National Energy Board

Office national de l'énergie

Natural Gas for Power Generation:

ISSUES AND IMPLICATIONS

AN ENERGY MARKET ASSESSMENT JUNE 2006

Canada

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FIGURES

Acronyms

AAGR	average annual growth rate
B.C.	British Columbia
EIA	(U.S.) Energy Information Administration
EMA	Energy Market Assessment
EPG	electric power generation
GTN	(TransCanada) Gas Transmission Northwest system
IPP	independent power producers
IT	interruptible transportation
LDC	local distribution company
LNG	liquefied natural gas
M&NP	Maritimes and Northeast Pipeline
N.B.	New Brunswick
NEB	National Energy Board
N.S.	Nova Scotia
OEB	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation Inc.
PNW	Pacific Northwest
RFP	request for proposal
RFO	one percent sulphur residual fuel oil
TransCanada	TransCanada Corporation
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WECC	Western Electricity Coordinating Council

Natural Gas Units

m^3	= cubic metres
m^3/d	= cubic metres per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day

Energy Measures

GJ	gigajoule
MW.h	megawatt hour
GW.h	gigawatt hour

Power Measures

MW	megawatt	$= 10^6$ watts
GW	gigawatt	$= 10^9$ watts

Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas.

The NEB collects and analyzes information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. In addition, policy makers are informed of the regulatory and related energy issues that need to be addressed. On this note, the Board has received feedback from a wide range of market participants across the country that the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA report, titled *Natural Gas for Power Generation: Issues and Implications*, is an assessment of the possible issues arising from the growing use of natural gas for electricity generation in North America. A key objective of this report is to provide a broad understanding and a perspective on the potential implications, challenges and opportunities for Canadian natural gas and electricity markets associated with the development of gas-fired generation.

During the preparation of this report, the NEB conducted a series of informal meetings and discussions with gas and electricity industry officials, government departments and agencies, consultants and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

INTRODUCTION

In its previous reports, *Looking Ahead to 2010 – Natural Gas Markets in Transition and Outlook for Electricity Markets (2005-2006)* the Board noted that the demand for electricity in Canada and North America will continue to grow and that a significant part of the incremental demand will be met through electricity generated from natural gas. The reports also highlighted that there are uncertainties with respect to future natural gas supply and infrastructure that may be needed to meet the growing requirement for electricity, the largest growth market for demand of natural gas.

Driven by a combination of increasing population, economic growth and the greater use of electrical equipment, the demand for electricity is expected to continue to grow steadily in the coming years. Much of the rising need for electricity is likely to be met through natural gas-fired generation. In fact, since 1998, of the almost 211 500 MW of incremental electricity generation capacity installed in the United States, over 200 000 MW or 96 percent is capable of using natural gas.

Although gas-fired generation does not make up as large a percentage of total capacity in Canada as in the United States, it has grown substantially. Since 1998, 57 percent of the new generating capacity in Canada has been gas-fired. In 1995, natural gas-fired generation made up only four percent (4 500 MW) of Canada's total generating capacity, whereas in 2004, it made up around nine percent (10 514 MW). Growth in industrial demand, such as the oil sands development, will further increase the demand for natural gas and electricity supply. While the growth in gas-fired generation has not been as rapid as in the United States, the trend is likely to intensify in Canada.

Today, over 45 percent of installed electricity generation capacity in the United States is capable of using natural gas as fuel compared with about 30 percent a decade ago. This substantial and rapid increase in potential demand and dependency on natural gas has led to uncertainties regarding the adequacy of existing natural gas and electricity infrastructure and concerns over the reliability of future natural gas and electricity supply.

This EMA examines the potential impacts of growing natural gas-fired generation on Canadian natural gas markets and infrastructure, and the potential changes that may be experienced in natural gas flows and natural gas services.

Scope of this Report

The objective of this report is to present a historical examination of trends in natural gas-fired generation in North America and to provide a perspective on issues and potential implications of increasing reliance on natural gas. In particular, the discussion will focus on potential changes to Canadian energy consumers, natural gas infrastructure and services, and on potential implications for Canadian natural gas and electricity prices. While discussions will emphasize Canadian situations and issues, energy markets are integrated and "gas for power" trends may reflect developments outside of Canada. Therefore, much of the analysis and discussion presented in this report will be from a broader regional and continental perspective.

Chapter 2 examines the historical trend toward natural gas-fired generation of electricity in the United States and Canada and provides a general overview of the potential issues for Canadian natural gas markets, infrastructure and services. Although, incremental gas-fired generation has been installed in most regions, the utilization and impacts of new gas generation has varied across regions depending on the availability of natural gas and diversity of alternate generation options.

Chapters 3, 4 and 5 examine these issues in closer detail from a regional perspective and discuss the changes in generation and natural gas markets in three regions: western, eastern and central North America. The implications and questions that arise from the analysis of specific regional supply, demand and infrastructure situations are examined in Chapter 6.

BACKGROUND

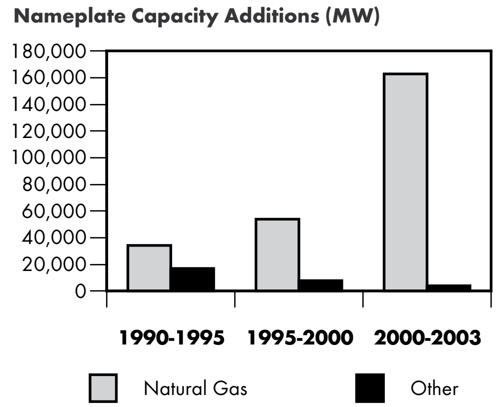
2.1 Development of Gas-Fired Generation in Canada and the United States

For more than a decade, natural gas has been the fuel of choice for new power generation in North America, especially in the United States. In fact, over the last five years alone, total generating capacity in the United States has increased by more than 25 percent with natural gas-fired generation accounting for 96 percent of the additional generation (Figure 2.1). Overall, natural gas-fired generation in the United States has doubled since 1990 (Figure 2.2).

In Canada, the development of electricity generation has proceeded at a slower pace as demand for electricity has been relatively stable. As well, while incremental electricity generation in Canada is increasingly fueled by natural gas, the trend has been less consistent and much slower due to the varying availability of natural gas and the presence of other generation options across regions. In most provinces where natural gas is available, gas-fired generation has had to compete with other traditional sources of generation such as coal, hydro

FIGURE 2.1

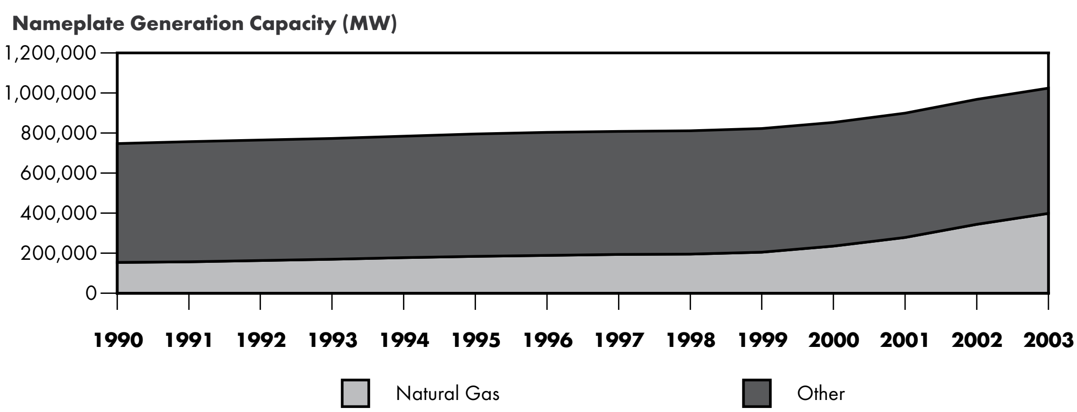
Generating Capacity Additions in the United States, 1990 – 2003



Source: EIA

FIGURE 2.2

Electricity Generation Capacity in the United States, 1990 – 2003



Source: EIA

and refurbished nuclear power, which have been relatively abundant in the past. Nonetheless, the portion of Canadian electricity generation that is gas-fired has increased from four percent in 1995 to nine percent in 2004.

Despite recent cost increases, gas-fired generation, particularly cogeneration facilities, continues to be an attractive option. These cogeneration plants operate at very high efficiency and provide a low cost source of process heat for end-use requirements. Hence, natural gas-fired cogeneration facilities are being developed in conjunction with the growing number of oil sands and in situ bitumen projects. As a result, Alberta has experienced the largest growth in gas-fired electricity generation capacity in Canada. In 2004, about 40 percent of installed electricity generation capacity in Alberta was natural gas-fired.

As would be expected, many regions across North America have witnessed the development of natural gas-fired generation. The significant growth in natural gas-fired generation capacity in North America has largely been attributed to low capital cost, a relatively short construction lead time for gas-fired plants, low natural gas prices (especially during the summer or cooling season) throughout the 1990s, and the preference for natural gas over other fossil fuels for its cleaner burning properties. Moreover, there has generally been less public opposition to building new natural gas-fired plants than to building coal-fired, hydroelectric or nuclear facilities.

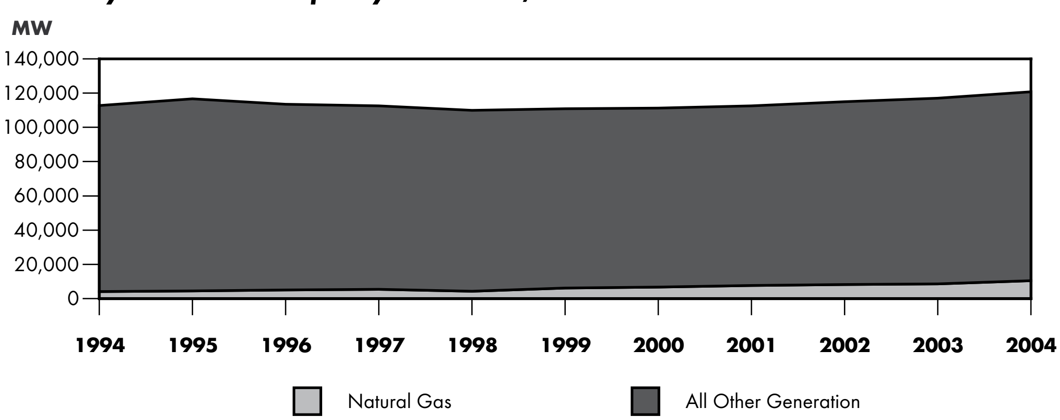
As a result, facilities capable of using natural gas now make up more than 45 percent of the approximately 1 000 000 MW of electricity generation capacity in the United States and about ten percent of the 118 000 MW electricity generation capacity in Canada (Figure 2.3).

This rapid build of North American gas-fired generation, often referred to as the “dash to gas”, exceeded the market need for these facilities in some regions. Consequently, many plants have been under-utilized or not utilized at all. The overall low utilization of gas-fired generation has been exacerbated recently by higher natural gas prices over the past few years. So, despite the relatively large natural gas component of total generation capacity, actual generation fuelled by natural gas is much less relative to the available capacity (Figure 2.4).

On the surface it would appear that the gas-fired generation fleet is too large and that it will take some time for the overall utilization of the fleet to expand to match its share of total generating capacity. While there has indeed been an overbuild of gas-fired generation, much of this occurred in

FIGURE 2.3

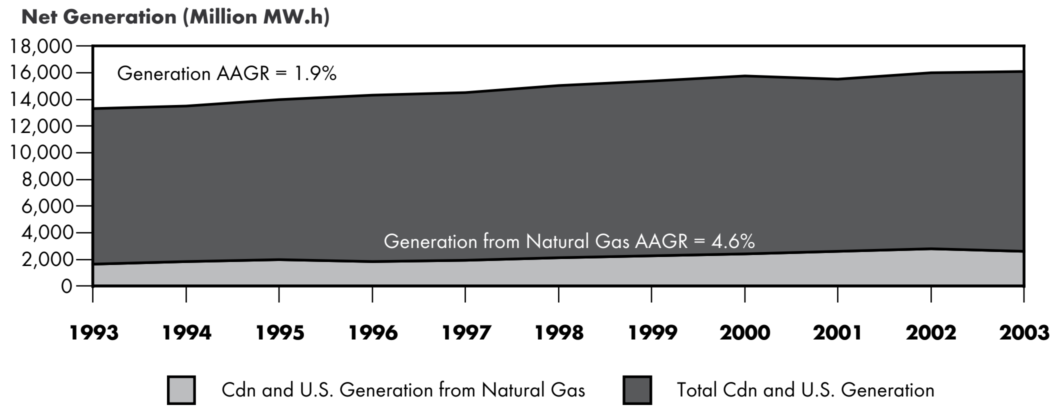
Electricity Generation Capacity in Canada, 1994 – 2004



Source: Statistics Canada

F I G U R E 2 . 4

Electricity Generation in Canada and the United States, 1993 – 2003



Sources: EIA, Statistics Canada

certain markets that either couldn't support the amount of incremental generation or where gas supply infrastructure limited the utilization of some plants.

Today, natural gas-fired generation continues to be developed across North America. In addition to the advantages of gas-fired generation noted earlier, new gas-fired generation facilities employ rapidly evolving technologies that provide significant cost advantages. For example, new cogeneration and combined-cycle gas plants are more efficient than older coal, natural gas or oil-fired generation. As well, smaller gas-fired facilities built closer to market loads may offer cost savings over construction of new power transmission lines from other generation sources.

As a direct result of the trend to gas-fired generation, projections for natural gas demand in North America indicate a significant and continuing increase. The Board estimates, partially based on the 2005 U.S. Energy Information Administration (EIA) outlook, that the combined Canadian and U.S. demand for gas will increase by almost 15 percent, or 283 million m^3/d (10 Bcf/d), by 2015, with gas-fired generation making up about one-half of that growth.

2.2 Convergence of Natural Gas and Electricity Markets

Although demand for electricity in both the United States and Canada has grown steadily and is expected to continue to grow at a relatively steady rate, changes in how the electricity is generated can be much more dramatic.

In the 1990s, natural gas was used to produce about 13 percent of the total electricity in the United States. This proportion has continued to increase with the addition of significant new capacity for gas-fired generation. In 2004, almost 18 percent of electricity generated in the United States was produced from natural gas.

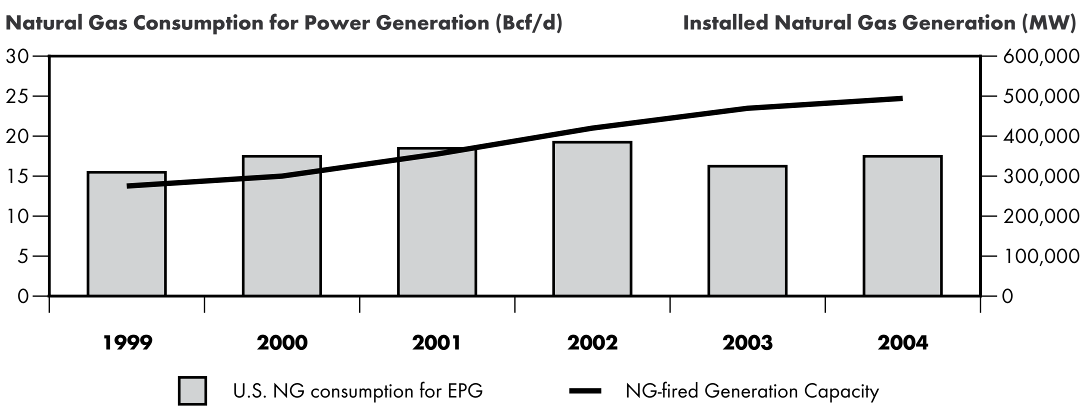
Even so, the generation of electricity from natural gas could have been even higher. High and volatile natural gas prices, less volatile power prices and regional gas supply constraints since 2001 slowed the utilization of gas for power generation (Figure 2.5). Despite this, new gas-fired generation continues to be installed in order to meet growing electrical demand, as new plants offer better technologies that are more efficient and economical. While natural gas consumption for electricity generation has been stable at around 510 million m^3/d (18 Bcf/d) since 2000, the amount of available gas-fired generation in Canada and the U.S. has increased by over 50 percent in this period with the construction of about 160 000 MW of gas-fired generators. This has resulted in a surplus of available gas-fired generation capacity in many regions that could be utilized to meet growing requirements for electricity, assuming availability and access to gas supply.

As the consumption of natural gas for power generation increases, this will lead to greater connection between gas and power markets within many regions. Not only will electricity prices be influenced by those of natural gas but, with power generation becoming the fastest growing sector of natural gas demand, natural gas prices will also be increasingly influenced by electricity markets. To illustrate, natural gas consumption for gas-fired generation has doubled over the past ten years and in 2005 it accounted for almost 27 percent of combined Canadian and U.S. gas consumption (Figure 2.6).

Moreover, as the electricity and natural gas industries become more integrated, reliability and operational issues in one can exacerbate the effects on supply and demand in the other; this may result in extreme and volatile energy prices at times. In regions where electricity and gas demand are particularly weather sensitive, peak demand in both markets may coincide, resulting in short-term escalation in electricity and natural gas prices. This is especially the case where available gas supply is limited, thereby resulting in competition between gas and electricity markets.

FIGURE 2.5

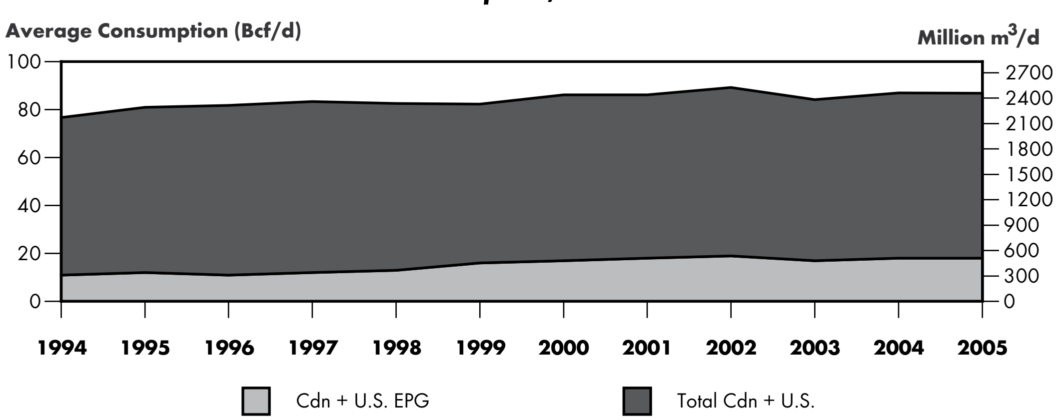
U.S. Natural Gas Consumption and Capacity for Power Generation, 1999 – 2004



Source: EIA

FIGURE 2.6

Canada and U.S. Natural Gas Consumption, 1994 – 2005



Sources: EIA and NEB estimates

The degree to which this can occur will vary greatly across regions depending on the availability and diversity of gas supply, reliance on gas-fired generation, operation and coordination between gas and electricity markets, availability of other coal-fired and nuclear generation, and the effect of other influences on gas supply and demand such as conditions for hydroelectric generation and demand sensitivity to weather. These factors and the implications of convergence in regional natural gas and electricity markets on Canadian gas flows and markets are examined further in Chapters 3, 4 and 5.

2.3 Environmental Considerations

Although high and volatile natural gas prices since 2001 may have slowed the utilization of gas for power generation and the pace of adding new gas-fired generation capacity, natural gas remains attractive with many potential advantages over other forms of generation (as outlined in Section 2.2). Natural gas is a cleaner burning fuel with lower emissions and impact on air quality compared with many other fossil fuels. This is likely to perpetuate the trend to more gas-fired generation, at least in the near future, until new technology and advances in alternative and renewable generation or clean coal combustion can provide appreciable contributions to North American electricity supply.

