National Energy Board
Office national de l'énergie

Canadian **Natural Gas** Market

Dynamics *and* **P**ricing

gas gas gas gas

An **ENERGY MARKET ASSESSMENT** • November 2000

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ACRONYMS

ABC-T Service	Agency Billing and Collection Transportation Service
ABM	Agent/broker/marketer
AECO-C	Alberta Energy Company storage facility
AECO-C/NIT	Alberta Energy Company/Nova Inventory Transfer
AEUB	Alberta Energy and Utilities Board
BCUC	British Columbia Utilities Commission
CPL	Champion Pipe Line Corporation Limited
CWNG	Canadian Western Natural Gas Company Limited
EMA	Energy Market Assessment
GMi	Gaz Métropolitain and Company, Limited Partnership
GSX Project	Georgia Strait Crossing Project
LDC	Local distribution company
LFO	Light fuel oil
M&NP	Maritimes and Northeast Pipeline
MBP	Market-Based Procedure
MIPL	Many Islands PipeLines Ltd
NBPUB	New Brunswick Board of Commissioners of Public Utilities
NEB	National Energy Board
NGL	Natural Gas Liquid
NGMA	Natural Gas Market Assessment
NGX	Natural Gas Exchange
NSURB	Nova Scotia Utilities and Review Board
NUL	Northwestern Utilities Limited
NYMEX	New York Merchantile Exchange
OEB	Ontario Energy Board
PBR	Performance-Based Regulation
PNGTS	Portland Natural Gas Transmission System
PNW	Pacific Northwest
Régie	Régie de l'énergie du Québec
PUBM	Public Utilities Board of Manitoba
SCP	Southern Crossing Pipeline Project
SOEP	Sable Offshore Energy Project
T-service	Transportation service
TCGS	TransCanada Gas Services
TCPL	TransCanada PipeLines Limited
TEP	TransGas Energy Pool
TQM	Trans Québec & Maritimes Pipeline Inc.
WACOG	Weighted average cost of gas
WCSB	Western Canadian Sedimentary Basin

METRIC TO IMPERIAL

Metric	**Imperial Equivalent Units**
1 cubic metre of natural gas	= 35.301 01 cubic feet (14.73 psia and 60ºF)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf

UNITS

Prefix	**Multiple**
MMcf	= million cubic feet
Bcf	= billion cubic feet
Tcf	= trillion cubic feet
GJ	= 10^9 joules
Btu	= British thermal unit

FOREWORD

The National Energy Board (the NEB or Board), as a part of its regulatory mandate, continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and their by-products) and the demand for Canadian energy commodities in both domestic and export markets.

In 1987, the Board adopted the Market-Based Procedure (MBP) for assessing applications for long-term natural gas export licences. The MBP is based on the premise that the marketplace will generally operate such that Canadian requirements for natural gas will be met at fair market prices. The MBP consists of a public hearing component and a monitoring component.

The monitoring component of the MBP involves an ongoing assessment of Canadian energy markets and results in the publication of *Canadian Energy Supply and Demand* reports as well as a series of *Natural Gas Market Assessment (NGMA)* reports. As a result of the increasing level of integration within energy markets, the Board has implemented a program of Energy Market Assessments (EMA) to provide analyses of the major energy commodities on either an individual or integrated commodity basis. The EMA program includes what were previously known as NGMAs as well as the *Canadian Energy Supply and Demand* reports.

This EMA, entitled *Canadian Natural Gas Market Dynamics and Pricing*, identifies the factors that affect natural gas prices and describes the current functioning of regional markets in Canada.

It does not provide a short-term outlook for supply, demand and prices in Canada. The Board is currently assessing the short-term natural gas supply from the Western Canada Sedimentary Basin. More information on this project will be provided in the near future.

During the preparation of this report, a series of meetings and discussions were conducted with a cross-section of the natural gas industry including producers, gas marketers, local distribution companies, consumer groups, end-users, industry associations and government agencies. The Board appreciates the information and comments it received.

INTRODUCTION

From 1975 to 1985, the price of Alberta natural gas sold to other provinces was regulated by the Governments of Alberta and Canada. The price of gas sold within Alberta and the other producing provinces was regulated by the corresponding provincial government. On 31 October 1985, the Governments of Canada, British Columbia (B.C.), Alberta and Saskatchewan signed the *Agreement on Natural Gas Markets and Prices*. The premise behind the Agreement was that competitive natural gas markets would better serve the needs of Canadian producers and consumers. For the first time, end-users in non-producing provinces were able to purchase gas directly from producers at negotiated prices. An important part of the market deregulation initiative was the assurance of non-discriminatory and flexible access to gas transportation services for all shippers.

Although gas sales were deregulated, the governments recognized that, due to the monopoly characteristics of the natural gas transmission and distribution systems, there was a continuing need to regulate them. Interprovincial and international transmission systems are regulated by the National Energy Board. The tolls are determined through a public hearing process or through settlements which are negotiated between pipeline companies and shippers. The local distribution systems are regulated by provincial regulatory bodies or directly by a provincial government.

Since 1985, Canadian natural gas prices have generally been lower than they were prior to deregulation. During this time, natural gas consumption in Canada increased by some sixty percent and, similarly, growth in gas consumption in the United States has been substantial. Canadian natural gas producers have responded to this growing market - gas production has doubled over the past fifteen years. Today, Canada supplies one-quarter of the natural gas requirements of North America[1] including 15 percent of gas demand in the United States.

The robust growth of the North American natural gas demand is expected to continue. At the same time, the growth in Canadian and U.S. gas supplies over the past two years has been sluggish. Consequently, this has led to a tightening in North American gas supplies with the result that North American gas prices have increased significantly over the past year. Natural gas users throughout Canada have expressed concern about the current high prices. It is in this context that this EMA is undertaken.

1 For the purpose of this report, the North American natural gas industry is defined to be Canada and the United States. It does not include Mexico because of the lack of significant infrastructure connections.

Context for Natural Gas Pricing in Canada

The purpose of this EMA is to examine the functioning of the Canadian gas market with particular focus on explaining natural gas pricing in Canada. However, to understand how pricing works in Canada, it is necessary to understand the broader context within which the Canadian natural gas industry is situated. This chapter provides a brief discussion of overall energy demand and world oil prices.

2.1 Overview of Energy Demand

Economic growth in North America has been strong over most of the past decade, leading to ongoing growth in energy demand, albeit at a slower pace than the growth in the economy. The slower growth in energy is due to a number of factors including: improved efficiency in energy use, faster growth in the less energy-intensive sectors of the economy (including services) and, to some extent, weather conditions.

Of note, the growth in electricity demand has been faster than the growth in overall energy demand, partly due to increased use of computing equipment in all sectors and increased use of electrical appliances (air conditioning, exterior lighting, home entertainment systems, refrigeration, etc.).

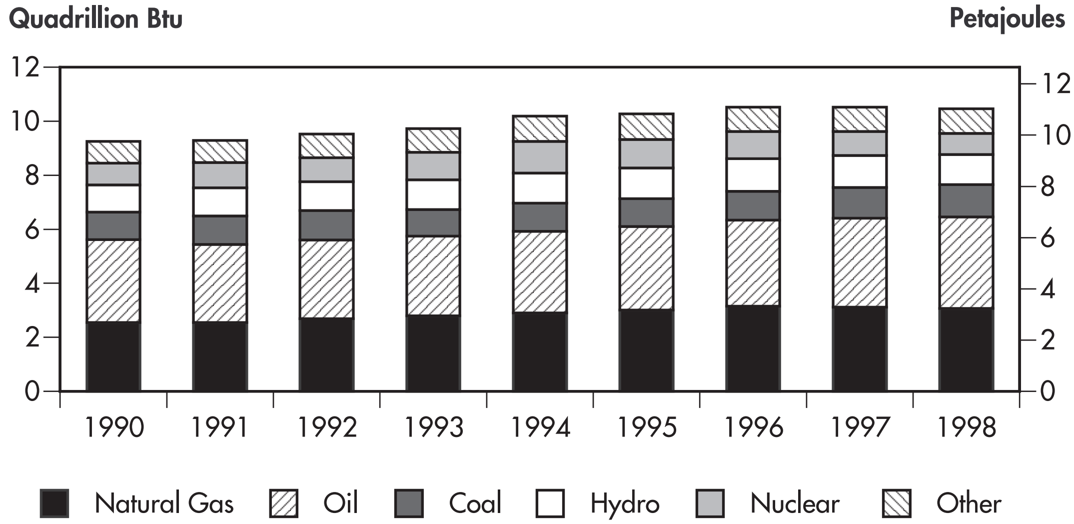
Canada and the United States rely primarily on oil to satisfy their energy needs (Figures 2.1 and 2.2). Natural gas use is also significant as it accounts for 29 and 24 percent of Canadian and U.S. energy needs respectively. Together, these two energy sources meet more than 60 percent of North American energy demand. Coal accounts for approximately 50 percent of electricity generation in the U.S. while hydro resources account for over 60 percent of electricity generation in Canada. Nuclear energy also makes a significant contribution to electricity generation in both countries.

Natural gas is primarily used for space heating in residential and commercial buildings, as a feedstock for the petrochemical industry, and as an energy source to produce steam for industrial purposes. During the past decade, natural gas has been increasingly used to generate electricity, particularly in the United States.

There are a number of energy sources that can substitute for natural gas. For example, both oil and electricity can be used for home heating, oil and natural gas liquids can be used as feedstock in the petrochemical industry, and both oil and coal can be used to produce steam in the industrial and electric generation sectors.

F I G U R E 2 . 1

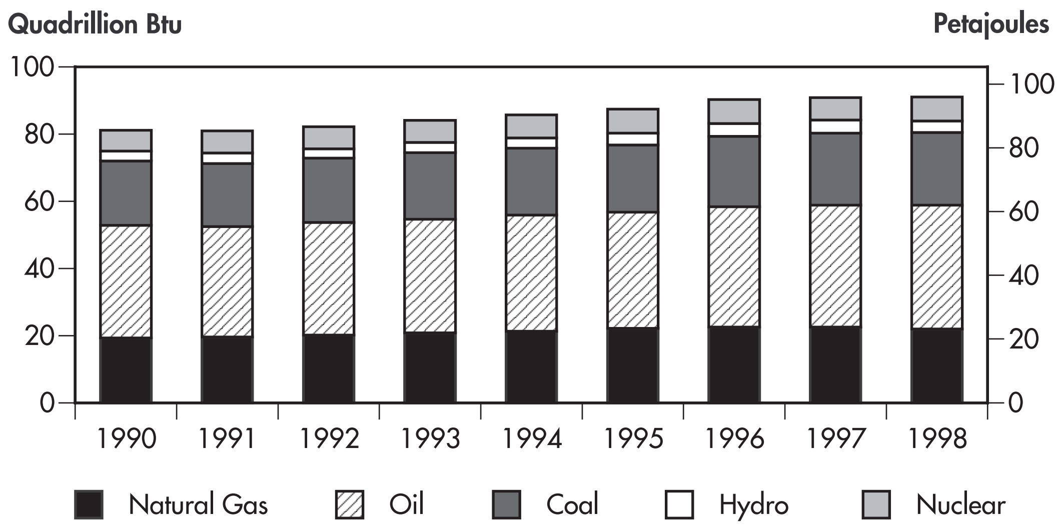
Canadian Energy Consumption 1990-1998



Source: Statistics Canada

F I G U R E 2 . 2

U.S. Energy Consumption 1990-1998



Source: U.S. Department of Energy

2.2 Recent Trends

A major trend in recent years has been the greater reliance on natural gas to provide the energy for new electricity generation projects. Natural gas combined-cycle and cogeneration power plants can be built more quickly and with lower capital costs than alternatives. As well, clean air legislation in the United States favours the use of natural gas. Thus, most observers have been predicting rapid increases in demand for natural gas as electricity demand grows.

For decades, natural gas has competed with fuel oil in industrial markets. For this reason, a number of large industrial users have developed the capability to quickly switch between these fuels, depending on price and availability.

Oil prices made a pronounced upward move commencing in March 1999. This increase followed a period of low prices which resulted from, among other factors, weak oil demand in the aftermath of the economic and financial difficulties in southeast Asia. Recent prices in the range of US$30-$35 per barrel are comparable to the highs reached during the Middle East crises in 1979/80 and 1990/91. The oil market has witnessed dramatic adjustments to price changes in the past, both on the demand side and the supply side. Thus, it is uncertain how long these recent higher prices will be sustained.

Changes in oil prices will tend to affect natural gas prices to the extent that oil products and gas compete in end-use markets. Trends in recent months, when both markets were tight, suggest a close relationship exists between higher oil prices and higher gas prices. While the relationship and timing are imprecise, it can also be expected that lower oil prices would lead to lower gas prices (Figure 2.3).

Increased use of gas for power generation has caused natural gas prices to be influenced by electricity prices as a result of the convergence of gas and electricity markets. Convergence has been facilitated by the restructuring of the electricity and natural gas industries as the markets for electricity and natural gas have been deregulated, and the price of the energy has been unbundled from the transportation costs.

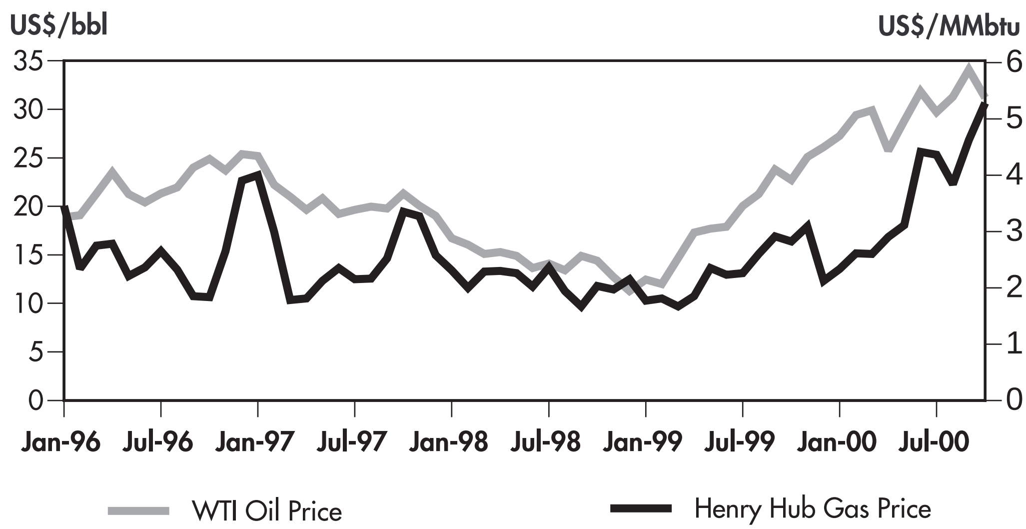
It is important to note that the ability to substitute one fuel for another varies considerably across regions and industries. In many cases, it is possible to substitute between fuels but only with considerable investment and a time lag. For example, most homeowners are unwilling to change their furnaces just because natural gas may enjoy a price advantage over fuel oil at a point in time. Finally, in some markets, such as transportation, there is still a very limited ability to substitute for oil.

2.3 Summary

The natural gas market is becoming more closely linked to the oil and electricity markets. The more closely energy markets are linked, the more closely movements in fuel prices are expected to follow one another.

FIGURE 2.3

Oil and Natural Gas Commmodity Prices



Source: Petroleum Industry Research Associates (PIRA).

Overview of North American Gas Supply and Markets

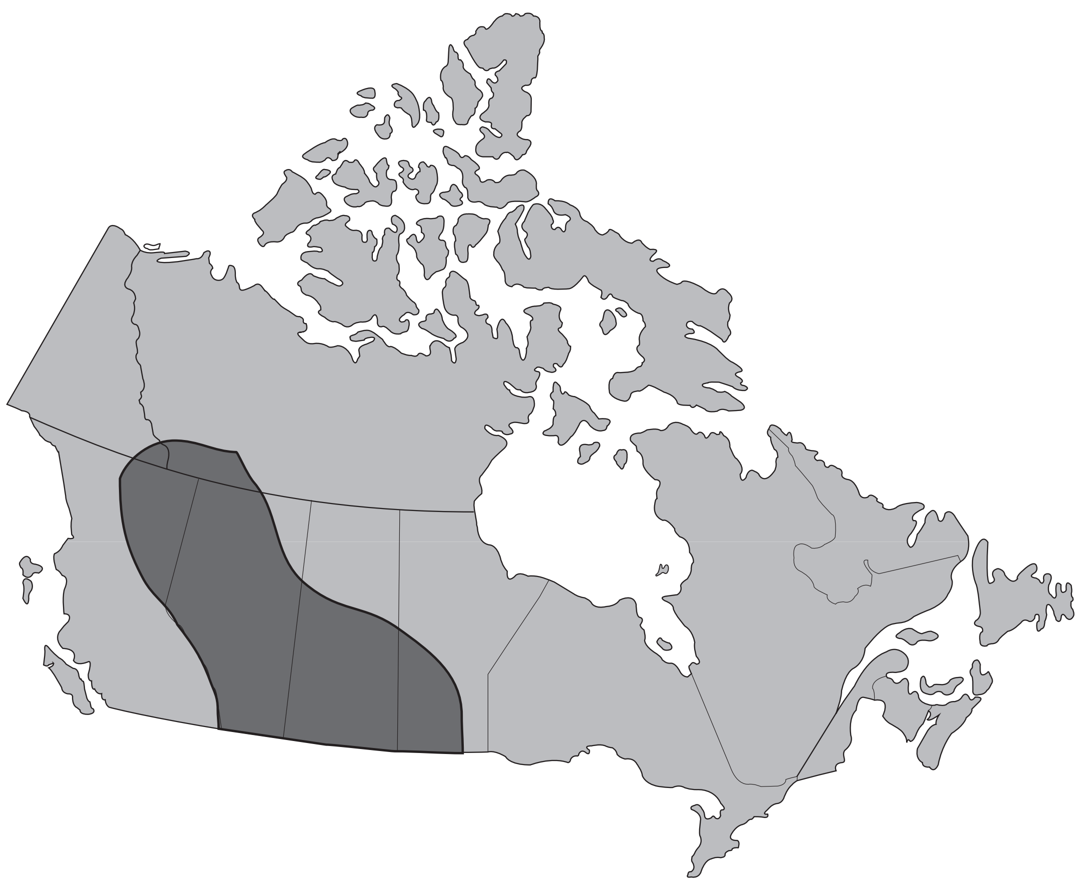
3.1 North American Gas Supply

Canada

Natural gas in Canada is primarily located in the Western Canada Sedimentary Basin (WCSB). This is a geologic region which includes most of Alberta, significant portions of British Columbia and Saskatchewan, as well as parts of Manitoba and the Northwest Territories (Figure 3.1). Other areas containing natural gas reserves are Ontario and offshore Nova Scotia.

FIGURE 3.1

Western Canada Sedimentary Basin



Remaining gas reserves[1] in Canada are estimated to be 1 606 10^9m^3 (56.7 Tcf) as of year-end 1999. The WCSB accounts for 1 517 10^9m^3 (53.6 Tcf). Offshore Nova Scotia is estimated to hold 85 10^9m^3 (3 Tcf) of gas reserves while Ontario is estimated to have 13 10^9m^3 (450 Bcf) as of year-end 1999.

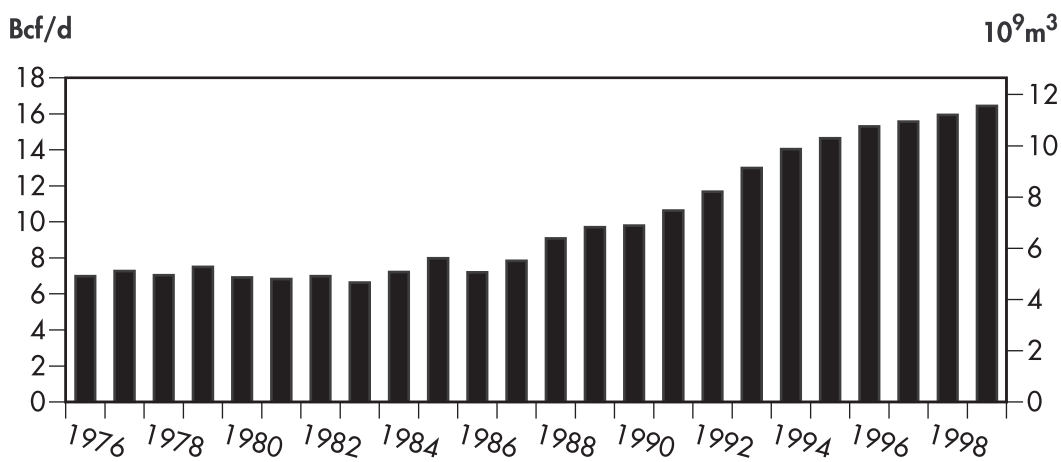
Since 1985, natural gas production has more than doubled (Figure 3.2). Canadian natural gas production in 1999 totalled 170.3 10^9m^3 (6.0 Tcf), essentially all of which was produced from the WCSB[2]. This corresponds to an average production of about 465 10^6m^3 per day (16.4 Bcf/d), causing the WCSB to rank as one of North America's most productive basins. Moreover, the WCSB accounts for a quarter of North American gas production. Of this, Alberta accounted for 83 percent of total Canadian production while British Columbia and Saskatchewan contributed 12 and four percent, respectively.

The natural gas producing sector is very competitive. There are hundreds of companies which are active in exploration and production of natural gas, all of which compete for a share of the gas market.

In late 1998, export capacity was increased substantially and another major expansion is expected to be in service by November 2000 (section 3.2). The producing sector responded to enhanced access to markets and to higher natural gas prices in 1999 by drilling a record 6,300 gas wells (Figure 3.3). Expectations are that the producing sector will surpass this record level of drilling in 2000. At the same time though, the average productivity from wells in the WCSB has been declining and this trend has been tempering production increases from higher drilling activity.

FIGURE 3.2

WCSB Production

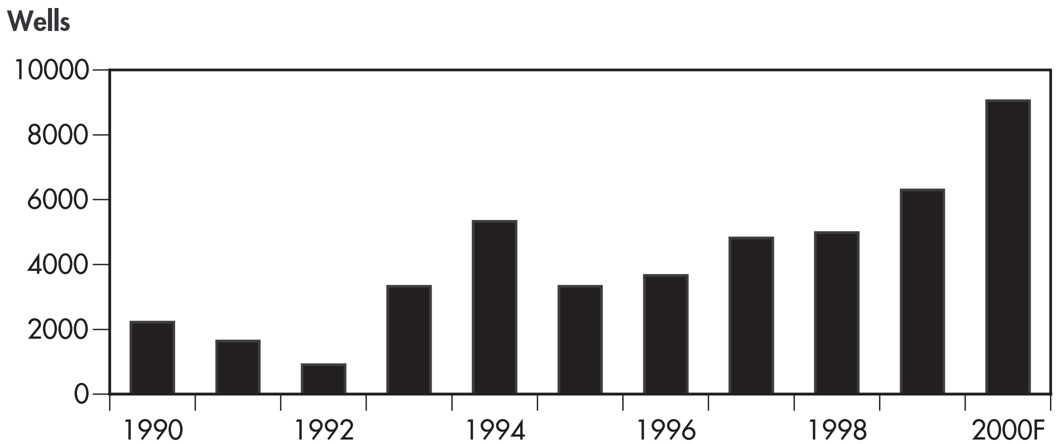


1 Gas to be recovered from a reservoir taken into account the amount of reserves recovered to date.

2 Ontario also produced a minor amount of natural gas.

FIGURE 3.3

Natural Gas Wells Drilled in Canada



Recent Developments

The end of 1999 marked the commencement of production from Sable Island, offshore of Nova Scotia. By mid-2000, production from this area had reached as high as 14.2 10^6m^3 per day (0.5 Bcf/d). Production from Sable Island is currently being exported to New England. Distribution systems in the Maritimes are expected to commence flowing gas to customers later this year. It is expected that the domestic market will consume up to one-third of production from Sable Island within the next two years.

