and Integrating Module (D&I), in conjunction with other GSAM modules, balances the supply and demand sides of the natural gas market to determine market equilibrium prices and quantities. This is accomplished in part, by solving an integrating linear program (LP) which is based on maximizing total surplus (i.e., consumer surplus + producer surplus). This LP determines flows of gas along the pipeline network , various levels of storage, supply and demand, such that each region is balanced.

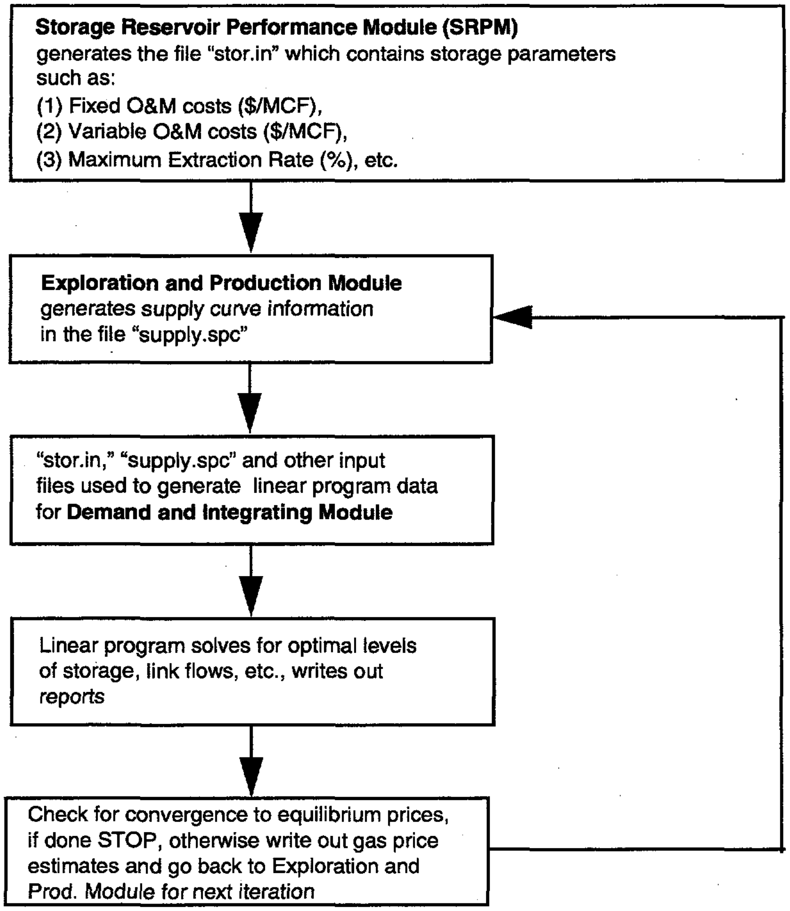
The modifications made to the D&I for the storage project included incorporation of a data base for approximately 525 existing and new storage reservoirs directly into the integrating LP. Previously, only aggregate figures for each region were used. This storage data base is created in the new Storage Reservoir Performance Model (SRPM) and includes data on: capacity of the reservoir, maximum extraction and injection rates, the first year that the site is available, the fuel usage %, as well as various relevant costs. A flowchart of the storage information is illustrated in Exhibit X-4.

Because data on actual (or potential) storage reservoirs is used, the LP is able to select which reservoirs should be active as well as the appropriate levels for storage extraction and injection. Previously, only summary figures for the region as a whole could be obtained. Thus, specific storage reservoir-level information is made available in the output reports from the linear program.

<u>How Storage Variables Are Used in the Demand and Integrating Model</u>

One of the main functions of the integrating linear program is to determine optimal levels of storage (and other factors) so that supply and demand are balanced at each node (region) in the gas network. In particular the choice of when to use storage versus for example adding more pipeline capacity, is handled in the material balance constraints.

Exhibit X-4
Flow Chart of Storage Information



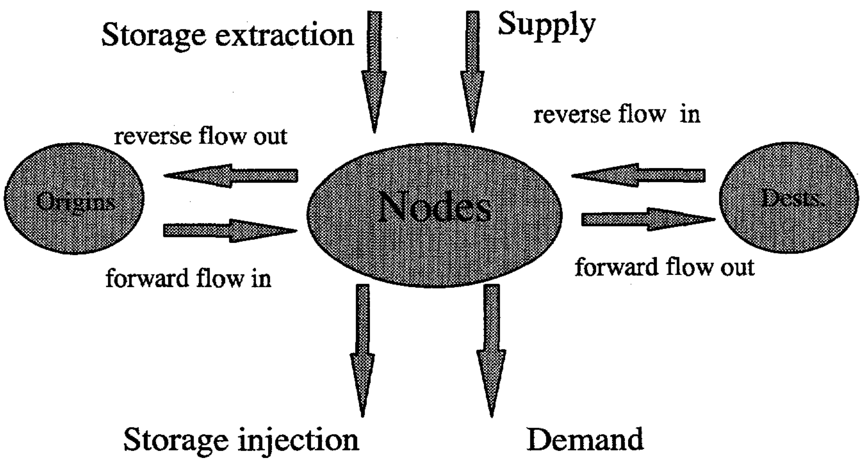
In these constraints, at a particular node, year, and season (winter or summer),
[the total net forward flow in + storage extraction] + [regular supply + peak supply + extra supply] =
[the total net reverse flow + storage injection + demand (residential, commercial, industrial, & electric utility)]

Note that not every node has all of this supply and demand values so that the description above is the most general possible. The material balance constraints are depicted in Exhibit X-5.

Storage extraction and injection are selected over other options if the relative costs are less for storage than for these other alternatives. The costs (in $/MCF) for storage activity are the levelized investment and the fixed O&M, and the variable O&M. The first two costs are relevant for activating/not activating the reservoir, the variable O&M determines the actual level of storage activity that is desired. In addition to the material balance constraints, storage activity is constrained by extraction and injection capacities, the maximum capacity of the reservoir, and the loss of gas used for compression.

The main benefits of incorporating the new storage reservoir data base is that changes at the individual reservoir-level can now be analyzed, whereas before they could only be approximated at the regional level. This of course allows the user much more flexibility in analyzing storage cost/deliverability tradeoffs and the potential impacts of technology changes.

Exhibit X-5
Material Balance at Nodes



XI. Model Testing and Analysis of Storage Demand

Upon completion of the gas storage module and its integration with the rest of GSAM, the module was used to test the demand for gas storage facilities under various scenarios. The scenarios were designed to assess how this demand might change under different economic and technological conditions. This chapter describes the results of these tests.

A. Test Case Scenarios

Four model run cases were tested to determine the effects on storage demand that result from changes in economic and technology scenarios. A Base Case, using essentially the *status quo* for supply, demand, and price parameters, provides the benchmark against which the other three cases are compared. Four of the Base Case assumptions are common to all four of the scenarios. They are: 1) gas continues to be exported from the U.S. to Mexico, 2) gas from Sable Island, Nova Scotia begins flowing into New England by 1995, 3) the Northern Border Pipeline capacity expansion of 700 million cubic feet per day is in service between 2000 and 2005, and 4) there are no major changes in environmental regulations through the forecast period to 2010.

There are two scenarios that deal with economic changes from the Base Case. They are a Low Demand Case and a High Demand Case. The Low Demand Case differs from the Base Case only in the effects of gas and coal competition for fueling electric power generation. The Low Demand Case assumes that coal wins in competition with gas for this major growth market. Coal wins through lower coal prices relative to gas prices and by more rapid development of higher efficiency coal-fired generation technology. Since power generation is expected to be the major growth market for gas, any significant loss in market share to coal will reduce the future demand for gas.

The High Demand Case differs from the Base Case in that it assumes that gas wins in the competition with coal for power generation markets. Gas wins because it is assumed to be less expensive than coal and because gas-fired generation technology retains its efficiency lead over coal-fired technology.

The fourth scenario tested, the Technology Case, assumes that E&P technology advances aggressively for both producing reservoirs and storage reservoirs, reducing the cost of finding, producing, and storing gas, primarily through improved well completion designs and practices. Changes from the Base Case include the use of both advanced well stimulation techniques and horizontal wells in reservoirs where these completions are appropriate. However, under this scenario, coal and gas remain highly competitive with each other to serve a growing electric power generation market.

Descriptions of these four scenarios are summarized in the following table.

Scenario Summary

Base Case	Low Demand Case	High Demand Case	Technology Case
Current electric market for gas	Coal wins electric market	Gas wins electric market	Current electric market for gas
Evolutionary E&P technology	Evolutionary E&P technology	Evolutionary E&P technology	Aggressive E&P technology for producing & storage reservoirs
Current environmental rules	Current environmental rules	Current environmental rules	Current environmental rules
Expand Northern Border	Expand Northern Border	Expand Northern Border	Expand Northern Border
Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline
Export gas to Mexico	Export gas to Mexico	Export gas to Mexico	Export gas to Mexico

All of the cases assume that only 50 percent of the working gas capacity for each active gas storage reservoir is utilized in a year. This assumption was made for several reasons. First, it is unreasonable to assume that all working gas is withdrawn from each active storage reservoir every year, because of the difference in severity of winter weather. Although the future average annual capacity utilization of gas storage reservoirs is unknown, an initial assumption of 70 percent utilization resulted in essentially no new storage capacity being developed. Even at the 50 percent level for storage capacity utilization, many existing storage reservoirs are not chosen for operation by the storage module. The operation of the integrating linear program for finding optimal solutions to balancing supply and demand and the seasonal construction of GSAM both contribute to the low level of storage demand found in the four cases investigated. These modeling issues are described below.

The GSAM supply/demand integrating model optimizes the use of gas storage in balancing gas supplies and demand. It finds the least costly storage reservoir in a demand region and selects it for use, if its use results in lower gas costs than using additional gas pipeline capacity. The module uses all of the capacity available in that reservoir before looking for the next more expensive storage reservoir and comparing its costs to those of pipeline capacity. If allowed to use 100 percent of each storage reservoir's working capacity, far fewer existing storage reservoirs would be selected for operation each year. The storage optimization process looks at current economics for using either storage or more pipeline capacity and develops an efficient solution based on the fixed and variable costs of deliverability. Through this process the storage module has indicated that many existing storage reservoirs are uneconomic. This is reasonable to some extent, because there are probably numerous existing storage reservoirs that would not be developed today in competition with new storage or other supply alternatives.

The fact that GSAM is structured to recognize two seasons in a year is a major improvement over many energy models in widespread use today. Two seasons, for example, allows for gas storage injection and withdrawal periods, and provides a basis for comparing the economics of using gas pipeline capacity vs. storage capacity. However, a winter season of 151 days adds bias against storage demand. Because the model assumes an average winter demand over 151 days rather than a shorter peak demand period and that any new pipeline capacity will be used for 151 days, pipeline capacity can be justified unrealistically. Substantially more storage capacity would be justified if it were to be compared with the costs of providing pipeline capacity for a few peak demand days each winter. Until GSAM is modified to handle a shorter winter period, the benefits of gas storage will not be fully recognized.

Despite these weaknesses in the GSAM analysis of demand levels for storage capacity, many valuable results have been developed through use of the storage module. The more efficient storage reservoirs in each region have been identified. Large differences in regional storage needs and excess storage capacities have been found. Major differences in the cost of using storage have been discovered. And lastly, the regional effects on storage demand from changing economic conditions and improvements in E&P technologies have been computed. These results are discussed in the following section.

B. Data Issues

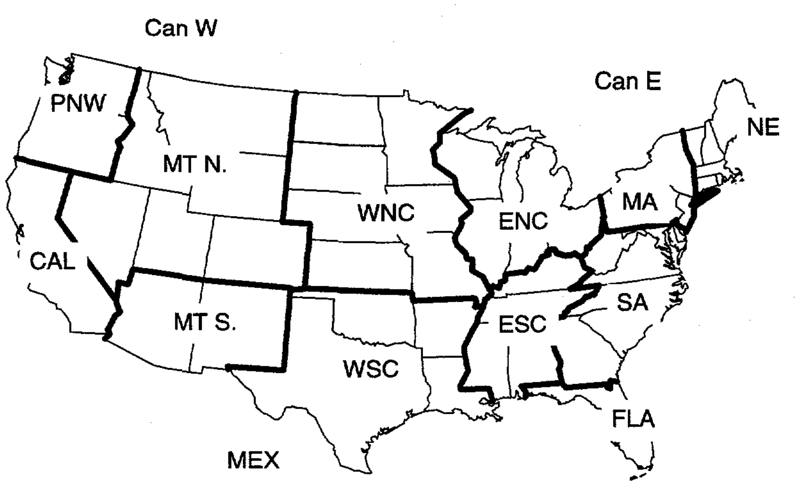
Several problems exist in the data available for both the existing storage reservoirs and the depleted reservoirs that are available for development as gas storage facilities. The most comprehensive data available for existing storage reservoirs is the American Gas Association (AGA) 1993 Report, *Survey of Underground Gas Storage Facilities in the United States and Canada.* This source does not provide any porosity or permeability values and many reporting companies have not provided data for all of the facility parameters listed. These missing data prevented precise physical characterizations of the reservoirs involved. These problems were overcome by estimating the missing properties based on the properties that are provided, from conversations with storage operators, the knowledge ICF Resources has regarding reservoirs in similar plays, and use of the U.S. Geological Survey play data.

The major problem for potential storage reservoirs is the lack of a data base for depleted reservoirs in the Appalachian region. Because this region is so highly dependent on gas storage, this omission had to be overcome. The solution was to generate representative data for a set of potential storage reservoirs using play characterizations based on data for existing storage reservoirs in the region and U.S. Geological Survey play data for the reservoirs that may be future candidates for storage facilities. A second problem with the depleted reservoir data was that some very large multi-reservoir fields are reported by NRG Associates, Inc. as single reservoirs, thereby overstating all of the capacity data. This problem was handled by deletion from the data base used in the study all of the "reservoirs" that were judged to be so large that re-pressuring costs would be prohibitive.

C. Study Results

Although the results of the four test scenarios are not considered to be precise regarding the demand for storage, for the reasons described above, they do support the conventional wisdom that storage capacity is in surplus in some parts of the U.S. The following paragraphs summarize the study findings for storage demand, storage costs, gas supply and demand, gas prices, and pipeline capacity additions. The demand regions used are illustrated in Exhibit XI-1.

Exhibit XI-1
GSAM Demand Regions



D. *Storage Demand*

The total regional gas storage demand (including both existing storage facilities and reservoirs selected for development of new storage facilities) selected by the GSAM demand and integrating module for the four scenarios analyzed are summarized in Exhibit XI-2. These storage demand volumes represent annual gas extractions from storage.

Exhibit XI-2
Extraction Rates for Storage Gas, Bcf

	Base Case			Low Demand Case		
Region	2,000	2005	2010	2,000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	350	308	260	357	329	270
West South Central	208	169	137	241	202	170
West North Central	58	47	36	58	47	36
Mountain South	2	1	1	16	15	15
Mountain North	39	11	34	41	39	45
California	62	56	48	73	68	58
U.S.	1,077	905	765	1,144	1,013	843

	High Demand Case			Technology Case		
Region	2,000	2005	2010	2,000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	359	313	261	372	341	280
West South Central	227	189	156	227	188	148
West North Central	59	47	36	58	47	36
Mountain South	2	1	1	57	56	51
Mountain North	26	7	21	35	33	31
California	67	61	52	78	72	59
U.S.	1,098	931	776	1,185	1,050	854

In all four scenarios, the demand for gas storage declines over the forecast period. There are two reasons for this decline. First, there is the model assumption that storage reservoir deliverability declines by five percent each year. For those reservoirs that have lower deliverabilities, this deliverability decline sometimes means that the working gas available for withdrawal cannot all be extracted in the 151-day winter period. Thus, depending on their maximum gas extraction rates, the volume that can be withdrawn from individual reservoirs tends to decline unevenly during the 1995 to 2010 forecast period. The demand for new storage facility development is inadequate to make up for these annual losses in withdrawal capacity. As explained earlier, the demand for new storage would likely be much larger if the GSAM winter season were structured to deal with peak demands rather than just a winter season demand.

The second reason for the declines in storage use is that most of the gas demand increases forecast are for electric power generation, rather than for temperature sensitive residential and commercial loads. With these seasonal loads making up a smaller part of total gas demand, the economic need for storage is reduced. The following table shows how the share of total gas demand used for electric generation grows in the four cases tested.

Shares of Gas Demand Used for Power Generation

CASES	2000	2005	2010
Base	20.0%	24.9%	26.6%
Low Demand	19.8%	20.4%	18.3%
High Demand	20.2%	26.3%	29.6%
Technology	21.3%	26.9%	28.3%

Although the 2010 U.S. demand for new storage in the Low Demand Case exceeds that for the Base Case, there is a rationale for this counter intuitive result. When comparing the Low Demand and Base Cases, most of the loss in gas demand that the Low Demand Case sees is for fueling less electric power generation. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. On the other hand, in the Low Demand Case, coal fuels a larger share of power generation and the loss of this gas load causes gas demand to become more seasonal. Lower summer use of gas pipelines means that more gas storage can be economically justified.

E. New Storage Facilities Added

The number of new gas storage facilities selected by the demand and integration module for use between 2000 and 2010 varies from four for the Base Case to 11 for the Technology Case. All of the new storage facilities are forecast to start up in the year 2000. The regions where these new facilities are forecast to be added are summarized in the following table.

Summary Of New Storage Facilities

Region	Base Case	Low Demand Case	High Demand Case	Technology Case
East North Central	1	1	1	2
West South Central	1	3	3	2
Mountain South	0	2	0	5
California	2	2	2	2
Totals	4	8	6	11

The demand and integrating module selects new reservoirs in only four regions for the four scenarios tested. Thus, of the 12 U.S. demand regions in GSAM, eight require no new storage capacity under any of the scenarios analyzed. The only region that has new storage capacity added in all four cases analyzed is California. The Technology and Low Demand Cases require the most new storage facilities at 11 and 8 reservoirs, respectively. The demand for new storage capacity is lower in the High Demand Case than for the Low Demand Case for reasons described below.

Although the demand for new storage in the Low Demand Case exceeds that for the High Demand Case, there is a rationale for this counter intuitive result, similar to the reasons provided in the prior discussion of total storage capacity demand. When comparing the Low and High Demand Cases, all of the increase in gas demand that the High Demand Case sees is for fueling more electric power generation. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. On the other hand, in the Low Demand Case, coal fuels a larger share of power generation and the loss of this gas load causes gas demand to become more seasonal. Lower summer use of gas pipelines means that more new gas storage can be economically justified.

The differences in U.S. gas demand for power generation fuel and total demand for gas are summarized in the following two tables.

Summary Of U.S. Gas Demand for Power Generation, Bcf

Year	Base Case	Low Demand Case	High Demand Case	Technology Case
1995	3,322	3,268	3,354	3,424
2000	4,450	4,471	4,554	4,899
2005	5,924	4,859	6,387	6,936
2010	6,330	4,360	7,259	6,995

Summary of Total U.S. Gas Demand, Bcf

Year	Base Case	Low Demand Case	High Demand Case	Technology Case
1995	20,108	20,028	20,152	20,304
2000	22,188	22,294	22,465	22,951
2005	24,216	23,327	24,511	25,890
2010	24,815	23,016	25,326	25,600

These tables show that in the year 2010, for example, gas demand to fuel power plants is 3,862 Bcf higher in the High Demand Case than in the Low Demand Case. In this same year total gas demand is only 3,265 Bcf higher in the High Demand Case, indicating that the other consuming sectors (residential, commercial, and industrial) had reduced demands for gas in this case. Higher gas prices in the High Demand Case are largely the cause for this loss of demand in these three sectors. Gas price projections are discussed in a later section.

F. *Use of Existing Gas Storage Facilities*

Across the four cases studied, the projected utilization of existing working gas capacity in the ten regions that have underground storage facilities varies from zero to 100 percent. As an example, neither of the two storage facilities in the Pacific Northwest region are selected for use. In the Base, High Demand and Technology Cases, gas demand growth in the Pacific Northwest is projected to be handled by additional pipeline capacity from the Rockies Foreland supply area. In the Low Demand Case, neither storage or new pipeline capacity are required for the Pacific Northwest. At the other extreme, the only storage reservoir in the Mountain South states of New Mexico and Arizona is always used. Similarly, in the Middle Atlantic and South Atlantic regions, storage capacity utilization varies from 97 to 100 percent in the four cases studied. In the other six regions storage capacity utilization ranges from 12 to 91 percent. The following table summarizes these storage utilization percentages for the ten storage regions.

Summary of Capacity Utilization Rates for Existing Gas Storage

Region	Base Case	Low Demand Case	High Demand Case	Technology Case
Mid Atlantic	100 %	100 %	100 %	100 %
South Atlantic	97 %	97 %	97 %	97 %
East So. Central	91 %	91 %	91 %	91 %
East No. Central	60 %	63 %	61 %	63 %
West So. Central	83 %	94 %	83 %	83 %
West No. Central	49 %	49 %	49 %	49 %
Mountain South	100 %	100 %	100 %	100 %
Mountain North	74 %	74 %	74 %	74 %
Pacific NW	0 %	0 %	0 %	0 %
California	90 %	90 %	90 %	90 %
U.S.	74 %	77 %	75 %	75 %

Although we cannot be sure that these capacity utilization values show the true economic use of existing gas storage facilities, they do indicate the variation in storage needs among the regions. These values tend to support the general belief that storage is over built in the East North Central, West North Central, and Mountain North regions. The fact that the East North Central region is shown to need only about 60 percent of its storage capacity and yet adds one or two new facilities in each case occurs because many of the existing reservoirs have low deliverability rates per unit of their cost of service. Because of this poor economic efficiency, many of the East North Central region storage facilities are not chosen for use in any of the cases studied. The new storage reservoirs chosen for the East North Central have substantially higher gas deliverability rates per unit of cost than the existing facilities that are not selected.

In addition to the eight new storage facilities developed in the Low Demand Case, as described earlier, the projected need for more storage capacity caused an additional ten existing storage reservoirs to be used that were not used in the Base Case. A different trend occurs in the High Demand and Technology Cases, the storage module selects several additional existing gas storage reservoirs for use and shuts down some existing storage facilities in the East North Central region that were used in the Base Case. This change in selection of which existing storage reservoirs to use in the High Demand and Technology Cases is caused by the more costly deliverability of many East North Central storage facilities. The following table shows the regions in which these changes in the use of existing storage facilities occur.

Summary Of Changes In Existing Storage Facility Use Compared To The Base Case

Region	Low Demand Case	High Demand Case	Technology Case
Middle Atlantic	1 Facility Added	No change	No change
East South Central	No change	No change	No change
East North Central	5 Facilities Added	1 Facility Added & 3 Facilities Dropped	1 Facility Added & 1 Facility Dropped
West South Central	3 Facilities Added	No change	1 Facility Added
Mountain North	1 Facility Added	No change	1 Facility Added

G. *Gas Pipeline Capacity Additions*

In the process of optimizing gas supply to meet growing demand, the demand and integrating module found that the efficient approach to increased gas deliveries was a mixture of adding gas storage capacity and more gas pipeline capacity. The following table shows where pipeline expansions occur, when the expansions began, and how much pipeline capacity was demanded by the year 2010, for the four cases analyzed. By far the larger expansions were needed from the Gulf of Mexico West to the Texas Gulf Coast and from the Mid-Continent to the Mountain North region, for all four scenarios. Also there was a major expansion on TransCanada Pipelines from Alberta to Canada East for the High Demand Case.

Gas Pipeline Capacity Additions, MMcfd

	Base Case Capacities			Low Demand Case Capacities			High Demand Case Capacities			Technology Case Capacities		
Location	**Initial**	**Expan.Yr.**	**Final**	**Initial**	**Expan.Yr.**	**Final**	**Initial**	**Expan.Yr.**	**Final**	**Initial**	**Expan.Yr.**	**Final**
Alberta to Canada East	4,053	2005	6,982	4,053	2010	4,223	4,053	2000	7,204	4,053	2000	5,596
South La. to Florida	1,957	None	1,957	1,957	None	1,957	1,957	None	1,957	1,957	2000	2,492
Gulf of Mex.W to Tex.Gulf Cst	2,662	2000	6,606	2,662	2000	7,011	2,662	2000	6,903	2,662	2000	6,899
Mountain N. to Mid Cont.	385	2005	8,580	385	2005	7,458	385	2005	8,832	385	2005	9,437
Mountain N. to San Juan	150	2000	2,235	150	2000	1,802	150	2000	2,387	150	1995	4,551
Sable Is.to New England	0	2005	400	0	2005	400	0	2005	400	0	2005	400
Rockies to Pacific Northwest	254	2005	415	254	None	254	254	2005	810	254	2005	456
San Juan to Permian	987	None	987	987	2010	1,305	987	None	987	987	2010	4,071
Alberta to West N Central	1,568	2005	2,268	1,568	2000	2,268	1,568	2000	2,268	1,568	2000	2,268
Rockies to West N Central	547	2000	1,147	547	2000	1,147	547	2000	1,147	547	2005	1,147

H. *Storage Prices*

Tariff rates for gas storage service are typically comprised of two monthly fixed charges, one for storage capacity and the other for withdrawal deliverability. Variable volumetric rates are charged for the amounts of gas injected and withdrawn and sometimes a separate fuel charge based on storage use. Typical variable rates would be one or two cents per Mcf injected and another one or two cents for volumes withdrawn. The fixed charges are many times the size of the variable costs, bringing the tariff rates of storage up to a range of from $0.30 to $1.40 per Mcf, depending on the age of the facility. Older facilities are typically much less expensive than newer ones. A major cause of this difference is the cost of the capitalized base gas in the reservoir. Today's base gas value can be ten times that of 25 years ago.

The ranges of storage rates for the facilities used in each region are summarized in the following table. Rates for the facilities not chosen by the storage module were in some cases substantially higher than the rates shown here.

Price Ranges For Gas Storage Facilities Used, $/Mcf

Region	Base Case	Low Demand Case	High Demand Case	Technology Case
Middle Atlantic	$0.17 to $0.92	$0.17 to $0.92	$0.17 to $0.93	$0.16 to $0.92
South Atlantic	$0.26 to $0.62	$0.25 to $0.62	$0.26 to $0.63	$0.28 to $0.62
Florida	None used	None used	None used	None used
East South Central	$0.16 to $1.13	$0.16 to $1.13	$0.16 to $1.13	$0.16 to $1.13
East North Central	$0.15 to $1.63	$0.15 to $1.63	$0.21 to $1.38	$0.15 to $1.38
West South Central	$0.11 to $0.90	$0.11 to $1.10	$0.11 to $0.91	$0.11 to $0.90
West North Central	$0.30 to $0.97	$0.30 to $0.97	$0.30 to $0.97	$0.30 to $0.97
Mountain South	$0.22	$0.22	$0.22	$0.22
Mountain North	$0.17 to $0.78	$0.17 to $0.78	$0.17 to $0.78	$0.17 to $0.78
California	$0.29 to $1.04	$0.29 to $1.03	$0.29 to $1.04	$0.29 to $1.04
Pacific Northwest	None used	None used	None used	None used

These gas storage prices were developed in two ways. Prices for existing gas storage facilities were based on cost of service tariff rates filed by the owners or operators. Prices for new storage facilities were calculated, based on reservoir properties, the investments required to develop them, and estimated operating and maintenance costs. The procedure for calculating storage costs for the individual reservoirs in existing storage facilities and new facilities is described in Chapter IV.

I. Gas Supply

The GSAM net U.S. gas supply forecasts that support the storage demand results of this study vary from a low of 19,278 Bcf in the Low Demand Case for the year 1995 to a high of 25,708 Bcf for the year 2010 in the High Demand Case. These supply figures include U.S. gas production and peak shaving volumes, but exclude imports. The following table summarizes total supplies for each of the four scenarios.

Summary of Total U.S. Gas Supply, Bcf

Year	Base Case	Low Demand Case	High Demand Case	Technology Case
1995	19,309	19,278	19,397	19,637
2000	21,976	22,060	22,253	22,559
2005	24,054	23,202	24,300	26,232
2010	24,222	22,547	24,728	25,708

Between 1995 and 2010 gas imports from Canada continue to grow as they have in recent years. By 2010 Canadian gas supply to the U.S. in the Base Case grows by another 15 percent, reaching 3,245 Bcf. In the Low Demand Case the 2010 total is 2,948 Bcf, an increase from 1995 of less than five percent. Even less Canadian gas is needed to meet U.S. demand by 2010 in the Technology Case, as U.S. supply costs are lowered and domestic supply increases. In the Technology Case, the growth in Canadian gas imports from 1995 is only a little over one percent, reaching 2,827 Bcf in 2010. A summary of Canadian gas imports for the four scenarios is provided in the following table.

Summary Of Canadian Gas Imports, Bcf

Year	Base Case	Low Demand Case	High Demand Case	Technology Case
1995	2,829	2,816	2,817	2,790
2000	2,522	2,593	2,600	2,768
2005	2,804	2,551	2,772	2,598
2015	3,245	2,948	3,296	2,827

J. Gas Prices

Improving E&P technology and an accessible resource base provide the foregoing supply volumes at relatively small price increases until the year 2010, when average U.S. prices for the preceding five years climb by 32 to 72 percent, among the four scenarios tested. The lowest average U.S. price projections are for the Technology Case, reaching only $2.00 per Mcf by the year 2010. The highest 2010 price is found in the High Demand Case at $2.35 per Mcf. Exhibit XI-3 summarizes gas supply prices for the total U.S. and several supply areas for the four scenarios analyzed

Exhibit XI-3
Summary Of Gas Supply Prices, 1995$/Mcf

Location	Year	Base Case	Low Demand Case	High Demand Case	Technology Case
U.S. Average	1995	1.23	1.20	1.38	1.32
	2000	1.38	1.40	1.27	1.21
	2005	1.64	1.34	1.74	1.16
	2010	2.17	2.03	2.35	2.00
Rockies	1995	1.04	1.07	0.99	0.95
	2000	1.01	0.98	0.88	0.87
	2005	1.19	0.92	1.27	0.74
	2010	1.69	1.56	1.85	1.52
Alberta	1995	0.90	0.91	1.05	0.89
	2000	1.18	1.21	1.09	0.67
	2005	1.25	1.22	1.36	0.97
	2010	1.69	1.63	1.87	1.69
Gulf of Mex. West	1995	0.94	0.95	1.37	1.30
	2000	1.25	1.28	1.15	1.06
	2005	1.49	1.18	1.68	1.11
	2010	2.32	2.16	2.39	2.06
Appalachia	1995	1.63	1.65	1.62	1.55
	2000	1.67	1.70	1.57	1.46
	2005	2.02	1.71	2.12	1.52
	2010	2.63	2.45	2.85	2.54

By the year 2010, the highest gas prices among all of the regions shown occur in the High Demand Case and the lowest prices are in the Technology and Low Demand Cases. Consistent with history, the highest price seen in 2010 is in the Appalachian region at $2.85 per Mcf in the High Demand Case. The lowest price in the year 2010 among all regions occurs in the Williston Basin at $1.48 per Mcf in the Technology Case.

Examples of consumer prices in several demand regions that these gas supply prices translate to after adding delivery charges are summarized in Exhibit XI-4. The range of consumer prices is illustrated by the electric power generation and residential sectors. The five demand regions shown are the largest in the U.S.

Exhibit XI-4
Examples of Regional Gas Prices for Electric and Residential Sectors, 1995$/Mcf

Region	Sector	Year	Base Case	Low Demand Case	High Demand Case	Technology Case
Mid Atlantic	Electric	1995	1.58	1.62	1.57	1.55
		2010	2.44	2.19	2.96	2.54
	Residential	1995	6.96	6.97	6.94	6.83
		2010	8.10	7.96	8.25	7.92
S. Atlantic	Electric	1995	1.56	1.59	1.55	1.55
		2010	2.74	2.42	2.66	2.73
	Residential	1995	6.47	6.48	6.45	6.34
		2010	7.68	7.54	7.82	7.48
E.N.Central	Electric	1995	1.50	1.54	1.48	1.47
		2010	2.31	2.08	2.86	2.31
	Residential	1995	4.99	5.00	4.98	4.87
		2010	6.07	5.98	6.23	5.89
W.S.Central	Electric	1995	1.36	1.40	1.35	1.33
		2010	2.21	1.93	2.54	2.18
	Residential	1995	5.14	5.15	5.12	5.02
		2010	6.17	6.07	6.34	6.00
California	Electric	1995	1.70	1.73	1.63	1.61
		2010	2.33	2.00	2.65	2.24
	Residential	1995	5.98	5.99	5.92	5.85
		2010	6.60	6.41	6.82	6.47

As should be expected, gas prices for power generation are lowest in the West South Central region where gas is plentiful and alternative fuel prices are relatively low. By contrast, residential gas prices for the regions shown here are highest in the Middle Atlantic states where gas transmission distances are greater and alternate fuel prices are relatively high. The higher gas prices for electric generation appear in the South Atlantic region. Residential prices are lowest in the East North Central region for all scenarios.

XII. EFFECTS OF TECHNOLOGY ON DEMAND FOR GAS STORAGE

Two comparisons of test cases have been made to observe the effects of improved technology on the demand for natural gas storage. These two scenarios were designed to: 1) analyze the effects of improved technology for both E&P and storage reservoirs compared to a Base Case and 2) analyze the effects of improved technology on a High Demand Case for both E&P and storage reservoirs compared to a High Demand Case without improved technology. This chapter describes the results of these tests.

A. Test Case Scenarios

Four model run cases were tested to determine the effects on storage demand that result from changes in technology scenarios. A Base Case, using essentially the status quo for supply, demand, and price parameters, provides a scenario against which the Technology Case is tested. The Technology Case, assumes that E&P technology advances aggressively for both E&P and storage reservoirs. This reduces the cost of finding and producing gas, primarily through improved well completion designs and practices. Changes from the Base Case include the use of both advanced well stimulation techniques and horizontal wells in reservoirs where these completions are appropriate. The Base Case assumes that technology advancements are evolutionary for E&P and storage reservoirs.

The High Demand Case differs from the Base Case in assuming that gas wins in the competition with coal for power generation markets. Gas wins because it is assumed to be less expensive than coal and because gas-fired generation technology retains its efficiency lead over coal-fired technology. The High Demand Case assumes that technology advancements are evolutionary for E&P and storage reservoirs. The High Demand/Technology Case differs from the High Demand Case in that it assumes that E&P technology advances aggressively for both E&P and storage reservoirs.

Scenario Summary

Base Case	**Technology Case**	**High Demand Case**	**High Demand/Tech Case**
Current electric mkt. for gas	Current electric mkt. for gas	Gas wins electric market	Gas wins electric market
Evolutionary E&P technology	Aggressive E&P technology	Evolutionary E&P technology	Aggressive E&P technology
Current environmental rules	Current environmental rules	Current environmental rules	Current environmental rules
Expand No.Border pipeline	Expand No.Border pipeline	Expand No.Border pipeline	Expand No.Border pipeline
Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline
Export gas to Mexico	Export gas to Mexico	Export gas to Mexico	Export gas to Mexico

All of the cases assume that only 50 percent of the working gas capacity for each active gas storage reservoir is utilized in a year. This assumption was made for several reasons. First, it is unreasonable to assume that all working gas is withdrawn from each active storage reservoir every year, because of the difference in severity of winter weather. Although the future average annual capacity utilization of gas storage reservoirs is unknown, an initial assumption of 70 percent utilization resulted in essentially no new storage capacity being developed. Even at the 50 percent level for storage capacity utilization, many existing storage reservoirs are not chosen for operation by the storage module. The operation of the integrating linear program of GSAM for finding optimal solutions to balancing supply and demand and the seasonal construction of GSAM both contribute to the low level of storage demand found in the four cases investigated. These modeling issues are described below.

The GSAM supply/demand integrating model optimizes the use of gas storage in balancing gas supplies and demand. In effect it finds the least costly storage reservoir in a demand region and selects it for use, if its use results in lower gas costs than using additional gas pipeline capacity. The module uses all of the capacity available in that reservoir before looking for the next more expensive storage reservoir and comparing its costs to those of pipeline capacity. If allowed to use 100 percent of each storage reservoir's working capacity, far fewer existing storage reservoirs would be selected for operation each year. The storage optimization process looks at current economics for using either storage or more pipeline capacity and develops an efficient solution based on the fixed and variable costs of deliverability. Through this process the storage module has indicated that many existing storage reservoirs are uneconomic. This is reasonable to some extent, because there are probably numerous existing storage reservoirs that would not be developed today in competition with new storage or other supply alternatives.

The fact that GSAM is structured to recognize two seasons in a year is a major improvement over many energy models in widespread use today. Two seasons, for example, allows for gas storage injection and withdrawal periods, and provides a basis for comparing the economics of using gas pipeline capacity vs. storage capacity. However, a winter season of 151 days adds bias against storage demand. Because the model assumes an average winter demand over 151 days rather than a shorter peak demand period and that any new pipeline capacity will be used for 151 days, pipeline capacity can be justified unrealistically. Substantially more storage capacity would be justified if it were to be compared with the costs of providing pipeline capacity for a few peak demand days each winter. Until GSAM is modified to handle a shorter winter period, the benefits of gas storage will not be fully recognized.

Despite these weaknesses in the GSAM analysis of demand levels for storage capacity, many valuable results have been developed through use of the storage module. The more efficient storage reservoirs in each region have been identified. Large differences in regional storage needs and excess storage capacities have been found. Major differences in the cost of using storage have been discovered. And lastly, the regional effects on storage demand from changing economic conditions and improvements in E&P technologies have been computed. These results are discussed in the following section.

B. Data Issues

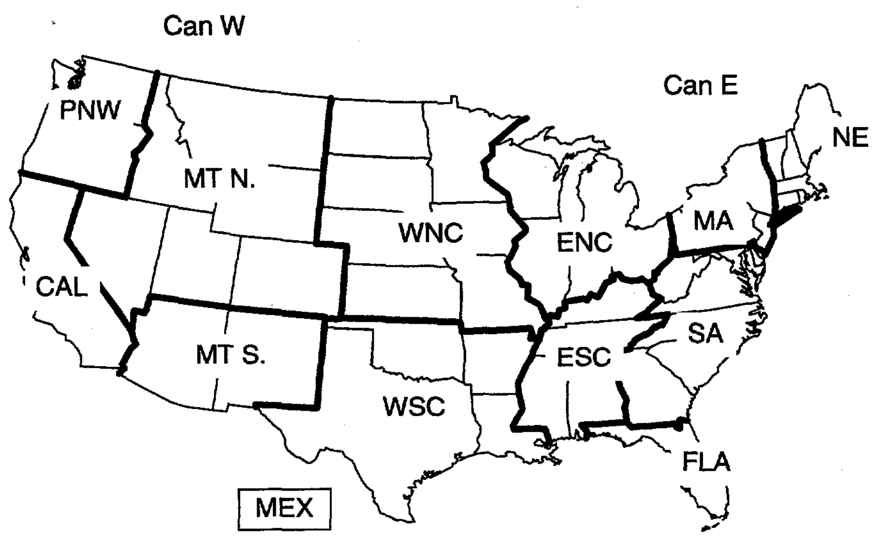
Several problems exist in the data available for both the existing storage reservoirs and the depleted reservoirs that are available for development as gas storage facilities. The most comprehensive data available for existing storage reservoirs is the American Gas Association (AGA) 1993 Report, *Survey of Underground Gas Storage Facilities in the United States and Canada.* This source does not provide any porosity or permeability values and many reporting companies have not provided data for all of the facility parameters listed. These missing data prevented precise physical characterizations of the reservoirs involved. These problems were overcome by estimating the missing properties based on the properties that are provided, from conversations with storage operators, the knowledge ICF Resources has regarding reservoirs in similar plays, and use of the U.S. Geological Survey play data.

The major problem for potential storage reservoirs is the lack of a data base for depleted reservoirs in the Appalachian region. Because this region is so highly dependent on gas storage, this omission had to be overcome. The solution was to generate representative data for a set of potential storage reservoirs using play characterizations based on data for existing storage reservoirs in the region and U.S. Geological Survey play data for the reservoirs that may be future candidates for storage facilities. A second problem with the depleted reservoir data was that some very large multi-reservoir fields are reported by NRG Associates, Inc. as single reservoirs, thereby overstating all of the capacity data. This problem was handled by deletion from the data base used in the study all of the "reservoirs" that were judged to be so large that re-pressuring costs would be prohibitive.

C. *Study Results*

Although the results of the four test scenarios are not considered to be precise regarding the demand for storage, for the reasons described above, they do support the conventional wisdom that storage capacity is in surplus in some parts of the U.S. The following paragraphs summarize the study findings for storage demand, storage costs, gas supply and demand, gas prices, and pipeline capacity additions. The demand regions used are illustrated in Exhibit XII-1.

Exhibit XII-1
GSAM Demand Regions



1. Storage Demand

The total regional gas storage demand (including both existing storage facilities and reservoirs selected for development of new storage facilities) selected by the GSAM demand and integrating module for the four scenarios analyzed are summarized in Exhibit XII-2. These storage demand volumes represent annual gas extraction from storage.

It is obvious from Exhibit XII-2 that the total U.S. storage usage is greater in the two scenarios with aggressive technology than in the two comparative scenarios with evolutionary technology advancement. As will be shown later in this report chapter, the technology cases provide greater total gas supply and demand at lower prices than the two comparative cases, thereby increasing the market for gas and for storage. Exhibit XII-2 also shows that the High Demand/Technical Case uses less storage than the Technical Case. As explained later, any case that includes the High Demand Case parameter of increased electric power generation demand for gas reduces the demand for storage.

In all four scenarios, the demands for gas storage shown in Exhibit XII-2 decline over the forecast period. There are two reasons for this decline. First, there is the model assumption that storage reservoir deliverability declines by five percent each year. For those reservoirs that have lower deliverabilities, this deliverability decline sometimes means that the working gas available for withdrawal cannot all be extracted in the 151-day winter period. Thus, depending on their maximum gas extraction rates, the volume that can be withdrawn from individual reservoirs tends to decline unevenly during the 1995 to 2010 forecast period. The demand for new storage facility development is inadequate to make up for these annual losses in withdrawal capacity. As explained earlier, the demand for new storage would likely be much larger if the GSAM winter season were structured to deal with peak demands rather than just a winter season demand.

Exhibit XII-2
Extraction Rates for Storage Gas, Bcf

	Base Case			Technology Case		
Region	2000	2005	2010	2000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	350	308	260	372	341	280
West South Central	208	169	137	227	188	148
West North Central	58	47	36	58	47	36
Mountain South	2	1	1	57	56	51
Mountain North	39	11	34	35	33	31
California	62	56	48	78	72	59
U.S.	1,077	905	765	1,185	1,050	854

	High Demand Case			High Demand/Tech Case		
Region	2000	2005	2010	2000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	359	313	261	383	336	276
West South Central	227	189	156	231	192	155
West North Central	59	47	36	59	47	36
Mountain South	2	1	1	43	42	36
Mountain North	26	7	21	25	23	20
California	67	61	52	74	68	59
U.S.	1,098	931	776	1,173	1,021	831

The second reason for the declines in storage use is that most of the gas demand increases forecast are for electric power generation, rather than for temperature sensitive residential and commercial loads. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. The following table shows how the share of total gas demand used for electric generation grows in the four cases tested.

Shares of U.S. Gas Demand Used for Power Generation

CASES	2000	2005	2010
Base	20.0%	24.5%	25.5%
Technology	21.3%	26.8%	27.3%
High Demand	20.3%	26.1%	28.7%
High Demand/Tech	22.2%	27.3%	29.8%

2. New Storage Facilities Added

The number of new gas storage facilities selected by the demand and integrating modules for use between 2000 and 2010 varies from four for the Base Case to 11 for the Technology Case. All of the new storage facilities are forecast to start up in the year 2000. The regions where these new facilities are forecast to be added are summarized in the following table.

