

Impact of Power Generation Gas Demand on Natural Gas Local Distribution Companies

Prepared for:
American Gas Association

Prepared by:
Energy and Environmental Analysis, Inc.
October 2001

Catalog No. F22001

IMPORTANT NOTICE ABOUT THIS DOCUMENT

The AGA and Energy and Environmental Analysis, Inc., their members, and those acting on their behalf, disclaim liability for any personal injury, property or other damages of any nature whatsoever, whether special, indirect, consequential or compensatory, directly or indirectly resulting from this publication, use of, or reliance on this document. They also make no guarantee or warranty as to the accuracy or completeness of any information published herein.

In issuing and making this document available, the AGA and Energy and Environmental Analysis, Inc are not undertaking to render professional or other services for or on behalf of any person or entity. Nor are they undertaking to perform any duty owed by any person or entity to someone else. Anyone using this document should rely on his or her own independent judgment or, as appropriate, seek the advice of a competent professional in determining the exercise of reasonable care in any given circumstances.

TABLE OF CONTENTS

	<u>Page</u>
Executive Summary	ES-1
1. Introduction	1
2 Projected Gas Use for Power Generation	3
3. Profile of Gas Use for Power Generation	39
4. Pipeline Operational Challenges	51
5. Evaluating the Impact of Growing Power Generation Demand	65

.....

Executive Summary

Overview

Growth in the amount of gas used for power generation has the potential to affect natural gas markets and natural gas industry operating practices in a number of fundamental ways. Indeed, the use of gas in power generation has already contributed to unprecedented gas price volatility and capital budget planning. One need only review the experiences of the gas markets in California to understand the potential magnitude of the impacts of power generation gas use.

Market price volatility is, however, only one aspect of the changes that power generation gas use will bring to the gas industry. Power generation demand growth could impact operating conditions on the natural gas pipeline network in ways that have the potential to affect LDC operations. The objective of this report is to consider the wide range of potential impacts of the growth in this segment on natural gas Local Distribution Companies (LDCs).

The impact of growth in power generation demand is not the same for all regions of the country and for all LDCs. This analysis is designed to identify factors that could contribute to the impacts between different companies in different regions and different market conditions.

Future Gas Use for Power Generation

There is a growing need for new electricity generation capacity in a number of regions of the country. While electricity markets in California and the Northeast have received the most attention from federal policy makers, markets in the Southeast, Midwest, Florida, and the Gulf Coast all require that substantial generation be added over the next five years with requirements continuing to grow through the remainder of the decade.

In response to these requirements, a very large number of power generation projects are being planned, announced, and built. As much as 240 GWs of capacity has been announced publicly in press releases and public filings. Of these more than 85 percent of the capacity is gas-fired. While all of the announced projects may not be built, the majority of the capacity will be needed by the end of the decade.

Energy and Environmental Analysis, Inc. (EEA) is projecting Lower-48 natural gas demand for power generation to almost double within the next ten years, reaching nearly

8 Tcf in 2010, up from a little over 4 Tcf in 2000. With an average growth rate of 4.2 percent per year, gas demand for power generation is expected to increase faster than gas demand growth in any other sector. Figure 2-1 shows the projected growth of power generation gas consumption relative to gas demand in other end-use sectors. The power generation share of the total natural gas market is projected to increase to 24 percent in 2005, and 27 percent in 2010 compared with 18 percent in 2000.

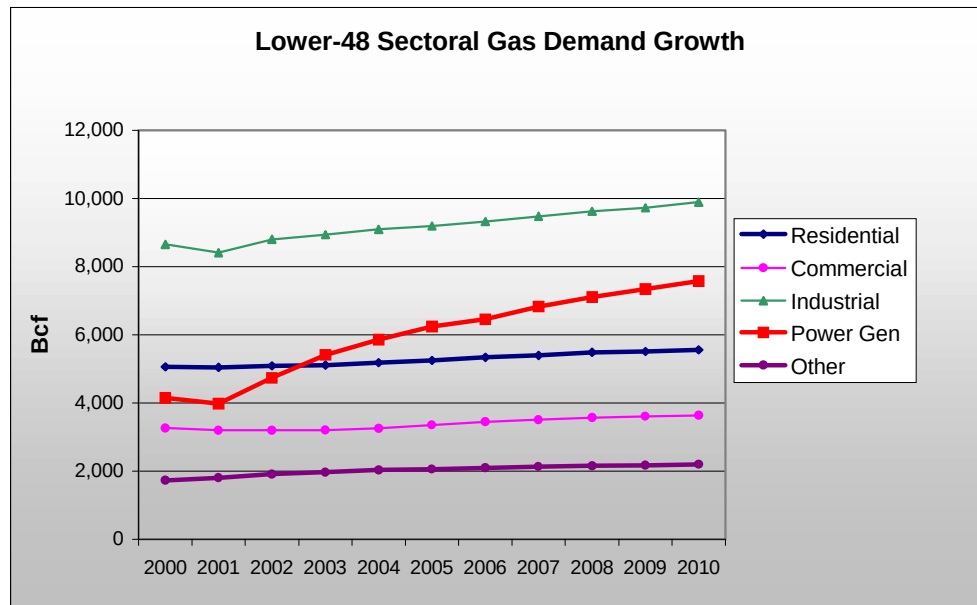


Figure ES-1

Incremental electricity demand is satisfied with increases in both gas/oil-fired and coal generation. Gas-fired generation is expected to account for 68 percent of the increase in total generation. By 2010, gas-fired generation grows to 24 percent of total generation, versus 13 percent in 2000. Most of this growth occurs in new gas-fired generating capacity.

Characteristics of Gas-fired Generation

There are two basic, distinctively different, types of gas-fired generation units:

- Base and intermediate load units, and
- Peaking units.

Base and intermediate load units are designed to operate at a relatively high annual capacity factor – 40 to 70 percent. New base and intermediate load units are generally combined-cycle units (CC) – a gas turbine unit that operates in conjunction with steam cycle generation driven by the hot exhaust gases for the turbine – because of the fuel efficiency advantage of these units that result in lower average generating costs.