Following discoveries by Chevron and Paramount in 1999, gas production began this year from the Fort Liard area in the Northwest Territories. Production from this area reached 7.1 10^6m^3 (250 MMcf/d) and flows into British Columbia where it connects to the pipeline grid.

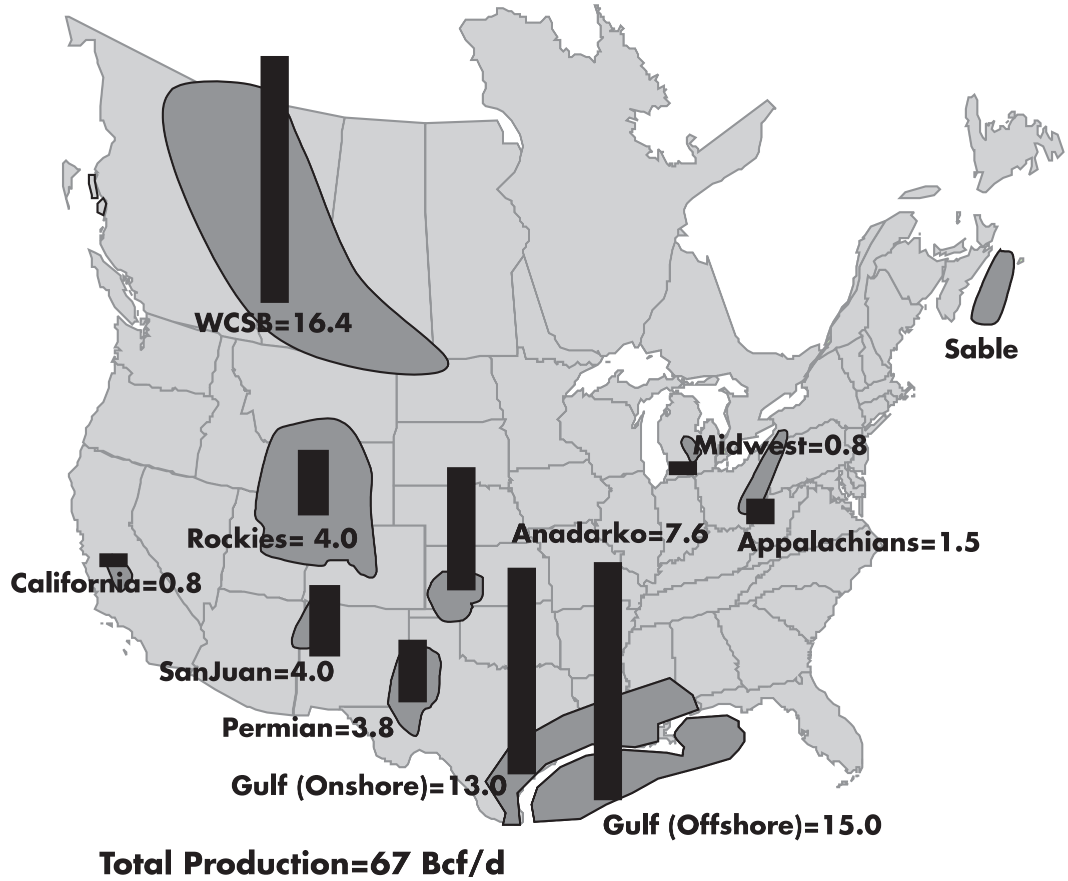
United States

In contrast to Canada, gas supply in the United States is found in several basins. There are a half-dozen major natural gas basins in the United States with the onshore and offshore areas of the Gulf of Mexico being the most significant (Figure 3.4).

Remaining gas reserves in the lower 48 States are estimated to be 4 475 10^9m^3 (158 Tcf) while gas production in 1999 averaged 1.4 10^9m^3 per day (50.5 Bcf/d) - a slight decline from the previous year. About half of total U.S. production comes from the onshore and offshore areas of the Gulf of Mexico in approximately equal proportions. The latter area in particular is key in terms of total U.S. production. Gas production from the offshore Gulf of Mexico is very sensitive to drilling activity. During the low oil price environment of 1997/1998, drilling activity and hence, gas production, decreased resulting in a direct impact on total U.S. production. A recovery in production from the offshore Gulf of Mexico, and total U.S. production, has been sluggish. This, in turn, has led to considerable speculation on the ability of North American gas supply to meet demand in the short-term.

FIGURE 3.4

North American Gas Production 1999



3.2 Canadian Gas Transportation Systems

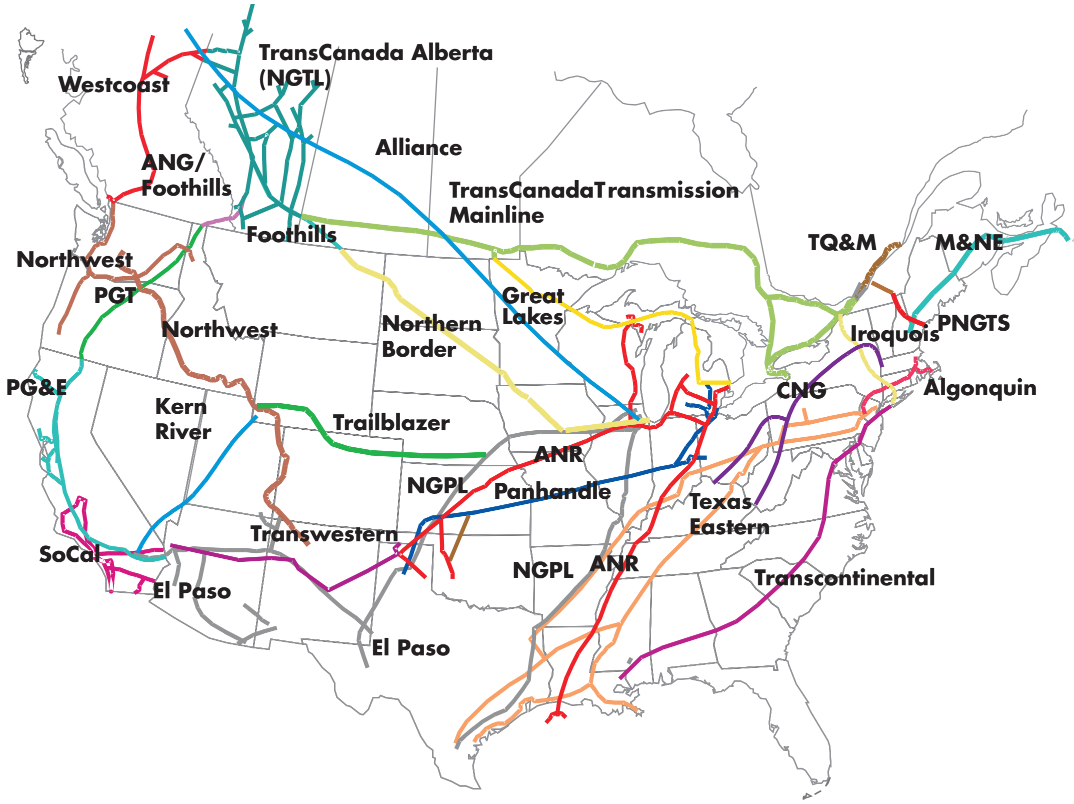
Canada is part of an integrated North American natural gas market as shown by the many thousands of kilometres of pipelines which connect supply basins with regional markets (Figure 3.5). Today, buyers can purchase natural gas from a number of supply sources and have that gas delivered through numerous pipeline interconnects.

The Canadian pipeline grid consists of gas gathering, transmission, and distribution systems that transport processed natural gas. Once natural gas is produced, it is processed at gas plants to remove any impurities such as sulphur. The processed gas is then collected by gathering systems which feed into transmission pipelines. These transmission pipelines typically transport large volumes of gas at high pressure over long distances from supply sources to market centres.

The Canadian gas market is served by several major transmission pipelines which also interconnect with the U.S. pipeline grid at a dozen export points. TransCanada PipeLines Limited (TCPL) is one of the largest carrier of natural gas in North America. Through its ownership of the TransCanada Alberta system (formerly NOVA Gas Transmission Limited), TransCanada Transmission Mainline (TCPL-Mainline), the TransCanada - B.C. System (formerly Alberta Natural Gas Pipeline) and its majority interest in Foothills Pipe Lines Ltd., it moves about 12 Bcf/d of Alberta gas on its system. Interprovincial and international pipeline transportation systems are regulated by the NEB.

FIGURE 3.5

Canadian and U.S. Natural Gas Pipelines



Distribution systems are the retail component of the pipeline industry. Local distribution companies (LDCs) receive gas off the transmission pipelines and deliver it to end-users, such as homes, within a franchise area. The LDCs are regulated by provincial regulatory boards or commissions or directly by a provincial government.

Gas storage is an important element of the gas transportation system and is located in both producing and consuming regions of North America. When production exceeds demand (usually in the summer season) producers will deliver the excess gas to storage sites and will withdraw it to supplement production when demand is high (usually in the winter heating season). Storage facilities are also used for pipeline load balancing, supply security (e.g. in the event of pipeline rupture) and price risk management.

In Alberta, the largest storage facility, AECO-C, is operated by Alberta Energy Company. Located near Suffield, AECO - C facilities are connected to the TCPL-Alberta system, which provides it with access to all major transmission pipelines leaving the province.

Recent Developments

The Alliance pipeline system is expected to commence service by November 2000. This pipeline will have an initial capacity to deliver some 37 $10^6m^3/d$ (1.3 Bcf/d) from the WCSB to the Chicago area. The Vector pipeline system is also expected to be in service this fall. This system will be able to transport up to 20 $10^6m^3/d$ (700 MMcf/d) from the Chicago area into southwestern Ontario. Buyers in Ontario (and even Quebec) will thereby be provided with the option of obtaining supply from the

WCSB (or U.S. supplies) through the Alliance and Vector systems instead of the historical route via the TCPL-Mainline system.

3.3 North American Gas Markets

The combination of rapid economic growth, a preference for gas-fired electricity generation in the United States, and low gas prices led to sustained growth in gas demand throughout the 1990s. Canadian gas now meets over 25 percent of North American demand. Since 1995, exports of Canadian gas have exceeded domestic consumption with gas exports accounting for about 55 percent of Canadian production in 1999. Nonetheless, all Canadian gas demand continues to be met by production from the WCSB.

Gas demand might have been higher in recent years, but there have been a succession of warmer-than average winters that have reduced the demand for gas space heating during the winter months. This reduction was somewhat offset by a series of hot summers in the U.S., resulting in increased demand for gas for electric power generation during the summer to meet the air conditioning load.

Domestic Market

Natural gas met almost one-quarter of total Canadian energy demand last year - second only to oil. Alberta and Ontario are the primary consumers of natural gas in Canada and together account for about two-thirds of the domestic market, which totalled 68 $10^9 m^3$ (2.7 Tcf) or about 210 $10^6 m^3$/d (7.4 Bcf/d) in 1999. Further details of the domestic gas market are contained in Chapter 4.

Export Market

Since 1985, the level of exports quadrupled to 95 $10^9 m^3$ (3.4 Tcf). Canadian gas now meets about 15 percent of U.S. demand compared with four percent in 1985. The revenue generated from natural gas exports has also grown substantially reaching some $11 billion in 1999.

As gas exports have grown, there has been a trend toward exporting gas on a short-term basis, under authorizations that have a duration of two years. In 1999, short-term exports accounted for nearly three-quarters of Canadian gas exports. This trend is primarily attributable to unbundling in the U.S, which led to pipeline companies divesting their merchant role to, primarily, gas marketing companies. Pipeline companies used to contract long-term supplies (up to 25 years) while gas marketing companies use a portfolio of supply contracts and trade gas on a daily basis.

The U.S. Midwest is Canada's primary gas export market, accounting for nearly 40 percent of Canadian exports in 1999. The U.S Northeast, which includes New England and the mid-Atlantic states of New York, New Jersey and Pennsylvania, consumed about one-quarter of exports in 1999. California and the Pacific Northwest accounted for 20 and 15 percent of exports respectively. With the commencement of production from Sable Island in early 2000, and with the Alliance pipeline being placed in service in late 2000, exports to the U.S Midwest and Northeast regions are expected to increase.

3.4 Summary

Canadian and U.S. gas markets have increasingly evolved into an integrated North American market. Natural gas can be bought from many supply sources and delivered to any market centre through an extensive North American pipeline grid. With the increased integration of the markets, regional supply and demand forces are felt throughout the marketplace. Chapter 4 will examine the pricing of natural gas in more detail.

NATURAL GAS PRICING DYNAMICS IN CANADA

4.1 Change in Natural Gas Contracting Practices

Since 1985, gas sales practices have changed significantly. As mentioned earlier, contracts have become increasingly short-term. Furthermore, pricing is market responsive as prices are determined through index-based mechanisms which fluctuate either monthly or daily. The homogenous nature of natural gas has permitted the development of a larger and more competitive gas market.

Today, natural gas is traded like any other commodity, with the price determined by supply and demand. An active spot market[1] has developed at various locations across North America. Some pricing points have become hubs. Hubs are typically market centers where several pipelines interconnect and where numerous buyers and sellers trade gas, thereby creating a liquid pricing point. The level of liquidity is primarily determined by the volumes traded, and the number of transactions and players.

Spot markets have had a significant impact on the pricing of natural gas. The pricing in many sales contracts, including long-term contracts, is based on monthly indices in the relevant market region. The emergence of electronic gas trading systems enhanced price discovery by providing timely information to market participants. There are three main trading systems in Alberta: Natural Gas Exchange (NGX), Enron-on-line and Altrade.

The AECO-C/NIT[2] hub is the main pricing point for Alberta natural gas with about 12 Bcf/d, on average, of gas flowing through this point. Other hubs in Canada include Sumas/Huntingdon, British Columbia and Dawn, Ontario. Sumas is not as liquid as AECO-C/NIT as there are a limited number of transactions occurring and gas flows average about 1.6 Bcf/d. Dawn is a fast growing hub with gas flow averaging about 3 Bcf/d.

4.2 Integration of the Natural Gas Market in Canada and the U.S.

Since 1985, the Canadian and U.S. market has become more integrated. In a fully-integrated competitive gas market, the price of gas in one region should differ from the price in another region only by the cost of transportation. For example, suppose that the price of natural gas in the U.S. was higher than in Canada. In such a situation, natural gas exporters would prefer to sell in the U.S.

1 The spot market includes all transactions for sales of 30 days or less, but most typically refers to a 30-day sale.

2 AECO-C/NIT is the interconnection between the Alberta Energy company's facilities and Nova Inventory Transfer ie. TCPL-Alberta system.

because the returns would be higher. More supplies would be offered in the U.S. and sellers would divert their volumes from Canada. As more supplies were offered in the U.S., the price would tend to fall; conversely as less natural gas was offered in Canada, the price would tend to rise. This process will continue until the exporters are indifferent between selling in either market. At this point, the netback prices[1] from sales into Canada and the U.S. would be the same, and prices in the two markets would be the same, adjusted for differences in transportation costs. Integration can only occur if there is price transparency and no transportation barriers.

Figure 4.1 shows average netback prices for Canadian export sales to various markets from 1995 to 1999. As can be seen, prices have converged in 1999, indicating that the gas market is well integrated.

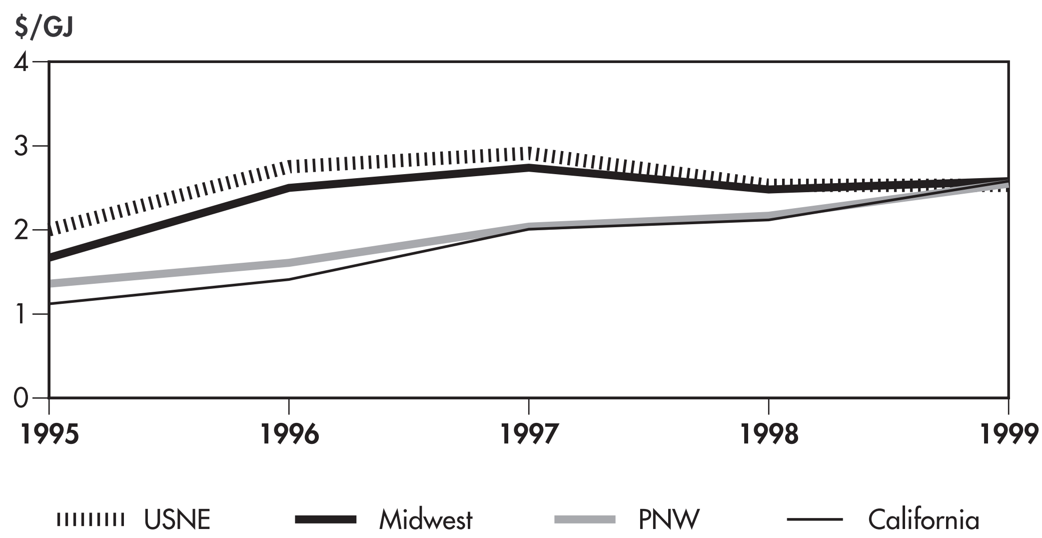
The most significant factor affecting gas pricing was the commencement of trading futures contracts on the New York Merchantile Exchange (NYMEX) in 1990. A futures contract is a commitment to deliver or take delivery of a specific amount of gas (usually 10,000 MMBtu) at a point in the future. The delivery point of gas sold under NYMEX is Henry Hub. Henry Hub is located near the major gas producing and consuming region of the Gulf of Mexico. This region accounts for over 40 percent of gas production and 30 percent of gas demand in North America. Accordingly, Henry Hub has access to many large interstate pipeline systems.

NYMEX furture contracts have become an important benchmark for natural gas pricing in North America. The emergence of the NYMEX was also in response to the desire of market participants for price transparency, liquidity and a mechanism for protecting themselves against adverse price movements.

Figure 4.2 compares the 30-day prices at AECO-C/NIT and NYMEX[2] Henry Hub from 1993 to October 2000. In 1993, prices in Alberta mirrored the prices at Henry Hub. However, from 1993 to 1998, prices in Alberta were well below that of NYMEX. In 1996, the average NYMEX price was

FIGURE 4.1

Netback Prices for Canadian Exports

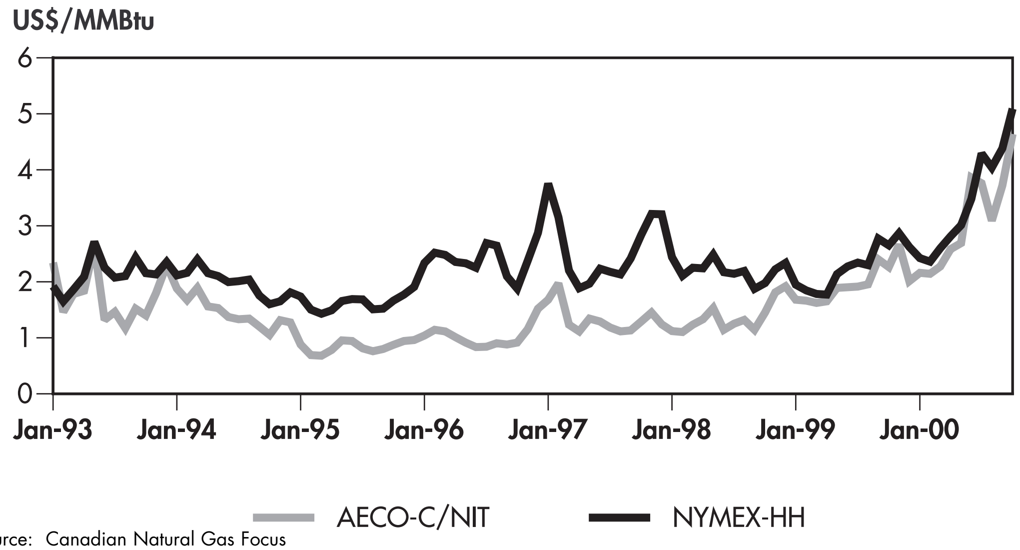


1 Netback prices are average prices at the international border less inter-provincial transportation costs.

2 NYMEX average for the near month.

F I G U R E 4 . 2

AECO-C/NIT versus NYMEX Henry Hub Prices



Source: Canadian Natural Gas Focus

U.S. $2.40/MMBtu compared with $1.02/MMBtu at AECO-C / NIT, a differential of $1.38/MMBtu. As a result, Canadian producers received substantially less for their gas than producers operating in the Gulf of Mexico. This reflects the fact that Canadian pipelines were operating at near capacity and that excess gas supply conditions existed in western Canada, creating intense gas-on-gas competition. Consequently, prices were determined by local market conditions. In the fall of 1998, additional pipeline capacity from the WCSB, along with some expansions of west-to-east pipelines in the United States, alleviated the capacity constraint that prevailed and resulted in convergence of the Alberta and NYMEX prices. This means that natural gas prices in Alberta are connected with those elsewhere in the North American gas market when there is adequate pipeline capacity out of the WCSB.

Domestic and Export Prices

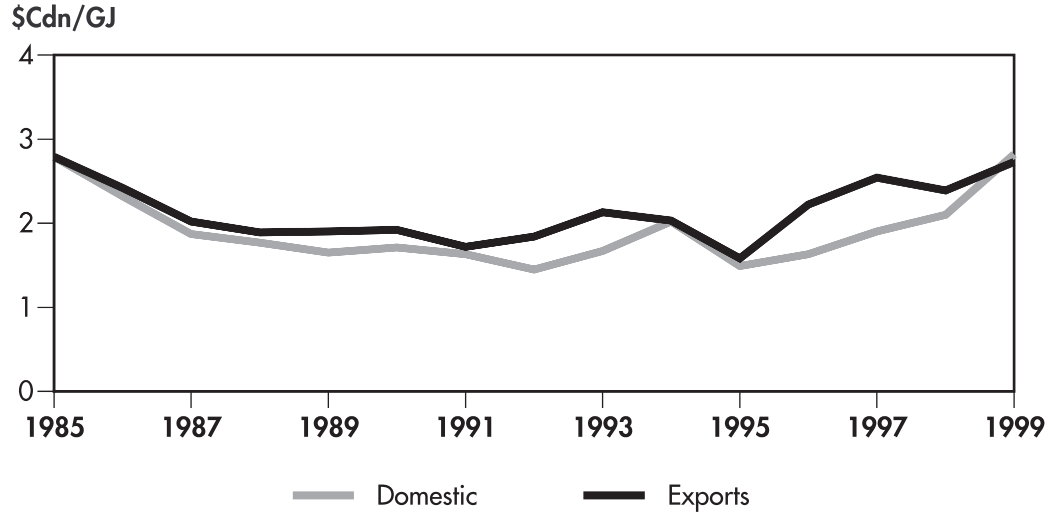
Another indicator of the integration of the Canadian and U.S. natural gas market is provided by a review of the prices paid for Alberta gas by Canadian and U.S. buyers. A premise of the MBP is that, in an open unregulated market, Canadian buyers should have an opportunity to buy gas on similar terms and conditions, including price, as those offered in the export market. Figure 4.3 shows the annual weighted average price paid by domestic and export markets for Alberta gas from 1985 to 1999. It indicates that domestic buyers benefitted from lower gas prices until late 1998. Since then, prices paid by both Canadian and U.S. gas buyers have converged and have increased at the same rate.

