1986 1987 1988 1989 1990 1991 1992

NATURAL GAS MARKET ASSESSMENT

10 YEARS *after* DEREGULATION

National Energy Board
September 1996

1993 1994 1995

NATURAL GAS MARKET ASSESSMENT

Canadian Natural Gas

TEN YEARS *after* DEREGULATION

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LIST OF ACRONYMS

ABM	Agent/broker/marketer
ANG	Alberta Natural Gas Pipeline
B.C.	British Columbia
Bcf	Billion cubic feet
BCUC	British Columbia Utilities Commission
The Board/NEB	The National Energy Board
CPI	Consumer price index
COS	Cost of service
EBB	Electronic bulletin board
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
GJ	Gigajoule
GLGT	Great Lakes Gas Transmission
HHI	Hirschman-Herfindahl Index
LDC	Local distribution company
MBP	Market-Based Procedure
MCS	Minimum conditions of supply
MEMPR	Ministry of Energy, Mines and Petroleum Resources (B.C.)
MPUB	Manitoba Public Utilities Board
MMcf/d	Million cubic feet per day
NGTL	NOVA Gas Transmission Limited
NYMEX	New York Mercantile Exchange
OEB	Ontario Energy Board
PGT	Pacific Gas Transmission
Régie	Régie du Gaz Naturel
R/P	Remaining reserves to production ratio
Tcf	Trillion cubic feet
TQM	Trans Quebec and Maritimes
U.S.	United States
WACOG	Weighted average cost of gas
WCSB	Western Canada Sedimentary Basin

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O V E R V I E W

The National Energy Board (the Board) is required by the National Energy Board Act to ensure that applied-for long-term natural gas exports will be surplus to reasonably foreseeable Canadian requirements before it issues an export licence. In July 1987, the Board adopted a new procedure, known as the Market-Based Procedure (MBP), by which it makes this assessment. The basic premise of the MBP is that the market will work to satisfy Canadian requirements for natural gas at fair market prices. For this to be fulfilled, markets must be competitive, there should be no abuse of market power, and all buyers should have access to gas on similar terms and conditions.

The Board implemented the MBP shortly after the Governments of Canada and the three gas producing provinces of British Columbia, Alberta and Saskatchewan signed an Agreement on Natural Gas Prices and Markets on 31 October 1985. This Agreement provided for a landmark change in the Canadian natural gas market by allowing gas buyers, for the first time, to directly contract for supplies with producers, marketers and other agents at freely negotiated prices. From 1975 to 1985, the price of natural gas sold in interprovincial trade in Canada had been regulated by joint agreement between the federal government and Alberta. Further, prior to the Agreement, gas buyers in non-producing provinces could purchase their gas requirements only from a pipeline company at a “bundled” price which included the cost of gas and the cost of transportation.

While the 1985 Agreement created the necessary conditions for the establishment of a competitive natural gas market, the signatory parties recognized that the pipeline transmission sector of the gas industry would continue to be regulated because of its natural monopoly characteristics. A necessary requirement for establishing a competitive gas market was that open non-discriminatory access be provided to all shippers on interprovincial gas pipelines. The Board subsequently ensured that such access was provided.

As part of the MBP, the Board committed itself to monitoring the Canadian natural gas market and to publishing reports on the structure and functioning of the market from time to time.

The purposes of this report are to:

1) **review the changes that have taken place in the Canadian natural gas market in the ten years since the gas market was deregulated;**

2) **describe the current functioning of the market; and**

3) **assist the Board in assessing whether or not the market is generally operating in such a way that Canadian requirements for natural gas are being met at fair market prices.**

The report provides a review of the major changes that have occurred in the gas producing and transmission sectors, as well as reviewing the developments in gas markets and sales practices.

Gas Producing Sector

The main story in the natural gas producing sector in the last decade was the 40 percent fall in wellhead prices that occurred from 1985 to 1987 and the subsequent actions by the sector to survive in the lower price environment that has persisted since then. The gas producing sector has responded by aggressively cutting costs and rapidly expanding export sales. Cost reductions have come from corporate downsizing, applications of new technology such as "3-D" seismic, improved drilling practices, improved inventory management, and increased attention to costs in each step of the exploration and production process. As a result of all these actions, gas replacement costs in Alberta have been reduced in real terms by about 50 percent since 1985.

Cash flow from gas production was maintained by an almost fourfold increase in exports from 21 billion cubic metres (740 Bcf) in 1986 to 78 billion cubic metres (2.76 Tcf) in 1995. These increased exports drove export revenue up from $2.6 billion in 1986 to $5.5 billion in 1995. Although domestic gas sales increased by 30 percent over the period, the increase in volume was offset by the steep fall in wellhead prices.

Despite the doubling of cash flow from exports, the upstream petroleum sector has not enjoyed strong financial results in the last decade. Return on investment averaged only four percent per year between 1986 and 1994. These mediocre returns are reflective of the lower price environment for both natural gas and crude oil and the competitive structure of the sector. Nevertheless, the upstream sector has been very successful in attracting investment capital, indicating that investors are optimistic about the long-term financial health of the Canadian oil and gas industry.

The evidence in recent years indicates that the producing sector has been very responsive to market signals. Not only did the sector dramatically reduce replacement costs in response to lower market prices, it also appears to have reacted quickly to upswings in prices. When gas prices increased in 1993-94, signalling that demand was increasing relative to available supply, the sector rapidly increased productive capacity by drilling over 3500 new gas wells in 1994, up from 525 in 1992.

Total Canadian gas production has doubled from 74.9 billion cubic metres (2.6 Tcf) in 1986 to 150.0 billion cubic metres (5.3 Tcf) in 1995. At the same time, estimates of the ultimate potential of the Western Canada Sedimentary Basin have increased, and this potential is now estimated to be about 50 percent higher than estimated ten years ago. The sector's demonstrated ability to reduce costs and develop new reserves indicates that it can be expected to respond to the demands of the marketplace in coming years.

Gas Transportation Sector

Canadian natural gas pipelines have expanded considerably since deregulation to accommodate the growth in gas sales, particularly to export markets. Throughputs have increased rapidly while tolls have remained relatively constant, albeit with some variations on a pipeline-specific basis. This stability in tolls was achieved partly due to economies of scale and partly because the existence of under-utilized capacity in the late 1980s allowed some growth in throughput without major capital expenditures.

As a result of the sharp fall in wellhead prices, transportation costs now account for a larger percentage of the delivered price of gas. Faced with a low wellhead price environment, the gas producing sector became increasingly concerned about the level of pipeline tolls in the early 1990s. Given their own success in cutting costs, producers believed that efficiency gains were also possible in gas transportation and began to vigorously pursue alternatives to traditional cost-of-service regulation. The Board indicated its support of the quest for improvement by issuing guidelines for negotiated settlements in 1988 and by hosting a workshop on incentive regulation in 1993.

In the past year, these efforts were rewarded with the signing of a multi-year incentive agreement between TransCanada PipeLines Ltd. (TransCanada) and its shippers which was subsequently approved by the Board. NOVA Gas Transmission Limited and its shippers signed an incentive agreement during the summer which is currently awaiting approval by the Alberta Energy and Utilities Board. It is expected that incentive schemes will be proposed by shippers or the pipelines for other major gas transmission systems in Canada. These agreements reduce regulatory costs because tolls are determined by the terms of the agreements, eliminating the need for costly public hearings to determine the annual allowable cost of service. Incentive regulation also holds some promise for facilitating efficiency gains in pipeline operations and serves to better align the interests of shippers and the pipelines in improved efficiency.

A major part of the story of the last decade in gas transportation has been the introduction of considerable flexibility into the Canada/United States (U.S.) network. Pipelines have responded to the needs of shippers by providing an expanded array of services, including backhaul service, delivery-point flexibility, bid-rates for various services, and storage and parking services. These services have greatly enhanced shippers' ability to maximize the value of their gas shipments and sales. In addition, growth in storage capacity has helped maximize the efficiency of the entire network by reducing the need for transmission facilities and by providing security of supply and enhanced delivery flexibility.

Shippers who hold firm capacity on pipeline systems incur considerable risk because of the large financial obligations associated with the reservation charges to which they must commit under the terms of a long-term transportation contract. Since 1988, a secondary market has arisen which allows shippers to sell transportation rights to other shippers on a short- or long-term basis. The secondary market on TransCanada has been very active and has provided numerous benefits, including better risk management for shippers and better utilization of its system. Since the Board in 1995 removed a prohibition against selling capacity on the secondary market at prices above the regulated toll, the price of capacity moves freely to reflect its true market value.

In contrast to the highly competitive producing sector, the pipeline sector of the natural gas industry still retains monopoly characteristics. Thus, although cost-of-service regulation is being supplemented by incentive regulation, the sector still requires regulatory oversight. However, there is potential for increased competition between pipeline companies if some of the proposed new pipeline systems are constructed.

Gas Markets and Sales Practices

The gas market has gone through some major changes in the last ten years. Prior to price deregulation, most gas was sold by merchant pipelines to local distribution companies (LDCs) under long-term contracts. With the unbundling of pipeline transportation services and establishment of open access, hundreds of buyers and sellers entered the market. Gas is now sold directly by producers, aggregators, and a variety of marketing companies and brokers to LDCs, industrial, commercial and residential consumers.

As the number of players in the market multiplied and the market became more competitive, there was also a move away from traditional longer-term contracts to shorter-term contractual arrangements and sales. By the late 1980s, a very active spot market for one-month sales had developed. Although large volumes of gas in Canada are still sold under long-term contracts, the pricing in many of these contracts is tied in whole or in part to spot price indices. The development of a well-functioning spot market has improved price transparency and enhanced the efficiency of the natural gas market.

As gas has evolved into a commodity, the potential to earn profits through arbitrage has decreased. As a result, there has been some rationalization in gas marketing. Another aspect of the commoditization of gas has been the development of futures markets and the use of a variety of hedging instruments. A futures contract for gas first opened up on the New York Mercantile Exchange in 1990 and, since then, three new contracts have been launched with the latest being for gas deliveries within Alberta. Spot prices for natural gas have been very volatile and these instruments allow gas buyers and sellers to protect themselves from sudden adverse movements in price.

A number of developments have combined to form a more integrated Canada/U.S. natural gas market. Regulatory approaches to rate structures on pipelines were harmonized when the U.S. Federal Energy Regulatory Commission ordered U.S. pipelines to adopt a straight-fixed variable toll methodology, which was already the norm in Canada. Simplification of export and import approval procedures on both sides of the border have worked to lessen the distinction between domestic and export markets. The unbundling of sales and merchant functions on both sides of the border, the increase in the number of buyers and sellers, the rise of an open spot market and the increasing use of futures markets all have contributed to an increasing harmonization of gas sales practices. These developments have also contributed to the creation of a highly-competitive continental gas market.

The degree of integration between the various market and supply regions in Canada and the U.S. varies over time as demand shifts, new gas supplies are developed and new pipeline facilities are constructed. In recent years, a split emerged between the eastern and western halves of the Canada/U.S. gas market. In the west, productive capacity greatly exceeds demand and gas prices are generally low. In the east, the reverse is true. Although there is a substantial flow of gas from western producing basins to consumption centres in the east, pipeline capacity has been inadequate to eliminate the large price differentials which have developed between eastern and western markets. Most recently, it appears that the links between Alberta and western U.S. producing regions have weakened.

Canadian gas producers have diversified sales by establishing a very significant presence in the U.S. Northeast market, developing export sales to electricity generation markets, and following a portfolio approach to sales with a mix of long-term, short-term and spot sales. The U.S. Northeast has provided the highest netback prices to Canadian gas exporters in recent years.

Canadian gas buyers also have diversified their sources of supply. Whereas a decade ago the major LDCs bought virtually all their gas from pipeline companies under fixed-price contracts, these companies now hold a portfolio of gas purchase contracts. These include both long- and short-term contracts with aggregators, direct sellers and U.S. suppliers. Industrial gas-users and large commercial gas-users generally purchase gas directly from suppliers of their choice. In recent years, access to direct purchase has been made available to small commercial and residential gas-users. The specific options available vary somewhat from province to province according to the regulatory rules in each province.

The share of the total Canadian energy market held by natural gas has increased by only a couple of percentage points over the last decade. The steep fall in prices at the wellhead translated into lower delivered prices to industrial gas users. However, prices to end-users in the residential and commercial sectors in eastern Canada only fell modestly in real terms, in part due to increases in distribution and storage costs. Not surprisingly, gas consumption rose relatively quickly in the industrial sector while gas consumption in the residential and commercial sectors increased more moderately. Nonetheless, all Canadian gas consumers have benefitted from increased choice and overall lower prices.

In the decade since deregulation, Canadian gas buyers have, on average, paid prices equal to or lower than the prices paid by U.S. buyers, as measured at the Alberta border. Along with increased choice of suppliers and generally lower prices since deregulation, this provides strong evidence that the natural gas market is functioning in the best interests of Canadian gas buyers.

Concluding Remarks

This report finds that the current functioning of the Canadian natural gas market is consistent with the basic premise of the MBP. The market is generally working so that the requirements of Canadian natural gas buyers are being satisfied at fair market prices. There are no barriers which would prevent major gas buyers from accessing competitively-priced supplies from western Canada. The eastern Canadian LDCs continue to purchase almost all of their gas requirements from western Canada even though they have established a large import capacity from the U.S.. Gas prices are set through the operation of competitive markets, and gas production and marketing are very competitive businesses which provide maximum choice to gas buyers. Finally, the available evidence indicates that domestic gas buyers have been able to obtain Canadian natural gas supplies on terms and conditions at least as favourable as those available to U.S. buyers.

Overall, our report finds that the natural gas industry is efficient and responsive to the demands of the marketplace. The pipeline sector has developed a new range of services which, along with improved storage capability, has greatly enhanced the flexibility and reliability of the delivery system. The gas producing sector has cut costs sharply and has increased production dramatically, despite persistently low wellhead prices. While production has increased, the pace of technological change and improved knowledge of the producing basin in western Canada indicates that supply can be expected to meet Canadian and export demand for the foreseeable future. Current estimates of the ultimate potential of the Western Canada Sedimentary Basin are about 50 percent greater than those of ten years ago.

INTRODUCTION

From 1975 to 1985, the price of Alberta natural gas sold to other provinces was regulated at levels agreed upon 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. Gas transportation was available from merchant pipelines who bought gas under long-term contracts and then re-sold the gas in the markets at the end of their pipeline systems. The gas producing sector was experiencing excess productive capacity which resulted from, in part, high regulated natural gas prices and generous take-or-pay provisions in gas supply contracts.