A base-load combined-cycle is generally built with the intention of running on a regular schedule. For example, a unit may be designed to operate for 16 hours per day, seven days a week. In almost all instances, the base-load gas-fired generators will be pulled “off-line” during the late night and early morning hours, coming back “on-line” in the early morning.

Peaking load units are designed to run many fewer hours in the year. In the extreme, some units may only operate less than 50 hours per year during periods of peak electricity demand. Despite the low annual utilization, merchant peaking units can operate profitably by selling power during periods when the marginal electricity price is very high. However, to capture these opportunities, generators must be ready to come “on-line” quickly, often with little advanced notification. If a peaking generator misses an opportunity to capture extremely high marginal electricity prices on even a few occasions, the project’s profit potential for the year may be lost.

Ramp-up and Ramp-down

Gas turbines can operate in a range of zero to 100 percent of the peak capacity rating, but efficiency levels begin falling rapidly when the turbine is operated below 80 percent of the rated capacity. The relationship between capacity utilization and efficiency means that, even though gas turbines are often used for load following purposes, or are kept online as spinning reserve, the desired mode of operation generally results in a rapid startup. Since the majority of gas turbine power stations include more than one turbine, plant startup can be staged to follow load by staging the operation of the various available turbines. A simple cycle gas turbine can be brought to full speed and peak natural gas consumption within 15 to 25 minutes of startup. The startup time for a combined cycle unit depends on the design of the unit. Steam turbines take significantly longer to bring to full power than a gas turbine, and typically require a staged startup process.

Moreover, a power plant may have relatively little advance knowledge that the unit will be dispatched. In a number of regions, the Independent System Operator (ISO) may require units to ramp-up to replace units that are experiencing unanticipated outages.

Pipeline Service Requirements

As a result of these characteristics, power generation load exhibits more variability within each day than traditional pipeline customers. As pipeline customers, power plants will require services that allow them to manage the hourly swings in gas consumption.

Pipelines routinely have to adjust operating practices to meet the challenges of maintaining system pressure and adjusting to changes in rate gas consumption and gas flow patterns. Power plants amplify these changes because the fluctuation in consumption volumes is large and the rate of change is larger for power plants than for any other class of customers. The gas industry has served power plants for years – the unprecedented increase in gas demand for this sector, however, points to operational challenges.

To meet these challenges, pipelines may have to add facilities and/or change operating practices to compensate for the more volatile pressure conditions. For example:

- A pipeline may be able to add compression to respond to changes in operating conditions.
- A pipeline may be able to add looping upstream of the power generation facility to allow for additional gas flow and to decrease the magnitude of the pressure decline that accompanies power plant ramp-up.
- A pipeline could add flow control devices at key locations and at power plant delivery points to manage system operations.
- A pipeline could enhance system monitoring to insure that pressure changes are addressed efficiently.
- A pipeline could utilize state-of-the-art and dynamic flow modeling to evaluate operational scenarios and significantly reduce the risk of operational disruptions.

In addition, LDCs and other shippers may have assets and facilities that can be employed to address the operating changes. LDC assets that could support power generation include:

- Utility owned storage facilities that could increase the supply available in proximity to a power plant.

- Peakshaving facilities that could be operated to displace pipeline gas.
- Storage injections into contract storage that could be managed on a daily or hourly basis to support pipeline linepack.
- The ability to adjust and balance gas deliveries between multiple city-gate delivery points serving the LDC.

Communication between the generator, the pipeline and other pipeline shippers is important to effectively utilize LDC and other shippers' assets to manage and protect the operational integrity of the pipeline system. Shippers with assets that are available to maintain pressure and gas flow to generators must be aware that the opportunity exists in the marketplace. When these services are marketed to generators, the communication protocols could help to assure that the assets are being utilized in a similar manner.

Likewise, regulatory structures that allow shippers to effectively compete with pipelines are also important. To utilize existing assets efficiently, LDCs must not be restricted from utilizing their portfolios in a manner that meets the needs of the generator. In addition, competition between the pipeline and shippers can help assure that cost of services that require new facilities is minimized.

.....

1

INTRODUCTION

Growth in the amount of gas used for power generation has the potential to affect natural gas markets and natural gas industry operating practices in a number of fundamental ways. Indeed, the use of gas in power generation has already contributed to unprecedented gas price volatility, pipeline expansion proposals and capital budget planning. The objective of this report is consider the wide range of potential impacts of the growth in this segment of the market and discuss the implications of these impacts on natural gas Local Distribution Companies (LDC).

Gas use for power generation is a major opportunity for companies in the gas industry. By most estimates, gas use for power generation will account for more than half of the total growth in gas markets over the next ten years on a volumetric basis. Connecting new power plants will require investment in new infrastructure and provide an opportunity to offer services such as gas procurement, balancing and load management. While many of the new power plants will likely be connected directly to an interstate pipeline, LDCs want to compete for the growing power generation market by constructing facilities and using their portfolio of assets to serve the fuel service needs of generators. Moreover, many LDCs are pursuing business models that include power generation and power marketing as part of their core portfolio of energy products.

Market price volatility and market growth opportunities are not the only changes that gas use for generation will bring. Power generation demand growth will dramatically affect operating conditions on the natural gas pipeline network in ways that have the potential to affect LDC operations. Because of the large number of power plants slated for several regions of the country and the large amount of gas consumed at a power plant and the rapid and sometimes unanticipated changes in the hourly rate of consumption, gas-fired power plants have the potential to cause significant swings in the operating pressures on a pipeline. The principal operational concern expressed by LDCs is that pressure drops at the LDC's city-gate that could accompany the ramp-up of one or more power plants could disrupt and reduce the rate of gas flow through the LDC's meter station and into the distribution facilities. Pipelines, shippers and regulators will need to utilize "state of the art" analytic and communication tools to ensure that traditional customers as well as power generation applications receive the quality of service needed to meet gas consumers' needs.