4.3 Seasonality of Gas Demand

As shown on Figure 4.4, demand for natural gas is very seasonal, mainly because of weather patterns. The consumption profile of each market sector is important as it defines the type of contracting practices and risk management which each sector will pursue. For example, residential markets are sensitive to weather and usually have no fuel-switching capability, thus require peaking arrangements to meet demand in the winter. This seasonality may result in higher prices during the winter when Canadian demand is almost double that in the summer.

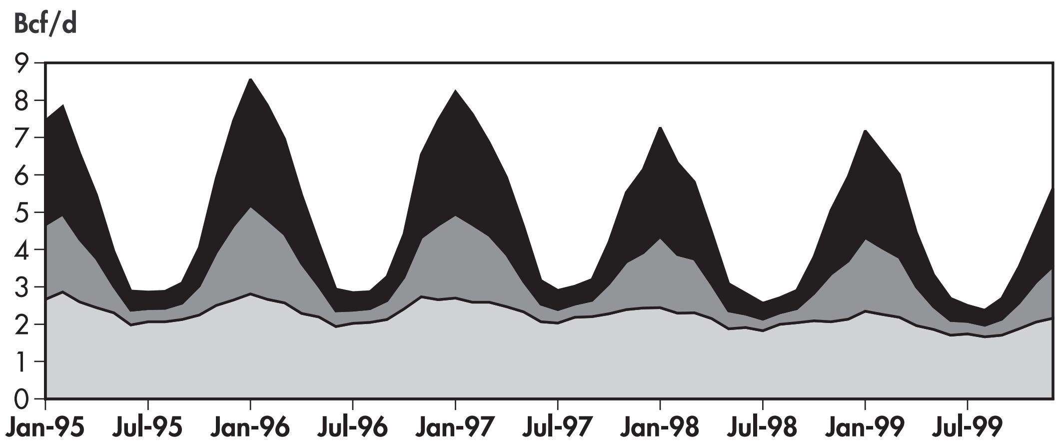
F I G U R E 4 . 3

Annual Weighted Average Border Price for Alberta Gas



F I G U R E 4 . 4

Canadian Natural Gas Demand by Sector 1995 - 1999



Source: Statistics Canada

Peak requirements are usually met by gas in storage. Traditionally, storage is used to balance seasonal demands through injection, storage and withdrawal. This reduces the need for additional pipeline capacity to meet peak requirements, improves the reliability of supply and dampens price spikes that occur in tight supply conditions. However, the role of storage has evolved over the last few years, becoming a marketing service under which many services such as parking, swaps, transportation exchanges and gas loans are offered. These services add flexibility and provide arbitrage opportunities.

Financial Instruments

Today, natural gas prices fluctuate with daily market conditions. To minimize the risk of adverse price fluctuations, market participants are engaging in hedging i.e. locking in a price maximum if a buyer or price minimum if a seller. Some financial tools available include futures market contracts and over the counter instruments such as collars and swaps. The futures market provides a means for price discovery into the future and allows parties to manage the price risk associated with the commodity, which, in turn, increases the efficiency of the market.

4.4 Summary

Today, most industry observers believe that the U.S. and Canadian natural gas markets can be considered as one large integrated market. There are no major transportation bottlenecks and price information is quickly conveyed to all market participants. There are active spot and futures markets, such as the NYMEX, which provide market participants with timely and accurate price discovery and allow them to manage their risks by contracting on a forward basis.

Natural Gas Dynamics and Pricing - A Regional Analysis

Within the provinces, natural gas is delivered to end-users by Local Distribution Companies (LDCs). Customers are typically divided into industrial, commercial and residential classes. The commercial and residential classes use gas primarily for space heating, whereas the industrial class uses gas for process heat in manufacturing process or as a feedstock in petrochemicals production. Large industrials usually pay a lower delivery charge per unit of gas than residential and commercial gas users because the fixed cost of serving them are spread over a larger volume of gas use.

Prior to 1985, the LDCs purchased all their gas under long-term contracts from pipeline companies and delivered gas to end-users within their franchise areas. Deregulation allowed consumers the option of purchasing gas from their LDCs or through a direct sale in which the end-user entered into a gas purchase agreement with a supplier at negotiated prices. Most large end-users, such as industrial customers, have been buying their gas directly from suppliers since 1985. Many regulatory initiatives have been undertaken in various provinces to provide more choice for smaller end-users such as residential customers. Smaller customers, who are able to buy under direct purchases, usually utilize the services of an agent/broker/marketer (ABM).

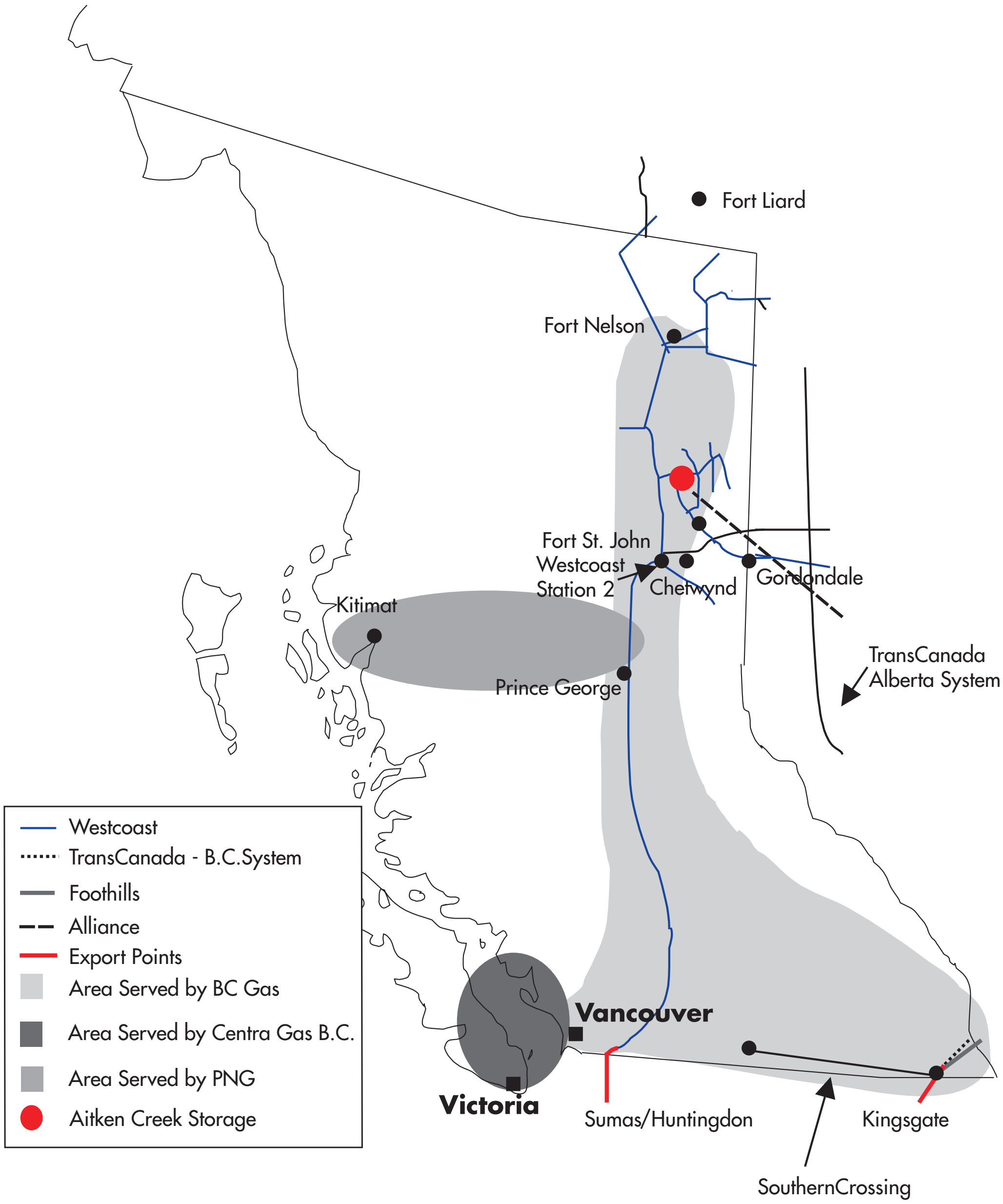
There are a few options offered by LDCs to facilitate direct purchases: a transportation service (T-service) arrangement, a Buy/Sell Mechanism and an Agency Billing and Collection Transportation Service (ABC-T Service). Under a T-Service, an ABM purchases gas from suppliers and arranges for transportation for its customers. In a buy/sell arrangement, the end-user buys gas at market price and then provides it to the LDC. The LDC then purchases the gas from the end-user at the buy/sell reference price, which is set at the utility's weighted average cost of gas (WACOG) less any relevant transportation costs. Customers benefit when they purchase their gas supplies at a cost lower than the buy/sell reference price. Under an ABC-T Service, the ABM negotiates a price with its customers and the LDC collects the money on behalf of the ABM for a fee.

An LDC's average cost of gas is reviewed and approved by the provincial regulatory body. The cost of gas is included in rates recovered from end-users. In most jurisdictions, rates are set on a forward test year based on the forecasted cost of gas; differences between the actual and forecasted cost of gas are recorded in deferral accounts. This means that if natural gas rates recover more than actual costs, the difference is returned to customers when the new rates are set. If natural gas rates do not recover actual costs, LDCs apply for a rate increase to recover the amounts accumulated in deferral accounts.

Of note, the LDCs are not allowed to make any profit on the commodity price of gas. The costs incurred are passed on to end-users without any mark up. On the other hand, prices offered by ABMs are not regulated. In most provinces, ABMs are able to offer a fixed price for the commodity for a one, three or five year term. ABMs operate in accordance with a code of conduct and may be licensed and sometimes are required to post a bond.

This chapter provides an overview of the energy market, prices and gas market dynamics in each province. For ease of reference, the components of the natural gas price shown, in each section, are expressed in units most commonly used in each jurisdiction and therefore, may not be necessarily the same.

5.1 British Columbia



5.1.1 Market Overview

Energy Demand

In 1998, energy demand in B.C. was fueled primarily by oil and natural gas (Figure 5.1.1). Oil and oil products are used mainly for transportation and to a lesser extent in the industrial sector. Abundant hydroelectric power also met a significant component of the province's total energy requirements. Alternative or *other* fuels within B.C. account for a much higher proportion than the Canadian average due to the substantial use of wood and wood waste products by the pulp and paper industry.

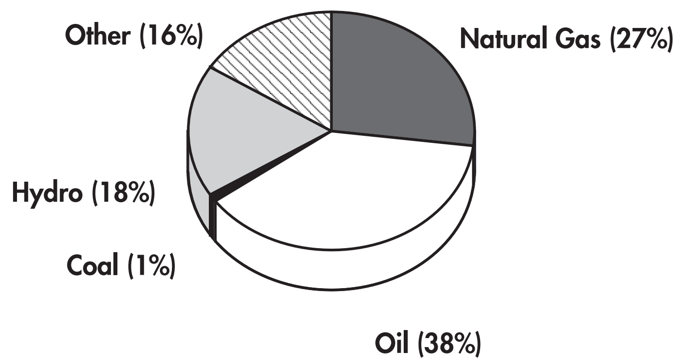
Natural Gas Market

British Columbia is the second largest producer of natural gas in Canada and the third largest consumer, following Ontario and Alberta. In 1999, slightly less than 50 percent of production in B.C. was used within the province. The remaining natural gas was exported.

In 1999, B.C. consumed 7 685 10^6m^3 (271 Bcf) of natural gas. The residential sector accounted for 28 percent of demand, the commercial sector for 24 percent, and the industrial sector for 48 percent. Natural gas is used in industries such as wood and paper, petroleum and mining, and agriculture (e.g. to heat green houses). Total demand for natural gas has been stable over the last five years (Figure 5.1.2).

FIGURE 5.1.1

BC Energy Mix by Fuel Type, 1998



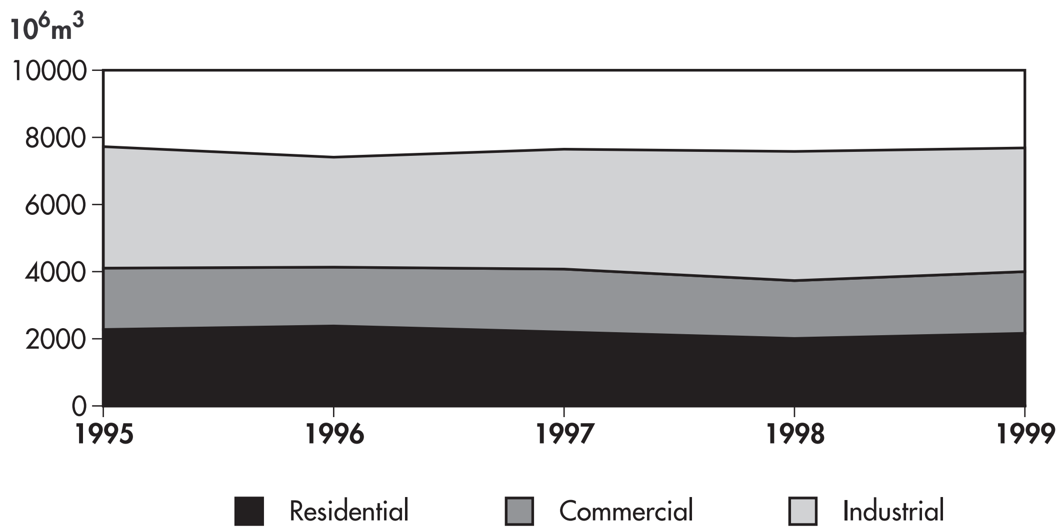
Source: Statistics Canada

There are three LDCs in B.C. BC Gas Utility Ltd. (BC Gas) is the largest and serves over 756,000 customers, representing about 90 percent of the natural gas consumers in the province. BC Gas franchise extends from Vancouver east to the Kootenays and north to communities including Prince George, Chetwynd and Fort Nelson. The service areas are defined as Lower Mainland (Greater Vancouver to Hope), Inland (Okanagan to Northern B.C.) and Columbia (east Okanagan to the Kootenays). In 1999, BC Gas transported 5 967 10^6m^3 (211 Bcf) of gas.

Pacific Northern Gas Ltd[1] (PNG) delivers natural gas to 23,000 customers and a number of large industrial operations in west-central B.C. Pacific Northern Gas (N.E.), a subsidiary of PNG, serves

FIGURE 5.1.2

BC Natural Gas Demand, 1995 - 1999



Source: Statistics Canada

1 Westcoast owns 41 percent of PNG and 100 percent of voting shares.

some 16,000 customers in northeastern B.C. PNG and its subsidiaries delivered 1 272 10^6m^3 (44.9 Bcf) of gas in 1999.

Centra Gas British Columbia Inc.[1] (Centra B.C.) provides gas distribution and related services to residential, commercial and small industrial customers located on the Sunshine Coast, the eastern part of Vancouver Island from Campbell River south to Victoria and, through a westerly lateral on the Island, to customers in the community of Port Alberni. In 1999, Centra B.C. had over 66,000 customers and transported 810 10^6m^3 (28.6 Bcf) of gas.

The LDCs are regulated by the British Columbia Utilities Commission (BCUC). The BCUC reviews natural gas contracts to ensure that the prices and terms are prudent and that the LDCs are buying gas at the lowest overall cost.

A number of marketers operate in B.C., and they currently serve industrial and large commercial customers. Approximately 85 percent of BC Gas' industrial customers purchase their gas through an ABM. About four years ago, core customers were given the opportunity to purchase gas from an ABM through buy/sell arrangements offered by LDCs. In a declining gas price environment, marketers were able to make some inroads in the core sector because they could acquire gas at a lower price than the prices offered by the LDCs. However, as natural gas prices started to increase, marketers no longer had an advantage compared with an LDC in purchasing gas for core customers. Therefore, marketers in B.C. returned all of their core customers to the LDCs.

Since 1998, a Market Unbundling Group, including the BCUC and BC Gas have been working towards again providing residential and commercial customers with the option to purchase gas directly. The BCUC initiated the development of an Agency, Billing and Collection Transportation (ABC-T) tariff for BC Gas. BC Gas is in the process of changing its customer information system which will support retail commodity deregulation. This initiative will likely be completed in 2001.

Natural Gas Supply and Transportation

Westcoast operates the major gas transmission system in British Columbia. Gas transported on the Westcoast system is split between the B.C. domestic and export markets (principally in the Pacific Northwest (PNW) and California). Gas is delivered to export markets through interconnects with Northwest Pipeline and other smaller pipelines at Huntingdon, B.C. and through interconnects with the TCPL-Alberta system at Gordondale, Alberta. Westcoast delivers gas to LDCs and to various industrial plants and gas processing facilities directly connected to its system.

While BC Gas procures the majority of its supply from B.C., it also receives some Alberta volumes from the TCPL-B.C. system that passes through the southeast corner of the province from Alberta to Kingsgate. BC Gas also holds a small amount of capacity on Northwest Pipeline for storage facilities to diversify its supply portfolio. B.C. is unique in that there is no market area storage. Rather, on a peak day, BC Gas' incremental requirements are met by LNG and gas exchanges using, for example, Washington storage and backhaul service on Northwest Pipeline. BC Gas relies on storage in other areas to manage its gas supply portfolio. BC Gas has access to storage at Jackson Prairie, Washington; Clay Basin, Utah; Aitken Creek, B.C.; Carbon, Alberta; Mist, Oregon; and in Southern California.

Traditionally, BC Gas had 365-day contracts for its gas supply with supply aggregators. Over the past few years, BC Gas has increased gas purchases from individual producers, thereby diversifying its supply portfolio. BC Gas is in the process of reducing its reliance on baseload volumes and is

1 Westcoast owns 100 percent of Centra B.C.

planning on acquiring more spot and peaking/seasonal volumes. This strategy reduces BC Gas' requirement to hold transportation capacity on Westcoast.

Recent Market Developments

In February 2000, British Columbia began receiving about 7.08 $10^6 m^3/d$ (250 MMcf/d) from Fort Liard in the southern Northwest Territories. Development of this gas source is in the initial stages; hence, there is a strong potential for production to increase. British Columbia is expected to supply up to one-third of the gas shipped on the Alliance pipeline system or about 11.3 $10^6 m^3/d$ (400 MMcf/d). This volume is equivalent to one-quarter of provincial gas production; consequently, in the short-term, supply could tighten in British Columbia leading to increased gas prices. However, at the same time, drilling activity has increased substantially and this should translate into higher gas production.

The BC Gas Southern Crossing Pipeline (SCP), which extends from Yahk to Oliver, B.C., will be in-service by November 2000. Its initial capacity is 7.08 $10^6 m^3/d$ (250 MMcf/d). This pipeline will serve the need for seasonal supply to the B.C. Interior and also provide a peaking resource in the Lower Mainland. The SCP provides access to Alberta gas and therefore improves supply diversity especially for Interior industrials. The BCUC has directed BC Gas to file a comprehensive rate design application, incorporating SCP, in early 2000, which is likely to lead to increased gas delivery rates.

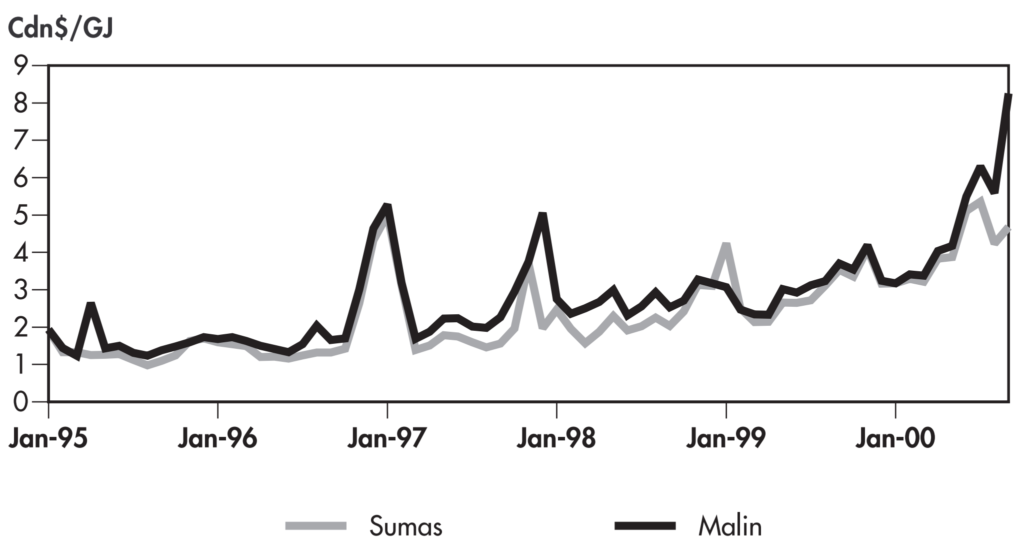
Centra B.C. delivers natural gas to Vancouver Island under a provincial government initiative that requires customers to pay market-based rates reflecting the cost of competitive fuels (i.e. oil and electricity). The rates are not cost-based and large cost deferrals are being accumulated. With new industrial customers joining the system, the BCUC has asked Centra B.C. to file its first comprehensive rate design in the fall of 2000.

5.1.2 Regional Prices

There are two pricing points in B.C.: Sumas/Huntingdon and Westcoast Station 2[1]. BC Gas buys most of its gas through annual and seasonal contracts that are indexed to Sumas. Changes in gas

FIGURE 5.1.3

Spot Gas Prices Sumas vs. Malin

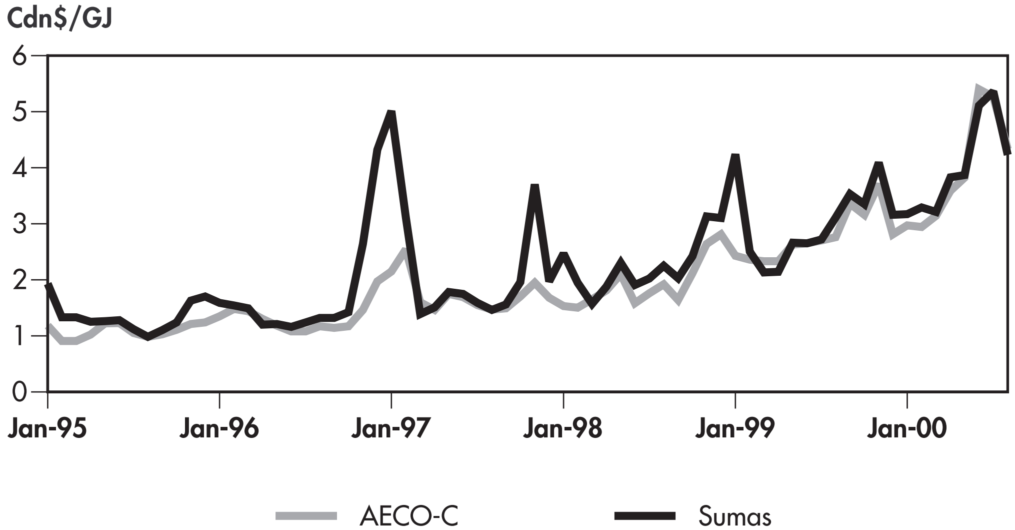


Source: Canadian Natural Gas Focus

1 Westcoast Station 2 is a small pricing point where volumes are thinly traded. This is expected to change as Alliance comes into service.