The governments of the day recognized that increased flexibility was needed to improve the long-term health of the industry and on 31 October 1985, the Governments of Canada, British Columbia (B.C.), Alberta and Saskatchewan signed an Agreement on Natural Gas Markets and Prices. The basic premise behind the Agreement was that competitive natural gas markets would better serve the needs of Canadian producers and consumers. The Agreement established the conditions under which a competitive gas market could develop by deregulating prices (over a one-year transition period) and by allowing, for the first time, end-users in non-producing provinces to purchase natural gas directly from producers. The direct link between gas users and producers allowed prices to be freely negotiated. An important part of the market deregulation initiative was the assurance of non-discriminatory and flexible access to gas transportation services for producers and other shippers. Although gas sales were deregulated, the governments recognized that, due to the natural monopoly characteristics of the natural gas transmission and distribution segments of the industry, there was a continuing need to regulate them.

The National Energy Board (the Board), under authority of Part VI of the National Energy Board Act, is empowered to grant licences for the long-term export of natural gas. In assessing an application for a licence, the Board is required by the Act to have regard to all considerations that appear to it to be relevant. In particular, the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada.

After the implementation of the 1985 Agreement, the Board twice reviewed and modified the procedure by which it assesses whether the gas to be exported under long-term licence applications is surplus to reasonably foreseeable Canadian requirements. In a 1987 decision, the Board adopted a Market-Based Procedure (MBP) for assessing applications for long-term natural gas export licences.[1] 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 includes a public hearing component and a monitoring component. As part of the monitoring component, the Board stated that it would publish periodic reports on various aspects of the

[1] See NEB Reasons for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures, July 1987.

natural gas market. One purpose of these reports, known as Natural Gas Market Assessments, is to monitor whether or not the market is in fact working according to the premise of the MBP.[2]

Following price deregulation and the establishment of open access, eastern Canadian local distribution companies (LDCs) who used to rely on TransCanada for all of their gas supplies began to purchase from a variety of suppliers. In turn, most industrial gas users quickly elected to buy their gas directly from suppliers, rather than from their LDC. Many new companies jumped into the business of natural gas marketing, including gas producers and newly-formed marketing companies, as well as subsidiaries of the pipelines.

Natural gas wellhead prices fell by 40 percent from 1985 to 1987 and fell a further fifteen percent by 1995 (Figure 1.1). During the same time, production and exports grew rapidly (Figure 1.2). Over the ten years since deregulation, there have been advances in seismic and drilling technology, development of new and better pipeline services to meet the divergent needs of various customers, and increasing integration of the North American market. All of these developments have enhanced the competitive functioning of the Canadian natural gas market. In light of these ongoing developments, the Board has decided to examine and report on the current state of the Canadian natural gas market, ten years after deregulation. This report covers the period from 1986 to 1995, although it also includes some discussion of events that have occurred in 1996 up to the time of publication.

The main purposes of this report are to:

1) **review the changes that have taken place in the Canadian natural gas market in the ten years since the gas market was deregulated;**

2) **describe the current functioning of the market; and**

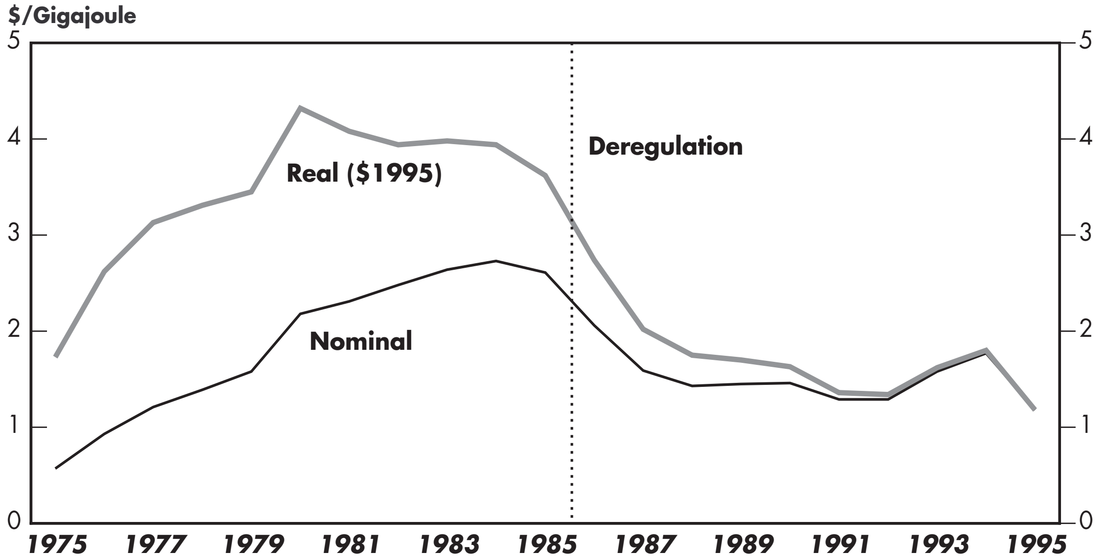
3) **assist the Board in assessing whether or not the market is generally operating in such a way that Canadian requirements for natural gas are being met at fair market prices.**

The report provides a review of the changes that have occurred in each of the major sectors of the Canadian gas industry. Chapter 2 reviews major developments in the gas producing sector, focusing on its demonstrated ability to reduce costs and respond to changing market conditions. Chapter 3 looks at the changes in the gas transportation sector in Canada and explains how, through the increasing flexibility of the transportation system, the needs of producers, sellers and buyers are better met in today's market. Chapter 4 examines the natural gas market from the perspective of both gas sellers and buyers.

[2] The Board published its first comprehensive assessment of the Canadian natural gas market in 1988 and followed with a second report in 1989. Since then it has published a number of reports on more specific topics affecting the gas industry. See Appendix I for a list of these reports.

FIGURE 1.1

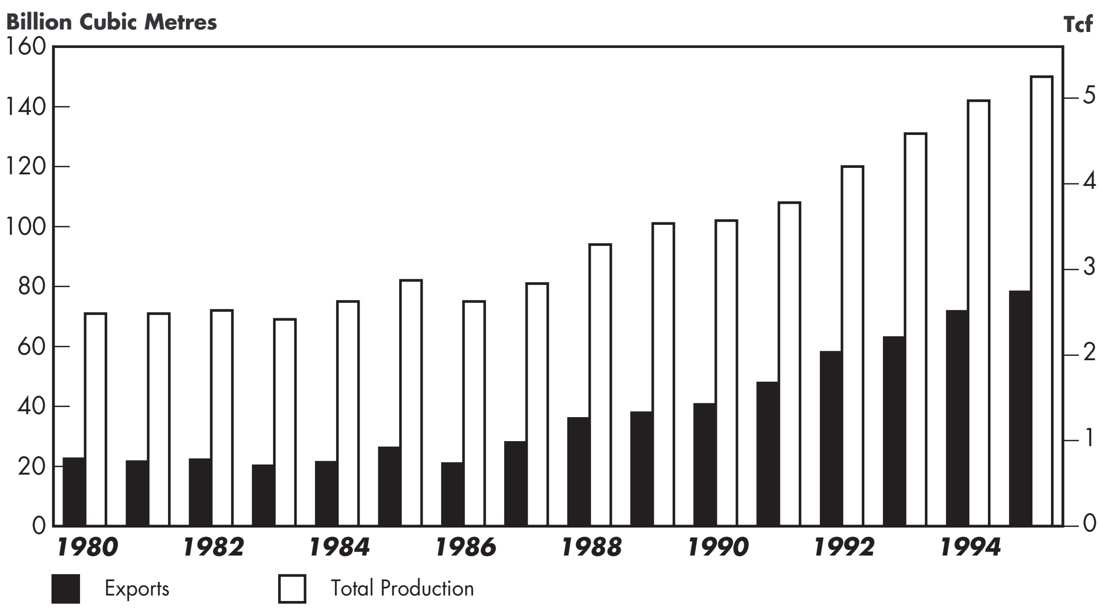
Alberta Average Annual Wellhead Price



Source: Canadian Association of Petroleum Producers Handbook

FIGURE 1.2

Natural Gas Production and Exports



GAS PRODUCING SECTOR

Since deregulation was implemented at the end of 1985, producers have responded to the signals provided in the newly-established competitive marketplace. Producers have continuously sought out cost savings in order to survive and remain competitive in the lower-price environment which has persisted over the last decade in the North American gas market.

This chapter first provides a brief outline of the structure of the Canadian natural gas producing sector. It then reviews the major developments in the sector since deregulation, focussing on changes in production and reserves, exploration and development activity, finding costs, supply management practices, taxation and regulatory changes, and the financial health of the sector.

2.1 Structure of the Gas Producing Sector

Most companies that operate in the upstream petroleum sector are engaged in exploration and production for both oil and natural gas. In the early days of the petroleum industry in Canada, natural gas was viewed largely as a by-product of crude oil exploration and production. Until major natural gas pipelines were constructed to transport natural gas out of the producing provinces, natural gas had relatively little value to producers.

Today there are over 700 companies that are active in exploration and production of crude oil and natural gas.[3] These companies range in size from large international corporations to small local operations. The actual numbers are constantly changing due to merger activity, company shut-downs and formation of new companies.

The natural gas producing sector is extremely competitive. In 1995, the top ten producers accounted for about 40 percent of total Canadian natural gas production, down from about 48 percent in 1986 (Table 2.1). No one company or group of large companies has an inordinate influence on the market. Supplies are available from hundreds of companies, all of which compete for their share of gas markets. Finally, concentration of production has become even more diffuse over the last ten years.

2.2 Reserves, Resources and Production

After several years of stagnation, natural gas demand began to increase after 1986, particularly in the United States (U.S.). Canadian natural gas producers were very successful in increasing sales, primarily by aggressively pursuing U.S. export markets. As illustrated in Figure 1.2 in the Introduction, Canadian natural gas production doubled from 74.9 billion cubic metres (2.6 Tcf) in 1986 to 150.0 billion cubic metres (5.3 Tcf) in 1995, while exports almost quadrupled.

[3] Source: Canadian Oil Register, 1995 Edition, published by C.O. Nickle Publications.

TABLE 2.1

Top Canadian Natural Gas Producers - 1986* and 1995**
(% of Total Canadian Daily Gas Production)

	1986		1995	
Rank	**Company**	**Percent**	**Company**	**Percent**
1	Shell Canada	7.9	Amoco Canada	7.3
2	Dome Petroleum	7.7	PanCanadian	4.9
3	Mobil Oil Canada	6.9	Shell Canada	4.8
4	Petro-Canada	5.0	Talisman Energy	4.0
5	PanCanadian	4.4	Petro-Canada	3.8
6	Gulf Canada	3.7	Imperial Oil	3.6
7	Amoco Canada	3.5	Anderson Exploration	3.5
8	Alberta Energy Company	3.5	Mobil Oil Canada	3.5
9	Imperial Oil	2.6	Norcen Energy Resources	2.6
10	Chevron Canada Resources	2.4	Renaissance Energy	2.5
	Top 10 Producers	47.6		40.4
	Top 20 Producers	64.4		59.4
	Top 100 Producers	90.1		87.6

Sources: * Oilweek/June 1987 and ** Oilweek/July 1996. The percentages were calculated by dividing the production numbers from Oilweek by the Board's estimates of total Canadian production. The companies' full legal names are not shown.

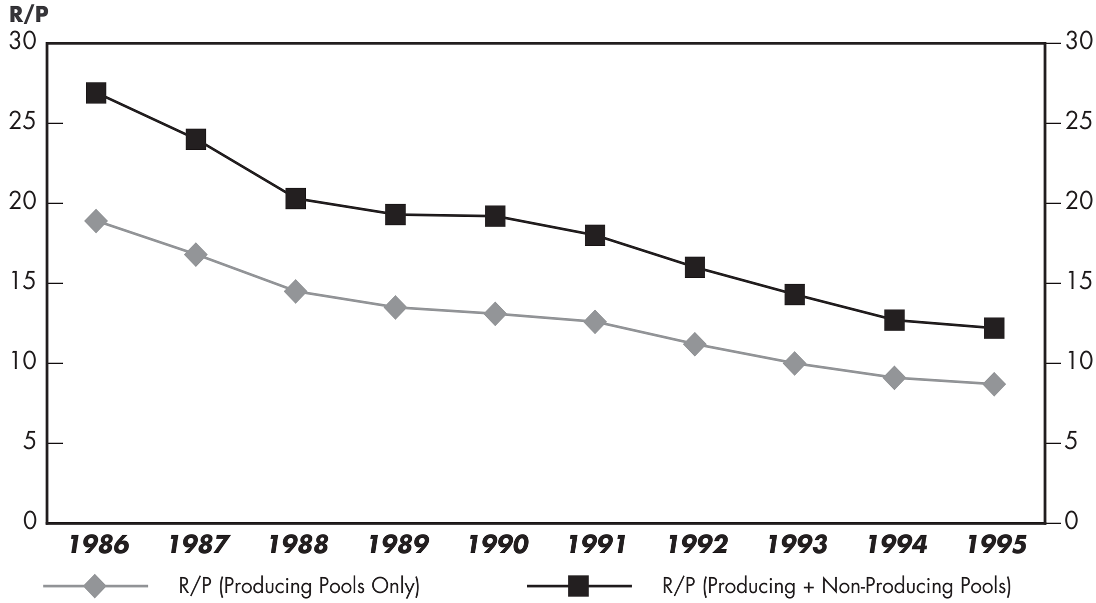
During the same period, the inventory of remaining established gas reserves (including both producing and non-producing pools) declined modestly by about 7% from 1940 billion cubic metres (68.4 Tcf) in 1986 to an estimated 1800 billion cubic metres (63.5 Tcf) in 1995. This decline in reserves is not indicative of depletion of the resource base. Producers have been able to double production from the basin during this period while maintaining remaining reserves at a relatively steady level. This has been achieved through ongoing exploratory and development drilling programs and by drawing on the excess productive capacity which existed at the time of deregulation. As a result, the Remaining Reserves to Production Ratio (R/P) has been reduced to about half of the 1986 level (Figure 2.1).

Estimates of the ultimate gas resource potential of the Western Canada Sedimentary Basin (WCSB) have tended to increase through time as a result of improved geological understanding, a growing body of knowledge and refined assessment methods. The estimates adopted by the Board for the WCSB have increased from a range of 4381 billion cubic metres to 5155 billion cubic metres (155 Tcf to 182 Tcf) in 1986 to an estimated 7216 billion cubic metres (225 Tcf) in 1995.[4]

[4] Canadian Energy: Supply and Demand 1985-2005, October 1986 and Canadian Energy: Supply and Demand 1993-2010, December 1994.