Current government initiatives in both Canada and the United States to control air pollution and greenhouse gas emissions have not only placed limitations on the use and development of oil and coal-fired generation, but have also added to the appeal of gas-fired generation. However, critics question the benefits and ability to sustain the continued growth in gas-fired generation.

While there are economic concerns with respect to over-reliance on natural gas and the implications this could have on prices, energy security and adequacy of natural gas infrastructure, generation from natural gas also has its environmental challenges. These include the impact of activity to find and develop new gas supplies in sensitive areas, incremental air emissions and pollutants from added fossil fuel generation, and impacts from new infrastructure that may be required to produce or deliver new energy supplies. The response to these challenges has varied across regions, often reflecting the different interests and priorities of jurisdictions.

Depending on how the various government initiatives and policies play out across jurisdictions, there could also be significant implications for gas and electricity markets in each region.

2.4 Future Natural Gas Supply

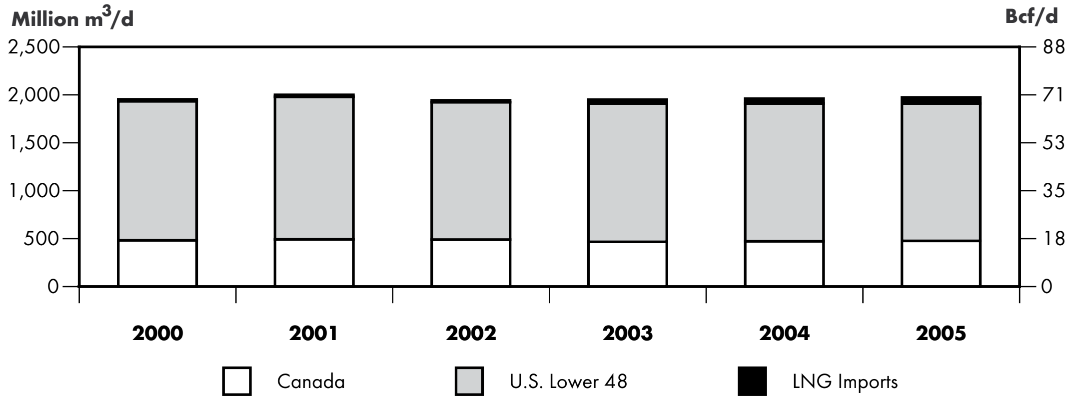
The increased use of natural gas for electric power generation has raised concerns over the adequacy of additional natural gas supply and infrastructure at a time when gas supply and demand has been in relatively tight balance.

High natural gas prices resulting from the tight balance between North American gas supply and demand has been a key factor in encouraging more gas drilling. However, increases in gas production that have resulted from the high levels of drilling have not kept pace with growth in demand. Rather, high levels of drilling activity have managed mostly to offset the higher decline rates and lower productivity of new wells. In other words, the producing sector needs to drill more wells each year just to keep production flat.

Overall, the outlook for natural gas supply in Canada and the U.S. is that production will grow marginally by 2006 to approximately 1 936.5 million m^3/d (68.4 Bcf/d). This level of production has been relatively flat over the past six years (Figure 2.7). The Board expects that average annual U.S. gas production will rise slightly over the projection period to approximately 1 458.9 million m^3/d (51.5 Bcf/d), with growth coming mainly from the U.S. Rockies.

FIGURE 2.7

Annual Average Natural Gas Supply for Canada and the U.S., 2000 – 2005



Source: NEB

The Board also expects a slight increase in Canadian gas deliverability to about 477 million m³/d (16.9 Bcf/d) by 2006. For further details on Canadian production and projections, refer to the NEB's report on *Short-term Canadian Natural Gas Deliverability, 2005 – 2007*.

These production increases alone are not sufficient to meet the projected future requirements for natural gas demand, including power generation. Consequently, any increases in demand for gas-fired generation would necessitate a reduction in gas consumption by other consumers and the development of further sources of gas supply.

A key supply source for North America is expected to be the rapidly developing global liquefied natural gas (LNG) market[1]. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, enabling the use of LNG as a cost competitive source of gas supply in North America.

In the past few years, existing North American LNG receiving terminals have undergone expansions and by early 2006 these terminals had the capacity to import about 147 million m³/d (5.2 Bcf/d). Further, in anticipation of growing natural gas requirements, numerous new receiving facilities and expansions of some existing terminals have been proposed, including sites in Canada.

2.5 Natural Gas Infrastructure Requirements

Given the potential changes to gas supply and demand in North America, significant investments will be required to enable the continuing development of gas from existing supply areas to develop and provide access to gas from new regions and LNG. A key determinant in the growth of gas-fired generation is the availability of adequate gas supply and infrastructure at competitive prices. Furthermore, the development of market area gas storage, distribution, fuel diversification, and other services may also be required to effectively manage dynamic electricity and natural gas markets and to provide natural gas supply in the reliable and timely manner needed to serve fluctuating and weather sensitive electricity and natural gas markets.

1 Natural gas becomes LNG when it is condensed into a liquid and stored at temperatures below -160°C (-256°F). This liquid state occupies only 1/600th of the volume of natural gas in its gaseous state, which facilitates and reduces the cost of transportation to the market.

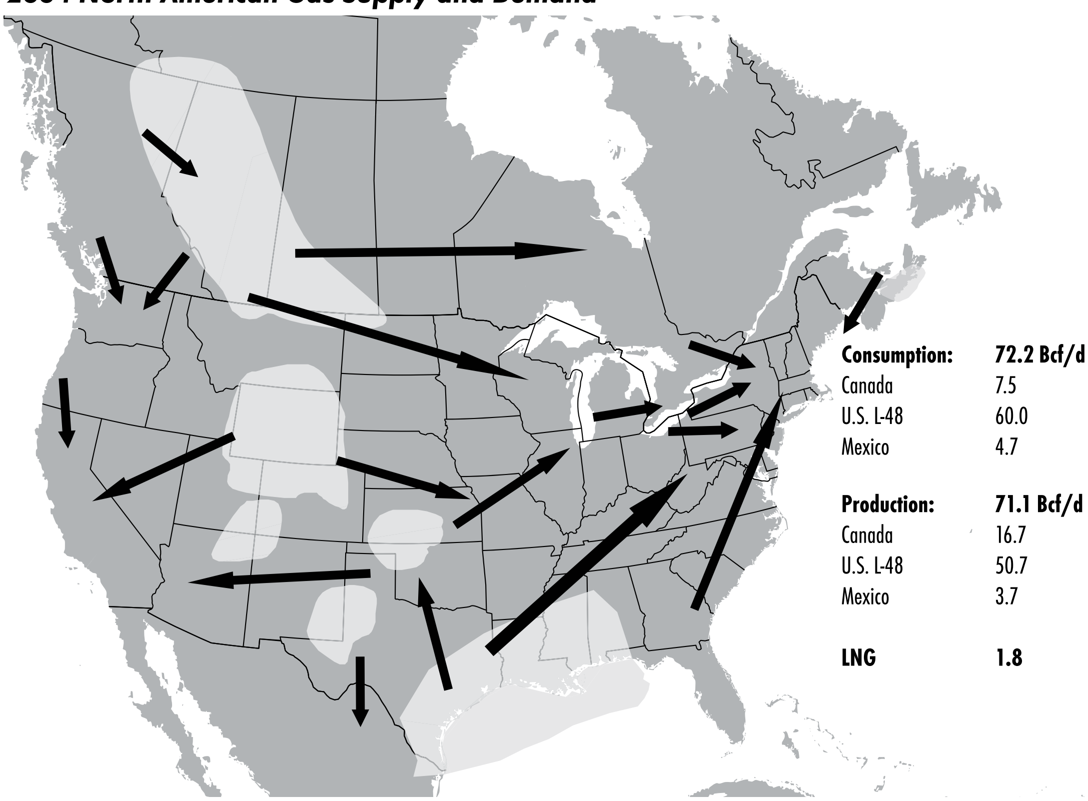
Much of the current North American gas production is situated along a corridor extending from northeast British Columbia to the Gulf of Mexico, while gas demand is more evenly distributed with areas of concentration in eastern Canada/U.S. Northeast, the U.S. Gulf Coast and California (Figure 2.8). Traditional major routes for transportation of gas from supply to consuming areas are illustrated. Taking into account expected growth in gas-fired power generation and the nature and location of future gas supply, there will likely be changes to the traditional flows of natural gas, and the need, usage, and costs associated with specific natural gas infrastructure in Canada.

The need for pipelines and infrastructure is also influenced by changes in gas demand. While growing demand for gas in distant markets may increase flows on pipelines, greater consumption of natural gas in supply regions, such as associated cogeneration requirements by oil sands operations in western Canada, may reduce the amount of gas available for other markets and the flow on transmission pipelines. The growing use of natural gas for electricity generation and heating may also mean greater swings in pipeline flows and greater reliance on the use of natural gas storage, LNG or other market area services to meet peak demands.

The amount and location of potential LNG imports will be a key factor in how gas flows and infrastructure requirements may change in North America. While under-utilized, existing LNG facilities and capacity on existing transportation routes would be the quickest means of providing increased imports of LNG, the potential for importing LNG closer to growing market regions (such as eastern Canada, the northeast United States and southern California) could reduce the future requirement for additional infrastructure along traditional routes.

FIGURE 2.8

2004 North American Gas Supply and Demand



Sources: NEB, EIA, Statistics Canada

The impact on gas infrastructure will be very dependent upon where LNG is landed in North America. Lateral pipelines may be required to connect LNG receiving terminals to the main transmission pipelines, and backhaul arrangements or reversal of existing pipelines may also be necessary to deliver the new gas supply to its market.

Some of the key regional changes occurring today include declining gas production and growing gas demand for oil sands development in Alberta; increasing gas supply from the U.S. Rockies region and LNG imports (particularly in the U.S. Gulf Coast); increasing demand for gas in eastern Canada and the U.S. associated with growing gas-fired power generation and replacement of coal-fired generation, and growing gas demand during summer and winter peak periods impacting gas storage and seasonal pipeline flows (Figure 2.9).

2.6 Implications of Gas for Power on Future Pricing

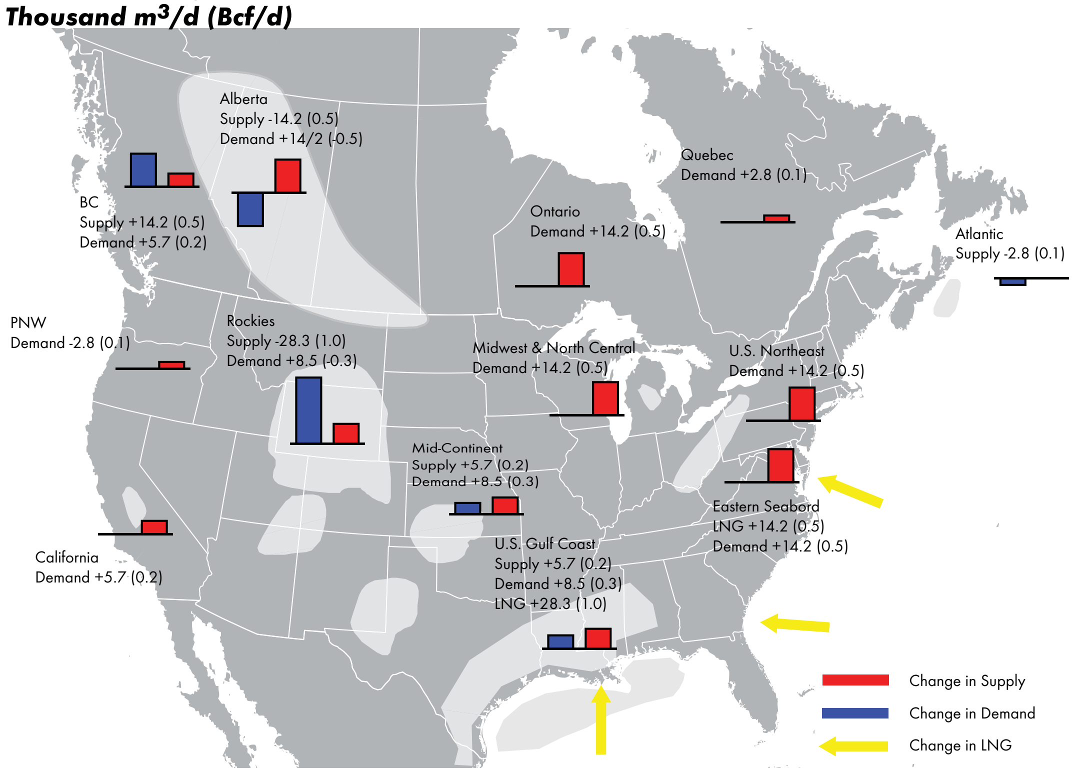
Continued growth in demand for natural gas-fired generation when gas supply and demand are in a relatively tight balance is expected to place additional upward pressure on gas prices. In some regions such as the U.S. Northeast, constraints on natural gas infrastructure and gas supply have also limited generation from natural gas despite the availability and addition of substantial gas-fired generation capacity in recent years. Specifically, high gas prices have rendered some gas-fired generators uneconomic.

Spark Spreads

Convergence in the natural gas and electricity markets over the past few years has led to new measures in gauging profitability for gas-fired power plants. One such measure is the spark spread. For example,

FIGURE 2.9

Potential Changes in Gas Supply and Demand: 2006 versus 2004
Thousand m^3/d (Bcf/d)



Sources: NEB, EIA, Statistics Canada

if a spark spread is a positive number, the price of the power is higher than that of the fuel and the generation is profitable. If the spark spread is a negative number, the power is priced at less than the cost of fuel and generation is not profitable. Figure 2.10 provides an illustrative example. The spark spreads shown for the western region compare the cost of generating power using a natural gas-fired unit at an efficient 7 000 GJ/GW.h heat rate with the cost of buying on-peak power from the market. The graph shows that the Mid-Columbia region (Mid-C) has experienced occasions when a negative spark spread made it more economic for generators to meet obligations by buying power at market prices and selling their natural gas rather than generating power.

Heat Rates

Heat rates are a measure of comparing the efficiencies of gas-fired power plants. The heat rate equals the Btu content of the fuel input divided by the kilowatt-hours of power output. As new technologies have emerged, heat rates have decreased leading to more efficient power plants being built. The increases in efficiency of newly built gas-fired power plants make them more economical than older natural gas-fired plants; consequently, the older plants are now primarily used to meet peak demands when power prices are higher.

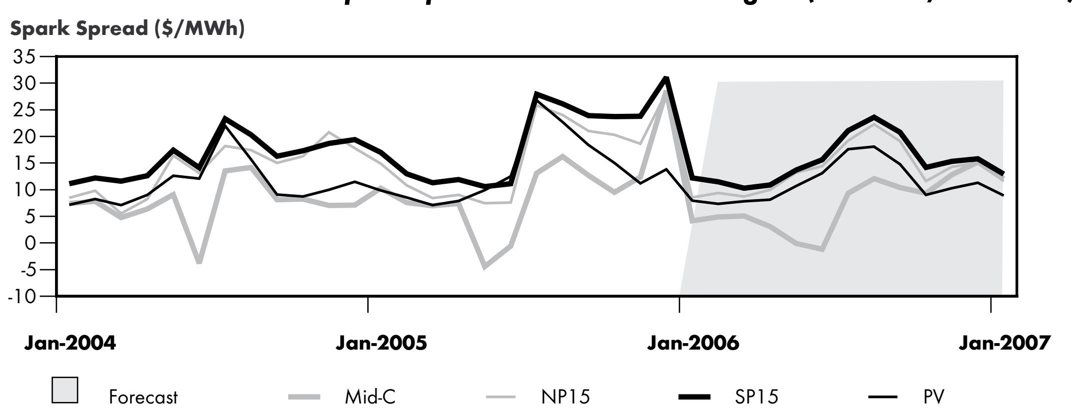
Some new plants are still being built with relatively high heat rates because construction costs are lower, construction is quicker and these plants can be dispatched to full-load almost instantaneously. These plants are often used as peakers, as they are being used during times of high power prices when demand is very strong. Other new gas-fired facilities are being built with very low heat rates; consequently, capital costs are secondary as these plants will be used for baseload and hence, will need to be reliable.

Higher gas prices have created a need for increased electricity prices in order for it to be economical for new power plants to operate. Heat rates for natural gas-fired plants typically range between 7 000 GJ/GW.h for efficient combined-cycle plants to 10 800 GJ/GW.h for less efficient simple-cycle facilities. In the illustrative example below, an efficient natural gas generator with an average operating heat rate between 7 000 and 10 800 GJ/GW.h would not have been able to meet its variable costs since October 2005, because the market heat rate (the ratio of electricity price to gas price) was too low (Figure 2.11).

The electricity and natural gas markets today are somewhat linked but, with the increase in demand for gas-fired generation there will be more connectivity between the two markets. The supply,

FIGURE 2.10

Historical and Forecasted Spark Spread for the Western Region (7 000 GJ/GW.h unit)



Source: PIRA

demand and price of natural gas are also influenced by key factors such as weather, competing fuel prices, storage levels, pipeline transportation and market psychology. While competition with fuel oil in multi-fuel capable facilities, particularly in the U.S. Northeast, has helped to connect continental natural gas prices to that of fuel oil products, competition with electricity generation has also connected short-term electricity and natural gas prices during periods of peak demand.

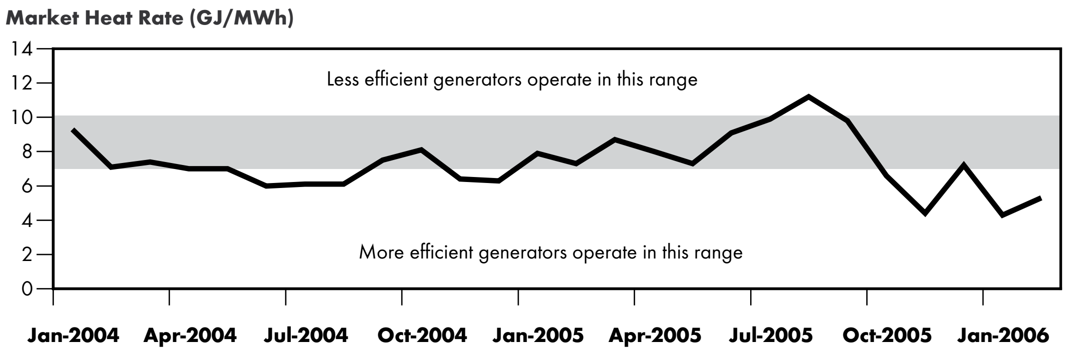
Historically in the New York region, for example, No. 2 heating oil generally provided an upper bound for natural gas prices, while the one percent sulphur residual fuel oil (RFO) generally provided the lower bound (Figure 2.12). From this, the connection between electricity and natural gas markets can be seen, as electricity prices can pull gas prices past these bounds, especially during periods of cold weather (i.e. peak demand).