The impact of growth in power generation demand is not the same for all regions of the country and for all LDCs. This analysis is designed to identify factors that could contribute to differences in impacts of power sector demand for gas between different companies in different regions and different market conditions.

To accomplish this objective, the report:

- Examines projected power generation gas demand growth in the United States on a regional basis,
- Evaluates the operating characteristics of gas generation and discusses the transportation and delivery service requirements to serve power generation load,
- Considers how power generation service and load profile can affect pipeline operating conditions and the service received by LDCs and other shippers on the pipeline, and
- Discusses how growth in power generation gas consumption can affect national and regional gas market conditions.

2

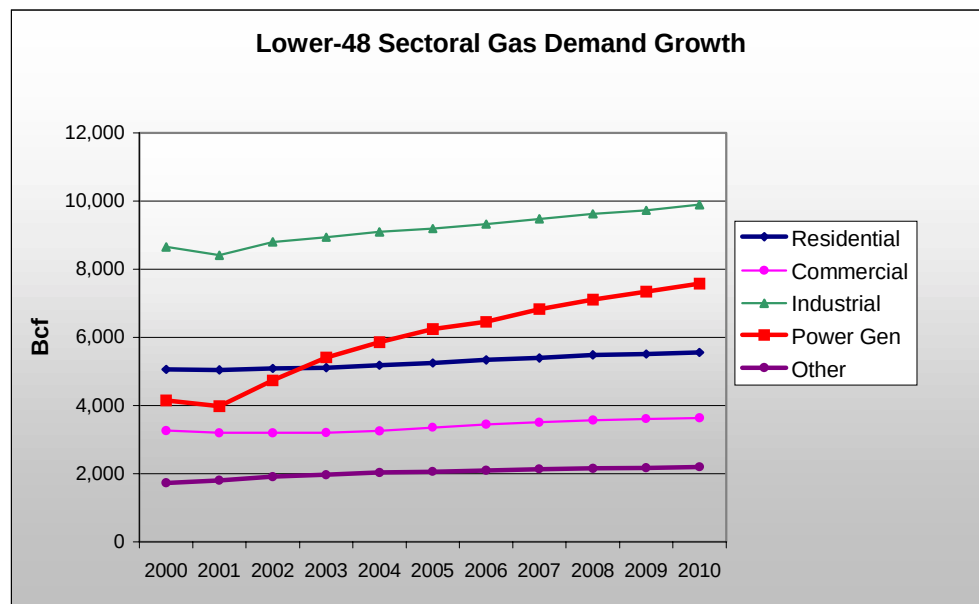
PROJECTED GAS USE FOR POWER GENERATION

2.1 Overview of Growth in Natural Gas Use for Power Generation

Power generation is currently the fastest growing market for natural gas. New lower cost gas-fired generating technologies, combined with long lead times and environmental compliance difficulties associated with other technologies have made natural gas generation the new capacity of choice for most new power plants currently under construction or in the planning phases.

EEA is projecting Lower-48 natural gas demand for power generation to almost double within the next ten years, reaching nearly 8 Tcf in 2010, up from a little over a 4 Tcf in 2000. With an average growth rate of 4.2 percent per year, gas demand for power generation is expected to increase faster than gas demand growth in any other sector. Figure 2-1 shows the projected growth of power generation gas consumption relative to gas demand in other end-use sectors. The power generation share of the total natural gas market is projected to increase to 24 percent in 2005, and 27 percent in 2010 compared with 18 percent in 2000.

Figure 2-1



Incremental electricity demand is satisfied with increases in utilization of existing coal generation capacity as well as new generation capacity. In total, gas-fired generation is expected to account for 68 percent of the increase in total generation. By 2010, gas-fired generation grows

to 24 percent of total generation, versus 13 percent in 2000. Most of this growth occurs in consumption at new gas-fired generating facilities.

Increases in coal-fired generation account for 25 percent of the increase in total generation, which represents 75 percent of the total increase in generation for all non-natural gas sources. However, very little new coal generation capacity is expected to be available before 2010. Most of the increase in coal-fired generation occurs to improvements in the utilization of existing coal units, which are projected to improve from 69 percent in 1999 to 73 percent in 2010. Overall, coal consumption falls to 69 percent of the fossil fuel consumption in 2010, versus 80 percent in 2000. SO₂ emissions remain in compliance with the stricter limits proposed in recent Ozone/PM standards because scrubbers are added to a reasonable portion of the coal generating capability.

Oil consumption grows by about 200 Tbtu from 2000 to 2010, which represents nearly 31 percent growth between 2000 and 2010. Much of this growth is due to an increase in fuel switching from natural gas to oil at dual-fuel capable facilities in response to higher gas prices, in the later years of the outlook.

Table 2-1
Lower-48 Generation and End-Use Electricity Sales (TWh) /1,2

	Coal	Oil	Gas	Nuclear	Hydro	Other	Total Generation	Electricity Sales
1997	1,790	75	277	629	336	7	3,114	3,120
1998	1,803	93	318	674	304	9	3,201	3,237
1999	1,772	80	343	731	293	9	3,229	3,274
2000	1,858	77	422	738	259	10	3,365	3,364
2001	1,855	93	441	735	250	10	3,385	3,386
2005	1,827	87	767	760	278	15	3,734	3,695
2010	2,012	115	987	762	278	22	4,176	4,099

1. Generation at all utility-owned capacity and non-utility capacity constructed after 1997.
Does not include generation for own use.
2. Electricity sales only include sales from the grid.

Table 2-2
Lower-48 Power Generation Sector
Fossil Fuel Demand (Tbtu) /1

	Coal	Gas	Oil
1997	18,681	3,031	790
1998	18,837	3,485	979
1999	18,549	3,727	841
2000	19,303	4,272	801
2001	19,191	4,095	945
2005	18,405	6,428	833
2010	19,708	7,805	1,014

1. Includes fuel use at all utility-owned capacity and non-utility capacity constructed after 1997. Fuel used at cogeneration and other industrial facilities is included in Industrial sector demand.