F I G U R E 2 . 1

Ratios of Remaining Reserves to Production



2.3 Exploration and Development Activity

From 1986 to 1992, exploration and development activity maintained a moderate pace (Figure 2.2). Due to excess productive capacity, there was no need to undertake extensive drilling efforts either to establish new reserves or to develop existing reserves. However, when gas prices began to increase in 1993 and 1994, producers responded by greatly increasing their drilling efforts. The number of development wells increased from 525 in 1992 to over 3500 in 1994. This activity enabled the producing sector to quickly increase productive capacity to meet growing demand.

The rapid drilling response of the producing sector demonstrates its responsiveness to market signals. In fact, it appears that when prices increase, the producing sector may over-react and develop more productive capacity than is required by the market or that can be accommodated by existing pipeline capacity in the short-term. This behaviour is characteristic of competitive supply markets.

Although Figure 2.2 shows drilling activity against wellhead prices, we note that producers are motivated to engage in drilling activity for reasons other than price changes. These include producers' needs to maintain cash flow and their asset base, as well as the need to replace inventories and to fulfil contractual commitments.[5]

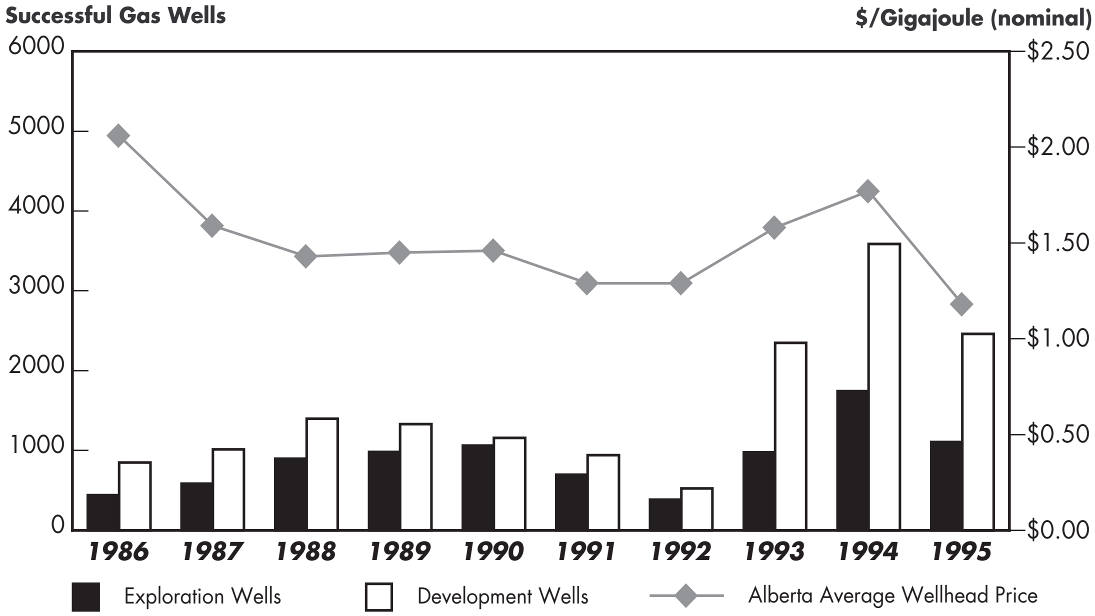
2.4 Finding and Development Costs

Replacement costs are a measure of the full-cycle costs of exploring for and developing new gas reserves. Replacement costs are broken down into finding costs and development costs. Finding costs include the costs of land acquisitions, geological and geophysical expenses and exploration drilling. Development costs include the costs of development drilling, field equipment and other associated costs. Replacement costs do not include royalties and other taxes paid by production companies.

[5] For a further discussion of drilling activity in the WCSB, see the Board's Natural Gas Market Assessment which deals with producers' response to changing market conditions over the period 1992-1996, to be published in early 1997.

F I G U R E 2 . 2

Successful Exploration and Development Wells



The sharp fall in natural gas prices in 1985-87 and the lower-price environment which has persisted since that time forced producers to implement cost efficiencies in all aspects of their operations. As illustrated in Figures 2.3 and 2.4, Canadian gas producers have been very successful in reducing natural gas replacement costs over the last decade.

In Alberta, which accounts for about 85 percent of Canadian production, replacement costs have trended steadily downward, falling from about $1.06/GJ in 1987 to $0.48/GJ in 1994.[6] Reduction of finding costs was the dominant reason for the downward trend, as development costs have remained fairly constant.

Replacement costs in B.C., which have been on average higher than in Alberta over the study period, have also shown a general decline, albeit in an irregular pattern.

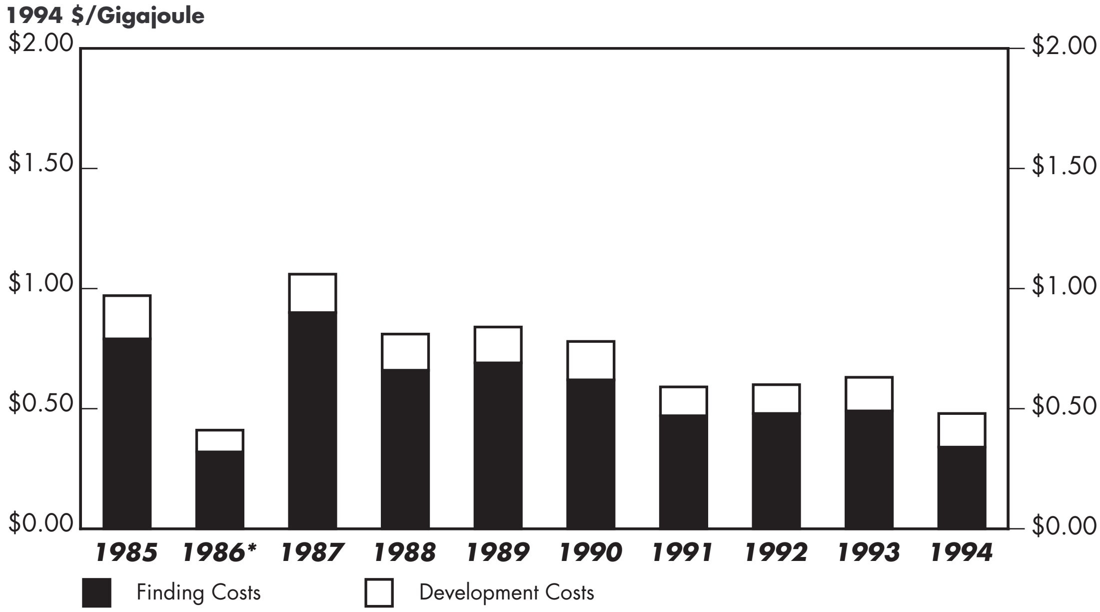
The reasons for declining replacement costs in Alberta and B.C. can be attributed to several factors, which include:

- technological improvements such as 3-D seismic and better understanding of the geology;
- better drilling practices, including coiled tubing, superior drill bits, new well-logging techniques, infill drilling, use of portable gas processing units, and more selective drilling;
- better data management, improved communication systems, and innovative use of existing equipment; and,
- overall improvements to business practices, downsizing, and company amalgamations and takeovers.

[6] 1986 was an anomalous year due to a large discovery at Caroline, Alberta which sharply reduced the calculated average for that year.

FIGURE 2.3

Alberta Natural Gas Replacement Costs

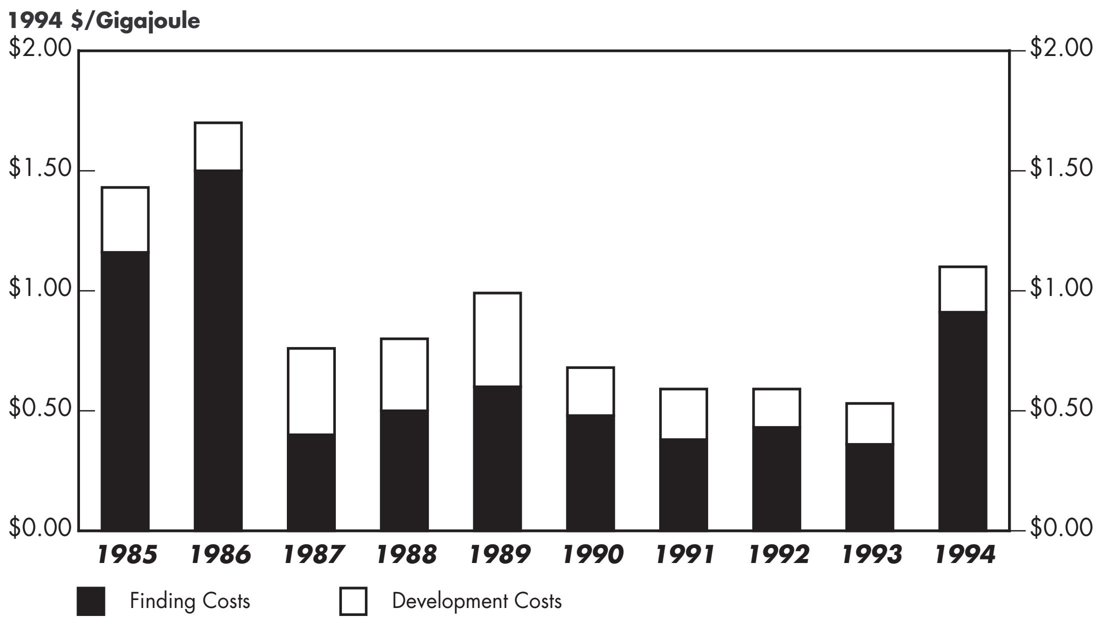


*1986 data was skewed downwards by a large discovery at Caroline.

Source: Calgary Energy Consultants Ltd.

FIGURE 2.4

British Columbia Natural Gas Replacement Costs



Source: Calgary Energy Consultants Ltd.

2.5 Major Initiatives to Enhance Supply Reliability

Two major initiatives in supply management undertaken since deregulation have been the rapid development of upstream storage and the implementation of daily gas balancing on the NOVA Gas Transmission Limited (NGTL) pipeline system.

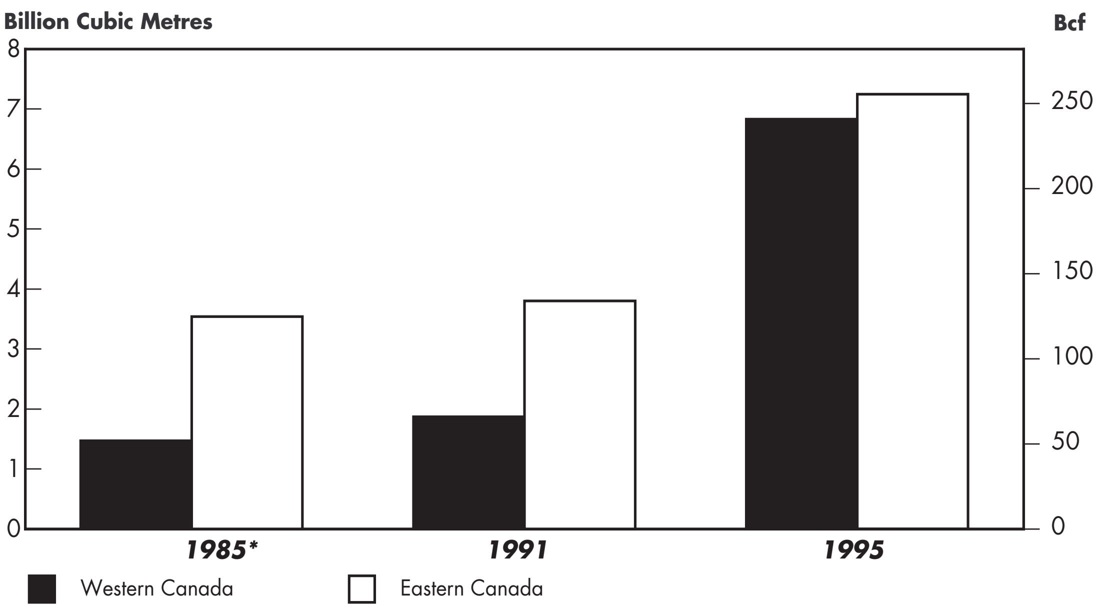
The supply and demand profile for natural gas has always demonstrated a seasonal imbalance. During the summer months, productive capacity and pipeline deliverability capacity normally exceed the demand for gas while the opposite occurs during the winter months. Historically, this has encouraged the development of storage reservoirs in both Canada and the U.S., particularly near major consuming centres. Storage injections take place during the summer when demand is lower, while withdrawals are done during the peak demand winter months. Thus, the use of downstream storage helps maintain the utilization of long-distance pipelines at high rates throughout the year, reduces the need for costly additional pipeline construction and improves reliability of supply to the end-user.

In the last five years, there has been a surge in working gas storage capacity in both gas producing and gas consuming areas. Working gas storage capacity grew most rapidly in western Canada, increasing from 1870 million cubic metres (66 Bcf) in 1991 to over 6800 million cubic metres (240 Bcf) in 1995 (Figure 2.5)

From the producers' perspective, the availability of gas supply from storage reservoirs to handle short-term fluctuations in demand means that there is a reduced need to manage well production levels to meet fluctuating requirements. As a consequence, the costs associated with varying the rate of production are reduced and the most appropriate production rates can be maintained. Other benefits of increased storage capacity at both ends of the transportation system are the

FIGURE 2.5

Working Gas Storage - Maximum Capacity



*1985 storage values obtained from a 1994 publication by Natural Resources Canada titled "Natural Gas Storage: A Canadian Perspective".

dampening of price spikes that could occur in tight supply conditions and the improved overall reliability of the supply system in the event of unexpected interruptions or failures.

A second major change to the management of gas supply in Alberta occurred in 1992. Prior to this year, on any given day shippers could withdraw more gas from the NGTL system than they had delivered, as they were only required to ensure that their withdrawals and injections matched on a monthly basis. In 1992, NGTL took advantage of advances in metering technology and implemented a procedure which required each shipper to balance its injections and withdrawals into the system on a daily basis, commonly referred to as daily gas balancing.

Increased storage capacity and the implementation of daily gas balancing on NGTL have contributed to the development of a more market-responsive and reliable gas supply system.