2.7 Reliability of Natural Gas and Electricity

Much of the attention of long-term electricity market resource planners is being focused on the role that transmission additions and upgrades could play in electricity market reliability. There is an acknowledgment that transmission development is required in concert with new generation supply in order to overcome the three major challenges planners face: a growing economy, the possibility of a major disturbance and extreme weather. The strategic location of generation supply within

FIGURE 2.11

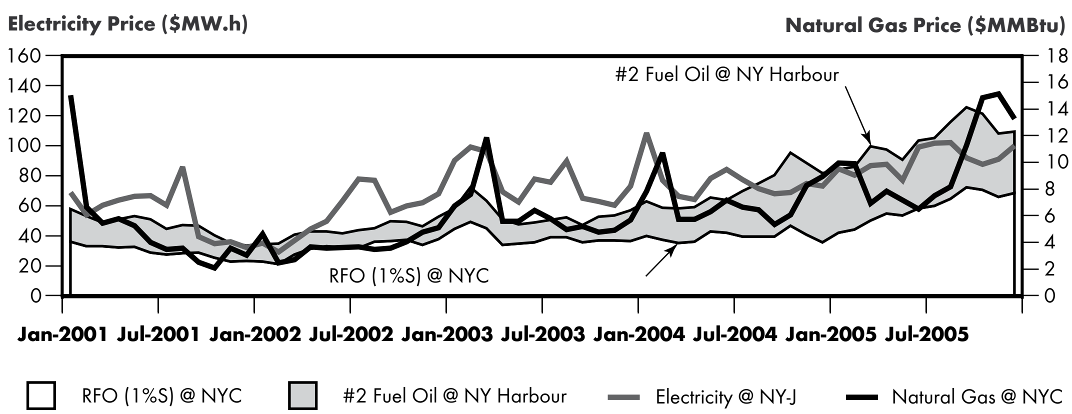
Market Heat Rates Required for Natural Gas Units



Sources: NEB, PIRA

FIGURE 2.12

Energy prices in the New York City Region, 2000 – 2005



Sources: PIRA, GLJ Energy Publications

the electrical grid and consideration of the trade-off between new generation developments and transmission upgrades is foremost on the mind of planners.

Policy makers are also focused on the role transmission plays in resource planning for reliability and acknowledge that government needs to assist industry with regard to transmission policy. In many regions the time required to approve transmission projects is a barrier to new construction. Measures are being taken to simplify the process and to ensure that the political will is there to get transmission constructed in a timely manner.

2.7.1 Coordination of Natural Gas and Electricity Operation

Supporting natural gas services from storage, distributors, suppliers and pipelines are necessary for gas-fired generation to provide electricity to match the highly variable requirements in the electricity market. As illustrated in the Figure 2.13, power market requirements, shown on the right side of the chart, can be extremely variable and require adjustments to electricity output by the electricity system operator on a near real-time basis, as frequent as five-minute intervals. Gas flows on the other hand (as illustrated on the left side of the chart), have less frequent variation, reflecting daily average and uniform flows with few intra-day variations necessary to enable scheduling flows across potentially multiple gas facilities.

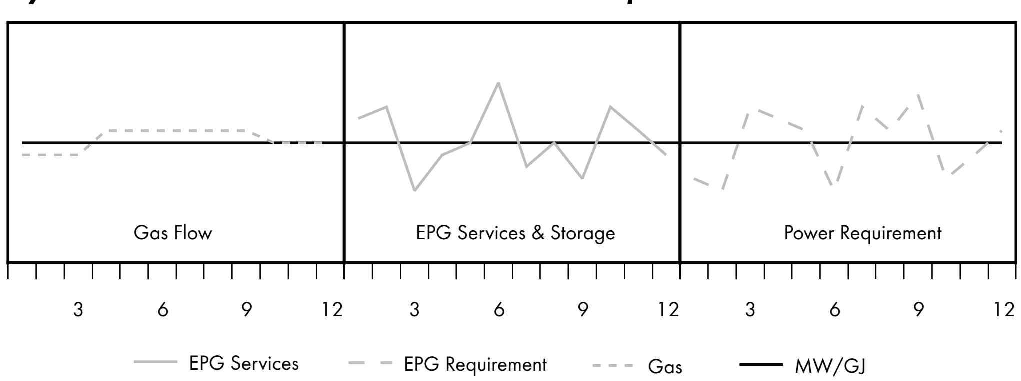
Flexible services through the use of gas storage, flow diversion or balancing on pipelines are needed to bridge the natural gas and electricity operation, as illustrated by the central portion of the chart, by enabling service providers to offer frequent flow changes in gas flow rates, and enable reliable gas supply on little notice to meet variable power requirements. However, provision of these services will require dedicated infrastructure, which entails costs for construction or taking away from capacity currently used for other natural gas services.

2.8 Rationale for Regional Analysis and Approach

The implications of increased gas-fired generation and the resulting changes to gas supply, transportation and delivery services and infrastructure requirements and the effects on other gas consumers will vary across regions. While generally there will be increased use of natural gas for power generation in all regions, the diversity (age, fuel diversity, type, efficiency, etc.) of electricity generation assets, the amount of new gas-fired generation capacity relative to future demand and the

FIGURE 2.13

Stylized Illustration of Gas Flow versus Power Requirement



Source: NEB

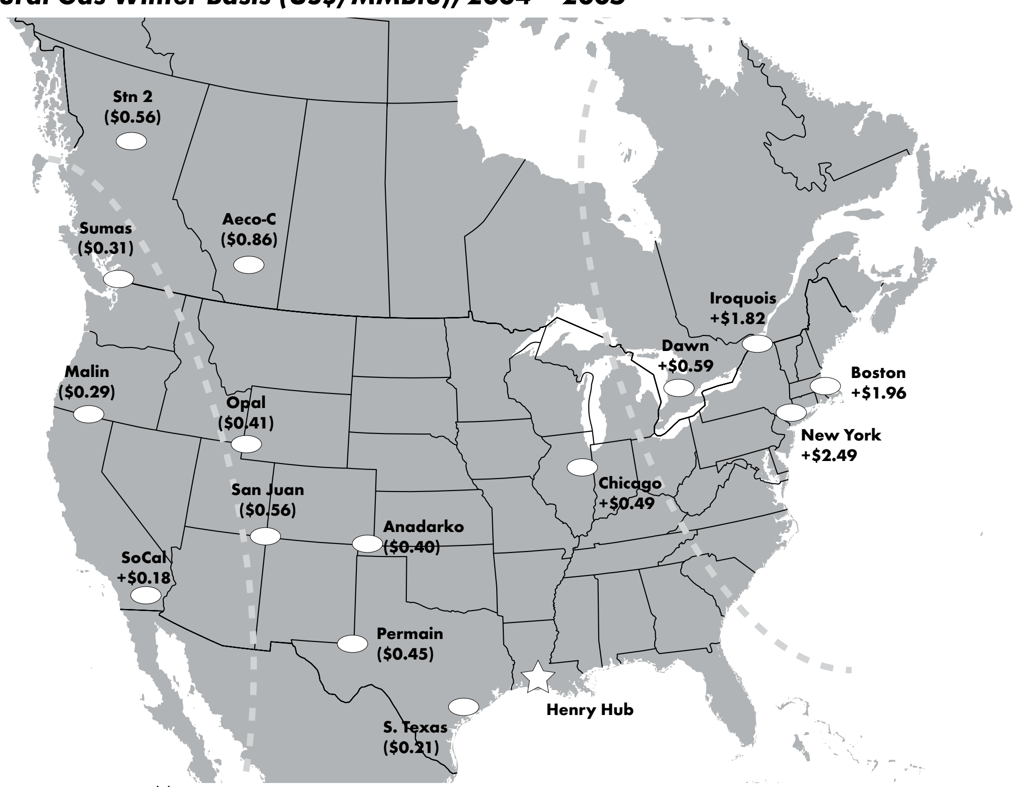
services available in a region will determine the influence of natural gas on regional electricity markets and prices. In addition, the amount and diversity of gas supply and infrastructure will influence the reliance and sensitivity of the regional electricity market on natural gas.

Government policy and initiatives may also vary significantly across regions and influence the extent and impact of natural gas-fired generation in a region. For example, changes are expected as a result of Ontario's policy to remove 7 500 MW of coal-fired capacity. Although refurbishment of existing nuclear generation and the construction of new wind energy may replace some of the displaced coal, it is also likely that some incremental natural gas-fired generation is required, along with associated changes to ensure adequate gas supply and infrastructure to serve the new requirements.

In the following chapters of this report, a closer analysis of the different characteristics and make-up of gas supply, demand and infrastructure and the trends and issues with respect to natural gas-fired generation are examined. As illustrated through regional pricing, the characteristics and implications could vary greatly between eastern, central and western regions (Figure 2.14). This EMA will examine the characteristics and situations in three regions (western, eastern and central North America) and apply the results toward stimulating the debate on the issues surrounding Canada's ability to adjust to a changing energy landscape.

FIGURE 2.14

Natural Gas Winter Basis (US$/MMBtu), 2004 – 2005



Source: GLJ Energy Publications

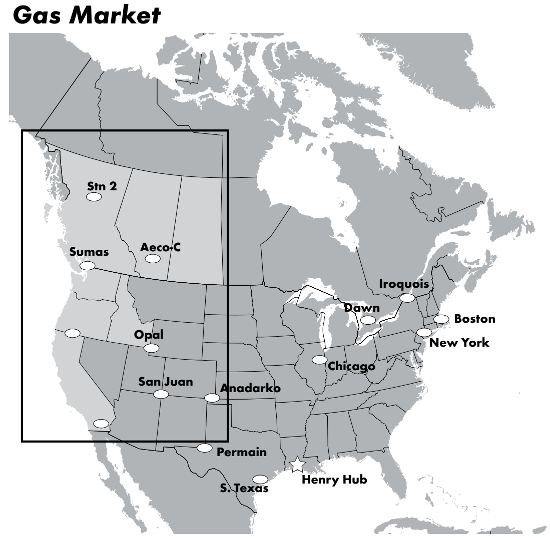
WESTERN MARKET – REGIONAL ANALYSIS

For the purpose of this report, the western region includes British Columbia (B.C.), Alberta, Saskatchewan, Washington, Idaho, Oregon and California (Figure 3.1). The geographic size of the western region allows for great diversity and contrast in weather patterns, population growth and density, economies and resource accessibility. These factors create variability in the western energy market in terms of demand, supply options and prices. Notwithstanding these differences, all areas within the region are interconnected through various electricity and gas infrastructure and markets.

The interconnected electricity market that the western region falls within is defined as the Western Electricity Coordinating Council (WECC). WECC encompasses a vast area of nearly 1.8 million square miles and is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council. WECC's service territory extends from Canada to Mexico. In addition to the western region defined for this report, WECC includes the northern portion of Baja California, Mexico and all or portions of the 14 western states in between.

FIGURE 3.1

Western Region in the North American Gas Market



Source: NEB

The abundance of hydroelectric resources in the region creates a symbiotic relationship between each state and province. This relationship can be seen in both the electricity and gas capacity. Historically, as hydro levels change, states and provinces within the western region depend on each other for electricity trade. For example, when hydro levels are below normal in B.C., power can be imported from Alberta, where power generation is primarily coal-based. Similarly, power from B.C. can be exported south along the coast into the U.S. Pacific Northwest (PNW) where it is either used, depending on local hydro levels, or moved farther south into California to meet high demand. Southern California is dependent on electricity exports from Canada, the PNW and other states to satisfy its demand during peak times.

3.1 Natural Gas Demand

Natural gas use in the western region varies considerably from Canada to California due to major differences in climate and population. Average natural gas demand for the western region is almost equally split between sectors (Figure 3.2).

In western Canada, gas demand is much lower than in the neighbouring western U.S. primarily due to the smaller population in Canada. A significant portion of the natural gas demand in western Canada is for residential and commercial space heating. On average, about 28 million m^3/d (1 Bcf/d) is consumed in western Canada to meet residential and commercial demand. Industrial demand is relatively small in B.C. and Saskatchewan; however, industrial demand in Alberta averages 42 million m^3/d (1.5 Bcf/d). This volume is primarily accounted for by the high demand for natural gas at the oil sands projects, which are expected to continue to grow further.

In contrast to the relatively small western Canadian gas market, the western U.S. region makes up just over nine percent of total North American gas demand. California has the highest population density in the western region and gas demand in California dominates the region. On average, California consumes 173 million m^3/d (6.1 Bcf/d), which is about 81 percent of gas demand in the western U.S. region. A large portion of gas demand in California is for electric power generation during the summer to meet cooling demand. The PNW consumes about 42 million m^3/d (1.5 Bcf/d) on average.

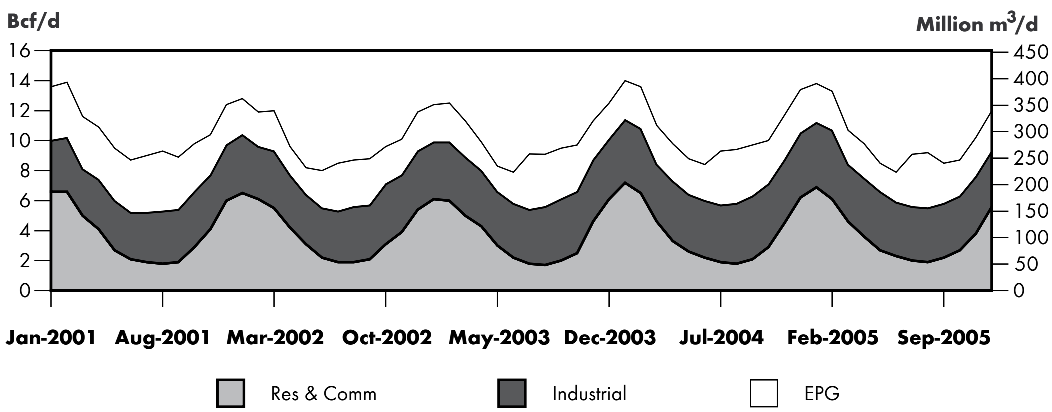
3.2 Outlook for Natural Gas Consumption

Throughout most of the western region, natural gas demand has been relatively stable over the past five years. An exception would be the development of oil sands projects in Alberta, which have witnessed rapid growth in natural gas consumption. Since 2001, natural gas demand for oil sands development has increased by 50 percent to 23 million m^3/d (0.8 Bcf/d). This rate of growth is expected to continue with natural gas demand reaching 42 million m^3/d (1.5 Bcf/d) by 2010.

Over the next decade, the EIA projects that the requirements for natural gas in the western U.S. will increase by about 28 million m^3/d (1.0 Bcf/d) from natural gas requirements in 2005 (Figure 3.3). Of this, 9 million m^3/d (312 MMcf/d), or 30 percent, is expected to be used for the generation of

FIGURE 3.2

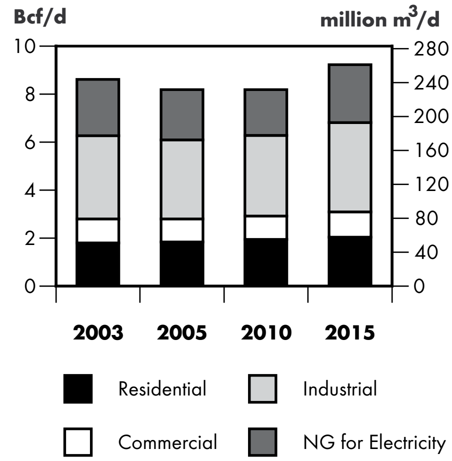
Western Region Natural Gas Consumption by Sector, 2001 – 2005



Sources: EIA, Statistics Canada, NEB estimates electricity. Most of the remaining increase in gas demand is expected to be in the industrial sector, primarily in California.

FIGURE 3.3

U.S. Western Region Projected Natural Gas Consumption



Source: EIA Outlook

3.3 Natural Gas Supply and Infrastructure

Both western Canada and the western U.S. are surrounded by major sources of gas supply. The western U.S. has more diversity in natural gas supply options than other regions in North America, as it has access to the Western Canada Sedimentary Basin (WCSB), Rockies, and the San Juan Basin and some indigenous supply (Figure 3.4). In addition, it is expected that there will be some LNG supply from Baja California available to the region in 2008.

Western gas markets are served by a few main pipelines from three sources of supply. The western region has several major pipelines connecting multiple supply basins to market (Figure 3.5).

Gas demand in B.C. and a large portion of the demand in the PNW is met from the WCSB. The Duke Energy pipeline connects gas supplies in northeastern B.C. to the northwest pipeline system, which serves the PNW. Currently, 79 million m³/d (2.8 Bcf/d) is exported from Canada to the western U.S. Close to 34 million m³/d (1.2 Bcf/d) of this gas is consumed in the PNW and the remainder is exported to California (Figure 3.6).

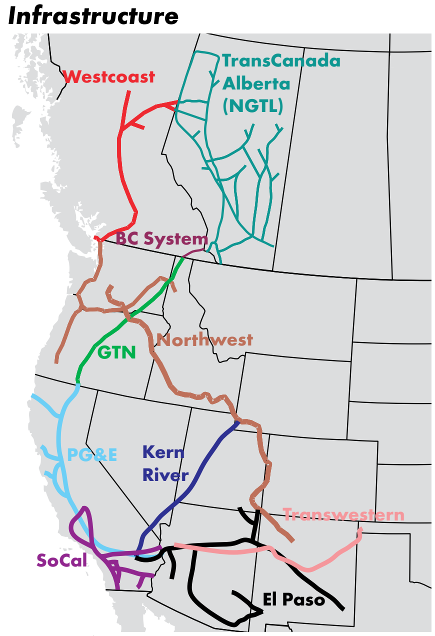
FIGURE 3.4

North American Natural Gas Supply Basins

Source: NEB

FIGURE 3.5

Western Natural Gas Pipeline Infrastructure



Source: NEB

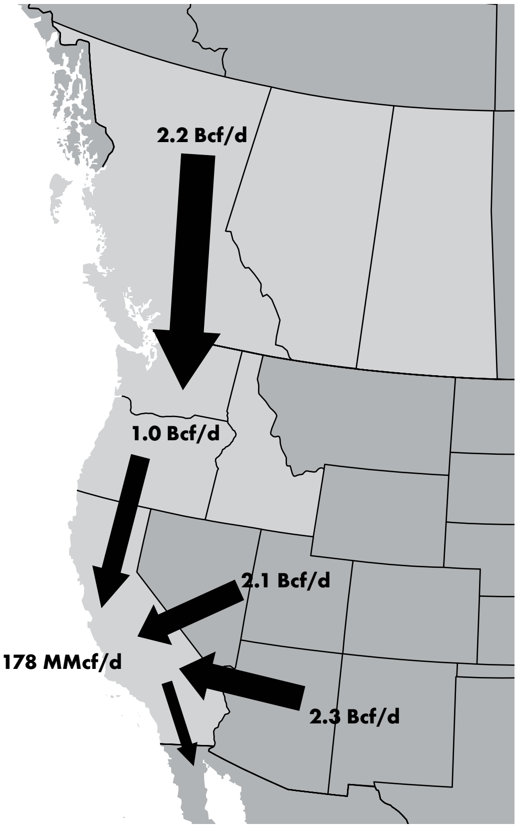
New expansions to infrastructure will eventually need to be made throughout most of the western region in order to meet growing demand for natural gas. Without additions to infrastructure, such as storage capacity, the ability to serve demand will diminish. However, since the PNW is so reliant on hydroelectric generation, gas-fired power generators often do not hold firm transportation services.

The California gas market is served by multiple supply sources (Figure 3.7). Approximately 25 percent of California's gas supply originates from the WCSB and is delivered through the TransCanada Corporation (TransCanada) Gas Transmission Northwest system (GTN). Another main source of supply for California is the U.S. Rockies Basin. The Kern River pipeline delivers Rockies gas to California. There is some extra capacity on the Kern River pipeline on an average day; however, the expansion to southern California is full. Currently, 45 million m^3/d (1.6 Bcf/d) is supplied from the Rockies and is destined solely for the California market. With Canada and the Rockies as the traditional suppliers, the California market will be adequately supplied and have potential for further growth. The western market is also supplied from both the San Juan Basin and the Gulf of Mexico. From these sources, the El Paso and Transwestern systems deliver about 45 million m^3/d (1.6 Bcf/d). The natural gas delivered via these systems is primarily consumed in southern California, with only 5 million m^3/d (178 MMcf/d) exported to Mexico.

Growing economies, increased population, reliability issues, such as hydro levels, and the need to compete for gas has led the west to look for ways to diversify its gas supply. Around 2008, California is expected to be able to further diversify its supply by importing up to 14 million m^3/d (500 MMcf/d) of regasified LNG from the Costa Azul facility in Baja California. This is a key development as LNG provides market areas with gas supply and storage.