Electricity Capacity Requirements

Lower-48 electricity demand is projected to grow at 2.1 percent annually. This growth rate is above NERC projections of 1.8 percent per year, but is consistent with most other projections of electricity demand growth. Electricity demand grows most in the southern U.S., where substantial population growth is expected to continue. Based on percentage change, Florida exhibits the largest growth in electricity demand and Texas is a close second.

In order to meet the growth in electricity demand, U.S. electricity generating capacity is expected to increase by 160 gigawatts (GW) of capacity, or 21 percent between 2000 and 2010. Table 2-3 shows total lower-48 U.S. generating capacity by type. This growth includes 171 GW of new gas and dual-fuel fired combustion turbine (CT) and combined cycle (CC) units, offset in part by 21 GW of oil and gas capacity retirements. The new CT and CC capacity represents almost 95 percent of total incremental capacity during this period.

Table 2-3
Lower-48 Generating Capacity (GW) /1

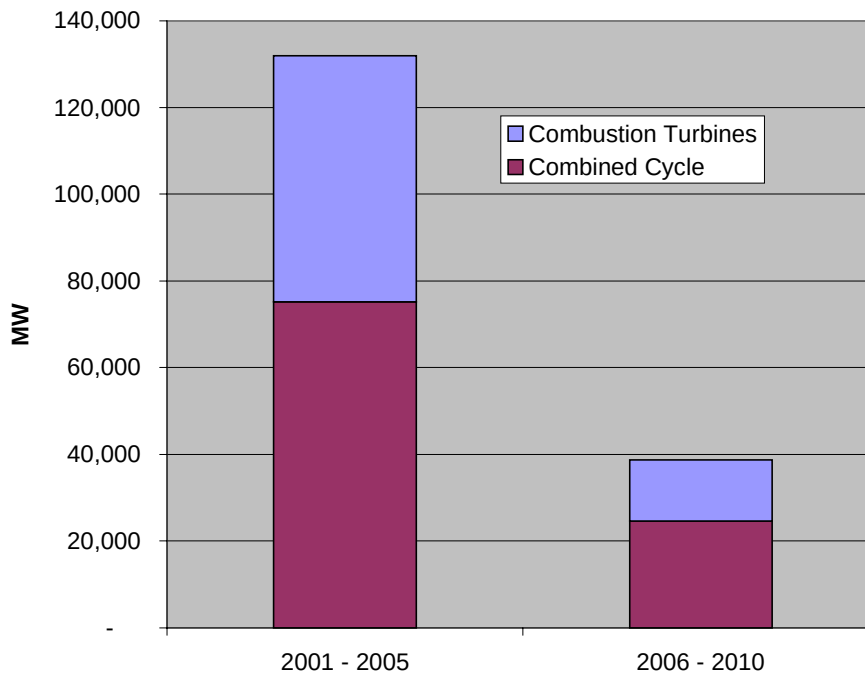
	Coal	Oil/Gas Steam /2	CC/CT /3	Nuclear	Hydro	Other	TOTAL
1997	304	217	0	95	100	7	724
1998	304	217	2	95	100	8	727
1999	304	219	11	95	99	9	736
2000	305	221	34	95	99	9	762
2001	306	214	79	95	99	10	802
2005	313	190	165	95	99	14	873
2010	315	190	204	93	99	20	914

1. All utility-owned capacity and non-utility capacity constructed after 1997.
2. Includes combined cycle and combustion turbines built prior to 1998.
3. New additions of combined cycle and combustion turbines after 1997.

Peaking vs. Baseload Capacity

Natural gas is expected to be the new capacity fuel of choice to meet both baseload and peaking capacity requirements. Figure 2-2 shows the expected mix of new combined cycle and single cycle combustion turbine capacity added between 2000 and 2010. The majority of new gas-fired power generation capacity is expected to be combined cycle plants. The combined cycle share of new gas-fired generation capacity market is expected to increase over time, from 57 percent of total gas-fired capacity additions between 2001 and 2005, to 64 percent of total gas-fired capacity additions between 2006 and 2010.

Figure 2-2

New Gas-Fired Generating Capacity**Key Uncertainties****Gas Prices**

The high natural gas prices in the 2000/2001 winter are stimulating an effort to reassess the long-term reliance on new gas-fired generating capacity to meet electricity needs. However, over the next decade, natural gas will likely capture more than 90 percent of new generation capacity additions. The lead-time required to build a significant amount of new coal-fired capacity or any nuclear capacity effectively removes these options from the marketplace during the next several years. Moreover, with prices continuing to moderate over the next several years, natural gas will reassert its economic advantage over other generation options. However, if the expected price moderation does not occur, there will be an effort to examine other options in the second half of the decade. If there is an extended period of high gas prices, new coal-fired plants and other non-gas generation capacity will enter the mix. As a result, natural gas's share of total capacity additions could decline during the 2005-2010 time period.

Dual-fuel Capability

There has been a tendency over the last few years to avoid adding dual-fuel capabilities at new gas-fired power plants. However, the recent high gas prices have improved the economics of dual-fuel capabilities, and we expect to see an increase in the percentage of new gas-fired

generating capacity built with dual-fuel capabilities. This will take two forms: Plants with ready access to fuel oil supplies, either via water or product pipeline, will be more likely to install long term capability to run on fuel oil as well as natural gas. For these plants, the fuel decision will be based partially on fuel price economics, and partially based on air emissions criteria.

Plants without easy access to long term fuel oil supplies will be more likely to install short term (3 to 5 days) switching capabilities with the objective of ensuring reliability. Plants that have the logistical capability for monthly or seasonal fuel switching will utilize the capability in order to take advantage of natural gas/oil price arbitrage opportunities. Over the next decade, the arbitrage opportunity could be as high as \$3.00 per MMBtu during the winter heating season. If the percentage of plants with seasonal fuel switching increase, the power generation's gas consumption during peak winter months will be less than expected. Conversely, if seasonal dual-fuel capability is restricted, peak winter gas consumption would be larger than that forecasted in the EEA base case.