2.6 Changes in Taxation and Regulatory Regimes

With the advent of deregulation, a number of federal fiscal measures were scrapped, including the Petroleum and Gas Revenue Tax, the Incremental Oil Revenue Tax and the Petroleum Incentives Program. These measures reduced the tax burden on the upstream petroleum sector and reduced government incentives to conduct exploration activity.

As owners of most natural gas reserves, the producing provinces collect royalties from natural gas producers.[7] Royalties have traditionally been based on the wellhead price of natural gas. By the late 1980s, calculating the price of natural gas for royalty purposes became extremely complex because many gas sales contracts were priced at the point of sale rather than at the wellhead, thereby forcing producers to make calculations for their royalties for each sales contract. To simplify this process, the Alberta government proposed a reference pricing mechanism which tied royalties to an average Alberta market price or to the producer's Corporate Average Price for the year. These mechanisms were fully implemented by October 1992.

In general, the three producing provinces have tended to implement simplifications to the royalty schemes rather than changes in the royalty structure. In addition, there have been some reductions in royalty rates. These changes have led to administrative savings and tax savings for the producing sector.

The most significant change in federal regulation was the Board's elimination of its formula approach to assessing whether or not applied-for gas exports were surplus to reasonably foreseeable Canadian requirements. The last reserves formula which was employed by the Board prior to 1986 compared the quantity of remaining established reserves, with certain adjustments, to the sum of 25 times the current year's Canadian demand plus the maximum quantity of gas exportable under existing licences. If established reserves, as adjusted, were greater than these requirements, the amount of excess was deemed to be the maximum exportable surplus. As explained in the Introduction, the MBP, which was implemented in 1987, is more consistent with the operation of a competitive natural gas market. Since 1987, the filing requirements associated with the MBP have been reviewed and streamlined.

At the provincial level, the Alberta Energy and Utilities Board (EUB) has recently implemented new processes for approving various types of applications. The EUB has dropped a number of

7 Some producers own the mineral rights and do not have to pay crown royalties. In other cases, producers pay royalties to private parties or Aboriginals who own the mineral rights.

filing requirements for granting gas removal permits and has clarified its approach to approving applications for gas production and processing facilities. On environmental matters, it is shifting its regulatory approach from an emphasis on pre-approval to a compliance-based approach.

Although this section only touches on the major changes in taxation and regulatory regimes in the last decade, the general thrust of actions by both the federal government and the governments of the three producing provinces has been to reduce direct taxation and regulation of the producing sector.

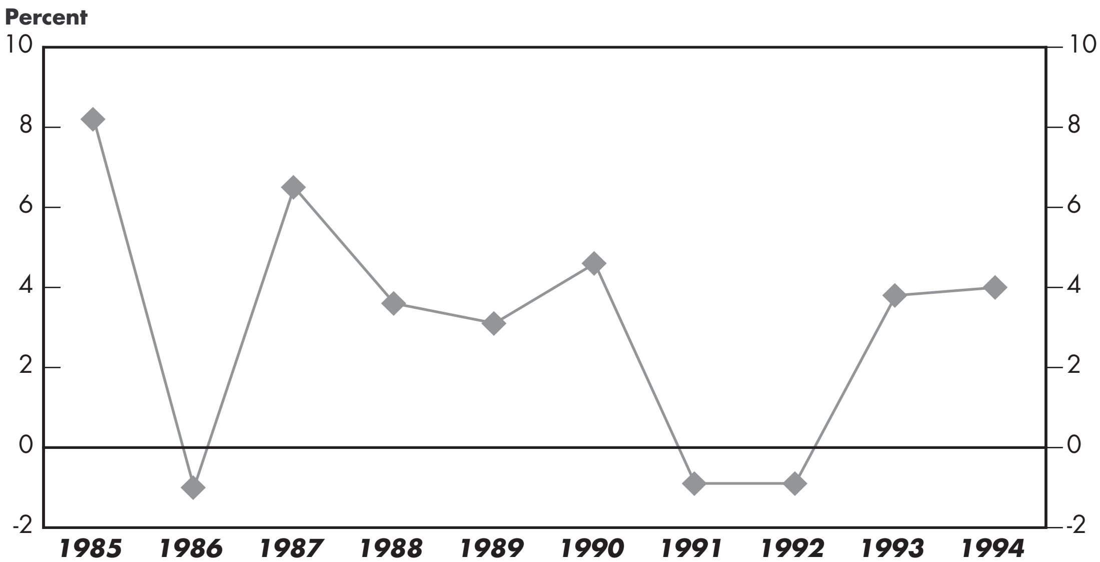
2.7 Financial Health of the Upstream Petroleum Sector

Since deregulation was implemented, rates of return on capital in the upstream petroleum sector have generally declined (Figure 2.6).[8] Average rates of return fell from 8.2 percent in 1985 to 4.0 percent in 1994, with negative returns experienced in three out of the ten years. This reflects the extremely competitive environment in which producers operate, the steep fall in oil prices that occurred in 1986 and the lower prices that producers have received for natural gas over the last decade.

In spite of the low returns, the upstream petroleum sector has been able to maintain cash flow and attract equity capital (Figure 2.7). Share issues have trended upward over the last ten years as financing has been shifted from debt to equity, indicating that investors are confident of oil and gas producers' ability to generate adequate returns on investment in the long-term. Cash flow experienced a mid-period slump from 1986 to 1991, but has recovered in recent years. The producing sector has been able to compensate for the impact of lower prices on cash flow by reducing costs and increasing sales volumes.

FIGURE 2.6

Average Rate of Return on Capital Employed

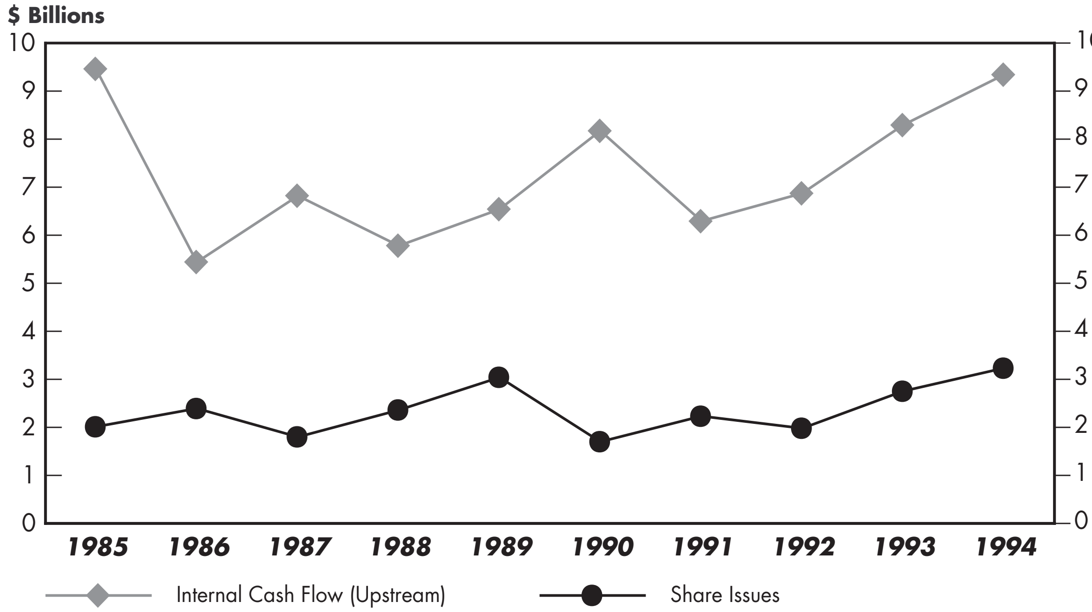


Source: Petroleum Monitoring Agency

8 The data represent results for oil and natural gas producers for all operations. It is not possible to separate overall profitability results from gas and oil producing activities. Data were not available in a consistent form for 1995.

F I G U R E 2 . 7

Cash Flow and Share Issues



Source: Petroleum Monitoring Agency

2.8 Summary and Current Issues

The Canadian natural gas producing sector has had to cope with a much lower price environment since price deregulation was implemented. The sector responded by:

- rapidly expanding sales volumes to maintain cash flow;
- aggressively cutting costs; and
- improving management of its gas inventory and taking steps to enhance the reliability of supply.

The gas producing sector has doubled production since deregulation. At the same time, estimates of the ultimate potential of the WCSB have increased, and this potential is now estimated to be about 50 percent higher than estimated ten years ago. The sector is very responsive to market signals, as evidenced by the responsiveness of drilling to price upswings. The sector is financially strong and, with the dramatic reductions in costs, it is well-situated to respond to the demands of the marketplace in coming years.

One issue facing the producing sector is its seeming propensity to overdevelop supply in response to short-term increases in price. This behaviour is characteristic of many commodity markets and, more generally, of highly competitive supply markets.

U.S. GAS PRODUCING SECTOR

SINCE 1986, gas production in the U.S. has increased from about 15 Tcf to 17.6 Tcf in 1995 (Figure 2.8). Reserves additions exceeded production in four of the past ten years. R/P ratios have fallen and are now only slightly over eight. Of greater significance is that reserves additions, while relatively constant over the past four years, have been achieved with fewer total active drilling rigs (down from 532 in 1990 to 385 in 1995) and fewer gas well completions (from over 16,000 in 1985 to 7300 in 1995). This is indicative of improved efficiency in the U.S. exploration and production industry.

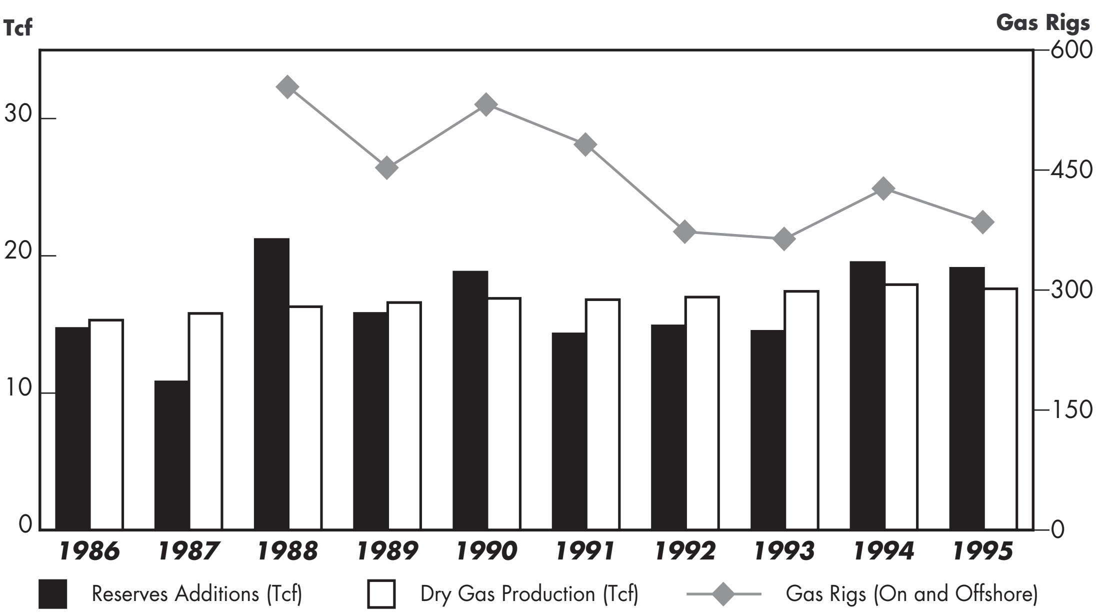
Due to an absence of readily available data, it is difficult to determine the trend of finding and replacement costs in the U.S..However, given the reduction in the number of wells drilled, it would be reasonable to infer that these costs have declined. PIRA (Petroleum Industry Research Associates) estimates that replacement costs have declined 15 percent over the past five years.

The structure of the U.S. producing industry has also changed with many more independent companies entering the arena. This is due, in part, to technological improvements in the offshore Gulf Coast, where higher costs previously limited the ability of smaller companies to participate.

In summary, the changes in the U.S. exploration and production industry have roughly paralleled the changes in Canada's industry. Inventory ratios and replacement costs have both fallen, indicating improved efficiency in the sector. U.S. producers, like their Canadian counterparts, have had to cope with a competitive lower price environment by aggressively cutting costs.

FIGURE 2.8

U.S. Reserves Additions, Production and Active Gas Rigs



Sources: 1995 U.S. Energy Information Agency Annual Reserves Report and Baker Hughes Rig Count, 1995.

GAS TRANSPORTATION

The Canadian natural gas pipeline system provides a vital link between gas production in the WCSB and consuming regions of eastern Canada and export markets in California, the Pacific Northwest, the U.S. Midwest and U.S. Northeast.[9] Producers in western Canada depend upon reliable transmission systems to access markets. At the same time, as the cost of transportation is a key determinant of the delivered cost of gas, both producers and gas buyers are interested in keeping the costs of gas transportation as low as possible.

The Canadian natural gas pipeline sector has undergone a significant transition over the last ten years. In the early 1980s, gas demand was stagnant, most of the Canadian pipeline system was under-utilized, and some pipelines were operating well below their design capacity.

Since deregulation, the utilization of the Canadian pipeline system has increased dramatically. The excess capacity was eliminated by the late 1980s and was followed by a series of large pipeline expansions. While the pace of pipeline expansions has slowed in the last few years, the Canadian pipeline system continues to operate at high utilization rates. Recently, there have been several proposals to increase capacity to move gas from the WCSB, primarily to U.S. export markets.

This chapter provides a brief review of: the growth in the gas transmission system over the last ten years; the changes in transportation tolls; the development of new pipeline services and the evolution of the secondary market for capacity; and changes in the regulatory structure.

3.1 Growth of the Canadian Pipeline System

The major gas transmission systems in Canada include NGTL, TransCanada, Westcoast, Alberta Natural Gas Pipeline (ANG)/Foothills, Foothills (Saskatchewan), and Trans Quebec and Maritimes (TQM) (Figure 3.1).[10] The map also shows the major U.S. pipelines to which the Canadian system is connected.