Summary Of New Storage Facilities

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
East North Central	1	2	1	1
West South Central	1	2	3	2
Mountain South	0	5	0	3
California	2	2	2	2
Totals	4	11	6	8

The demand and integrating modules select new reservoirs in only four regions for the four scenarios compared. Thus, of the 12 U.S. demand regions in GSAM, eight require no new storage capacity under any of the scenarios analyzed. All of the four regions that require new storage facilities, except Mountain South, add new storage in each of the four cases. The two cases with aggressive technology require the most new storage facilities at 11 and 8 reservoirs, respectively. The requirement for new storage capacity is lower in the High Demand/Technical Case than for the Technical Case for the same reasons described earlier for storage utilization and as further described below.

When comparing the Technology and High Demand/Technology Cases, all of the increase in gas demand that the High Demand/Technology Case sees is for fueling more electric power generation. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. On the other hand, in the Technology Case, gas fuels a smaller share of power generation and the loss of this gas load causes gas demand to be more seasonal. Lower summer use of gas pipelines means that more new gas storage can be economically justified.

The differences in U.S. gas demand for power generation fuel and total demand for gas are summarized for each scenario in the following two tables.

Summary Of U.S. Gas Demand for Power Generation, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	3,322	3,424	3,354	3,440
2000	4,450	4,899	4,554	5,221
2005	5,924	6,936	6,387	7,074
2010	6,330	6,995	7,259	7,781

Summary of Total U.S. Gas Demand, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	20,108	20,304	20,152	20,324
2000	22,188	22,951	22,465	23,505
2005	24,216	25,890	24,511	25,912
2010	24,815	25,600	25,326	26,122

3. Use of Existing Gas Storage Facilities

Across the four cases studied, the projected utilization of existing working gas capacity in the ten regions that have underground storage facilities varies from zero to 100 percent. As an example, neither of the two storage facilities in the Pacific Northwest region are selected for use in any of the cases. In each of the four cases, gas demand growth in the Pacific Northwest is projected to be handled by additional pipeline capacity from the Rockies Foreland supply area. At the other extreme, the only storage reservoir in the Mountain South states of New Mexico and Arizona is always used. Similarly, in the Middle Atlantic and South Atlantic regions, storage capacity utilization varies from 97 to 100 percent in the four cases studied. In the other six regions storage capacity utilization ranges from 28 to 91 percent. The following table summarizes these storage utilization percentages in the year 2010 for the ten storage regions.

Summary of Capacity Utilization Rates for Existing Gas Storage in 2010

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Mid Atlantic	100%	100%	100%	100%
South Atlantic	97%	97%	97%	97%
East So. Central	91%	91%	91%	91%
East No. Central	60%	63%	61%	63%
West So. Central	83%	83%	83%	94%
West No. Central	49%	49%	49%	49%
Mountain South	100%	100%	100%	100%
Mountain North	74%	74%	74%	28%
Pacific NW	0%	0%	0%	0%
California	90%	90%	90%	90%
U.S.	74%	75%	75%	73%

Although we believe that these capacity utilization values do not show the true economic use of existing gas storage facilities, they do indicate the variation in storage needs among the regions. These values tend to support the general belief that storage is over-built in the East North Central, West North Central, and Mountain North regions. The high storage utilization rates in the Mid Atlantic, South Atlantic, and East South Central regions should be expected as these regions are directly involved in the gas flow to New England, where no underground storage is available and seasonal swings in gas demand are large.

The fact that the East North Central region is shown to need only about 60 percent of its storage capacity and yet adds one or two new facilities in each case occurs because many of the existing reservoirs have low deliverability rates per unit of their cost of service. Because of this poor economic efficiency many of the East North Central region storage facilities are not chosen for use in any of the cases studied. The new storage reservoirs chosen for the East North Central have substantially higher gas deliverability rates per unit of cost than the existing facilities that are not selected.

In addition to the 11 new storage facilities developed in the Technology Case, as described earlier, the projected need for more storage capacity caused an additional six existing storage reservoirs to be used that were not used in the Base Case. Similarly, in the High Demand/Technology Case, an additional eight existing storage reservoirs are used that were unused in the Base Case along with the eight new reservoirs selected for storage development. A different trend occurs in the High Demand Case where only one additional existing storage reservoir is selected for addition to the six new storage facilities chosen and three existing storage facilities are shut down. All of the existing storage facilities that are shut down are in the East North Central region, except for one in the Mountain North region in the High Demand/Technology Case. This change in selection of which existing storage reservoirs to use is caused primarily by the more costly deliverability of many East North Central storage facilities. The following table shows the regions in which these changes in the use of existing storage facilities occur.

Summary Of Changes In Existing Storage Facility Use
Compared To The Base Case

Region	Technology Case	High Demand Case	High Demand/Tech Case
Middle Atlantic	No change	No change	No change
East South Central	No change	No change	No change
East North Central	4 Facilities Added & 1 Facility Dropped	1 Facility Added & 3 Facilities Dropped	4 Facilities Added & 1 Facility Dropped
West South Central	1 Facility Added	No change	3 Facilities Added
Mountain North	1 Facility Added	No change	1 Facility Dropped

4. Technology Effects on Storage Characteristics

At present, the GSAM model and storage modules cannot be used to accurately test existing storage reservoirs for the effects of technology advancements, because data for a large part of the existing storage reservoir capacity is not available and the storage module has been designed to work around this data problem. However, potential new storage reservoirs that are evaluated by the model for use as new storage reservoirs have been tested for the effects of improved technology. This report section describes the effects observed from four model runs that comprise two comparisons. A Technology Case is compared with a Base Case and a High Demand/Technology Case is compared with a High Demand Case.

Typically, the impact on a potential new storage reservoir from adding aggressive technology advancement to a given scenario: 1) raises the volume of working gas available in the reservoir, 2) increases reservoir deliverability, 3) raises the levelized investment cost, and 4) lowers the total tariff rate per Mcf. Since the technology advancements applied to gas storage reservoirs typically involve improvements in well completions, it is logical that less cushion gas is needed in a given reservoir, hence more working gas is available. Improved well completions can also enhance the deliverability of some reservoirs, unless, for example, the net pay is too thick to benefit from horizontal wells or fracturing is ineffective. In all cases observed, the cost of improved well completion technology raises the storage facility levelized investment when the cost of cushion gas is excluded. Total fixed costs, including the cost of cushion gas required for the reservoir, are typically lower with advanced technology involvement because less cushion gas is required and the price of cushion gas is usually lower in the technology cases.

6. Storage Prices

Tariff rates for gas storage service are typically comprised of two monthly fixed charges, one for storage capacity and the other for withdrawal deliverability. Variable volumetric rates are charged for the amounts of gas injected and withdrawn and sometimes a separate fuel charge based on storage use. Typical variable rates would be one or two cents per Mcf injected and another one or two cents for volumes withdrawn. The fixed charges are many times the size of the variable costs, bringing the tariff rates of storage up to a range of from $0.30 to $1.40 per Mcf, depending on the age of the facility. Older facilities are typically much less expensive than newer ones. A major cause of this difference is the cost of the capitalized base gas in the reservoir. Today's base gas value can be ten times that of 25 years ago.

Exhibit XII-3 provides six regional examples of how advanced technology affects the performance and costs of candidate reservoirs for storage service. Three of the sample reservoirs, located in areas where new storage reservoirs were more often chosen in competition with additional pipeline capacity, were selected for storage use by GSAM. The other three candidate reservoirs were not chosen for storage use. As should be expected, the levelized investment costs and total fixed costs for the reservoirs selected for storage service are substantially lower than the reservoirs not selected.

When comprehensive Appalachian reservoir data are available and the storage module is modified to allow application of technology advancements to existing gas storage reservoirs, the same types of effects on existing storage reservoir performance and costs as found for new storage reservoirs can be analyzed by GSAM. Results are expected to be similar to those in Exhibit XII-3 for new storage reservoirs.

Initially, the storage module was designed to analyze the effects of technology advancements on existing storage reservoirs despite inadequate reservoir data for the eastern United States. Poor history matching for costs and performance resulted in modification of the storage module to work around this data problem. This modification does not allow testing of existing storage reservoirs for the effects of new technologies.

Exhibit XII-3
Examples of Technology Effects on Storage Reservoir Candidates

Storage Characteristic *Region*	**Base Case**	**Technology Case**	**Change**	**High Demand Case**	**High Demand/ Tech Case**	**Change**
Mountain South (Selected)						
Working gas, MMcf	18,083	18,644	561	18,083	18,644	561
Deliverability, MMcfd	52	65	13	52	65	13
Investment, $/Mcf	$ 0.10	$ 0.11	$ 0.01	$ 0.10	$ 0.11	$ 0.01
Total fixed cost, $/Mcf	$ 0.47	$ 0.31	$ (0.16)	0.43	0.371	$ (0.06)
California (Selected)						
Working gas, MMcf	54,913	57,575	2,662	54,913	57,575	2,662
Deliverability, MMcfd	176	178	3	176	178	3
Investment, $/Mcf	$ 0.10	$ 0.11	$ 0.01	$ 0.10	$ 0.11	$ 0.01
Total fixed cost, $/Mcf	$ 0.50	$ 0.40	$ (0.10)	$ 0.46	$ 0.48	$ 0.02
West South Central (Selected)						
Working gas, MMcf	55,288	57,366	2,078	55,288	57,366	2,078
Deliverability, MMcfd	155	178	23	155	178	23
Investment, $/Mcf	$ 0.10	$ 0.11	$ 0.01	$ 0.10	$ 0.11	$ 0.01
Total fixed cost, $/Mcf	$ 0.50	$ 0.38	$ (0.12)	$ 0.47	$ 0.43	$ (0.04)
East N. Central (Not selected)						
Working gas, MMcf	32,135	32,456	321	32,135	32,456	321
Deliverability, MMcfd	67	114	46	67	114	46
Investment, $/Mcf	$ 0.96	$ 0.99	$ 0.03	$ 0.96	$ 0.99	$ 0.03
Total fixed cost, $/Mcf	$ 1.92	$ 1.54	$ (0.38)	$ 1.89	$ 1.57	$ (0.32)
Middle Atlantic (Not selected)						
Working gas, MMcf	6,891	8,064	1,173	6,891	8,064	1,173
Deliverability, MMcfd	27	35	8	27	35	8
Investment, $/Mcf	$ 0.60	$ 0.71	$ 0.11	$ 0.60	$ 0.71	$ 0.11
Total fixed cost, $/Mcf	$ 1.16	$ 1.08	$ (0.08)	$ 1.13	$ 1.11	$ (0.02)
West N. Central (Not selected)						
Working gas, MMcf	40,938	41,570	632	40,938	41,570	632
Deliverability, MMcfd	94	133	39	94	133	39
Investment, $/Mcf	$ 0.37	$ 0.39	$ 0.03	$ 0.37	$ 0.39	$ 0.03
Total fixed cost, $/Mcf	$ 0.96	$ 0.72	$ (0.24)	$ 0.93	$ 0.76	$ (0.17)

Notes:

1. All reservoirs shown are gas reservoirs not currently in storage service.
2. Regions labeled (Selected) were selected by GSAM to be new storage reservoirs.
3 Investment costs exclude cushion gas purchases and are levelized over a 20-year life for the volume of gas withdrawn.
4. Total fixed costs include the cost of cushion gas.
5. All examples are from year 2010 projections.

5. Gas Pipeline Capacity Additions

In the process of optimizing gas supply to meet growing demand, the demand and integrating modules found that the efficient approach to increased gas deliveries was a mixture of adding gas storage capacity and more gas pipeline capacity. Exhibit XII-4 shows where pipeline expansions occur, when the expansions began, and how much pipeline capacity was demanded by the year 2010, for the four cases analyzed. The larger expansions were needed from the Mountain North to Mid-Continent, the Mountain North to San Juan, and Gulf of Mexico West to the Texas Gulf Coast regions. There also were major expansions on TransCanada Pipelines from Alberta to Canada East for all four cases and from San Juan to Permian in the Technology and High Demand Technology cases.

It is significant that the two aggressive technology cases need less pipeline capacity from Alberta to the east on TransCanada Pipelines. The increased U.S. supply at lower prices made available by the E&P technology advancements reduces U.S. dependence on Canadian supply.

Exhibit XII-4
Pipeline Capacity Additions, MMcfd Gas

		Base Case			Technology Case			High Demand Case			High Demand/Tech Case		
Pipeline Route	1995 Capacity All Cases	2010 Capacity	Added Capacity	Years Expanded	2010 Capacity	Added Capacity	Years Expanded	2010 Capacity	Added Capacity	Years Expanded	2010 Capacity	Added Capacity	Years Expanded
Alberta to Canada East	4,053	6,982	2,929	2005-2010	5,596	1,543	2000-2010	7,204	3,151	2005	6,653	2,600	2000-2010
South Louisiana to Florida	1,957	1,957	0	None	2,492	535	2000	1,957	0	None	2,492	535	2000
Gulf of Mex.W. to Tex.Gulf Coast	2,662	6,606	3,944	2000-2005	6,899	4,237	2000-2010	6,903	4,241	2000-2010	6,683	4,021	2000-2010
Mountain North to Mid Cont.	385	8,580	8,195	2005-2010	9,437	9,052	2005-2010	8,832	8,447	2005-2010	9,519	9,134	2005-2010
Mountain North to San Juan	246	2,235	1,989	2000-2005	4,551	4,305	2000-2010	2,387	2,141	2000-2010	4,374	4,128	2000-2010
Mid Atlantic to New England	2,210	2,210	0	None	2,257	47	2010	2,210	0	None	2,257	47	2000
Sable Is.to New England	0	400	400	2005	400	400	2005-2010	400	400	2005	400	400	2005-2010
Rockies to Pacific Northwest	254	415	161	2005	456	202	2005	810	556	2005-2010	793	539	2005
San Juan to Permian	987	987	0	None	4,071	3,084	2010	987	0	None	3,708	2,721	2010
Alberta to West N. Central	1,568	2,268	700	2000-2005	2,268	700	2000	2,268	700	2000-2005	2,268	700	2000
Rockies to West N. Central	547	1,147	600	2000	1,147	600	2005	1,147	600	2000	1,147	600	2000-2005

The ranges of storage tariff rates for the facilities used in each region are summarized in the following table. Rates for the facilities not chosen by the storage module were in some cases substantially higher than the rates shown here.

Price Ranges For Gas Storage Facilities Used, $/Mcf

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Middle Atlantic	\$0.17 to \$0.92	\$0.16 to \$0.92	\$0.17 to \$0.93	\$0.19 to \$0.93
South Atlantic	\$0.26 to \$0.62	\$0.28 to \$0.62	\$0.26 to \$0.63	\$0.28 to \$0.63
Florida	None used	None used	None used	None used
East South Central	\$0.16 to \$1.13	\$0.16 to \$1.13	\$0.16 to \$1.13	\$0.17 to \$1.13
East North Central	\$0.15 to \$1.63	\$0.15 to \$1.38	\$0.21 to \$1.38	\$0.16 to \$1.38
West South Central	\$0.11 to \$0.90	\$0.11 to \$0.90	\$0.11 to \$0.91	\$0.13 to \$1.14
West North Central	\$0.30 to \$0.97	\$0.30 to \$0.97	\$0.30 to \$0.97	\$0.32 to \$0.97
Mountain South	\$0.22	\$0.22	\$0.22	\$0.22 to \$0.73
Mountain North	\$0.17 to \$0.78	\$0.17 to \$0.78	\$0.17 to \$0.78	\$0.20 to \$0.71
California	\$0.29 to \$1.04	\$0.29 to \$1.04	\$0.29 to \$1.04	\$0.31 to \$1.04
Pacific Northwest	None used	None used	None used	None used

These gas storage prices were developed in two ways. Prices for existing gas storage facilities were based on cost of service tariff rates filed by the owners or operators. Prices for new storage facilities were calculated, based on reservoir properties, the investments required to develop them, and estimated operating and maintenance costs. The procedure for calculating storage costs for the individual reservoirs in existing storage facilities and new facilities was described in Chapter IV.

7. Gas Supply

The GSAM net U.S. gas supply forecasts that support the storage demand results of this study vary from a low of 19,278 Bcf in the Low Demand Case for the year 1995 to a high of 25,708 Bcf for the year 2010 in the High Demand Case. These supply figures include U.S. gas production and peak shaving volumes, but exclude imports. The following table summarizes total supplies for each of the four scenarios.

Summary of Total U.S. Gas Supply, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	19,357	19,637	19,397	19,613
2000	22,027	22,559	22,253	23,028
2005	24,054	26,232	24,463	26,115
2010	24,222	25,708	24,728	25,902

Between 1995 and 2010 gas imports from Canada continue to grow as they have in recent years. By 2010 Canadian gas supply to the U.S. in the Base Case grows by another 15 percent, reaching 3,245 Bcf. In the Technology Case the 2010 total is 2,827 Bcf, an increase from 1995 of a little over one percent. This shows that improved technology can make the U.S. less dependent on Canadian gas. The same result is evident when comparing the High Demand and High Demand/Tech Cases. Canadian gas imports grow by 17 percent in the High Demand Case and only 11 percent when aggressive technology advancement is added to that case. A summary of Canadian gas imports for the four scenarios is provided in the following table.

Summary Of Canadian Gas Imports, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	2,829	2,790	2,817	2,828
2000	2,522	2,768	2,600	2,935
2005	2,804	2,598	2,772	2,701
2015	3,245	2,827	3,296	3,140

Exhibit XII-5
Summary Of Gas Supply Prices, 1993$/Mcf

Location	Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
U.S. Average	1995	1.23	1.32	1.38	1.32
	2000	1.38	1.21	1.27	1.12
	2005	1.64	1.16	1.74	1.16
	2010	2.17	2.00	2.35	2.16
Rockies	1995	1.04	0.95	0.99	0.95
	2000	1.01	0.87	0.88	0.75
	2005	1.19	0.74	1.27	0.81
	2010	1.69	1.52	1.85	1.69
Alberta	1995	0.90	0.89	1.05	0.91
	2000	1.18	0.67	1.09	0.54
	2005	1.25	0.97	1.36	0.80
	2010	1.69	1.69	1.87	1.76
Gulf of Mex. West	1995	0.94	1.30	1.37	1.31
	2000	1.25	1.06	1.15	0.97
	2005	1.49	1.11	1.68	1.19
	2010	2.32	2.06	2.39	2.24
Appalachia	1995	1.63	1.55	1.62	1.55
	2000	1.67	1.46	1.57	1.38
	2005	2.02	1.52	2.12	1.59
	2010	2.63	2.54	2.85	2.73

8. Gas Prices

Improving E&P technology and an accessible resource base provide the foregoing supply volumes at relatively small price increases until the year 2010, when average U.S. prices for the preceding five years climb by 32 to 72 percent, among the four scenarios tested. The lowest average U.S. price projections are for the Technology Case, reaching only $2.00 per Mcf by the year 2010. The highest 2010 price is found in the High Demand Case at $2.35 per Mcf. Exhibit XII-5 summarizes gas supply prices for the total U.S. and several supply areas for the four scenarios analyzed

By the year 2010, the highest gas prices among all of the regions shown occur in the High Demand Case and the lowest prices are in the Technology Case. Consistent with history, the highest price seen in 2010 is in the Appalachian region at $2.85 per Mcf in the High Demand Case. The lowest price in the year 2010 among all regions occurs in the Williston Basin at $1.48 per Mcf in the Technology Case.

The Technology Case, which has the lowest priced supply, predictably has the largest demand for gas. Under this scenario, the technology advancements are so robust that, even at the lower prices, gas reserves and production are able to support the increases in demand. These higher demands occur in each of the four major consuming sectors.

Examples of consumer prices in several demand regions that these gas supply prices translate to after adding delivery charges are summarized in Exhibit XII-6. The range of consumer prices is illustrated by the electric power generation and residential sectors. The five demand regions shown are the largest in the U.S. in gas consumption.

As should be expected, gas prices for power generation are lowest in the West South Central region where gas is plentiful and alternative fuel prices are relatively low. By contrast, residential gas prices for the regions shown here are highest in the Middle Atlantic states where gas transmission distances are greater and alternate fuel prices are relatively high. The higher gas prices for electric generation appear in the South Atlantic region. Residential prices are lowest in the East North Central region for all scenarios.

Exhibit XII-6
Examples of Regional Gas Prices for Electric and Residential Sectors, 1995$/Mcf

Region	Sector	Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Mid Atlantic	Electric	1995	1.58	1.55	1.57	1.55
		2010	2.44	2.54	2.96	2.84
	Residential	1995	6.96	6.83	6.94	6.83
		2010	8.10	7.92	8.25	8.12
S. Atlantic	Electric	1995	1.56	1.55	1.55	1.55
		2010	2.74	2.73	2.66	2.95
	Residential	1995	6.47	6.34	6.45	6.34
		2010	7.68	7.48	7.82	7.68
E.N.Central	Electric	1995	1.50	1.47	1.48	1.46
		2010	2.31	2.31	2.86	2.75
	Residential	1995	4.99	4.87	4.98	4.87
		2010	6.07	5.89	6.23	6.08
W.S.Central	Electric	1995	1.36	1.33	1.35	1.34
		2010	2.21	2.18	2.54	2.40
	Residential	1995	5.14	5.02	5.12	5.03
		2010	6.17	6.00	6.34	6.18
California	Electric	1995	1.70	1.61	1.63	1.61
		2010	2.33	2.24	2.65	2.48
	Residential	1995	5.98	5.85	5.92	5.85
		2010	6.60	6.47	6.82	6.66

Following the same pattern seen in supply prices, the two cases with improved technology result in lower consumer prices than their comparison cases without the aggressive technology advancements. Thus, the cost reductions provided by advanced technology for E&P and storage reservoirs are passed on to consumers.

XIII. Major Findings From Task 3 And Task 5 Analyses

Separately from the specific conclusions reached for each of the analytical tasks of this project, there are a number of more general findings that are summarized in this chapter.

A. *Demand for Storage Capacity*

As currently designed with only two seasons, GSAM is incapable of applying appropriate economic measures of the value of storage. Consequently, GSAM is biased toward adding pipeline capacity instead of storage. Evidence of this bias against storage appears in forecasts of storage usage. Some regions that have operating storage reservoirs today are shown as not needing any storage capacity. In some scenarios, existing storage reservoirs are dropped from active use while other existing storage reservoirs are added to the active list. Even though these model test runs have assumed that the maximum withdrawal of gas from each active storage reservoir is only 50 percent of the working gas capacity, the forecast average U.S. capacity utilization is only 75 percent of this restricted availability. Despite its severe winters, the East North Central region is projected to use only about 60 percent of its storage capacity.

Three of the regions that are projected to use nearly all of their available working gas capacity are ones that move gas toward New England, which has no storage facilities and experiences large seasonal swings in gas consumption. Despite this full use of existing capacity, these three regions (East South Central, South Atlantic, and Mid Atlantic) add no new storage capacity in any of the scenarios tested.

B. *Demand for Pipeline Capacity*

Significant amounts of new pipeline capacity are projected by GSAM, but it is primarily for moving gas out of regions where large production increases are anticipated. The largest of these pipeline expansions are for moving gas out of the Rocky Mountains, to the Midwest and southward to the San Juan for redirection to the east and west. Other major pipeline expansions are out of the Gulf of Mexico West and western Canada. The only new pipeline capacity projected for New England is from Sable Island, beginning in 2005.

C. *Effect of Electric Industry Reorganization on Storage Demand*

If coal should become the favored fuel for power generation in the future, GSAM predicts that more storage capacity will be needed. This somewhat counter-intuitive projection is logical because gas demand is forecast to continue to grow in the other consuming sectors. The residential and commercial growth will increase the amount of winter demand relative to summer demand, thereby worsening the load factors of pipelines and making storage more economically attractive.

If gas should become favored over coal for power generation, the seasonal differences in gas demand will be reduced because electricity use is greater in summer for air conditioning in most regions. The less difference there is between summer and winter gas demand in a region, the more pipeline capacity can be economically justified to serve the region.

D. Effects of Improved Technology on Storage Costs

In the comparisons made, the application of improved technology typically increases the investment for new storage facilities because horizontal wells, fracturing, and other improved well completion techniques cost more than more conventional completions. However, the typical increase in working gas capacity in a reservoir results in purchasing less cushion gas. This reduced need for cushion gas, plus the lower price of gas in the higher technology scenarios, results in substantially lower projections for total fixed costs for new storage capacity. The range of total fixed cost decreases observed in a sample of new storage reservoir candidates using advanced technology varied from two to 18 percent.

E. Effects of Improved Technology on Storage Deliverability

The projected effects of improved well completion technologies on storage deliverability vary markedly, depending on the physical characteristics of the gas producing formation. The range of deliverability increases observed in a sample of new storage reservoir candidates using improved technology varied from two to 69 percent.

F. Effects of Improved Technology on Natural Gas Supply, Demand, and Price

GSAM model runs project that the application of aggressive advanced technology for E&P and storage reservoirs will raise U.S. gas supply and demand and lower gas prices compared to scenarios with the same economic assumptions but only evolutionary technology changes. For the scenarios tested in Tasks 3 and 5 for this study, U.S. gas supply and demand increases created by technology vary from two to nine percent between the years 2000 and 2010. U.S. average gas supply prices during this time period are projected to be from eight to 33 percent lower when advanced technology is used.

G. Effects of Improved Technology on Canadian Gas Imports

The effects on Canadian gas imports from applying advanced technology on comparable GSAM test scenarios is an initial imports increase in the year 2000, then reductions through 2010. The range of reduced imports observed was from three to 13 percent.

XIV. Recommended Improvements to GSAM Modules

In the course of analyzing model results for Tasks 3 and 5 of this project, the need for several improvements to three GSAM modules have become apparent. These three modules are the demand module, the storage module, and the integrating module. The importance of these improvements varies from some that are minor to others that are imperative for obtaining more precision in determining: 1) the level of storage capacity that is economic now and in the future, and 2) the impact of applying aggressive technologies to E&P and storage reservoirs. The recommended improvements are described below in approximate order of priority.

1. The demand module must be expanded to incorporate more than two seasons. Without shorter winter seasons to properly evaluate the economic benefits of underground storage and peak shaving supplies, the model will continue to be biased toward increasing pipeline capacity. Without this improvement, any model runs made can provide only indications of the effects of changes in economic and technology assumptions, not the quantitative effects needed for decisions on technology R&D projects.

2. Another major impediment to obtaining better quantitative results of storage demand and costs is the lack of comprehensive reservoir data in the Appalachian region. The lack of adequate data for reservoirs in the Appalachian region seriously constrained the ability to perform reasonable history matching on storage performance and costs in the eastern U.S. This severely restricts any analyses of the impact of aggressive technology advancements applied to existing storage reservoirs. Appalachian reservoir data are critical to the storage module because this region has 32% of the U.S. storage capacity.

3. When more comprehensive Appalachian reservoir data become available, the storage module needs to be modified to allow for testing the effects of technology advancements on existing storage reservoirs. Since deliverability improvement of existing reservoirs appears to be an industry trend, this module improvement should be given high priority.

4. The integrating module logic should be modified to balance supply and demand at one-year or five-year periods at time to avoid the unrealistic "perfect foresight" used now. Currently GSAM balances all future years simultaneously, limiting the number of bad decisions made in the near term because future supply, demand, and prices are foreseen.

5. The storage module assumption for storage reservoir deliverability decline should be changed from five percent per year to three percent per year.

6. The storage module assumption for storage reservoir well workover cycle should be changed from every two years to every five years.

7. The demand module needs to be modified to account for interfuel competition (including electricity) in the residential and commercial sectors. Without this change, GSAM will not be an adequate tool for evaluating the impacts of the competition gas will face from coal and electricity as the electric industry deregulates and reorganizes.

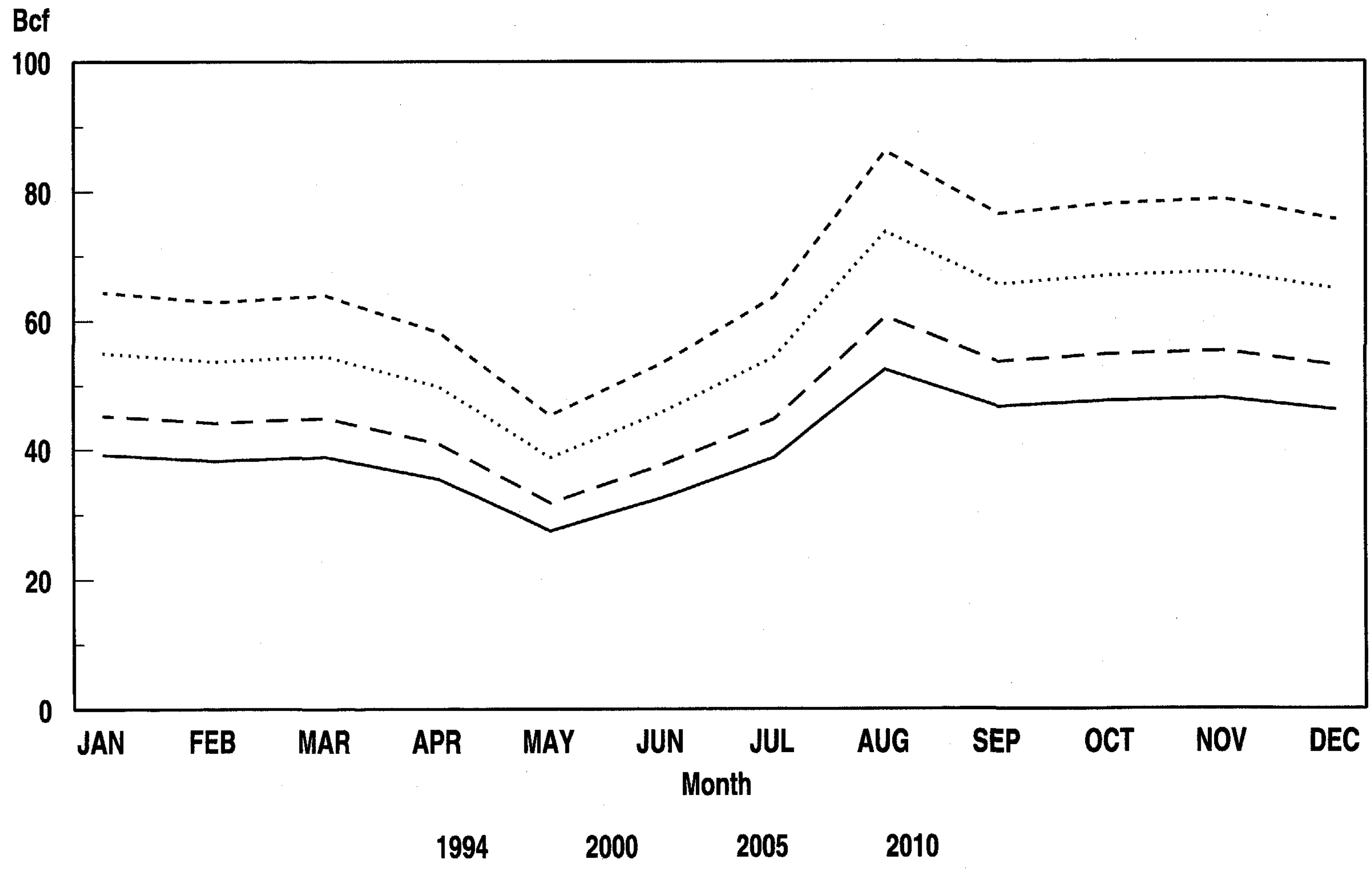
8. The integrating module should be modified to use individual supply curves for each production region, rather than use a national supply curve.

Numerous additional but lower priority recommendations for model improvements have been documented in the memorandum, "Recommendations from the GSAM Workshop February 5-6, 1997." These seven model improvements have been highlighted because they are considered to be more critical for enhancing the results of gas storage analyses.

APPENDIX A
ELECTRIC GENERATION GAS DEMAND FORECASTS

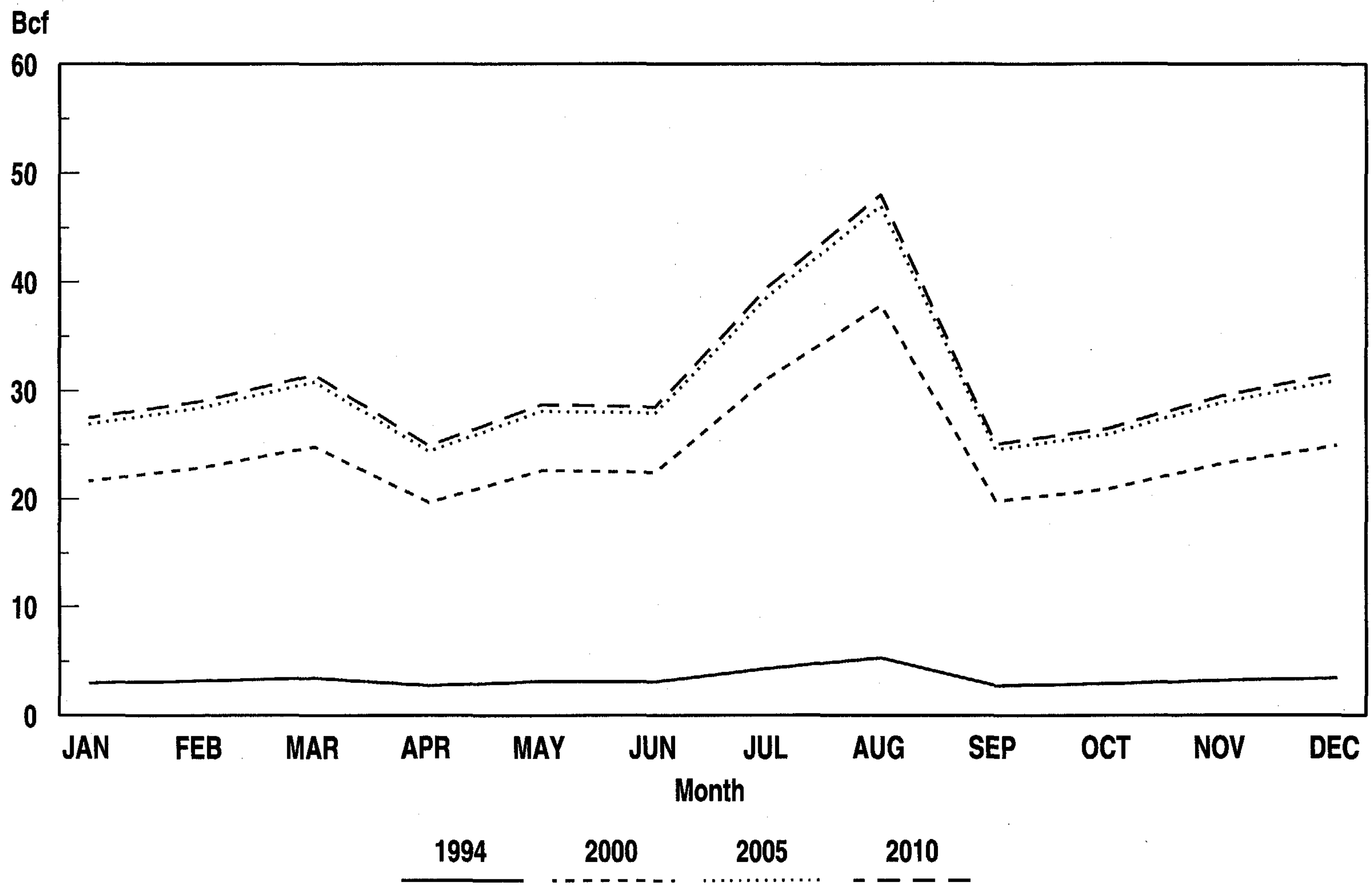
California

Monthly Electric Generation Gas Demand Curve



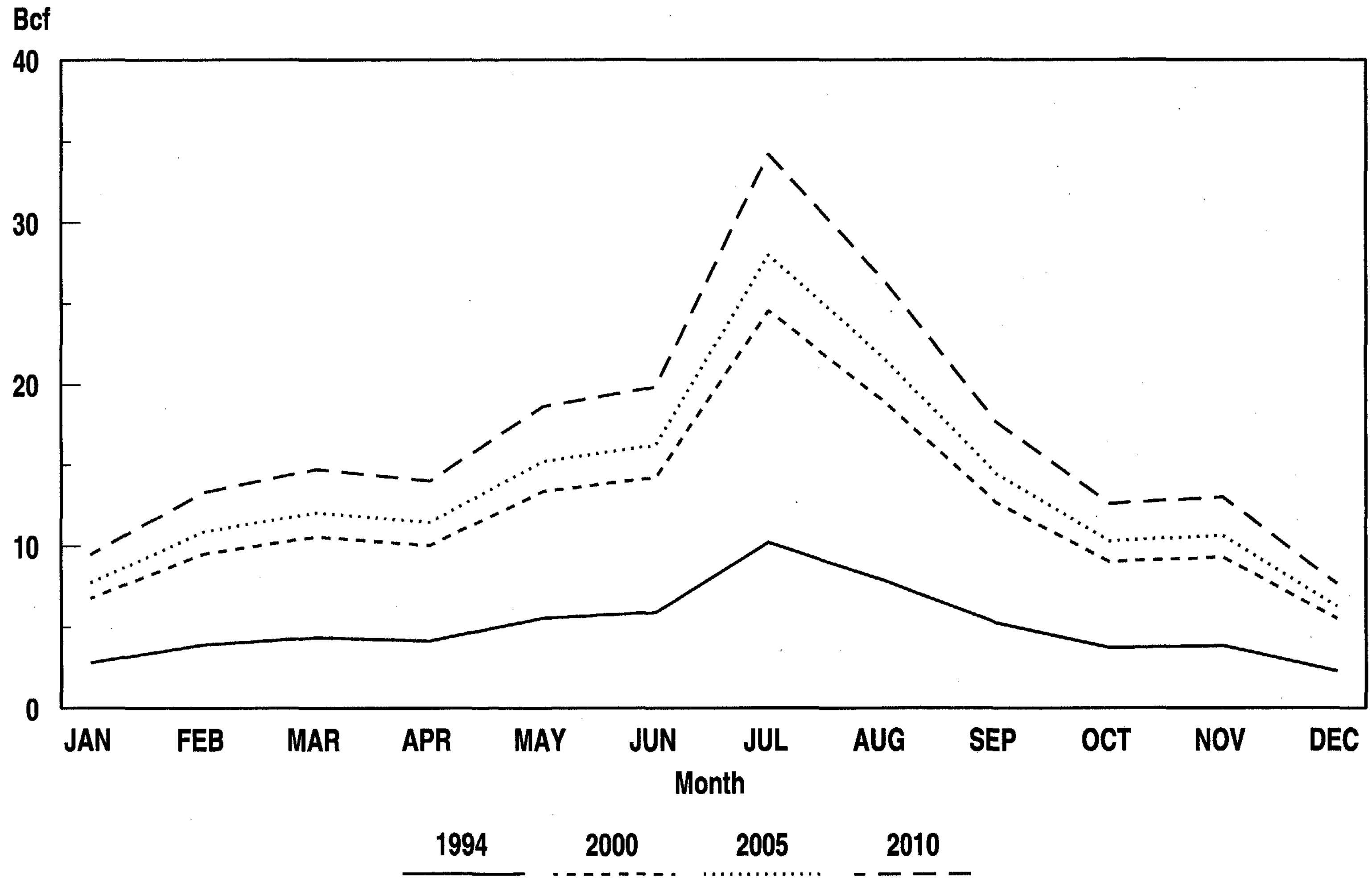
East North Central

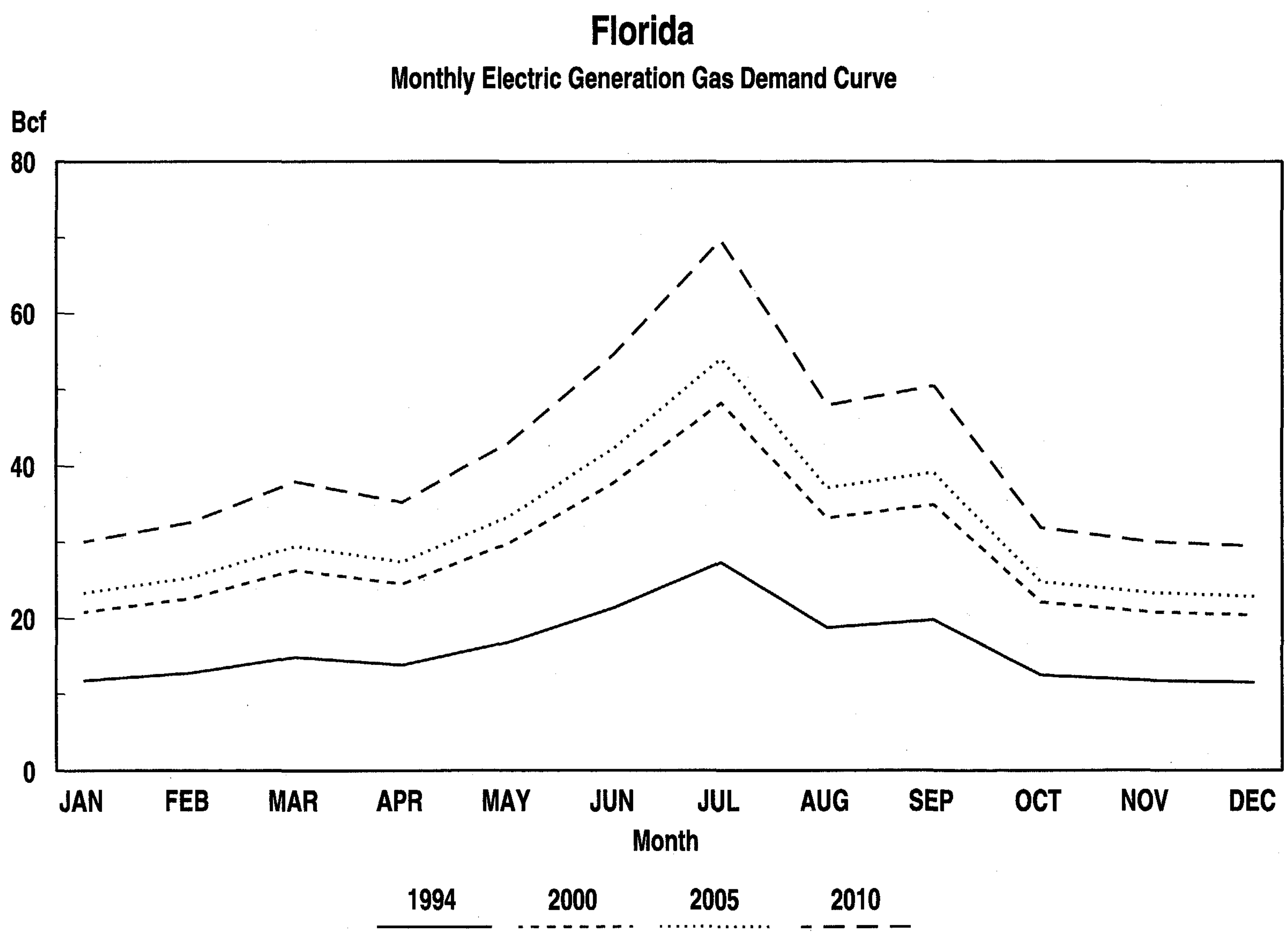
Monthly Electric Generation Gas Demand Curve