FIGURE 5.1.4

Spot Gas Prices AECO-C/NIT vs. Sumas



Source: Canadian Natural Gas Focus

prices at Sumas more closely track gas price changes at Malin, California than changes in prices at AECO-C/NIT (Figures 5.1.3 and 5.1.4). This suggests that, historically, pricing of gas in B.C. has been influenced by supply/demand dynamics in the PNW and California.

Also, greater price spikes in the winter periods at Sumas than at AECO-C / NIT reflect the larger amount of storage capacity in Alberta. As more pipeline capacity between B.C. and Alberta is added, such as Alliance and the Southern Crossing pipeline, the B.C. market is expected to become more connected to AECO-C / NIT pricing.

An LDC can apply to the BCUC for a rate change at any time. Traditionally, for purposes of convenience and stability, rate adjustments were made once per year. However, with recent rapid increases in the price of the gas commodity, rate increases have occurred more often. The BCUC has tried to limit rate shock for consumers by approving lower estimates of gas commodity prices than have proven to be the case. As a result, debit balances have accumulated in LDC deferral accounts, and B.C. consumers are repaying them through gas cost riders. The BCUC is in the process of considering how frequently gas rates should be adjusted in the current environment.

End-use Prices

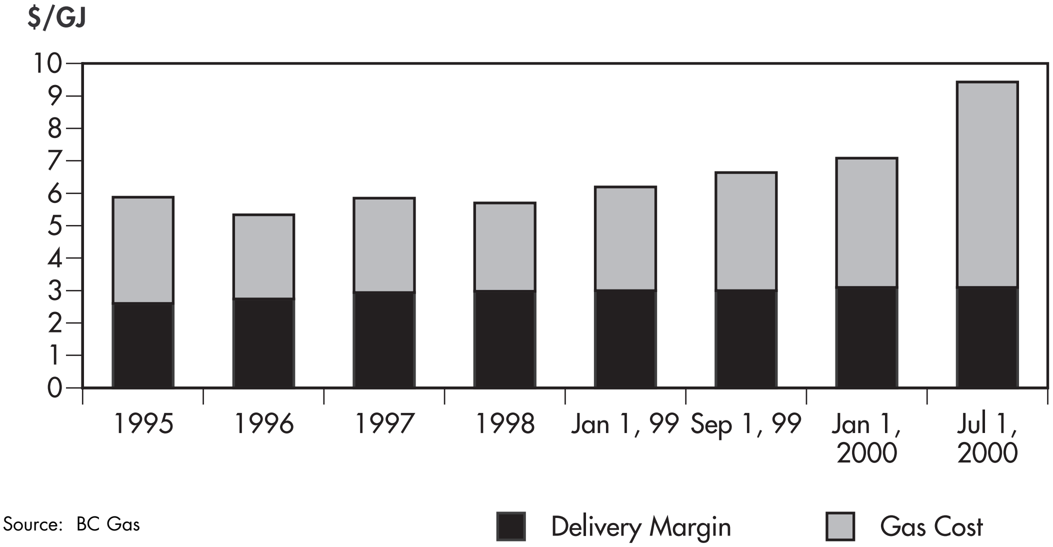
Figure 5.1.5 shows the change in the delivered gas prices[1] for a residential BC Gas consumer in the Lower Mainland with an average consumption of 120 GJ/year over the period 1995-2000. The delivery margin covers the cost of delivering gas through the BC Gas pipeline system. The gas cost includes the gas commodity price paid at the wellhead, the pipeline demand and commodity tolls[2], supply reservation fees and storage and seasonal costs. Until 1999, the delivered price of gas was less than the 1995 price. Between 1 January 1999 and 1 July 2000, the delivered price of gas increased from $6.18/GJ to $9.43/GJ, an increase of 53 percent. Most of this increase is due to the gas cost; the remainder is due to a small increase in the delivery margin.

1 The prices do not include gas cost credits or riders.

2 Since 1997 the tolls paid for transportation on the Westcoast system have been determined by a negotiated settlement between shippers and the pipeline.

F I G U R E 5 . 1 . 5

Residential Gas Price Components BC Gas



Source: BC Gas

Since 1999, commercial and industrial consumers have also experienced increases in the price of delivered gas largely because of the increased gas commodity costs. However, commercial and industrial customers usually pay lower delivery costs per unit of gas than residential customers because their load profile is more consistent throughout the year, and many are able to use interruptible service. Interruptible service is less expensive than firm service because customers can be curtailed on short notice.

5.1.3 Regional Dynamics

In the next several years, demand for natural gas is expected to grow considerably in the PNW and B.C. Natural gas will be required for new electricity generation. Two gas-fired generators are under construction and several more have been proposed in the PNW. An expansion of BC Hydro's Burrard Thermal plant has been planned as well as the addition of cogeneration facilities on Vancouver Island. Additional capacity will likely be required in B.C. to meet incremental gas demand.

Recent Developments

BC Hydro and Williams Pipelines have announced a proposal to build a second gas pipeline to Vancouver Island. The Georgia Strait Crossing Project (GSX Project) would run from Sumas, Washington to Vancouver Island. The proposed in-service date is November 2002. The GSX Project would supply gas to cogeneration facilities on Vancouver Island and provide supplemental supply to Centra B.C.. The pipeline is designed initially to transport 2.29 $10^6 m^3$/d (81 MMcfd) of gas, primarily sourced from B.C., with a supplementary supply via the Northwest Pipeline system.

Westcoast is currently facing about 5.70 $10^6 m^3$/d (200 MMcf/d) of decontracting, which could increase in the short-term, depending on volumes that come from Fort Liard and volumes moving on Alliance and Southern Crossing. The toll incentive settlement between Westcoast and its shippers expires at the end of 2001, and uncontracted capacity could result in higher Westcoast tolls.

Impact on Consumers

Consumers in B.C. have expressed concern to the BCUC and the NEB about increased natural gas costs. Industrial and commercial customers have also been affected by higher natural gas prices. B.C.'s largest industrial gas user, Methanex, decided to close its petro-chemical plant at Kitimat on 1 July 2000 for up to one year due to high gas costs. Methanex is PNG's largest customer, accounting for about 60 percent of the volumes transported on its distribution system. If the plant does not reopen, it could have a significant impact on rates for consumers in the PNG franchise area.

Forestry, B.C.'s largest industry, is very energy intensive. Two-thirds of the industry's energy requirements are met through mill wood residue and pulp mill black liquor incineration, and the remainder is met by natural gas, electricity and refined petroleum products. Recent high gas prices have added to the economic challenges the industry has been facing over the last decade particularly since low natural gas prices had provided a competitive advantage for some.

Energy consumers will try to switch to the lowest cost fuel if possible. BC Gas has conducted a competitive fuel cost comparison for residential, small commercial and large commercial customers as of July 2000. For residential and most small commercial customers, natural gas was the lowest cost fuel ($/GJ equivalent) compared with furnace oil, propane and electricity. However, this calculation did not include the capital costs associated with switching to or using a particular fuel type (e.g., for residential customers, the acquisition and maintenance of a natural gas furnace versus. electric baseboards). For large commercial customers, electricity at the variable rate was the cheapest fuel source.

For many commercial customers, switching from natural gas to another fuel may not be a practical possibility because of emissions concerns or the cost of switching equipment. Some businesses, such as greenhouses growing fruits and vegetables, may have to close because energy comprises 50 to 60 percent of their input costs. Customers in this sector have stated that they would like to see real time pricing for natural gas so they would immediately see their true costs rather than waiting for rate adjustments to be approved by the regulator.

5.1.4 Summary

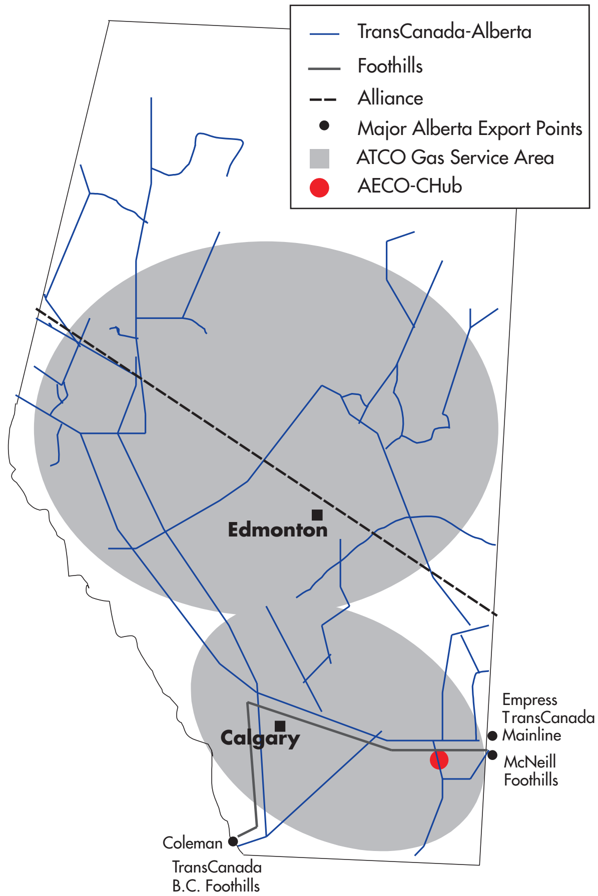
Gas buyers in B.C. have access to gas supplies from British Columbia, Alberta and the Northwest Territories. Prices are generally based on transactions at the Sumas pricing point. These prices have been closely linked to prices in California but are becoming more closely linked to Alberta prices. The Southern Crossing Pipeline will serve the need for seasonal supply and will provide access to Alberta supplies, thereby improving supply diversity.

5.2 Alberta

5.2.1 Market Overview

Energy Demand

Natural gas is the most widely used fuel in Alberta (Figure 5.2.1). In 1998, natural gas met 43percent of the province's total energy requirements. Coal and oil each accounted for one-quarter of total energy needs. Electricity generation is mostly coal-fired.



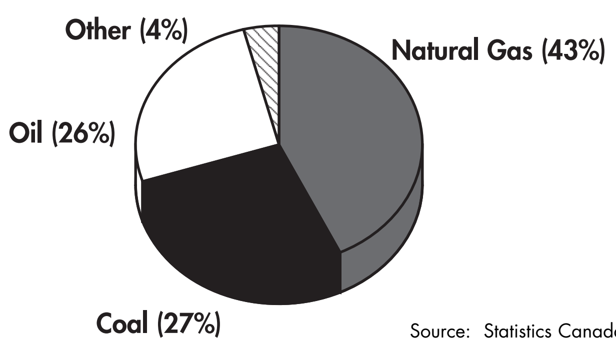
Natural Gas Market

After Ontario, Alberta is the second largest gas market in the country, representing about one-third of Canada's natural gas demand. In 1999, Alberta consumed 20 114 10^6m^3 (710 Bcf) of natural gas. The industrial sector is the largest user of natural gas in Alberta accounting for 70 percent of total consumption. Industrial consumers include petrochemical and fertilizer manufacturers, oil producers for enhanced oil extraction processes, electrical power generators and pipelines. The balance, about 30 percent, is used for heating by residential and commercial customers.

ATCO Gas is the largest LDC in Alberta and serves 82 percent of the retail gas market. The company operates as ATCO Gas North and ATCO Gas South. ATCO Gas North, formerly Northwestern Utilities Limited (NUL), operates in Edmonton and the northern half of the province. ATCO Gas South, formerly Canadian Western Natural Gas Company Limited (CWNG), operates in Calgary and the southern half of the province. When NUL and CWNG merged in 1998, ATCO Gas took over natural gas distribution and ATCO Pipelines acquired the gas transmission assets. The ATCO Group of Companies owns ATCO Gas and ATCO Pipelines.

FIGURE 5.2.1

Alberta Energy Mix by Fuel Type, 1998

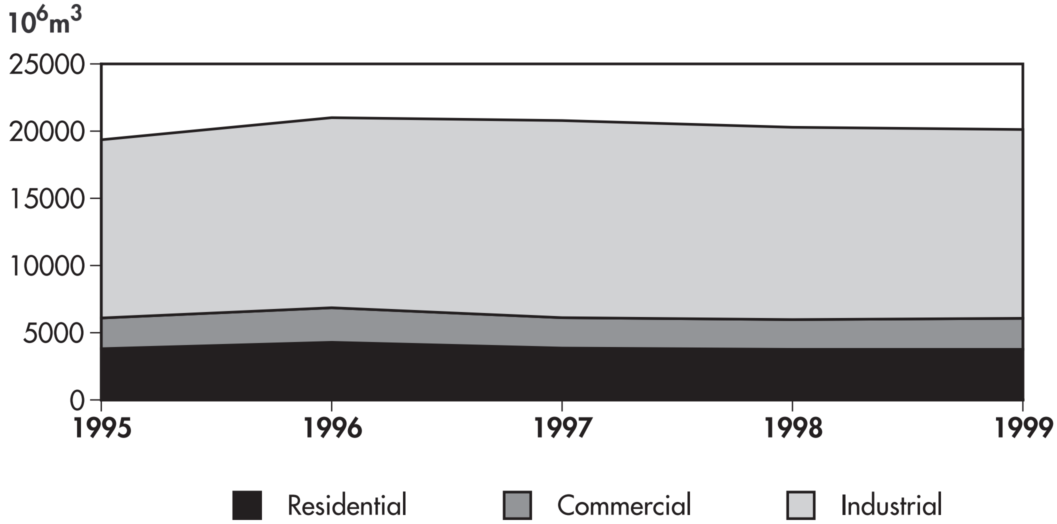


Source: Statistics Canada

The remaining 18 percent of the retail gas market is divided amongst AltaGas Utilities Inc., municipally owned utilities, such as the City of Medicine Hat, and a variety of rural gas co-operatives. Many of Alberta's industrial consumers buy gas directly in the wholesale market from gas producers or natural gas marketers. Very few residential and small commercial gas users buy their gas directly and, hence, natural gas marketers hold a very small portion of the retail market.

FIGURE 5.2.2

Alberta Natural Gas Demand, 1995 - 1999



Source: Statistics Canada

Natural Gas Supply and Transportation

Alberta has an abundant supply of gas from the WCSB. Over 80 percent of Canadian natural gas production originates in Alberta. The TCPL-Alberta system is the primary gas gathering and transmission pipeline system in Alberta. It collects gas from across the province and delivers gas to major transmission pipelines at the Alberta border for shipment to Canadian and U.S. markets. ATCO Pipelines, the major intra-Alberta distribution pipeline system interconnects with TCPL - Alberta and ships gas to LDCs and large industrial customers within the province.

Recent Market Developments

The Alliance Pipeline will bypass the TCPL-Alberta gas gathering and transmission system and provide natural gas producers in Northwestern Alberta with increased access to markets in the U.S. Midwest. Alliance could have an impact on the utilization of existing pipeline systems.

5.2.2 Regional prices

Wholesale Prices

Alberta consumers have generally paid lower prices for natural gas than other consumers in North America. The most commonly quoted intra-Alberta price for natural gas is the AECO-C/NIT market price. As discussed in section 4.2, AECO-C/NIT prices have been lower than NYMEX prices, until late 1998. The recent rise in the AECO-C/NIT price has resulted in an increase in the price of gas paid by Alberta consumers.

The price of gas paid by Alberta utility customers is based on a portfolio of AECO-C/NIT daily and monthly price indices. Some utilities own their own gas wells and/or have long term fixed contracts with natural gas producers. These arrangements influence the cost of gas paid by retail consumers.

Alberta's industrial consumers are free to manage their own gas portfolios. Industrials can purchase gas directly at wholesale prices from producers or marketers under long term contracts or on the

AECO-C/NIT market. Industrial buyers can also use financial tools to manage risk. A common financial practice is to buy futures contracts to lockin current gas prices for future delivery.

Transportation costs in Alberta are low because of the proximity of gas supply. Alberta consumers pay a common province-wide intra-Alberta transportation toll on the TCPL-Alberta system. This intra-Alberta toll is lower than the toll charged on gas leaving the province as average shipping distances to Alberta consumers are shorter than shipping gas to the Alberta border.

Retail Prices

The Alberta Energy and Utilities Board (AEUB) regulates natural gas rates charged to consumers by investor-owned gas utilities such as ATCO Gas and AltaGas Utilities Inc. Rates paid by customers of natural gas marketers, rural gas co-ops and municipal gas utilities are not regulated by the AEUB. Also excluded from regulation is the wholesale market.

Regulated gas service rates include the cost of gas, transportation costs from producing areas, local distribution costs and a fair rate of return. The cost of gas is flowed through to customers at cost without any profit to the utility. This is called the Gas Cost Recovery Rate. Gas rates are set using winter and summer price forecasts. Gas prices tend to peak during the winter months and decline during the summer months. If the gas cost to the utility is higher or lower than forecast, then the deficit or extra revenue from customers is put into a deferred gas account. At the end of each gas season, rates are adjusted to recoup losses or credit customers.

The cost of gas delivery is recovered from a Fixed Charge and a Base Energy Charge. The Fixed Charge pays for direct costs (pipeline, meters, billing) related to delivering natural gas to a customer's home or place of business. The Base Energy charge varies depending on customer consumption. This charge covers capital and operating costs related to gas delivery (labour, supplies, financing).

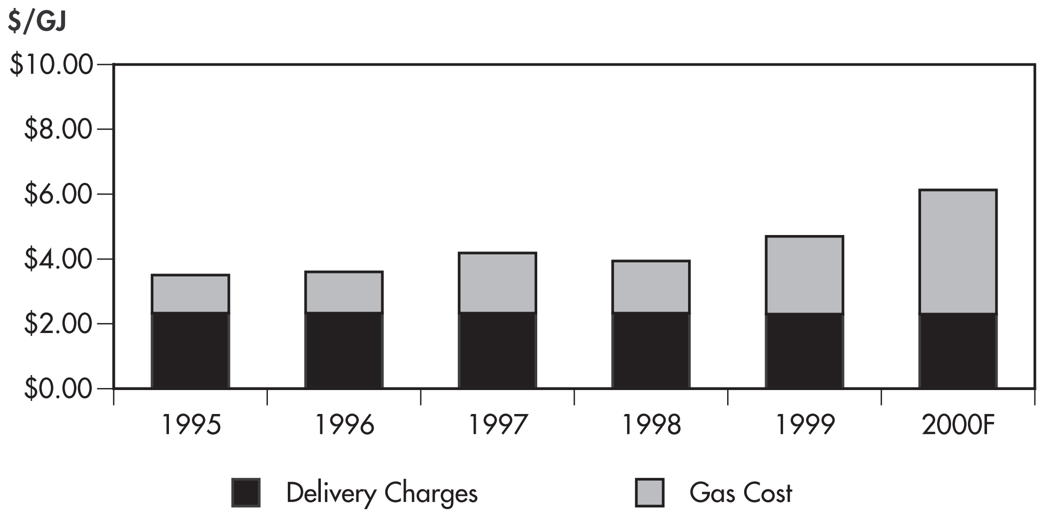
The cost of natural gas is now the major portion of a residential gas bill in northern and southern Alberta (Figures 5.2.3 and 5.2.4). In 1995, gas costs accounted for 33 percent of total gas service costs in northern Alberta and 40 percent in southern Alberta. ATCO Gas North has lower gas costs than ATCO Gas South. The difference in gas costs between the two zones is attributable to ATCO Gas North owning some gas wells while having longer-term producer contracts than ATCO Gas South. Since 1995, gas costs have escalated while gas delivery costs have been reduced. Based on current estimates, the cost of gas for 2000 will constitute 63 percent of a typical residential gas bill in the ATCO Gas North service area and 71 percent in the ATCO Gas South service area.

Retail choice for customers of gas utilities was made available in 1995 under the *AEUB's Gas Utilities Core Market Regulations*. The prices and contract terms offered by natural gas marketers are not regulated by the AEUB. Instead, natural gas marketers operate in accordance with Natural Gas Direct Marketing Regulation under the Fair Trading Act. All retail natural gas direct marketers must be licensed with the Government of Alberta.

Natural gas marketers only sell gas; the utility company continues to provide gas delivery. Marketers may offer retail customers a variety of terms including multiple year gas contracts. The AEUB sets utility company gas prices at least twice a year at rates similar to market rates, to reflect winter and summer market conditions. Individual customers must decide whether the price options offered by natural gas marketers or utility companies meet their needs. To date, most customers have been reluctant to leave their local gas utility.

FIGURE 5.2.3

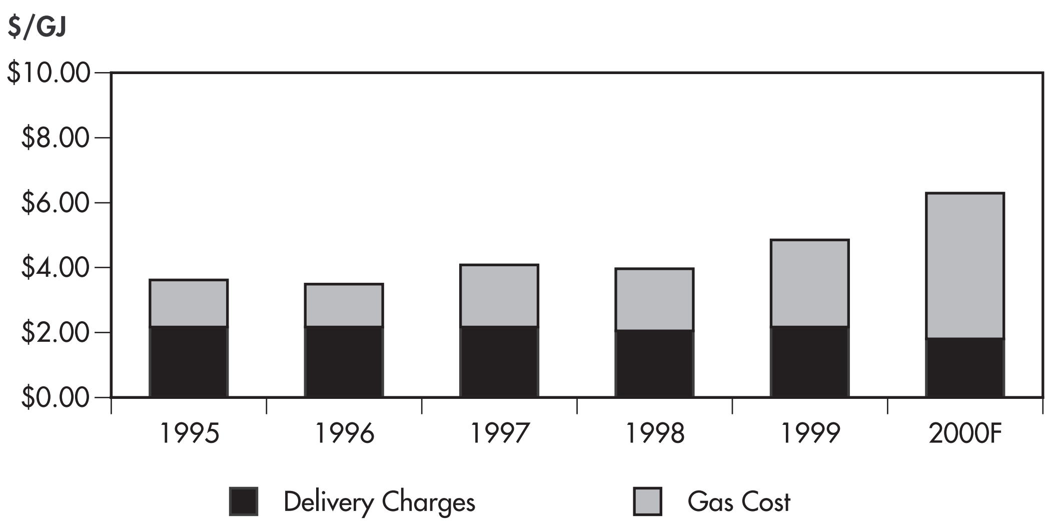
Residential Gas Price Components - ATCO Gas North



Source: ATCO Gas

FIGURE 5.2.4

Residential Gas Price Components - ATCO Gas South



Source: ATCO Gas

Impact on Consumers

Residential and commercial consumers do not have any fuel switching capability. Moreover, natural gas is the predominant heating fuel in Alberta. To help offset higher energy costs to consumers (natural gas and gasoline), the provincial government announced on September 6 2000, that it will provide a $300 Energy Tax Refund to every Alberta resident over the age of 16.

Using long term gas delivery contracts and futures commodity contracts, many of Alberta's major industrial users have locked in gas prices at rates lower than the current market prices at AECO-C/NIT. However, if a high gas price environment endures after the expiry of these arrangements, industrial users will assess their alternatives. For example, Agrium Inc., a fertilizer manufacturer that uses natural gas for feedstock, recently announced the temporary shutdown of one of its ammonia manufacturing plants in order to reduce the company's exposure to higher gas prices.