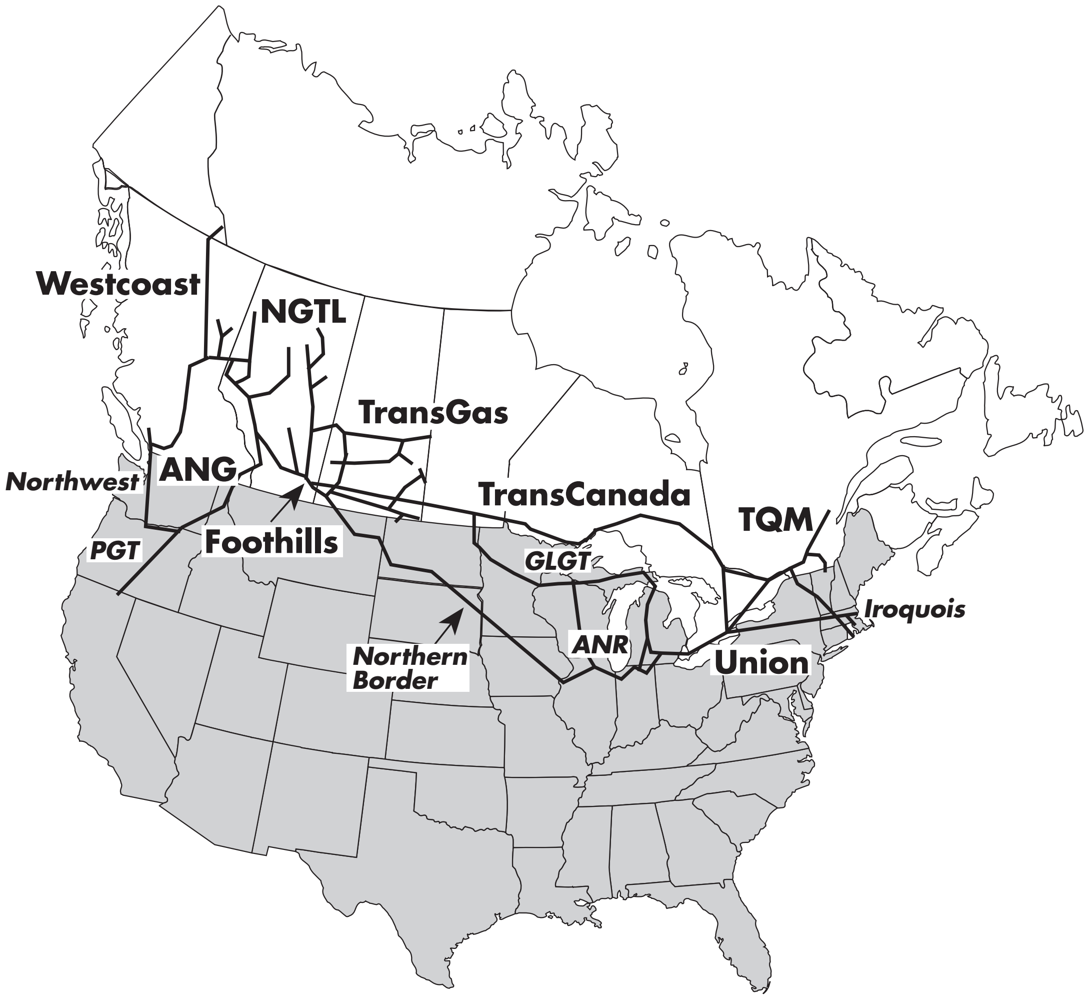
NGTL is a combined gas gathering and transmission system that collects gas downstream of gas processing plants and carries it to intra-provincial markets in Alberta and, via interconnects with ANG, Foothills and TransCanada, to extra-provincial markets. About 80 percent of all the gas produced in Canada is transported on NGTL's system. Throughput has more than doubled on

[9] Gas transmission facilities generally include pipeline systems that transport large volumes of natural gas at high pressure over long distances. In this report, we do not examine local gathering facilities, which generally collect gas from producing fields and transport it to gas processing plants prior to delivery to a transmission system, nor do we review developments in the gas processing sector.

[10] In addition to the above-identified transmission systems, most large distribution companies operate high pressure lines within provincial boundaries (see Table 4.2 for a list of the major LDCs in Canada).

F I G U R E 3 . 1

The Canadian Pipeline System



the NGTL system since 1986, reaching 121 billion cubic metres (4.3 Tcf) in 1995. To accommodate this increase, NGTL has invested about $2.6 billion in the last decade.

TransGas, like NGTL, is a combined gathering and transmission system that collects gas downstream of processing plants and carries it to intra-provincial markets in Saskatchewan and, via interconnections with TransCanada and Foothills (Saskatchewan), to extra-provincial markets. In 1995, TransGas had the capacity to transport 47.9 million cubic metres per day (1700 MMcf/d).

The **Westcoast** system consists of an extensive gas gathering system in Northeast B.C. (which extends into parts of northwest Alberta, the Yukon and the Northwest Territories), a number of gas processing facilities, and a mainline transmission system which transports gas to B.C. markets. Through an interconnection with Northwest Pipeline in the U.S., Westcoast transports natural gas to export markets, primarily in the Pacific Northwest. Finally, through interconnections with NGTL in Alberta, gas is delivered to all markets which are accessible from NGTL's system.

In 1986, the Westcoast mainline was being used at only about 55 percent of its capacity. After deregulation, gas throughputs increased until the system was fully utilized in the late 1980s. Westcoast subsequently invested about $650 million to increase its mainline capacity from

42.0 million cubic metres per day (1482 MMcf/d) in 1986 to 53.7 million cubic metres per day (1895 MMcf/d) in 1995. Large investments were also made in upstream gathering and processing facilities.

The **ANG/Foothills** system is a 171 kilometre pipeline system that connects the NGTL system to Pacific Gas Transmission (PGT), a major export pipeline which serves markets in Northern California, the Pacific Northwest and, through an interconnection with Tuscarora Gas Transmission, markets in Northwest Nevada.[11] In 1993, the system underwent a major expansion that increased capacity from 43 million cubic metres per day (1520 MMcf/d) to 69.5 million cubic metres per day (2455 MMcf/d), making it the single largest export point for Canadian natural gas.

Foothills Pipe Lines owns 637 kilometres of pipeline which connects to NGTL at Caroline, Alberta and to the Northern Border system at Monchy, Saskatchewan. Foothills (Saskatchewan) transports gas to markets in the U.S. Midwest. In 1986, this system was being utilized at only about 30 percent of its capacity. System utilization increased rapidly in the late 1980s and in 1992 capacity was increased from 30.4 million cubic metres per day (1075 MMcf/d) to 41.9 million cubic metres per day (1480 MMcf/d).

TransCanada was originally constructed in 1958 to carry natural gas from the WCSB to markets in eastern Canada and it still remains the sole transporter of gas over this route. Today, TransCanada receives gas via interconnections with NGTL in Alberta and TransGas in Saskatchewan and delivers gas to domestic markets in Saskatchewan, Manitoba, Ontario and Quebec, and to export markets in the U.S. Midwest and U.S. Northeast.

Since 1989, TransCanada invested approximately $5.5 billion to increase its transportation capacity, primarily to serve growth in export markets. Capacity on the western section of the system increased from 115 million cubic metres per day (4060 MMcf/d) in 1986 to 181 million cubic metres per day (6390 MMcf/d) in 1995. Large investments were also made in connecting U.S. pipelines, particularly for the construction of the Iroquois pipeline system to serve markets in the U.S. Northeast. Gas deliveries on TransCanada have increased by about 80 percent since 1986, comprised of a 23 percent increase in domestic deliveries and a near-sixfold increase in export deliveries. In 1995, export deliveries nearly equalled domestic deliveries.

The **TQM** pipeline connects to the TransCanada system at St. Lazare, Quebec near Montreal and extends east to serve markets up to Quebec City and across the St. Lawrence River to the south shore. Capacity on TQM in 1995 was about 14.6 million cubic metres per day (515 MMcf/d), up from 10.7 million cubic metres per day (379 MMcf/d) in 1986.

In summary, the Canadian pipeline system has expanded rapidly in the last decade, particularly in the 1989-1993 period, primarily to accommodate the large increases in export sales. Total export capacity on Canadian pipelines was approximately 246 million cubic metres per day (8.7 Bcf/d) in 1995.

[11] ANG and Foothills in B.C. are operated as a single pipeline system by ANG. However, they are, in fact, separate companies.

Pipeline Expansion Proposals

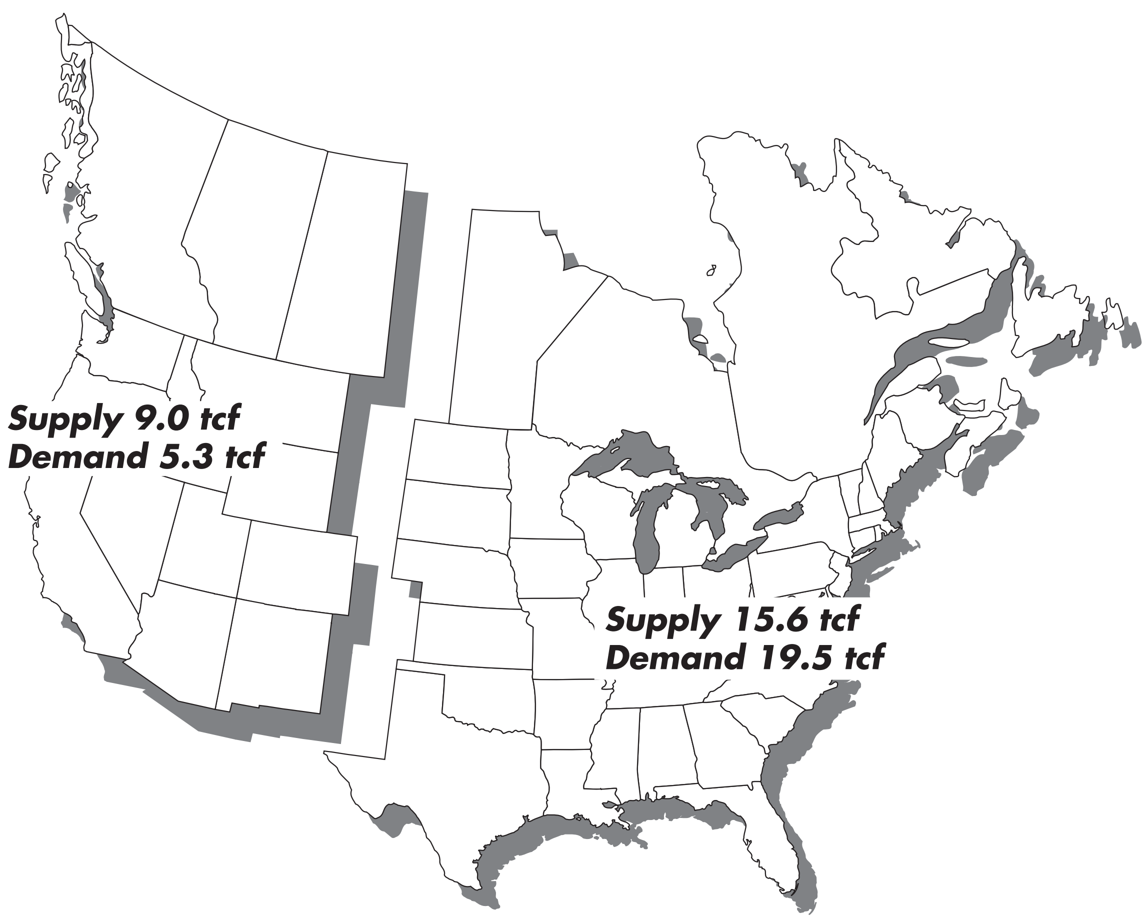
In recent years, a split has developed between the eastern and western portions of the Canada-U.S. gas market.[12] This is largely the result of the west having more gas producing capacity than demand, while the reverse is true in the east (Figure 3.2). There is, of course, a large net flow of gas from west to east. However, the price gap between eastern and western markets has been widening, leading many observers to argue that more capacity is required to transport gas from western producing basins to eastern consumption centres.

The combination of lower prices in the west and widening east-west price differentials has given rise to several pipeline projects to move the excess gas out of the western region in both Canada and the United States. The most popular intended destination appears to be the U.S. Midwest market with over 99 million cubic metres per day (3.5 Bcf/d) of new pipeline capacity being proposed. There are also projects being planned to increase western Canadian access to eastern Canada and the U.S. Northeast.

In addition to plans to move western gas eastward, a group of producers have plans to develop the Sable Island field offshore of Nova Scotia. Realization of this project would require the construction of a new transmission system.

F I G U R E 3 . 2

Canada/U.S. Gas Supply and Demand Balance (1995)



12 See section 4.3 for further discussion of the east-west pricing split.

3.2 Pipeline Tolls and Their Determinants

Pipeline tolls have a significant impact upon the final price of gas paid by consumers, as well as on the prices received by producers. This section briefly reviews the changes in pipeline tolls over the last ten years on Canada's major transmission systems and important connecting U.S. pipeline systems.

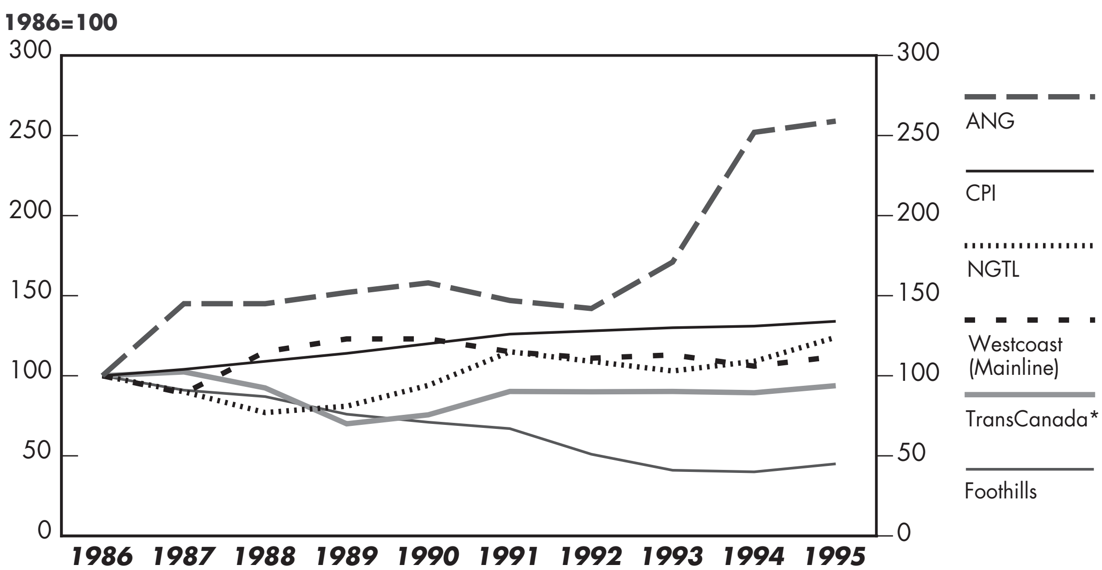
The tolls on all of Canada's major inter-provincial gas pipeline systems are subject to regulation by the Board, while the tolls on NGTL are subject to regulation by the EUB. For most of the past decade, tolls have been approved subject to a traditional Cost-of-Service (COS) approach. Under COS regulation, a pipeline is allowed to recover all of its prudently-incurred capital and operating costs, plus earn a reasonable rate of return on its investment capital.