East South Central

Monthly Electric Generation Gas Demand Curve




Florida
Monthly Electric Generation Gas Demand Curve
Bcf
80
60
40
20
0
JAN
FEB
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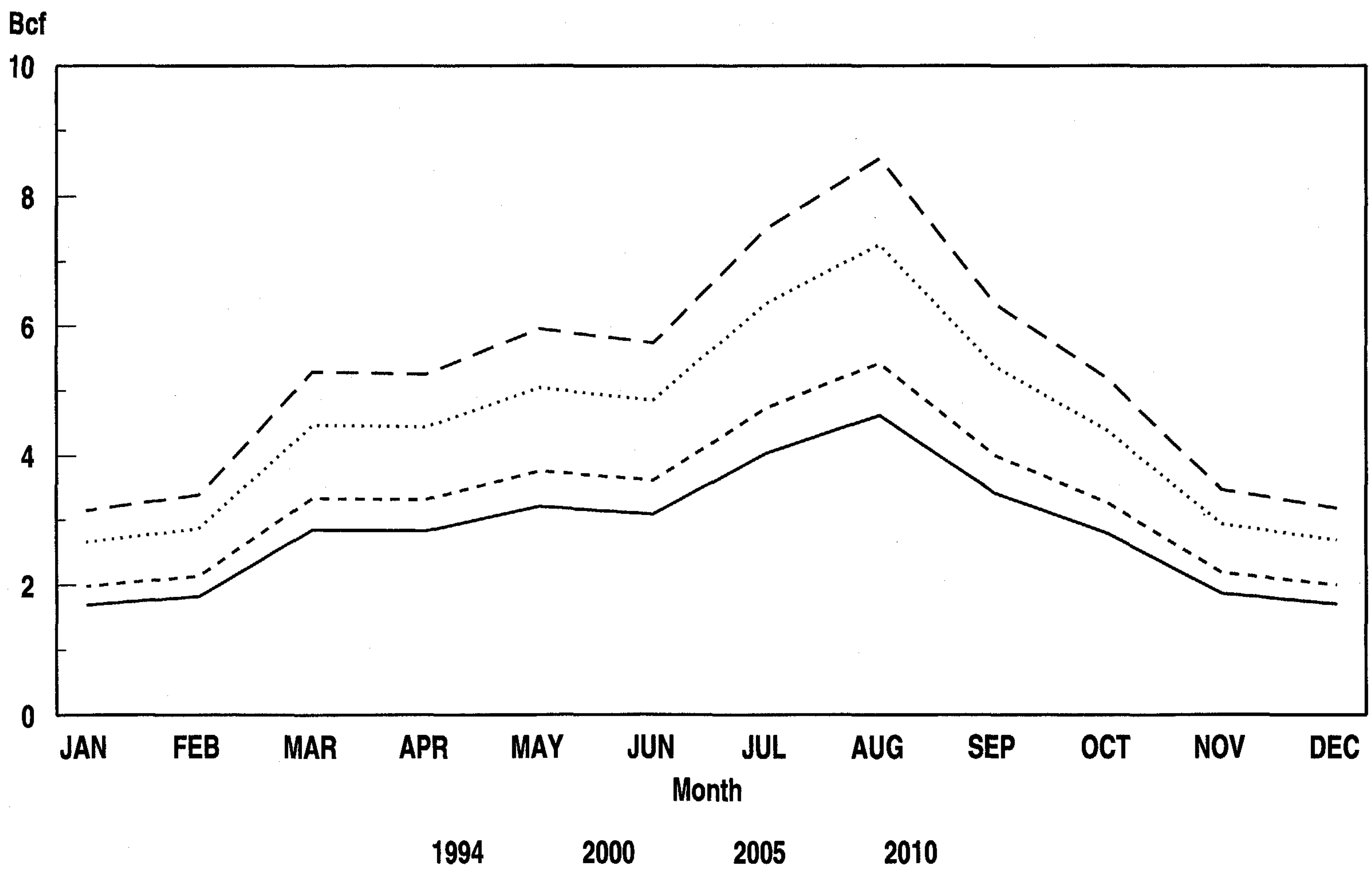
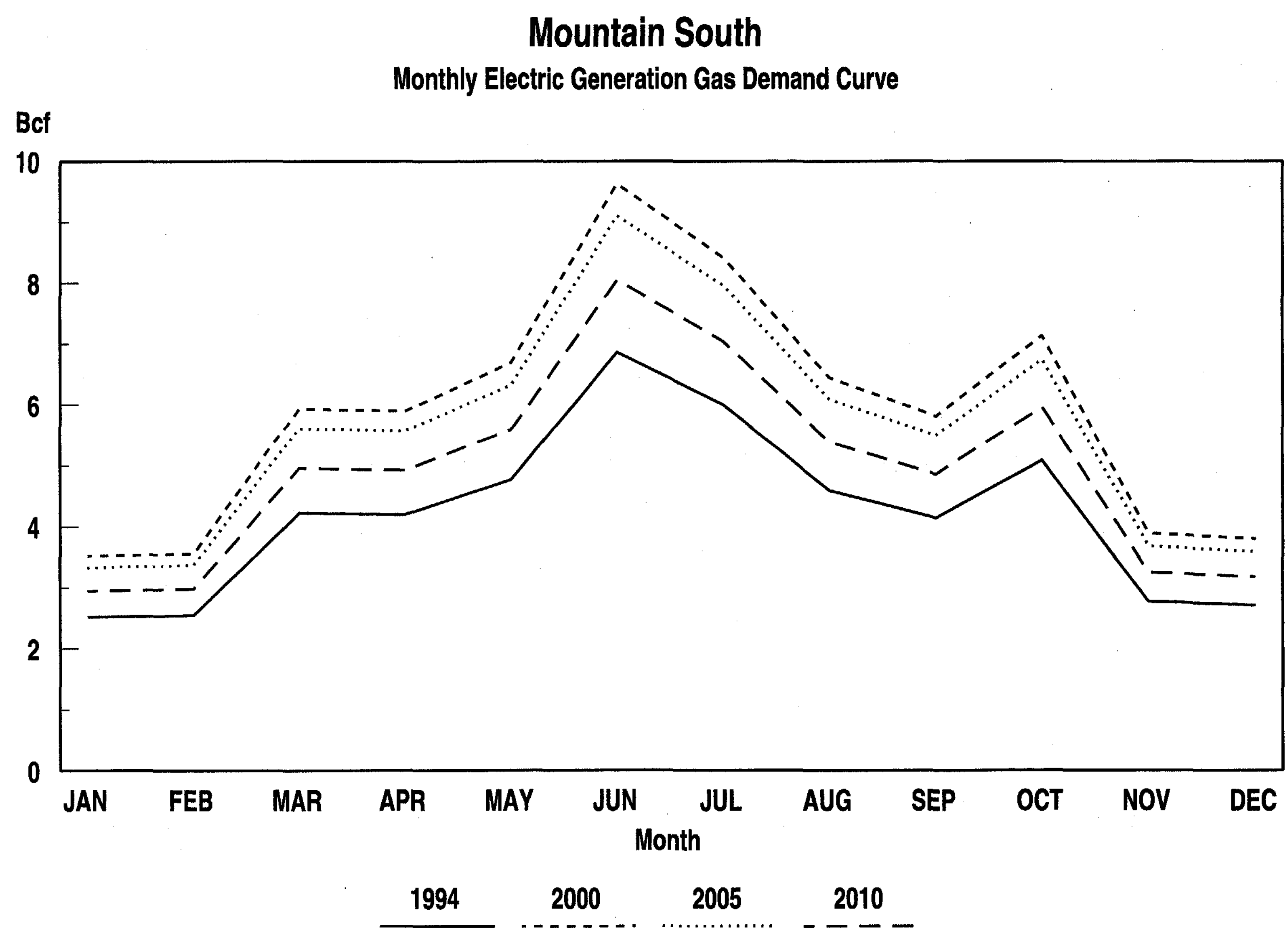
Month
1994
2000
2005
2010

Mountain North

Monthly Electric Generation Gas Demand Curve





Mountain South
Monthly Electric Generation Gas Demand Curve
Bcf
10
8
6
4
2
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JAN
FEB
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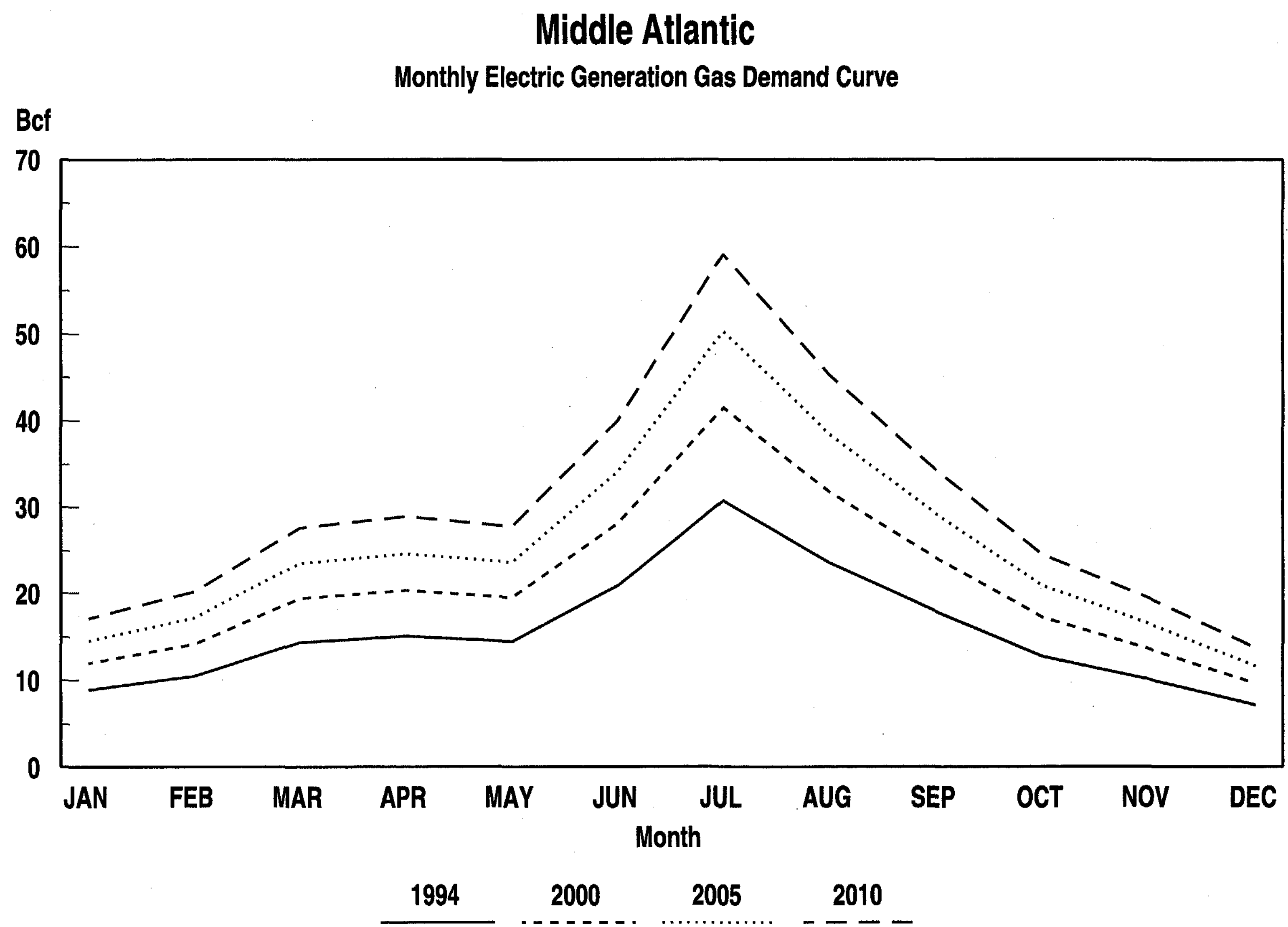
Month
1994
2000
2005
2010


Middle Atlantic
Monthly Electric Generation Gas Demand Curve
Bcf
70
60
50
40
30
20
10
0
JAN
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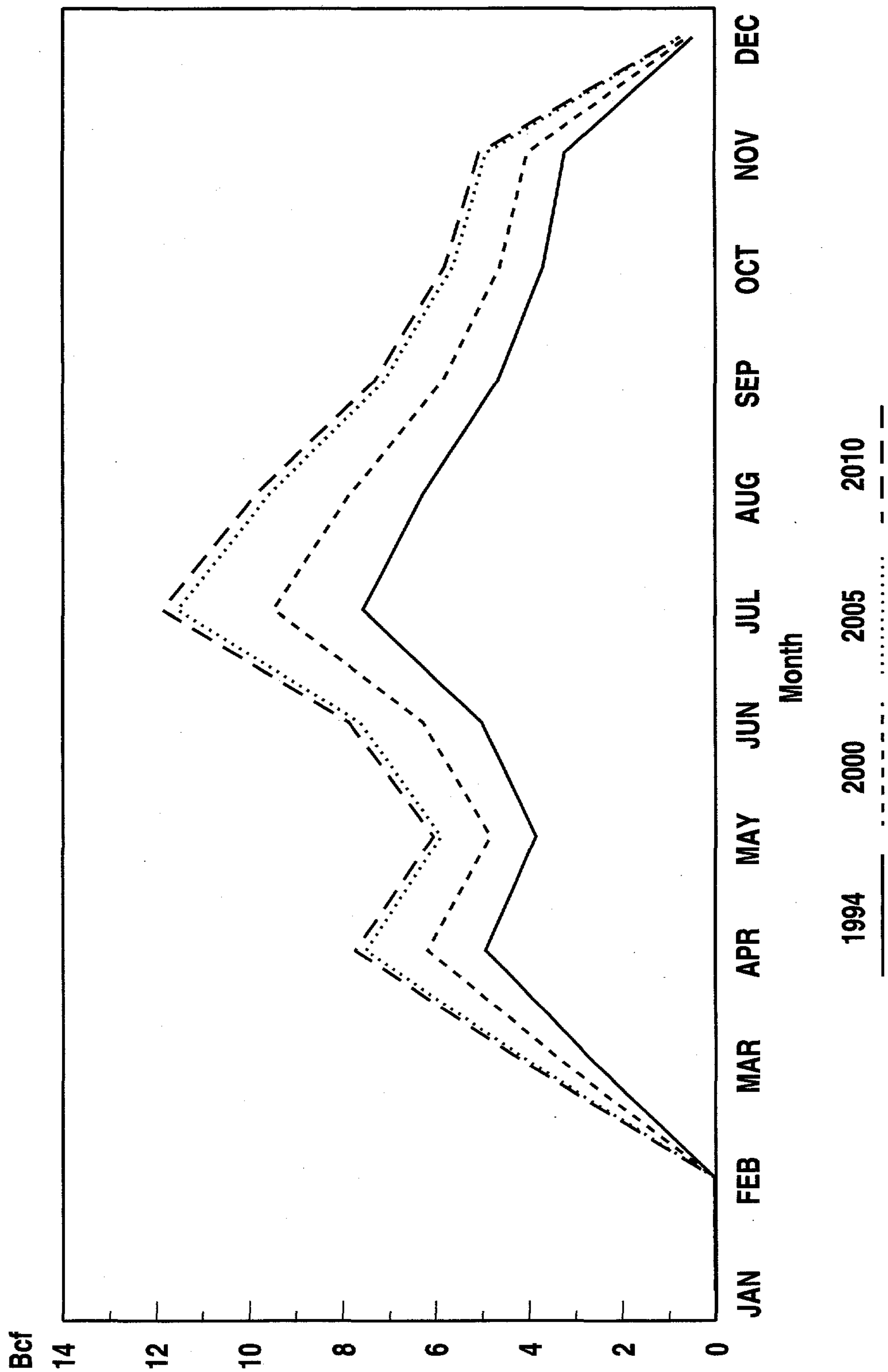
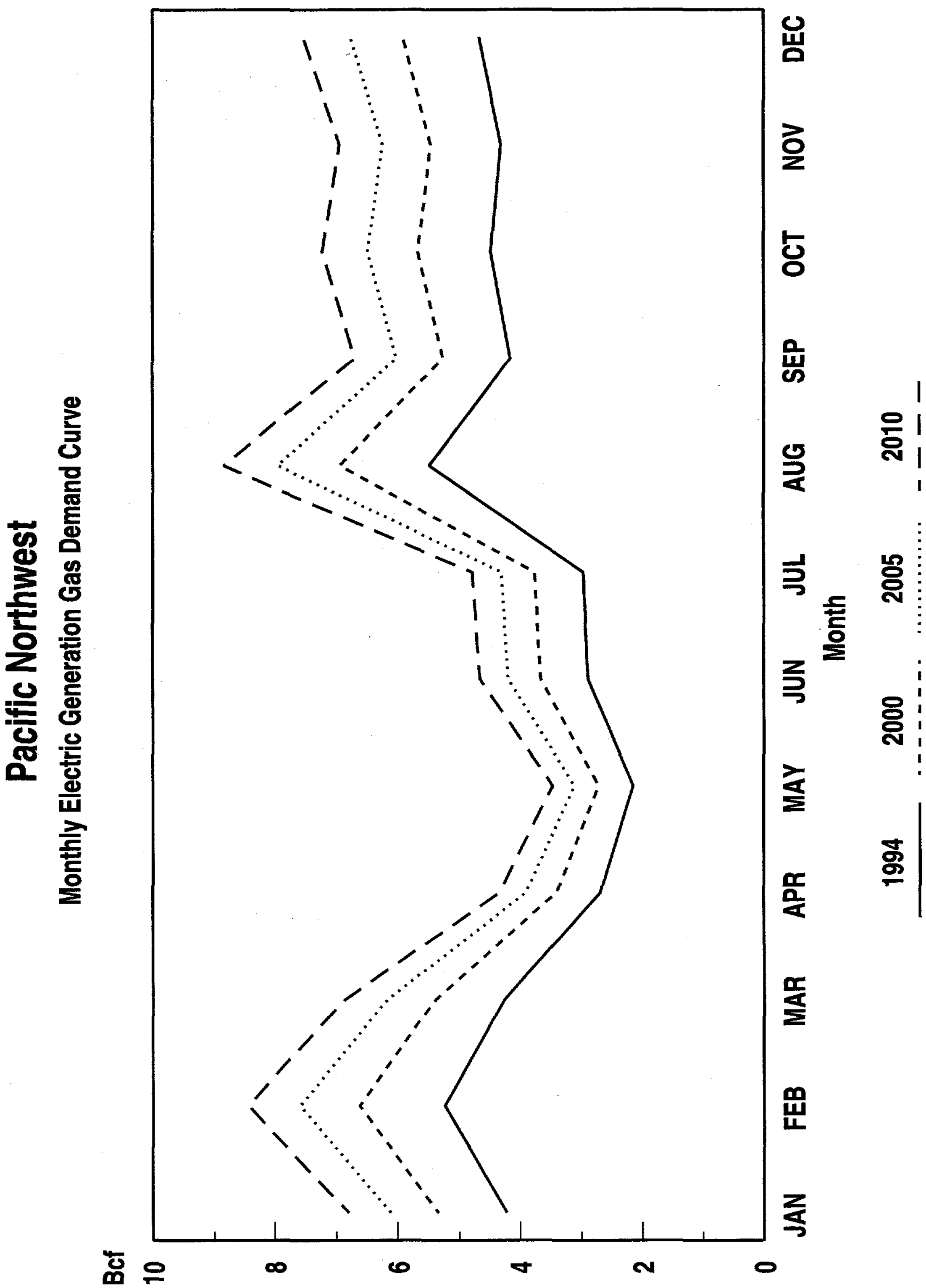
Month
1994
2000
2005
2010

New England

Monthly Electrical Generation Gas Demand Curve




Pacific Northwest
Monthly Electric Generation Gas Demand Curve
Bcf
10
8
6
4
2
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JAN
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1994
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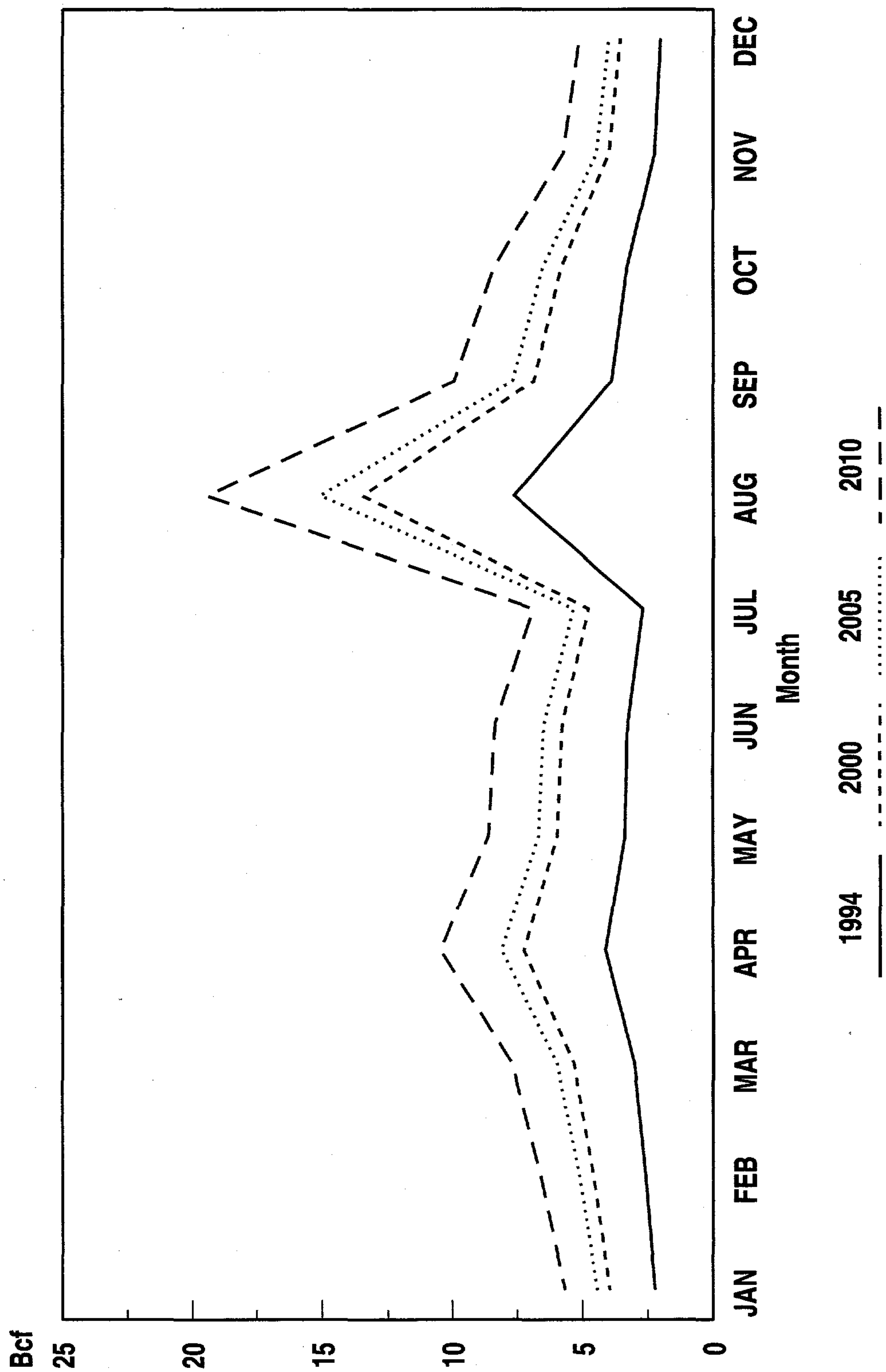
2010

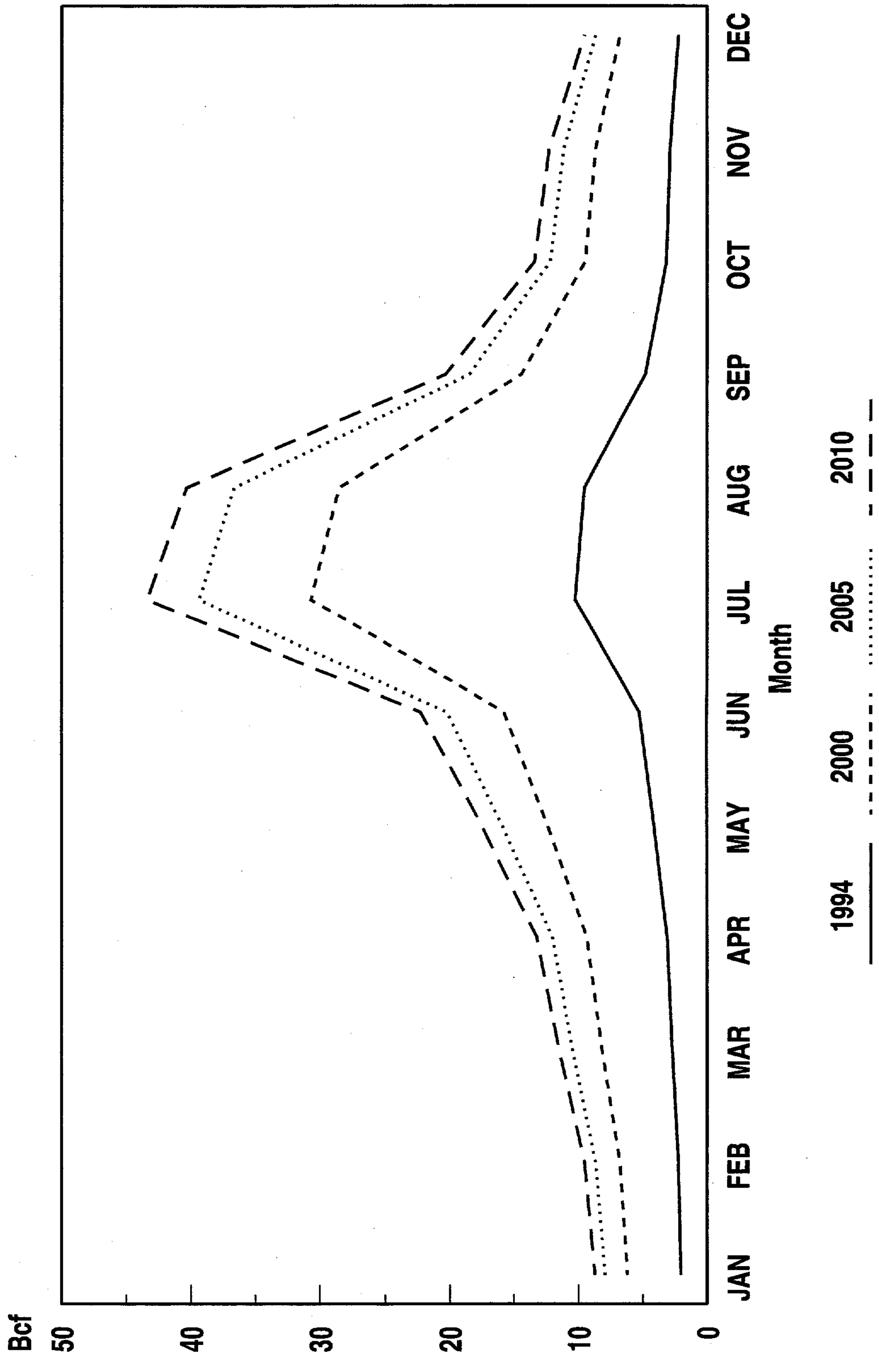
South Atlantic

Monthly Electric Generation Gas Demand Curve



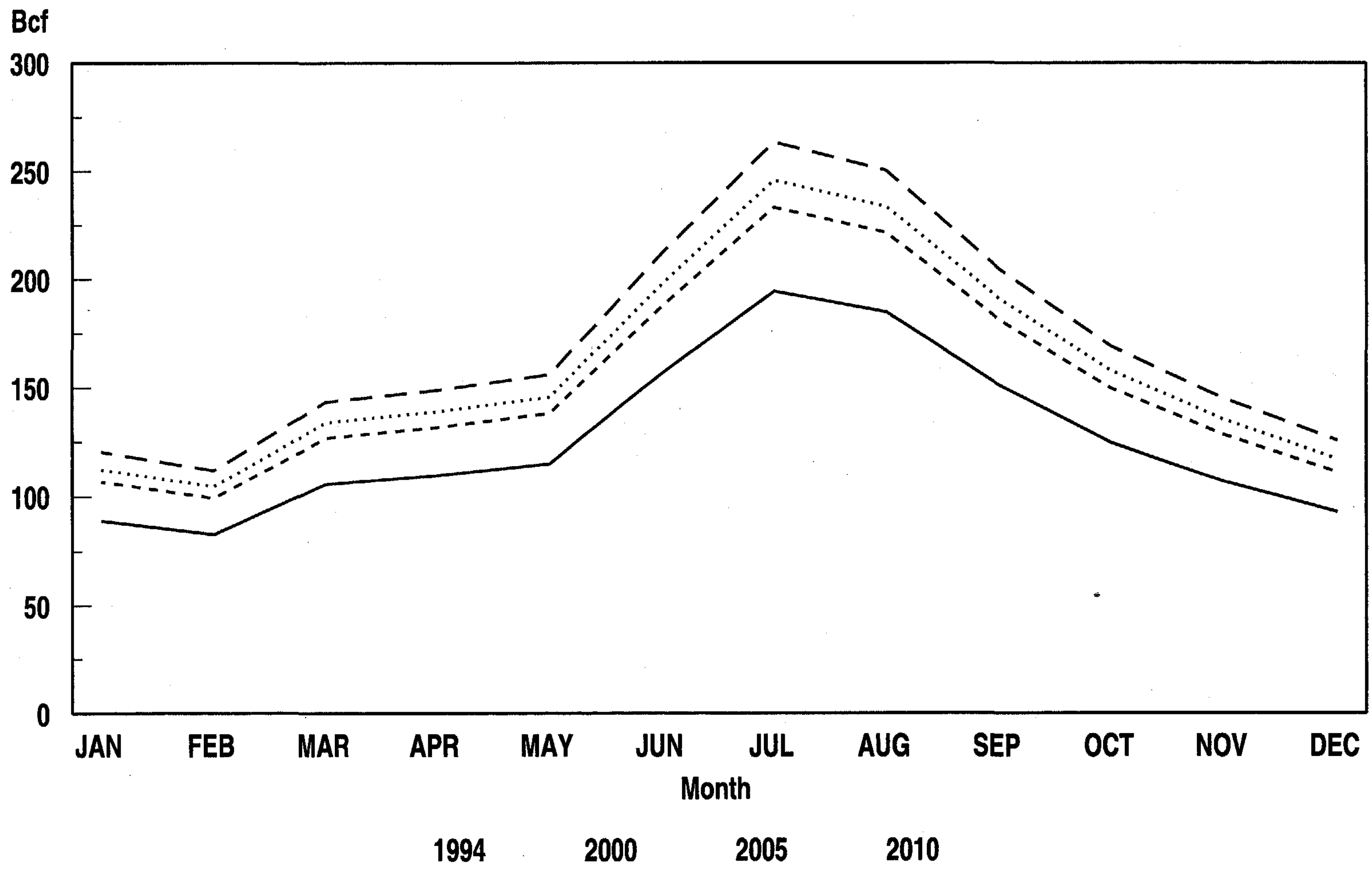
West North Central

Monthly Electrical Generation Gas Demand Curve



West South Central

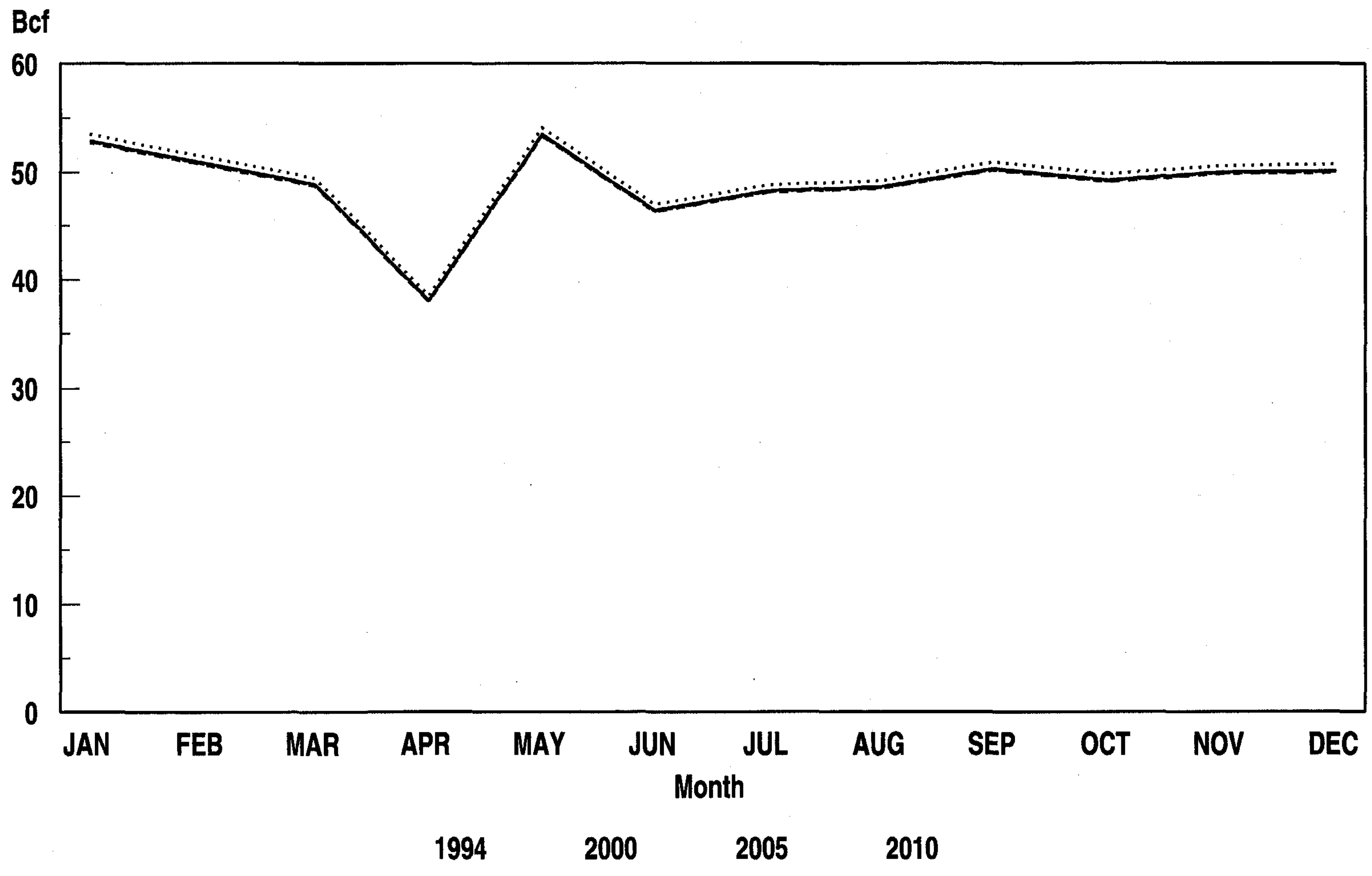
Monthly Electric Generation Gas Demand Curve