FIGURE 3.6

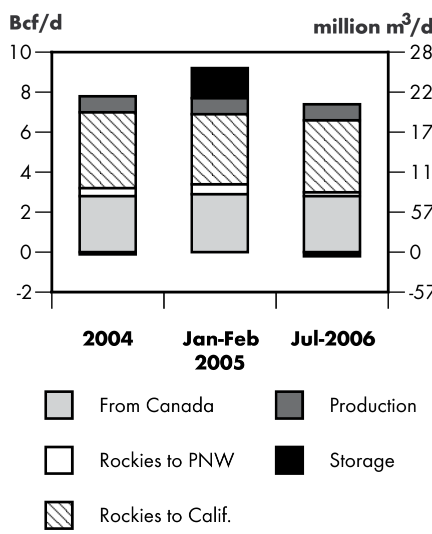
2005 Western Region Gas Flows



Sources: Lippman Consulting, NEB

FIGURE 3.7

PNW/California Natural Gas Supply



Source: Lippman Consulting

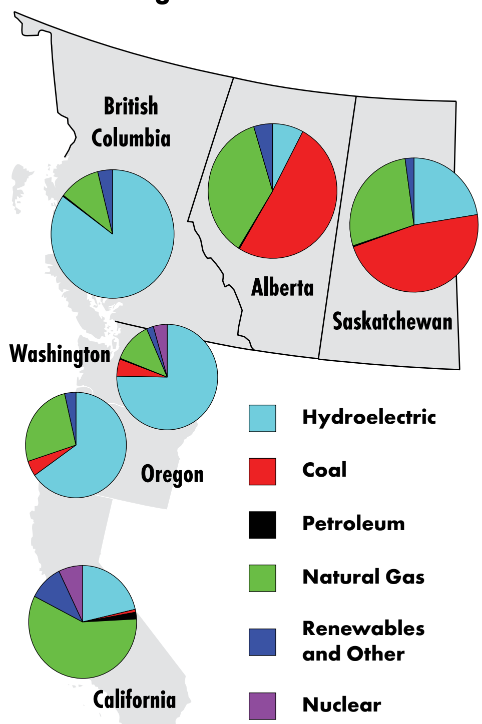
3.4 Electricity Generation Fuel Mix

Access to ample natural gas supply combined with historically low gas prices, concerns of prolonged periods of drought, expectations of growing power demand and high wholesale electricity prices have contributed to the significant build in gas-fired generation. In fact, an “overbuild” of natural gas-fired generation occurred throughout the western U.S. This overbuild pattern has been seen in other parts of North America but it is mainly a regional consequence of the deregulation of the California energy market. After the California energy crisis of 2000–2001, many gas-fired power plants were built in order to alleviate uncertainties over reliable electrical supply. Between 1998 and 2003, natural gas-fired capacity increased 86 percent in Washington state, 44 percent in California and 132 percent in Oregon. The subsequent lack of demand after the California energy crisis coupled with higher gas prices caused many of these plants to become uneconomical and remain unused or partially constructed. This is unlikely to change because new plant technologies and efficiencies have improved so that the economics of constructing and operating a new plant are better than the cost of purchasing and operating an existing plant.

The use of natural gas for electricity generation, however, varies considerably across the western region (Figure 3.8). In B.C. and the northwestern coastal states, hydroelectric generation is predominant and there is little gas-fired capacity. The generation mix in Alberta and Saskatchewan is composed mainly of coal, although there is some reliance on natural gas-fired generation to meet system peak demand requirements. In California, installed generation capacity is primarily natural gas-fired at about 60 percent with 20 percent hydroelectric, ten percent renewable and seven percent nuclear. In 2004, more than 97 percent of new generation was fueled by natural gas.

FIGURE 3.8

Western Region Generation Fuel Mix



Sources: EIA, Statistics Canada

Each of the provinces and states in the western region take advantage of trade opportunities with connected regions to optimize the economic benefits of their electricity resources. From the standpoint of inter-provincial transfers, electricity normally flows from B.C. to Alberta during the peak hours and from Alberta to B.C. during the off-peak hours. This is a result of synergies that exist between the resource mix of the two provinces and because hydro storage allows energy banking. Likewise, with respect to Canada–U.S. inter-regional transfers, weather patterns between the winter peaking PNW and the summer peaking California support economic power flows in both directions (Figure 3.9).

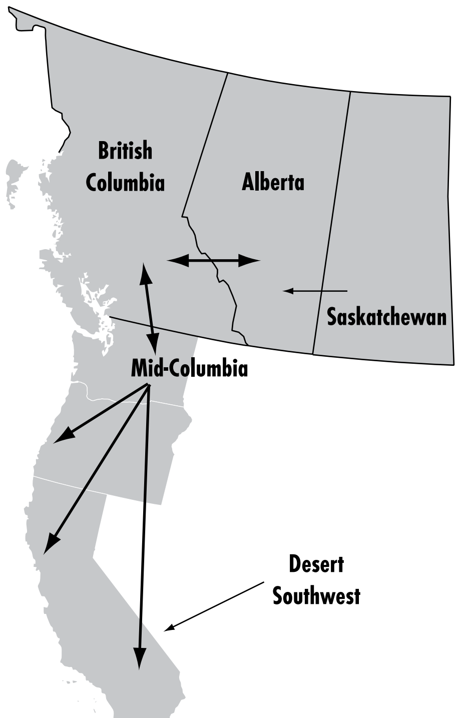
3.5 Electricity Generation Markets and Gas-Fired Generation

Canadian Markets

Through market restructuring, Alberta has developed a healthy reserve margin with over 3 000 MW of new generation brought onto the system between 1998 and 2004. Over half of Alberta’s generation capacity is made up of coal-fired generation. However, the largest increase in Alberta’s generation

FIGURE 3.9

Inter-regional Electricity Flows



Source: NEB

capacity in recent years has been natural gas-fired primarily due to the increased use of cogeneration technology at oil sands projects. Currently, there are 1 042 MW of installed cogeneration capacity at existing oil sands projects, with five units under construction. Alberta now generates about one-third of its electricity (4 158 MW) with natural gas, so the price of natural gas has a substantial effect on electricity prices.

About 4 874 MW of new generation has been announced for future development. Natural gas will continue to be an important fuel source for electricity generation. Of the proposed generation, 39 percent (1 913 MW) would be gas-fired, with about 1 568 MW of cogeneration being constructed at oil sands operations. Only one natural gas-fired generation plant, located north of Calgary, is proposed to meet growing domestic load requirements. Other future generation sources include coal (34 percent) and wind (21 percent).

With the rapid development of cogeneration facilities at oil sands projects, the insufficiency of transmission lines has been cited as an issue. Recently, there has been a shift in strategy by oil sands developers toward locating cogeneration facilities closer to their oil sites, leaving lower export capacity for electricity. This change was motivated by high natural gas prices, low electricity prices, a lack of certainty that transmission constraints would be addressed and a lack of transmission access to markets outside of Alberta.

Like Alberta, the abundance of coal in Saskatchewan has led to the development of significant coal-fired generation. Just under one-half of the total generation capacity in the province is coal-fired. Natural gas and hydroelectric generation compose most of the remaining installed capacity.

In contrast to Alberta and Saskatchewan, B.C. is a hydro-dominated region with only 11 percent gas-fired generation capacity. The province has three major gas plants with installed capacity of 1 043 MW, as well as roughly 550 MW of cogeneration facilities at pulp and paper and newsprint facilities. The 950 MW Burrard generating facility located on the Lower Mainland is primarily used to supplement the hydroelectric system in years when water inflow is low. The Burrard plant is scheduled to be decommissioned in 2014, but there is some opposition to its closure from parties arguing that refurbishment of the plant is a better approach because it would keep the backstop resource available. Without the unit, the province would rely more on imports from Alberta to lessen the short-term impact of low water levels.

Since the mid-1980s, B.C.'s abundant domestic electricity surplus steadily declined to the point where the province became a net importer in 2000, purchasing about 12 percent of its electricity, primarily from Alberta, to meet domestic demand. Assuming the continued availability of imports, B.C. Hydro forecasts an adequate supply base to meet domestic energy and capacity requirements through 2010.

Cogeneration projects that produce electricity and process heat simultaneously are included in the province's long-term energy strategy titled, *Energy for Our Future: A Plan for BC*. These plants have been included because they are more fuel-efficient compared with other plants and thus, provide a net environmental benefit. Other environmentally responsible energy alternatives include wind, solar, tidal, wave, fuel cells and geothermal energy. Nuclear power is not included as a potential energy source.

American Markets

Like B.C., the generation mix of the PNW region is composed primarily of hydroelectric resources. Hydroelectricity makes up 71 percent of regional generating capacity. Natural gas, the fuel of choice for most new power plant projects in the PNW, makes up 13 percent of generation capacity in Washington and 26 percent in Oregon.

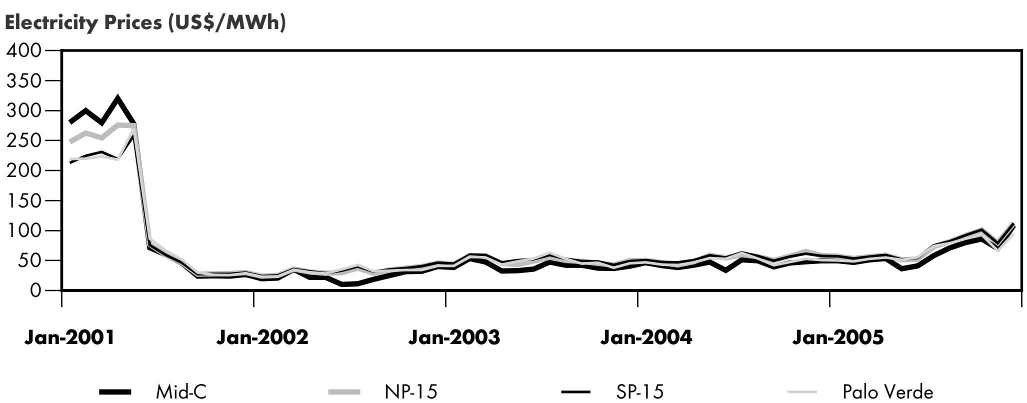
During and after the California electricity crisis of 2000–2001, there was a rush to permit and construct new gas-fired combined-cycle power plants. More than 4 000 MW of new generation was constructed by independent power producers (IPPs). Following the California electricity crisis, the western region electricity prices decreased sharply and later stabilized at moderately high levels (Figure 3.10).

During 2000/2001, merchant generators and utilities made decisions to invest in gas-fired generation on the basis that there would be enough days where electricity traded at several hundred dollars per MW.h to allow investors to recover and earn a return on their investment. At the time, a gas price of $2.50/MMBtu was also assumed. Gas prices subsequently rose much higher than expected and many utilities made the choice to refurbish older coal units rather than continue their investment in natural gas-fired plants. Many of the gas plants under construction continue to sit idle. The main reason that construction of these stalled plants is not being re-started is that independently owned utilities and generation companies are looking to develop new, more efficient gas-fired generation facilities. As well, some developers have exited the electricity marketing business or have gone bankrupt. The remaining existing natural gas-fired units with higher heat rates are being used as peakers to meet high load demands. They are run relatively infrequently because of low electricity market prices and high gas prices. Since June 2001, notwithstanding some daily price spikes, market heat rates have generally been too low for natural gas-fired generators to operate (Figure 3.11 - a grey band shows where generator heat rate efficiencies range between 7 000 GJ/GW.h to 10 800 GJ/GW.h).

California did not construct new generating capacity to support electricity demand growth through the 1990s. Instead, California became increasingly dependent on power imports from the PNW and

FIGURE 3.10

Western Region Electricity Prices



Source: PIRA

the desert southwest. Although a boom in generation construction between 2000 and 2004 added over 10 400 megawatts of generation capacity, California's statewide reserve margin remains low and at times it relies on imports from the PNW. There are concerns that lower than normal hydroelectric output in California and the PNW will cause severe transmission constraints during the summer months when demand is at its highest. These concerns are only intensified as a significant number of aging plants continue to be retired, causing reserve margins in the south to be very low by 2008. Electrical energy imported from the PNW into California generally serves northern California, although there is a large 500 kV line capable of transmitting power to the south of the state where it is often most needed because of low reserve margins.

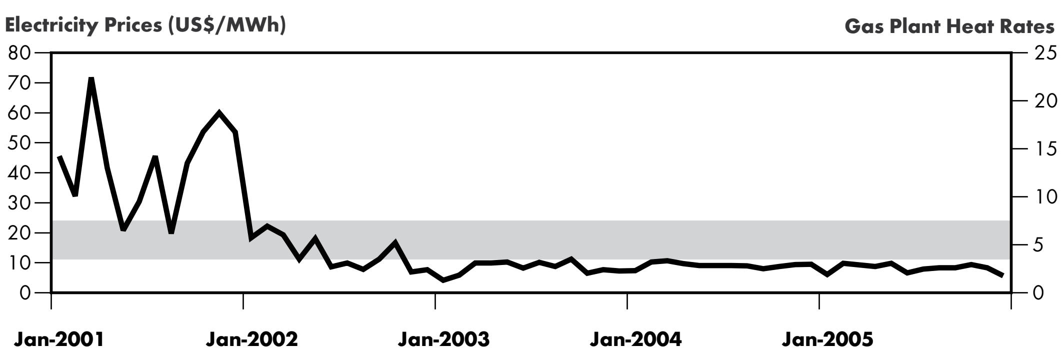
A steadily growing population along the west coast is expected to drive the need for more power generation. While some renewable projects, such as solar and wind, are under construction, gas-fired generation is expected to play a large role in meeting incremental demand for electricity. In California, for example, 95 percent of the 5 308 MW of proposed new generation is gas-fired. Similarly, in Oregon, about 4 140 MW of natural gas-fired generation is planned.

All of these new developments will exacerbate natural gas demand. Although new technologies, such as clean coal have become much more viable, the coastal areas are unlikely to adopt these technologies. Environmental concerns have become too important to allow coal to become an option. Clean coal will be considered in the future for further development in Alberta and Saskatchewan.

Given the potential changes to gas supply and demand in North America, significant investments will be required to enable the continuing development of gas from existing supply areas, as well as to develop and provide access to gas from new regions and LNG. As regions such as California look for ways to increase reliance on natural gas, more LNG terminals will likely be developed. A key determinant in the growth of gas-fired generation will depend on the availability of adequate gas supply and infrastructure at competitive prices. Furthermore, development of market area gas storage, distribution, fuel diversification and other services may also be required to effectively manage dynamic electricity and natural gas markets and to provide natural gas supply in the reliable and timely manner that is needed to serve fluctuating and weather sensitive electricity and natural gas markets.

FIGURE 3.11

Mid-C Market Heat Rate and Natural Gas Generation Heat Rate Efficiencies



Sources: NEB, PIRA

EASTERN MARKET – REGIONAL ANALYSIS

The eastern region, for the purpose of this report, consists of Quebec, Nova Scotia, New Brunswick, Prince Edward Island, Newfoundland/Labrador and the New England and Mid-Atlantic regions of the U.S. (Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey and Pennsylvania) (Figure 4.1).

FIGURE 4.1

Eastern Region in the North American Gas Market

Source: NEB

In general, this region is distant from the major gas supply basins in North America and employs a variety of energy sources for power generation. Until the Maritimes and Northeast Pipeline (M&NP) began operation in December 1999, the region could generally be characterized as being at the "end of the pipe" or the farthest market from major gas supply basins in western Canada, the U.S. Rockies and the Gulf of Mexico. With the exception of a small amount of production in the western part of the region plus some LNG imports at Everett, Massachusetts, the majority of gas supply in the eastern region is provided via long-haul gas pipelines from other regions in North America.

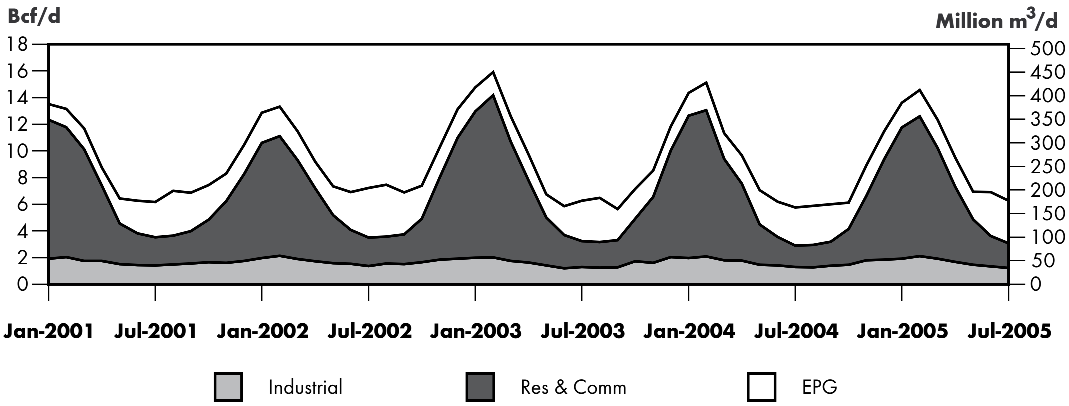
The expansion of gas delivery infrastructure to the U.S. Northeast, has enabled the region to become a significant market for natural gas and has connected the prices and supply and demand influences in this region with those of other regions across North America. Currently, about one-third of the natural gas consumed in the U.S. Northeast is sourced from Canada, thus closely connecting natural gas prices there with those in Ontario, Quebec and Atlantic Canada.

4.1 Eastern Region Natural Gas Demand

The use of Canadian natural gas in the U.S. Northeast has increased substantially since the mid-1980s — enabled through greater access to gas markets following de-regulation and expansion of pipeline infrastructure. Natural gas is predominantly used in the residential and commercial sectors, which accounts for 58 percent of usage. It is also used in applications such as space heating, with smaller quantities used as industrial fuel and electricity generation at 17 and 25 percent, respectively (Figure 4.2).

FIGURE 4.2

Eastern Region Natural Gas Consumption by Sector, 2001 – 2005



Sources: EIA, Statistics Canada, NEB estimates

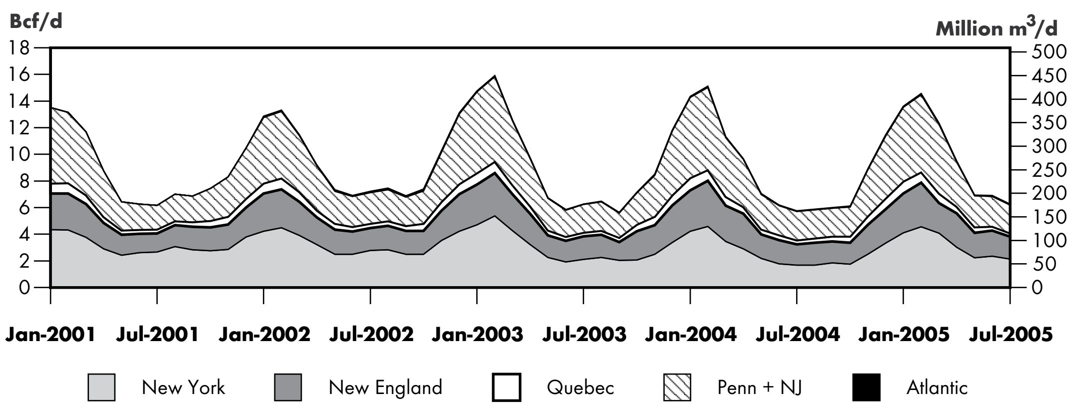
In Atlantic Canada and Quebec, natural gas consumption is much lower than in the adjacent U.S. Northeast primarily due to an abundance of other generation options such as hydro, limited gas delivery infrastructure, and a smaller population and industry base. On average, about 8.5 Bcf/d of gas is consumed in the eastern region, with about 95 percent of that in the U.S. Northeast (Figure 4.3).