Coal is a competitive energy source for large industrial fuel consumers and utilities in the medium to long term; however, in the short term, many companies are not equipped to burn coal. Some cement producers, such as Lafarge Canada Inc. and Inland Cement, are examining the feasibility of converting gas-fired furnaces to burning coal.

5.2.3 Regional dynamics

The cost of natural gas is the largest component of the cost of gas service to Alberta consumers. However, Alberta consumers benefit from nearby gas supplies and low transportation costs. Indeed, some utilities such as ATCO Gas North and the City of Medicine Hat own natural gas production. Market proximity gives Alberta's local gas utilities and large industrial and commercial consumers direct access to gas producers, thereby providing purchasers with many options for supply. As a result of these advantages, natural gas will continue to be the preferred fuel option for Alberta consumers.

The most significant market adjustments will occur in the pattern of industrial consumption. Product margins and feedstock cost differentials with competitors in other parts of the world will determine the amount of gas that manufacturers will use for feedstock.

Natural gas demand is expected to increase in Alberta. There are currently many proposed gas-fired electricity generation plants. Furthermore, strong oil prices provide support to current expansions in Alberta's oil sands extraction industry and to the development of heavy oil projects. These oil extraction processes use large amounts of natural gas for fuel.

5.2.4 Summary

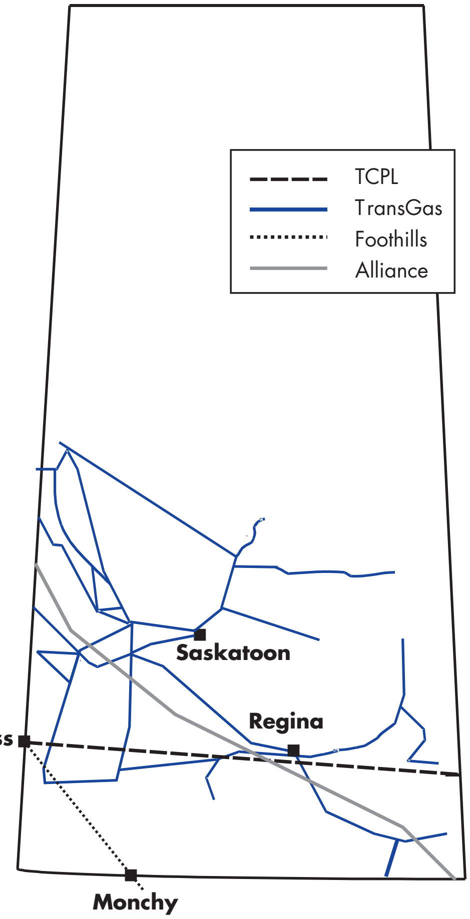
Gas buyers in Alberta have access to many suppliers in the province. Given the proximity of gas supply, transportation costs in Alberta are relatively small. Consumers paid less for natural gas until late 1998 as a result of the excess gas supply stranded within the WCSB. Prices in Alberta are based on transactions at the AECO-C/NIT hub; the most liquid pricing point in Canada. The prices at AECO-C/NIT are closely linked to NYMEX prices.

5.3 Saskatchewan

5.3.1 Market Overview

Energy Demand

In Saskatchewan, natural gas comprises approximately one-third of Saskatchewan's energy mix, about the same proportion as oil and coal. The use of coal is nearly three times greater than the Canadian average due to its abundance. Coal is an important fuel for electricity generation.



Natural Gas Market

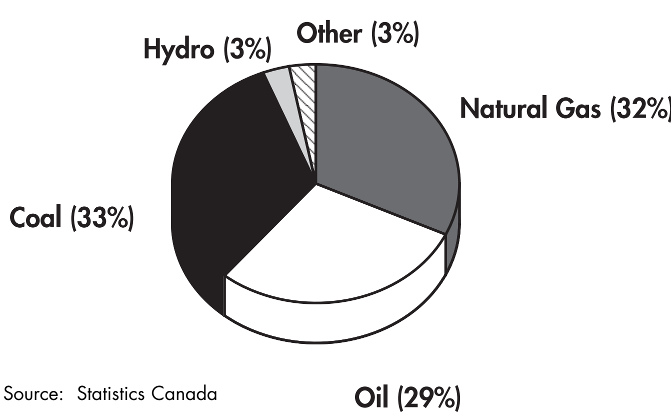
In 1999, Saskatchewan consumed 4 800 $10^6 m^3$ (169.4 Bcf). The industrial sector accounted for 64 percent of total sales while residential and commercial sectors, together, accounted for 36 percent. Almost all industrial sales were made under direct sales. Gas customers have had the opportunity to purchase gas directly from an ABM through a bundled T-service since 1987. SaskEnergy Incorporated (SaskEnergy)[1] provides natural gas distribution and related services to end-use consumers in Saskatchewan. In 1999, SaskEnergy distributed 1 889 $10^6 m^3$ (66.7 Bcf) of gas to end-use consumers.

Natural Gas Supply and Transportation

The province of Saskatchewan is the third largest producer of natural gas in Canada. In 1999, natural gas production totalled 6 693 $10^6 m^3$ (236 Bcf) or 4 percent of total Canadian production. Production in excess of provincial requirements is exported to markets in eastern Canadian and the United States. In addition to local production, Saskatchewan has direct access to gas supplies from Alberta through TransGas Limited (TransGas)[2] subsidiary Many Islands Pipelines (MIPL). In 1999, approximately (71 Bcf) of natural gas from Alberta production was transported to markets through the TransGas and MIPL system.

FIGURE 5.3.1

Saskatchewan Energy Mix by Fuel Type, 1998



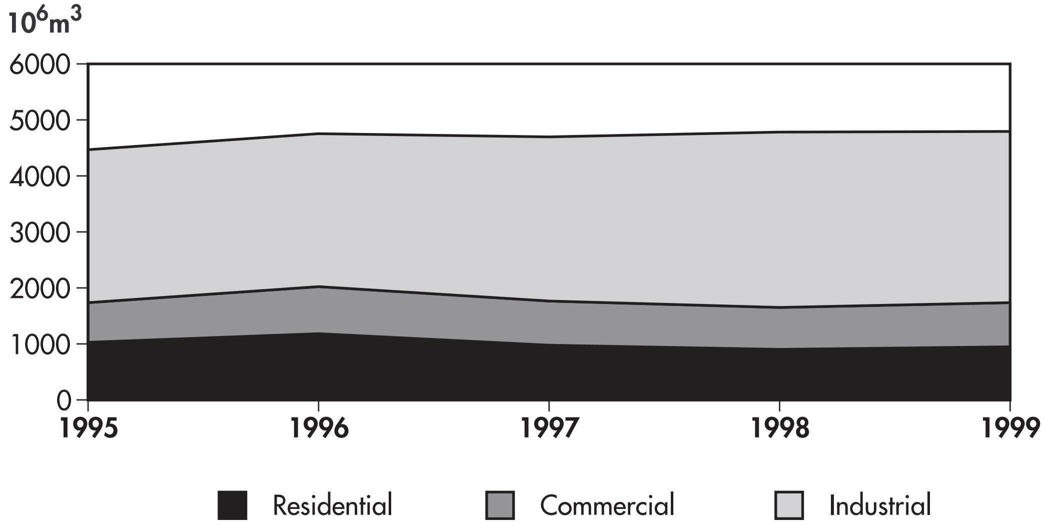
Source: Statistics Canada

1 SaskEnergy is a provincial crown corporation.

2 TransGas is a wholly owned subsidiary of SaskEnergy.

F I G U R E 5 . 3 . 2

Saskatchewan Natural Gas Demand, 1995 - 1999



Source: Statistics Canada

TransGas operates transmission, gathering, compression, treatment and storage facilities within the province. SaskEnergy and TransGas operate under *The SaskEnergy Act*, *The SaskEnergy Regulations* and *The Crown Corporations Act*, *1993*. SaskEnergy's Board of Directors is directly accountable to the Minister Responsible for the Crown Investments Corporation of Saskatchewan. In October 1999, the Saskatchewan Interim Rate Review Panel (Panel) was established to review the recovery of increasing natural gas costs. Recommendations by the panel are forwarded to the Minister for consideration.

TransGas transports natural gas for a variety of customers to destinations both within and outside the province. TransGas customers are classified into three main categories: export, intra-Saskatchewan, and distribution. Export customers are primarily gas producers and marketers transporting natural gas to eastern Canada and markets in the U.S. Intra-Saskatchewan customers are large volume end-use customers with direct access to the TransGas system, while distribution customers receive their gas through SaskEnergy distribution facilities. TransGas' 11 storage facilities have a total working gas volume of 1 240 10^6m^3 (44 Bcf) with a peak deliverability of 16.2 10^6m^3 (570 MMcf/d).

In November 1996, TranGas unbundled its transportation service into receipt and delivery services and developed the TransGas Energy Pool (TEP). The TEP functions similar to the TCPL-Alberta system in that receipt transportation is required to ship gas from the plantgate/receipt point to the TEP or to TransGas storage. A separate contract for delivery transportation is required to ship gas from the TEP for delivery to an end-use customer in Saskatchewan or to an interconnecting pipeline for export to markets outside the province. The TEP, together with the single price to deliver gas from the TEP to a market, provides a mechanism to facilitate transactions and price discovery for natural gas within the Saskatchewan market. Since the creation of the TEP, an increasing number of transactions have taken place at the notional hub. In 1999, SaskEnergy acquired approximately one-half of its supplies at the TEP.

SaskEnergy purchases gas primarily from Saskatchewan sources. Gas purchasing has increasingly been moving to shorter-term contracts. Prior to 1995, almost all gas purchase contracts were for a term greater than one year. Currently, only about 55 percent of SaskEnergy's supply portfolio is based on supply contracts in excess of one-year. Furthermore, nearly all gas purchase contracts are indexed to monthly prices at AECO-C/NIT.

While the price that SaskEnergy pays for the majority of its gas is based on a monthly market index, SaskEnergy sells natural gas to its customers on a one-year fixed price basis. This has sheltered customers from current market conditions. To ensure that the cost of gas supply does not surpass revenue from projected sales, a number of financial instruments such as natural gas price swaps, options and futures contracts are used as hedging tools to reduce price volatility while still providing natural gas to consumers at a competitive cost. SaskEnergy's practice of selling natural gas on a one-year fixed price basis may change in the future. The Province is beginning to consider the establishment of a Gas Purchase Variance Account as a means of ensuring that SaskEnergy would not fully assume the risk associated with variable commodity prices.

5.3.2 Regional Prices

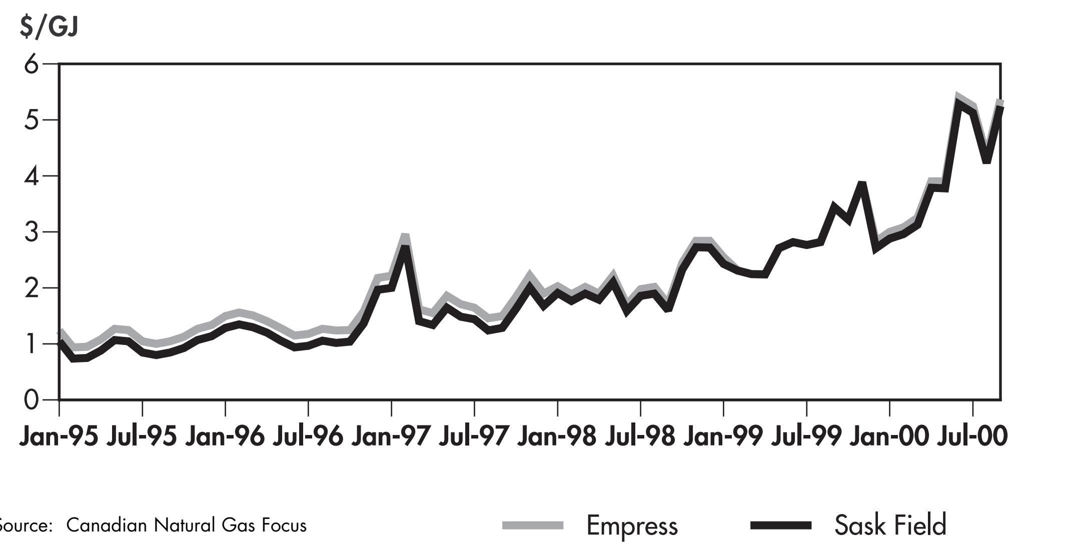
Wholesale gas prices in Saskatchewan are closely linked to gas prices at Empress, Alberta. Access to export markets through the TCPL - Mainline system is readily available to Saskatchewan producers who compare the returns of selling gas at an Empress, Alberta price with the returns from selling within the province. Figure 5.3.3 compares Saskatchewan plantgate prices with the Empress, Alberta price. This figure indicates a strong link between the two prices and demonstrates how wholesale gas prices in Saskatchewan have followed the rising prices of natural gas in Alberta.

End-use Prices

Figure 5.3.4 depicts the change in the delivered price of natural gas for a residential household in the SaskEnergy delivery area with an average consumption of 3 500 m^3 per year. Prior to September 1998, the cost of transportation and distribution was combined with the cost of natural gas supply to produce a bundled energy charge. As indicated by the graph, the increase in the delivered cost of gas is almost entirely attributable to the rising costs of gas supply. In 1999, the cost of gas supply represented approximately 45 percent of the total annual delivered cost of gas while transportation and delivery represented about 55 percent. Under the new rate schedule, proposed to be in effect in November 2000, the cost of gas supply would increase by 41 percent from 1999 and would represent approximately 60 percent of the total annual delivered cost of natural gas in Saskatchewan.

FIGURE 5.3.3

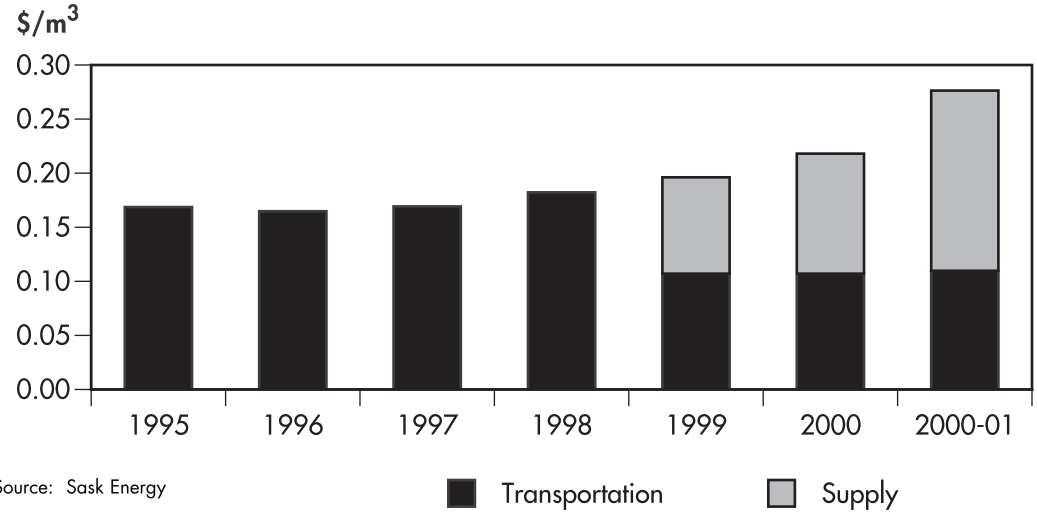
Saskatchewan Plantgate vs. Empress Gas Prices



Source: Canadian Natural Gas Focus

F I G U R E 5 . 3 . 4

Residential Gas Price Components - SaskEnergy



Source: Sask Energy

5.3.3 Regional Dynamics

In addition to the relative good health of the upstream natural gas industry, transportation rates are a key variable in a competitive environment. TransGas has announced a two-year rate freeze for 2000 and 2001 while rates on the TCPL-Alberta system are expected to increase. The relatively lower toll on TransGas is expected to increase the incentive for Alberta producers with access to TransGas facilities to use these facilities to transport their natural gas to markets downstream of Alberta.

In Saskatchewan, the major industrial markets for natural gas include potash mining, fertilizer production and the pulp and paper industry. The fuel switching capabilities of these industries are limited, and in some instances, natural gas is integral to the production process. To date, there has been no material change in the gas consumed by these industries. Since the products of these industries are generally related to world commodity prices, there is little opportunity to pass higher costs on to the consumers of these products. In that regard, higher gas prices have begun to impact the profit margins within these industries.

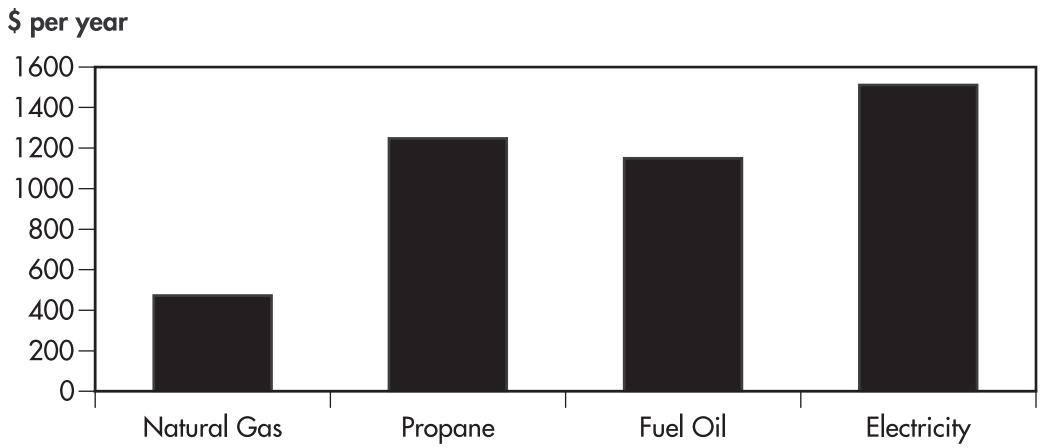
For residential consumers, higher natural gas prices are not expected to have a significant impact on the demand for natural gas. As shown in Figure 5.3.5, natural gas is still the lowest cost alternative.

5.3.4 Summary

Gas buyers in Saskatchewan have several purchase options and have access to supplies from both Saskatchewan and Alberta. Prices of natural gas are closely linked to Alberta. However, consumers have been sheltered from current market conditions because SaskEnergy sells gas to its customers at a one-year fixed price. The establishment of a Gas Purchase Variance Account could provide a means to aligning end-use gas prices in Saskatchewan with prevailing market conditions more frequently.

FIGURE 5.3.5

Saskatchewan Annual Heating Fuel Costs



Source: Sask Energy

5.4 Manitoba

5.4.1 Market Overview

Energy Demand

In 1998, abundant hydroelectricity accounted for 39 percent of total energy requirements in Manitoba. Oil and natural gas comprised 30 and 23 percent, respectively.

Natural Gas Market

Manitoba is a small natural gas market. In 1999, Manitoba consumed 2 016 10^6m^3 (71.2 Bcf) of natural gas. Together, the residential and commercial sectors accounted for 82 percent of total demand. The industrial sector only accounted for 18 percent of gas demand.

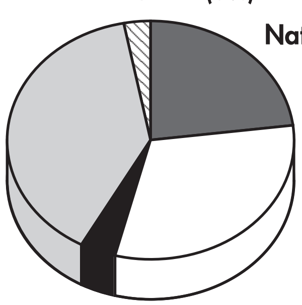
Centra Gas Manitoba Incorporated[1] (Centra) distributes natural gas to more than 243,000 customers throughout southern Manitoba. Centre is regulated by the Public Utilities Board of Manitoba (PUBM).

Since 1991, core customers have had the option to buy gas directly from a supplier other than Centra[2]. Direct sales currently represent over one-quarter of all sales in the province. The residential market accounts for approximately 70 percent of direct sales while the industrial and commercial markets account for 30 percent. Approximately 20 percent of all residential consumers purchase gas directly from suppliers other than Centra.

The PUBM maintains a list of all gas marketers registered and licensed to do business in Manitoba.

FIGURE 5.4.1

Manitoba Energy Mix by Fuel Type, 1998



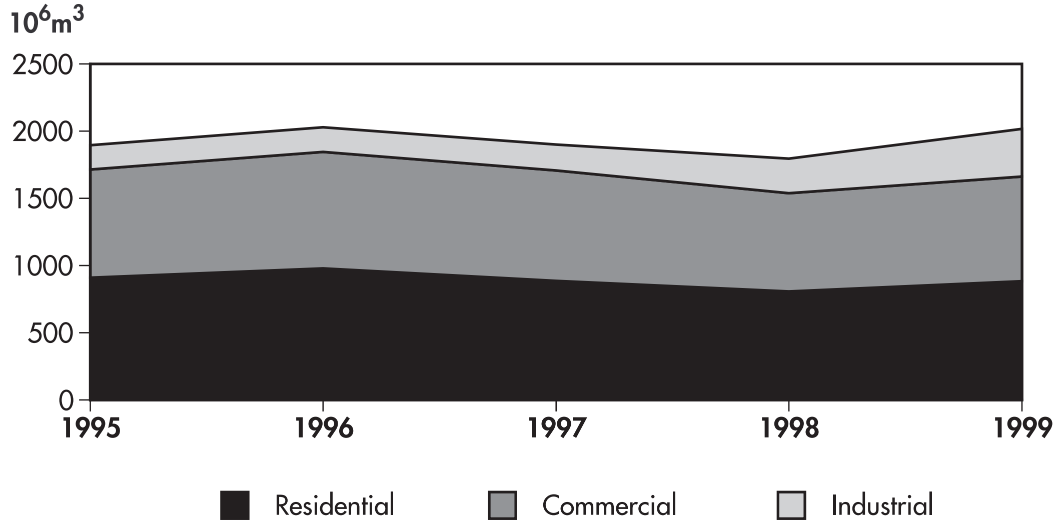
Source: Statistics Canada

1 Centra is a wholly-owned subsidiary of Manitoba Hydro, a crown corporation.

2 A pamphlet entitled "A guide to the purchase of natural gas in Manitoba" provides further information. It is available by contacting Centra or the MPUB.

FIGURE 5.4.2

Manitoba Natural Gas Demand 1995-1999



Source: Statistics Canada

Natural Gas Supply and Transportation

Almost all gas consumed in Manitoba comes from Alberta and Saskatchewan via the TCPL-Mainline system. Gas is exported at Emerson, Manitoba where TCPL facilities interconnect with the Viking Gas Transmission Company and Great Lakes Gas Transmission.

Centra's gas supply portfolio is diversified and includes short-term and long-term contracts. Nearly all gas contracts have prices which are indexed to AECO-C/NIT and vary monthly with market fluctuations.

Since 1991, core customers have bought gas directly through Buy/Sell Arrangements. This mechanism is scheduled to be phased out by November 2001. In May 2000, Centra introduced a Western T-Service, which provides consumers with the option of entering into a contract with a marketer to provide gas supply at an agreed upon price. The marketer would purchase gas supply on behalf of its customers and provide that supply to Centra for delivery to the consumer. Centra would then bill the consumer for the gas supply, at the previously agreed upon price, and pay the natural gas marketer on behalf of the consumer. This is very similar to the ABC-T Service offered to Ontario customers.