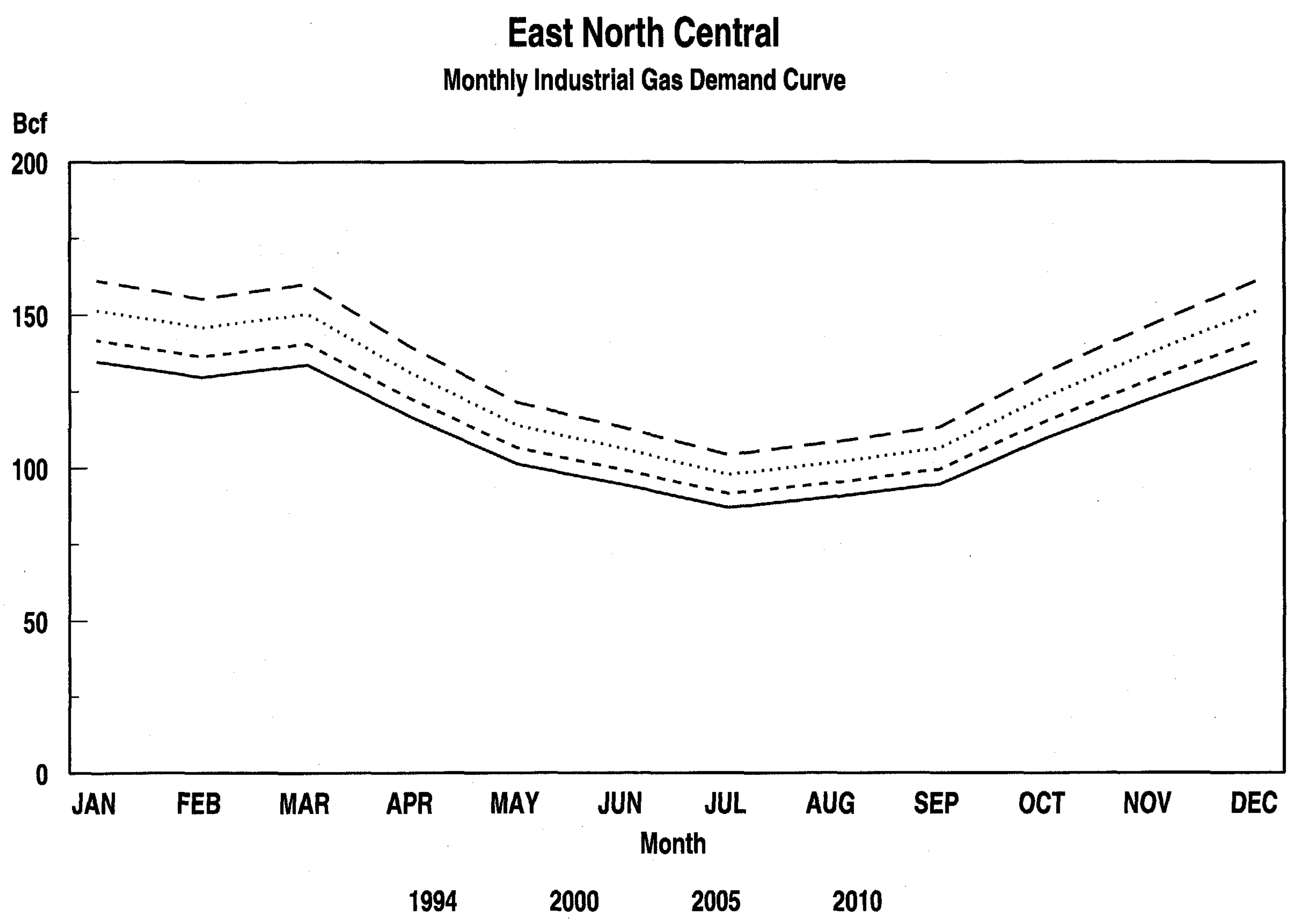


APPENDIX B
INDUSTRIAL GAS DEMAND FORECASTS

California

Monthly Industrial Gas Demand Curve




East North Central
Monthly Industrial Gas Demand Curve
Bcf
200
150
100
50
0
JAN
FEB
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Month
1994
2000
2005
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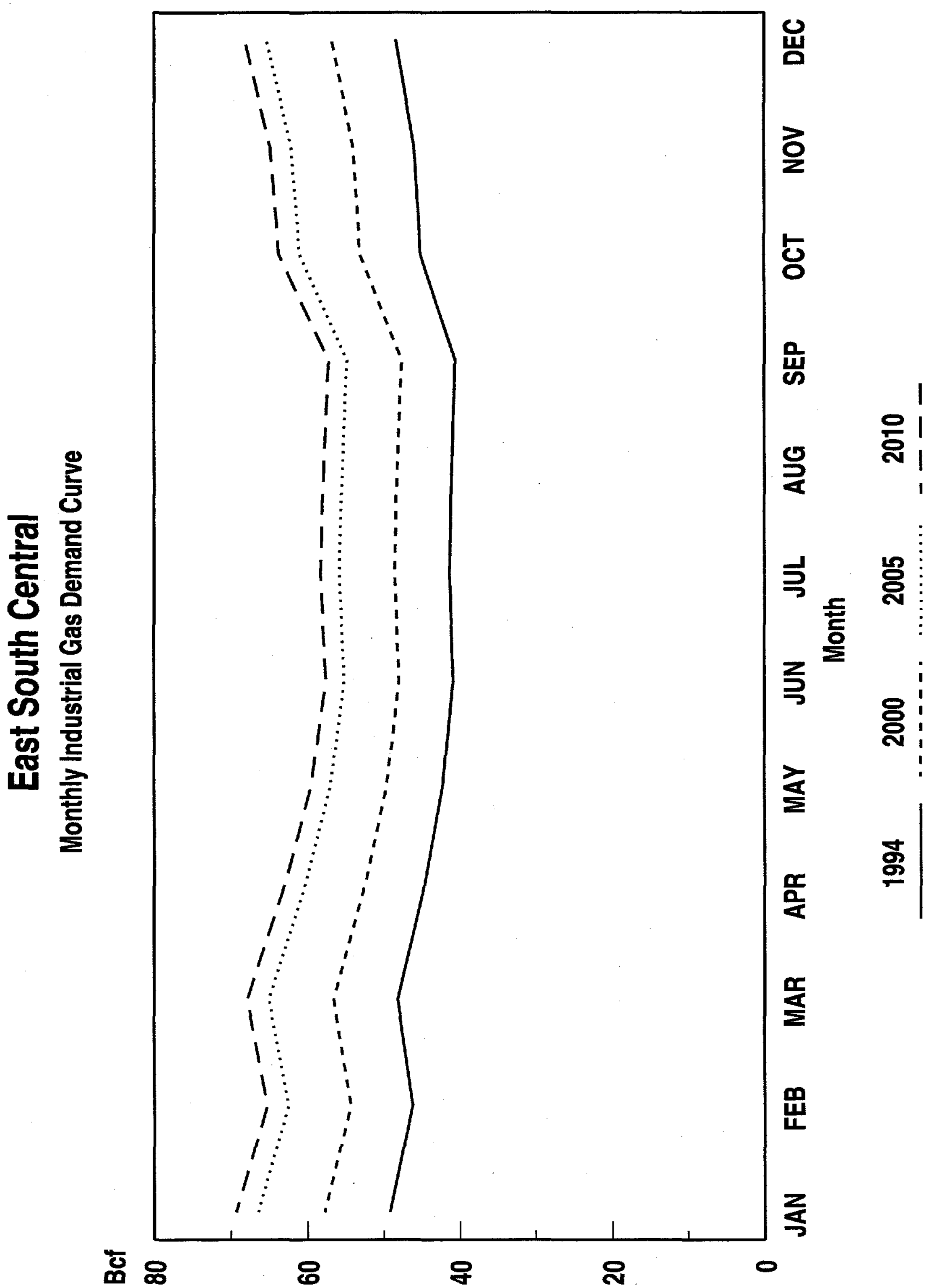
East South Central
Monthly Industrial Gas Demand Curve
Bcf
80
60
40
20
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JAN
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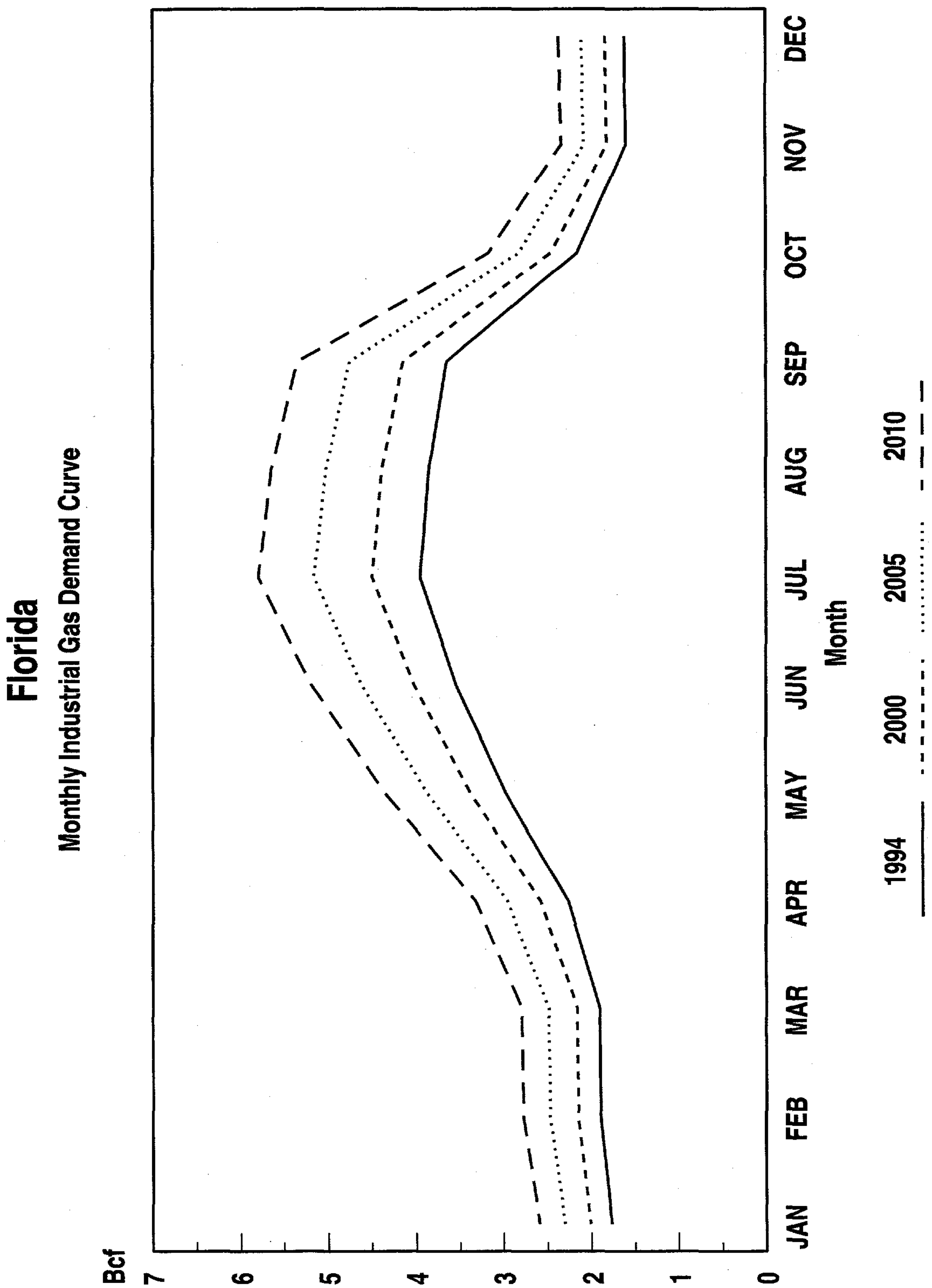
Florida
Monthly Industrial Gas Demand Curve
Bcf
0
1
2
3
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5
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7
JAN
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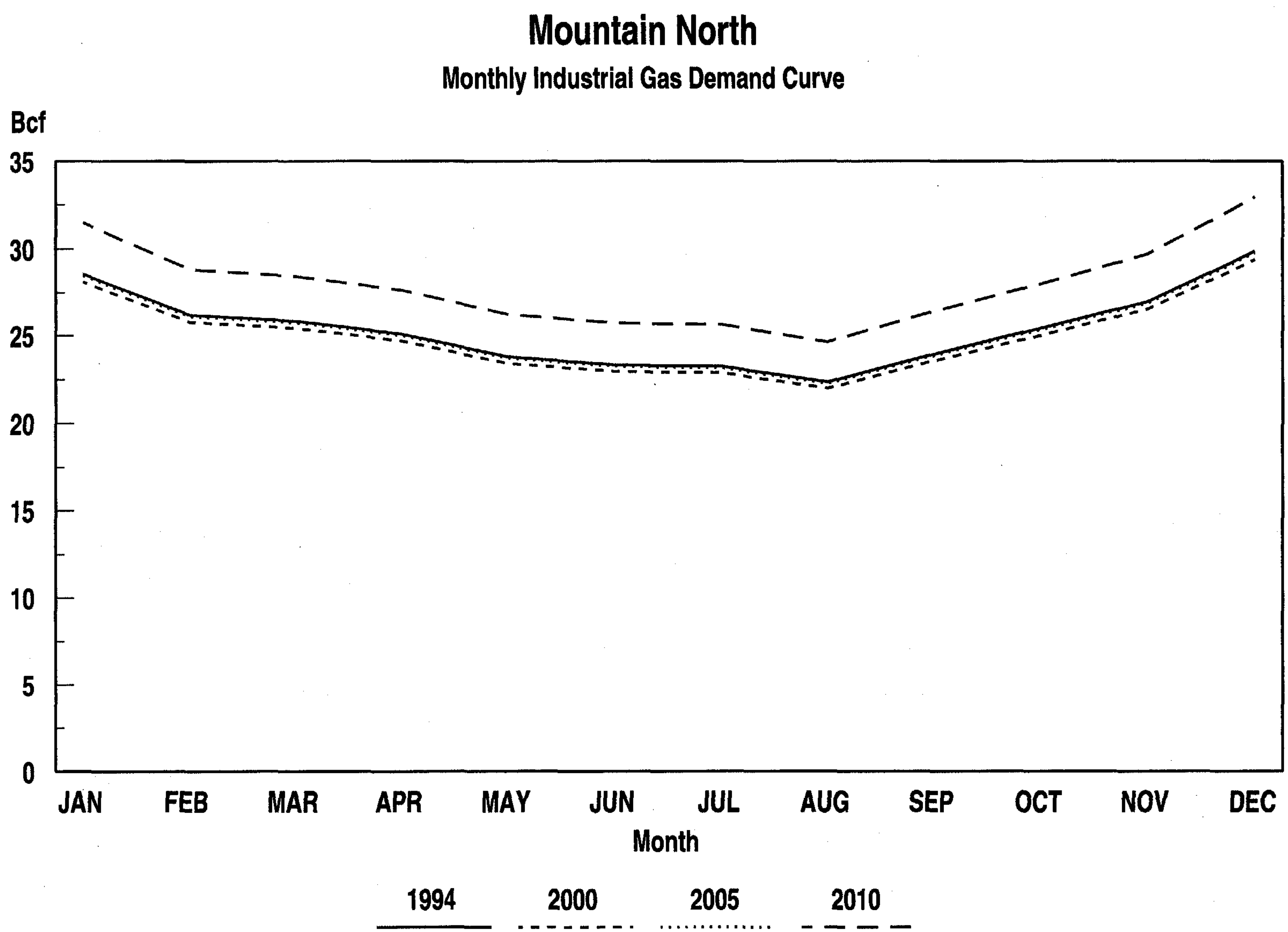
2010


Mountain North
Monthly Industrial Gas Demand Curve
Bcf
35
30
25
20
15
10
5
0
JAN
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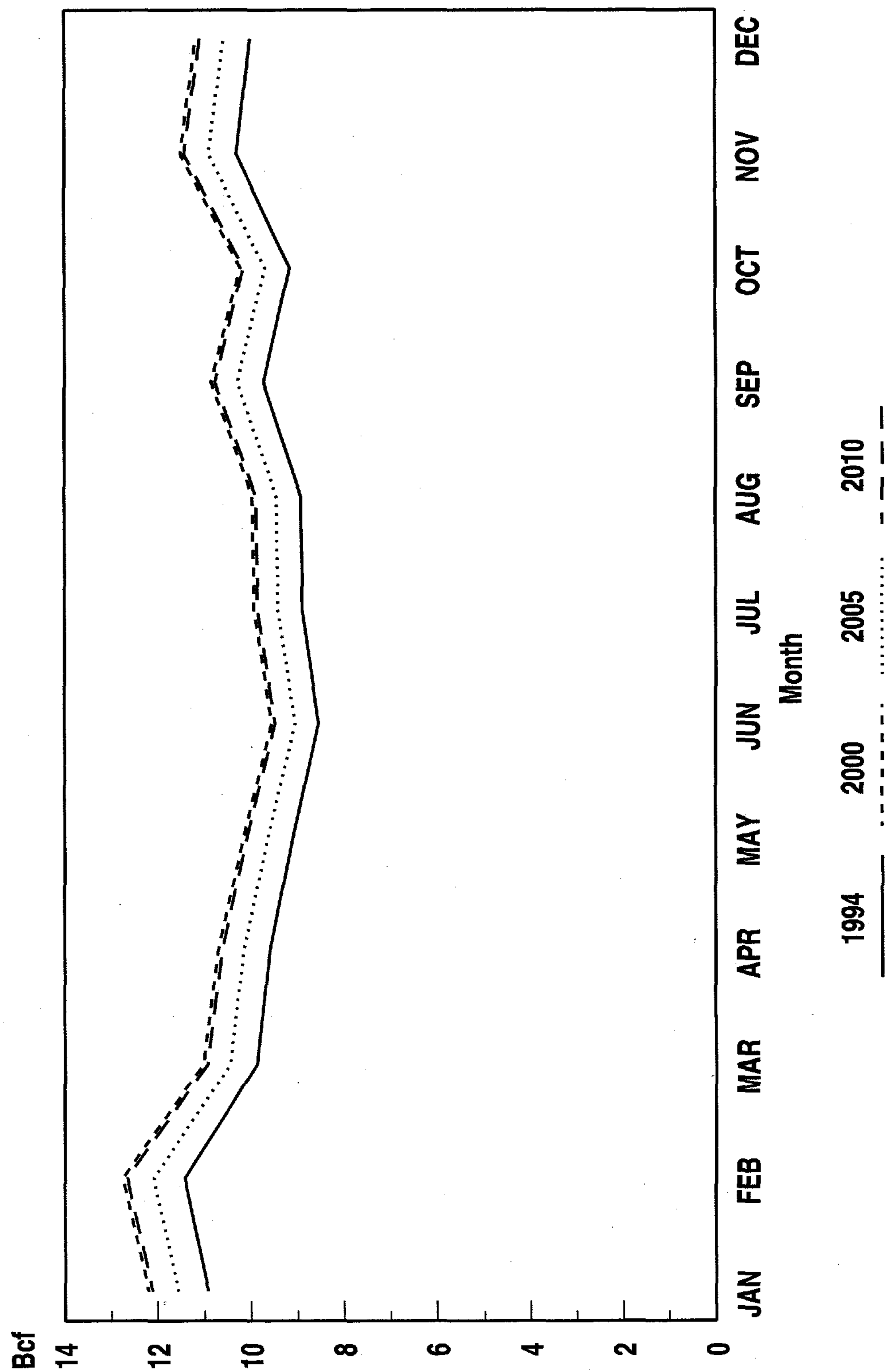
2010

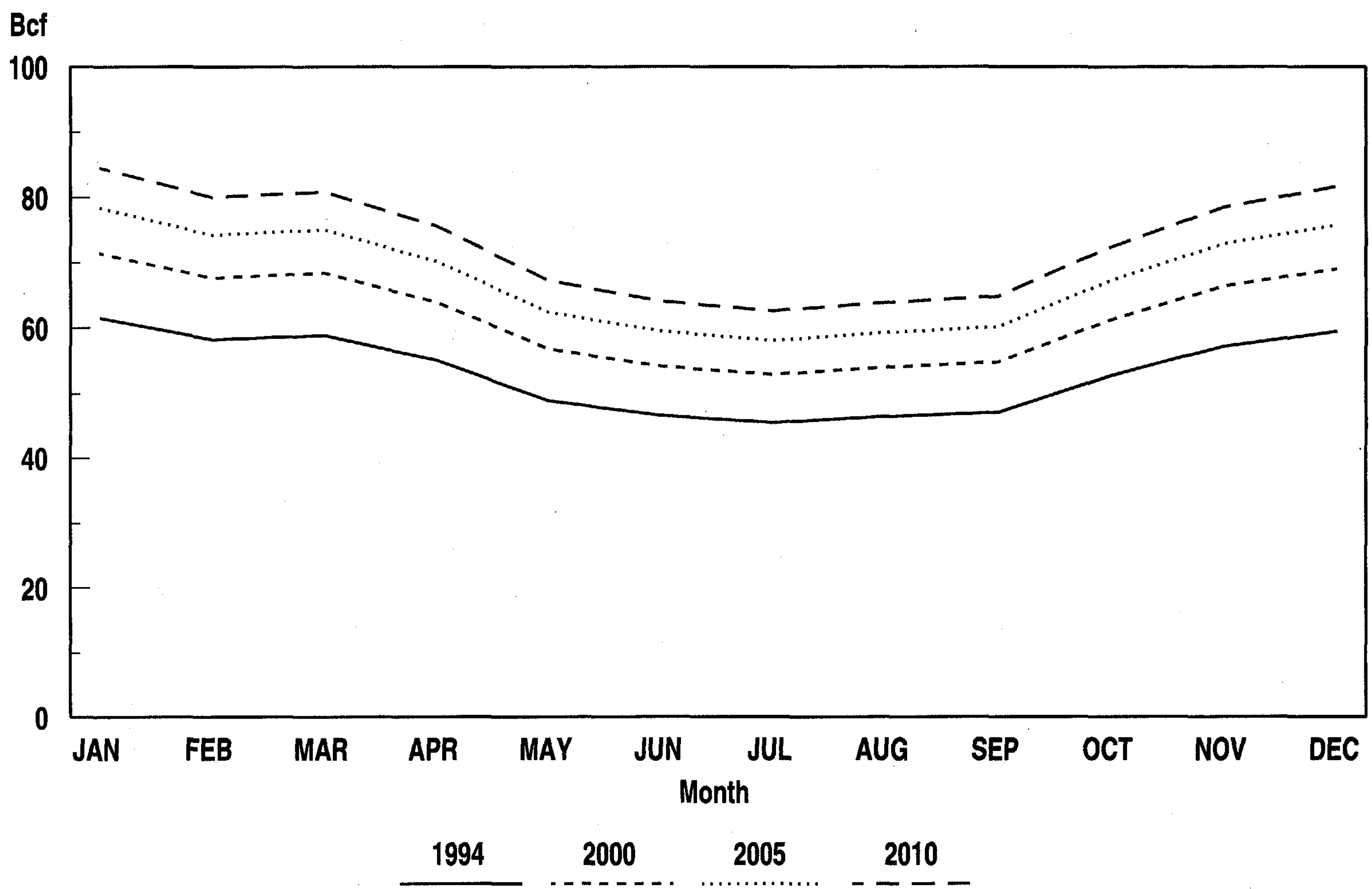
Mountain South

Monthly Industrial Gas Demand Curve

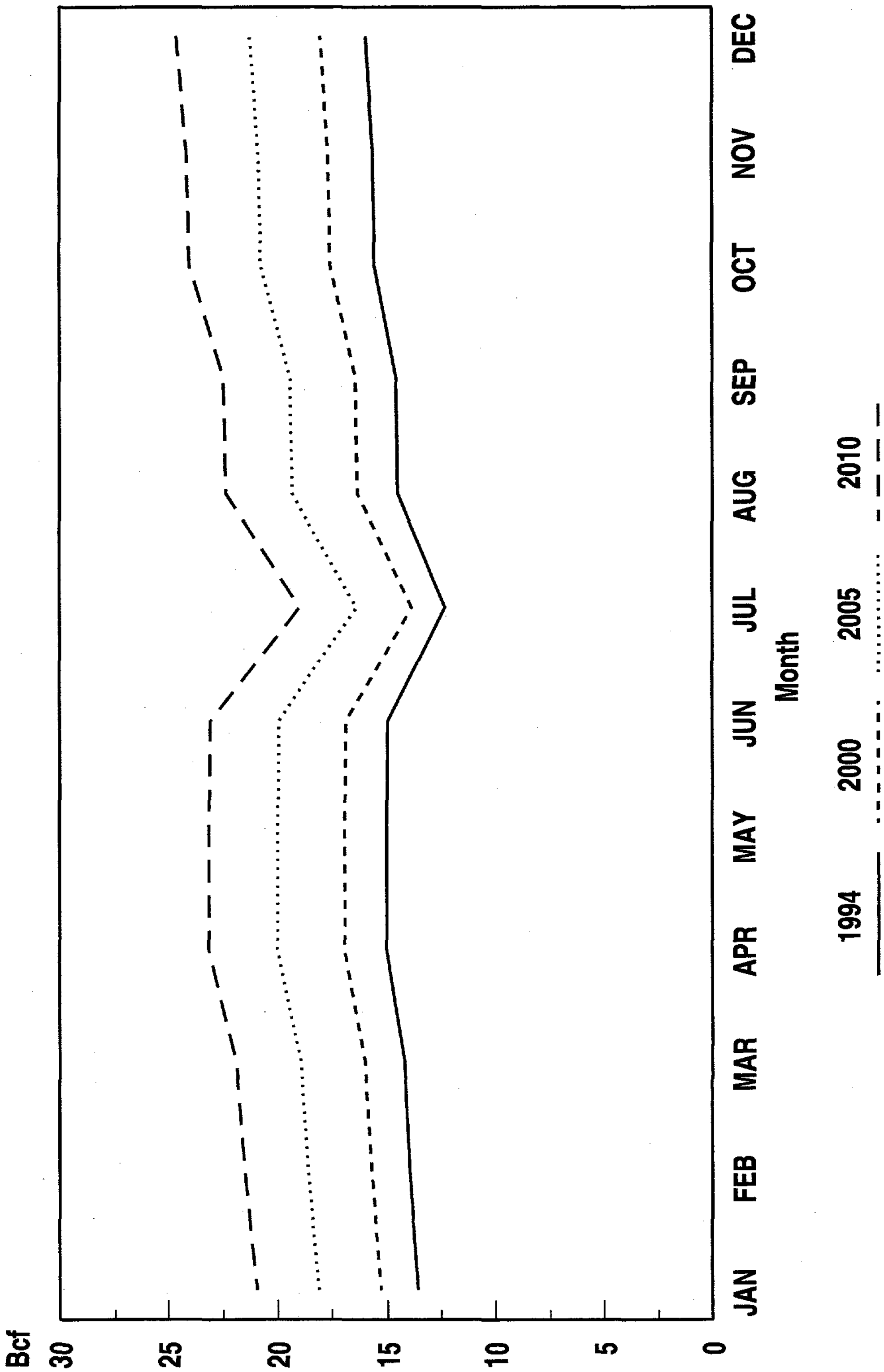


Middle Atlantic

Monthly Industrial Gas Demand Curve

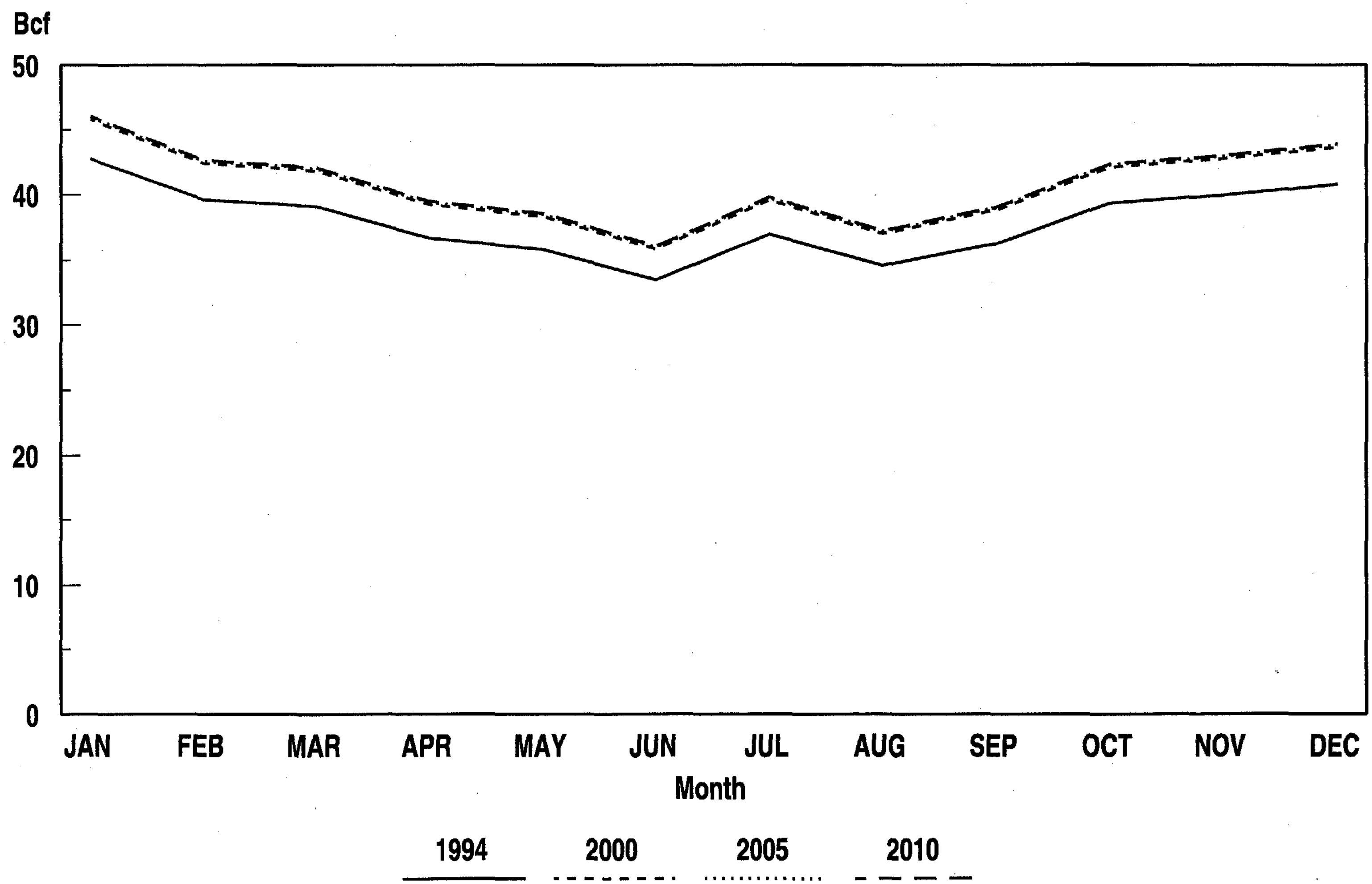


New England
Monthly Industrial Gas Demand Curve



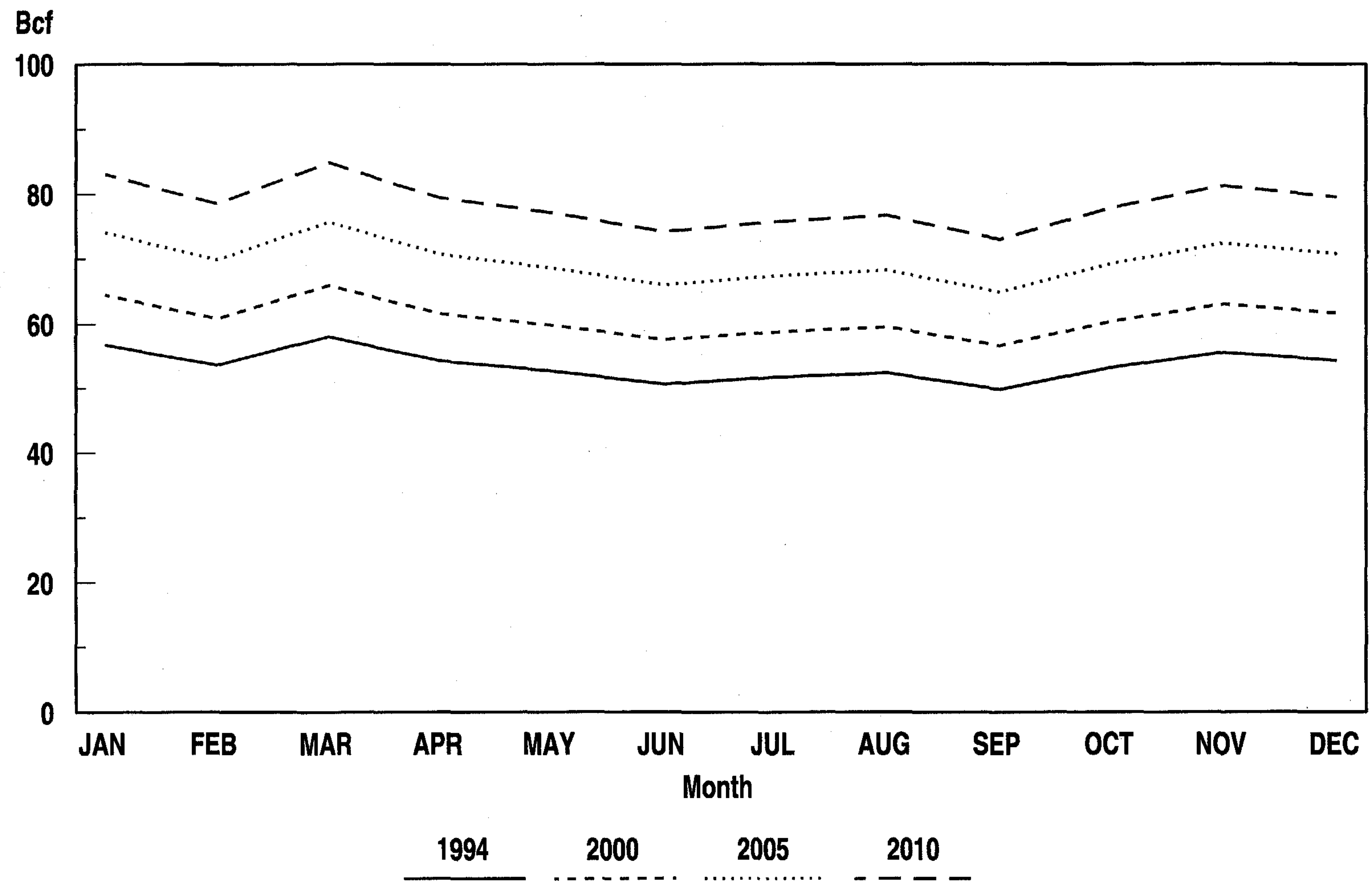
Pacific Northwest

Monthly Industrial Gas Demand Curve



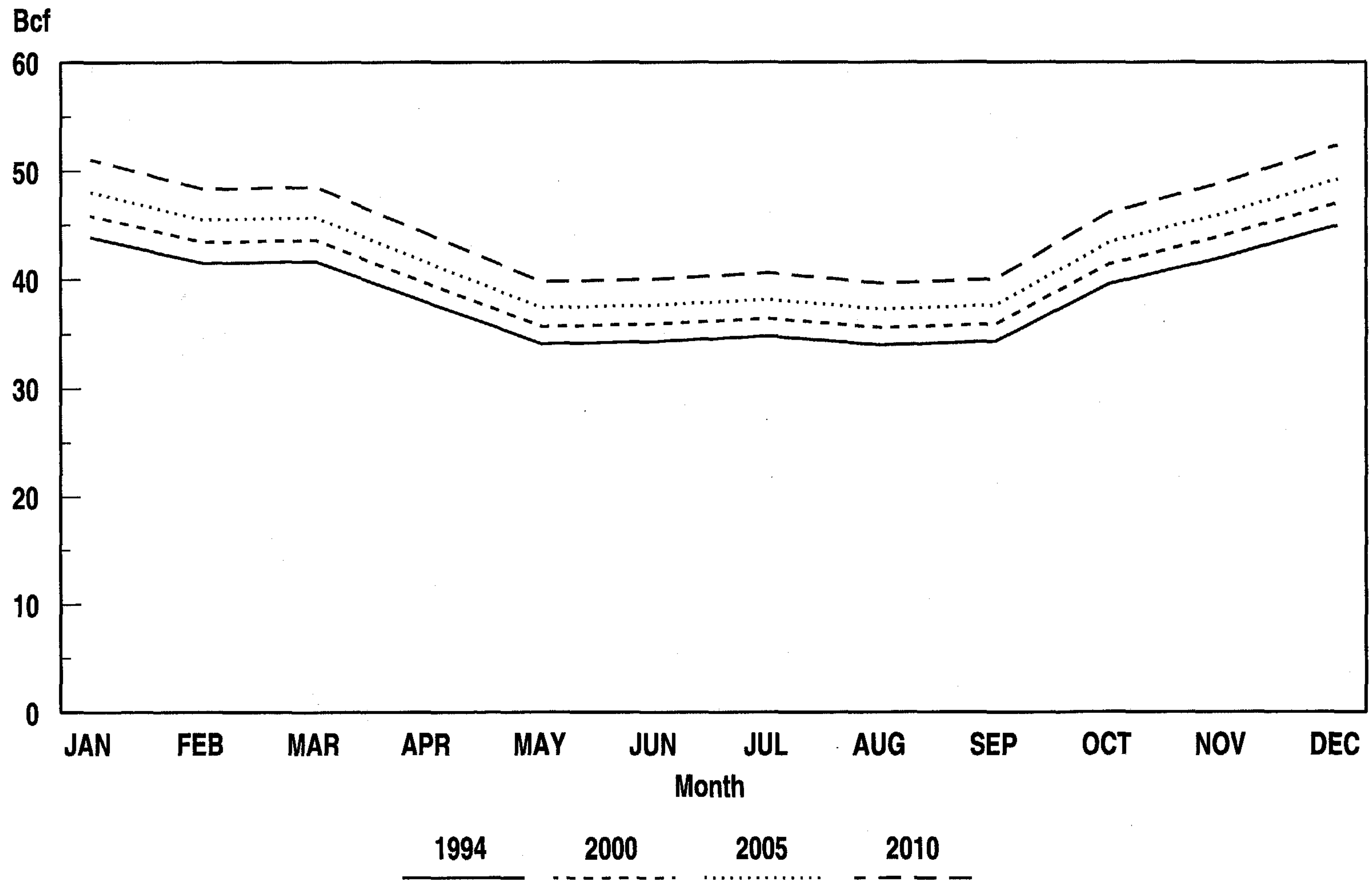
South Atlantic

Monthly Industrial Gas Demand Curve



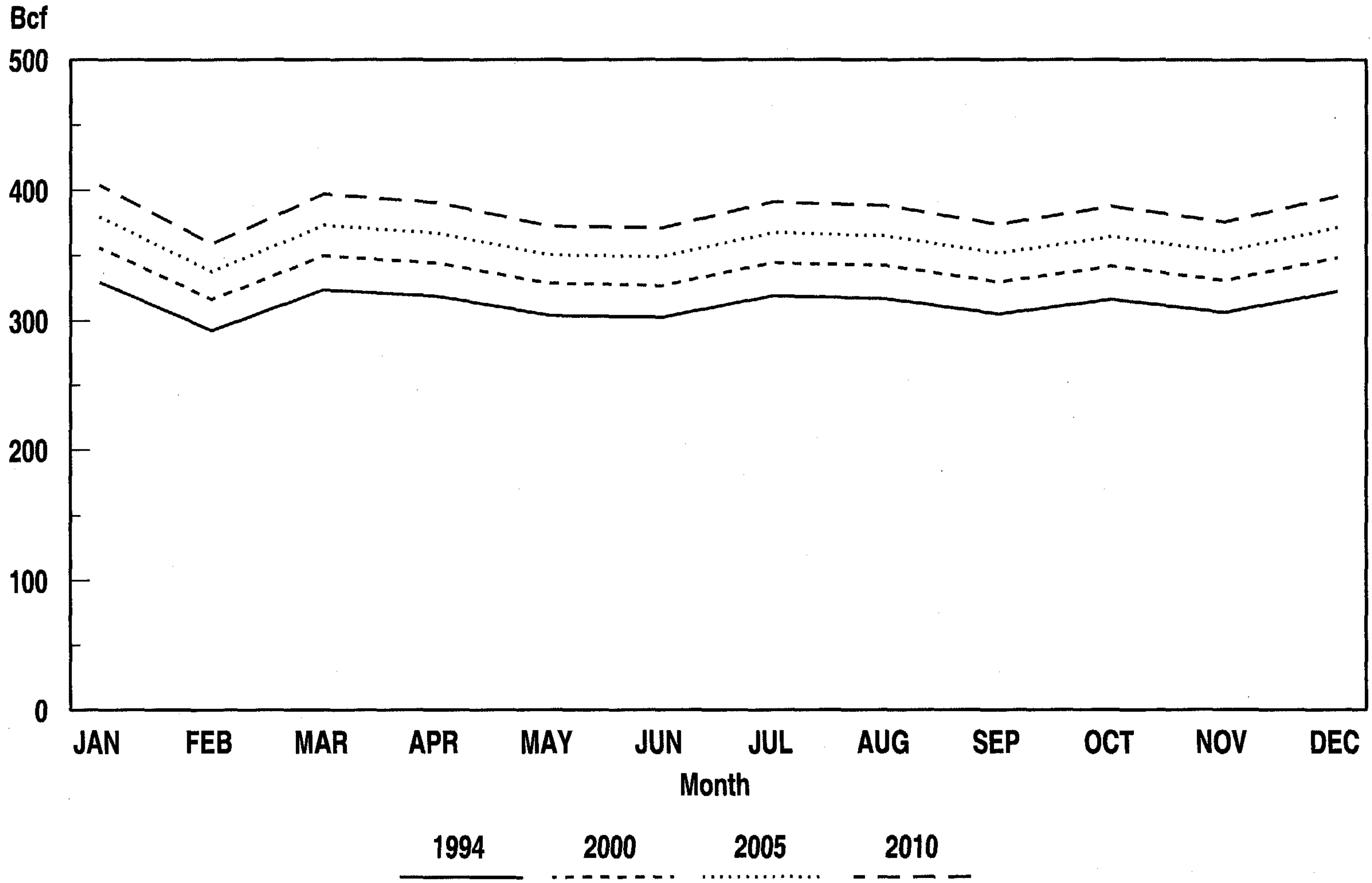
West North Central

Monthly Industrial Gas Demand Curve

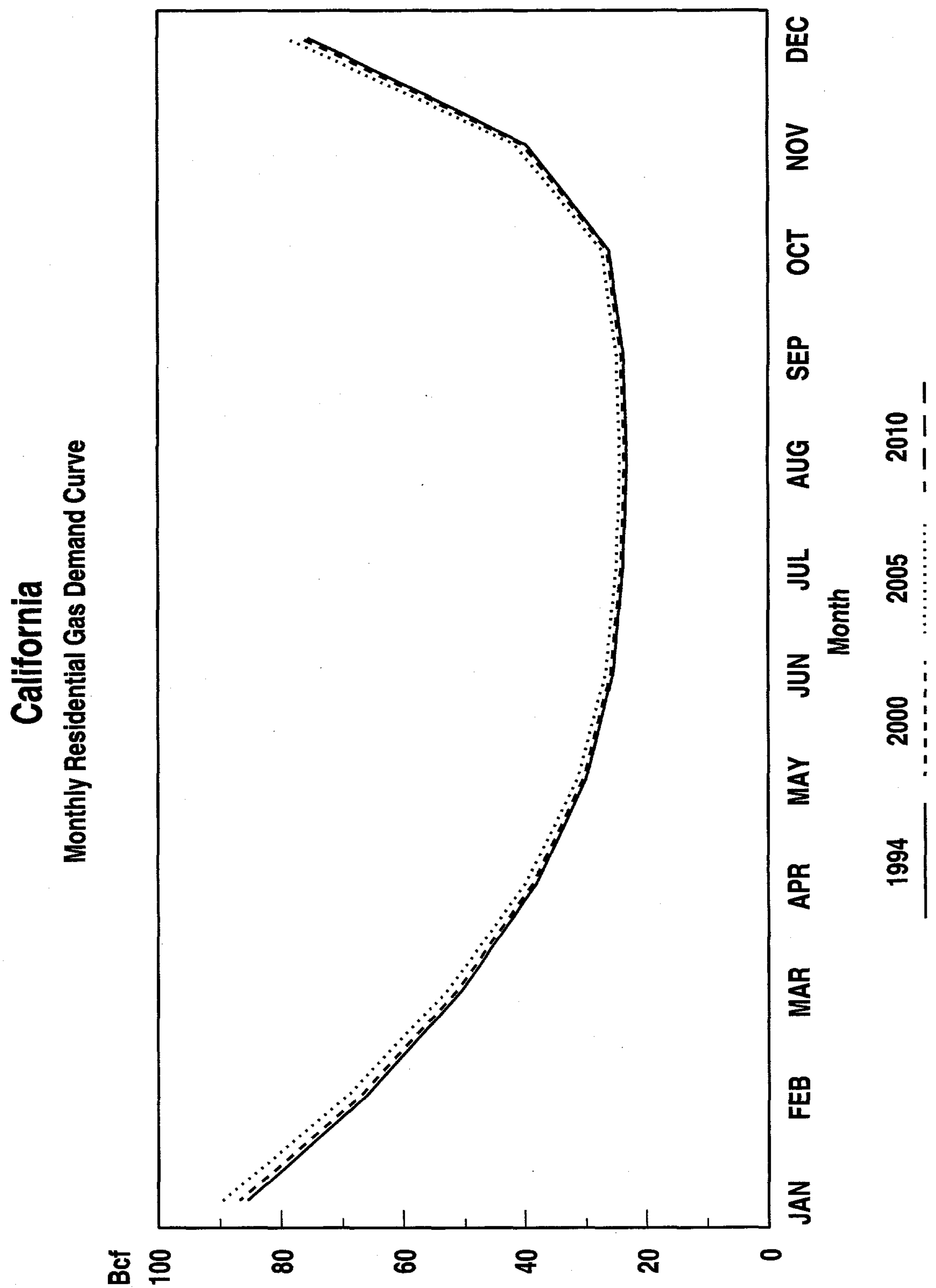


West South Central

Monthly Industrial Gas Demand Curve



APPENDIX C
RESIDENTIAL GAS DEMAND FORECASTS


California
Monthly Residential Gas Demand Curve
Bcf
100
80
60
40
20
0
JAN
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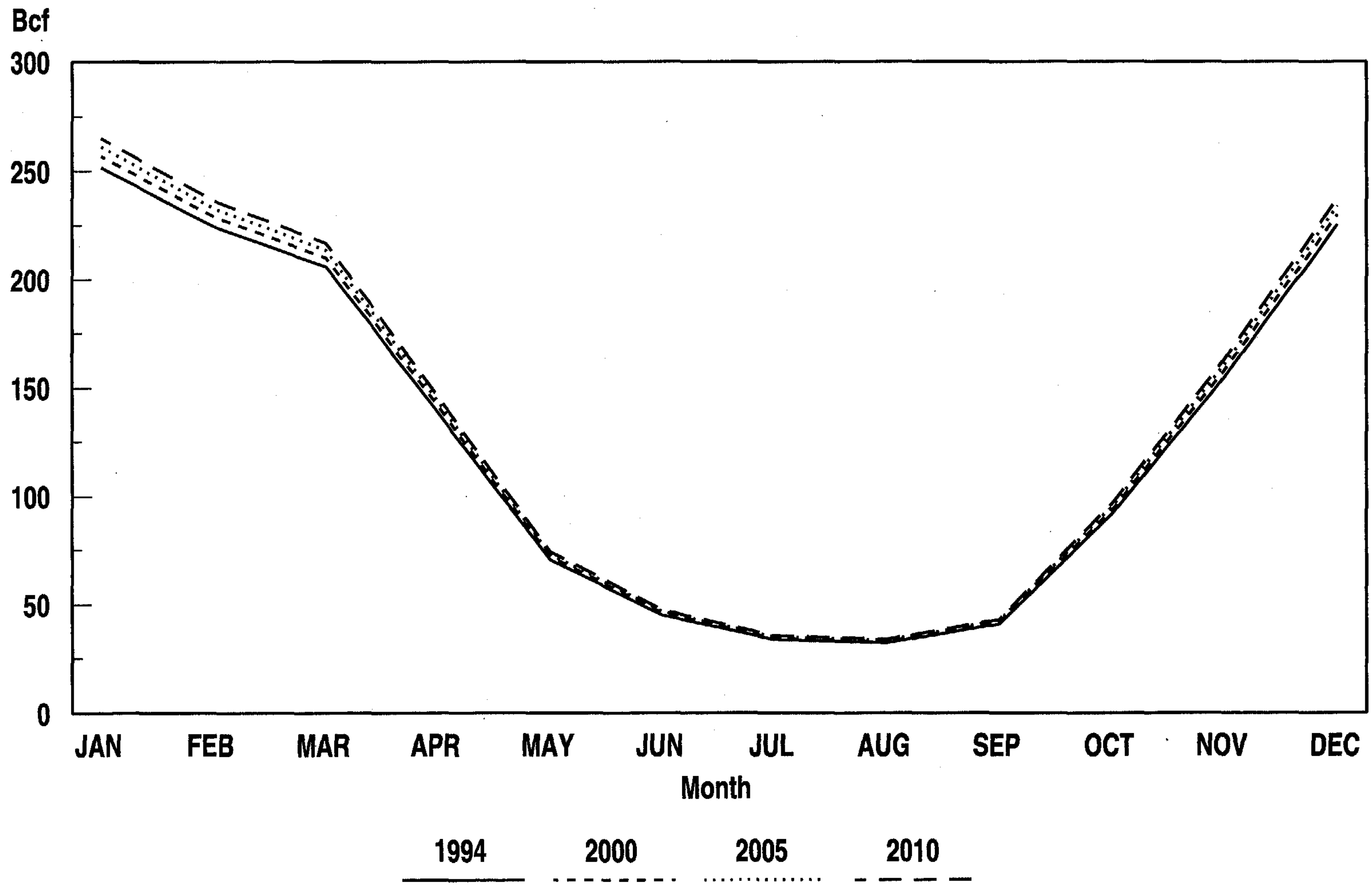
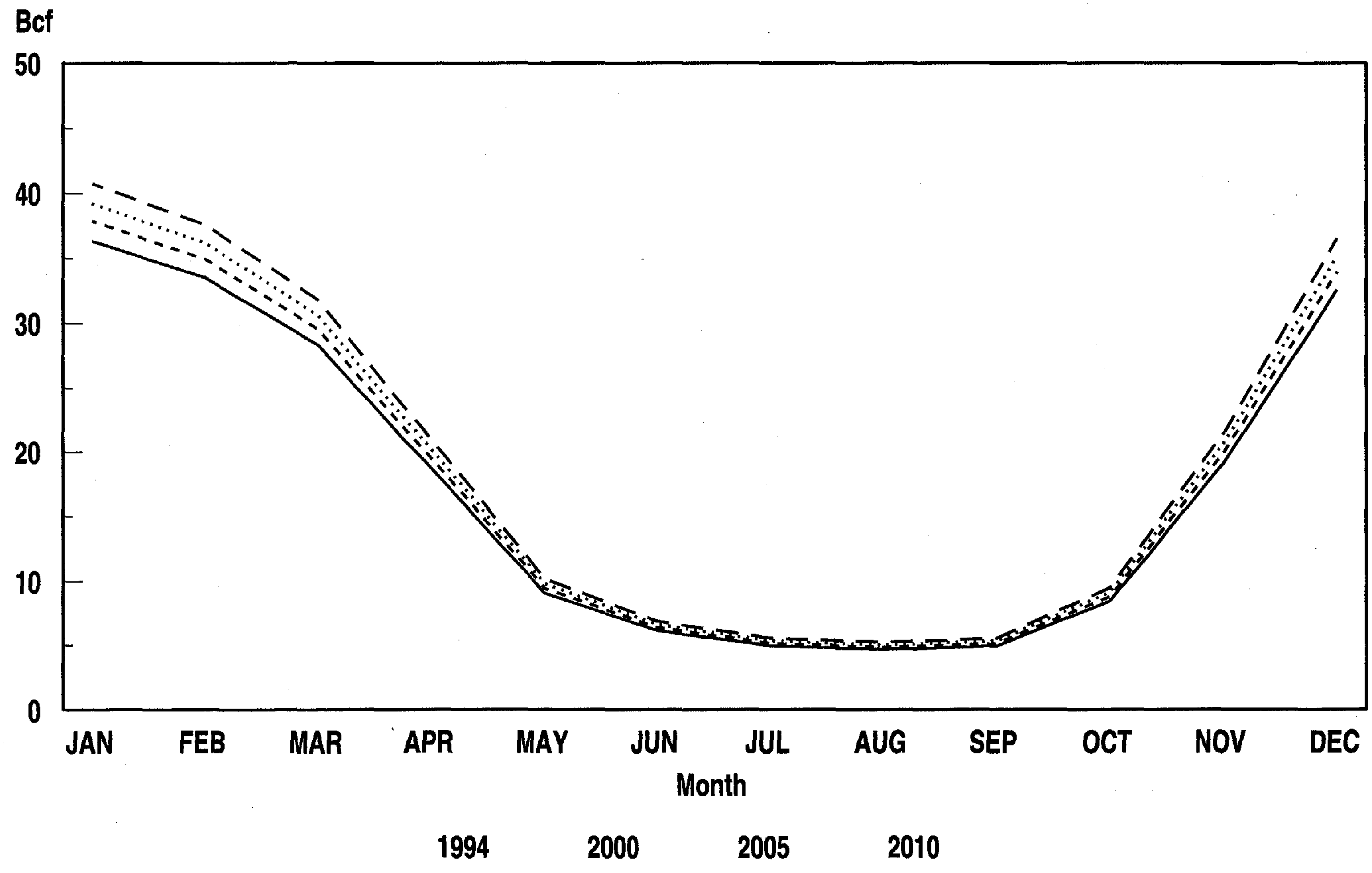
East North Central