Gas-fired Generation Capacity Additions

Over the past several years, there has been a constant stream of press releases announcing new gas-fired power projects. In total, EEA has identified more than 240 GW of announced capacity, a number that is well above the amount of capacity that is projected to be built in the base case. It is likely that a significant portion of the announced capacity will not be built according to the announced schedules.

However, if all of the announced gas capacity were to be built, the projected amount of gas consumed for power generation would not increase. In fact, depending upon the mix of combined cycle plants and peaking combustion turbine plants, the amount of gas consumed might be lower than the base case projection.

The projected gas prices result in gas units being dispatched to meet the marginal electricity requirements. Coal, nuclear, and hydro generation is all dispatched ahead of the gas plants. The demand for electricity, not the amount of gas-fired capacity that is built, will determine the amount of gas that is consumed for power generation. If the generation market is "over-built" in the next few years, all of the new generators will compete for hours of operation. The overall load factor for the new units will decline. In fact, "over-building" could result in meeting peak electricity requirements with more efficient combined-cycle units, reducing the amount of gas consumed.

2.2 Regional Growth in Gas Fired Generation

While the growth in gas-fired power generation nationally indicates that LDCs in most areas of the U.S. will be impacted by the growth in power generation demand, actual impacts on specific LDC's will depend on a variety of local and regional issues, rather than the national trends. This section of the report focuses on regional changes in gas use during peak demand periods in order to identify regions where gas demand growth for power generation is likely to have the greatest impact on existing gas users and facilities.

Table 2-4
Growth in Natural Gas Demand for Power Generation by Region
(Annual Units in Bcf, and monthly units in Bcfd. Capacity in GW)

	Annual			January			Gas-Fired Capacity		
	2000	2010	Change	2000	2010	Change	2000	2010	Change
Lower-48	4,148	7,583	83%	10.1	19.4	93%	254.1	394.4	55%
New England	134	242	80%	0.3	0.6	62%	16.4	21.9	34%
New York	263	322	22%	0.5	0.6	22%	34.5	40.5	17%
MAAC	85	296	247%	0.3	0.9	174%	23.6	27.3	16%
SERC	86	742	766%	0.8	2.9	256%	19.8	41.8	111%
Florida	352	766	117%	1.0	1.8	80%	23.6	32.5	38%
ECAR	89	447	402%	0.3	1.3	363%	10.8	31.3	190%
MAIN	51	244	374%	0.2	0.6	221%	11.0	26.5	141%
MAPP	94	329	248%	0.3	1.1	293%	10.6	17.9	69%
SPP	695	858	23%	1.6	1.7	8%	32.2	48.6	51%
ERCOT	1,297	1,789	38%	2.7	4.0	49%	44.3	60.1	36%
CA/NV	761	1,018	34%	1.7	2.6	56%	30.1	36.6	22%
Northwest	93	252	171%	0.2	0.8	453%	4.0	9.5	138%
Rockies	146	277	89%	0.3	0.6	117%	8.0	14.8	85%

2.2.1 New England (ME, NH, MA, CT, RI)

Figure 2-3 illustrates expected natural gas demand growth by sector in New England. On an annual basis, New England natural gas demand for power generation is projected to increase by more than 100 Bcf by 2010 – from 134 Bcf in 2000 to 242 for the year 2010. From 2005 through 2010, the rate of growth slows, with some annual cycling in response to nuclear refueling patterns.

Gas demand for power generation shows the largest increase of all other demand sectors. Figure 2-4 shows that power generation gas demand increases its share of total demand for natural gas increasing to 27 percent in 2005 from 18 percent in 2000. On an annual basis, the percentage of total generation from natural gas increases from 19 percent in 2000 to 37 percent in 2005. The percentage declines to 35 percent in 2010 as switching to oil increases because of higher gas prices.

The growth in power generation gas demand shows a substantial increase in the share of electricity generated from gas relative to other sources in the region. Figure 2-5 presents gas generation's share of total generation on an annual basis and for the peak generation month. New England is a winter peaking electricity market with the marginal generation units being dispatched in the months where dual fueled generation generally switches to oil. As a result, the gas share of generation is lower than the annual average through most of the decade.