Under COS regulation, tolls are generally insensitive to developments in the market for natural gas. They are primarily determined by factors such as the age of a pipeline system and the cost of major capital additions. In the absence of capital spending, tolls fall as the cost of facilities are depreciated over time. If a major capital program is implemented after a long period of little or no capital investment, there will likely be a major increase in tolls. The specific pattern of toll changes over time on each pipeline will also be influenced by the particular engineering characteristics of each system and the marginal cost of expansion at any point in time.

Indices of tolls on Canada's major gas pipelines over the period 1986-95 are shown in Figure 3.3.[13] As can be seen, with the exception of ANG, pipeline tolls have increased more slowly than the Consumer Price Index (CPI) over this period. The increase in ANG's tolls resulted primarily from the major expansion that occurred in 1993.

F I G U R E 3 . 3

Indices of Canadian Pipeline Tolls vs. CPI



*1986 tolls on TransCanada adjusted downward to net out fuel costs.

[13] Indices show the change in tolls over time relative to the starting value. Indices are used for illustrative purposes instead of actual values due to the large differences in tolls on different pipeline systems.

Perhaps the most striking point illustrated by Figure 3.3, when considered in conjunction with the large capacity increases discussed in the previous section, is that tolls on four major pipeline systems have either declined or only slightly increased despite the very large capital investments that were made over the period. This reflects in some measure the ability of the pipeline companies to take advantage of economies of scale.

U.S. Pipeline Tolls

For illustrative purposes, this section examines the changes in tolls for selected U.S. pipelines, including Northwest Pipeline, PGT, Northern Border, Natural Gas Pipeline and Great Lakes Gas Transmission (GLGT).

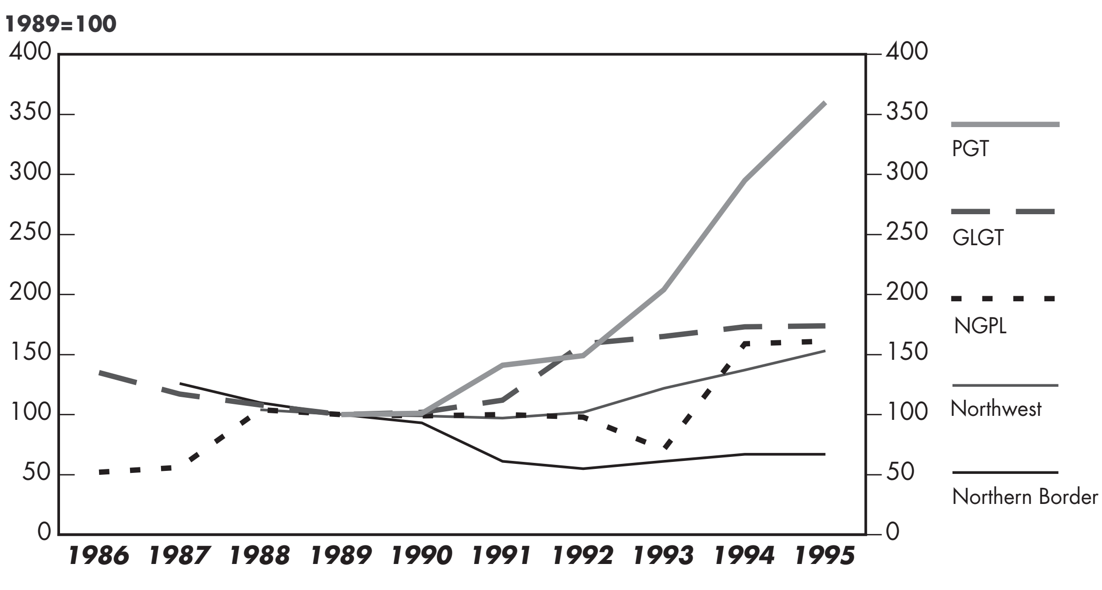
Figure 3.4 compares indices of available tolls expressed in Canadian dollars for these pipelines over the 1986-95 period. Tolls from 1986 are available for Natural Gas Pipeline and GLGT and from 1987 for Northern Border and from 1989 for PGT and Northwest. This necessitates the use of 1989 as an index base year for this data.

Comparing 1995 tolls to 1986, tolls on Natural Gas Pipeline increased by 210 percent and tolls on GLGT increased by 29 percent. Tolls on Northwest increased by 53 percent, while tolls for shippers on PGT increased by 260 percent.[14] In contrast, Northern Border's tolls have declined nearly 50 percent since 1987. With the exception of Northern Border, tolls for Canadian gas on all U.S. connecting pipelines examined here have risen substantially during the study period.

Part of the increase in tolls on these U.S. pipelines since 1991 was a result of the large decline in the value of the Canadian dollar over this time period (since the indices are denominated in Canadian dollars). Nonetheless, the net effect has been that the cost of transporting Canadian natural gas to export markets in California and the U.S. Northeast has increased substantially over

FIGURE 3.4

Indices of U.S. Pipeline Tolls



[14] The toll on PGT was affected by a surcharge which was levied for restructuring costs related to implementation of Order 636. The surcharge expired in August 1996.

the study period. The cost of transportation to U.S. Midwest markets has remained roughly constant while the cost of transportation to Pacific Northwest markets has risen slightly.

3.3 Pipeline Transportation Services and the Secondary Market for Capacity

Prior to 1985, pipelines acted as merchant carriers, taking ownership of all the gas that was transported through their systems and re-selling the gas to buyers at the end of their systems. The buyers, mainly LDCs, purchased the gas and transportation as a single "bundled" commodity and then in turn sold the gas to end-users as a bundled commodity, the price of which also included their distribution charges.

Under this system, end-users could not buy gas from the supplier of their choice, nor could they purchase transportation options that best-suited their individual needs. Today, pipeline companies offer a full slate of transportation options and services, including firm service, short-term firm service, peaking service, storage and interruptible transportation.

The toll structure for firm transportation service on Canadian pipelines usually consists of a demand charge and a commodity charge. The demand charge is essentially a capacity reservation charge through which the fixed costs of providing capacity are recovered. Variable costs of transporting gas are recovered through the commodity charge. As the major costs of providing gas transportation services arise from the fixed costs associated with the provision of capacity, most costs are recovered through the demand charge.

Provision of new firm service normally requires a pipeline to construct new facilities. Traditional contracting practices require shippers who are contracting for new firm service to make a long-term commitment for capacity, usually for a period of ten years or more. These contracts provide the pipelines with a level of assurance that they will be able to recover their investment costs. The combination of the toll structure, plus the requirement to commit to a long-term transportation contract, puts a high degree of risk on shippers contracting for new firm service.[15]

In the last ten years, pipelines have implemented a number of service options which enhance the flexibility of gas transportation. For example, under the terms and conditions for firm service on TransCanada, shippers are permitted to divert gas to points other than those specified in the shipper's contract. Under backhaul service, TransCanada allows shippers to borrow gas from the system at an upstream point and repay it with downstream gas. A backhaul is desirable in a case where a shipper needs to deliver gas upstream of the point at which the shipper's gas is delivered to the pipeline. These services help ensure that pipeline capacity will be used and reduce the risk to shippers of having to pay demand charges for unused capacity.

The use of gas storage close to major gas consumption centres also has become increasingly important to the transmission system. Storage helps maximize the use of the natural gas infrastructure by smoothing the peaks and valleys in pipeline utilization, thereby reducing the need for expensive additions to the transmission system.

[15] In Canada, once a firm-service contract expires, shippers normally have an ongoing right to renew firm service for a one-year period ("perpetual" renewal rights). As the percentage of capacity on a pipeline held by renewing shippers rises, the risk to the pipeline company grows because there are diminishing long-term contractual commitments to use the system.

A number of market hubs recently have developed across the continent, usually in areas where large storage capacity exists. Hubs typically provide access to multiple pipeline systems, thereby allowing greater access to supply basins and end-use markets. Pipeline companies provide other services at hubs, such as parking and peaking, which increase the ability of shippers to manage their transportation portfolios.[16] Hubs also provide focal points for reliable price discovery which allows market participants to continually evaluate the relative value of gas in different markets.

The Secondary Market for Transportation Services

In 1988 and 1989 the Board approved changes on the TransCanada system to allow shippers to re-assign firm transportation rights to third-party shippers. The market in which these transfers occur is known as the secondary market for transportation service rights.

Capacity on TransCanada, for which the most active secondary market exists, can be traded for any length of time to which the traders agree. Although it is difficult to collect reliable information on the size and liquidity of the secondary market, there is evidence that the market is very active. For example, in the fall of 1995 there were over 400 firm service agreements outstanding, of which more than one-third were under temporary assignment with TransCanada's knowledge. Unofficial reports indicate that assigned capacity can typically exceed 11.3 million cubic metres per day (400 MMcf/d) in a normal winter month, not including informal verbal deals. It is even more difficult to obtain firm numbers for the more informal market but indications are that between 50 to 100 verbal deals are made each day.

The secondary market also appears to be very competitive. In 1995 there were over 60 firm service shippers under contract on TransCanada, each of which could potentially trade their capacity on the secondary market. The largest holder of capacity was TransCanada Gas Services with 18.9 percent of the available capacity, followed by Consumers' (16.1 percent) and Union (11.2 percent). No other shipper held more than ten percent of capacity. This suggests that there is little potential for the abuse of market power in the secondary market for capacity on TransCanada.[17]

The secondary market on other Canadian pipelines is less developed. The tariffs on Westcoast and Foothills (Saskatchewan) allow capacity to be traded, but only with the approval of the pipeline. The secondary market on ANG is in the development stage largely because, until recently, there were very few shippers on the system. The most significant re-assignment occurred when shippers supporting the proposed 1995 ANG expansion were able to find released capacity and avoid a further expansion of the system.

In 1995, the Board decided that it was unnecessary to require mandatory posting of capacity trades on electronic bulletin boards (EBBs), as is required in the U.S. The Board also endorsed the removal of the price cap, which had limited the price of transportation capacity sold on the secondary market to the level of the firm service toll. Thus, the price of capacity on the secondary market moves freely to reflect its market value at any point in time.

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[16] Parking involves a short-term loan of gas to the hub while peaking is a short-term loan from the hub.

[17] One way to assess the degree of market power in a market is to calculate a concentration index, such as the Hirschman-Herfindahl Index (HHI). The HHI is calculated by adding up the squares of the market shares of all market participants. An HHI close to zero indicates a highly competitive market while an HHI of one indicates a monopoly. For 1995, the estimated HHI on the secondary market for transportation service on TransCanada, calculated according to the number of firm shippers and the percentage of capacity they hold, was 0.10, which is indicative of a competitive market structure.

Finally, a number of pipelines have formed a company known as the NrG Highway, the purpose of which is to provide a single point of contact for multiple pipeline systems. Among other things, NrG Highway has developed an EBB which allows shippers to advertise that they have capacity to sell or to search for another user who has expressed interest in acquiring capacity on a number of pipeline systems. Negotiations still take place between parties, but the EBB feature helps to bring buyers and sellers together.

In summary, the growth of the secondary market has:

- provided a means for capacity to be transferred to those users who value it most;
- helped to ensure that the pipeline system is used efficiently and at high levels of utilization;
- improved the ability of the industry to deliver gas in the lowest cost way;
- increased the ability of shippers to manage the risk of holding long-term transportation contracts; and
- reduced the need to construct additional facilities.

In addition, prices on the secondary market can provide an important market signal as to the value of transportation capacity. As explained in Appendix II, the secondary market for pipeline capacity also can provide some indication of the level of market support for a pipeline expansion.

The introduction of new pipeline services, along with the options provided by the secondary market, provides a great deal of flexibility in natural gas transportation. This flexibility enables shippers to access the best markets as well as permitting the pipelines to maximize the use of their systems on a year-round basis.

3.4 Changing Nature of Regulation

Historically, Canadian pipelines have been regulated on a COS basis, pursuant to which their costs were reviewed in public hearings. The need for rate regulation was largely based on the premise that service could best be provided by a single company which could maximize the benefits that arise from economies of scale, but that monopolies required oversight to ensure that their tolls were just and reasonable.[18]

Although COS regulation seemed to work well for a number of years, the determination of tolls in annual public hearings could be costly and time-consuming to both the applicant and interested parties. In the late 1980s, gas producers who found themselves forced to cut costs to survive in the lower price environment began to argue that the cost-plus nature of COS regulation did not provide effective incentives for pipelines to seek out efficiencies and reduce costs.

In 1988, the Board responded, in part, by establishing guidelines for negotiated settlements (updated in 1994). These guidelines set out rules under which parties can negotiate settlements

[18] A simple analysis of the concentration in the pipeline industry indicates that there is significant market power held by the major gas transportation companies in Canada. The HHI for ex-Alberta transportation was approximately 0.85 in 1995 which suggests that there is little effective competition between pipelines for Alberta producers' gas. The only distinct route to transport natural gas from the WCSB to eastern Canada is via TransCanada. Finally, the supply options available to eastern Canadian consumers indicated an HHI of 0.8 in 1995. (See footnote 17 for an explanation of HH indices.)

pertaining to all or part of the issues normally debated in public hearings and file legally-acceptable settlements with the Board. In brief, the guidelines state that the Board will accept any settlement providing that: all interested parties have had a fair opportunity to participate; the settlement is unanimously accepted by all parties; and it does not contain any provisions which are contrary to the NEB Act. Since 1988, many items which normally would have been settled by the Board after an adversarial public hearing have been determined by mutual agreement between shippers and pipeline companies. This has resulted in cost savings to all parties.

In 1993, the Board hosted a workshop on incentive regulation, thereby further indicating its willingness to explore improvements to traditional regulatory processes and, in particular, the COS methodology. In the fall of 1994, the Board held a multi-pipeline hearing at which it simultaneously determined the cost of capital for all the major pipelines under its jurisdiction for a multi-year period. This action eliminated the need for costly annual hearings to determine the cost of capital for pipelines.