Monthly Residential Gas Demand Curve



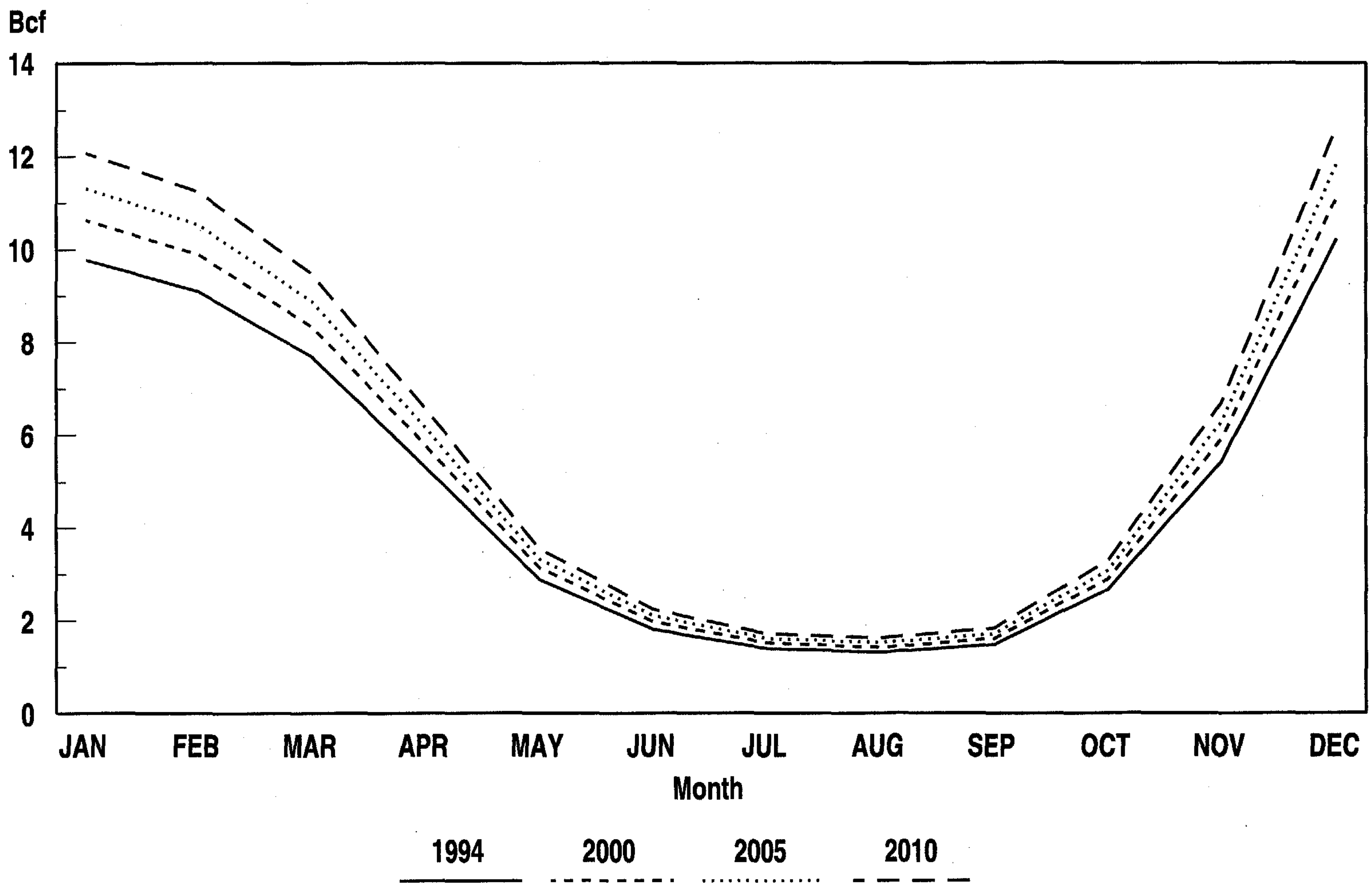
East South Central

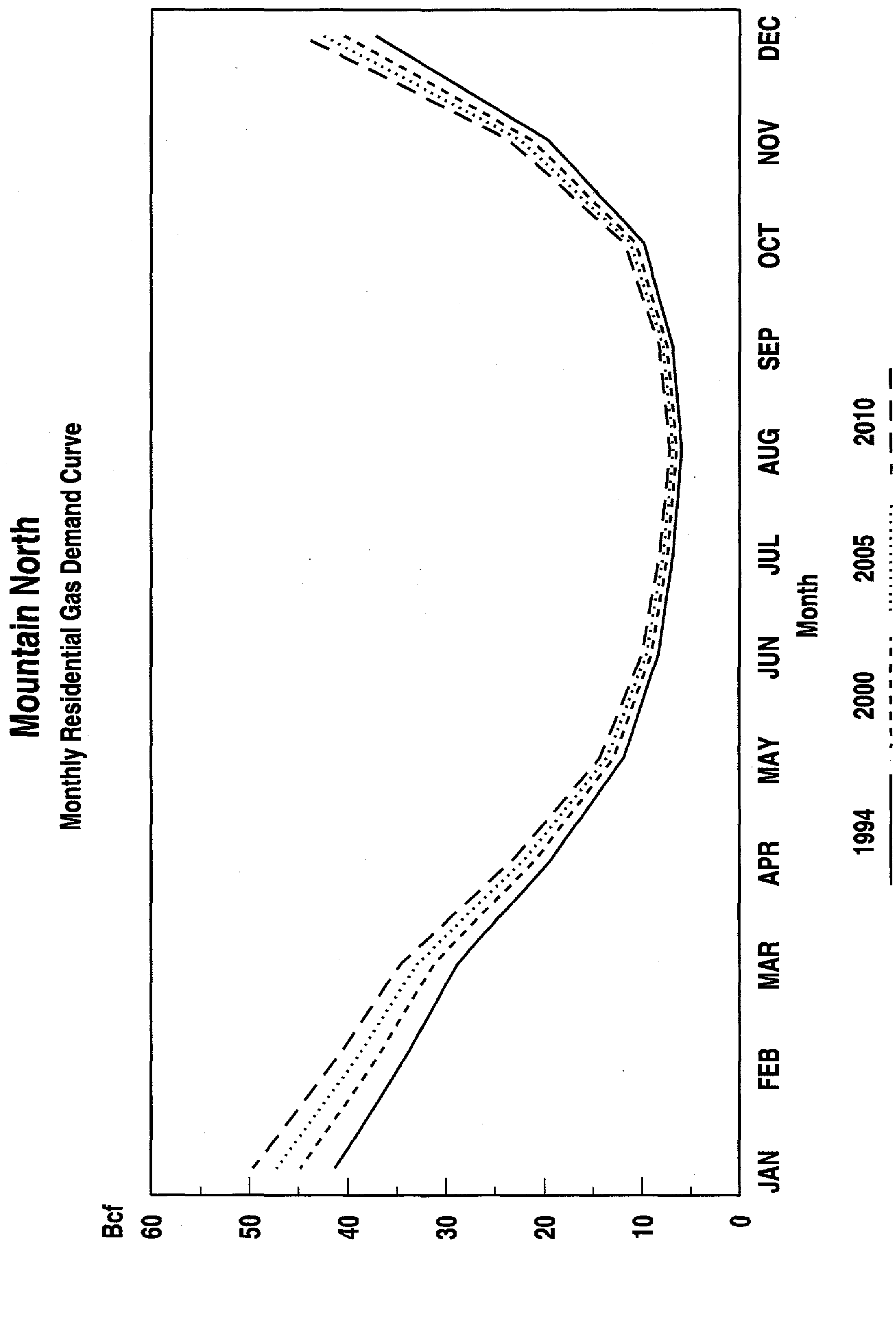
Monthly Residential Gas Demand Curve



Florida

Monthly Residential Gas Demand Curve




Mountain North
Monthly Residential Gas Demand Curve
Bcf
60
50
40
30
20
10
0
JAN
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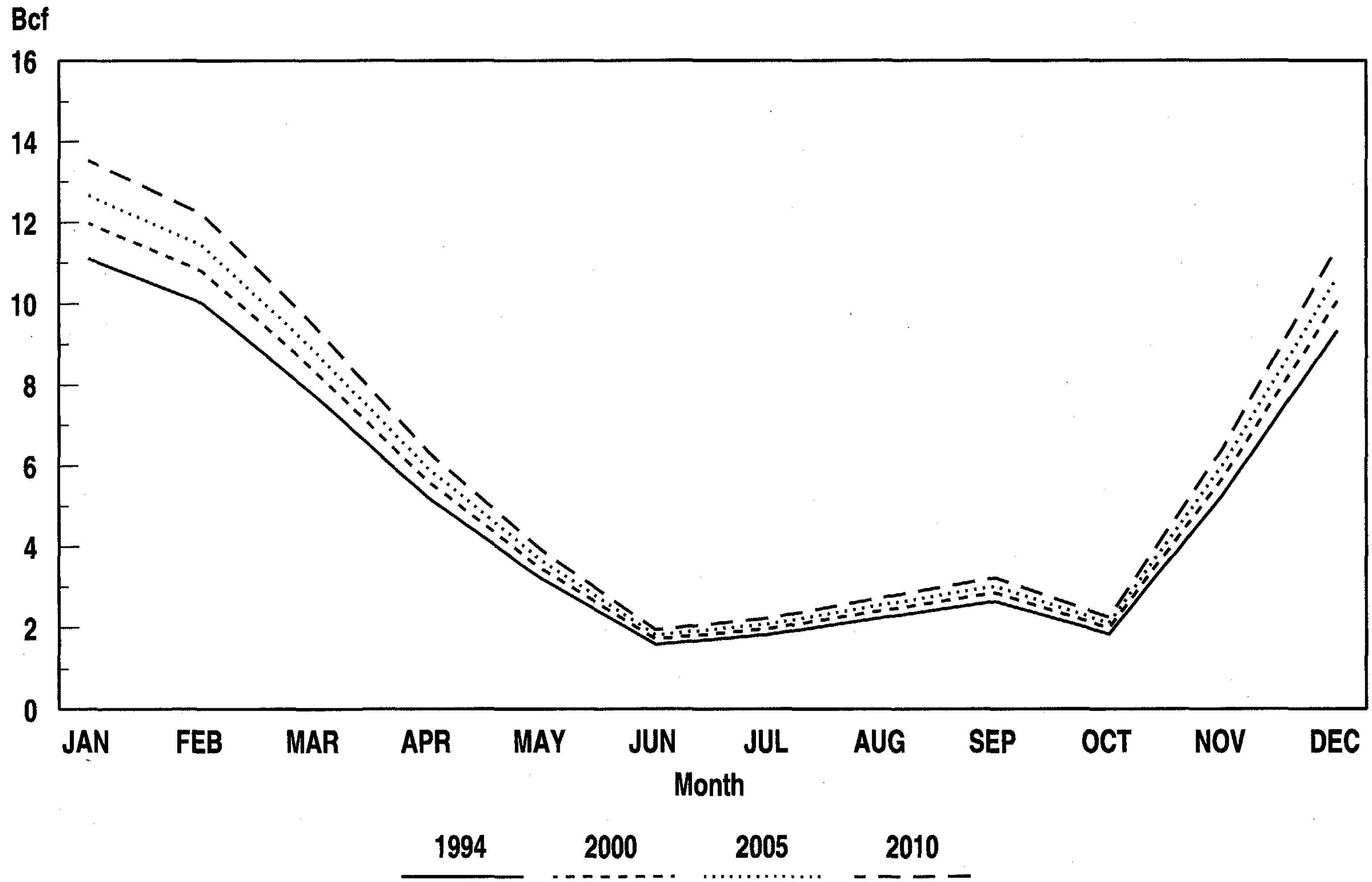
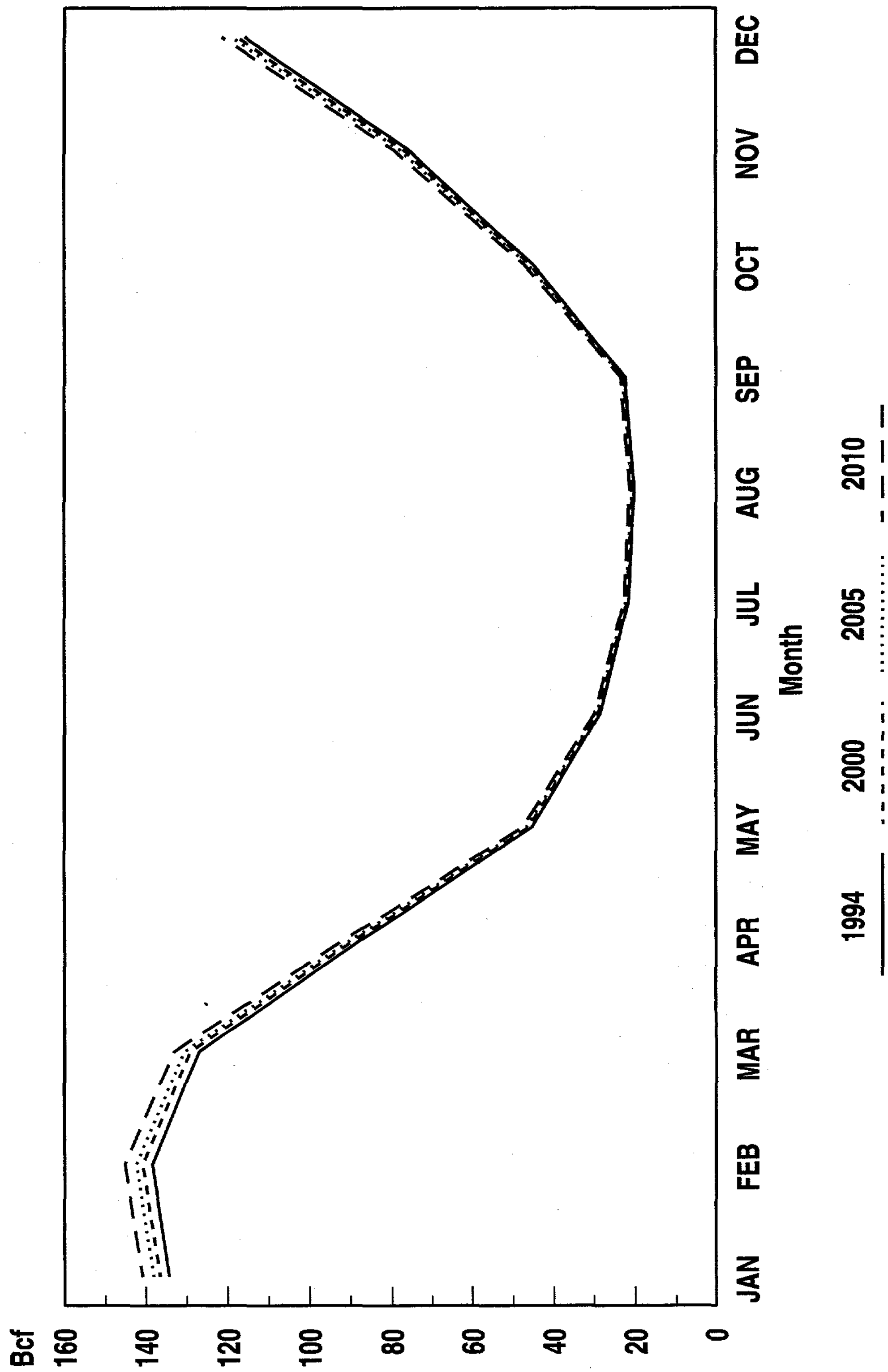
Mountain South