5.4.2 Regional Prices

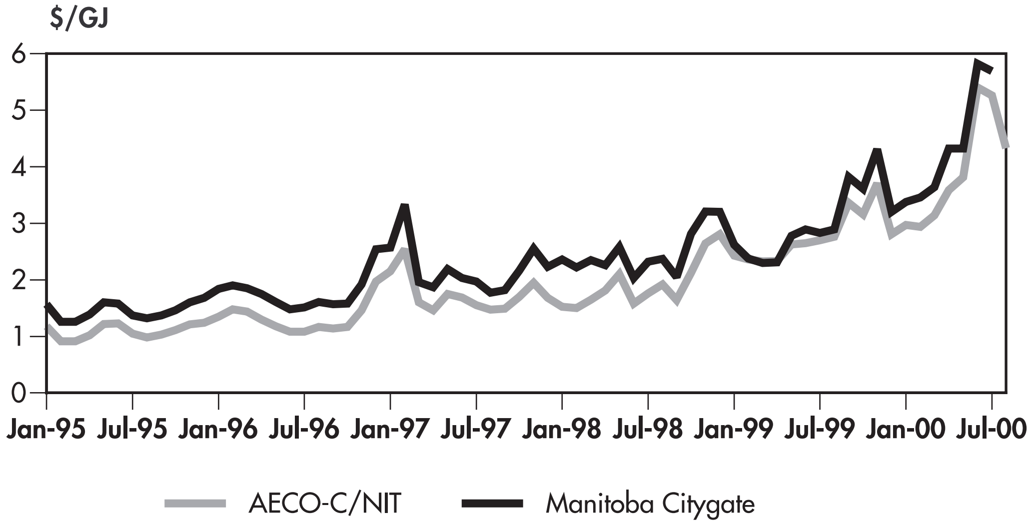
Between 1995 and 1999, the difference between prices at AECO-C/NI T and prices at the Manitoba Citygate was about $0.42, on average, or roughly the cost of transporting gas between these two points. This indicates that the Manitoba market is integrated with the Alberta market (Figure 5.4.3).

End-use Prices

Figure 5.4.4 depicts the change in the delivered price of natural gas for a residential household in the Centra delivery area with an average consumption of 3 500 m^3 per year. Prior to July 1999, the cost of transportation was bundled together with distribution charges to produce a total cost of delivery. As indicated by the graph, the increase in the delivered cost of gas is almost entirely attributable to

FIGURE 5.4.3

AECO-C/NIT vs. Manitoba Citygate Prices



Source: Canadian Natural Gas Focus

the rising costs of gas supply. In 1995, the cost of gas supply represented 28 percent of the total annual delivered cost of gas while transportation and delivery represented about 72 percent. Under the rate schedule effective November 2000, the total delivered cost of natural gas has increased by about 60 percent since 1995. The cost of gas supply now represents about 56 percent while transportation and delivery accounts for about 44 percent of the total annual cost of gas.

In October 2000, Municipal Gas Manitoba, an energy marketer, was offering residential consumers a three-year fixed rate for natural gas supply of $0.2140 per cubic meter.

Recent developments

Centra received approval to implement a new rate management program, that would adjust rates on a quarterly basis effective 1 August 2000. This program will minimize the impact of rapidly changing prices of natural gas as rates were previously set twice a year. Significant amounts were accumulated in Centra's deferral accounts (the difference between the cost of gas included in rates and the actual cost of gas) which, ultimately, must be recovered from consumers.

5.4.3 Regional Dynamics

Until the introduction of T-Service, ABMs were only offering rebates against Centra's WACOG. This provided some assurances to end-users that they would not pay more than Centra's WACOG. In the event that a marketer was unable to provide gas supply according to the contract terms, Centra will attempt to provide the consumer with the required gas supply but the price paid for the natural gas could be higher than either the agreed upon contract price or the WACOG.

Higher natural gas prices are not expected to have a significant impact on the residential demand for natural gas as it is the predominant fuel used for home heating and still compares favourably with other alternative fuels in term of price (Figure 5.4.5). Of note, this market is saturated with 93 percent of households in the City of Winnipeg using natural gas. In rural areas, where natural gas distribution is not available, electricity and fuel oil are used for space heating.

Natural gas consumption is not expected to grow significantly in the province. Unlike many other provinces, the demand for natural gas for electricity generation is not expected to increase significantly in Manitoba because of the province's abundant hydro resources.

5.4.4 Summary

Gas buyers in Manitoba have access to gas supplies from Western Canada and over 80 percent of residential customers purchase gas directly from suppliers other than Centra. Natural gas prices in Manitoba are integrated with the Alberta market. For a typical residential customer, the commodity cost of gas accounts for over 50 percent of the total delivered cost of natural gas.

FIGURE 5.4.4

Residential Gas Price Components - Centra

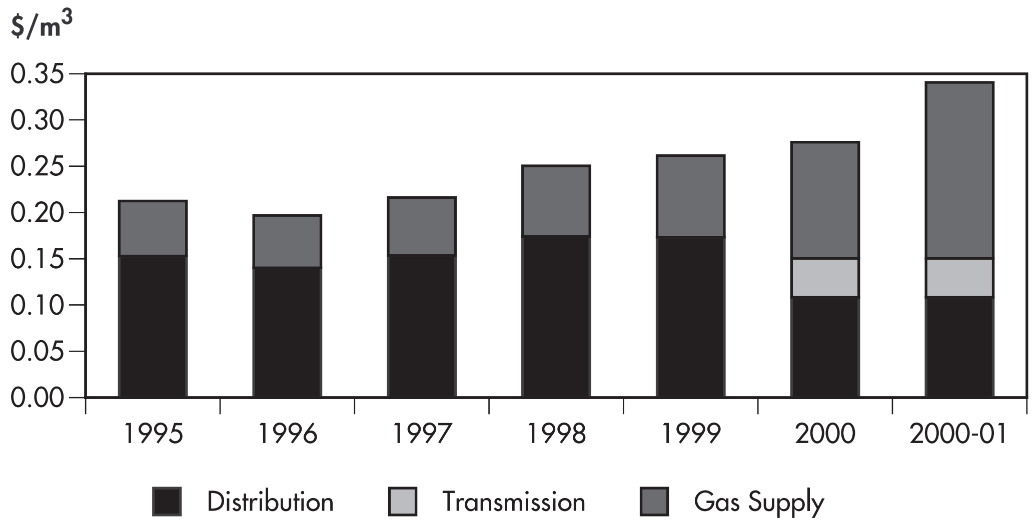
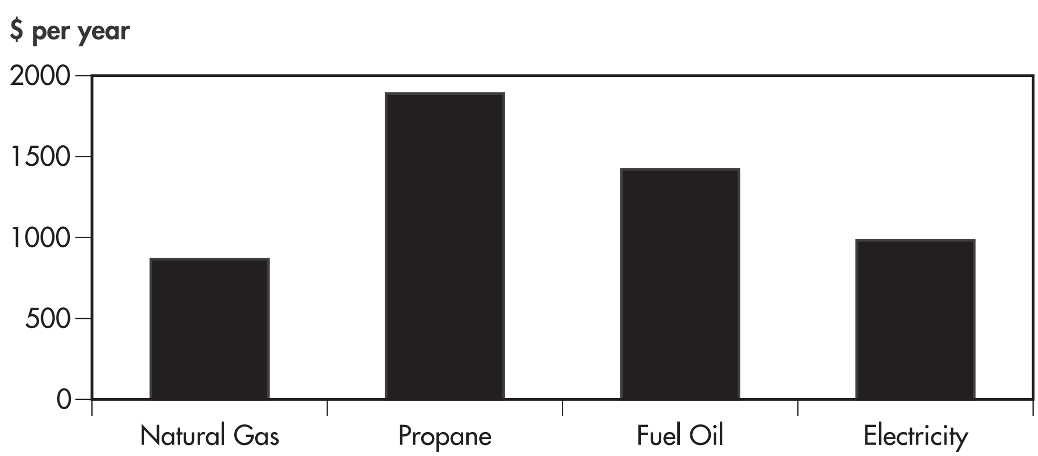


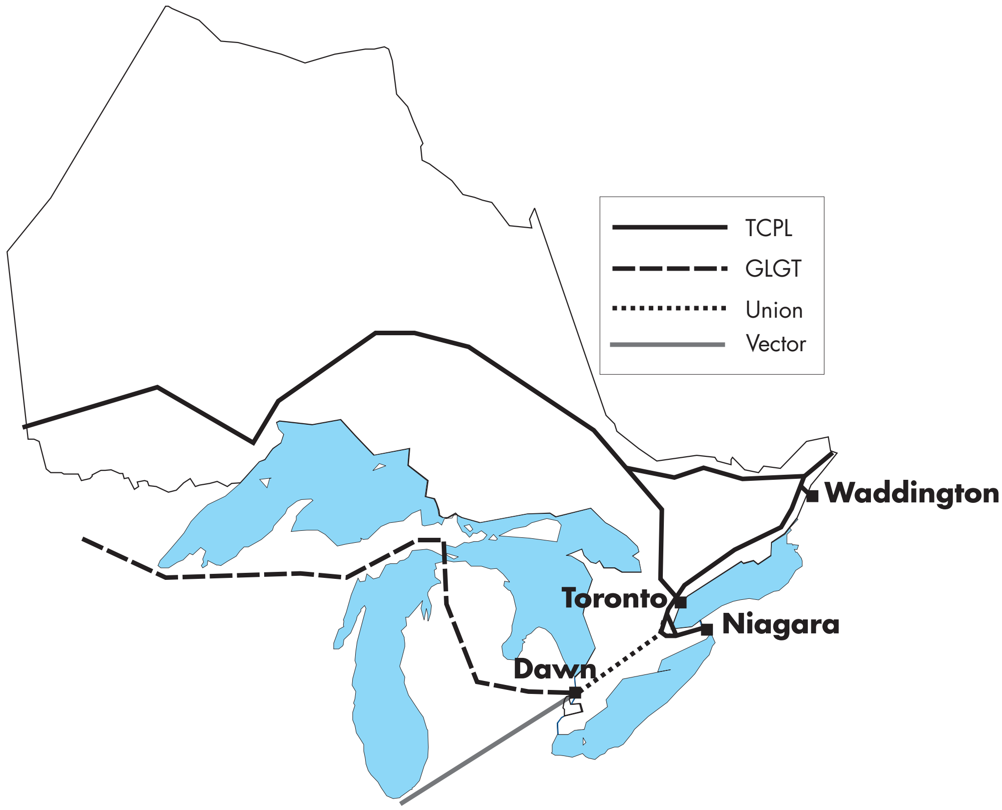
FIGURE 5.4.5

Manitoba Annual Heating Fuel Costs



Source: Centra

5.5 Ontario



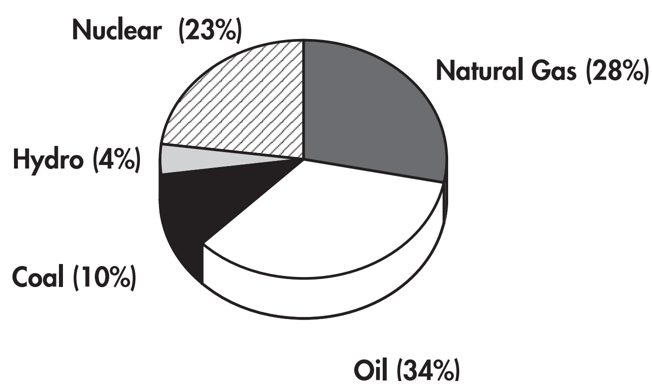
5.5.1 Market Overview

Energy Demand

Oil meets one-third of Ontario's energy requirements followed by natural gas at 27 percent. Nuclear and coal account for 22 percent and 10 percent, respectively. Nuclear is an important fuel in Ontario as approximately 45 percent of electricity generation comes from nuclear facilities (Figure 5.5.1).

FIGURE 5.5.1

Ontario Energy Mix by Fuel Type, 1998



Source: Statistics Canada

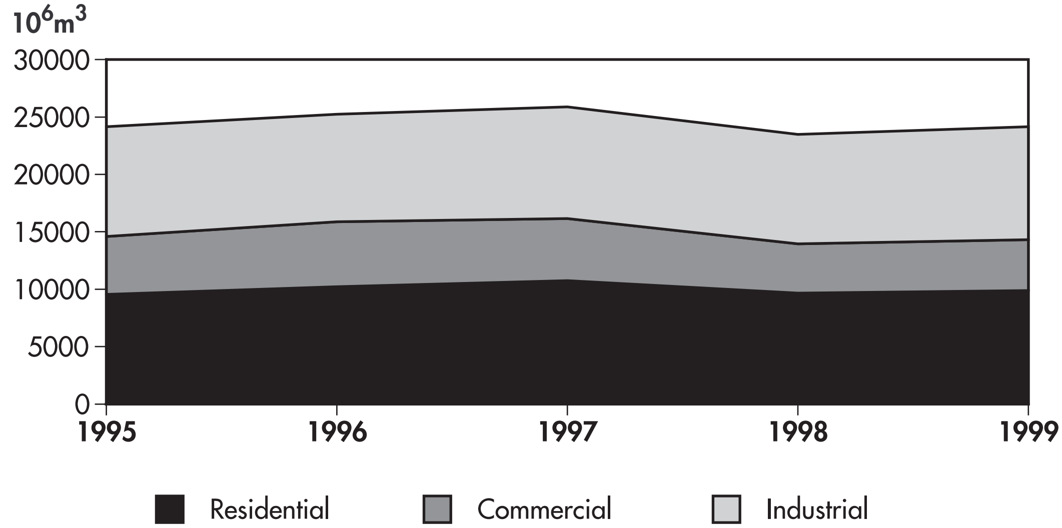
Natural gas market

Ontario is the largest market for natural gas in Canada. In 1999, gas sales totalled 24 148 10^6m^3 (852 Bcf) (Figure 5.5.2). The industrial and residential sectors each account for over 40 percent of total sales. The commercial sector represents 18 percent. Direct sales now represent 54 percent of the total market for natural gas in Ontario.

The two major LDCs in Ontario are Union Gas Limited[1] (Union) and Enbridge Consumers Gas (Enbridge)[2]. Enbridge is the largest natural gas distribution company in Canada with over 1.4 million customers in eastern and southeastern Ontario. Union provides distribution services to more than one

FIGURE 5.5.2

Ontario Natural Gas Demand 1995 - 1999



Source: Statistics Canada

million customers in northern, eastern and southwestern Ontario. The LDCs are regulated by the Ontario Energy Board (OEB).

In 1999, Enbridge distributed over 11 330 10^6m^3 (400 Bcf) of natural gas. Approximately 30 percent of this volume was for customers purchasing system gas from Enbridge while the remainder was transported on the behalf of other parties.

Transmission

In addition to its distribution system, Union also operates important transmission facilities that connect with the TCPL-Mainline system and several pipelines from the U.S. In 1999, Union transported 34.6 10^9m^3 (1,220 Bcf) of gas to customers. Approximately 42 percent of the total volume was for customers within Union's franchise while 58 percent was transported to customers outside of Union's franchise area, including Enbridge, TCPL, GMi, and export customers delivering natural gas to markets in the U.S. Northeast.

Union's transmission facilities are bi-directional. During the winter months, gas flows from west to east to serve markets in eastern Canada and the U.S. Northeast. Typically, gas is injected into storage at Dawn during the summer months and flows east to west. The current capacity from Dawn to TCPL (interconnects at Kirkwall and Parkway) is 145.3 10^6m^3/d (5.13 Bcf/d). Union Gas plans to expand this capacity to 154.4 10^6m^3/d (5.45 Bcf/d) by November 2001.

Enbridge has interconnections with the pipeline transmission facilities of TCPL, Union, and ANR/MichCon via the Link Pipeline. These interconnections provide services to shippers and consumers in eastern Canada, and the U.S. Midwest and Northeast markets.

1 Union Gas Limited is a wholly-owned subsidiary of Westcoast Energy.

2 Enbridge Consumers Gas is a wholly-owned subsidiary of Enbridge Inc.

Natural Gas Supply

In 1999, Union purchased a total of 3 400 10^6m^3 (120 Bcf) of natural gas. Approximately 69 percent of supplies were purchased from Western Canada, four percent from Ontario production and the remainder was supplied from the United States. Natural gas supplies from the WCSB comprised 90 percent of Enbridge's gas supply portfolio.

Storage

Union owns and operates Canada's largest underground natural gas storage facility near Dawn, Ontario. The storage facilities have a working capacity of 3,900 10^6m^3 (137 Bcf) with a deliverability of 10.7 $10^6m^3/d$ (3.0 Bcf/d). Storage at Dawn balances the loads of Union's franchise customers and is also contracted out to ex-franchise LDCs, including Enbridge and GMi. Withdrawals from storage also augment TCPL-Mainline's transmission capabilities during peak demand periods.

The combination of physical storage and multiple interconnecting pipelines provides Union with the opportunity to provide transactional hub services to assist other pipelines and shippers to balance upstream supply with downstream market demands. In 1999, an estimated 3.7 Bcf/d of natural gas title transfers took place within Union's facilities at Dawn, making it one of the fastest growing market hubs in North America.

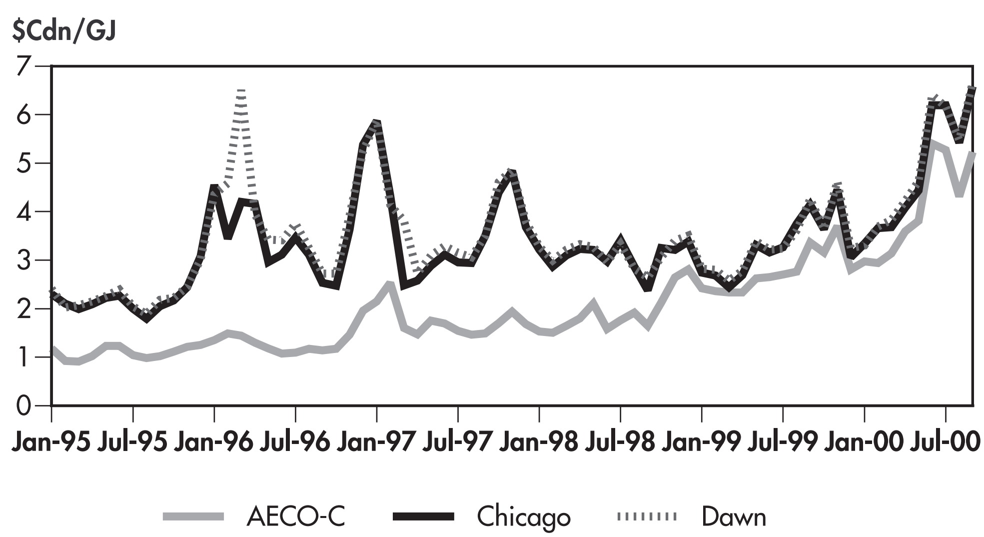
Enbridge is the owner and operator of Tecumseh Gas Storage in also located near Dawn, Ontario. The storage facility has a working capacity of 2 500 10^6m^3 (90.0 Bcf) with a peak deliverability of 42.5 $10^6m^3/d$ (1.5 Bcf/d).

5.5.2 Regional Prices

Figure 5.5.3 compares the price of natural gas at AECO-C/NIT, the primary pricing point for natural gas in Alberta, with the price at Dawn, the major pricing point for natural gas supplies in Ontario and with the Chicago city-gate price, one of the primary pricing points for natural gas in the U.S. Midwest. The chart indicates that wholesale gas prices in Ontario and the U.S. were closely related

F I G U R E 5 . 5 . 3

AECO-C/NIT vs. Dawn vs. Chicago Prices



Source: Canadian Natural Gas Focus

over the entire period. On the other hand, prices between Alberta and Ontario were less closely related, particularly until late 1998. Prior to 1998, the price of natural gas in Alberta and Ontario differed by as much as $5.00/GJ. With the construction of additional pipeline capacity out of the Alberta market in late 1998, the price differential has decreased significantly, and is equal to the approximate value of transportation between the two pricing points. This indicates that the Ontario market has become integrated with the Alberta market since early 1999.

A new rates schedule for Union Gas was approved effective 1 October 2000. Based on an annual consumption of 3 500 m^3 (123.6 Mcf), an average residential consumer in southwestern Ontario pays a total of $1132.30 for natural gas over a one-year period. The cost of natural gas represents approximately 61 percent of the total amount while transportation and distribution costs represents 11 and 28 percent, respectively (Figure 5.5.4). Under the previous rates effective 1 June 00, the cost of gas represented approximately 54 percent of the annual residential natural gas bill.

Figure 5.5.5 depicts the change in the delivered price of natural gas for a residential household in the Enbridge delivery area with the same average consumption. Enbridge combines the cost of transportation with the cost of distribution to produce a total cost of delivery. As indicated by the graph, the increase in the delivered cost of gas is almost entirely attributable to the rising costs of gas supply. The cost of gas, which represented 30 percent of the total annual delivered cost of gas in 1995, now accounts for 56 percent of total cost.

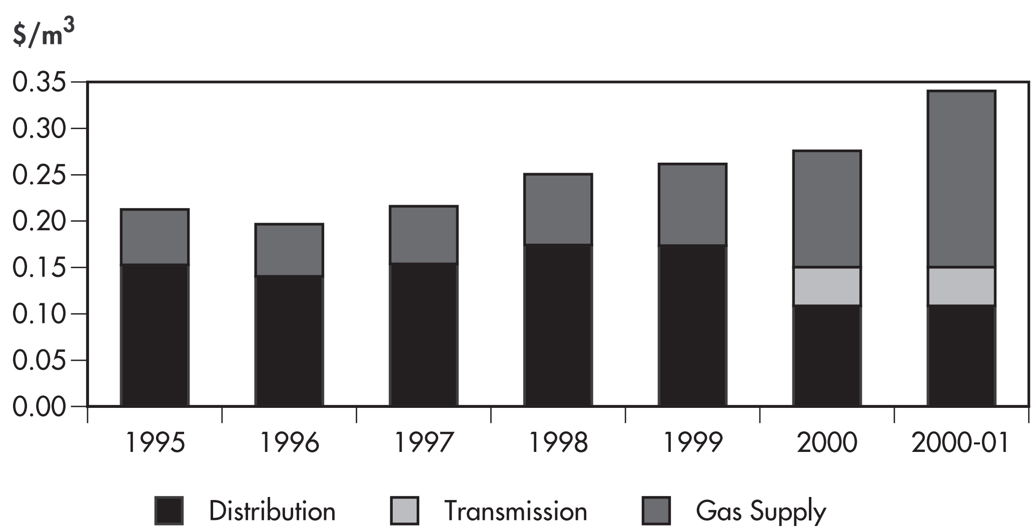
The three largest energy marketers in Ontario are Direct Energy Marketing, the Ontario Energy Savings Corporation, and Sunoco Home Energy. In October 2000, these marketers were offering fixed-rate contracts for natural gas supply ranging from $0.219 per cubic metre for three years to $0.265 cubic metre for a five-year term.

5.5.3 Market Dynamics

Deliveries on the Vector Pipeline are expected to start in November 2000. The pipeline is designed to transport Canadian and U.S. sourced natural gas from the market hub in Chicago, Illinois, to the hub at Dawn, Ontario. The initial capacity of 725 MMcf/d can be increased to1.5 Bcf/d with additional compression. This pipeline will increase diversity and provide further transportation options for Ontario consumers.