Essentially, Canadian gas markets in Quebec and the Maritimes are served by a single pipeline corridor (TransCanada and M&NP, respectively) while the U.S. Northeast has some additional gas supply and transportation options. The limited delivery infrastructure and dependence on a single source for gas supply when combined with availability of other inexpensive fuel options has meant only a limited penetration of natural gas into the Quebec and Maritimes heating and power generation markets. Competition for gas supply from larger markets in surrounding regions and vulnerability to constraints and volatile prices from a single source also made it difficult to significantly expand natural gas use and penetration.

Due to the significant portion of load for heating (residential and commercial) in winter and for electric power generation during the summer cooling season, natural gas use in the eastern region is greatly dependent on the weather. The residential and commercial heating load represents about a third of total consumption in the summer and over three-quarters of total gas consumption during

FIGURE 4.3

Eastern Region Natural Gas Consumption by Area, 2001 – 2005



Sources: EIA, Statistics Canada, NEB estimates peak winter months. Natural gas used for electricity generation represents about half of the total gas consumed in the summer and about 15 percent of total consumption during peak winter periods.

In winter months, the core residential and commercial heating loads are highest and utilize the majority of available transportation capacity on natural gas pipelines in the region. As a result, the availability of remaining pipeline capacity for other users, such as power generators, has become a limiting factor in the amount of natural gas used, even if the demand for electricity is high. While interruptible gas services used by many power generators may be lower cost during cold weather and periods of peak demand, their availability is less certain and limited.

In many areas of the U.S. Northeast, there is access to gas supply from a number of potential sources, including the Gulf of Mexico, mid-continent, western and eastern Canada, and LNG. In past decades this has provided a competitively priced gas supply (relative to fuel oil) and has enabled the development of gas delivery infrastructure and a better penetration of natural gas into energy markets compared to Atlantic Canada. In turn, having the delivery infrastructure to meet the winter heating market has provided additional opportunities to use natural gas for power generation in order to optimize the use and cost of this infrastructure. This is typically done using interruptible services during the summer and other non-peak heating periods when gas supply and transportation are not fully utilized by firm long-term customers and as a result, are usually at lower cost.

In recent years, natural gas development from the Sable Offshore Energy Inc. project in offshore Nova Scotia and construction of the M&NP pipeline has brought new and incremental gas supply to consumers in Nova Scotia, New Brunswick and New England and fueled optimism that further development would provide even more gas into the region. The optimistic outlook for gas supply, combined with air quality concerns, ageing existing generation facilities, difficulties in siting new (coal, oil, nuclear) facilities, and the growing demand for electricity all conspired to stimulate growth in the use of natural gas for generation of electricity. As a result, in the 1980s and 1990s, the U.S. Northeast was a rapidly expanding market for natural gas.

For the U.S. Northeast, during the period 2000–2004, over 20 000 MW of generation capacity was installed with over 80 percent of that capable of using natural gas. In eastern Canada (Quebec, Prince Edward Island, N.S. and N.B.), about 2 000 MW of new generation was added with about 40 percent being gas fired (Bécancour in Quebec, Bayside in New Brunswick). Meanwhile, pipeline capacity to deliver gas supplies to the region has not kept pace with the previous high expectations due to limited success in further gas development in the Scotian Basin, difficulty in expanding natural gas pipelines from the south, and greater competition for gas from traditional supply areas such as the WCSB where additional production deliverability has become more limited and consumption in Alberta and Ontario continues to increase.

Today, on average, about one-third of the gas used in the U.S. Northeast is imported directly from Canada or imported as LNG. Although there is a small amount of production in western New York and Pennsylvania, the majority of the gas supply is produced and transported from other regions by high pressure natural gas pipelines. Gas flows into the region have been relatively stable around 227 to 255 million m^3/d (8–9 Bcf/d) despite having very significant differences in seasonal natural gas consumption. During periods of lower consumption, some of the gas is transported and kept in underground storage, primarily in Pennsylvania, and used to supplement gas supply from pipelines during the winter when gas consumption is the greatest.

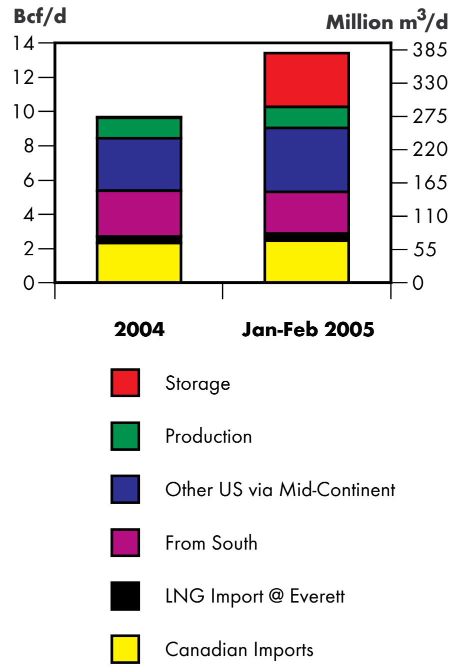
As illustrated using January and February 2005 data, storage withdrawals are a very significant and vital component of winter gas supply in this region (Figure 4.4). Pipeline capacity to the major cities tends to be highly utilized year round and leaves little room to substantially increase pipeline flows into the region during the winter. LNG is also stored at numerous satellite facilities located throughout the region and is used to meet short-term peaking requirements in local markets.

4.2 Outlook for Natural Gas Consumption

The growing gas requirement for use in power generation in the U.S. Northeast has meant increased demand and competition for gas that is being reflected in the natural gas price at surrounding markets. The rising cost of natural gas, due to a much tighter supply/demand balance in North America, has also helped to temporarily temper the amount of gas use for power generation in recent years. However, as electricity demand continues to grow and challenges with using other fuels for electricity generation remain, it is likely that gas-fired generation will also increase.

FIGURE 4.4

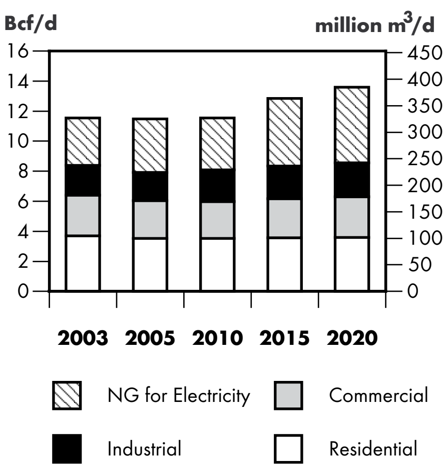
U.S. Northeast Gas Supply by Source



Source: Lippman Consulting

FIGURE 4.5

U.S. Northeast Projected Gas Consumption to 2020



Source: EIA Energy Outlook - February 2006

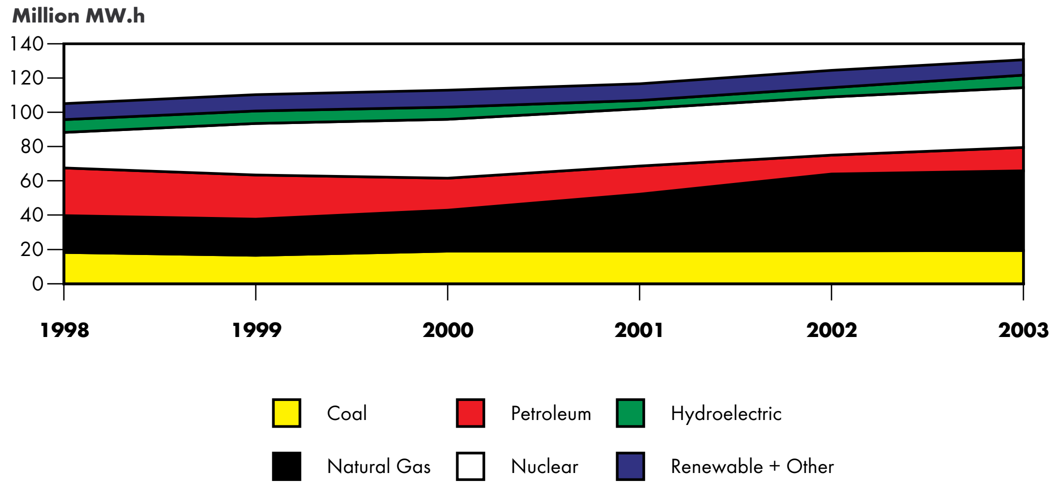
Over the next decade, the EIA projects that requirements for natural gas in the U.S. Northeast will increase by about 37 million m³/d (1.3 Bcf/d) over consumption levels in 2003. Of this, almost all is expected to be used for the generation of electricity (Figure 4.5).

Although the use of gas for power generation in the eastern region has been relatively flat in recent years, the trend differs significantly across parts of the region and consumption is expected to increase overall in the next few years. In New England, newly installed gas-fired generation was required to meet growing electricity demand and has represented a dramatic increase in gas consumption (Figure 4.6). However, in New York, new and more efficient gas-fired generation has been able to displace some older and less efficient generation, thereby keeping overall gas consumption flat (Figure 4.7). The strategic use of dual-fuel facilities in major load centres and resultant higher gas and electricity market prices have also enabled greater use of non-gas (namely nuclear and fuel oil) sources for power generation and have helped to manage the use of natural gas.

While the U.S. Northeast is expected to rely on gas for incremental power requirements over the next decade, this is not the case in eastern Canada. The abundance of hydro resources within the province of Quebec and in neighbouring Labrador has limited the need for natural gas in heating and power generation in Quebec. While Quebec has given some consideration to new natural gas cogeneration facilities in recent years, it is once again looking at

FIGURE 4.6

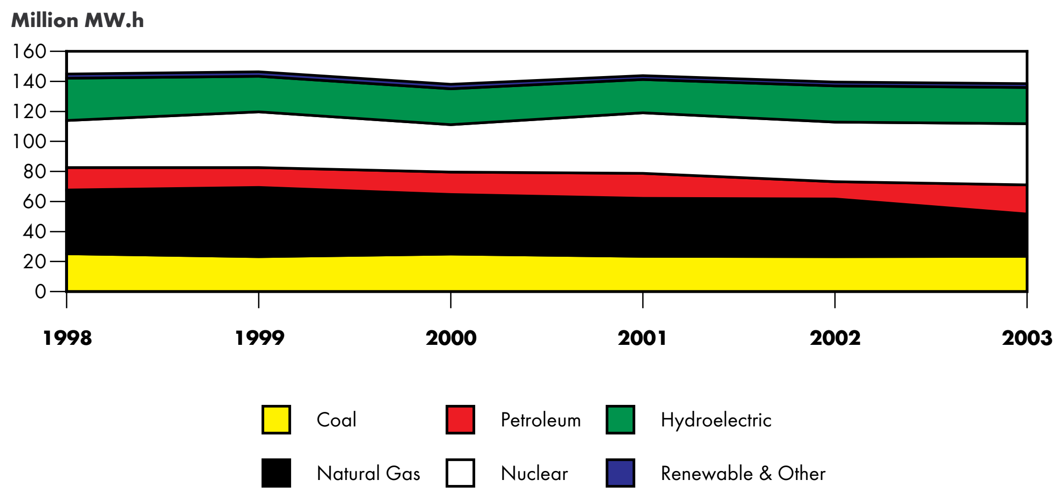
New England Electricity Generation by Source



Source: EIA

FIGURE 4.7

New York Electricity Generation by Source



Source: EIA

large hydropower developments and has significant plans to expand wind power, which has important synergies with hydro. Natural gas-fired generation will likely be considered on a more limited scale to capture synergies from cogeneration opportunities or to enhance regional reliability and markets. For Atlantic Canada, new gas-fired generation is only an option for New Bruswick and Nova Scotia.

Despite being only a very small fraction of the eastern region's total natural gas requirement, Canadian natural gas markets in Quebec and the Maritimes, like consumers elsewhere in North America, are integrated with markets in the U.S. Northeast and are subject to the same issues and natural gas pricing influences faced in the eastern region. The growing demand for electricity in both Canada and the United States, will require new incremental facilities for generation. Given difficulties to site and use new facilities for other traditional fossil fuels, a significant part of new generation will be gas-fired. This will require not only an incremental supply of natural gas, but the availability of pipeline capacity to the right locations, to ensure a reliable source of gas supply and cost effective operation.

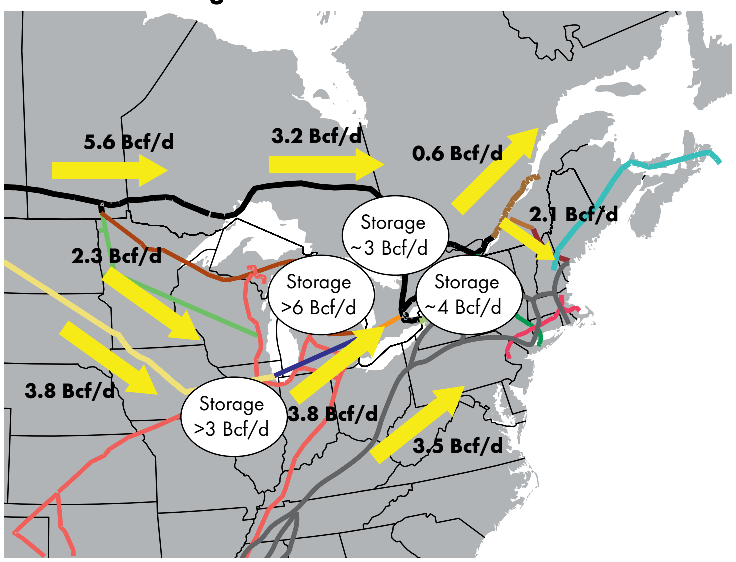
4.3 Natural Gas Supply and Infrastructure

Historical diversity in fuel options and having peak electricity demand in the summer for air conditioning (i.e. during periods when pipeline infrastructure is not fully utilized by other gas consumers with a peak requirement for space heating in the winter) enabled much of the gas supply and gas transportation arrangements for power generation development in this region to be made using lower cost interruptible gas transportation services through a variety of corridors (Figure 4.8). The practice of relying on interruptible services may be increasingly difficult going forward as new power generation is expected to account for almost 80 percent of the increase in gas demand for the U.S. Northeast over the next decade (Figure 4.9).

The use of interruptible transportation had enabled greater gas flows to storage and better utilization of pipelines during the summer and provided a substantial source of natural gas (from storage) in winter. Historically, this helped to provide for a lower cost supply of natural gas (and transportation) and enabled gas-fired power generation to develop. However, as pipeline utilization increases, these services have become less reliable or unavailable. As gas demand for power generation continues to increase without a corresponding increase in gas infrastructure (either storage or pipelines into the region), pipeline constraints may become prevalent and gas requirements for power may compete with the ability to refill storage in the summer.

FIGURE 4.8

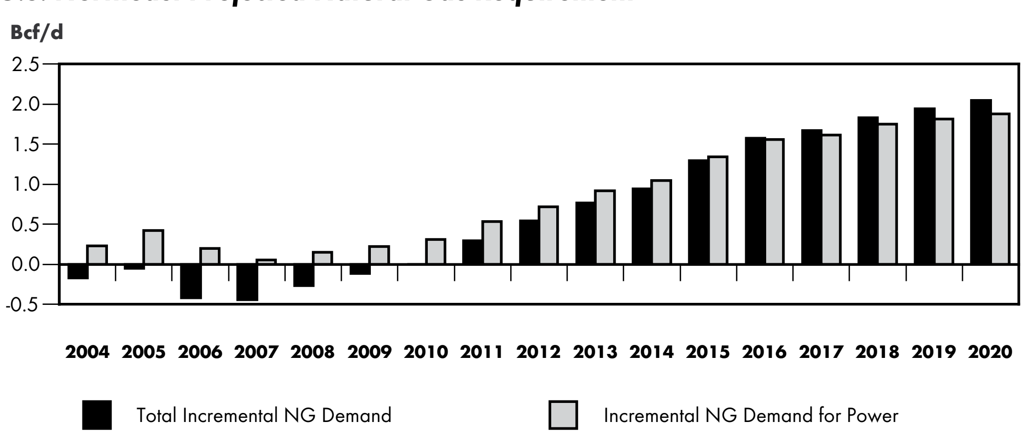
2004 Eastern Region Natural Gas Flows



Sources: Lippman Consulting, NEB

FIGURE 4.9

U.S. Northeast Projected Natural Gas Requirement



Source: EIA Energy Outlook

Over time, growing electricity demand has been met through the increased use of gas-fired generation in many parts of the region. The growing prevalence and frequency of gas-fired generation as the marginal electricity supply (especially during the winter) has put stress on both the natural gas and electricity delivery systems. The same infrastructure, weather and operational influences can affect the supply and demand of both commodities. The resulting competition that occurs between these end-use markets during periods of coincidental high demand exerts significant pressure on prices to allocate the scarce commodity. This is especially the case for short-term intraday requirements when options are limited and gas facilities may provide a more rapid response to demand. For example, in January 2004 and January 2005, intense competition between heating and electricity markets for limited gas supply and infrastructure capacity resulted in extreme short-term price spikes affecting natural gas prices in this region (Figure 4.10).

The extreme prices tend to be short in duration as time allows other measures to be deployed to reduce demand or provide additional generation. These measures include conservation, reduced consumer demand in response to prices and requests, use of alternate fuel (e.g., fuel oil), inter-region electricity imports, dispatching additional generation, or paying some users to curtail usage during periods of high demand. The extent of these tools will vary significantly across the region. In general, the significant amount of generation facilities that are capable of burning dual fuels (fuel oil and natural gas) have been key to enable reliable load-following generation capability. However, the use of fuel oil is often limited (for example, in New York to no more than 720 hours of operation per year) to control emissions and manage air quality.

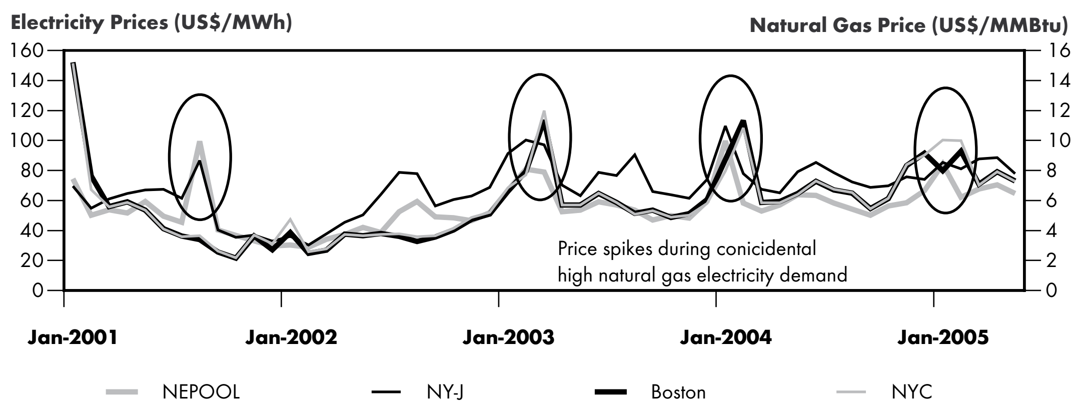
Having highly utilized (and sometimes constrained) pipeline capacity and a great reliance on storage withdrawals to meet growing peak winter demands puts the natural gas supply and demand of this region in a very tight and delicate balance that is highly sensitive to influences such as weather, oil markets, pipeline operations and other local conditions. Combined with increasing challenges to site new dual-fired gas/oil facilities, there will be significant requirements for natural gas infrastructure connecting gas supply to new gas-fired generation.