Figure 2-3

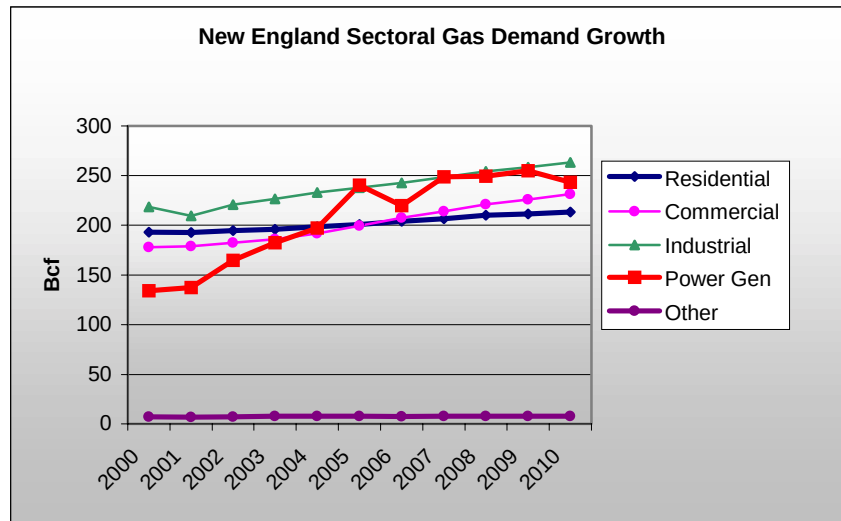


Figure 2-4

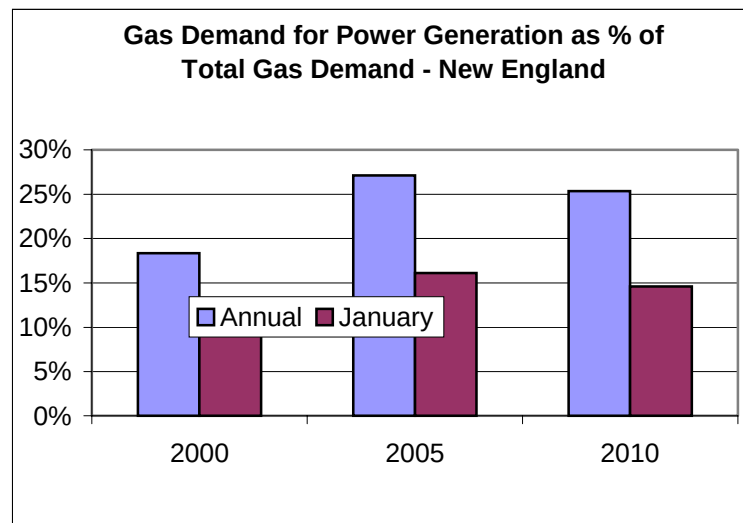
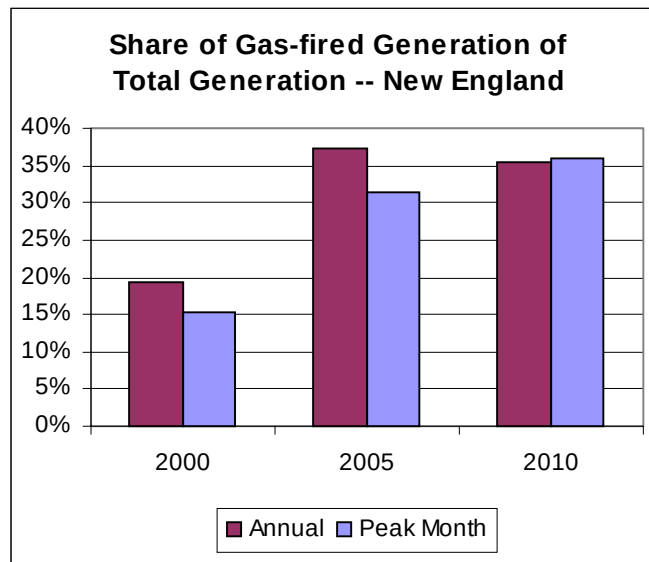


Figure 2-5



2.2.2 Northeast (N.Y., N.J., PA)

Figure 2.6 illustrates expected natural gas demand growth by sector in the Northeast. On an annual basis, Northeast natural gas demand for power generation is projected to increase by 200 Bcf in 2010 from current levels to reach over 600 Bcf, up from a little over a 400 Bcf for the year 2000. Gas demand for power generation shows the largest increase of all other demand sectors, with its share of total demand for natural gas increasing to 16 percent in 2005, and 19 percent in 2010 compared with 13 percent in 2000.

Growth in power generation gas demand during peak months is projected to increase at a faster rate than annual gas consumption. Figure 2-7 illustrates the change in January vs. annual power generation share of the natural gas market over the ten-year projection period. Power generation gas consumption represented 12 percent of total Northeast gas consumption during January 2000. By 2005, gas consumption for power generation is expected to account for more than 16 percent of total January natural gas demand in the region.

The growth in gas-fired power generation shows a substantial increase in the share of electricity generated from gas relative to other sources in the region. Figure 2-7 illustrates gas-fired power generation as a percent of the total annual generation and generation during January, the peak month for gas consumption in New York. On an annual basis, the percentage of total generation from natural gas increases from 23 percent in 2000 to 31 percent in 2010. The share of total electricity generated from natural gas is also expected to increase even faster during the peak electricity demand months. In the Northeast, electricity demand peaks in August. The share of the August generation market served by gas-fired capacity is projected to increase from 26 percent in 2000 to 36 percent by 2005 before falling slightly to 33 percent by 2010.