Monthly Residential Gas Demand Curve



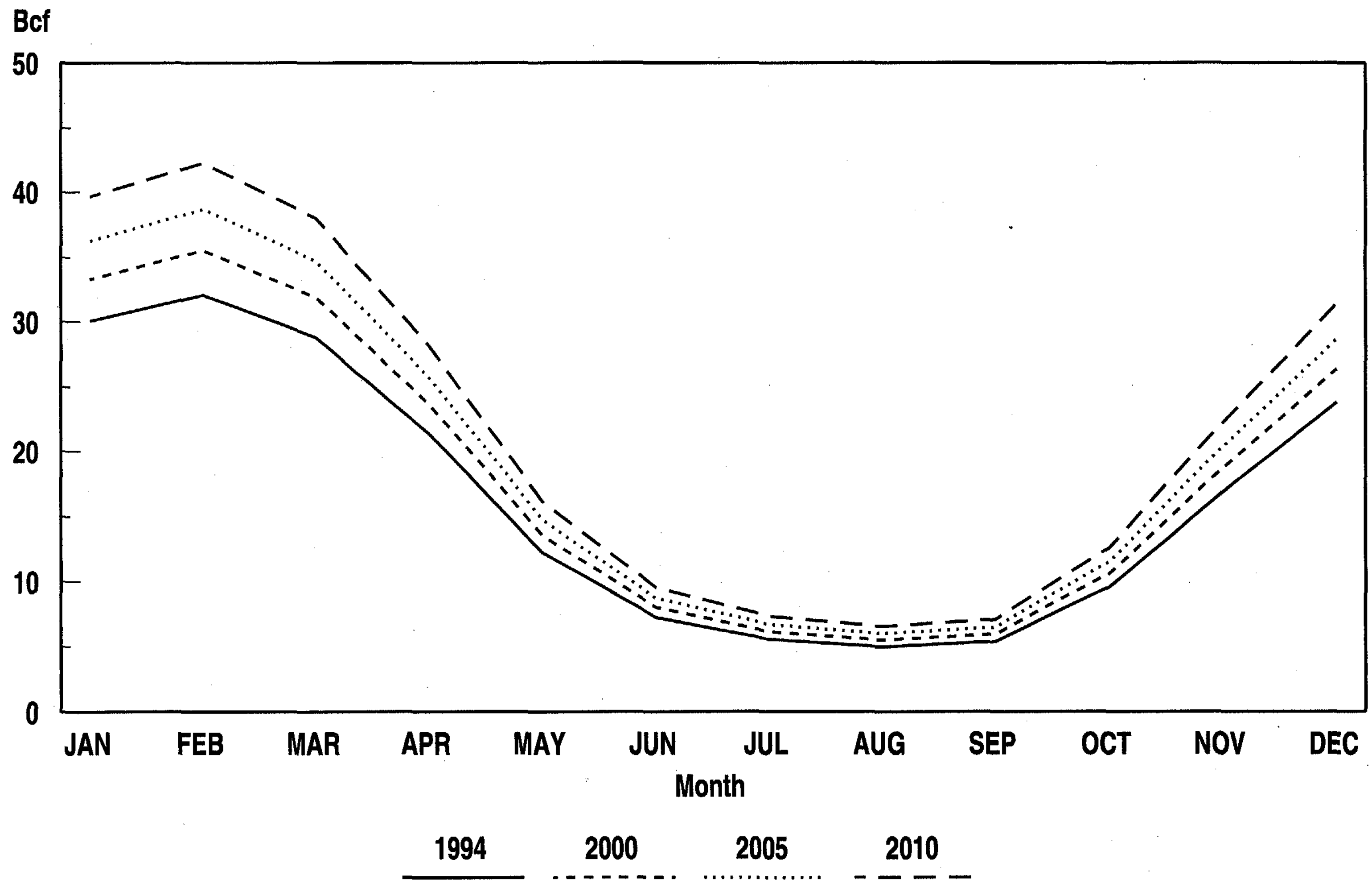
Middle Atlantic

Monthly Residential Gas Demand Curve



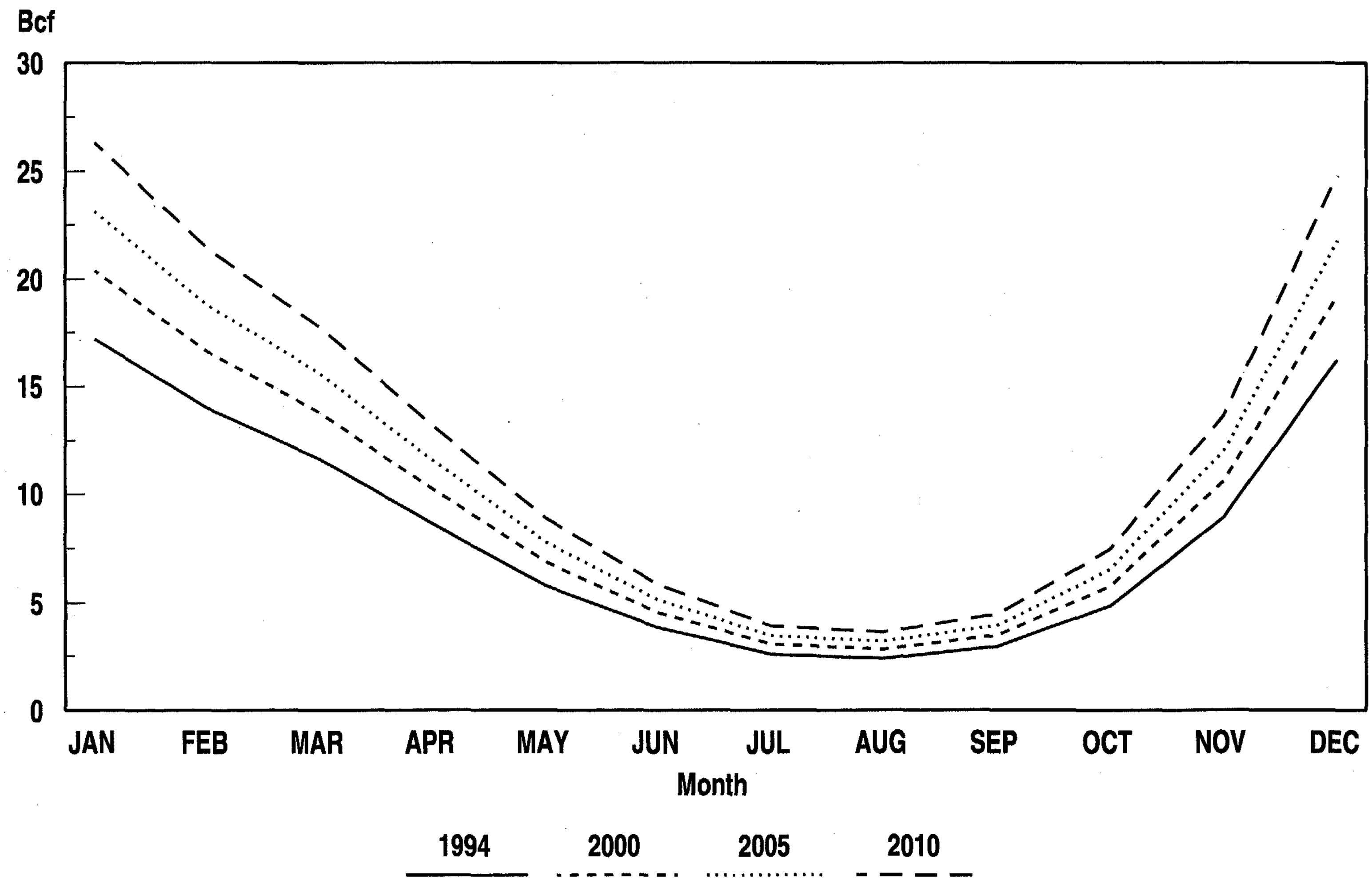
New England

Monthly Residential Gas Demand Curve



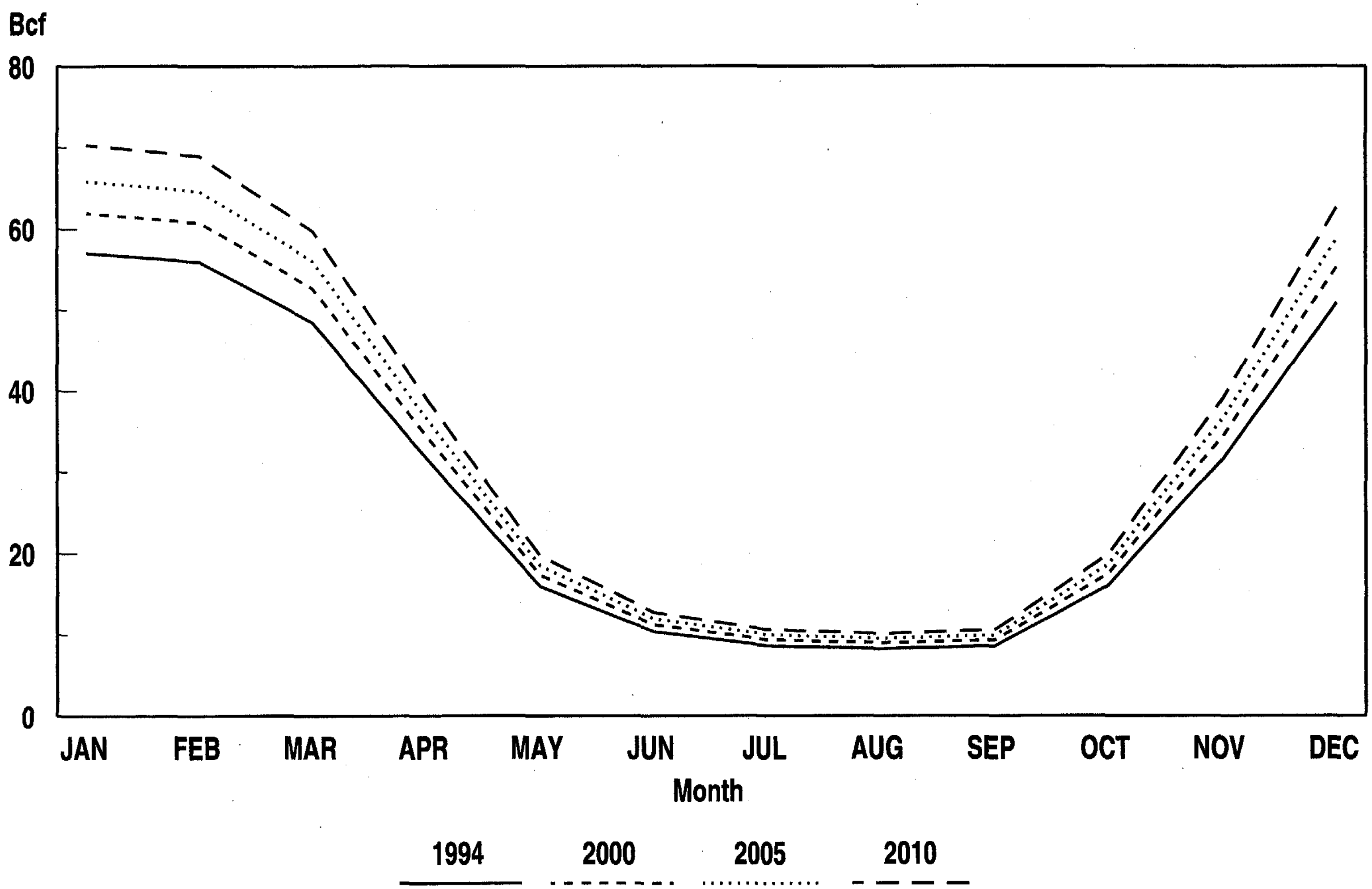
Pacific Northwest

Monthly Residential Gas Demand Curve

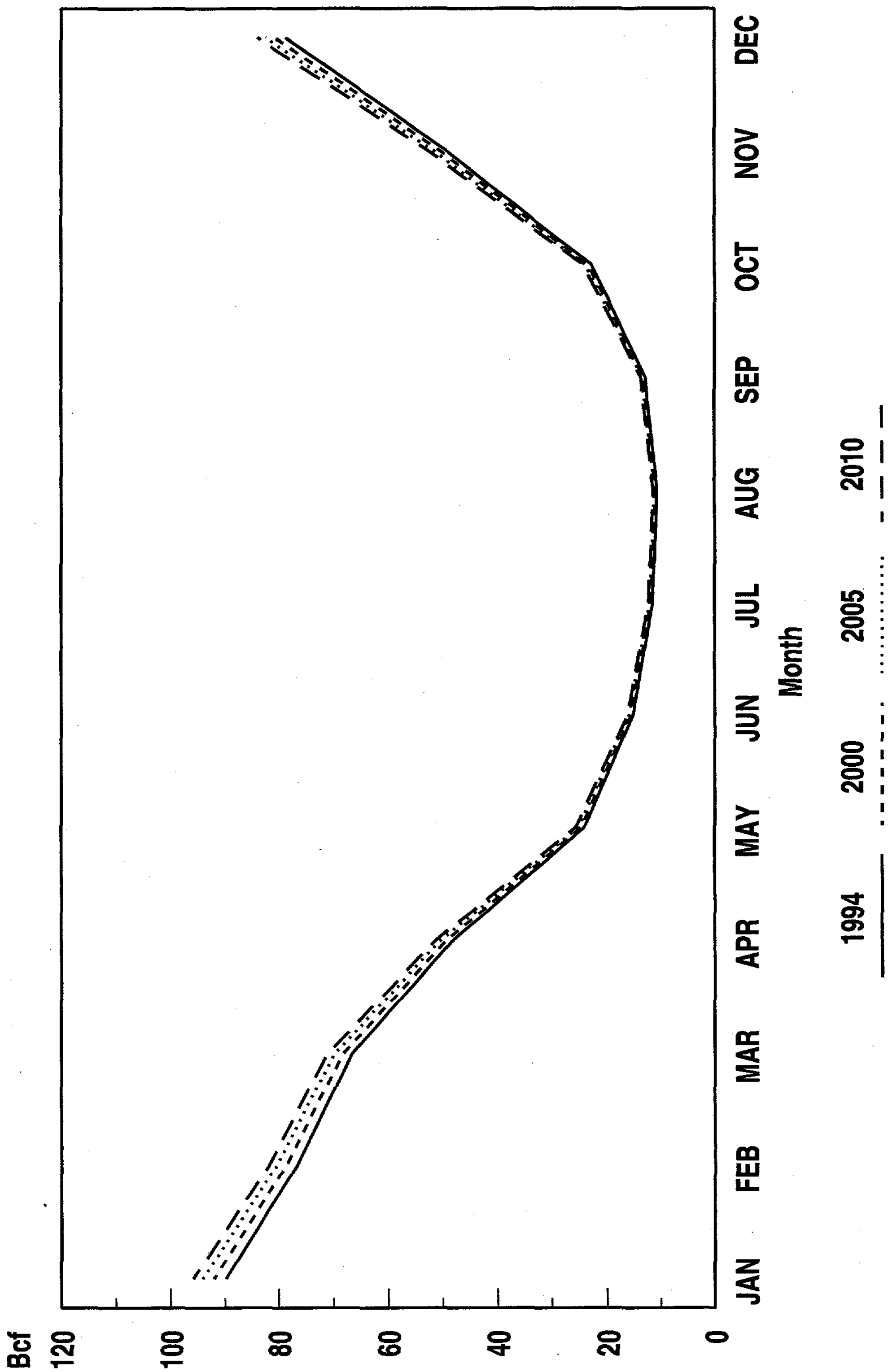


South Atlantic

Monthly Residential Gas Demand Curve

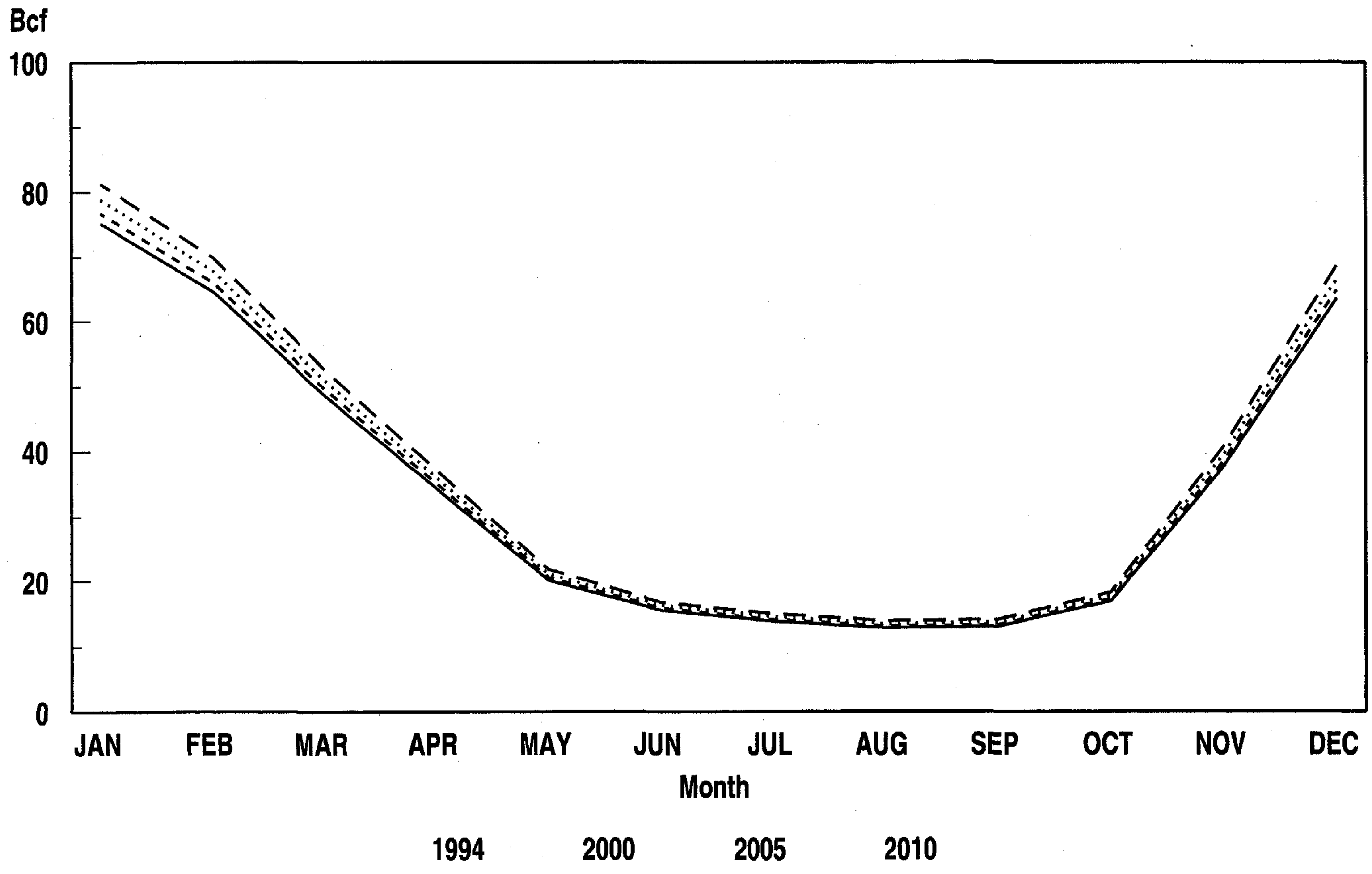


West North Central
Monthly Residential Gas Demand Curve



West South Central

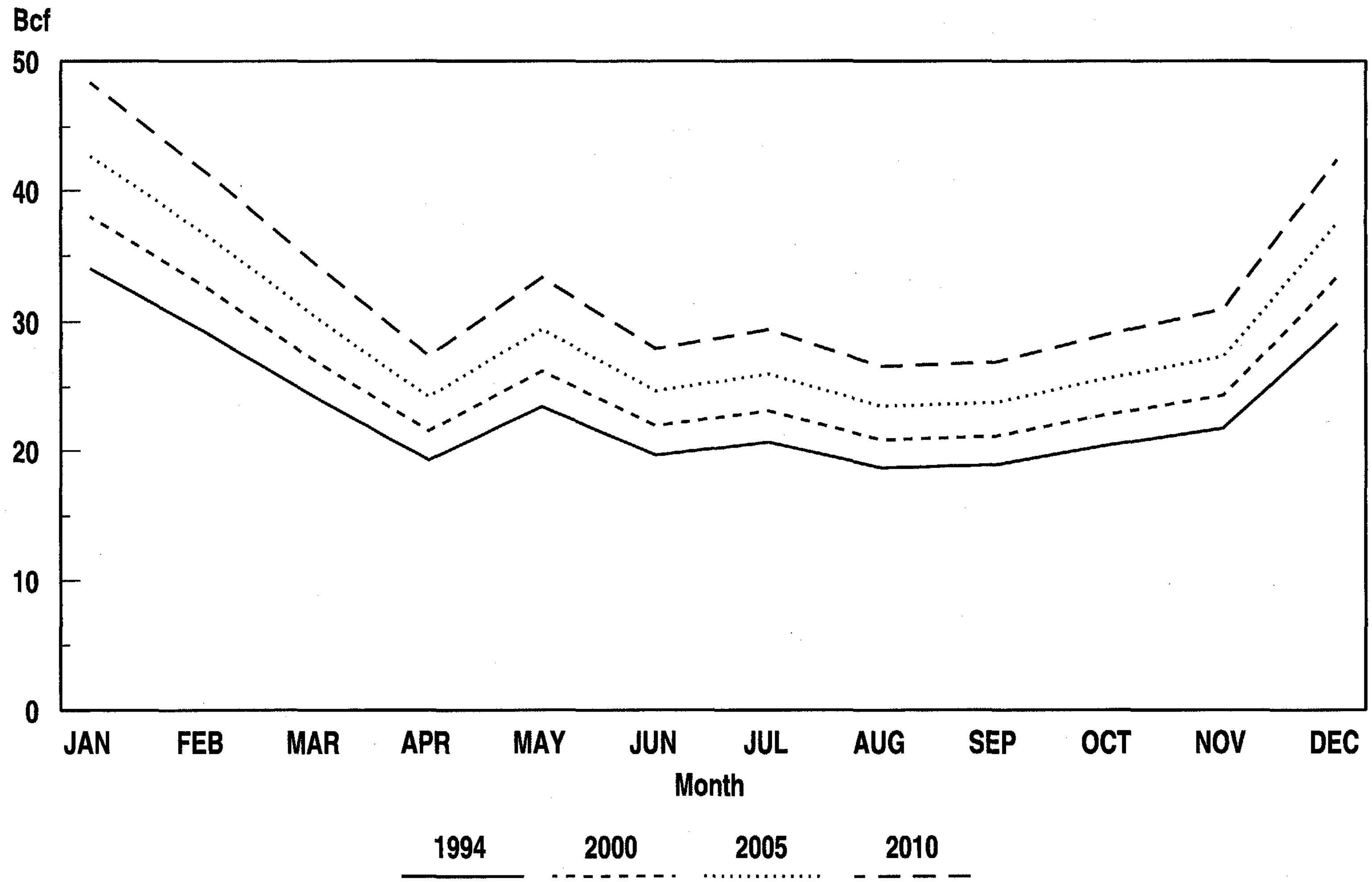
Monthly Residential Gas Demand Curve



APPENDIX D
COMMERCIAL GAS DEMAND FORECASTS

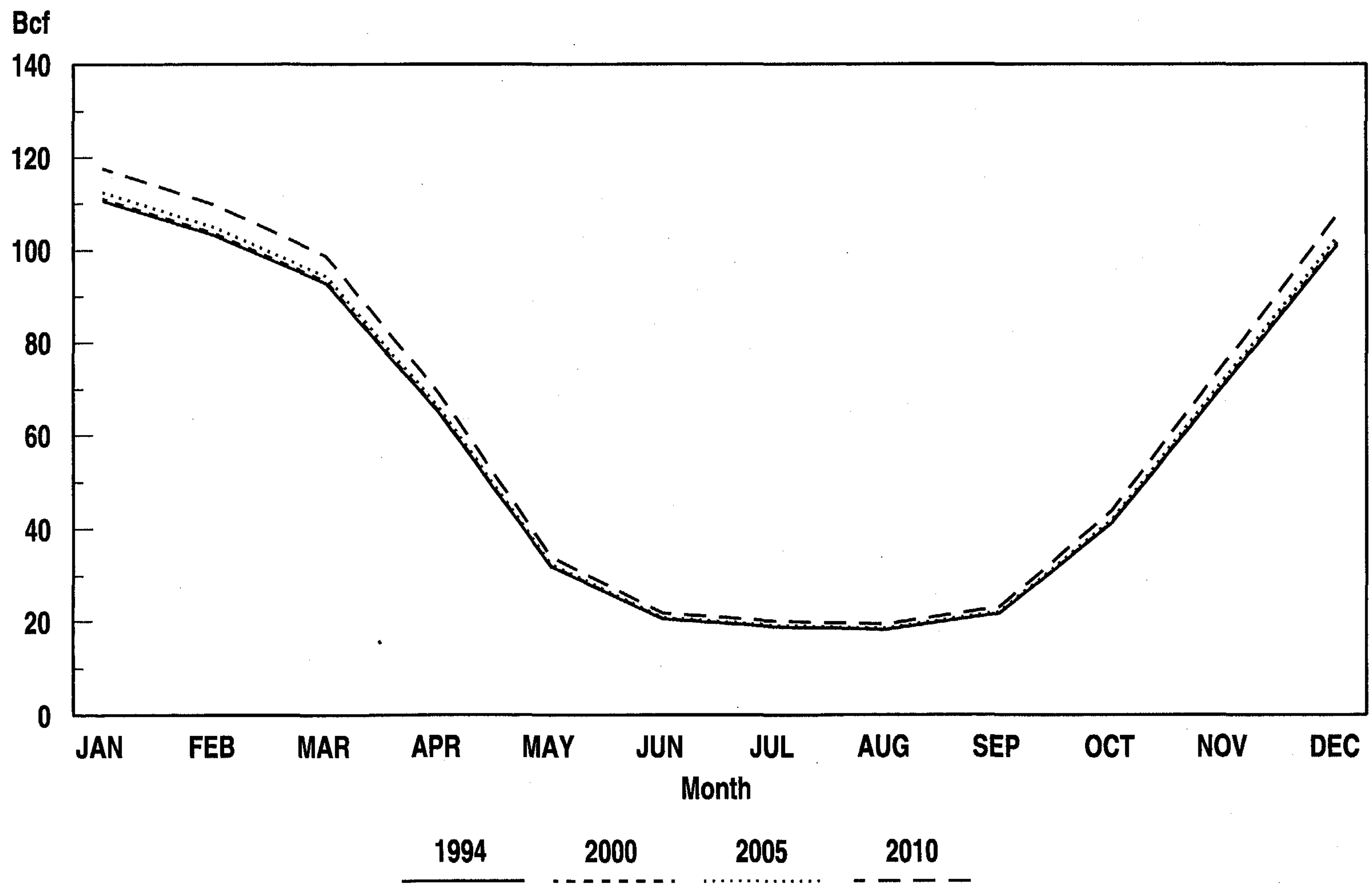
California

Monthly Commercial Gas Demand Curve

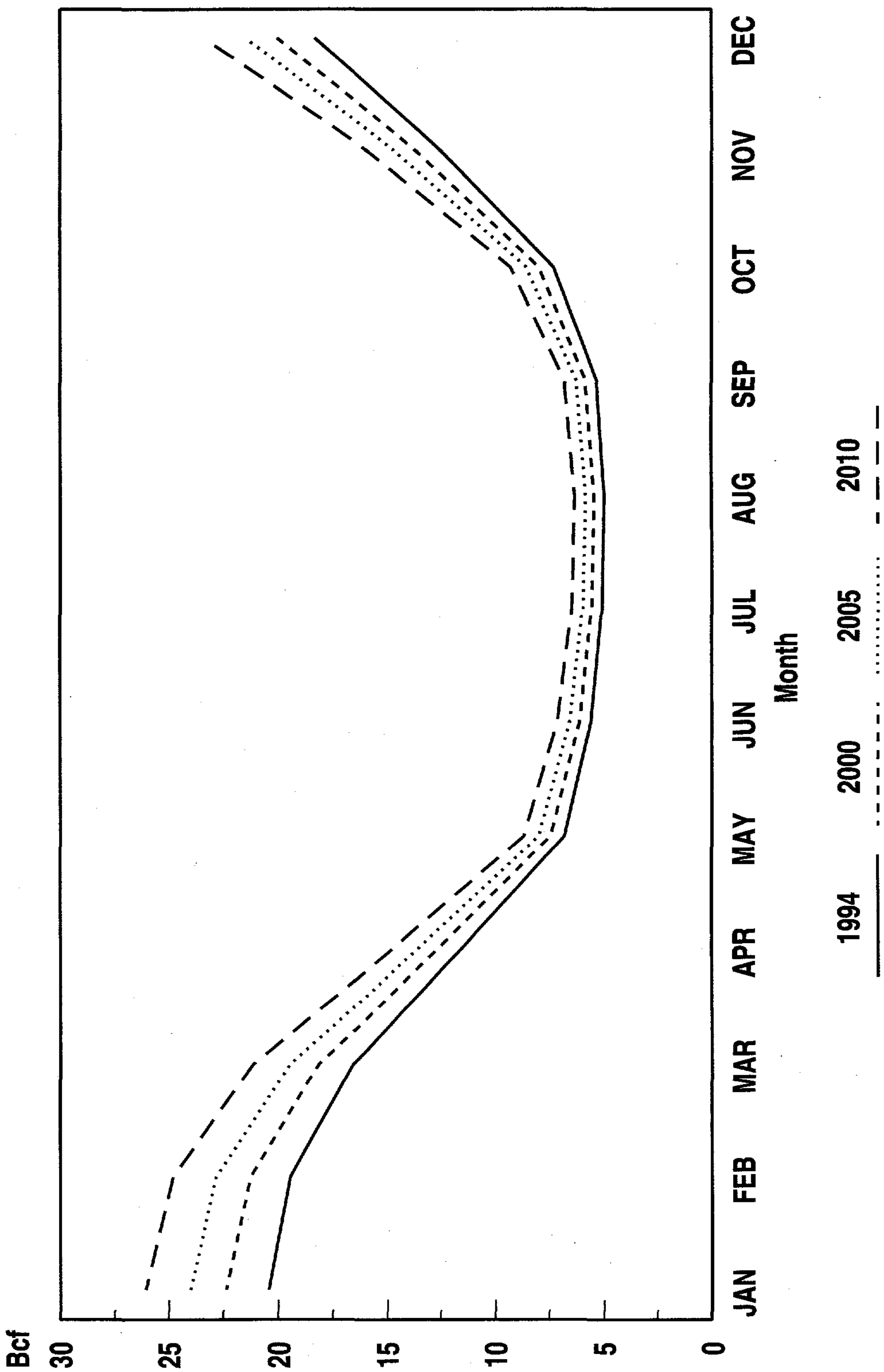


East North Central

Monthly Commercial Gas Demand Curve

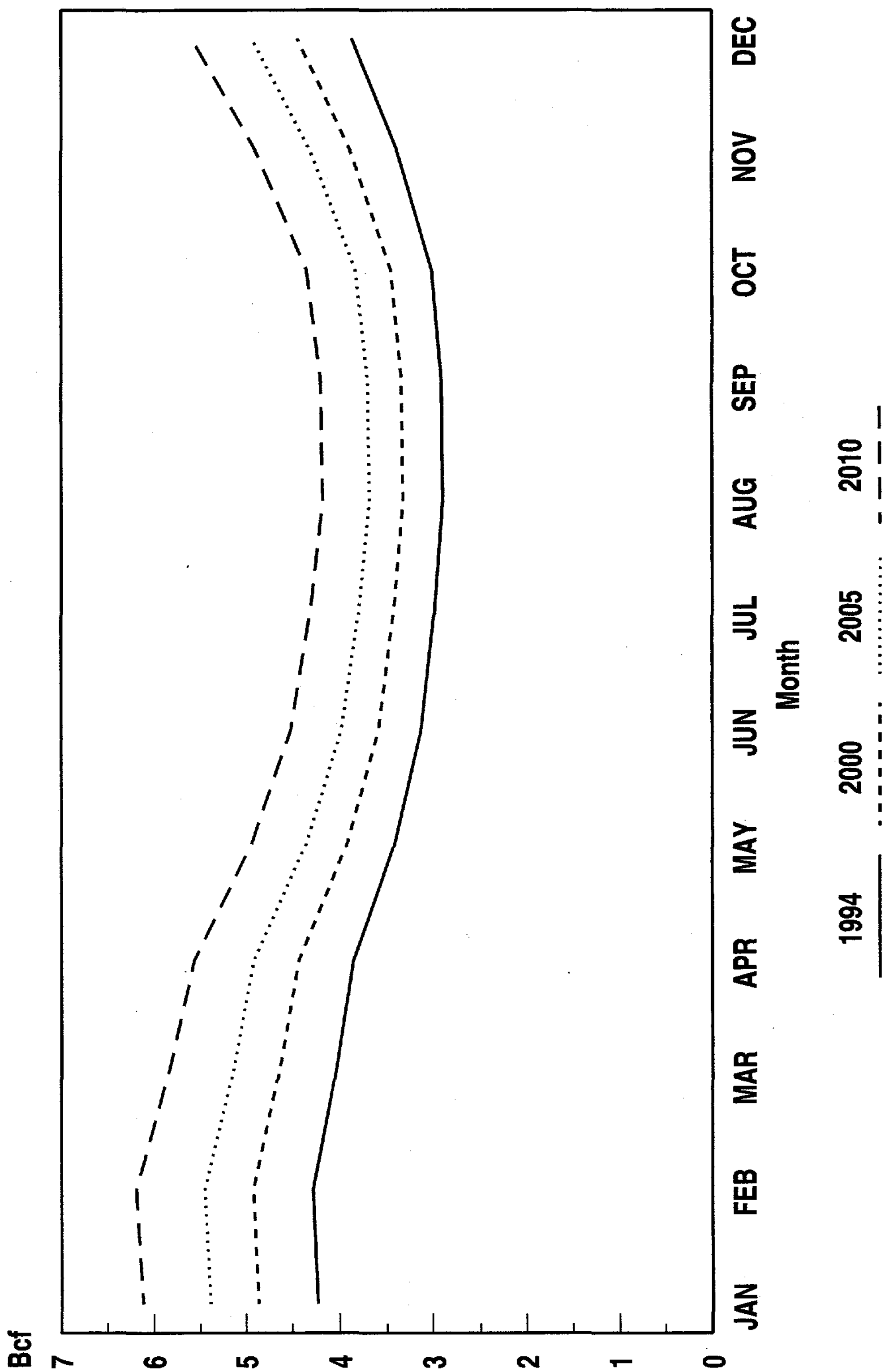


East South Central
Monthly Commercial Gas Demand Curve



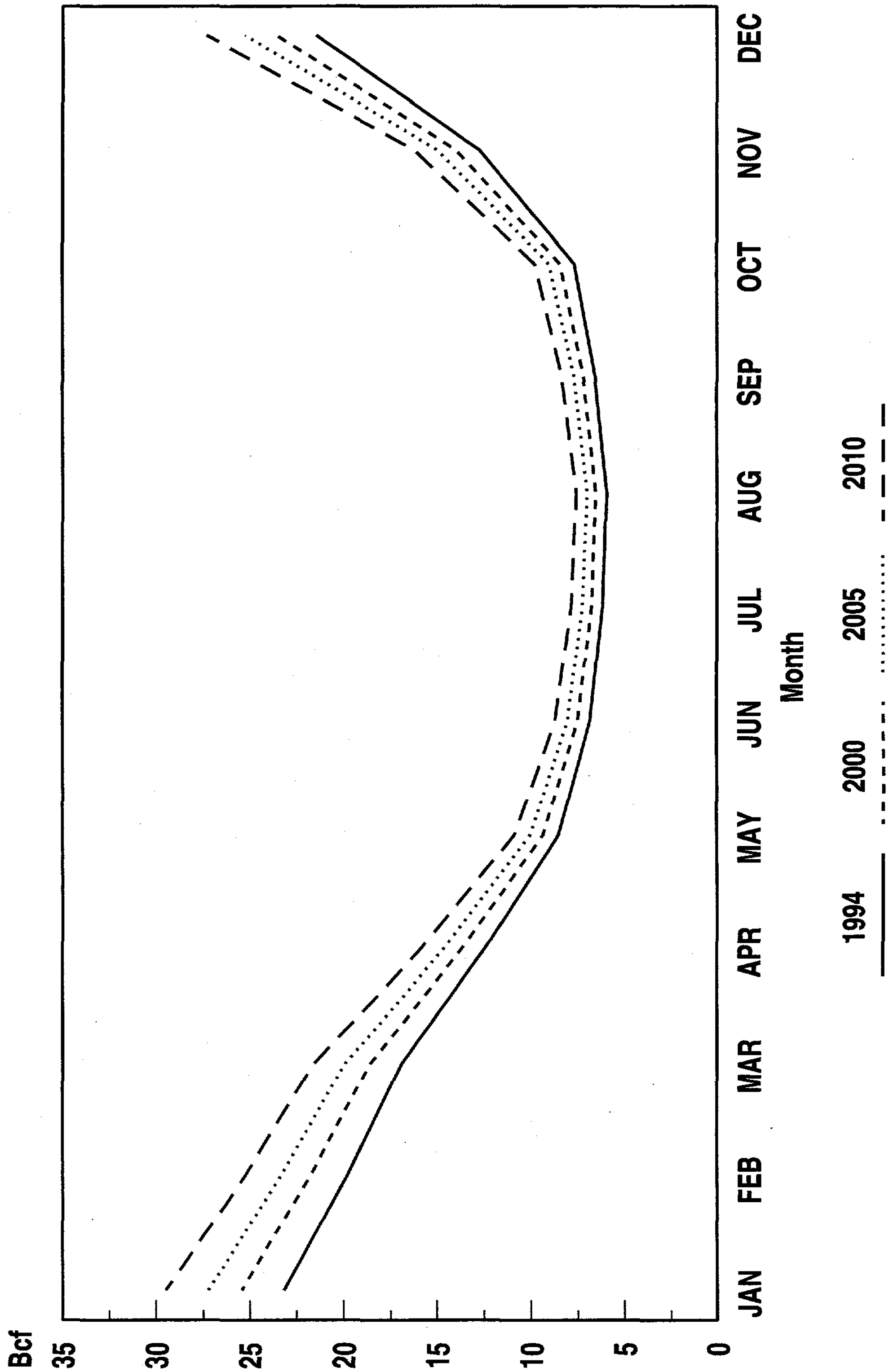
Florida

Monthly Commercial Gas Demand Curve



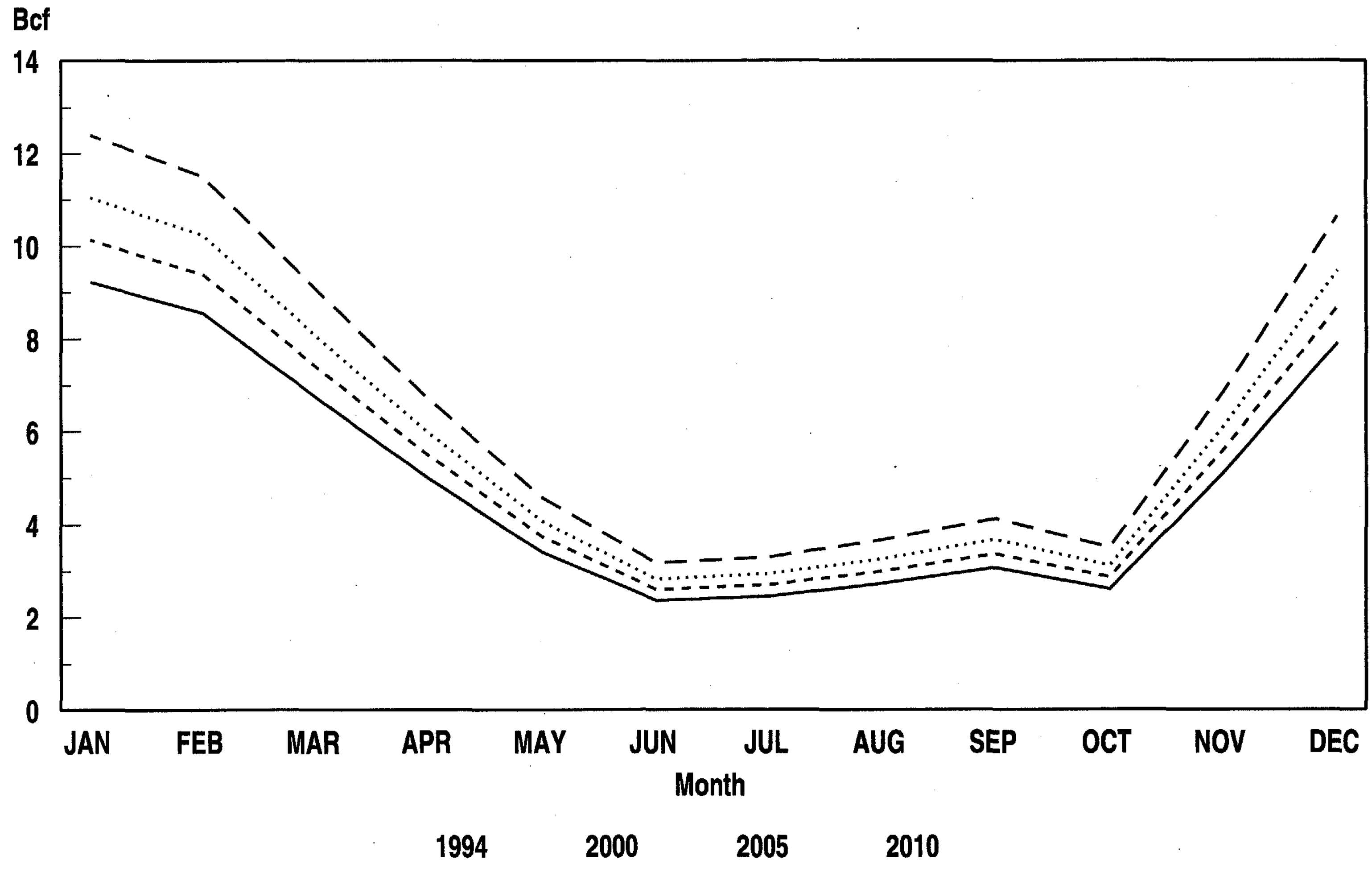
Mountain North

Monthly Commercial Gas Demand Curve



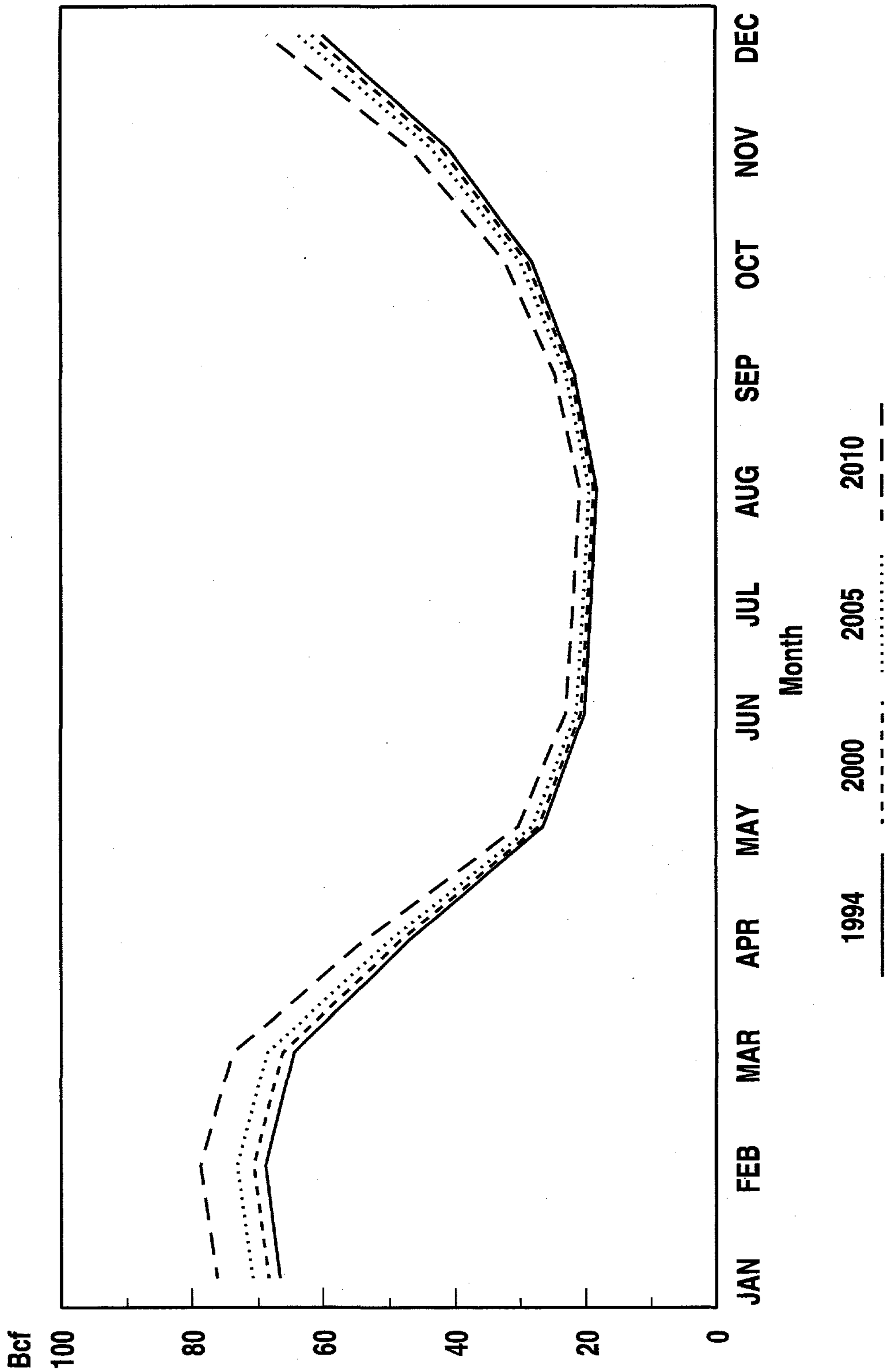
Mountain South

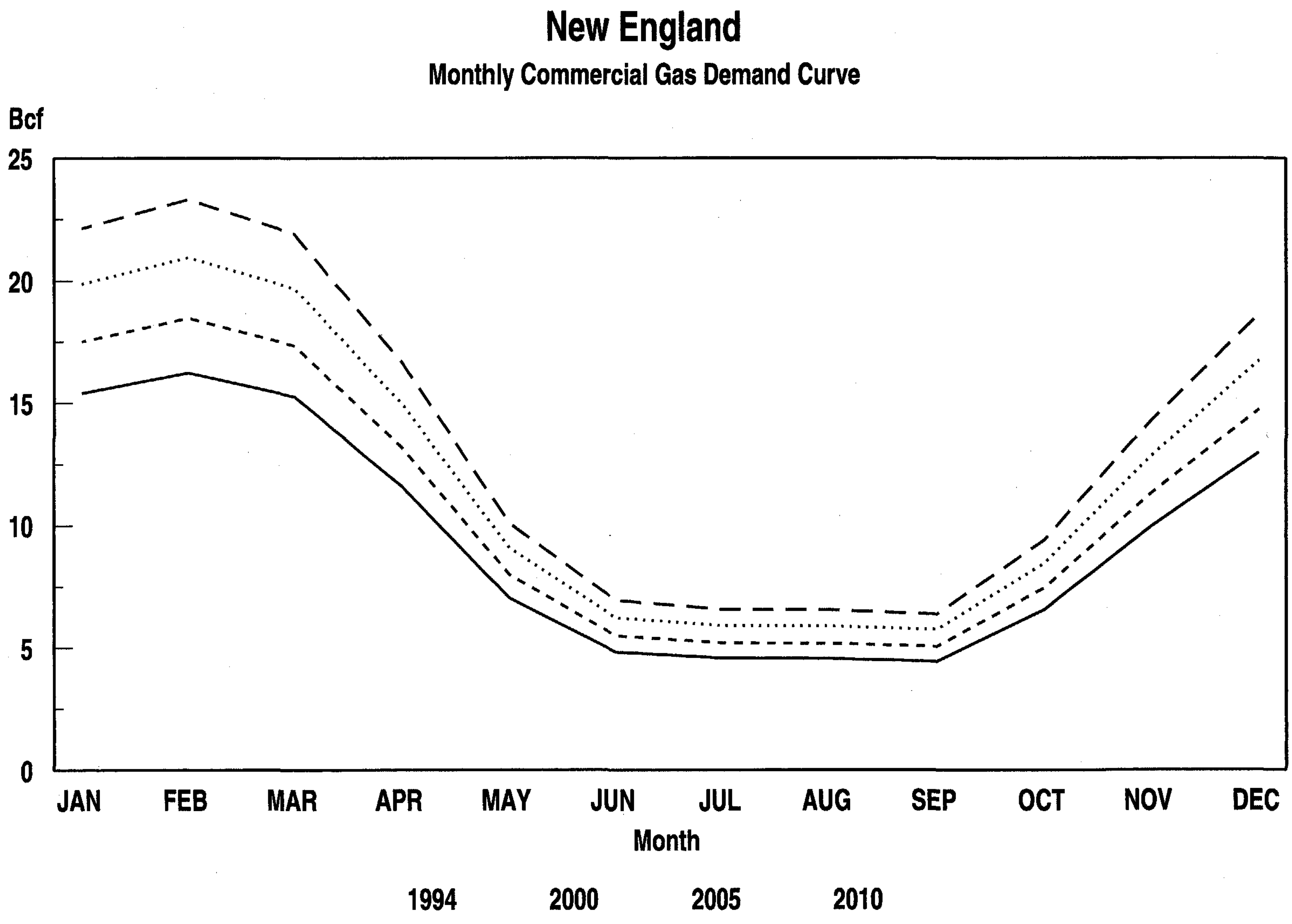
Monthly Commercial Gas Demand Curve



Middle Atlantic

Monthly Commercial Gas Demand Curve




New England
Monthly Commercial Gas Demand Curve
Bcf
25
20
15
10
5
0
JAN
FEB
MAR
APR
MAY
JUN
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AUG
SEP
OCT
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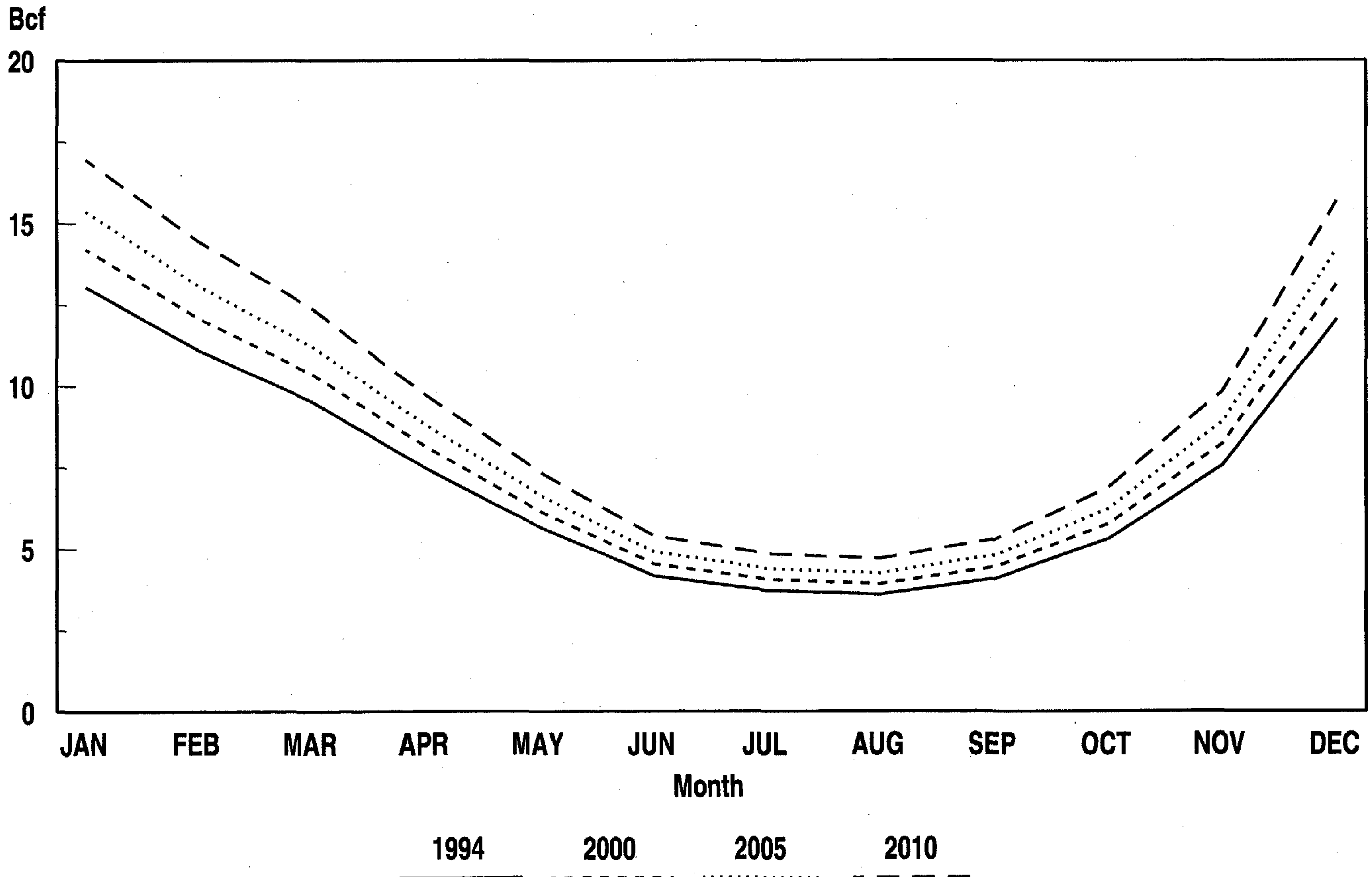
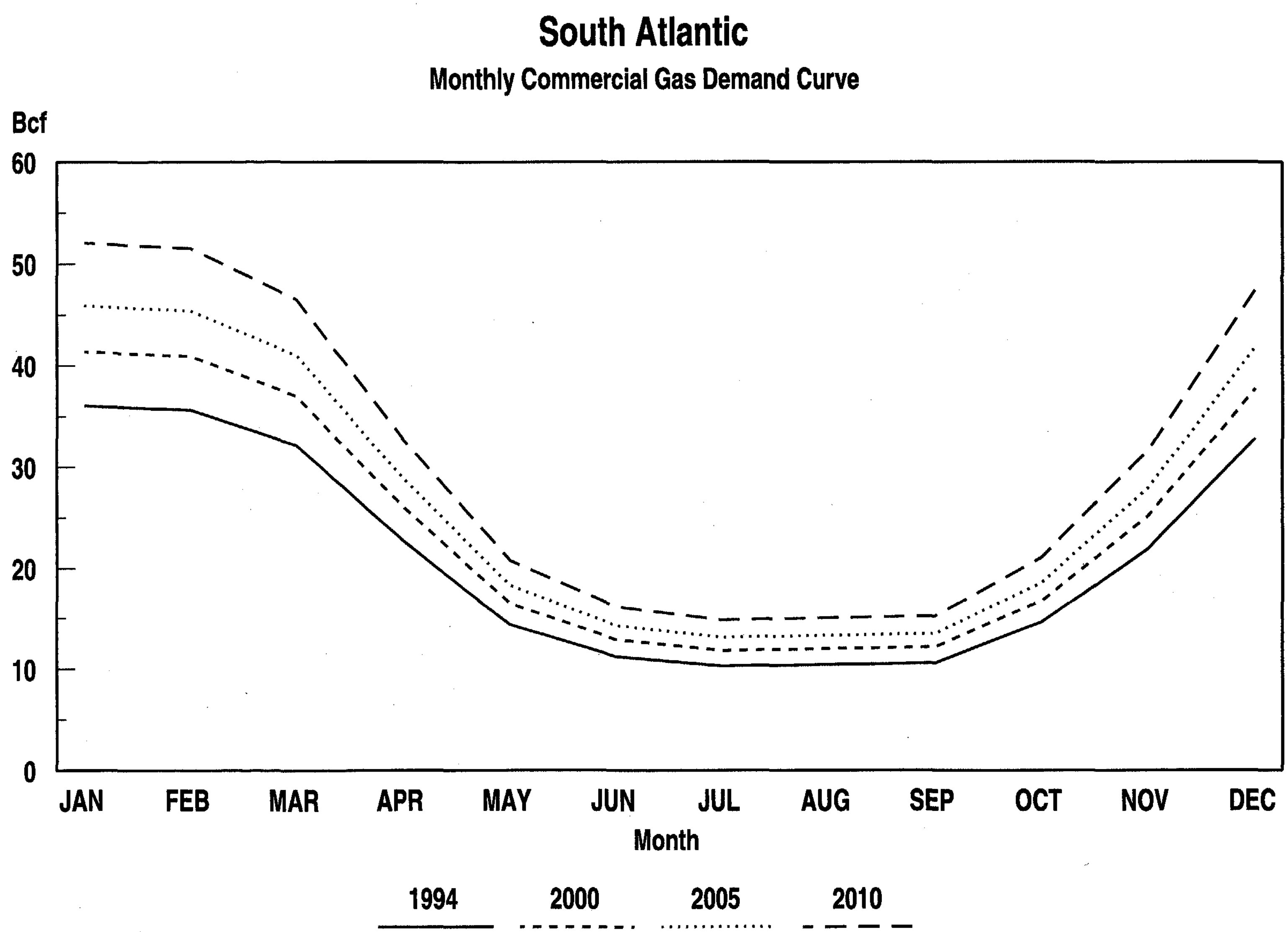
DEC
Month
1994
2000
2005
2010

Pacific Northwest

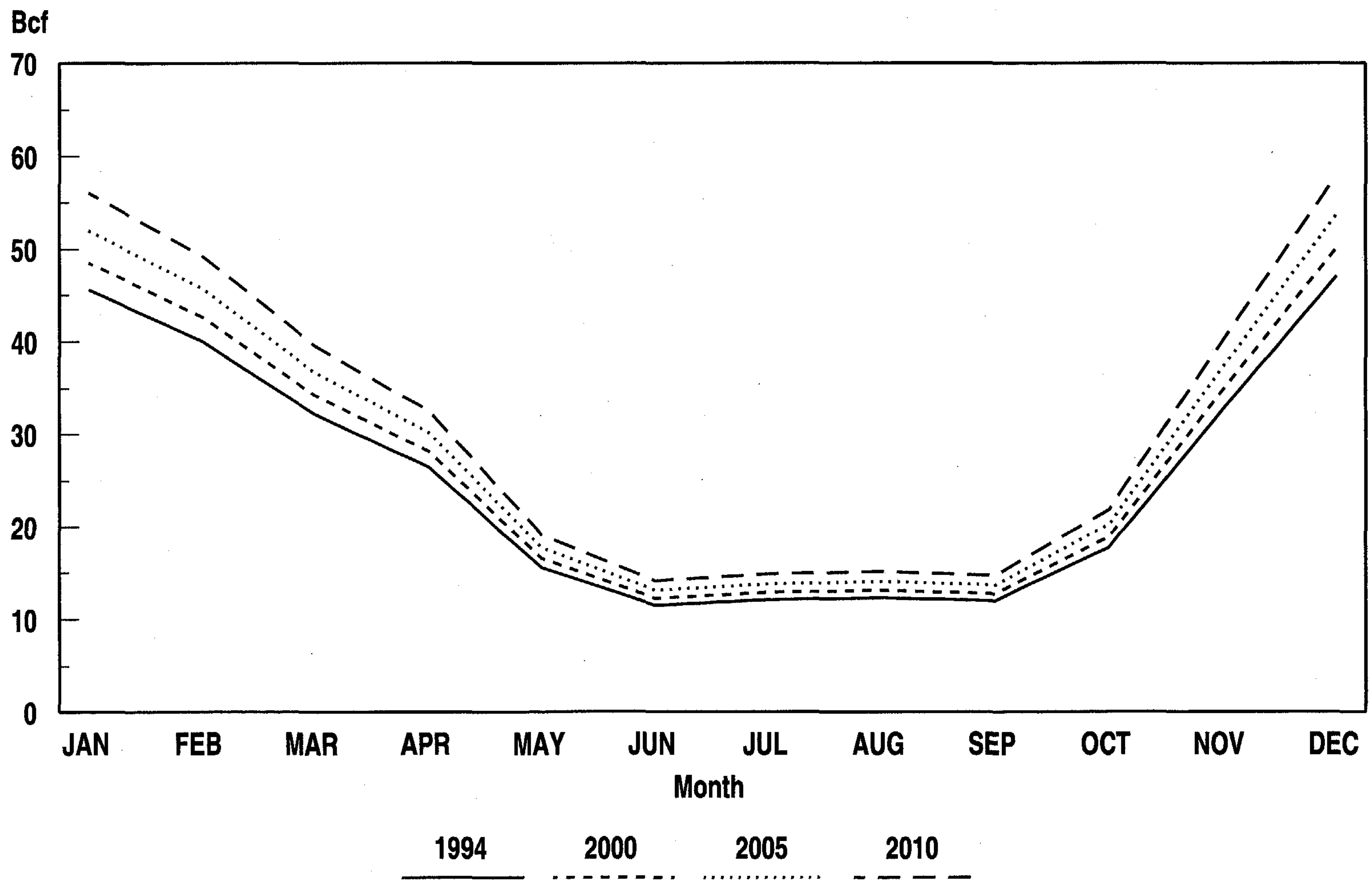
Monthly Commercial Gas Demand Curve

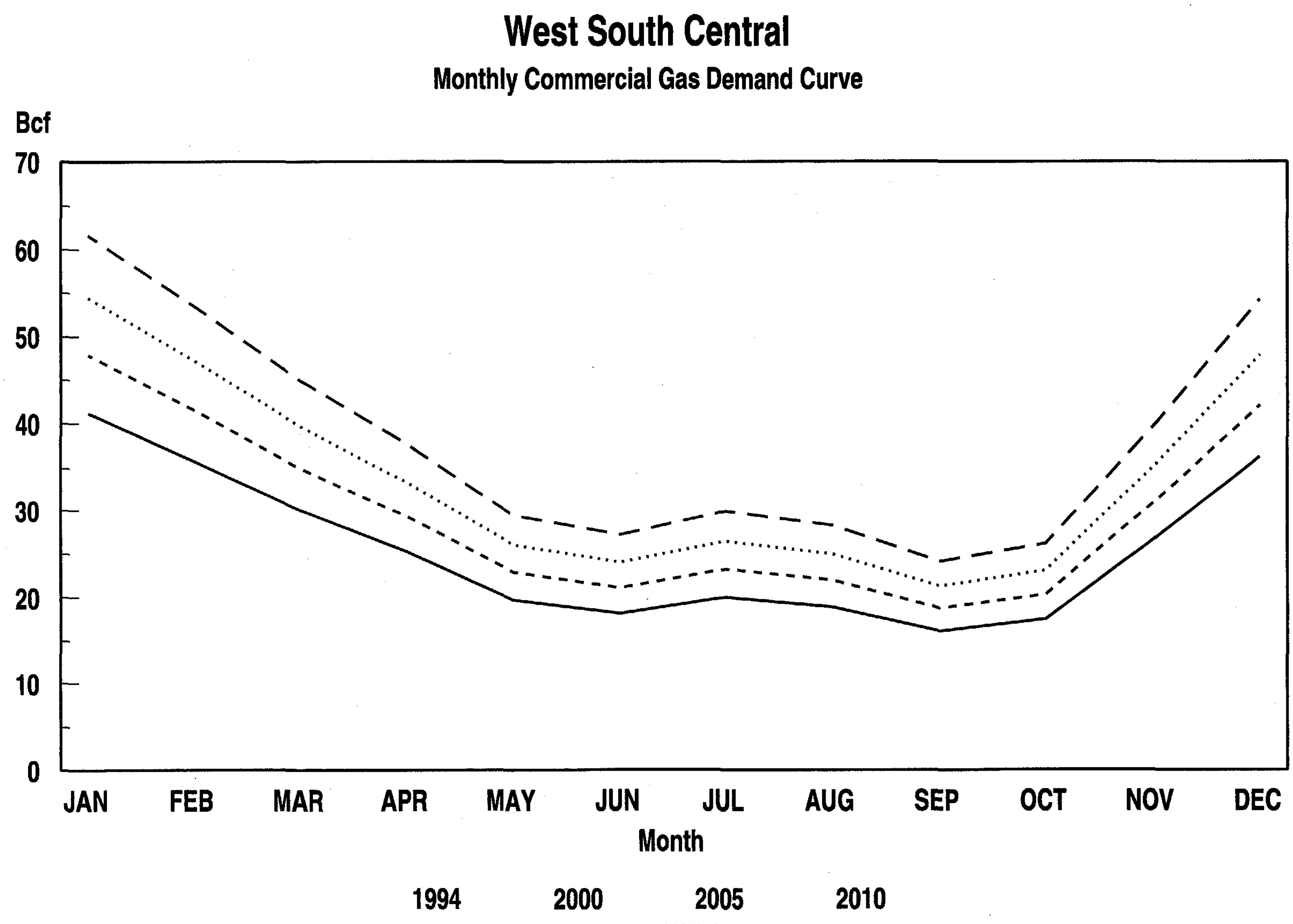



South Atlantic
Monthly Commercial Gas Demand Curve
Bcf
60
50
40
30
20
10
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Month
1994
2000
2005
2010

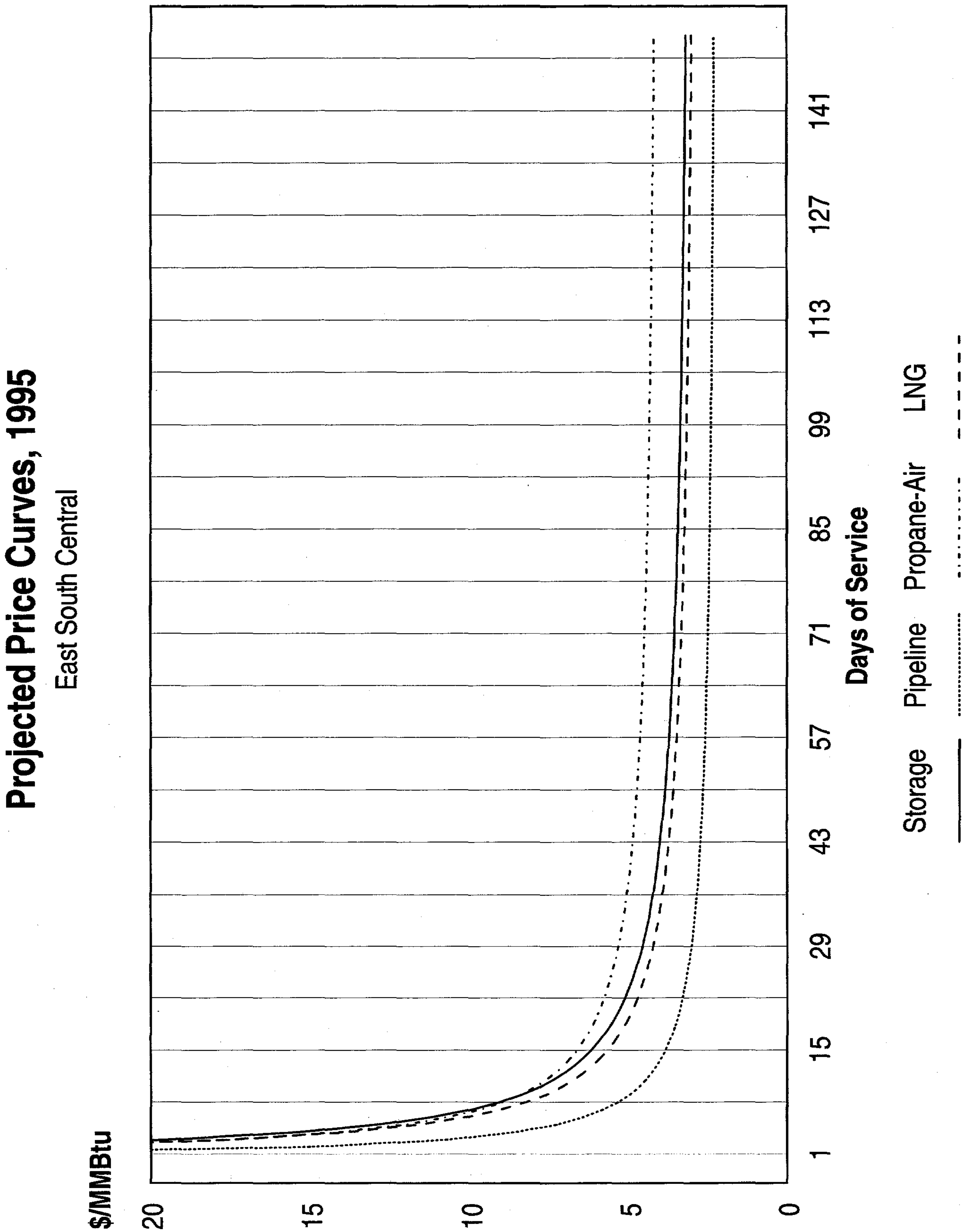
West North Central

Monthly Commercial Gas Demand Curve



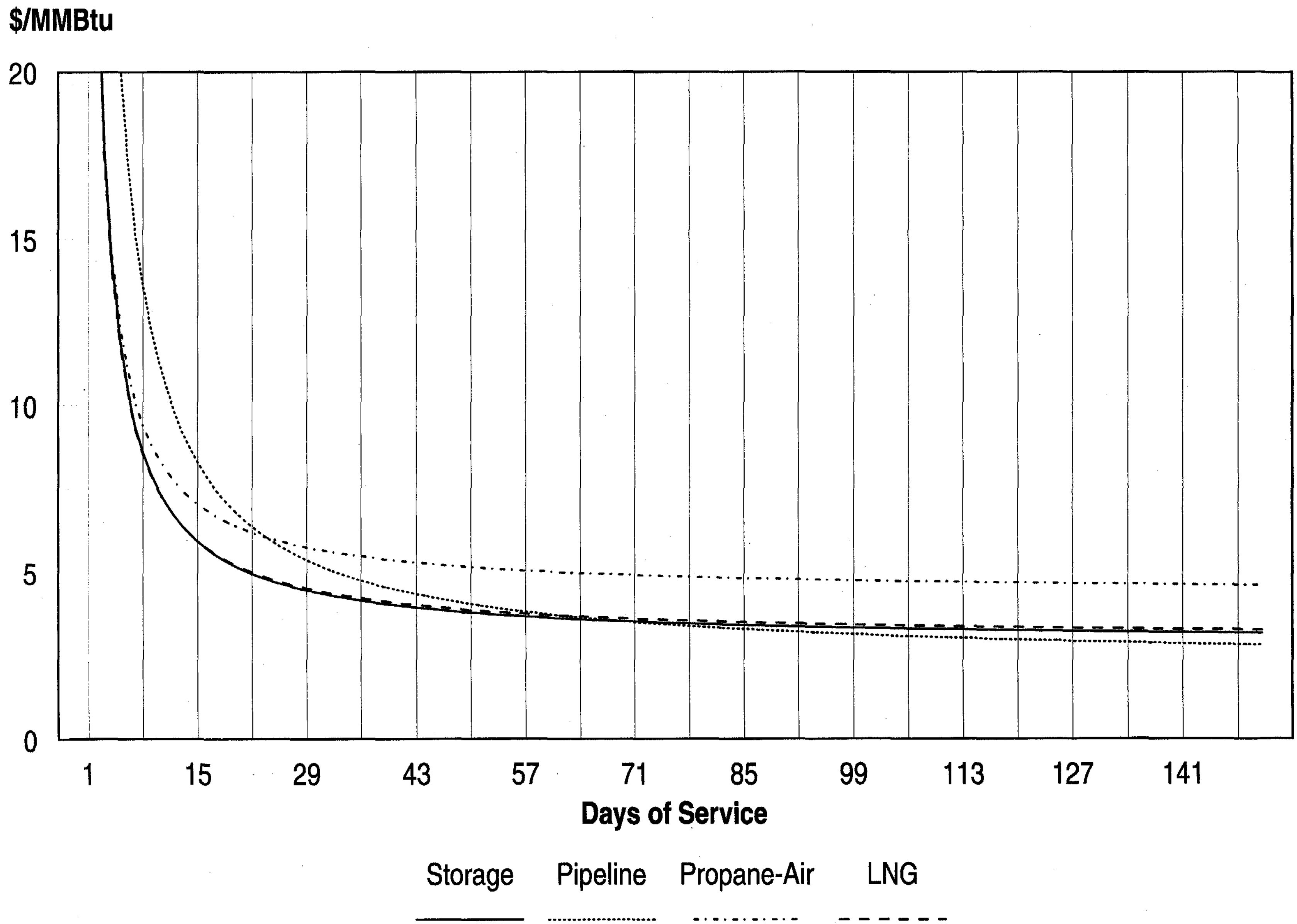

West South Central
Monthly Commercial Gas Demand Curve
Bcf
70
60
50
40
30
20
10
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Month
1994
2000
2005
2010