In 1994, the producing sector came forth with the PRIDE (Price Driven Efficiency) proposal. The goals of this initiative were to encourage pipelines and customers to focus on toll levels instead of the toll-making process, manage risks better, optimize the use of pipeline systems, increase the flexibility of pipeline systems and eliminate adversarial relationships between shippers and pipeline companies.[19]

These initiatives by industry and the Board led to a number of settlements for incentive regulation schemes on Canadian oil pipelines and, eventually, to a settlement for an incentive scheme between TransCanada and its shippers. The TransCanada settlement, which received Board approval in February 1996, covers the years 1995 to 2000 and is based on a revenue requirement that mainly consists of three envelopes: one incentive envelope; one with costs that flow-through to the revenue requirement; and one to account for non-routine adjustments.

Net savings or overruns in the incentive envelope are, for the most part, shared equally between TransCanada and its shippers. The company has an incentive to minimize these costs because it can increase its profits with its share of the savings. Other costs not included in the incentive envelope flow through to shippers as they would under COS regulation.

While the settlement has determined levels for revenues and tolls, the Board must still arbitrate items such as toll design issues. In addition, the Board must continue to fulfil its statutory mandate of ensuring that tolls are just and reasonable and not unjustly discriminatory. It is too early to say what the long-term impact of the settlement will be on future tolls. However, the settlements on TransCanada and the oil pipelines have already allowed for a reduction in the direct costs of regulatory processes by avoiding public hearings and increasing the certainty of the toll-making process. Another key benefit has been to better align the interests of shippers and pipelines, and encourage the pipelines to search for efficiencies.

In August 1996, NGTL filed a five-year incentive settlement with the EUB which, among other things, would allow NGTL and its shippers to equally share earnings above the negotiated threshold level. A decision by the EUB is expected in late 1996 or early 1997.

[19] PRIDE: A New Vision of Pipeline Regulation, Imperial Oil Limited, May 1994.

3.5 Summary and Current Issues

Canadian natural gas pipelines have expanded considerably since deregulation as gas producers increased sales rapidly, particularly to export markets. Throughputs have increased dramatically while tolls have remained relatively constant, with some variations on a pipeline-specific basis. This was achieved partly through the presence of economies of scale and partly due to the fact that some growth in throughput occurred in the late 1980s without any construction of new facilities. Although tolls on average have not increased significantly, with the sharp fall in wellhead prices, transportation costs now account for a larger percentage of the delivered price of natural gas.

A major part of the story of the last decade in gas transportation has been the introduction of considerable flexibility into the Canada/U.S. network. Pipelines have introduced many new services which provide shippers with greater service options and delivery flexibility. The rise of a secondary market for transportation rights has provided shippers with further flexibility and has neatly introduced a competitive market within the basic monopoly structure. The increased flexibility has provided numerous benefits, including better management of pipeline systems, better risk management for shippers and increased reliability of the entire gas delivery system.

In the last year, there has been a significant move to replace traditional COS regulation with incentive schemes on Canada's major gas transmission systems. Incentive regulation holds some promise for generating further efficiency gains in pipeline operations.

Perhaps the largest issue currently facing the gas transportation sector is the question of how much new pipeline capacity to add. Many market participants believe that there is a need for substantial additional capacity to transport natural gas from the WCSB east to markets in the U.S. Midwest and Northeast, but there is still considerable concern about the effect that the expansions may have on east-west price differentials. Although this differential is currently very large, it is possible that new capacity additions could decrease the differential by lowering the price of gas in the U.S. with little positive impact on producer netbacks.[20]

Finally, since tolls account for a large percentage of delivered prices, particularly for Canadian gas delivered to U.S. markets, producers will continue to be interested in measures which have the potential to reduce the cost of delivering their product to the marketplace.

[20] As discussed in Chapter 4, California gas prices fell considerably after a number of new pipeline projects were built to service California gas markets.

U.S. GAS TRANSPORTATION

DEREGULATION of the gas market and introduction of market mechanisms in the transportation market has proceeded somewhat more slowly in the U.S. than in Canada. In 1985, following partial deregulation of wellhead prices, the FERC issued Order 436 which encouraged interstate pipelines to unbundle gas sales and transportation. In 1987, the end-use market was expanded when the federal government repealed restrictions on the use of natural gas by industrial consumers and electric utilities. In 1989, the federal government passed the Natural Gas Wellhead Decontrol Act which removed all wellhead price controls by January 1, 1993. In November 1993, the FERC implemented Order 636 as one of the last steps in restructuring the interstate pipeline industry. Order 636 required all interstate pipelines to provide open-access transportation, to unbundle gas sales and transportation, and to adopt a straight fixed variable toll design. These actions have brought U.S. treatment of pipeline tolls into line with the Canadian approach to toll-making and have helped to create a more integrated Canada-U.S. gas market.

The secondary market in the U.S. only officially came into being since the implementation of Order 636. Under this Order, all capacity transactions with terms greater than a month are to be posted on an EBB, with capacity being allocated by a competitive bidding process. At no time can the bid price exceed the regulated COS toll. A number of industry participants have expressed dissatisfaction with the price cap on secondary market transactions and suggest that it has inhibited the efficiency of this market. In July 1996, the FERC announced several proposed changes to its capacity release rules which include allowing pipelines to remove the price cap on released capacity, interruptible transportation and short-term firm service if they are able to demonstrate that they lack market power. The FERC also proposed to remove the mandatory bidding requirement for released capacity but would continue to require transactions to be posted on EBBs after the fact.

The question of whether to roll-in the cost of new facilities or toll them on an incremental basis has, and may continue to be of interest, particularly on U.S. pipelines.[21] In a number of cases, including the PGT and GLGT expansions of the early 1990s, the FERC decided to toll the expansions on an incremental basis. In May 1995, the FERC issued a policy statement which established a presumption in favour of rolled-in tolls when a rate increase was less than 5 percent. In July 1995, in response to a June 1994 Court directive for further explanation of the GLGT incremental decision, the FERC re-established rolled-in tolls on GLGT retroactively. In September 1996, the FERC approved a settlement to re-establish rolled-in tolls on PGT, to take effect November 1996. These actions have also helped harmonize regulatory approaches to the tolling of mainline transmission facilities between the U.S. and Canada.

[21] Under a rolled-in tolling approach, the costs of an expansion are pooled with the existing costs, yielding a single toll for all shippers. Under an incremental approach, the incremental costs of an expansion are allocated to "new" shippers, who then pay a higher toll than the pre-expansion shippers.

NATURAL GAS MARKETS AND SALES PRACTICES

Canadian gas sales have increased rapidly in the last decade as total Canadian production grew from 74.9 billion cubic metres (2.6 Tcf) in 1986 to 150.0 billion cubic metres (5.3 Tcf) in 1995. While domestic sales have shown steady growth, export sales have almost quadrupled since 1986. In 1995, 53 percent of Canadian production was exported, compared to just 28 percent in 1986. Despite this rapid increase in exports, almost all Canadian gas needs continue to be satisfied from gas produced in the WCSB.

A major development in the last decade has been the integration of the Canadian and U.S. natural gas markets. Regulatory barriers to gas trade have been greatly reduced while remaining regulatory approaches, such as the rate structures on Canadian and U.S. pipelines, have been largely harmonized. With the more widespread use of futures contracts, electronic trading and the growth of the spot market, pricing has become more transparent throughout the Canada/U.S. market.

This chapter provides a review of developments in domestic and export markets over the last ten years. It then examines developments in the nature of gas sales practices and looks at the interaction between the markets for transportation and natural gas. The chapter closes with a brief summary and a discussion of issues in natural gas markets and sales.

4.1 Domestic Markets

Total domestic sales of natural gas have increased by 30 percent over the last ten years (Table 4.1). Domestic gas sales were 63.6 billion cubic metres (2.2 Tcf) in 1995 compared to 49.0 billion cubic metres (1.7 Tcf) in 1986.

Sales grew most rapidly in the industrial sector, which increased its share of the gas market from 54% in 1986 to 57% in 1995. Sales in the residential sector also grew fairly quickly, as it maintained its share of the gas market at about 25%. Sales in the commercial sector grew relatively slowly as its share of the gas market fell from 21% to 18%.

Despite the growth in overall gas sales, the share of natural gas in the total energy market has only increased marginally. The largest gain was made in the residential sector, where gas increased its share of the total energy market from 40 percent to 46 percent from 1985 to 1994. Gas made a modest gain in the industrial sector as its share increased from 32 to 35 percent. Gas use in the commercial sector has remained roughly constant at 42 percent of the energy market. Further increases in gas demand were constrained by the competitiveness of oil, the price of which declined precipitously in 1986, and by efficiency improvements, which reduced growth in energy demand.

TABLE 4.1

Canadian Domestic Sales by Sector

Sector	1986		1995	
	(10^6m^3)	(Bcf)	(10^6m^3)	(Bcf)
Residential	12,192	(430)	15,820	(558)
Commercial	10,361	(366)	11,582	(409)
Industrial[22]	26,493	(935)	36,195	(1278)
Total	49,046	(1731)	63,597	(2245)

Source: Statistics Canada

Prior to the 1985 Natural Gas Agreement, most end-users purchased gas from their LDC at a fixed price per unit of gas. In most cases, the end-user would not have been aware of the separate charges for gas, transportation on gas transmission systems, storage services, or delivery by the LDC. Currently, most consumers have the option of purchasing gas from their utilities or through a direct sale, in which the end-user enters into a gas purchase agreement with a supplier. Most large end-users, such as industrial customers, purchase their gas directly from suppliers. Smaller gas end-users who opt for direct purchases usually utilize the services of an agent/broker/marketer (ABM).

There are generally two options offered by LDCs to facilitate direct purchases: a transportation service arrangement (T-service) and a buy/sell mechanism. Under T-service, the shipper arranges for transportation on transmission and/or distribution companies. The delivery arrangement on the transmission system provides for delivery of gas to an LDC at a bundled price which includes the cost of gas plus the cost of transportation (such as Western T-service on TransCanada). The delivery arrangement on the distribution system may be bundled or unbundled (such as Ontario T-service). A bundled service on an LDC's system includes load balancing. The shipper may be a producer, a distribution company, an end-user or an ABM representing the end-user. Most industrial customers choose T-service for their direct purchases.

In a buy/sell arrangement, the end-user also enters into a gas purchase agreement with a supplier. The LDC then purchases the gas from the end-user at the buy/sell reference price which is approved by provincial regulatory bodies and is currently set at the utility's weighted average cost of gas (WACOG) less any relevant transportation costs. The LDC then commingles the gas with the balance of its supplies and sells gas to the end-user under the appropriate rate schedule. Therefore, buy/sell customers benefit when they purchase their gas supplies at a lower cost than the LDC's buy/sell reference price. The end-user who purchases gas via an ABM will receive a rebate from the ABM which amounts to the difference between the LDC's WACOG and the negotiated price with the supplier, less the ABM's fees. The buy/sell mechanism is currently the only economical vehicle available for smaller gas users who wish to purchase gas directly.

In most provincial jurisdictions, the LDC is the "supplier of last resort" in the event of supply failures and therefore has an obligation to serve within its franchise area. Incremental costs associated with back-stopping services provided by the LDCs are generally recovered from the suppliers who failed to deliver the gas supplies. On the other hand, storage and load balancing costs are included in the LDCs' distribution rates.

[22] Includes direct sales where the LDC acts solely as the transporter.

Although many end-users now purchase gas directly from producers, the LDCs are still by far the largest gas purchasers in Canada. Almost all gas must still flow through a distribution system before it reaches the end-user and LDCs are the largest holders of capacity on the major transmission systems in Canada. As discussed above, LDCs manage upstream transportation for all their customers whether or not these customers purchase their gas from the LDCs or opt to go the direct purchase route. The principal LDCs in Canada are listed in Table 4.2.

In the last decade, direct sales have grown rapidly to the point where they accounted for 59 percent of all gas sales in Canada in 1995 (Table 4.3). In 1985, all direct sales in Canada were made in Alberta and accounted for 4 billion cubic metres (143 Bcf) or nine percent of all gas sales to end-users. Industrial gas users quickly took full advantage of the opportunity to purchase gas directly and currently almost all of their gas needs are purchased via the direct purchase route.

TABLE 4.2

Major LDCs in Canada (1995)

Local Distribution Company	Province
Gaz Métropolitain and Company, Ltd. Partnership (GMi)	Quebec
The Consumers' Gas Company Ltd.	Ontario
Union Gas Ltd.	Ontario
Centra Gas Ontario Inc.	Ontario
Centra Gas Manitoba Inc.	Manitoba
SaskEnergy Inc.	Saskatchewan
Canadian Western Natural Gas Company Ltd.	Alberta
Northwestern Utilities Ltd.	Alberta
BC Gas Utility Ltd.	British Columbia

TABLE 4.3

Direct Sales and System Sales by Province (1995)*

Province	Direct sales		System sales		Total sales		Direct/Total Sales (%)
	(10^6m^3)	(Bcf)	(10^6m^3)	(Bcf)	(10^6m^3)	(Bcf)	
Quebec	4617	(163)	1275	(45)	5892	(208)	78
Ontario	15,240	(538)	8498	(300)	23,738	(838)	64
Manitoba	708	(25)	1133	(40)	1841	(65)	38
Saskatchewan	2663	(94)	1643	(58)	4306	(152)	62
Alberta	7705	(272)	5920	(209)	13,625	(481)	57
British Columbia	2738	(97)	4929	(174)	7667	(271)	36
Total - Canada	33,671	(1189)	23,398	(826)	57,069	(2015)	59

*Source: NEB Survey. System sales refer to gas sales by the LDC under which the LDC is also the purchaser of the gas.

The dramatic increase in direct sales has allowed many domestic gas users to benefit from competition between suppliers and the resultant lower prices.

The next step towards a fully-deregulated gas market would be to allow all core customers to purchase gas directly from the supplier of their choice.[23] Many regulatory initiatives have been undertaken since the 1985 Agreement to provide more choice to core market gas users Provincial core market policies currently vary across Canada. Several provinces allow ABMs to market gas directly to core customers, subject to requirements that they obtain licences or pay registration fees and post a bond. ABMs are also expected to follow a code of conduct which is intended to protect core customers from unethical trade practices. Appendix III provides a brief summary of the major developments with respect to core market policies across Canada.

In 1995, over 42 percent of gas volumes delivered to residential and commercial customers in Quebec were made under direct sales. Within the three Ontario LDC franchise areas, direct purchases were between 9 percent and 34 percent of total residential gas sales volumes and between 42 percent and 75 percent of total commercial gas sales volumes.

Since deregulation, the provinces have been assessing the role of LDCs in a deregulated market. The main issues revolve around the degree and desirability of separating the sales and transmission functions of LDCs, as well as the pros and cons of unbundling storage, transportation and load balancing services.