4.4 Gas-Fired Generation

The amount of natural gas-fired generation varies considerably across the eastern region (Figure 4.11). Natural gas for power generation in Atlantic Canada and Quebec is limited to a few recent facilities, while up to 50 percent of the installed generation capacity in the U.S. Northeast is capable of using

FIGURE 4.10

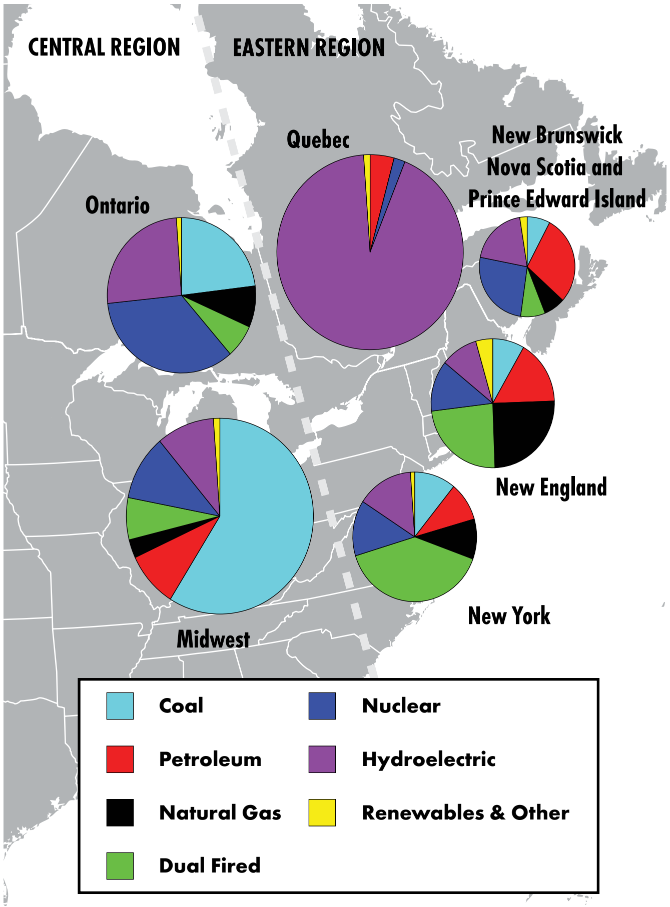
Northeast Natural Gas versus Electricity Prices



Source: PIRA

FIGURE 4.11

Eastern Region Generation Fuel Mix



Sources: EIA, Statistics Canada

natural gas. Much of the reason for the difference in fuel mix is a function of the age of facilities and the fuel options available at the time when the generation facilities were constructed.

In the Maritimes, there was neither gas supply nor gas delivery infrastructure in the region until M&NP began operation in December 1999. As a result, to date, there has only been very limited development of natural gas markets for heating and electricity generation. Higher natural gas prices in recent years arising from a much tighter North American natural gas supply/demand balance have also limited the use and conversion of existing oil facilities to natural gas.

In the U.S. Northeast, natural gas has been available in some locations for much longer, which has enabled the development of significant gas-fired generation resources over past decades. Difficulties in siting new coal, oil and nuclear projects have also begun to limit other fuel use for generation in favour of natural gas. In New York and New England, almost one-half of the total existing generation capacity has the capability to use natural gas. A substantial portion of these are converted oil facilities with the flexibility to burn either fuel oil or natural gas. This "dual-fuel" capability is a key feature of this market that can be used to mitigate periods of high natural gas prices or to enable reliable generation of electricity during periods where gas supply or transportation is constrained or being used by other gas consumers.

In key urban electricity load centres, dual gas/distillate generation capacity may be mandated to ensure reliability of electricity supply. These requirements and effective local market prices have enabled New York to have a greater amount of dual-fuel capability than other regions.

In general, there is diversity in fuels used for electricity generation. In addition to natural gas-fired generation, approximately 37 percent of other generation is fueled by coal, hydro, oil and nuclear energy. However, the fuel mix continues to evolve as environmental concerns and restrictions on emissions limit the use of other fossil fuel options and siting uncertainties are significant for new hydro and nuclear development. As a result, many of the recent new generation proposals tend to be gas-fired, despite the fact that there is limited natural gas production in the region. The prospect for natural gas-fired generation is further strengthened by provincial and state environmental restrictions that may limit the use of these other fuels.

Although new gas-fired facilities are more efficient, have short lead times to construct and may create less air quality concerns than other ageing fossil fuel facilities, they represent an incremental demand and growing reliance on natural gas. The growing gas demand and uncertainty in future gas supply have meant high and volatile natural gas prices and have led to greater and renewed focus to develop other non-gas generation. Although efforts to generate electricity from renewable sources such as wind and refurbish and increase output from existing nuclear facilities have helped to slow the growth in natural gas demand in the region, incremental gas-fired generation is still likely, placing strains on the gas and electricity infrastructure in the region. This is particularly the case in large urban centres where there is the greatest incremental demand, more difficulty in siting new infrastructure and larger swings in weather-related load.

4.4.1 Evolving Issues arising from Gas-Fired Generation in the Eastern Region

Need for Incremental Gas Supply and Infrastructure

To meet future demand growth, new infrastructure may be necessary to provide additional gas supply to the region and to ensure reliable operation of gas-fired power generation, particularly in the key load centers that are susceptible to pipeline constraints. With a significant proportion of incremental gas demand expected for power generation, it may no longer be reasonable to rely on interruptible services and existing infrastructure. However, the long term and firm contract arrangements that may be required to support new gas supply and transportation capacity will add to the costs of new generation.

Potential for Additional Gas Supply and Natural Gas Exports from Canada

With increasing difficulty and costs associated with expanding pipelines through populated areas to bring gas from southern U.S. supply areas (e.g., from the Gulf of Mexico), there is significant potential to provide additional gas supply to the eastern region via Canadian infrastructure. Incremental gas supply can come in the form of Canadian gas production from new areas provided through expansion of central and eastern Canadian pipeline corridors, or may be in the form of LNG imports or imports from other U.S. regions provided through Canadian infrastructure intended to receive and re-deliver gas in this region.

There are currently a number of proposals to expand Canadian pipelines that would enable delivery of additional gas volumes to markets in this region. These include pipeline expansions connecting gas supply and storage in the U.S. Midwest and Ontario (Dawn) to markets in eastern Canada and the U.S. Northeast and various proposals to construct LNG receiving terminals in Quebec (2), Nova Scotia (2), and New Brunswick (1). These projects, if built, may also enhance the ability of Canadian consumers to access continental and global gas supply and benefit from associated opportunities to trade gas in the region.

Access to incremental gas supply into this region via further development of East Coast production or LNG imports may hold additional appeal by diversifying gas supply and having a greater impact on the historical relationship of prices in this region to the rest of the continent (highest priced region). Many of these LNG projects also support associated gas-fired power generation facilities that can act as both an anchor market and a reliable source of electricity to the plant and local consumers. However, there are significant challenges with respect to the large investment required, uncertainty of supply, environmental impact and siting/acceptance of facilities. These projects, however, face stiff competition from Canadian pipeline expansion in Ontario and the Midwest and other pipeline, and LNG proposals in the United States.

Proposals for Gas Supply and Infrastructure in the U.S. Northeast

Canadian proposals are not unlike the numerous proposals for new gas infrastructure in the U.S. Northeast in that all strive to deliver incremental gas volumes to growing markets in the region or local area. Although the Gulf Coast is a large producing region with growing capacity for LNG imports, existing pipes that bring gas from that region are highly utilized and constrained during peak demand. Although high costs and challenges with building in highly populated areas make large scale development along that route more difficult, there are a number of proposals to debottleneck pipeline constraints, extend the reach of distribution and increase capacity to receive and transport LNG imports.

The seasonal and variable nature of gas loads for power and heating have also lead to proposals to develop new storage and transportation from western New York and Pennsylvania and from the Midwest to support this region. Storage development leveraged with other LNG or pipeline projects will help provide the variable gas requirements expected in this region.

Load-Following Capability of Gas-fired Generation

The ability for electricity generation to “follow load’ or respond to rapid and frequent changes in weather-sensitive electricity demand is a significant requirement that may be suited for gas-fired generation. Other growing sources of electricity cannot be assured to be available when required (wind), or may be more reliable and appropriately used as a continuous and baseload supply (nuclear power). Furthermore, the load-following requirement for electricity generation is likely to be greatest in urban areas with concentrated weather, sensitive heating and electricity demand.

Load following requires a close alignment of gas and electricity markets through pricing, more flexible balancing services and coordination of gas and electricity operation to enable better anticipation and response to load changes.

Potential Canadian Pipeline and Storage Services

The ability to respond rapidly to variable weather-sensitive load requires that power generators must not only be able to anticipate changes in load, but have natural gas pipeline and storage services that will allow frequent and significant changes in gas flow in response to changing conditions. Though not exclusive services for the eastern region, Canadian natural gas pipelines, distributors and storage operators are developing new services targeted for the growing power generation market. In general, these services would entail greater scheduling flexibility to allow highly variable gas flows and potentially the ability to change the point of supply or delivery in response to changing conditions.

However, these new services could entail higher costs and may tie up available infrastructure capacity that would have otherwise been used for other services.

Competition with Other Natural Gas Users

Without a corresponding increase in gas infrastructure to meet rising gas demand, there would be competition for available transportation capacity and gas services used to supply gas-fired generation and other users, like industrial customers. The proposed flexible services for power generation presents challenges to other users of current interruptible services because new services may not be ideally suited for users with a steady baseload operation, making it difficult to justify the higher costs. In addition, limited pipeline capacity may be reserved for the new service, which would reduce the availability and dependability of existing interruptible services.

Requiring new natural gas infrastructure or firm service to underpin incremental power requirements would likely lead to higher costs for new power generators. However, these costs would need to be reflected and recovered through the appropriate design of electricity pricing/markets or incorporated as greater risk adversely affecting the competitiveness of these new projects.

Coordination of Gas and Electricity System Operations

Anticipation of load changes and ensuring that gas-fired generation is available is a significant issue in this region. The situation is further challenged by differences in the gas and electricity operation and markets. For gas, most adjustments to flows on pipelines are scheduled a day in advance with a limited number of intra-day changes possible via a few fixed nomination windows. On the other hand, electricity system operation requires a close and continuous balance between electricity supply and demand and, as a result, needs the ability to dispatch generation on an ongoing and near real-time basis.

These ongoing adjustments, especially for increased electricity output from a gas-fired facility in the U.S. Northeast, are not always assured, as they depend on the availability of gas, interruptible pipeline capacity and ability to schedule corresponding gas flows. Although additional services are being developed to provide balancing, storage or more flexibility to make gas flow adjustment, currently these are provided at either a much higher cost or at the discretion of providers depending on availability.

Additional challenges also arise due to the "chunkiness" of gas-fired generation because these facilities perform best within a certain range of operation. For that reason, generation from gas-fired facilities is offered on the market in certain sized blocks to achieve optimum facility performance and to ensure market prices cover operating costs and provide adequate returns.

4.4.2 Market Prices to Reflect Service Requirements and Local Markets

The growing share of electricity produced from natural gas will increasingly tie the price of the electricity to that of natural gas. Appropriate electricity pricing is sought to ensure that the necessary gas-fired generation is built and located to serve these weather-sensitive markets. While effective market pricing can facilitate longer term investment and encourage locational and load-following capability, this also requires the commitment and acceptance of higher end-use energy prices to recover these investments. The higher cost of natural gas compared with other traditional fossil fuels (such as coal and heavy fuel oil) will mean increased prices for electricity in many parts of the region.

Market prices that reflect local electricity supply and demand and gas markets can help enable generators to anticipate prices. Where expected, prices can enable sufficient returns and cover operating costs, which helps to provide incentive and support for developing new generation projects in the appropriate locations. Where pricing signals are less clear, perhaps due to price caps or limitations in reflecting local conditions, there may be additional challenges to ensure appropriate investment and development of generation.

Other Implications to Canadian Natural Gas Markets

Although at this time the growing requirement for gas-fired power generation in the eastern region is mostly a phenomenon of the U.S. Northeast, Canadian natural gas provides about one-half of the natural gas consumed annually in New England and about one-third of the total natural gas requirement for the U.S. Northeast. As a result, eastern Canadian markets are strongly connected to the challenges and opportunities presented by proximity to this region.

The expansion of gas infrastructure in Canada and the growing use of natural gas for power generation in the eastern region will serve to connect Canadian natural gas users and prices more closely to those in the U.S. Northeast. While this presents challenges in terms of greater competition for gas supply and likely high and volatile natural gas prices, there are also potential opportunities associated with gaining better access to continental and global gas supply through this proximity.

4.5 Canadian Gas Infrastructure

Despite the potential higher costs of natural gas relative to other traditional fuels, increased gas demand is also expected in eastern Canada. However, gas demand in eastern Canada by itself is small and likely would be less able to economically support the major infrastructure additions required to bring incremental gas supply or storage development. Through proximity to the much larger markets in the U.S. Northeast, there is opportunity to gain economic access to infrastructure and incremental gas supply for local Canadian markets. Development to enable LNG import facilities in Canada, may also bring more diversity in supply and could provide for more stable prices through greater supply competition and security. Also, as seen from previous gas developments, new supply can also bring trade opportunities, especially where Canadian users may have dual-fuel capability.

CENTRAL MARKET – REGIONAL ANALYSIS

The central region for the purpose of this report includes Manitoba and Ontario and the Midwest region of the United States, which includes the West North Central (North & South Dakota, Nebraska, Kansas, Minnesota, Iowa and Missouri) and East North Central (Wisconsin, Illinois, Michigan, Indiana and Ohio) Divisions (Figure 5.1).

Although the central region has little natural gas production of its own, an extensive pipeline network provides the region with access to natural gas from western Canada and many of the major producing regions in the United States, including the U.S. Rockies, Mid-Continent and onshore/offshore Gulf of Mexico. This abundance of pipeline capacity has supported a substantial natural gas market in this region. In addition, the large amount of underground natural gas storage has allowed for many pipelines to converge or travel through this region and helps to support a very significant and variable load for space heating. Although the region has only a relatively small component of gas use for power generation, the concentration of underground gas storage and pipeline access to multiple gas producing areas and markets have made this a key region for contracting and pricing natural gas supply for natural gas markets in central and eastern North America.

FIGURE 5.1

Central Market Region in the North American Gas Market

Source: NEB

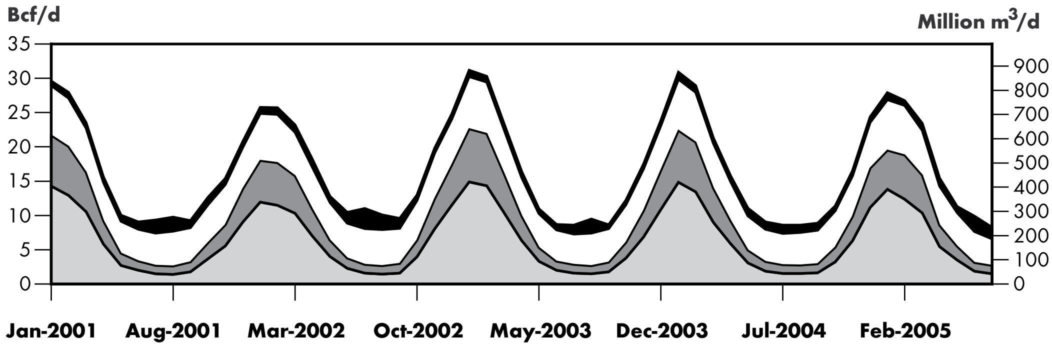
The gas requirements in the central region are split between a large weather-sensitive residential and commercial heating load, a significant industrial base and substantial flow-through to other markets in Quebec and the U.S. Northeast.

5.1 Natural Gas Demand

Today, natural gas consumption in the region accounts for up to 850 million m^3/d (30 Bcf/d) in the winter, or about one-third of total North American consumption. Use in the residential and commercial sectors represents the biggest part of regional consumption, accounting for over 567 million m^3/d (20 Bcf/d) or over two-thirds of the gas consumed in the winter and about 60 percent of gas consumed annually (Figure 5.2). Industrial natural gas consumption is next at

FIGURE 5.2

Central Market Region – Natural Gas Consumption



Sources: EIA, Statics Canada and NEB estimates

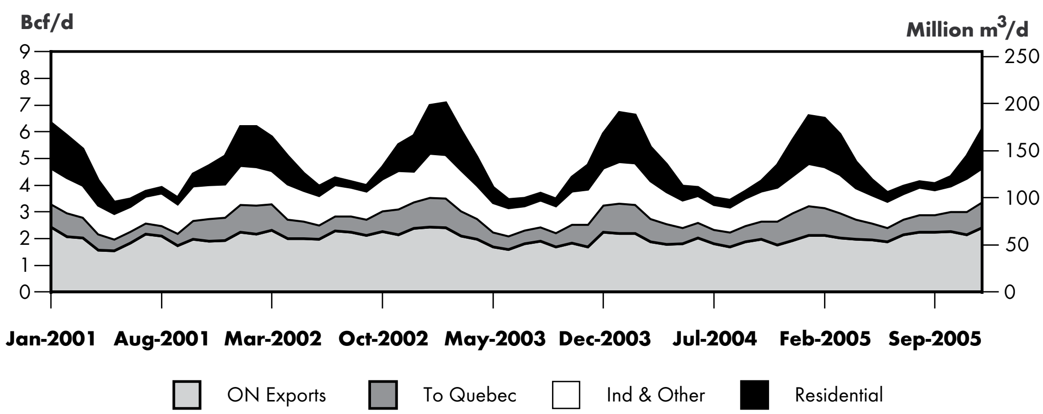
around 113 to 226 million m³/d (4 to 8 Bcf/d). Natural gas use for electricity generation, however, is relatively small in this region and accounts for only about six percent of the annual gas consumption. An abundance of coal resources, particularly in the U.S. Midwest has limited the use of natural gas for power generation in this region.

Natural gas consumption in Ontario and Manitoba represents about one quarter of the gas consumed in the central region. In Ontario, on average about 76 million m³/d (2.7 Bcf/d) of natural gas is consumed annually, although natural gas consumption can exceed 113 million m³/d (4 Bcf/d) during winter months. Like the central region, Ontario represents a substantial end-use market for natural gas, largely for seasonal heating requirements in the residential and commercial sectors and a significant industrial load (Figure 5.3). Gas is currently used for power generation at only a few facilities in Ontario and this generation accounts for about ten percent of gas consumption.

Canadian pipelines and storage play a key role in meeting the natural gas requirements of Ontario and other downstream markets in Quebec and the U.S. Northeast (Figure 5.4). Recent estimates for regional gas flows indicate that pipelines into Ontario provide access to an average of over 142 million m³/d (5 Bcf/d) of gas supply from both western Canada and the United States. During the winter months, Canadian pipelines, supplemented by storage withdrawals, may provide up to

FIGURE 5.3

Disposition of Natural Gas in Ontario



Source: Statistics Canada

almost 226 million m^3/d (8 Bcf/d) of gas supply. Meanwhile, Ontario's natural gas consumption varies between almost 57 million m^3/d (2 Bcf/d) in summer to over 113 million m^3/d (4 Bcf/d) during winter, indicating a very significant portion (over 85 million m^3/d or 3 Bcf/d) of the Canadian pipeline and storage infrastructure in this area is used to help meet the natural gas requirements in other downstream markets.

A similar situation occurs in the U.S. Midwest where about one-third of the gas supply and infrastructure within the region is used for gas exports to other markets in Canada and the U.S. Northeast (Figure 5.5). As a consequence, the natural gas markets and pricing in the eastern and central regions are closely connected through this infrastructure and changes to natural gas supply or demand in either region will have a direct effect on the other through pricing and competition for natural gas and infrastructure.