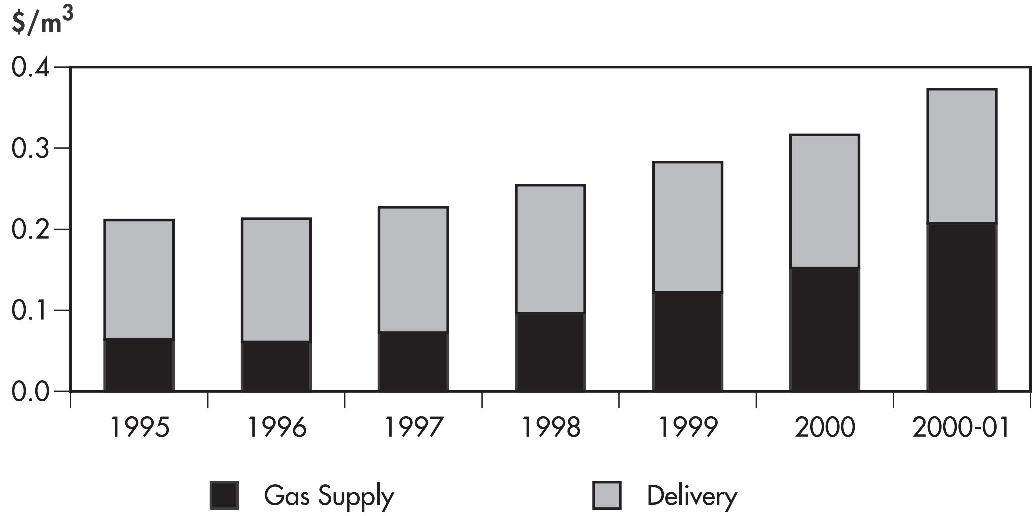
F I G U R E 5 . 5 . 4

Residential Gas Price Components - Union



F I G U R E 5 . 5 . 5

Residential Gas Price Components - Enbridge



Both Enbridge and Union are moving towards the further unbundling of their businesses and services into monopoly and competitive components. Performance Based Regulation (PBR) is designed to provide a framework to facilitate the unbundling of these services by allowing companies to earn returns that are commensurate with the levels of competitive risk in each business segment while providing rate certainty for the consumers of monopoly services.

The OEB has recently approved a PBR plan limited to operations and maintenance for Enbridge while an application by Union for a comprehensive five-year PBR is currently under review.

The OEB has convened a task force to examine the rules and regulations pertaining to customer mobility, service unbundling, and how the LDCs should deal with retailers and end-users. The expected result is a rulemaking pertaining to access to distribution services. OEB staff have indicated that the goal of this process is to develop rules that are non-preferential and non-discriminatory, that maintain symmetry with developments in the market for electricity, and that standardize business practices across gas distributors.

In 1998, the Ontario government enacted *The Energy Competition Act*, to provide for the competitive restructuring and further deregulation of both the natural gas and electricity markets in Ontario. The competitive electricity market initially proposed for November 2000 but since delayed indefinitely, generated a lot of interest by various market participants. For example, TransAlta Corp. recently announced plans to construct and operate a 440 MW co-generation facility and to acquire existing operations that currently generate another 210 MW of power. It is expected that deregulation of the electricity industry will accelerate convergence in energy markets by facilitating additional competition between fuel sources.

Natural gas is expected to capture almost the entire incremental demand for new electricity generation in Ontario. Due to the environmental attractiveness of natural gas, the use of coal to generate electricity is expected to decline in favour of gas-fired facilities. On the other hand, the future role of nuclear, although currently uncertain, could have a substantial impact on the demand for natural gas to produce electricity. Nuclear facilities comprise 43 percent of total electricity generation in Ontario; however, a portion of existing nuclear capacity is currently non-operational and its status is uncertain. Should these facilities be brought back into service, the role that natural gas has in meeting incremental electricity demand would be restricted. If, on the other hand, these facilities remain non-operational and additional facilities are retired, the increased demand for natural gas would be substantial. Any decision on the future of the non-operational nuclear facilities, as well as the retirement of existing facilities, will be based upon projected electricity prices and costs of operation, as well as environmental and safety concerns pertaining to nuclear power. The decision is not expected to be significantly influenced by the price of natural gas.

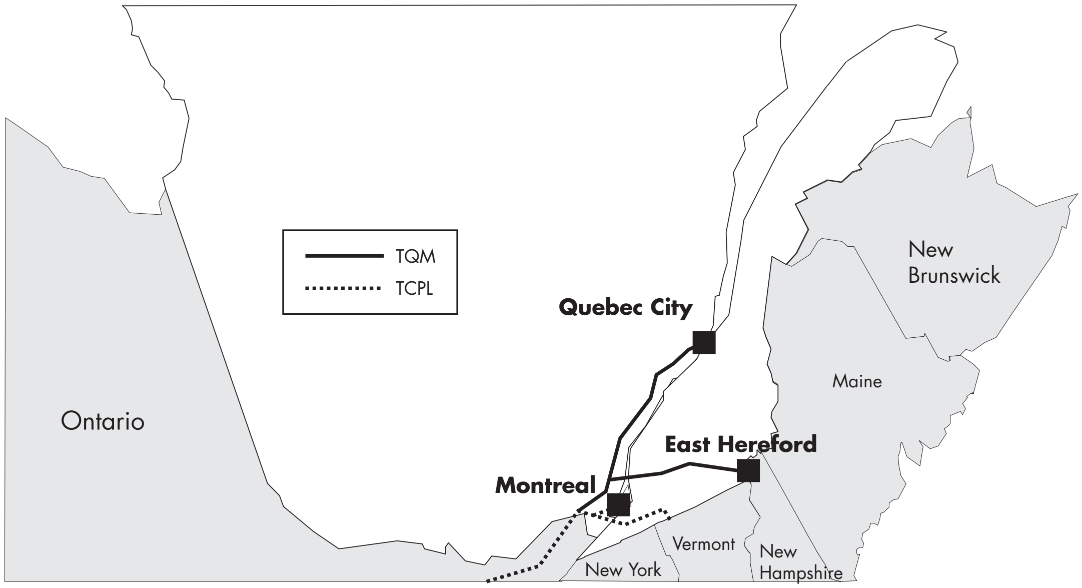
The current high natural gas prices are not expected to have a significant impact on the demand for gas by residential consumers. For example at the current natural gas prices Enbridge Consumers estimates that the use of fuel oil for space and water heating would cost a household approximately 27 percent more while the use of electricity would be about twice as expensive.

5.5.4 Summary

Gas buyers in Ontario have access to gas supplies from the WCSB and the U.S. New pipelines, such as Vector, will provide diversity of supply and transportation options. In addition, security of supply and flexibility is provided by large storage facilities in Ontario.

Natural gas prices in Ontario are linked to Alberta and Chicago prices. Dawn is becoming an important liquid pricing point in Ontario. These pricing points provide market participants with timely and accurate price discovery information.

5.6 Quebec



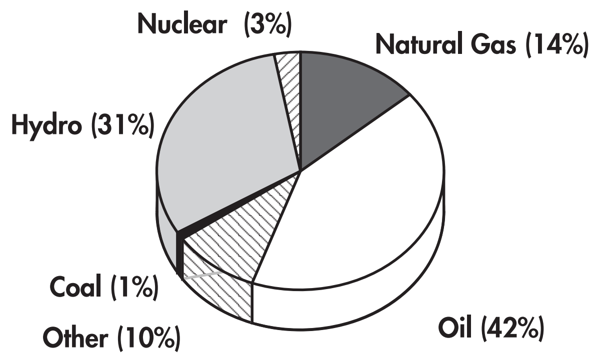
5.6.1 Market Overview

Energy Demand

Quebec is the second largest energy consumer in Canada. Abundant hydroelectricity and imported oil meet 42 and 40 percent, respectively, of the province's energy requirements. The remainder of the province's requirements is met by natural gas. Electricity is used widely in the residential, commercial and industrial sectors.

FIGURE 5.6.1

Quebec Energy Mix by Fuel Type, 1998



Source: Statistics Canada

Natural Gas Market

In 1999, Quebec gas consumption was 6 232 10^6m^3 (220 Bcf). The industrial sector accounted for 60 percent of total demand while commercial and residential represented 28 percent and 12 percent, respectively (Figure 5.6.2). Gas use for electricity generation in Quebec is negligible.

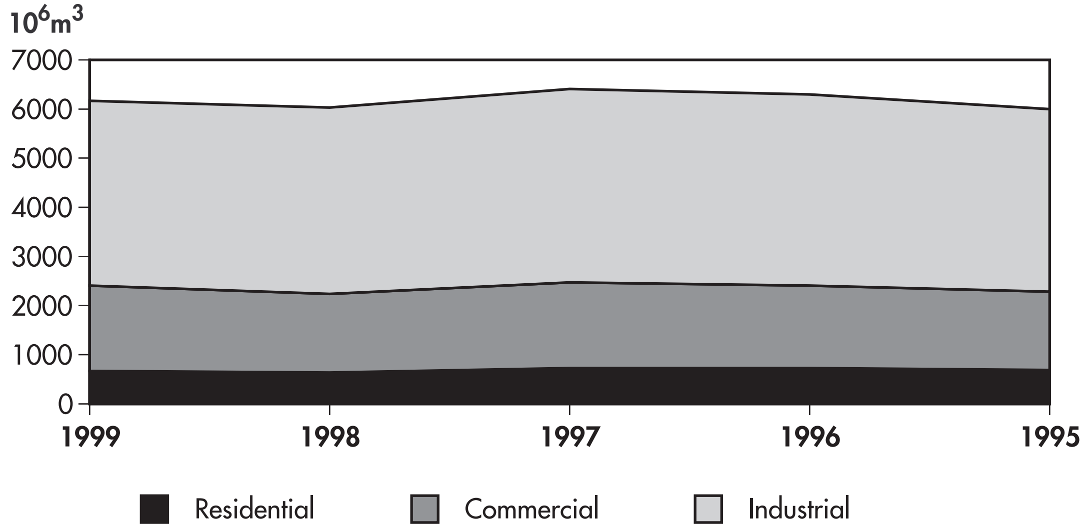
Gaz Métropolitain and Company, Limited Partnership (GMi)[1] is the largest LDC and delivers 97 percent of natural gas consumed in the province. The Gatineau-Hull area is served by Gazifère. The LDCs are regulated by the Régie de l'Énergie (Régie), a provincial regulatory board.

In 1999, about 70 percent of total volumes delivered by GMi were direct purchases whereby consumers acquired gas directly from a supplier of their choice. Direct purchases accounted for 98 percent of the volume in the large industrial sector and 30 percent of the volume in the commercial sector.

1 GMi is owned by Gaz Métropolitain Inc. (77.4%) and the remainder is widely held.

F I G U R E 5 . 6 . 2

Quebec Natural Gas Demand, 1995 - 1999



The largest ABMs in Quebec are TCPL Energy Limited, Duke Energy and Dynegy. Together, they account for approximately 90 percent of direct sale volumes. ABMs provide a range of gas supply services, including that of managing supply portfolios on behalf of their customers.

Natural gas is used in industries such as pulp and paper, smelters and metallurgy and the chemicals industry. In 1999, natural gas use in the industrial sector was 3 739 10^6m^3 (132 Bcf) in GMi's franchise area. The share of interruptible volumes has varied between 45 and 50 percent of total industrial sales over the past five years. This ratio reflects the capability of large industrial to switch between fuels. Accordingly, GMi would be impacted should gas become less competitive than alternative fuels.

For the industrial sector, heavy fuel oil provides the major competition for natural gas. Petroleum products are produced at three refineries in Quebec (total refining capacity at 385,000 barrels per day) and can also be imported readily.

Natural Gas Supply, Transportation and Storage

Almost all gas consumed in Quebec comes from the WCBS via the TCPL-Mainline system. In 1999, GMi purchased 2 266 10^6m^3 (80 Bcf) of gas.

GMi is involved in natural gas transportation through its wholly-owned subsidiary Champion Pipe Line Corporation Limited (CPL) and 50 percent owned subsidiary, Trans Québec & Maritimes Pipeline Inc.[1] (TQM). CPL operates two gas pipelines northwest of GMi's main distribution network in the Abitibi and Témiscamingue areas. The TQM transmission system extends from the TCPL-Mainline system at Vaudreuil to Quebec City.

Two U.S. export points are located on the Quebec border. The Philipsburg point interconnects with Vermont Gas Systems Inc. An extension of the TQM pipeline completed in March 1999 added 5.0 10^6m^3 (175 MMcf/d) of export capacity at East Hereford, Quebec. The TQM extension connects with the Portland Natural Gas Transmission System (PNGTS) for deliveries to the U.S. Northeast market.

1 TQM is owned equally by GMi and TCPL.

GMi has contracted for 600 10^6m^3 (21.2 Bcf) of underground storage capacity at Dawn, Ontario. About 397 10^6m^3 (14 Bcf) of the contracted storage capacity expires in 2003, although renewals are underway. GMi also has access to limited storage capacity in Quebec, at St-Flavien and Pointe-du-Lac to meet peak requirements[1]. Finally, GMi also operates a 2-Bcf LSR (liquefaction, storage and regazification) plant in Montreal-East.

Recent Market Developments

GMi has traditionally concentrated its marketing efforts towards the industrial and commercial sectors because of the prospects for growth and profitability. However, GMi has recently initiated a marketing campaign aimed at residential and agricultural sectors.

GMi has filed a new rate application with the Régie to unbundle the transportation and distribution components. A performance-based regulatory regime was approved by the Régie. This regime will provide incentives to the LDC to improve its overall performance, thereby reducing operating costs over time.

5.6.2 Regional Prices

Core customers in Quebec typically rely totally on the LDC to provide them with an integrated gas service. GMi charges its core customers a WACOG for its gas supply portfolio. Pricing is based on 30-day prices and one-year forward prices at Empress, Alberta and, for small volumes, at AECO-C/NIT. Therefore, end-use prices are closely tied to prevailing market prices in Alberta, which in turn, depend fundamentally on the North American gas supply and demand conditions. Rates are adjusted every month, on a rolling basis. Figure 5.6.3 shows GMi's reference price.

Large customers manage their own gas portfolios or rely on the expertise and services of marketers and brokers to ensure security of supply and hedging. Typically, they have a diversified supply portfolio, composed of volumes bought at fixed as well as indexed prices, and with terms varying up to three years. Contract prices are normally indexed to those at Empress and AECO-C/NIT.

End-use Prices

End-use prices in Quebec have increased significantly over the period 1995 to 2000 (Figure 5.6.4). The gas bill for a residential customer, with an average consumption of 3.8 $103m^3$ (134 Mcf) per year, rose 54 percent over the 1995-2000 period. This increase mainly reflects sharp increases in the commodity cost of gas. The share of the commodity price component rose from 14 percent in 1995 to 45 percent in 2000.

Commercial and industrial consumers have also experienced increases in the price of delivered gas largely because of the increased gas commodity costs. However, large industrial customers may use cheaper interruptible service.

Impact on Consumers

The rapid escalation of natural gas prices has tended to hinder market penetration and has affected many Quebec gas users. Some interruptible customers have switched to other fuels. Large industrial users have seen the share of the gas cost component rising, and to the extent the cost increase cannot be fully passed through in the price of their products, business profits have been affected. A few

1 The use of stored natural gas or liquefied natural gas (LNG) to supplement the normal supply of pipeline natural gas during periods of extremely high demand.

FIGURE 5.6.3

Empress vs. GMi Reference prices

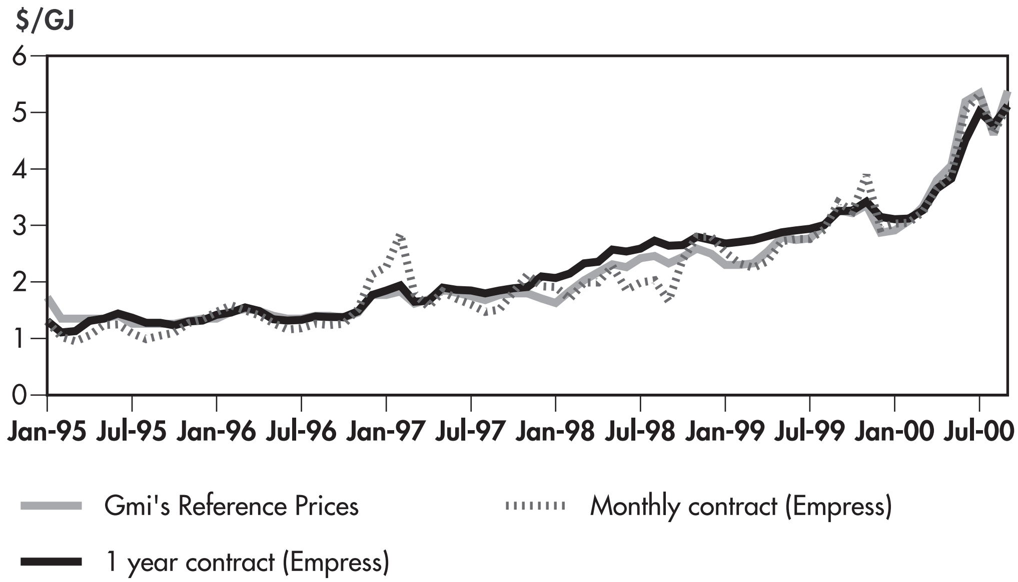
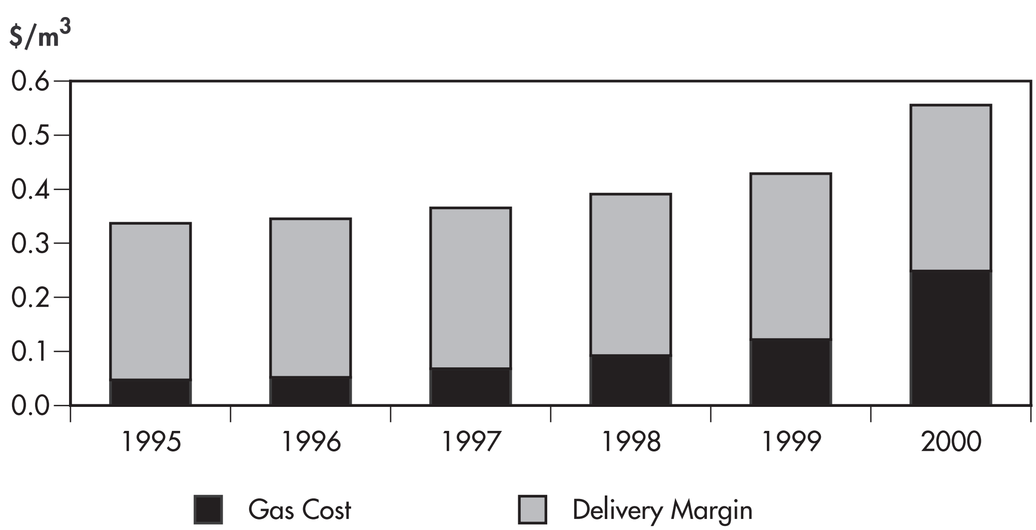


FIGURE 5.6.4

Residential Gas Price Components - GMi



industrial users have even considered reductions in their operations, or ultimately, shutting down their plants if the high price situation continues.

5.6.3 Regional Dynamics

Natural gas demand in Quebec is expected to increase. There are two proposed industrial plants which will use about 153 10^6m^3 (5.4 Bcf) of gas per year.

In order to diversify its supply sources, GMi is proposing the construction of a new pipeline system linking the Quebec natural gas market to Sable Island production basin. The first part of the system would be a lateral of the Maritime & Northeast system from Fredericton to the Edmundston region.

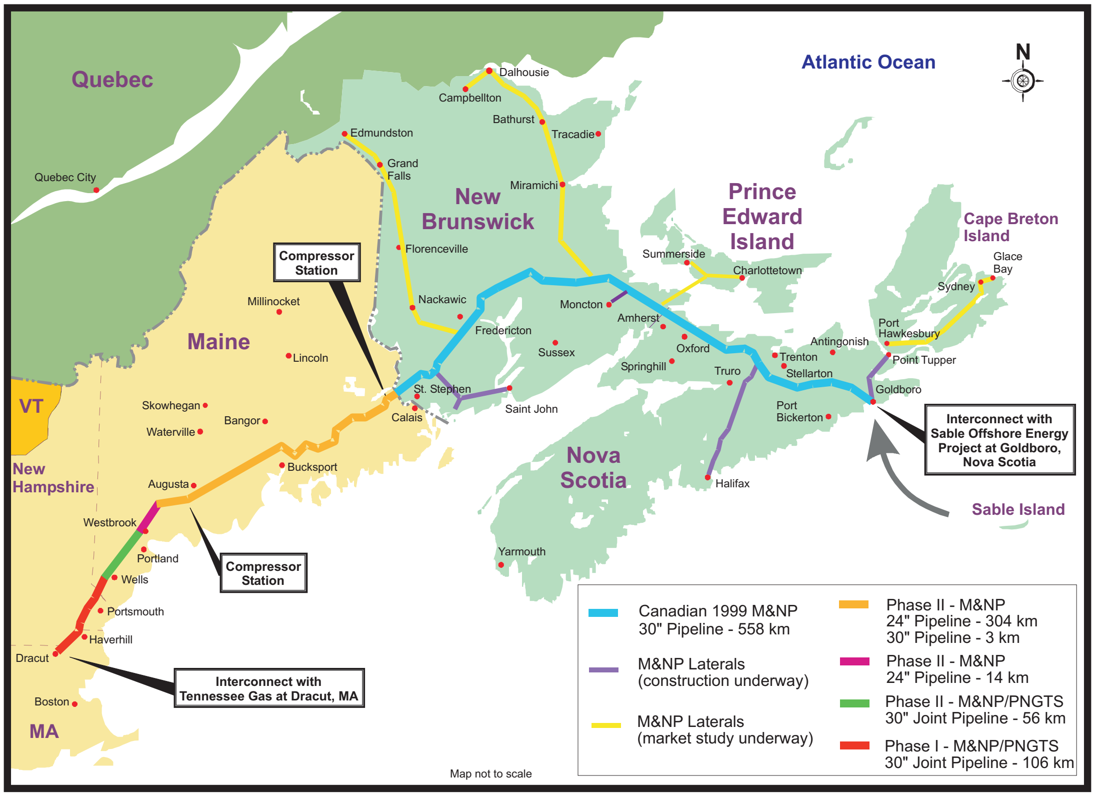
The second part of the system would be a stand alone transportation pipeline extending from the Quebec/New-Brunswick border to the South shore of Quebec City where it would interconnect to the TQM system.

5.6.4 Summary

Gas buyers in Quebec have access to gas supplies from Western Canada. With the commencement of Vector, they will have an opportunity to access Canadian and U.S. gas supplies from Chicago. If the Quebec market is linked to Sable, it would provide an additional source of gas for consumers in the province.

Natural gas prices in Quebec are linked to prices in Alberta.

5.7 Atlantic Market



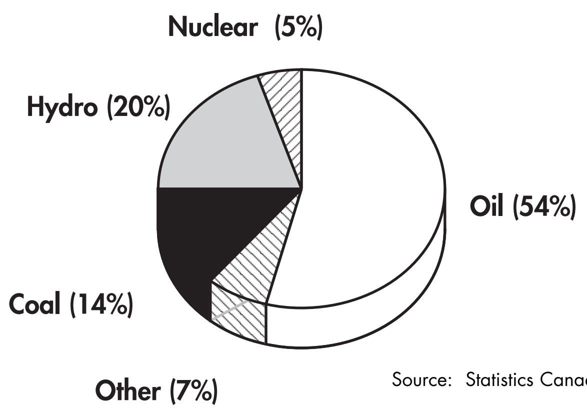
Source: Maritimes and Northeast Pipeline

5.7.1 Energy Demand

The Atlantic region has traditionally relied on fuel oil for over 50 percent of its energy requirements. (Figure 5.7.1). In particular, homes in the Atlantic region are predominantly heated by oil. The use of hydro and coal is also significant. Other fuels include wood, hog fuel and pulping liquor.