Figure 2-6

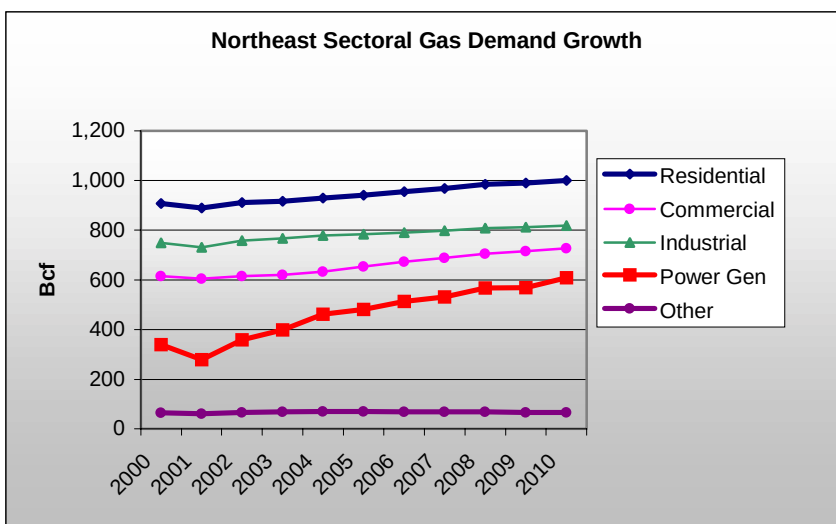


Figure 2-7

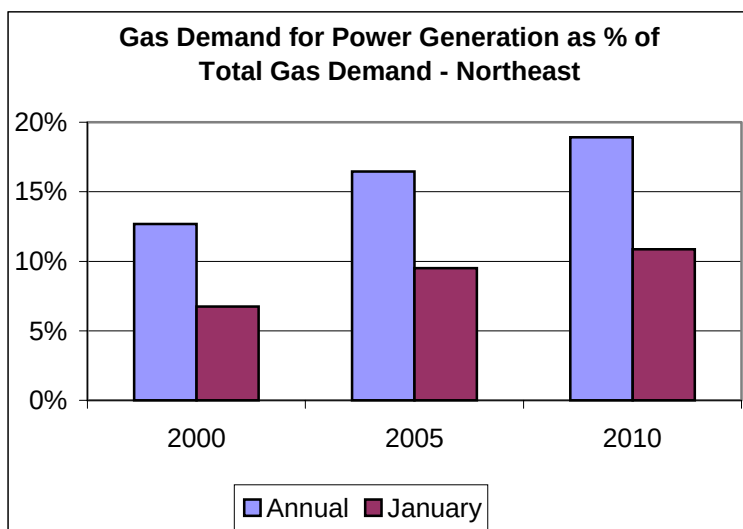
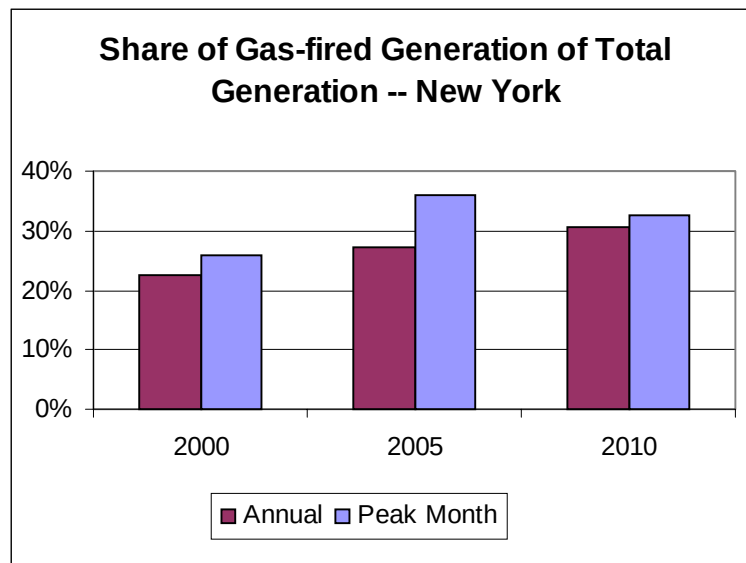


Figure 2-8



2.2.3 Mid-Atlantic (DE, MD, VA, WV)

Figure 2-9 presents expected natural gas demand growth by sector in the Mid-Atlantic. On an annual basis, Mid-Atlantic natural gas demand for power generation is projected to increase to 162 Bcf in 2010 from 39 Bcf for the year 2000. Gas demand for power generation shows the largest increase of all other demand sectors. As shown in Figure 2-10, power generation consumption increases its share of total demand for natural gas to 15 percent in 2005, and 22 percent in 2010 compared with only 6 percent in 2000.

While power generation's share of gas demand shows a steady increase on an annual basis, the power generation share of January gas consumption shows a different pattern. The January 2000 share of 14 percent was unusually high. Warm weather, which left pipeline capacity available and relatively inexpensive, and high oil combined to increase the power generation consumption and decrease the total core consumption. By contrast, power generation's share of demand in January 2001 was less than 8 percent. In the projection period, its share is forecasted to rise to nearly 16 percent by 2010 under normal weather.

The growth in gas-fired power generation shows a substantial increase in the share of electricity generated from gas relative to other sources in the region. Figure 2-11 presents gas-fired power generation as a percent of the total annual generation and generation during August, the peak month for gas consumption in MACC region. On an annual basis, the percentage of total generation from natural gas increases from 3 percent in 2000 to 9 percent in 2005 and 12 percent in 2010. The share of total electricity generated from natural gas is also expected to increase even faster during the peak electricity demand months. The share of the August generation market served by gas fired capacity is projected to increase from 5 percent in 2000 to 11 percent by 2005.