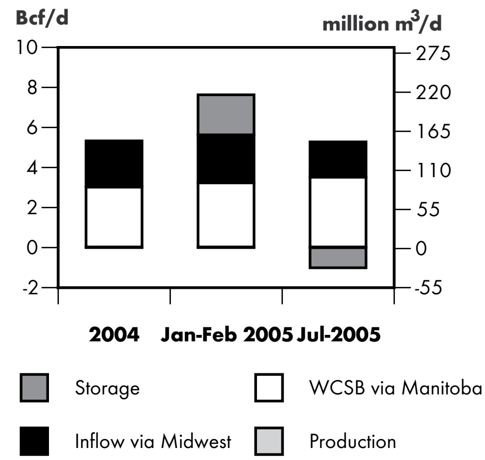
5.2 Outlook for Natural Gas Consumption

Due to the wide availability and use of coal and other fuel alternatives for power generation, natural gas use to generate electricity in Ontario and the U.S. Midwest has been a relatively small component of gas consumption. In 2004, gas use for power by utilities and industrials accounted for only about six percent of total gas consumption in the central region. Of that, the majority was used during the summer when electricity demand for air conditioning is highest and residential and commercial gas demand is low.

Natural gas infrastructure for power generation, as a result, has been mostly situated in areas where coal or other alternate fuels are less available and where natural gas pipeline and storage access are available close to the electricity load. In recent years, the installation of gas-fired generation has grown

FIGURE 5.4

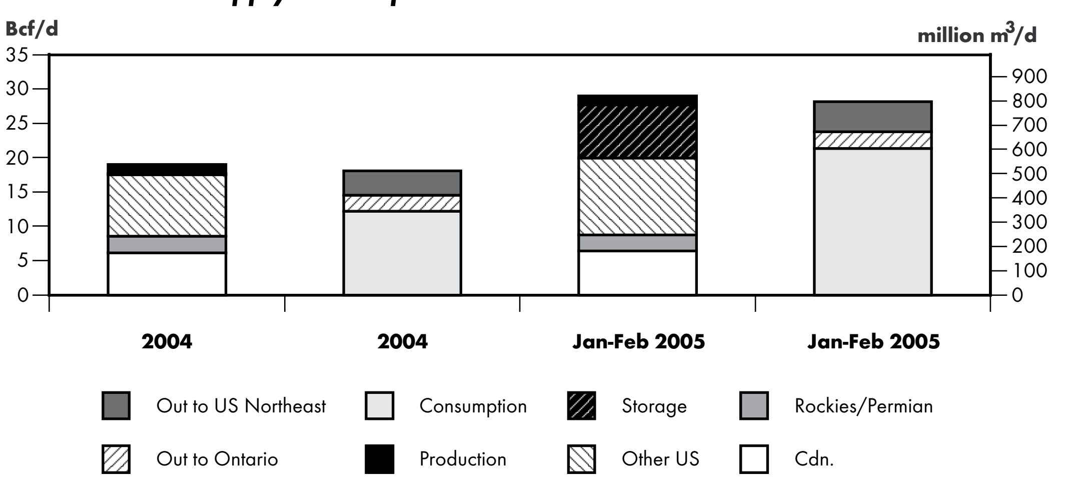
Sources of Supply to Ontario



Source: NEB

FIGURE 5.5

Midwest – Gas Supply and Disposition



Source: Lippman Consulting

noticeably, particularly where gas-fired facilities may be better suited or situated to provide peak generation requirements.

Like other regions in North America, the demand for electricity is projected to increase across this region, fueled by population and industrial growth. While incremental generation from coal will continue to provide the majority of this electricity in many parts of the region, environmental and air quality concerns may limit its use in others. Significant new generation from natural gas and other sources such as wind are also expected. According to the EIA's *2005 Energy Outlook*, electricity consumption in the U.S. Midwest is projected to increase by about 16 percent over the next decade, of which about 73 percent is derived from coal, 21 percent from natural gas and 5 percent from renewables, such as wind.

In Ontario, the potential for an increase in natural gas consumption is high, primarily driven by provincial government decisions on power generation in response to air quality concerns. The extent of gas utilization in electric power generation will be influenced by the choices Ontario makes in power generation over the next decade, starting with phasing out coal generation in the near term, currently planned to occur by 2009. Eliminating the use of coal would require that generation from other energy sources be increased to make up almost one-quarter of all electricity currently produced in Ontario from coal in addition to providing the incremental electricity to meet the greater demands of a growing population and economy.

Ontario's future generation mix, as planned by the Ontario Power Authority (OPA), includes a diverse supply of power sources. The options are natural gas, nuclear (refurbishment and longer term new-builds), an array of renewables (wind, small hydro, biomass), conservation and other forms of demand management, possible large hydropower developments in northern Ontario (longer term), and additional large-scale imports of hydropower from Quebec and Manitoba (longer term).

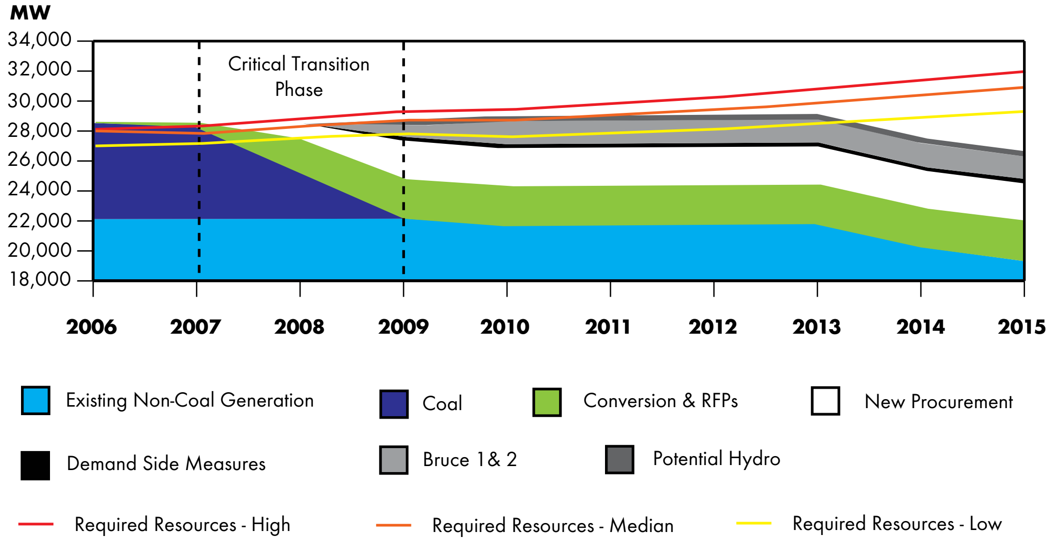
While a significant portion of coal replacement can be accomplished through the refurbishment and greater utilization of existing nuclear facilities, full replacement of coal will likely require a number of actions that may include conservation and demand-side management to limit consumption, increasing electricity supply from development of new generation from wind and other renewable energy, additional natural gas-fired generation, and possible increases to electricity imports. In the past year, 650 MW of new gas-fired generation have been installed and decisions have been made to restart an additional 515 MW of nuclear generation. Various projects have also been announced to provide about 2 550 MW of additional gas-fired generation and almost 400 MW in renewable energy projects.

5.2.1 Ontario

The impact of phasing out coal-fired generation in Ontario on the overall gas requirement in the region is highly dependent on the decisions and assumptions made regarding the amount of nuclear generation that can be returned and the ability to utilize supply and infrastructure from surrounding areas (i.e., gas supply and storage from the U.S. Midwest or hydroelectricity imports from Manitoba). The Board estimates the range for the incremental natural gas requirement in Ontario will be of about 8 to 20 million m^3/d (0.3 to 0.7 Bcf/d) by 2010. This range considers scenarios with a varying degree of nuclear refurbishment (Figure 5.6). The lower number represents a situation where there is a high degree of nuclear refurbishment and utilization, while the high requirement for natural gas represents the situation where nuclear refurbishment is limited to the already announced proposals, thus requiring significantly more gas-fired generation. In addition to increased generation from nuclear and natural gas-fired generation, the Ontario government has also directed the procurement of additional generation from renewables and other combined heat and power projects.

FIGURE 5.6

Sources of Potential Coal Replacement



Source: IESO 10-year outlook

5.2.2 U.S. Midwest

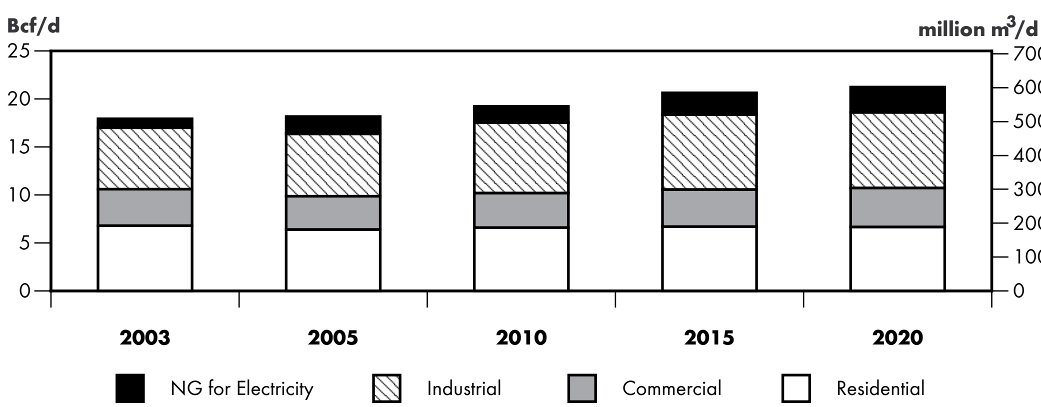
The EIA projects that gas demand in the U.S. Midwest will increase by over 57 million m³/d (2 Bcf/d) over the next decade (Figure 5.7). Even with expectations for a substantial increase in electricity generation from coal, incremental natural gas requirement for power generation is still substantial, accounting for almost 28 million m³/d (1 Bcf/d) or half of the projected increase in gas requirement.

5.3 Natural Gas Supply and Infrastructure

In total, incremental gas requirements for the central region, including Ontario and the U.S. Midwest, are projected to range from 79 to 96 million m³/d (2.8 to 3.4 Bcf/d) over the next decade. The implications of this extend beyond simply having available gas infrastructure and supply capable of providing those additional volumes to the central region. While the region may have adequate

FIGURE 5.7

U.S. Midwest – Projected Natural Gas Consumption to 2020



Source: EIA Energy Outlook - February 2006 pipeline infrastructure to access natural gas supplies, much of the existing supply and infrastructure is currently used to meet requirements in surrounding regions. With demand in the eastern region also projected to increase by more than 37 million m³/d (1.3 Bcf/d) over the same period, competition and requirement for new gas supply and infrastructure will likely increase over the next several years.

Furthermore, the pattern of gas consumption for power generation will become much more weather sensitive and will present a gas load profile with more frequent and substantial variation than would be experienced from many of the traditional industrial gas consumers that have operated as a stable baseload. This will be especially the case in locations where natural gas-fired generation facilities become a significant part of the overall gas requirement and are expected to provide the swing or the load-following capability in electricity supply. This may also be exacerbated somewhat where refurbished nuclear facilities may provide more of the baseload power generation, leaving natural gas facilities to provide the variable load-following supply of electricity.

Considering that the majority of Ontario's energy requirement for home heating is also supplied by natural gas or electricity, this could amplify swings in gas demand similar to that experienced in the U.S. Northeast. However, given a much lower capacity in Ontario for dual-fuel generation facilities, this may place greater requirements for variable operation of gas-fired generation facilities and more significant swings in natural gas consumption. In essence, replacing coal-fired generation with a significant addition of gas-fired generation will increase Ontario's reliance on natural gas and present challenges to ensure supply and reliability during periods of peak demand similar to that currently being experienced in the eastern region.

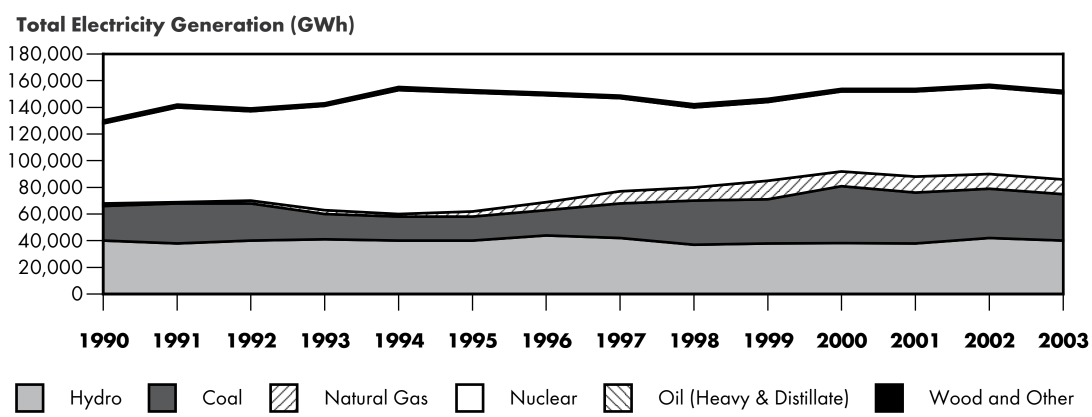
5.4 Electricity Generation Fuel Mix

5.4.1 Ontario

Ontario's electricity is currently generated from a diverse mix of energy sources (Figure 5.8). Until the mid-1990s, natural gas was not a significant fuel for power generation in Ontario. Until that time, the province had relied on the use of nuclear, hydro and coal as its main sources for electricity. Since the mid-1990s, there has been a marked reduction in output from ageing nuclear facilities, which has been made up by greater generation from coal and natural gas. In 2004, about nine percent of Ontario's electricity was generated from natural gas and 24 percent from coal. During the past

FIGURE 5.8

Central Region Natural Gas Flows



Source: Natural Resources Canada

decade, the combined increase in electricity generation from coal and natural gas has roughly offset the decline in output from nuclear facilities.

However, the landscape for Ontario's electricity generation continues to evolve. With growing concerns over air quality, the provincial government has taken a bold initiative to eliminate the use of coal for power generation by 2009. To accomplish this in the proposed timeline will likely entail a number of actions including greater electricity generation from renewable energy sources (such as wind), growth in gas-fired facilities, refurbishment of some of the previously inactivated nuclear facilities and perhaps greater imports from Manitoba, which enjoys an abundance of hydroelectric power.

In general, a diverse generation mix is desired to ensure efficiency and adequacy to enable dispatch flexibility and reduce vulnerability to constraints and prices in any one fuel. With the proposed elimination of coal in Ontario, this flexibility will need to be provided through installation of new generation.

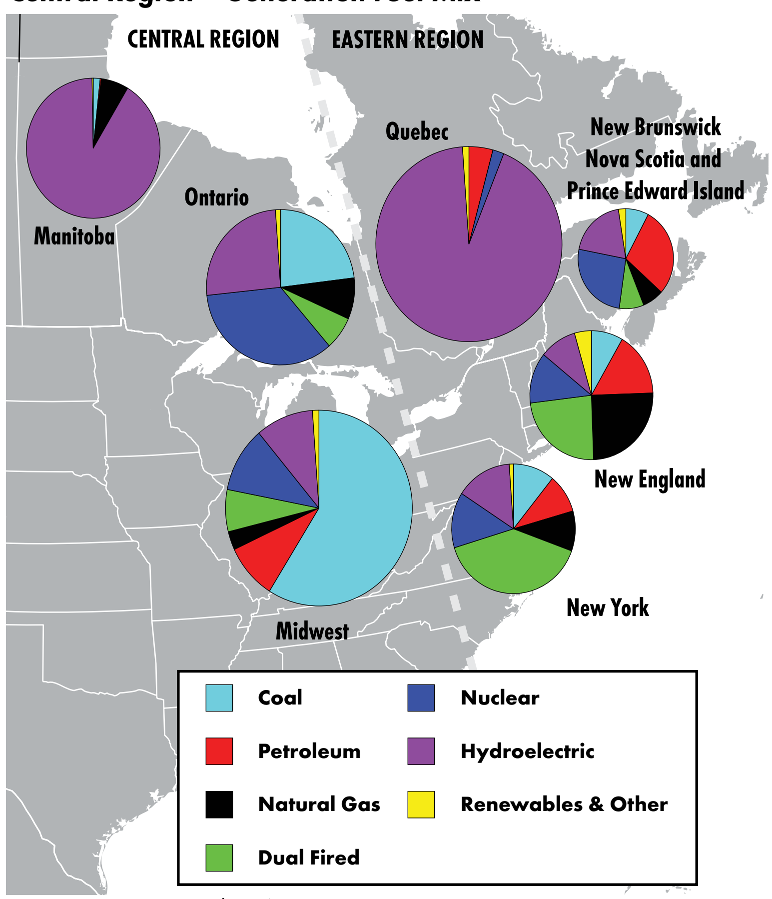
5.4.2 U.S. Midwest

Largely enabled through an abundance of the resource, coal has been the dominant fuel for electricity generation in the U.S. Midwest, providing almost 75 percent of the electricity produced in the region. Output from nuclear energy, unlike in Ontario, has been consistent over the years and provides about 18 percent, while power generation from natural gas has accounted for less than five percent.

The fuel mix actually used in electricity generation differs significantly from the fuel mix in installed capacity where coal accounts for only about half of generation capacity and natural gas facilities have become a more significant proportion of installed generation capacity (Figure 5.9). With significant investments in natural gas-fired generation in recent years, natural gas now accounts for over 20 percent of the generation capacity in the region. The large difference between fuel mix for generation and installed capacity highlights the significant amount of surplus capacity in the

FIGURE 5.9

Central Region – Generation Fuel Mix



Sources: Statistics Canada, EIA

region and the limited use of these facilities. Most of these are natural gas-fired facilities installed over the last few years. Since 1995, natural gas facilities have accounted for more than 90 percent of the generation installed in this region. To date, these have operated on a more dispatch or swing nature, with greater utilization during periods of high electricity demand.

5.5 Evolving Issues from Gas for Power Generation

5.5.1 Need for Incremental Gas Supply and Infrastructure

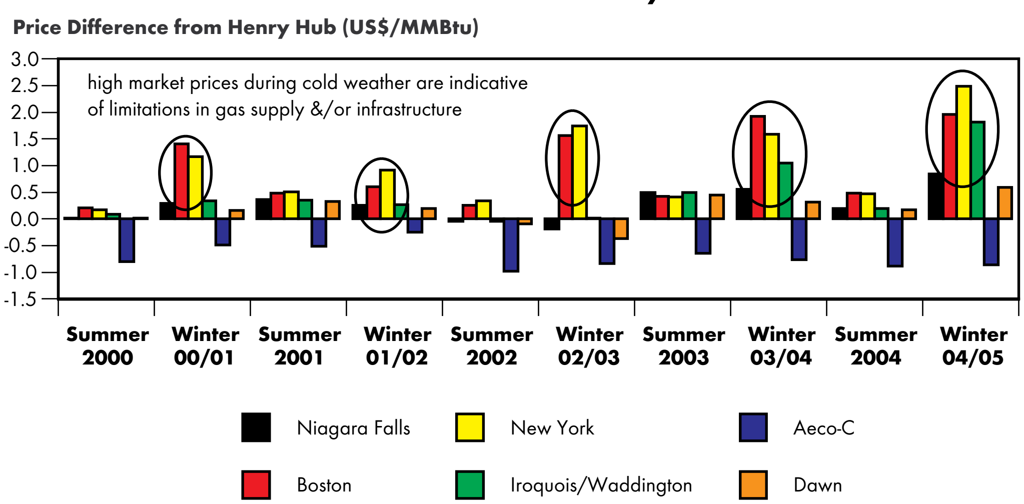
To satisfy the growing requirement for natural gas, there have been a number of proposals for new gas infrastructure to enhance the central and eastern regions' access to incremental gas supplies from traditional producing areas such as the U.S. Rockies and new gas supplies from LNG in the Gulf of Mexico.