APPENDIX E
PROJECTED PRICE CURVES


Projected Price Curves, 1995
East South Central
$/MMBtu
20
15
10
5
0
1
15
29
43
57
71
85
99
113
127
141
Days of Service
Storage
Pipeline
Propane-Air
LNG

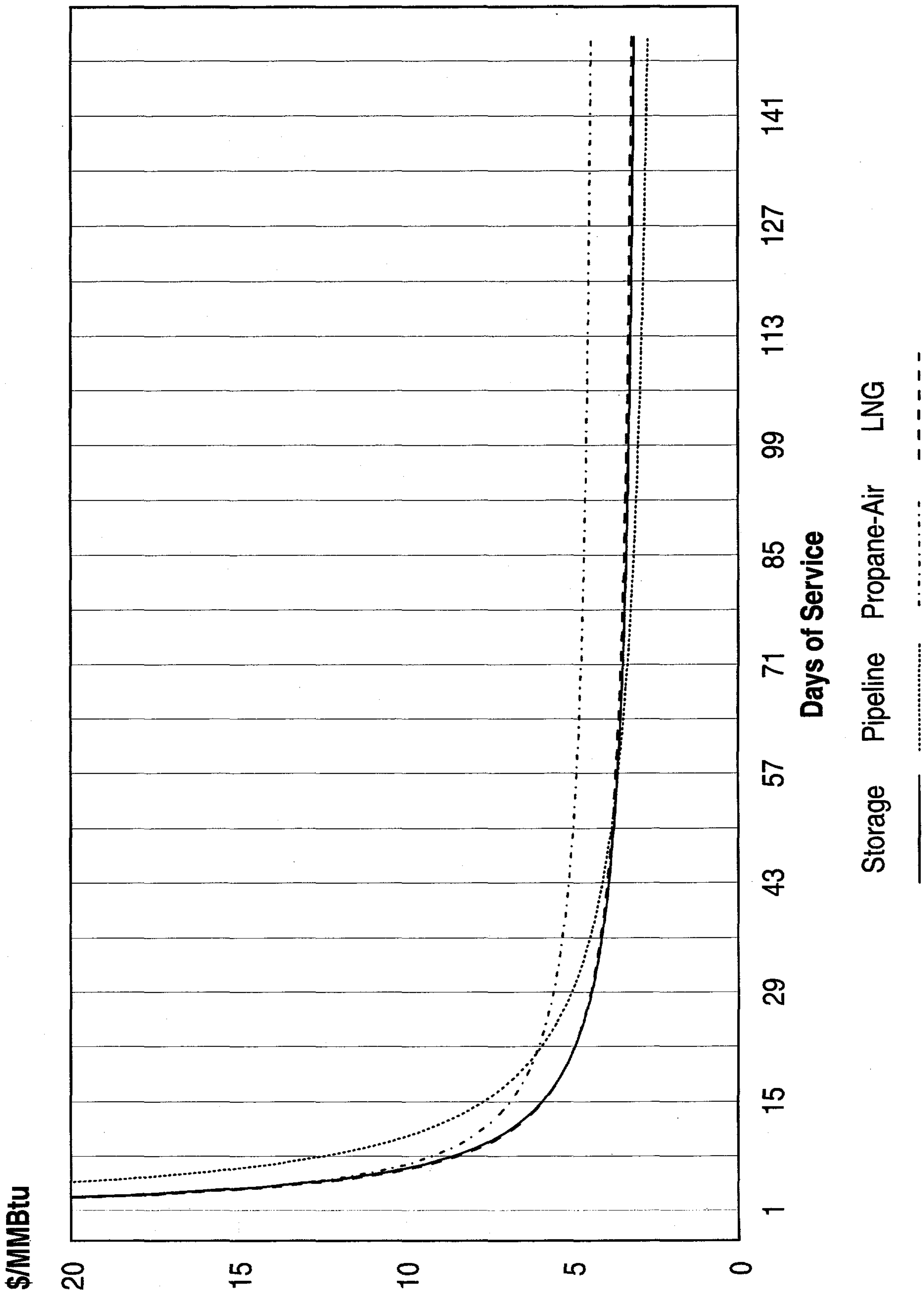
Projected Price Curves, 1995

East North Central



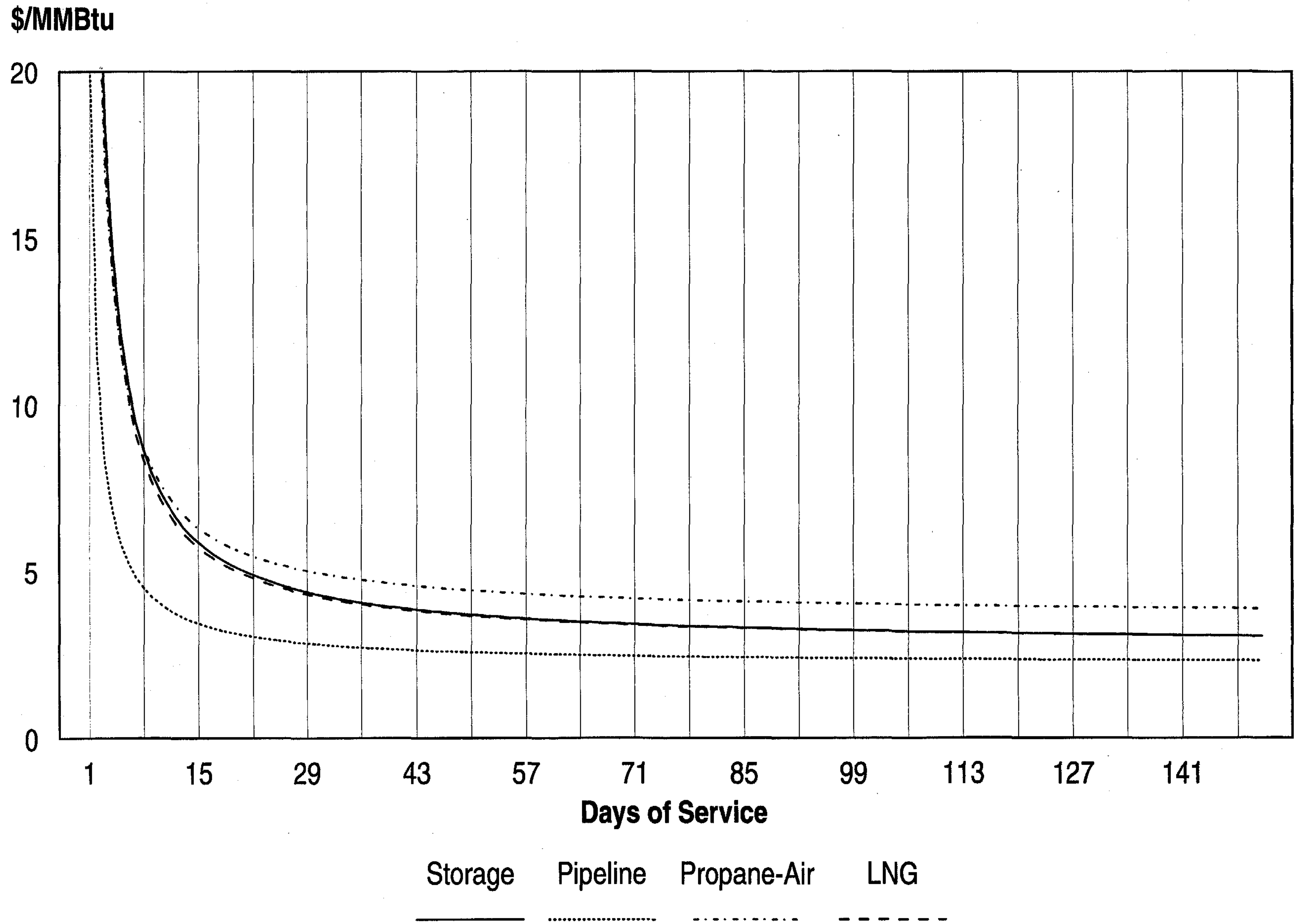
Projected Price Curves, 1995

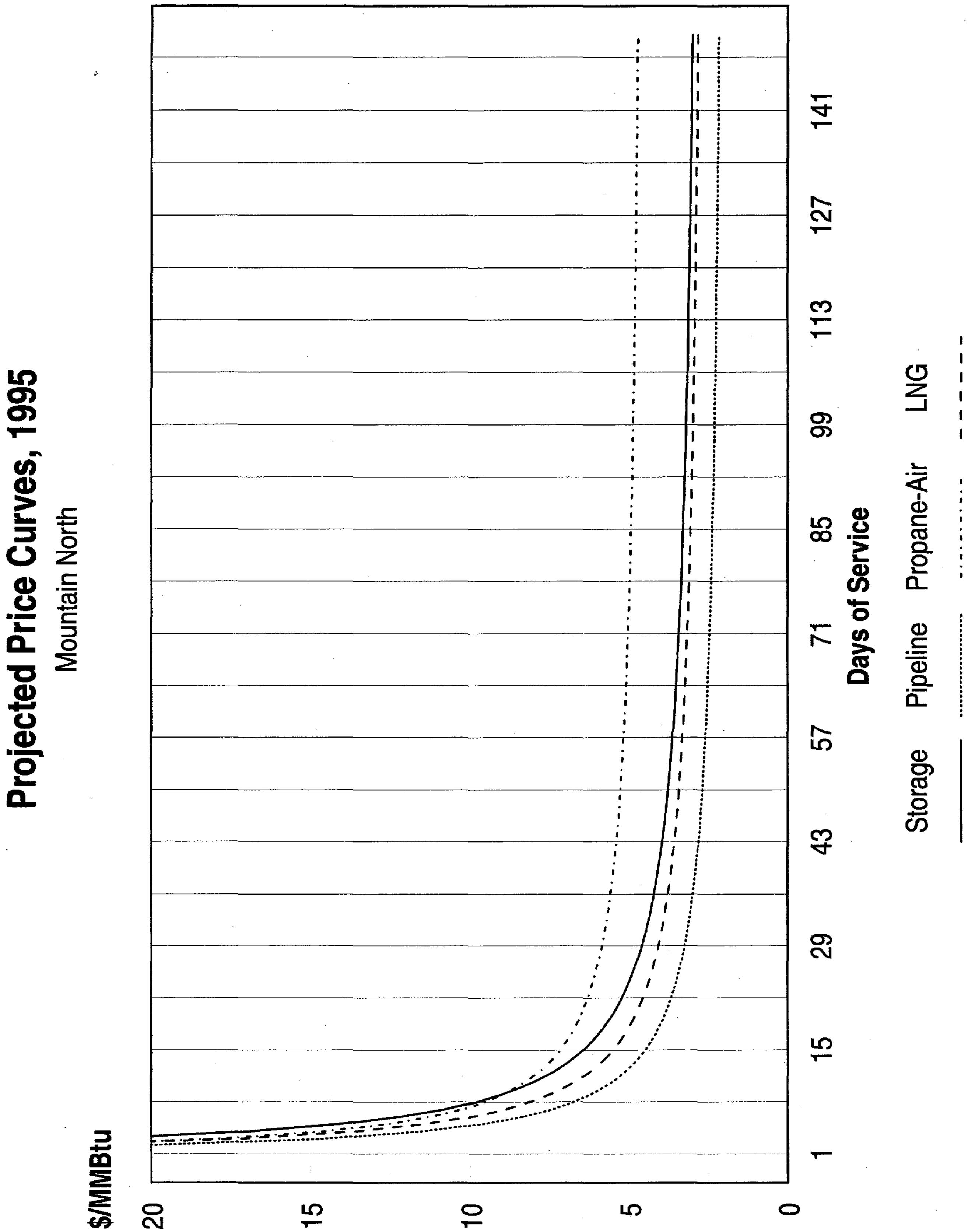
West North Central



Projected Price Curves, 1995

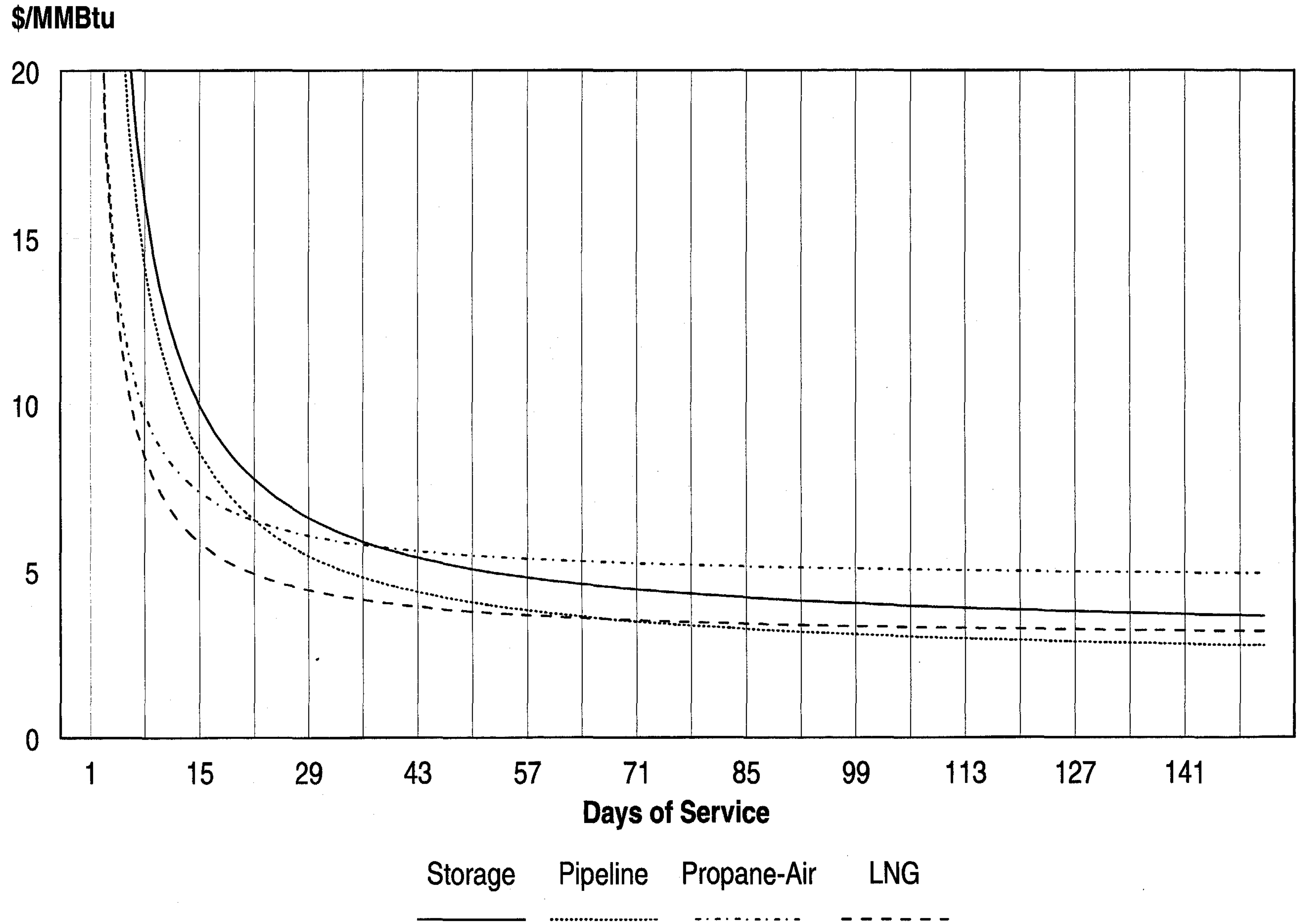
West South Central




Projected Price Curves, 1995
Mountain North
$/MMBtu
20
15
10
5
0
1
15
29
43
57
71
85
99
113
127
141
Days of Service
Storage
Pipeline
Propane-Air
LNG

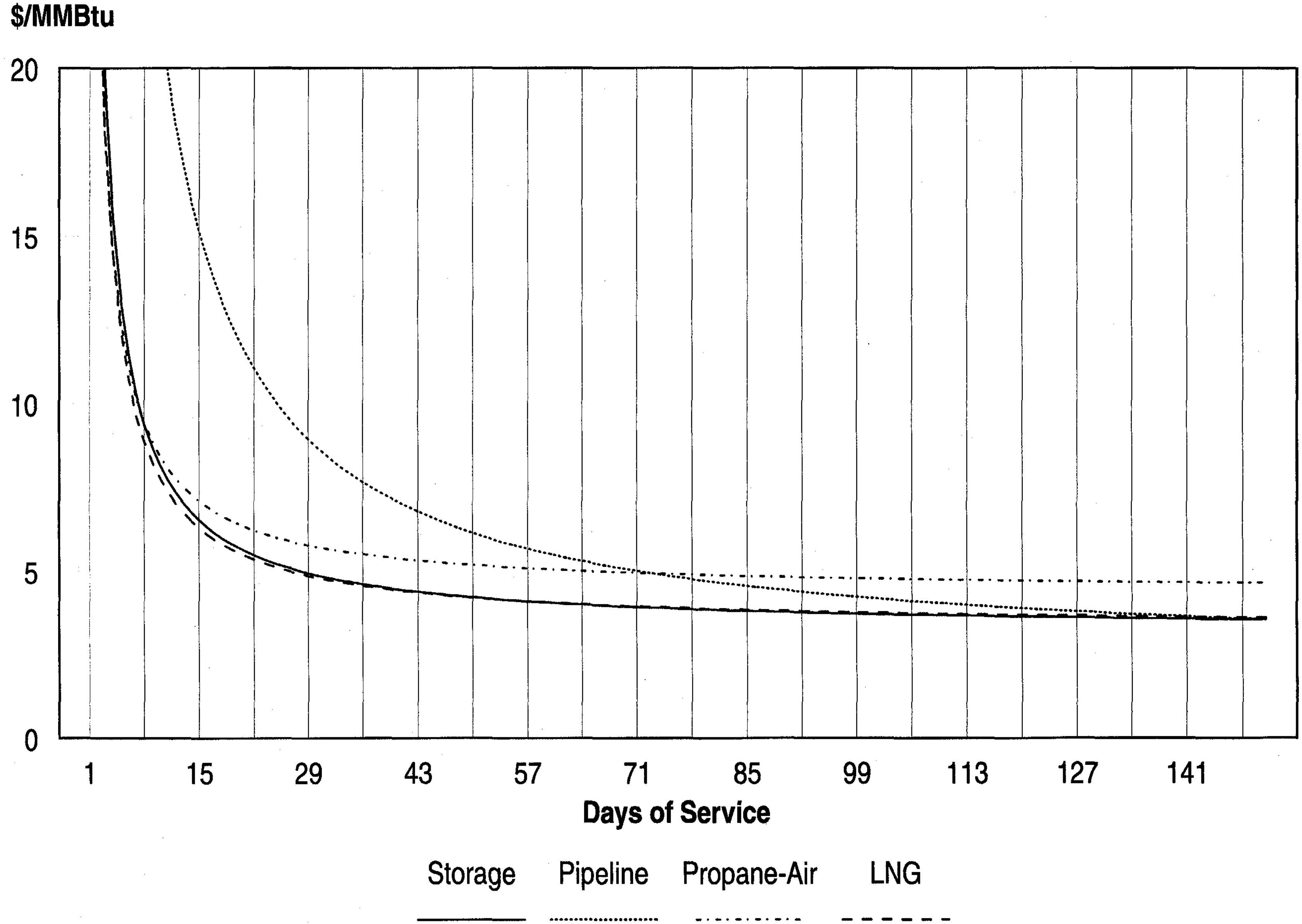
Projected Price Curves, 1995

California



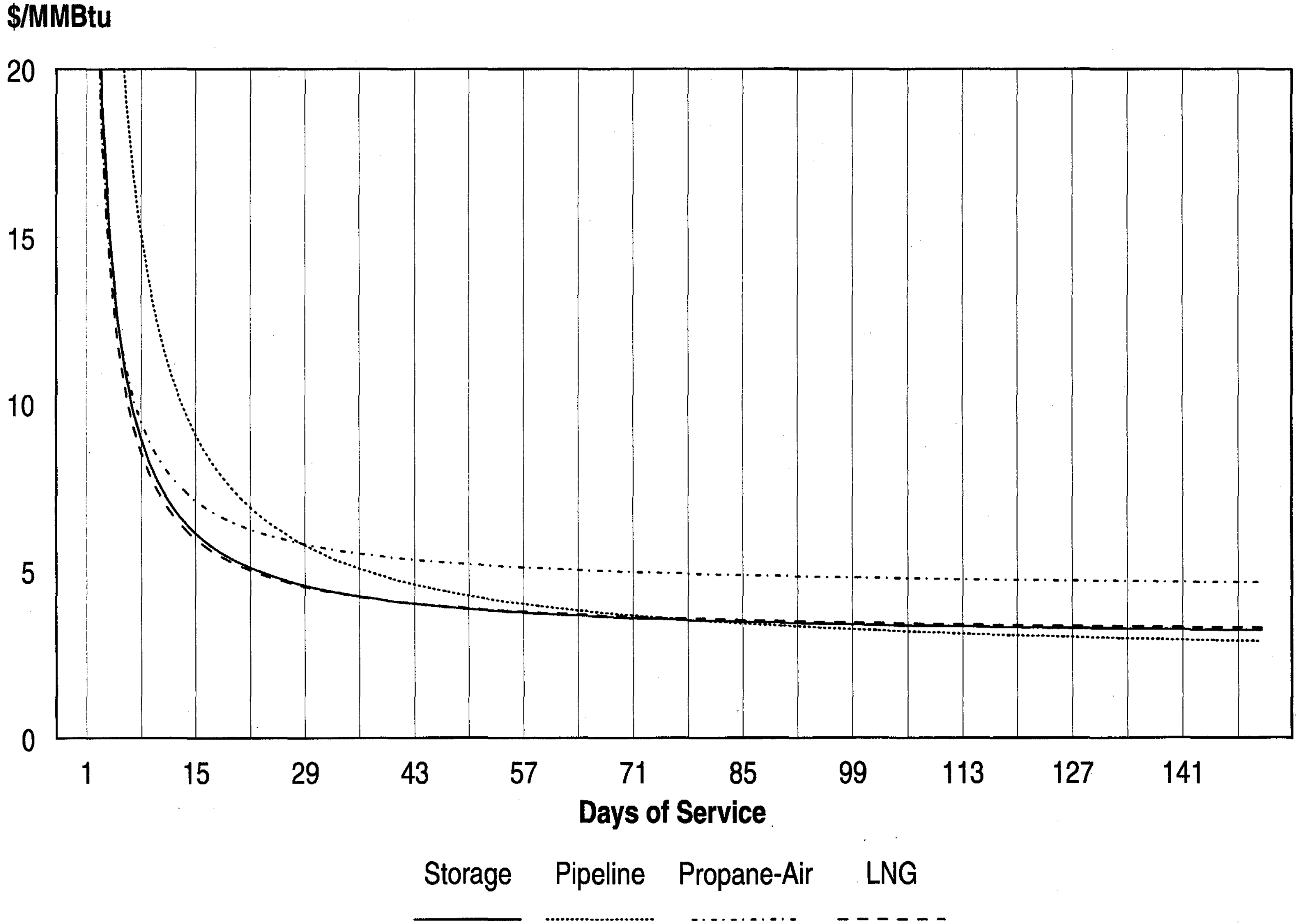
Projected Price Curves, 1995

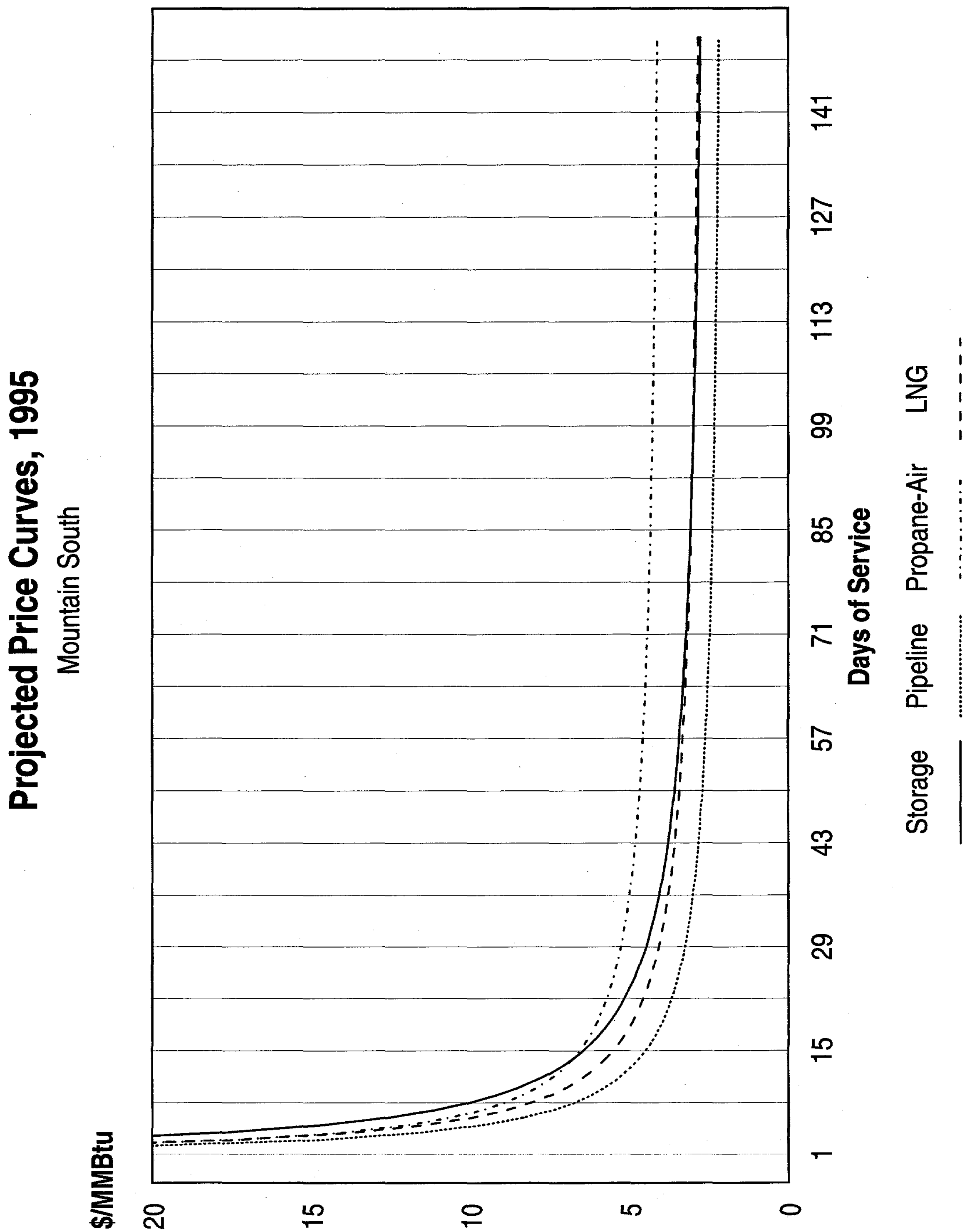
Middle Atlantic



Projected Price Curves, 1995

South Atlantic

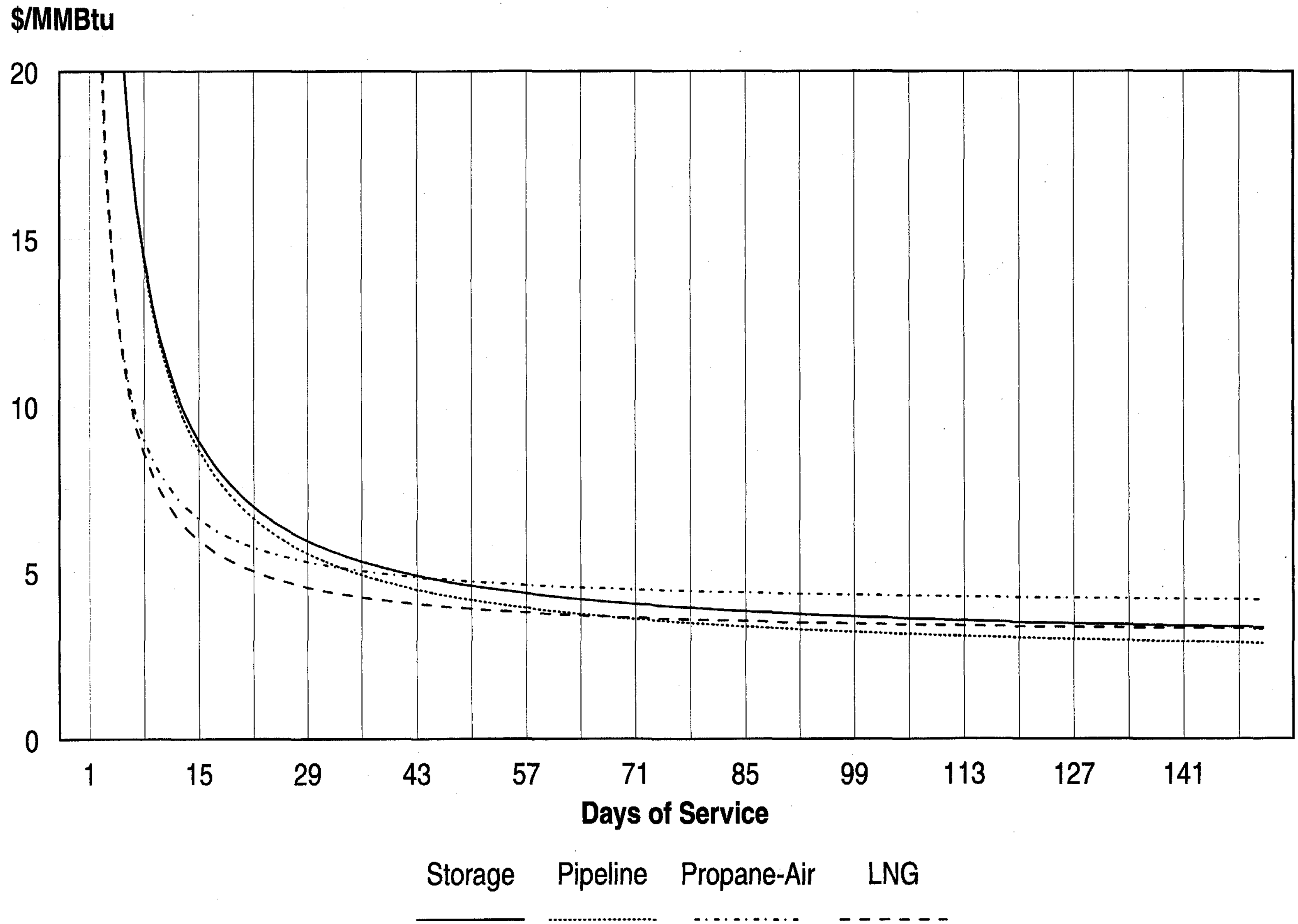




Projected Price Curves, 1995
Mountain South
$/MMBtu
20
15
10
5
0
1
15
29
43
57
71
85
99
113
127
141
Days of Service
Storage
Pipeline
Propane-Air
LNG