FIGURE 5.7.1

Atlantic Provinces Energy Mix by Fuel Type, 1998



Source: Statistics Canada

5.7.2 Overview of the Developing Gas Market

Natural gas service will be introduced to the Maritimes in late 2000, as parts of Nova Scotia and New Brunswick begin to receive gas flowing from the Sable Island area. The Sable Offshore Energy Project (SOEP)[1], which consists of natural gas producing, gathering and processing facilities, along with the Maritimes & Northeast Pipeline (M&NP)[2] mainline transmission project and local distribution systems, will provide the cities of Halifax, N.S. and Moncton, Fredericton and Saint John, N.B. the first opportunity to utilize natural gas as a source of energy.

1 SOEP owners: Mobil, 50.8%; Shell, 31.3%; Imperial, 9%; Nova Scotia Resources, 8.4%; and Mosbacher , 0.5%.

2 M&NP owners: Westcoast, 37.5%; Duke, 37.5%; Mobil, 12.5%; and Nova Scotia Power Corp., 12.5%.

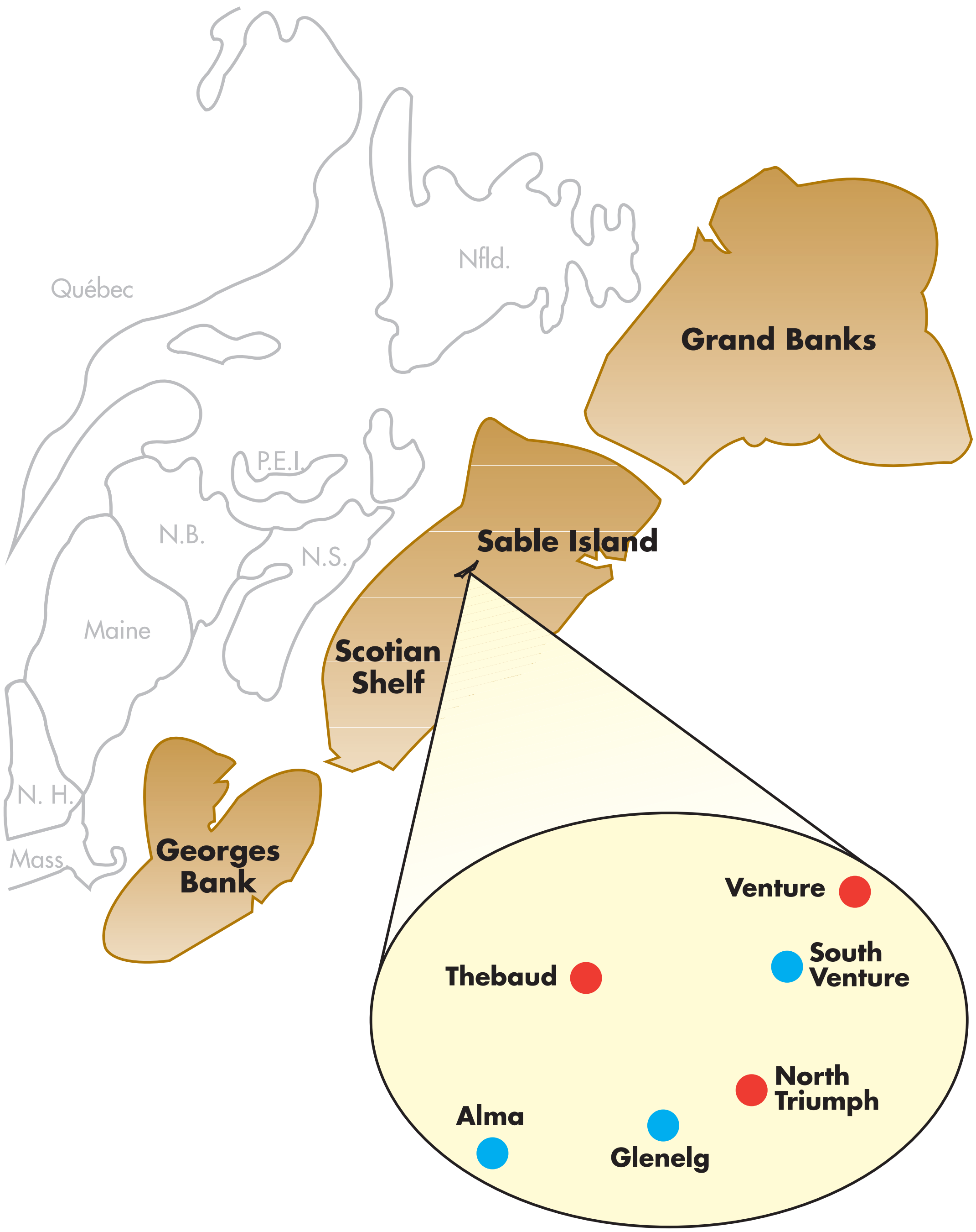
The remaining Atlantic provinces, Prince Edward Island and Newfoundland, have also been examining the feasibility of obtaining natural gas service, the former from Sable Island and the latter from areas offshore Newfoundland.

Natural Gas Supply

The six fields within SOEP contain established reserves totalling 85 10^9m^3 (3 Tcf) with the ultimate potential of the overall Scotian Shelf estimated to be 510 10^9m^3 (18 Tcf) by the Geological Survey of Canada. Production from SOEP commenced in December 1999 and is expected to reach

FIGURE 5.7.2

East Coast Supply Areas



14.4 $10^6m^3/d$ (510 MMcf/d) by fall 2000, the limit of the current production facilities of about 17.0 $10^6m^3/d$ (600 MMcf/d). An expansion of these facilities is currently being reviewed (Figure 5.7.2).

In the last year, PanCanadian Petroleum Limited (PanCanadian) announced the discovery of natural gas under its Cohasset-Panuke oil field area, located about 40 km west of Sable Island. While PanCanadian is still drilling test wells, results to date indicate that the gas accumulation could approach Sable Island in size. Production from this area could commence in about three years.

Producers are also exploring for additional gas supplies from deep water areas (600 to 3,000 feet) off the Scotian Shelf. Other areas of interest include the Laurentian Basin and Georges Bank. Total East Coast resource potential, estimated to be approximately 2 150 10^9m^3 (76 Tcf), represents about 11 percent of the Canadian ultimate natural gas resources potential.

Transportation

From the processing plant located at Goldboro, N.S., the combined Canadian and U.S. M&NP mainline transmission system transports processed natural gas to markets in N.S/, N.B., Maine and New Hampshire, before interconnecting with the existing North American pipeline grid near Dracut, Massachusetts. The contracted capacity on the M&NP system is $14.410^6m^3/d$ (508 MMcf/d) in Canada and 9.8 $10^6m^3/d$ (345 MMcf/d) in the U.S., the difference being the volumes absorbed by the domestic market. Capacity could increase to about 28.3 $10^6m^3/d$ (1 Bcf/d) with the installation of additional compression on the existing system.

In addition to the Canadian natural gas mainline facilities, two eight-inch pipelines (buried in the same trench) extend from the Goldboro processing plant to Point Tupper on Cape Breton Island, N.S.. The dual line, which crosses the Strait of Canso, includes a natural gas liquids (NGLs) line to a fractionation plant in Port Hawksbury on Cape Breton Island and a natural gas lateral line to Point Tupper. Gas service on the Point Tupper lateral is expected to commence in late 2000 while delivery of NGLs to Cape Breton Island commenced in April 2000.

M&NP is currently constructing two other laterals - one to Halifax, N.S. and the other to Saint John, N.B.. The three domestic laterals will have a capacity of about 9.9 $10^6m^3/d$ (350 MMcf/d) of which half is currently subscribed. Almost all of the subscribed capacity is contracted under firm service agreements with power generation and large industrial customers.

Feasibility studies are underway for potential future laterals to serve Northern Cape Breton Island, Northern New Brunswick and Prince Edward Island. In addition, various pipeline companies are considering interconnecting at the Quebec/New Brunswick border with a Northern New Brunswick lateral after 2003.

To facilitate development of the Canadian market, SOEP, M&NP, and the provinces of Nova Scotia and New Brunswick signed an agreement in 1997, referred to as the *Joint Position on Tolling and Laterals*, the main purpose of which is to lower the mainline rate for deliveries to Nova Scotia and New Brunswick. As part of this agreement, M&NP agreed to discount firm service tolls to delivery points located in Nova Scotia by 10 percent for the initial eight years, and by four percent for each of the succeeding two years. M&NP also agreed to discount firm service tolls to New Brunswick delivery points by four percent for the initial three years.

Distribution Systems

In 1999, Sempra Atlantic Gas Inc. (Sempra)[1] and Enbridge Gas New Brunswick (EGNB)[2] were awarded general distribution franchises in Nova Scotia and New Brunswick, respectively, to serve residential, commercial and industrial customers. Of note, the M&NP lateral policy poses a challenge for the distribution companies. This policy essentially permits large industrial consumers, including electricity generators, to bypass the LDCs, if the required lateral meets an economic test[3]. As a result, some of the typical distribution base load of large gas consumers may be absent.

As part of its franchise proposal, Sempra committed to providing service to 78 percent of households and to access all 18 counties within seven years. Construction of portions of the Nova Scotia distribution system commenced in September 2000 in the Halifax/Dartmouth areas, with deliveries expected to commence by late 2000 or spring 2001. EGNB commenced construction in its franchise area in August 2000. Service to Fredericton, Oromocto, Saint John, St. George, Riverview, Dieppe and Moncton is expected to commence prior to the end of 2000.

Sempra and EGNB are regulated by the Nova Scotia Utilities and Review Board (NSURB) and the New Brunswick Board of Commissioners of Public Utilities (NBPUB), respectively.

5.7.3 Regional Prices

Commodity Prices

To the extent that most of the production from Sable Island will be consumed in New England, the Nova Scotia and New Brunswick City Gate prices will be determined by the Boston City Gate price, less U.S. transmission costs. In other words, if the price at Boston is US$4.00/MMBtu, the price in Goldboro (i.e., the commodity price at the M&NP receipt point) would be about US$3.29/MMBtu or Cdn$4.58/GJ[4].

Transmission Tolls

The toll on the Canadian mainline portion, from Goldboro to the international border, is expected to be about $0.69/GJ to a maximum of $.71/GJ[5], with discounts for deliveries to Nova Scotia and New Brunswick during the initial years. For the U.S. portion of the MN&P system, the U.S. Federal Energy Regulatory Commission has approved a firm service toll of US$0.715/MMBtu.

Distribution Tolls

Nova Scotia

To attract core customers, Sempra is proposing to guarantee customers a five percent savings relative to other heating fuel costs. Sempra is also planning other incentives to encourage conversion to natural gas.

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1 A unit of Sempra Energy International, which is a subsidiary of Sempra Energy.

2 63 percent owned by Enbridge Consumers Energy and 37 percent by New Brunswick investors.

3 Economic feasibility test has a threshold of $0.60/MMBtu.

4 Boston price less U.S. Transmission = US$4.000/MMBtu - US$ .715/MMBtu = U$3.285/MMBtu Goldboro Price. This represents about Cdn$4.83/MMBtu or Cdn$4.58/GJ, based on a conversion rate of 1.054615 GJ/MMBtu and an exchange rate for the Canadian dollar of $0.68 U.S.

5 A conversion rate of 1.054615 GJ/MMBtu has been applied.

Sempra's proposed rate plan provides that distribution rates will be indexed to the Nova Scotia price of light fuel oil (LFO). The total delivered rate would be set so that costs to all consumers would be at least five percent less than the LFO delivered price. As oil prices fluctuate, the distribution rates will be adjusted monthly to ensure that the customer receives a discount. The distribution rates would also be subject to a proposed cap at approximately $7.00/GJ. Sempra has applied to the NSURB for approval of its distribution rates, and a decision from NSURB is expected in early 2001.

New Brunswick

For an initial development period, EGNB's distribution rates will be market based rather than cost-based rates. If gas prices increase significantly, EGNB has the flexibility to lower the distribution rate to maintain the competitive price relationship of natural gas without having to formally re-apply to the NBPUB.

In June 2000, the NBPUB approved EGNB's rate setting methodology. This methodology will provide discounts against fuel oil and electricity. EGNB's approved residential target rate includes a monthly charge of $8.00 and a delivery rate of $3.34/GJ[1], which would total about $4.00/GJ for an average customer. Table 5.7.1 shows the proposed discount level offered to customers.

TABLE 5.7.1

New Brunswick Distribution Rate Discounts to Fuel Oil

Residential and Small Businesses	30%
Medium to Large Institutions	15%
Large Industrial Customers	5%

Unlike some other market regions, there are no gas storage facilities in the Atlantic region. To optimize transportation rates, natural gas marketers in both provinces will be responsible for balancing their own fluctuating distribution load requirements. They will also be expected to hold firm capacity on distribution systems. Consequently, marketers in New Brunswick will charge customers, in addition to the commodity price, a load balancing fee (e.g., for peaking service or secondary market capacity) and marketer margins. Whether similar fees will be charged by marketers in Nova Scotia has yet to be determined.

End-use Prices

After adding Canadian transmission and distribution costs, as well as any marketer margins, to the commodity cost, the Nova Scotia and New Brunswick long-term delivered prices to the residential sector are expected to be about $9.00 to $11.50/GJ, depending on commodity price fluctuations. However, as markets are developed and pipeline throughput increases, transportation and load-balancing costs should decrease and reduce the overall delivered price of gas.

The transmission toll will represent about six to eight percent of the domestic delivered gas price. While Nova Scotia distribution rates have not been set, EGNB's residential rate will represent up to 50 percent of the delivered gas price; distribution rates for the commercial and industrial sectors in New Brunswick will account for about 20 and 25 percent, respectively, of the total delivered costs.

1 Assuming an average household consumes about 12.5 GJ per month, the $8.00 monthly charge would represent approximately $0.64/GJ.

5.7.4 Market Dynamics

Competing Fuel Prices

Rising natural gas costs, along with high conversion costs from oil or electricity, may impact the competitiveness of gas in the Atlantic region in the short term. However, fuel oil prices have also increased and are expected to remain high through at least the fourth quarter 2000. The American Petroleum Institute recently stated that U.S. supplies (especially the U.S. Northeast) of crude oil and petroleum products, such as heating oil and diesel fuel, are at record lows. Refiners usually switch to producing LFO/diesel fuel in late August or early September; however, there is concern that refinery runs this fall will not be able to replenish heating oil stocks quickly enough to meet seasonal heating demand. Consequently, heating oil prices may increase further during the winter of 2000/2001. Limited LFO supplies in the U.S. Northeast region last winter caused sharp spikes in prices in that region as well as in the Atlantic provinces.

Propane, another heating fuel that is extracted from the Sable gas supply at the Point Tupper fractionation plant, is expected to be competitive with natural gas. The recent price of Atlantic propane supply has been competitive with the historical supply of propane transported from Sarnia. However, the market share of propane for the region should increase only slightly.

Impact of U.S. Northeast Market

In light of its proximity and size, dynamics in the U.S. Northeast market (which includes New England) will have an impact on the price of natural gas in the Maritimes. Gas demand projections show significant growth will occur in the U.S. Northeast over the next few years driven primarily by power plant demand. If this level of growth materializes without any accompanying increase in supplies to the region either from Canada or U.S., natural gas prices may increase. Accordingly, the Atlantic provinces would also experience this increase to the extent that their gas price is determined by the Boston market.

Natural Gas Demand Projection

The level of gas demand in the Atlantic provinces will not be fully determined until all the distribution facilities are in place and customers have had the opportunity to convert. However, based on currently subscribed capacity and distribution forecasts, it is expected that gas demand could reach approximately 90 900 GJ/d (82.6 MMcf/d) for Nova Scotia and about 101 200 GJ/d (92.0 MMcf/d) in New Brunswick in 2001. Almost all of this demand will come from the industrial (refineries and pulp and paper plants) and power generation sectors.

With respect to space heating demand, residential applications may require complete conversion from existing central heating systems, which burn other fuels, to natural gas furnaces or boilers. While it is expected that gas will be priced lower than other fuels, the difference may not be sufficient to convert on purely economic grounds. As a result, in Nova Scotia, Sempra may offer incentives, including finance packages, to accommodate a reasonable payback period or improvement in the consumers's cash flow. In New Brunswick, it is expected that EGNB's target rates have been established such that the majority of customers will find it economically advantageous to convert to this equipment.

EGNB and Sempra will operate as distributors only. EGNB's franchise will offer only unbundled service (i.e., its customers will contract with marketers and not utilities for gas sales). EGNB and M&NP have signed a 20-year firm service agreement for 11 785 GJ/d (10.7 MMcf/d), which will be eventually assigned to marketers or directly to end users.

New Brunswick and Nova Scotia are currently in the process of marketer certification. Although a marketing affiliate of the LDCs could apply to receive a marketing certificate, to date an affiliate application has not been filed. There is currently only one marketing certificate application before the NBPUB. Irving Oil Limited and Engage Energy Canada Limited, as well as others, are expected to apply for a licence in New Brunswick. Once marketing regulations are in place in Nova Scotia, approximately six marketers, including Irving Oil and an affiliate of Sempra, are expected to apply for certificates. Approval of a marketing certificate is anticipated to take one month.

5.7.5 Summary

Buyers in the Atlantic provinces will have access to natural gas in the near future. The level of gas demand will not be determined until distribution facilities are in place. The commodity price of gas will be linked to the Boston market.

Summary and Conclusions

Canada has become part of an integrated North American natural gas market. Natural gas is traded on a daily basis with prices reflecting demand and supply factors in both Canada and the United States. The brisk growth in the North American economy during the past decade has translated into increased demand for energy. This is particularly true for natural gas, which has also benefited from being a relatively clean-burning fuel. In fact, many power generation projects that are planned or under construction will burn natural gas for environmental as well as economic reasons.

While growth in natural gas has been strong for several years, the growth in gas supply has lagged during the last few years. This is primarily attributable to the low oil price environment of 1997/1998, which reduced cash flow for the producing sector. In turn, drilling activity decreased throughout North America. With oil prices recovering sharply in 1999/2000, the producing sector has responded and drilling activity is at high levels. Despite this high drilling activity, there is still a lag between developing additional gas supplies and connecting these supplies to the market.

Since demand growth has outpaced supply growth, natural gas prices have increased significantly over the last year. Recent increases in the commodity price of gas have had a more significant impact on end-users in the western provinces because gas costs account for a large proportion of total delivered cost. In other words, the transportation costs to these markets are less because of their proximity to gas supplies. For example, the cost of gas now accounts for over 65 percent of the total delivered price in Alberta but only 45 percent in Quebec.

Natural gas producers throughout North America have been responding to the current high price environment with aggressive drilling programs. In time, there will be a supply and a demand response and accompanying relief in natural gas prices is expected. A period of market adjustment is necessary any time the dynamic between supply, transportation and demand is significantly changed. It is difficult, if not impossible, to predict with certainty any movements in the commodity markets.

A review of the annual weighted average border price paid for Alberta gas indicates that domestic gas users paid less than export customers until 1998 at which point the two prices have converged. This indicates that Canadians have had access to natural gas on terms and conditions, including price, no less favourable than export customers.

Electronic trading systems have enhanced price discovery by providing timely information to market participants. Active spot and futures markets, such as NYMEX and AECO-C/NIT, have had a significant impact on the pricing of natural gas. These allow market participants to manage price volatility by contracting on a forward basis.

An extensive pipeline grid provides numerous options for supply sources, transportation services and end-use markets. In the past few years, the NEB has approved several key projects that provide additional options for market participants. The Alliance Pipeline will provide further access to the export market and another option to reach markets in Ontario and Quebec via the recently approved Vector Pipeline. In addition, natural gas production from Sable Island has recently commenced and will provide Nova Scotia and New Brunswick with access to natural gas for the first time.

In summary, the natural gas market has been functioning so that Canadian requirements for natural gas have been satisfied at fair market prices.

GLOSSARY

Agency, Billing and Collection Transportation Tariff	an LDC acts as an agent on behalf of a marketer to arrange pipeline transportation service and the billing of customers.
Aggregator	a company that consolidates a number of suppliers into a group.
Backhaul Service	the transportation of natural gas by displacement on a pipeline system, so that the natural gas is redelivered upstream of its point of receipt.
Buy/Sell Arrangement	an arrangement whereby a party sells gas at the wellhead to a party with space on a pipeline, and then repurchases the gas downstream, paying transmission costs and any prearranged differentials.
Baseload Volumes	the minimum amount of natural gas delivered or required over a given period of time at a steady rate.
City Gate	the delivery point or the point of intersection between a gas transmission pipeline and a local distribution system.
Commercial Market	the portion of the natural gas market consisting of businesses and institutions including government, agriculture, the service sector, schools, hospitals and apartment buildings.
Core Customers	volumes that are typically supplied by the local distribution company to residential and commercial customers.
Deferral Account	used to record variances between forecast and actual costs of a particular type.
Direct Sales	gas purchase arrangements transacted directly between producers, brokers or marketers and end-users.
Displacement	in pipeline transportation, the substitution of a source of natural gas at one point for another source of natural gas at another point. Through displacement, natural gas can be transported by backhaul or exchange.
Electronic Trading	refers to gas purchases and sales which take place via an electronic trading system. These systems allow gas to be bought and sold on an anonymous basis and provide for price discovery.

Exchange Gas	natural gas that is received from, or delivered to, another party in exchange for natural gas delivered to, or received from that other party.
Hedging	hedging is the process of protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one transaction with another. A long position in an underlying instrument can be hedged or protected with an offsetting short position in a related underlying instrument.
Hog Fuel	fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.
Hub	a geographical location where large numbers of buyers and sellers trade natural gas and where gas can be physically delivered.
Industrial Market	the portion of the natural gas market consisting of manufacturing, forestry and mining operations.
Interruptible Service	gas service provided to customers which may be curtailed due to supply or system capacity limitations.
Load Factor	the ratio of the average load over a designated period of time to the peak load occurring in that time period.
LNG	liquefied natural gas
Netback Price	the per-unit price received by a gas producer from the sale of gas in end-use markets, less applicable costs. These typically include transportation and marketing fees.
Option	an agreement which gives a seller (or buyer) the right, but not an obligation to sell (or buy) a set amount of gas at a predetermined price.
Peaking Service	a service that entitles a buyer to a certain quantity of natural gas delivered at the buyer’s request during peak-demand periods.
Plantgate Price	the price received by producers for natural gas delivered to a pipeline system.
Pulping Liquors	a by-product of the manufacture of chemical pulp which can be used as a fuel.
Residential Customers	the portion of the natural gas market consisting of private dwellings and larger residential units with individually-metered apartments.
Rider	a temporary adjustment to rates usually reflecting the disposition of deferral account balances.

Secondary market	the market in which shippers or marketers contract with parties other than pipelines for transportation services or delivered gas services. This market is unregulated.
Spot Sale	transactions of gas which are generally for 30 days or less.
Swap	an agreement to exchange future cash flows. For example, a fixed-for-floating swap is the difference between a fixed price stream and a price stream based on an index such as the NYMEX.