The significant growth in natural gas demand for power generation in Ontario and the eastern region may also place increased demands on Canadian infrastructure to provide both a greater supply of natural gas and flexible services to enable large changes in pipeline gas flows with little or no notice. As an example, the price differences between Dawn in southern Ontario and Iroquois or other locations in the east illustrate that transportation routes to the U.S. Northeast via Ontario are becoming constrained (Figure 5.10). Furthermore, the increasing winter prices observed in Ontario over recent years highlight the competition for gas between consumers in Ontario and the eastern region.

While gas supply and prices in the Midwest and southern Ontario appear adequate and stable as indicated by pricing at Dawn, it is becoming evident that capacity to deliver gas to markets farther downstream is becoming more constrained as illustrated through rising winter prices at the Iroquois export point (to the U.S. Northeast) and Parkway (to Toronto). As gas demand increases in the U.S. Northeast, Ontario and the U.S. Midwest, there will likely be even greater requirements for services provided by pipeline and storage facilities in southern Ontario and the U.S. Midwest.

FIGURE 5.10

Natural Gas Prices at Various Markets versus Henry Hub



Source: Canadian Natural Gas Focus

The Board estimates between 17 to 28 million m^3/d (0.6 and 1.0 Bcf/d) of incremental gas infrastructure is required to meet the future requirements of Ontario and eastern markets to 2010. These expansions to Canadian pipeline and storage facilities may provide trade and economic opportunities, but may also serve to more closely connect the natural gas prices across regions.

Although other supply options such as LNG may also be available to eastern markets, they are unlikely to be able to fully replace the access to diverse sources of gas supply and abundant gas storage that is provided through gas infrastructure in Ontario and the U.S. Midwest.

5.5.2 Replacement of Coal-Fired Generation in Ontario

Replacing electricity that is currently supplied from the approximately 7 500 MW of coal-fired generation in Ontario will have significant implications on future gas and electricity requirements. Not only will new incremental generation be required from other energy sources to make up almost 30 000 GW.h currently produced from coal in Ontario, but the new generation will need to consider additional challenges associated with a growing weather-sensitive load and higher reliance on natural gas.

While lessons can be drawn from experiences in the U.S. Northeast, replacement of coal in Ontario presents some additional challenges to the procurement of electricity supply and the design of electricity markets and gas services. Without significant dual-fuel generation capability or fuel options that may exist in the U.S. Northeast, natural gas will be heavily relied on for the variable electricity or the load-following capability in generation. Although additional generation from nuclear and wind sources will provide some of the coal replacement, the dispatch flexibility to follow load is most likely to come from gas-fired generation.

Significant weather-induced variation in gas requirement is to be expected, especially considering the large percentage of homes currently using natural gas and electricity in Ontario. New gas-fired generation will likely exacerbate swings in gas demand and increase requirements on gas infrastructure and operations to meet fluctuating loads.

5.5.3 Requirement for Flexible Services from Pipelines and Storage

Without the significant dual-fired generation capability in Ontario, unlike in the U.S. Northeast, a greater reliance will be placed on having adequate reserve generation to ensure availability and gas-fired generation for the rapid start and variable load-following capability. According to the IESO, Ontario's future generation supply mix will place increasing value on the reliability that may be provided from generating assets with flexibility to provide load-following capability, operating reserve and generation control. For gas-fired generation to fulfill this function, gas services from storage and pipelines must also be provided to enable corresponding load-following requirements for natural gas. These high deliverability and no-notice gas services may be provided through gas storage or pipeline services relying on system linepack or more frequent scheduling of flow changes with other interconnecting facilities.

Arguably, providing these enhanced or higher value services by pipeline and storage operators may not benefit all gas consumers. If these services are supplied through redeployment of existing capacity toward new flexible (and likely more costly) services, there will be increased costs and reduced availability of capacity to other users of less flexible services. In many cases, these would be industrial consumers whose stable baseload nature would not require the more flexible and costlier services. Alternatively, if these new services are to be provided through new infrastructure, the costs of these facilities and services should be reflected in a higher price for electricity.

5.5.4 Potential Canadian Pipeline and Storage Services

The Ontario Energy Board (OEB) has requested that potential providers of these new flexible gas transportation and storage services in Ontario submit details of their proposals. The OEB will hold a public hearing to evaluate these proposals and consider the potential costs and infrastructure requirements to provide these service options and the reliable gas supply to meet the anticipated requirement for new gas-fired generation in Ontario.

In general, the service proposals being considered by the utilities and pipelines strive to provide greater flexibility in scheduling and ability for variable flow rates to potential power generation customers. The services provide for a greater frequency in gas flow changes, and provide coordination and balancing services on pipelines, distribution and storage. All of the proposals contemplate that contracted capacity for this service will need to be reserved to enable the type of flexibility in flow that is desired.

The various proposals may differ in the degree of scheduling (frequency and size of allowed changes) flexibility and location (point specific versus area flexibility) variation that may be allowed. These potentially have a large bearing on the eventual impact on facilities and cost.

5.5.5 Potential Implications to Other Natural Gas Users

The substantial amount of incremental gas that is required for power generation in Ontario and the central region will, at the very least, increase competition for natural gas in the region and likely result in higher costs for gas supply. In addition to any impacts on the cost of gas, the proposed services for power generation may impose additional challenges to other users of current interruptible services. For example, in the lowest cost scenario (where no additional facilities are required), any capacity that is reserved for such flexible services would be taken away from capacity currently used for other discretionary and short-term services such as IT. While "bumping" of scheduled IT would not be an issue, unless there is more pipeline capacity, it is likely that there would be less IT available.

Current service proposals may vary in degree of flexibility offered in the scheduling of gas flow and whether any diversion of physical flow is allowed. Should customers require greater diversion flexibility, this may cause greater uncertainty in flows; consequently, additional facilities, with an accompanying cost would be required. The appropriate cost of new service for such flexibility would be in question. While the revenue may provide some benefit to other shippers (through reduced tolls), many will question whether the mark up is sufficient.

Whether or not the service provides flexibility in flow from point to point or includes locational flexibility (on an area-to-area basis) will be a significant factor in system operation and planning, required facilities and cost of the service.

5.5.6 Coordination of Gas and Electricity System Operations

Anticipation of load changes and ensuring that gas-fired generation is available is a significant issue faced in this region. The situation is further challenged by differences in the gas and electricity operation and markets. For gas, most adjustments to flows on pipelines are scheduled a day in advance, with a limited number of intra-day changes possible via a few fixed nomination windows. On the other hand, electricity system operation requires a close and continuous balance between electricity supply and demand and as a result, needs the ability to dispatch generation on an ongoing and near real-time basis.

These ongoing adjustments, especially for increased electricity output from a gas-fired facility in the U.S. Northeast are not always assured, as they depend on the availability of gas, interruptible pipeline capacity and ability to schedule corresponding gas flows. Although additional services are being developed to provide balancing and storage or more flexibility to make gas flow adjustment, currently these are provided at either much higher cost or at the discretion of providers depending on availability.

5.5.7 Electricity Market Design in Ontario

Market prices in Ontario will need to recognize locational and operational requirements for these new electricity generating facilities and provide an appropriate mechanism to ensure generation is constructed in the right locations and that operators are compensated for variable operation to provide a reliable and effective supply of electricity. While some incremental electricity can also be supplied through greater transfers of power across regions, this may require additional electricity transmission from adjacent regions such as Manitoba. Electricity imports may also be possible from parts of the midwest although it could be difficult to justify larger imports from coal-dominated regions.

The Ontario wholesale power market is a "hybrid" composed of controlled pricing for most of the hydro, nuclear and other thermal assets of Ontario Power Generation Inc. (OPG), which currently account for about 70 percent of generation. Prices currently range between $33 and $49/MW.h and are subject to change based on regulatory decisions. While OPG's involvement in the market would be expected to decline as more supply is developed by IPPs, OPG still has some nuclear generation to bring back on line and presumably would be involved in any new nuclear developments in the future.

A growing part of the Ontario market is composed of requests for proposals (RFPs), currently issued by the OPA and effectively backed by the Ontario government. These are long-term, contract-based arrangements based on negotiated prices. They are composed of natural gas, wind and other cleaner and greener supply sources. Typically gas-based RFPs have been "accepted" in the range of $75–$85/MW.h. The remainder of generation (i.e., all non-OPG and non-RFP generation) is sold at the market rate in the wholesale market, which is influenced by prices for wholesale market transactions in adjacent states and provinces (over the past year, power prices in the Ontario power pool have been in the range of $50–$100/MW.h).

Overall, this structure can provide considerable price certainty to the final consumer as LDCs are effectively able to acquire much of their power at fixed prices. From the standpoint of power generators using natural gas, however, they are still subject to price and supply risks associated with natural gas. Even if they have an RFP they are still subject to the risk of their plants not being competitive in the Ontario wholesale market. The nature of the risk is that a power generator has to decide if the anticipated power price will cover its costs, at least gas costs and other variable costs.

If the arrangements for gas supply and power sales have the same timing, the required spread between power prices and gas supply can be "locked in." However, if there is a difference in the timing, the generator faces the risk of the market circumstances changing causing a profitable transaction to disappear or fail. In the case where the timing is different, the generator has two choices:

(a) commit to gas supply assuming that its power plant will be dispatched; or

(b) commit to selling the power, not being assured whether the gas supply (transportation arrangements) will be available.

In the first case, if the power market price drops making the gas purchase uneconomic, the generator must still pay for gas transportation and any other costs associated with not taking the gas (imbalance penalties). In the second case, the generator is faced with paying the charges associated with purchasing make-up power. These risks add to the cost of doing business.

According to 2004 data from the IESO, coal-fired generation set the price of electricity 56 percent of the time in the Ontario wholesale market, including peak and off-peak periods, and sets the price of gas about 30 percent of the time. When gas generation set the price, it is more than twice as high (about $78/MW.h, versus about $33/MW.h for coal). It follows logically that increased gas-fired generation in Ontario will likely result in higher electricity prices due to greater frequency in setting the price of electricity, greater operational flexibility required in gas supply and services to serve the electric power generation sector, and the potential risks inherent with timing differences between gas and electricity markets.

OBSERVATIONS AND CONCLUSIONS

Over the past twenty years, North America has witnessed rapid development in natural gas-fired generation as natural gas has been the fuel of choice for new power generation, especially in the United States. Since 1990, the “dash to gas” has resulted in the doubling of the amount of natural gas-fired generation in the United States. In fact, over the last five years, total generating capacity in the United States has increased by over 25 percent with natural gas-fired generation accounting for 96 percent of the additional generation.

In Canada, the development of electricity generation has been at a slower pace as demand for electricity has been relatively stable. Further, regions across Canada have had many other well-established generation options such as hydro-electric power and coal. Nonetheless, the share of Canada’s total generating capacity attributable to natural gas-fired generation has increased from four percent in 1995 to about ten percent today. This trend is likely to intensify in Canada. The amount of gas-fired generation in Alberta is expected to triple in the coming years, primarily for use at oil sands developments. Similarly, in Ontario, the replacement of coal-fired generation is expected to spur additional natural gas-fired generation.

The significant growth in natural gas-fired generation capacity in North America has stemmed from its low capital cost, a relatively short construction lead time for gas-fired plants, low natural gas prices (especially during the summer or cooling season) throughout the 1990s, and the preference for natural gas over other fossil fuels for its cleaner burning properties. Moreover, there has generally been less public opposition to building new natural gas-fired plants than to building coal-fired or nuclear facilities.

Despite the rapid growth in natural gas-fired generation in North America, which resulted in an “overbuild” of capacity in certain regions, the development of new gas-fired generation facilities is expected to continue, albeit at a slower pace. These new gas-fired generators employ rapidly evolving technologies that provide significant cost advantages by being more efficient than older facilities. This increased efficiency is particularly important as natural gas prices have increased with the growing tightness of natural gas supply and demand.

As the contribution from natural gas-fired generation increases, the relationship between gas and power markets will continue to strengthen within many regions. Not only will electricity prices be influenced by that of natural gas but, with power generation becoming the fastest growing sector of natural gas demand, natural gas prices will also be increasingly influenced by electricity markets. This growing interdependency may contribute to higher costs for natural gas and electricity that will have to be absorbed by a range of energy consumers.

Moreover, the substantial and rapid increase in reliance on natural gas to generate electricity has led to uncertainties regarding the adequacy of natural gas supply and existing natural gas infrastructure. For example, in some regions, existing constraints in natural gas or electricity infrastructure would be exacerbated by further development of gas-fired generation; consequently, the reliability of future natural gas and electricity supply is of growing concern.

In some regions, new infrastructure and services will be needed to meet the challenges stemming from further development of gas-fired generation. These services could include increased flexibility through the use of gas storage, flow diversion or balancing services on pipelines to bridge the natural gas and electricity operations. Such provisions would enable service providers to offer frequent flow changes in gas flow rates and enable the reliable and timely service that is needed to serve fluctuating and weather-sensitive electricity and natural gas markets. However, these types of services would, in some cases, require dedicated infrastructure, which entails costs for construction or taking away from capacity currently used for other natural gas services.

Looking forward to the challenges presented by the increasing interdependency between the natural gas and electricity markets, there are also accompanying opportunities for further discussion and debate amongst policy-makers, regulators, energy consumers and the energy industry. In this connection, the Board poses the following questions as potential areas for stakeholders to examine.

What are the advantages/disadvantages of increased reliance on natural gas for electricity generation?

Beyond the economic and environmental benefits of natural gas-fired generation, expectations of higher gas and electricity prices combined with the risk of diminished reliability raise the question as to whether there should be a debate or expanded discussion on the impacts of increasing the use of natural gas to generate electricity. Other consumers of gas, whether small residential and commercial customers or large industrials, may face higher energy costs as a greater portion of natural gas demand becomes increasingly weather sensitive. Further, some of these consumers may be challenged to compete with gas-fired generators for supplies of natural gas and related transportation services.

Given the tightness in the gas market, has fuel diversity for electricity generation been examined closely enough across various jurisdictions?

Notwithstanding the factors that have led to the rapid growth in natural gas-fired generation over past years such as higher efficiency and flexibility to respond to the demand load, does heavier reliance on natural gas lead to reliability concerns? Fuel diversity can play a key role in stabilizing energy costs as well as mitigating reliability concerns. Further, it may be reasonable to consider and potentially support the strategic use of some traditional fuels (e.g., coal, oil) to improve reliability. Diversity of the fuel mix could also be achieved through the provision of incentives to enable the development of alternative technologies. At the same time, there may be challenges associated with expanding fuel diversity beyond any one region because of the inter-regional relationships amongst energy markets.

Is the appropriate suite of services available to support continued use of gas-fired generation?

Considering the development of gas-fired generation that is underway or expected in the near term, pipelines, storage operators and market participants may need to adjust quickly to offer flexible services to electricity generators to better align the gas and electricity markets. Such services would bridge the gas market, which is scheduled on a daily basis and the electricity market, which adjusts in almost real time. Further, with existing delivery constraints in the gas and electricity markets, society may need to be willing to commit to new infrastructure and accept higher costs for firm services. This leads to questions of how the appropriate suite of services that is needed to enable efficient and flexible operations of electricity and natural gas systems can be developed and if there is a role for government to coordinate the markets.

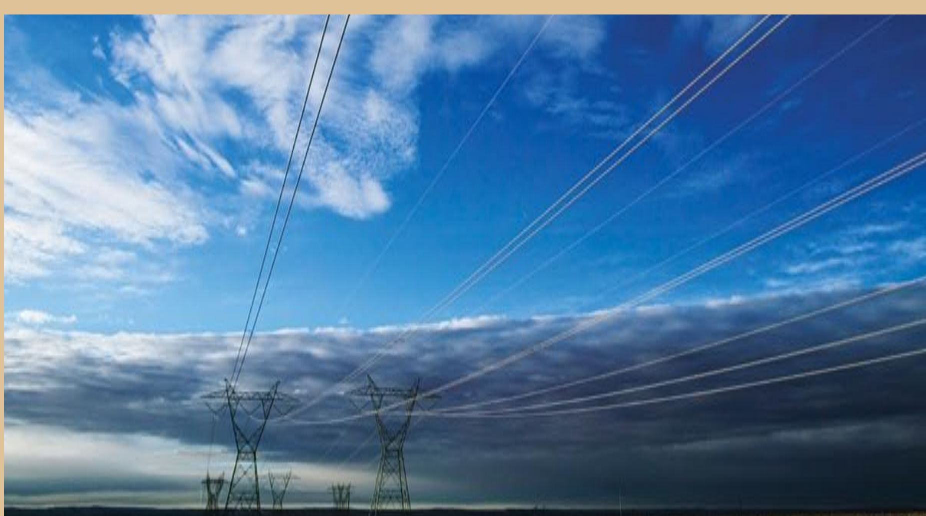
What is the appropriate role for government in ensuring adequate generation?

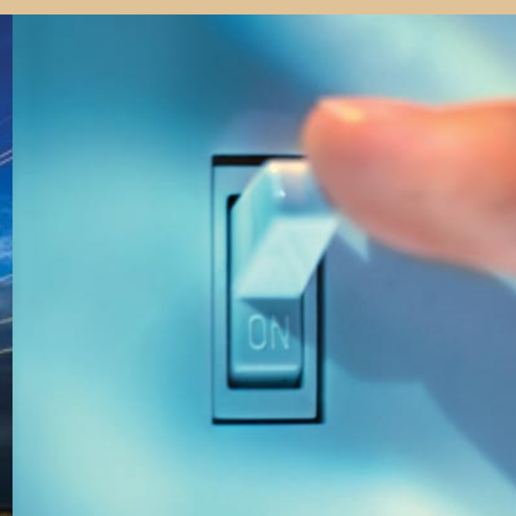
In order to ensure adequate generation, government may be requested to play a larger role through incentives, investment or policy. For example, government may be requested to consider providing incentives that would encourage the appropriate investment at specific locations that are currently strained. Would it be in the public interest to support market mechanisms that ensure an adequate amount of generation is available to provide load-following requirements to meet weather sensitive demand? Beyond this, there may be a need for longer-term solutions to growing electricity demand. The path to date has been to follow market signals. However, are these matters for the market to solve on its own or is there a role for policy-makers within the public interest mandate of government?

There are no obvious simple answers to these questions. The Board offers these questions, however, to stimulate the needed debate on very important issues and uncertainties facing Canada's energy future. Further, the Board will be examining the role of natural gas as a part of its analyses in its next report that examines Canada's energy futures, to be released in fall 2007.

GLOSSARY

backhaul service	The transportation of natural gas by displacement on a pipeline system so that the natural gas is delivered upstream of its receipt point.
basis or price differential	The difference in gas prices between two trading points.
cogeneration	A generating facility that produces electricity and another form of useful thermal energy, such as heat or steam as a by-product of generation.
distillate fuel oil	A refinery product that is used primarily for space heating.
energy banking	The storage of water in a reservoir during off-peak times to be released for generation during peak times.
interruptible transportation (IT)	Gas service provided to customers that may be curtailed due to supply or system capacity limitations.
linepack	The amount of gas in a pipeline system that can be adjusted by increasing or decreasing the pipeline pressure.
market heat rate	The ratio of electricity price to gas price.
nomination window	The period of time that a request for service can be made pursuant to a service agreement.
Peaker power plants	Power plants that generally run only when there is a high demand for electricity.
Renewables energy or renewables	Energy sources capable of being renewed by the natural ecosystem (e.g., wind, biomass, solar energy and hydro resources).
reserve margin	The amount of unused available capacity of an electric power system at peak load as a percentage of total capacity.
residual fuel oil	The remaining refinery product after the removal of the more valuable fuels such as gasoline, jet fuel, diesel and heating oil. It is used primarily for power generation and fuel for various industrial processes.
spark spread	The difference between the selling price of electricity and the cost of the fuel used to generate it.

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