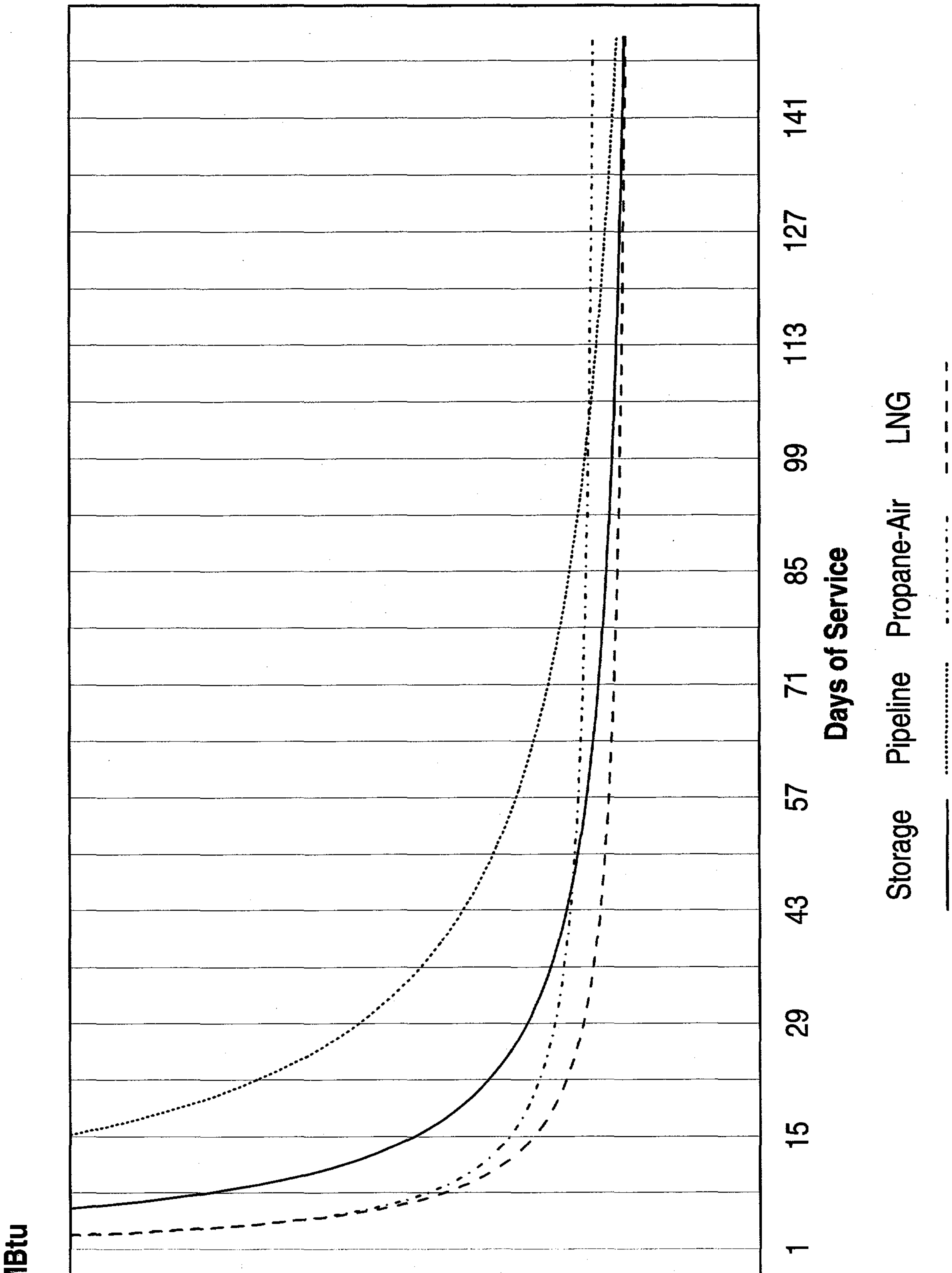
Projected Price Curves, 1995

Pacific Northwest



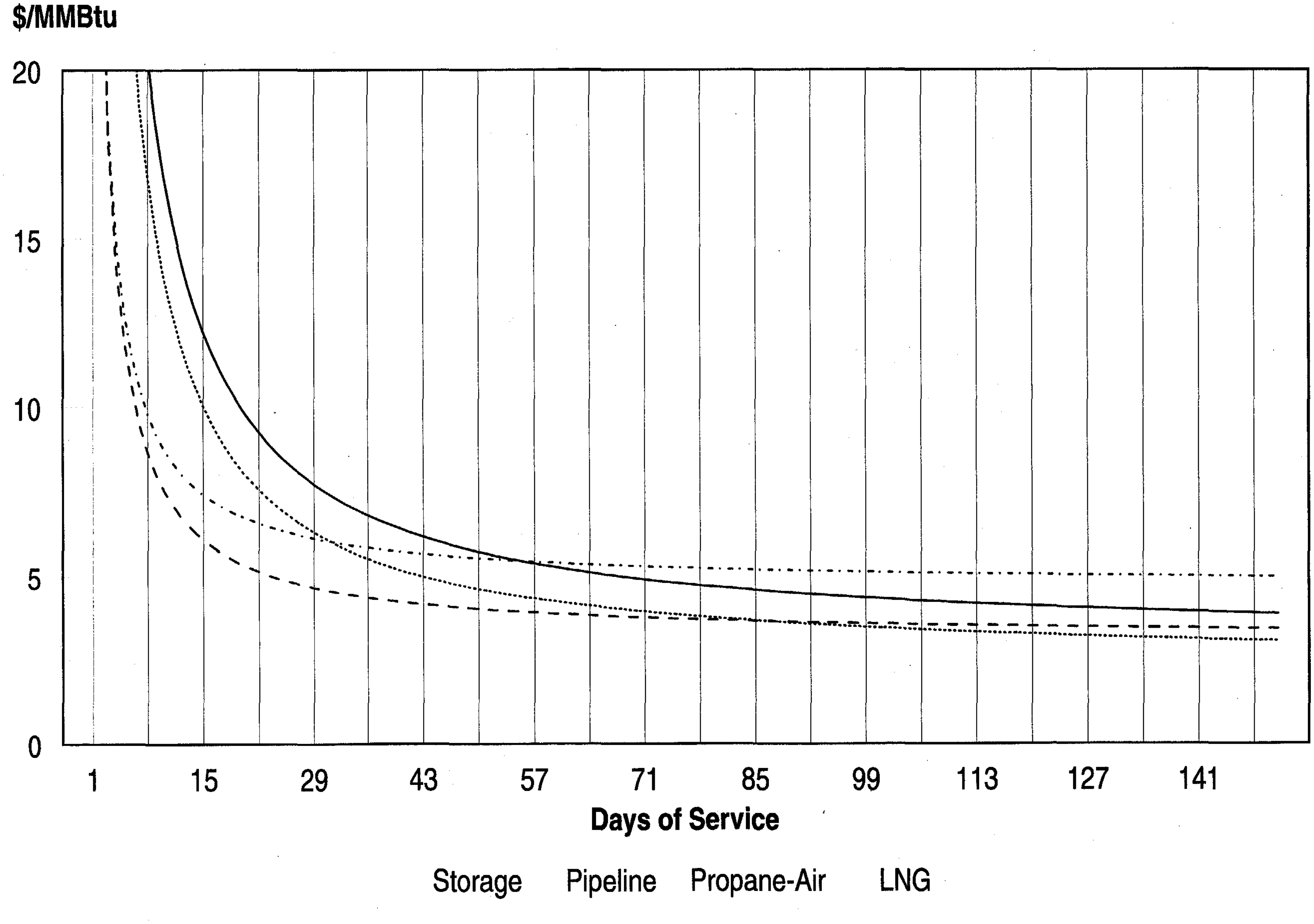
Projected Price Curves, 1995

New England



Projected Price Curves, 1995

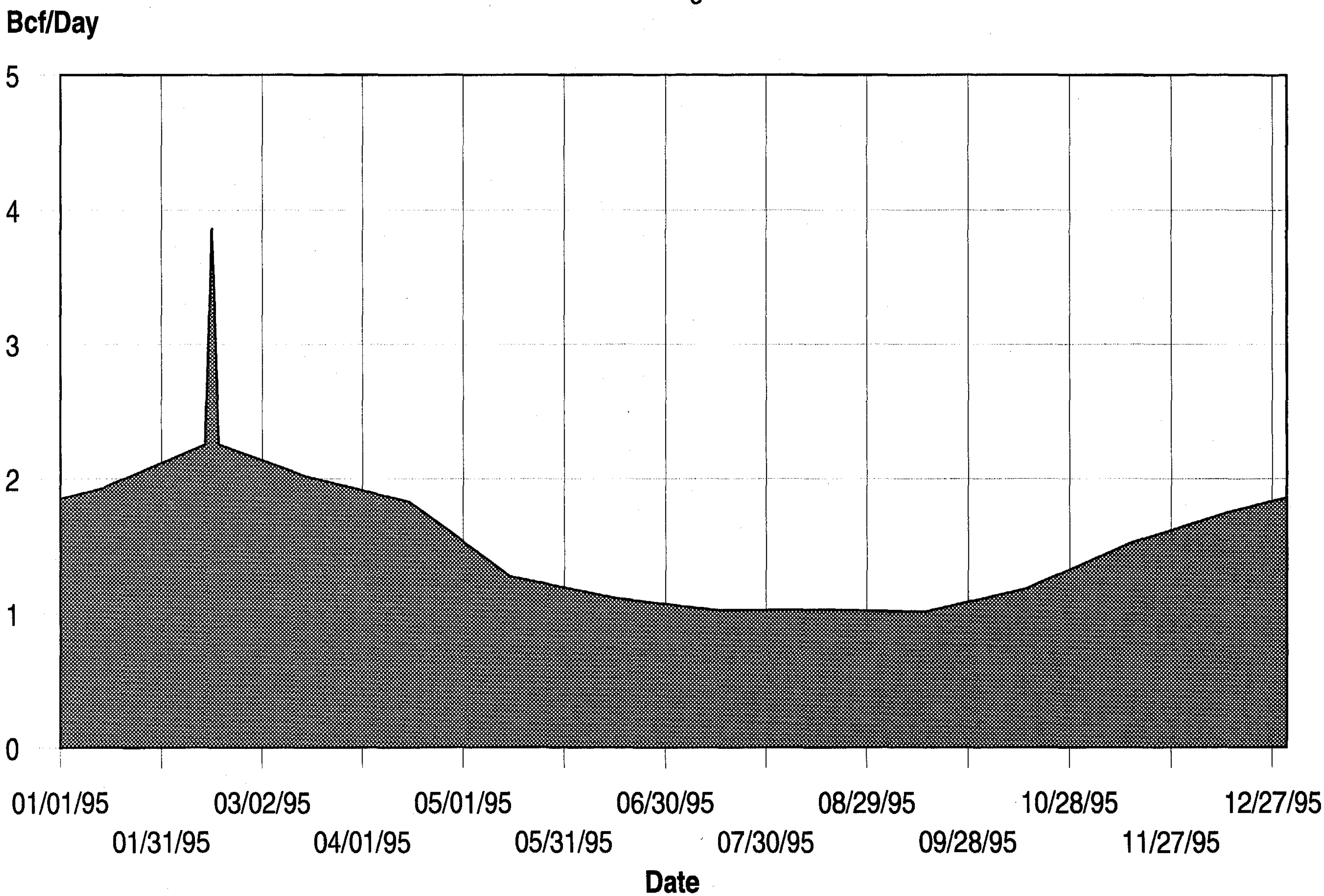
Florida



APPENDIX F
PROJECTED TOTAL GAS DEMAND CURVES

Projected Total Gas Demand Curve, 1995

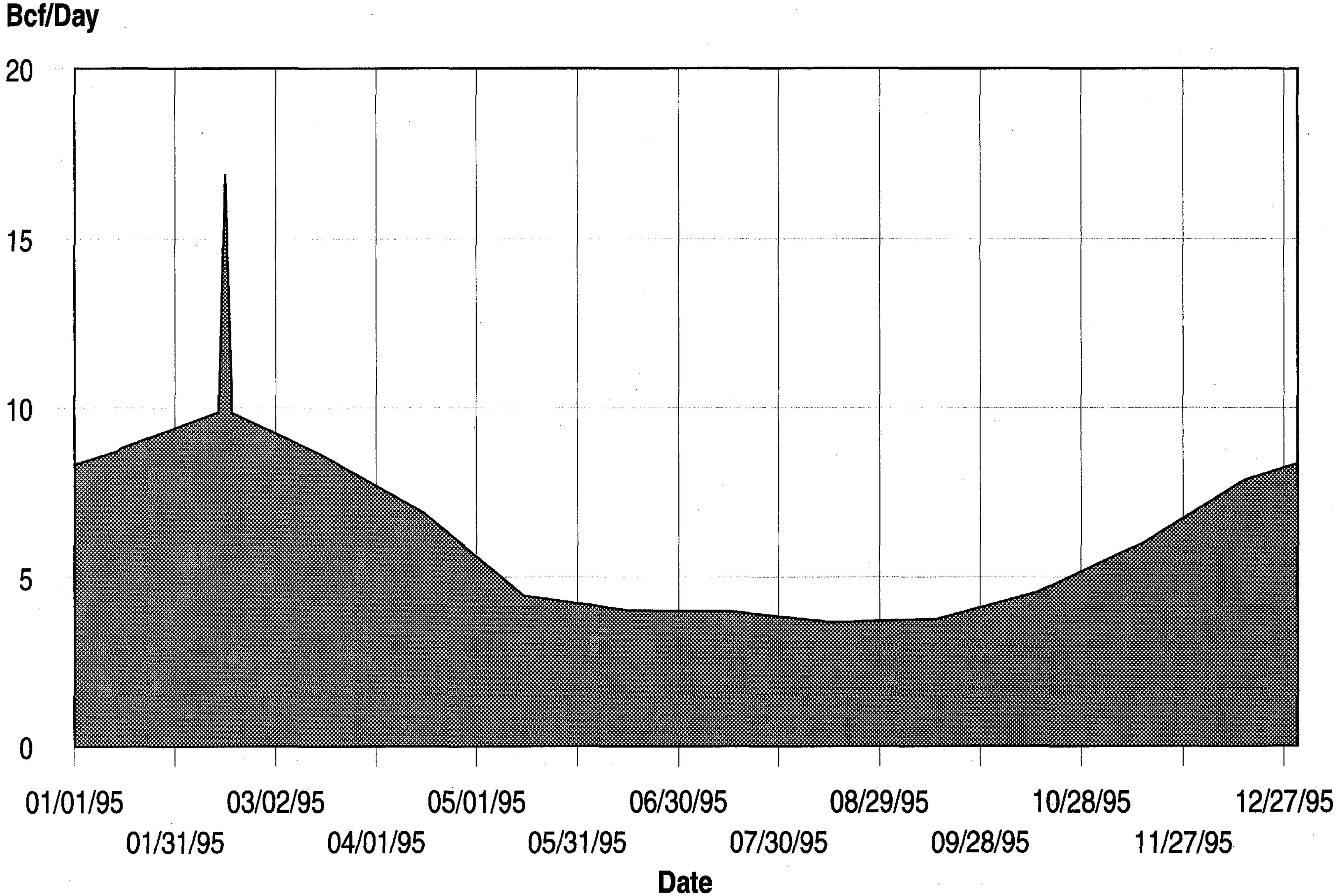
New England



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

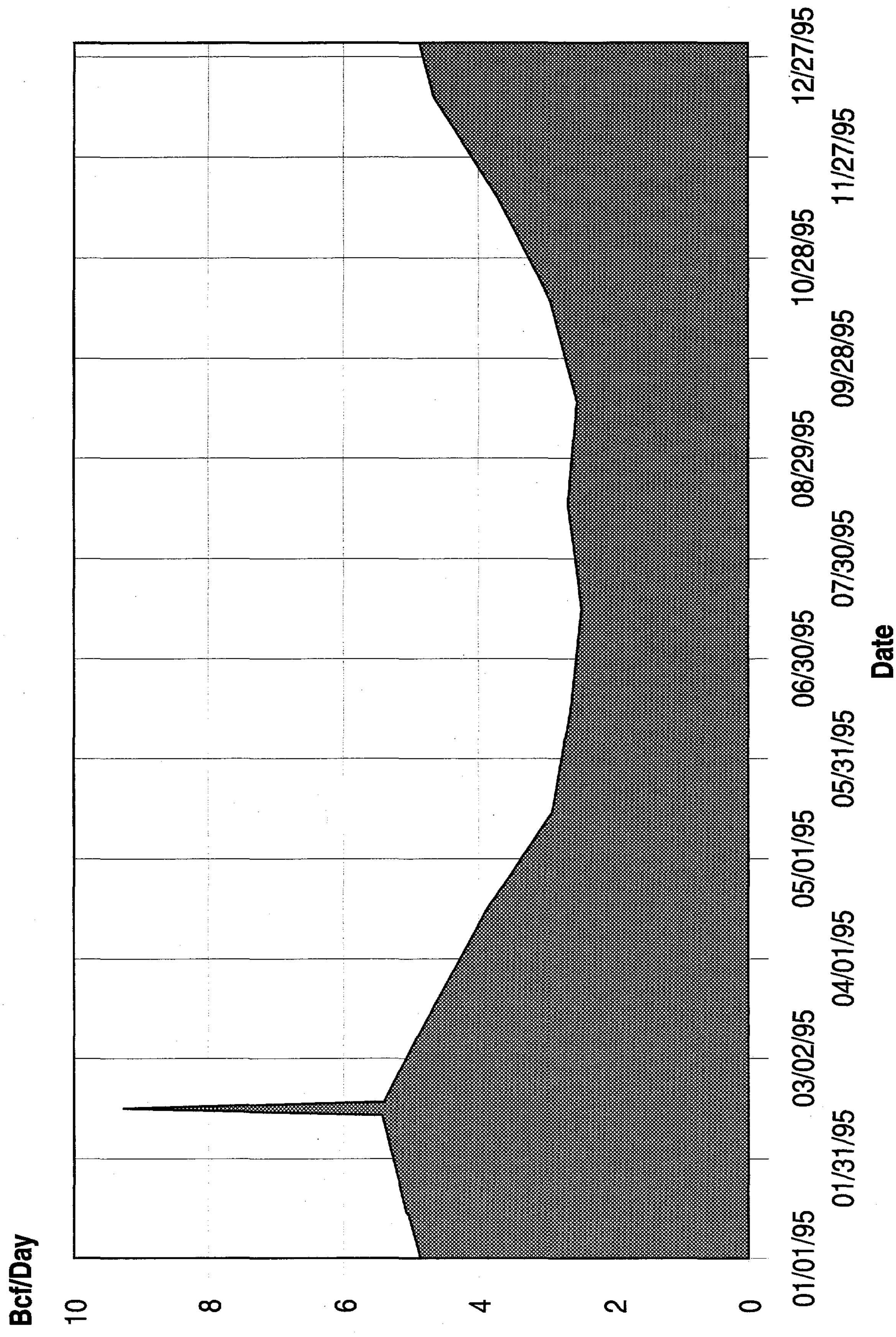
Middle Atlantic



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

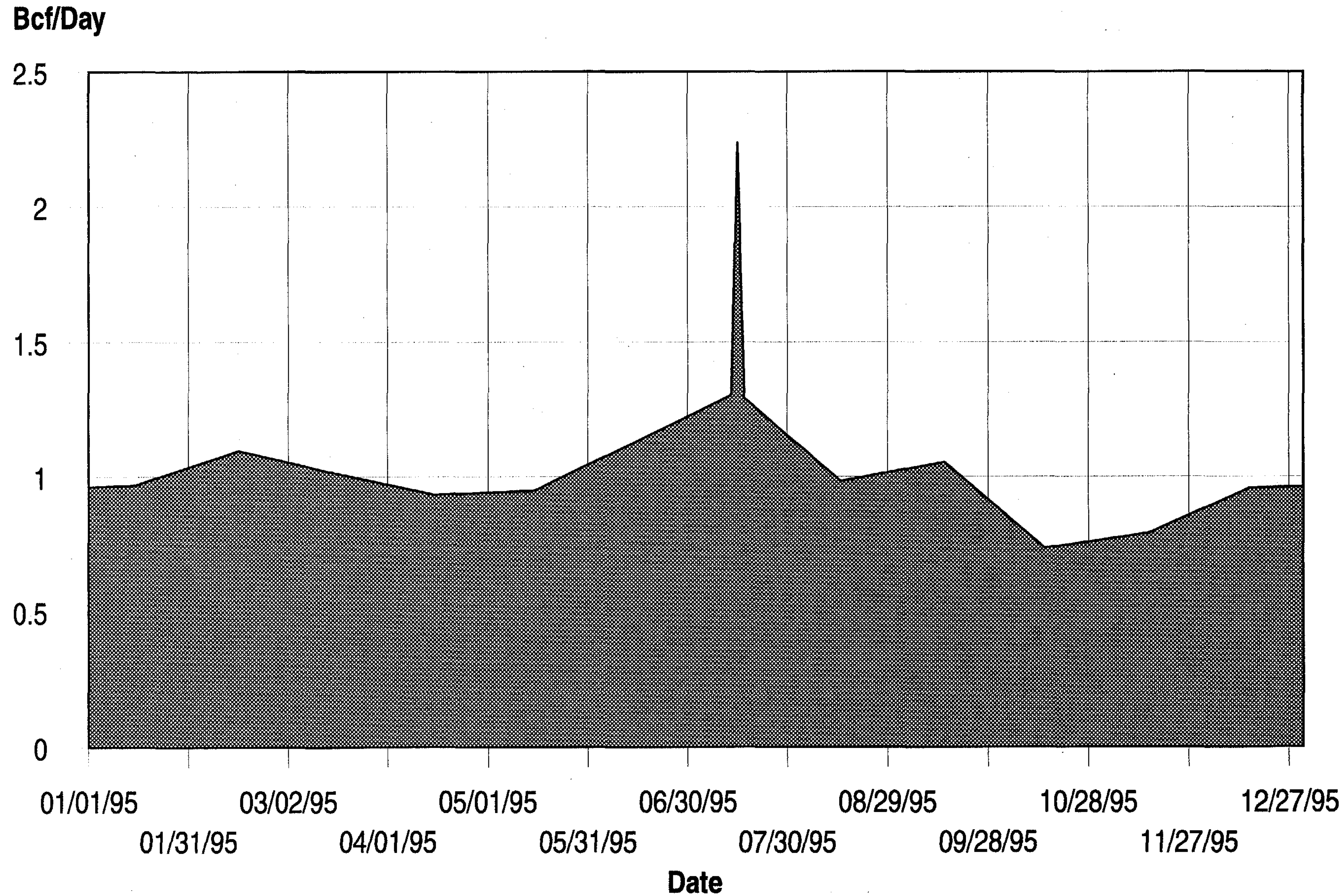
South Atlantic



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

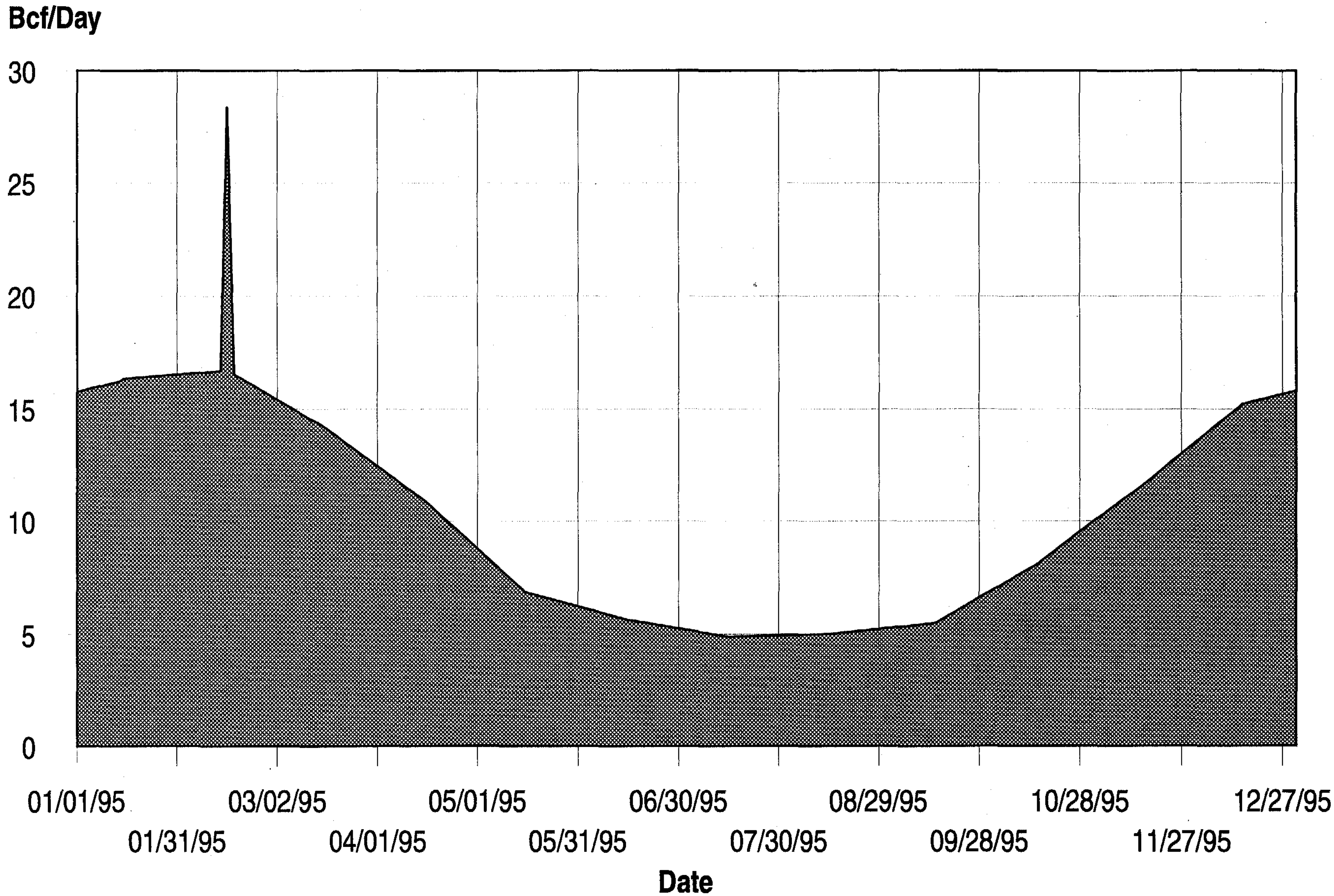
Florida



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

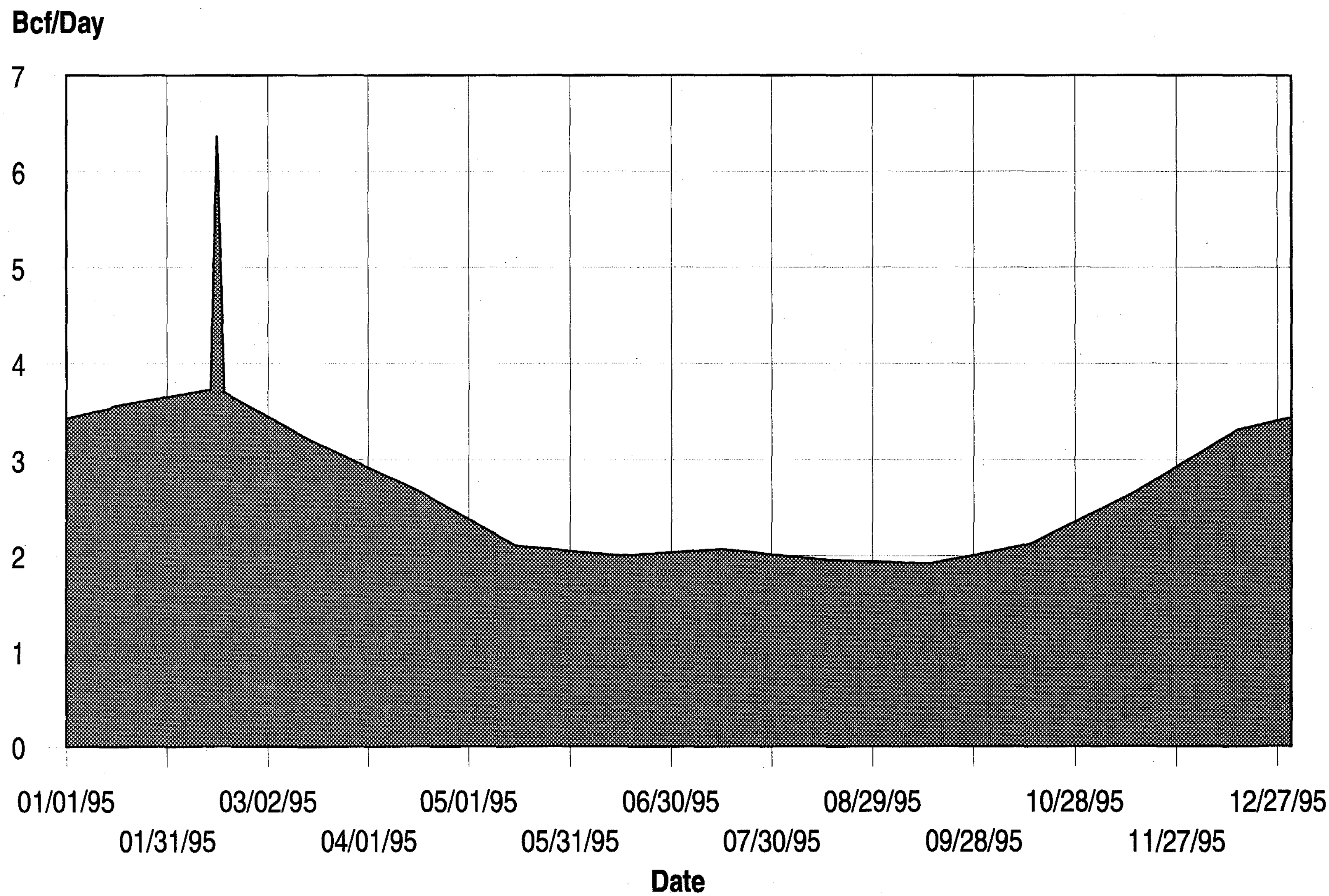
East North Central



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

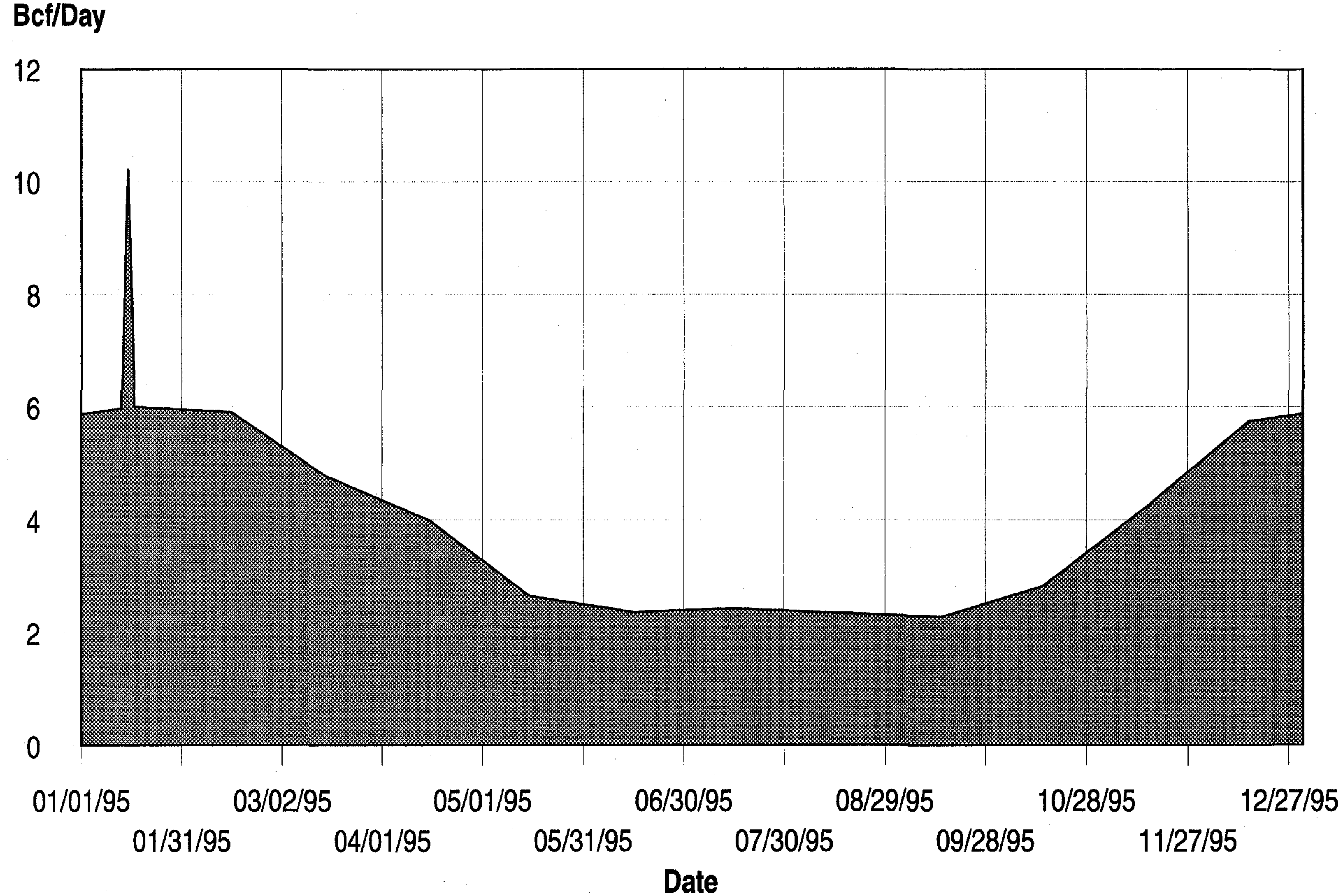
East South Central



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

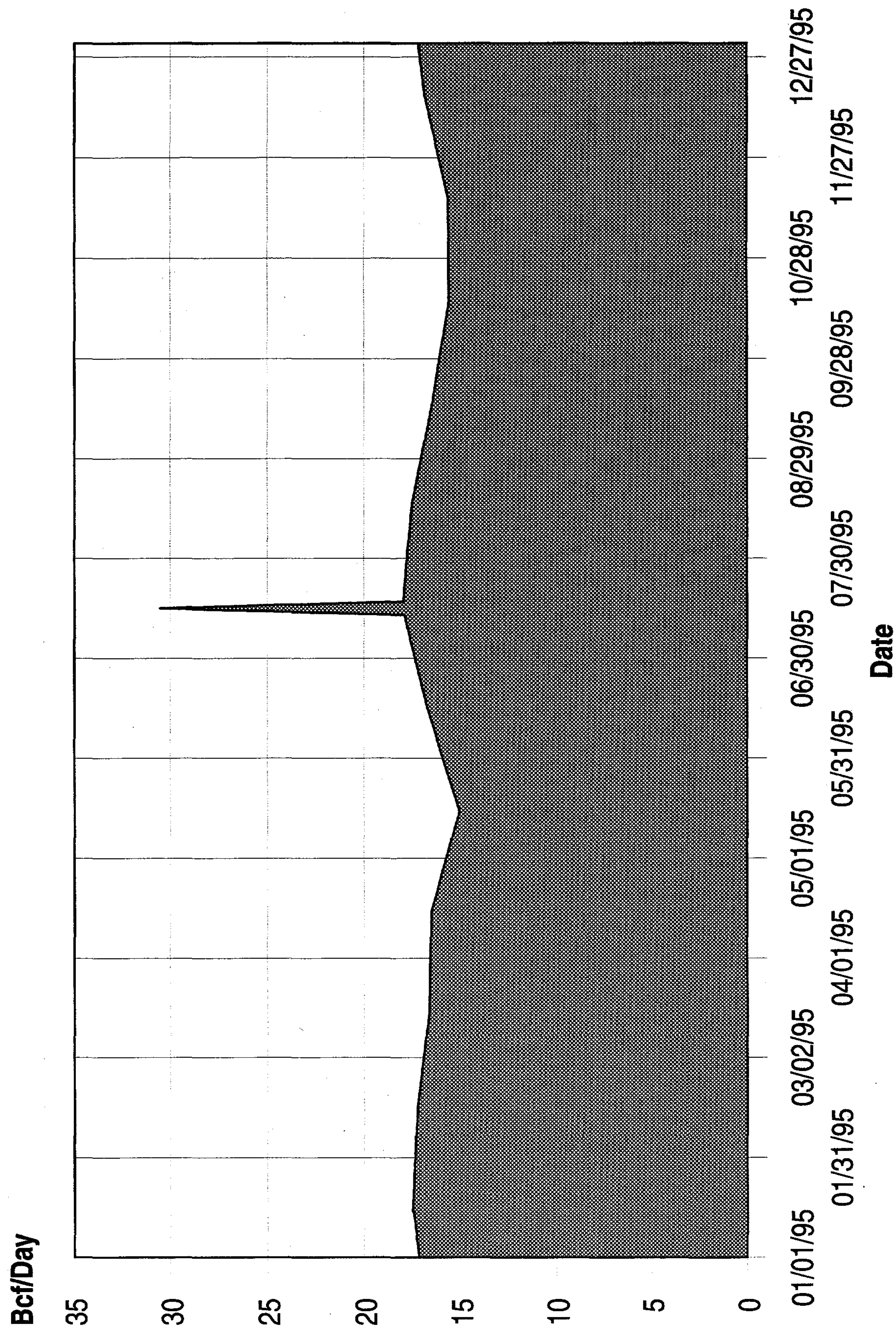
West North Central



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

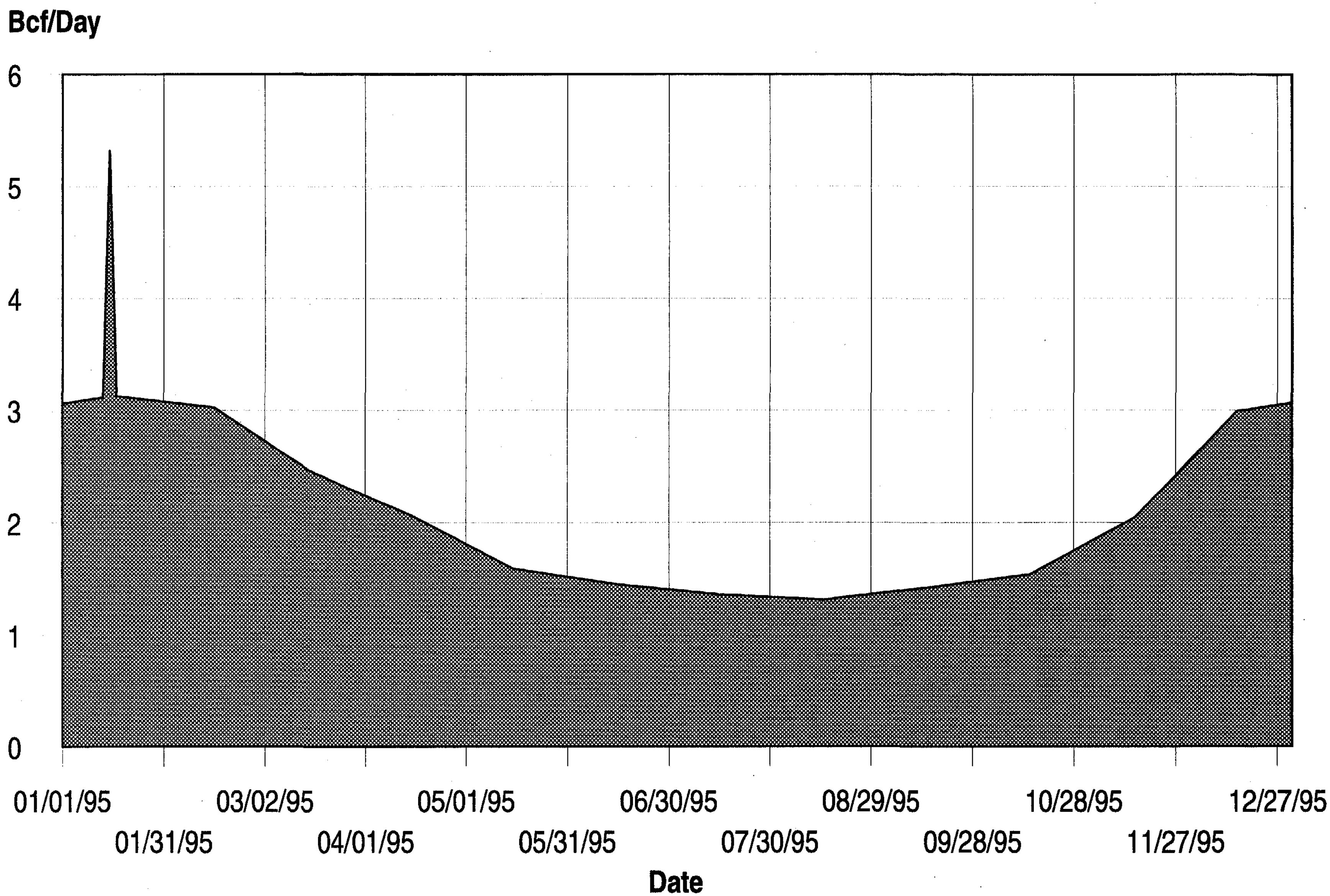
West South Central



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

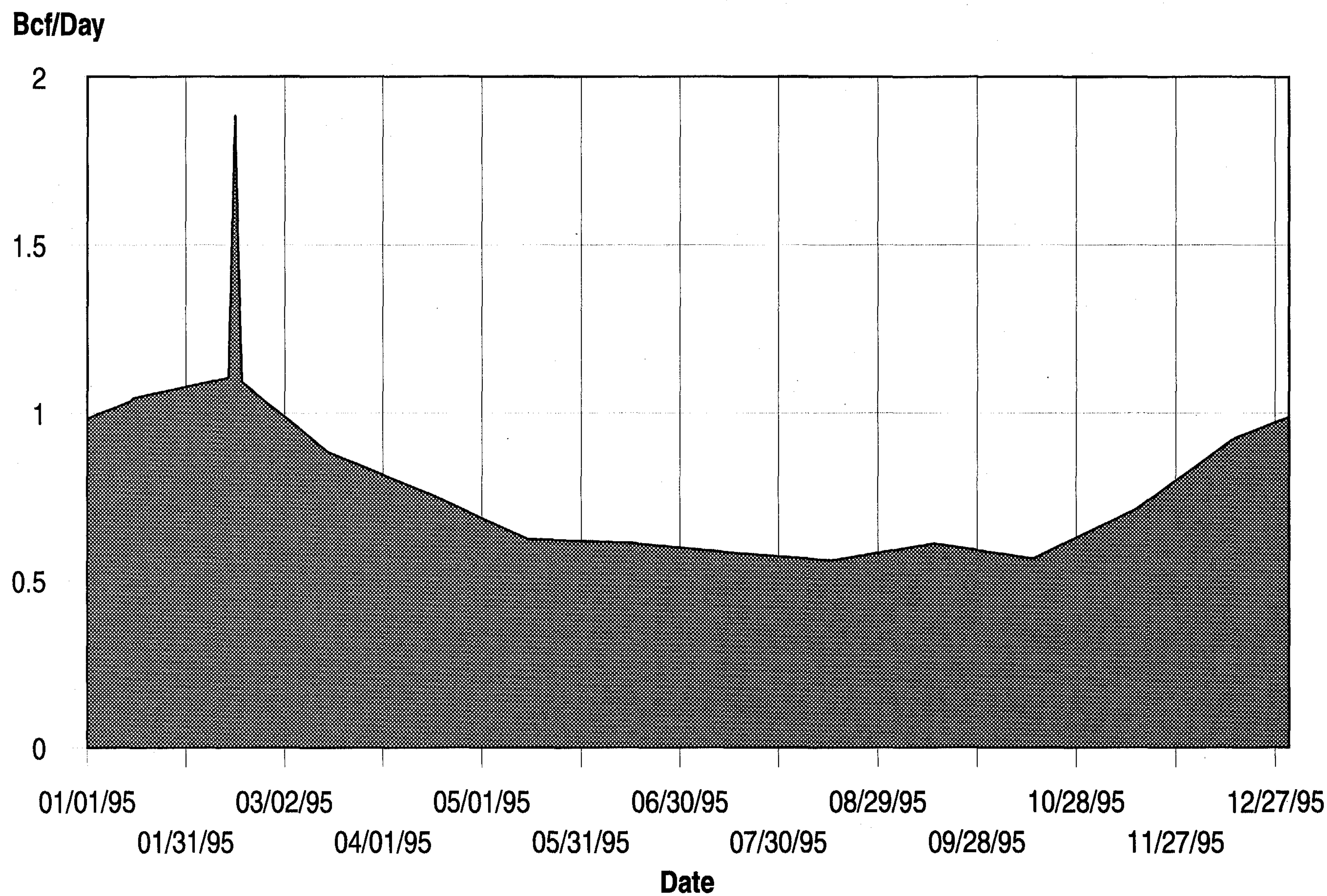
Mountain North



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

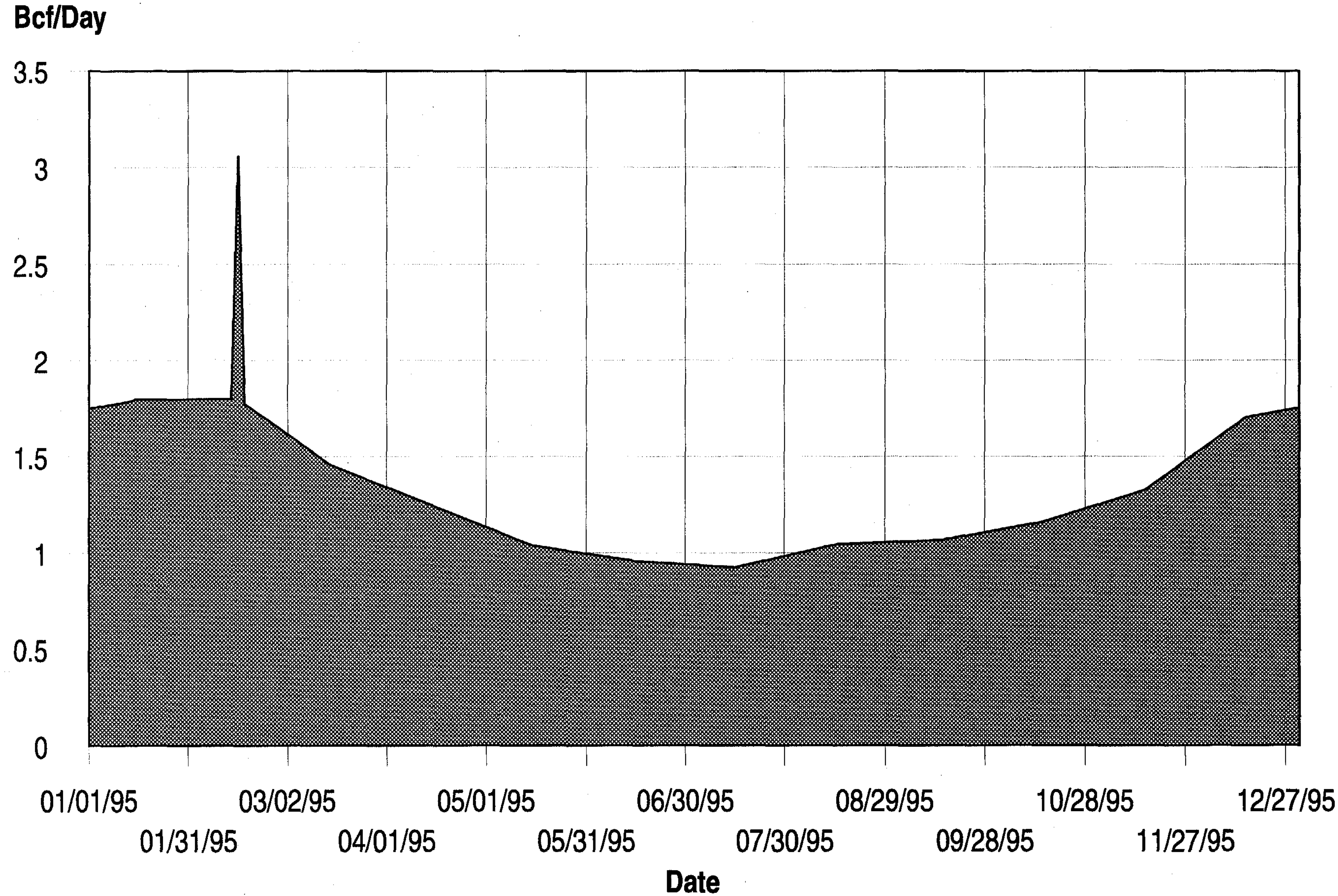
Mountain South



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

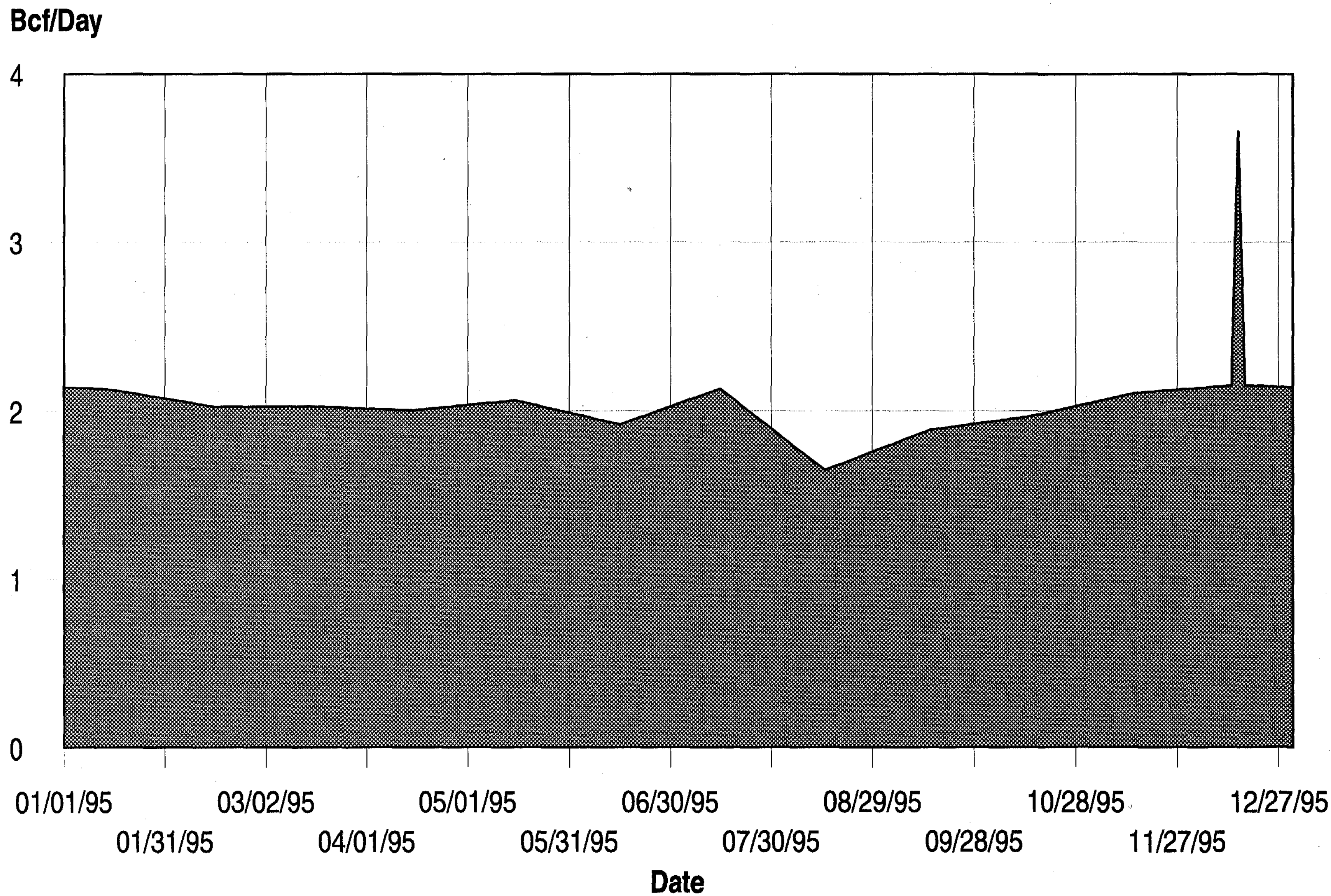
Pacific Northwest



Peak Day volume is included for illustrative purposes.

Projected Total Gas Demand Curve, 1995

California



Peak Day volume is included for illustrative purposes.