Figure 2-9

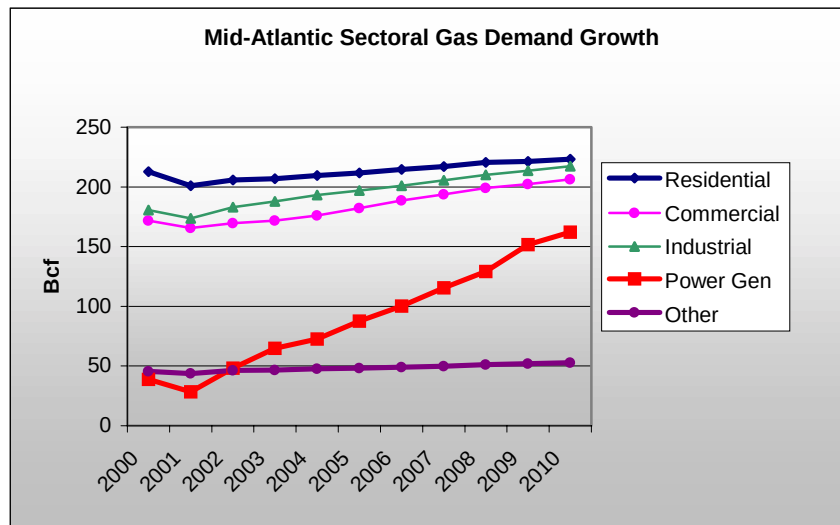


Figure 2-10

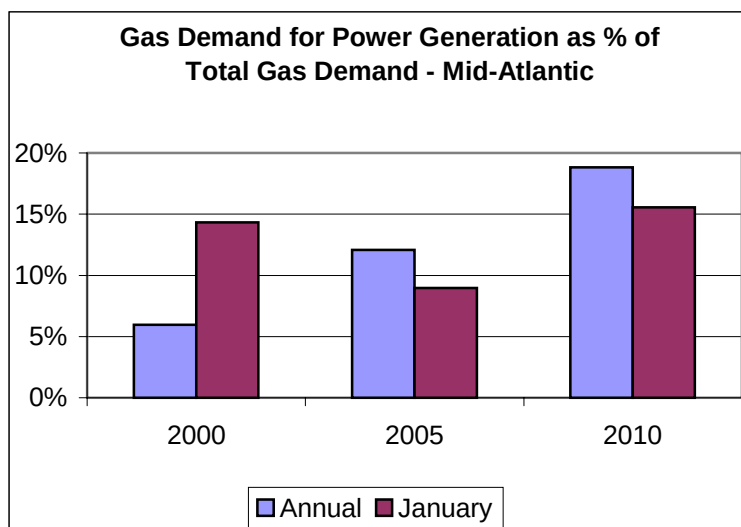
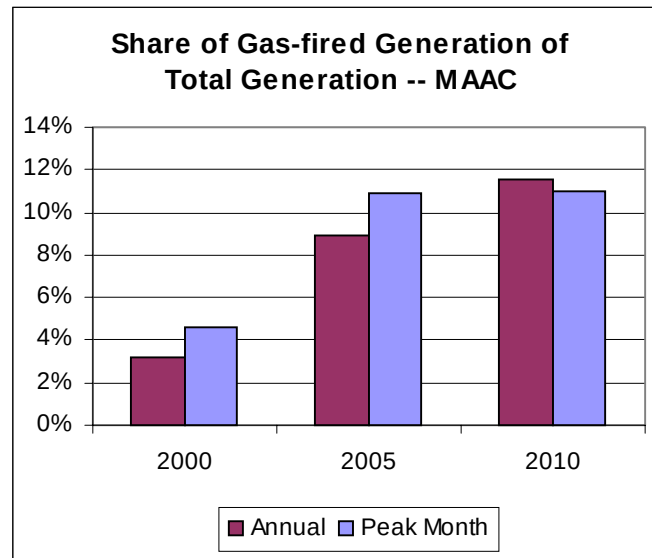


Figure 2-11



2.2.4 South Atlantic (NC, SC, GA)

Figure 2-12 presents the expected natural gas demand growth by sector in the South Atlantic. On an annual basis, South Atlantic natural gas demand for power generation is projected to increase by 359 Bcf between 2000 and 2010 to reach 388 Bcf. Driven by rapidly growing electricity sales, growth gas demand for power generation far outstrips the growth in any other demand sectors. On an annual basis, power generation's share of total demand is projected to grow from 4¹ percent of annual consumption in 2000 to 23 percent in 2005 and 29 percent by 2010.

The growth in power generation's share of January consumption is equally large. As shown in Figure 2-13, power generation's share of total gas consumption in January grows from 3 percent in 2000 to 21 percent in 2005 and 26 percent in 2010.

The growth in gas-fired power generation shows a substantial increase in the share of electricity generated from gas relative to other sources in the region. Figure 2-11 presents gas-fired power generation as a percent of the total annual generation and generation during August, the peak month for gas consumption in the SERC region. On an annual basis, the percentage of total generation from natural gas increases from 1 percent in 2000 to 8 percent in 2005 and 12 percent in 2010. The share of total electricity generated from natural gas is also expected to increase at a similar rate during the peak electricity demand months. The share of the August generation market served by gas-fired capacity is projected to increase from 1 percent in 2000 to 8 percent by 2005 and 13 percent in 2010.

¹ The percentages given are for utility power sales and exclude industrial combined heat and power applications.

Figure 2-12

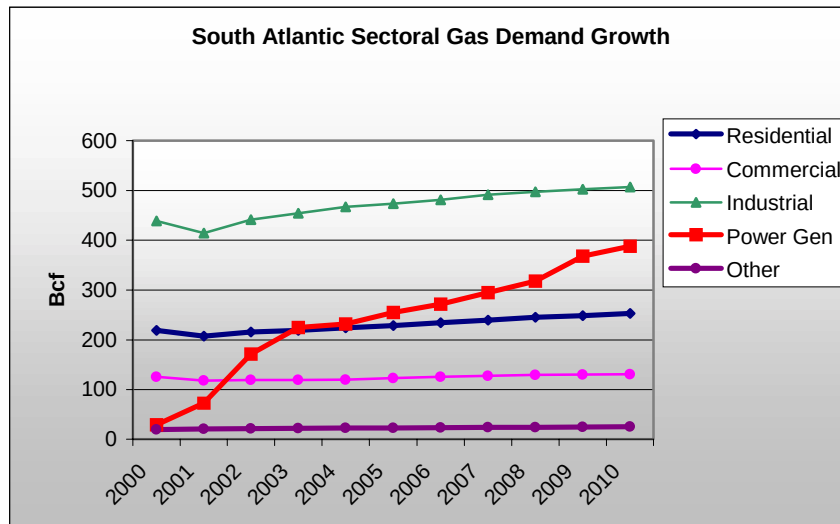


Figure 2-13

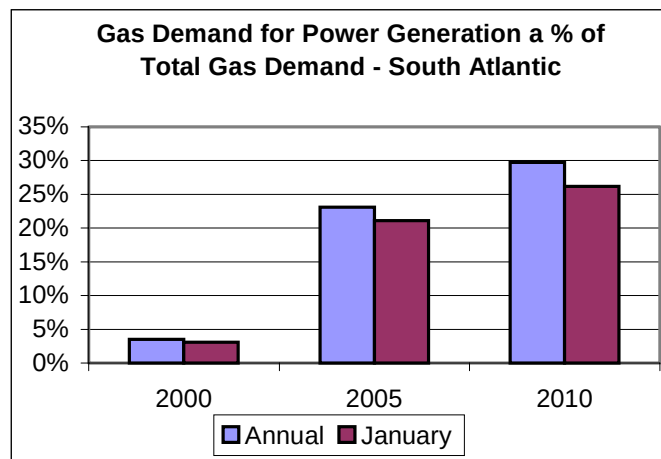


Figure 2-14