At the present time, these challenges are being addressed in a number of Canadian jurisdictions. The Ontario Energy Board (OEB) decided that, after ten years of deregulation, a review of the current market structure in Ontario would be appropriate and has conducted two workshops in the last year. These workshops addressed the strength and weaknesses of the current market in Ontario, focusing on the identification and discussion of alternatives. In September 1996, the OEB concluded that further deregulation of the natural gas commodity market has the potential to improve customer choice and market efficiency while reducing the need for regulation. It plans to continue its market review using a stakeholder working group and public hearing to determine the appropriate level of deregulation. The Manitoba Public Utilities Board (MPUB) convened a public hearing in June 1996 to determine the appropriate level of service that should be offered by Centra Gas Manitoba Inc. and the manner of delivery of its services in a competitive environment. During this proceeding, the MPUB reviewed the role of Centra with respect to its natural gas supply procurement, transportation and storage functions. A decision is expected later this year.

LDC Purchasing Practices

Gas purchasing practices in the Alberta and Saskatchewan markets have changed little since deregulation because the largest LDCs had already been purchasing most of their gas requirements directly from a large number of producers. However, the LDCs' gas purchasing practices in Quebec, Ontario, and Manitoba have changed significantly. Until 1988, LDCs in these provinces purchased nearly all their gas requirements from TransCanada under long-term contracts at the city-gate. These distribution companies now purchase all their firm gas requirements at the Alberta/Saskatchewan border from various suppliers and hold long-term transportation contracts on TransCanada to transport the gas to their franchise areas. Their gas supply portfolios are currently very diversified and include long-term, short-term and spot purchases from various sources and suppliers, including those in the U.S.

[23] While the definition of core customers varies within provincial jurisdictions, it is generally defined as residential and commercial consumers with no fuel-switching capabilities.

The B.C. market has been completely restructured over the last five years. Until 1991, the B.C. utilities were obligated to purchase their gas requirements from the British Columbia Petroleum Corporation.[24] In 1991, BC Gas Utility Ltd., the largest LDC in B.C., became its own supply aggregator and diversified its portfolio by contracting for gas from a range of suppliers at different points on the Westcoast system. In 1992 it further enhanced the diversity of its supply by accessing U.S. supplies with the construction of the Huntington International Pipeline Corporation facilities.

In the years immediately following deregulation, the commodity price in the LDCs' gas purchase contracts was negotiated on an annual or bi-annual basis, with no provision for price changes during the course of a year. Currently, most LDC gas purchase contracts are market responsive with pricing determined through index-based mechanisms which fluctuate monthly. For example, since 1993 the pricing structure in the long-term contracts between LDCs in Ontario and Manitoba and TransCanada Gas Services has been based on an index-based formula using prices on the New York Mercantile Exchange (NYMEX). Prices in these contracts are therefore responsive to market conditions. Furthermore, risk management strategies have been implemented by many Canadian utilities to manage the price volatility of their long-term firm supplies of gas.[25]

Electronic gas trading systems were created in 1994 to provide a price discovery mechanism for buyers and sellers of natural gas. In May 1996, a pilot project for utility customers to transact gas electronically on the Internet via an electronic gas trading system was introduced by Consumers Gas and GMi. The primary objective of this project was to provide end-users with enhanced access to competitively-priced gas and to improve the administrative efficiency of the purchasing, nominating and billing functions.

The LDCs in Ontario can potentially import large volumes of natural gas from the U.S. through interconnects with U.S. pipelines that have been built in the last decade. Despite this potential, they purchase almost all of their supplies from the WCSB. The import connections have been used primarily to help them meet peak requirements.

Domestic Gas Prices

An indicator of the degree to which all Canadian end-users have been benefitting from greater competition in the domestic market is to compare the Alberta border prices paid by residential, commercial and industrial customers in eastern Canada. However, it is very difficult to obtain the actual commodity price of gas paid by end-users because these contracts are privately negotiated and are not in the public domain. As an alternative, we have examined the evolution of prices to end-users in Quebec and Ontario over the last 10 years. In order to derive some estimates, the following data and assumptions were used:

- burner-tip prices derived from implicit gas prices published by Statistics Canada;
- TransCanada Eastern zone firm service tolls;
- for residential and commercial customers, GMi's and Consumers Gas' WACOGs were used as estimates for the price of gas from 1986 to 1992. From 1993 to 1995, the weighted Alberta border prices published by Canadian Enerdata Ltd. using one-year

[24] The B.C.P.C. was a crown-owned provincial supply aggregator which was privatized as CanWest Gas Supply Inc. in 1990.

[25] For an overview of financial instruments and hedging, see Appendix IV.

firm prices were used. For industrial customers, the Alberta border prices published by Canadian Enerdata Ltd. were used, based on 30-day weighted-average spot prices from 1986 to 1995

- residuals were assumed to be all costs associated with distribution;
- prices are shown in 1986 constant dollars; and
- all prices exclude provincial and federal sales taxes.

The burner-tip price for residential customers in Quebec, as measured in constant dollars, decreased from $6.49/GJ in 1986 to $5.86/GJ in 1995 (Figure 4.1). The burner-tip price for commercial customers declined from $5.70/GJ in 1986 to $4.24/GJ in 1995 (Figure 4.2). Industrial customers experienced the largest drop for the 1986-1995 period with a fall in the burner-tip price from $4.58/GJ in 1986 to $2.41/GJ in 1995 (Figure 4.3).

The decrease in burner-tip prices for residential customers in Ontario was greater than in Quebec as the average price fell from $5.79/GJ in 1986 to $4.31/GJ in 1995 (Figure 4.4). Over the same period, the burner-tip price for sales to commercial customers decreased from $4.81/GJ to $3.23/GJ (Figure 4.5). The burner-tip price for industrial customers fell from $4.01/GJ in 1986 to $2.38/GJ in 1995 (Figure 4.6).

Transportation tolls on TransCanada for delivery to southern Ontario and Quebec decreased in real terms from $0.97/GJ to $0.68/GJ over the 1986-1995 period.[26]

During the 1986-1995 period, the Alberta border price fell by $1.89/GJ, on average, for residential and commercial customers, and by $0.61/GJ, on average, for industrial customers. Industrial customers saw a very large drop in the border price between 1985 and 1986. Under the terms of the 1985 Natural Gas Agreement, most industrial customers were provided immediate access to direct purchases and realized large benefits within a year. However, since the Agreement stipulated that existing contracts would be respected and at the time the LDCs were committed to gas supply contracts for residential and commercial customers, the major benefits of price deregulation for these sectors were realized after 1986.

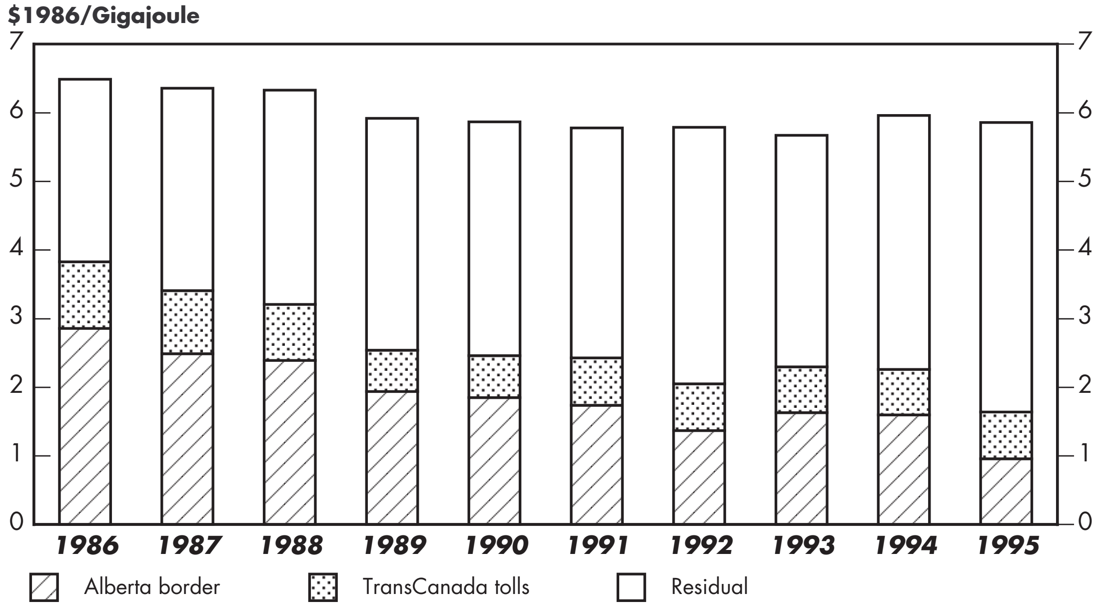
The residual, which is assumed to be all costs associated with distribution, increased for all residential and commercial customers over the 1986-1995 period. In Quebec, the residential residual increased from $2.66/GJ in 1986 to $4.22/GJ in 1995 while the commercial residual increased from $1.87/GJ to $2.60/GJ for the same period (Figures 4.1 and 4.2). In Ontario, the residential residual increased from $1.99/GJ to $2.67/GJ while the commercial residual increased from $1.01/GJ to $1.59/GJ (Figures 4.4 and 4.5). In contrast, the residual component for industrial customers decreased in both provinces. In Quebec, the industrial residual fell from $2.15/GJ in 1986 to $0.88/GJ in 1995 (Figure 4.3) while in Ontario it fell from $1.58/GJ to $0.85/GJ for the same period (Figure 4.6).

In summary, the delivered price of gas to Ontario and Quebec decreased in all sectors over the last ten years. Although these decreases were somewhat offset by increases in distribution costs in the commercial and residential sectors, all end-users in Quebec and Ontario have benefitted from lower burner-tip prices (as measured in constant dollars).

[26] The 1986 toll has been adjusted downward to net out fuel costs in order that the tolls be comparable over the period.

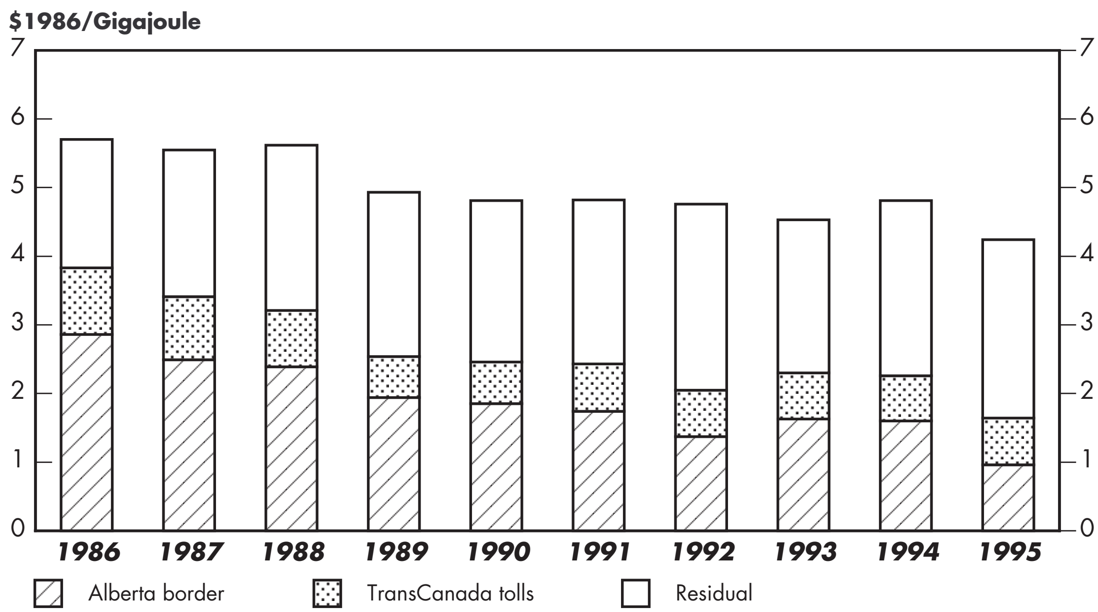
F I G U R E 4 . 1

Quebec Residential Burner-tip Prices



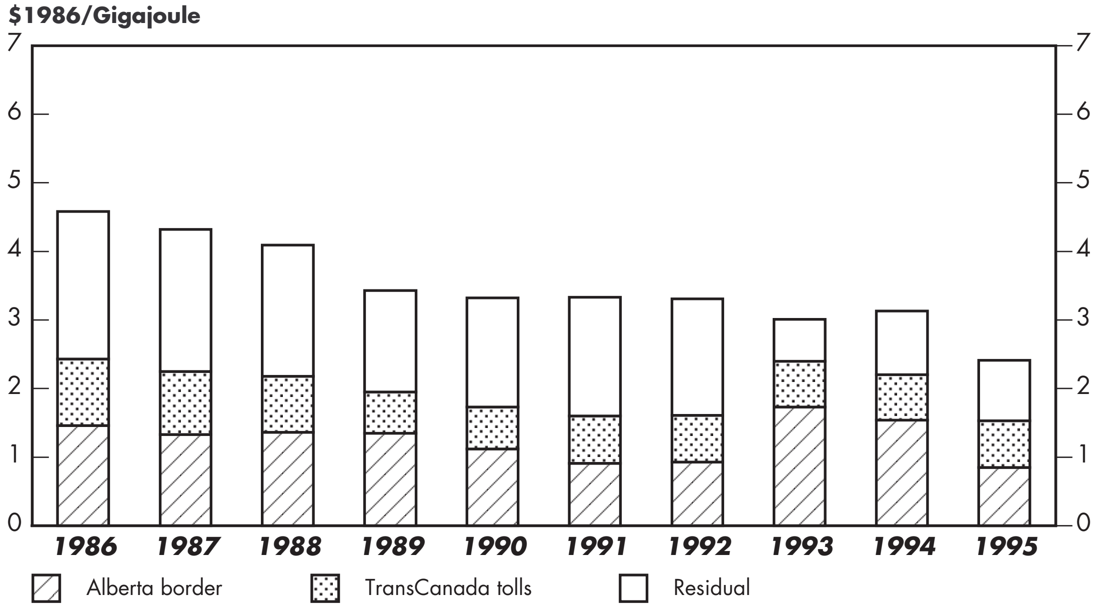
F I G U R E 4 . 2

Quebec Commercial Burner-tip Prices



F I G U R E   4 . 3

Quebec Industrial Burner-tip Prices



F I G U R E   4 . 4

Ontario Residential Burner-tip Prices

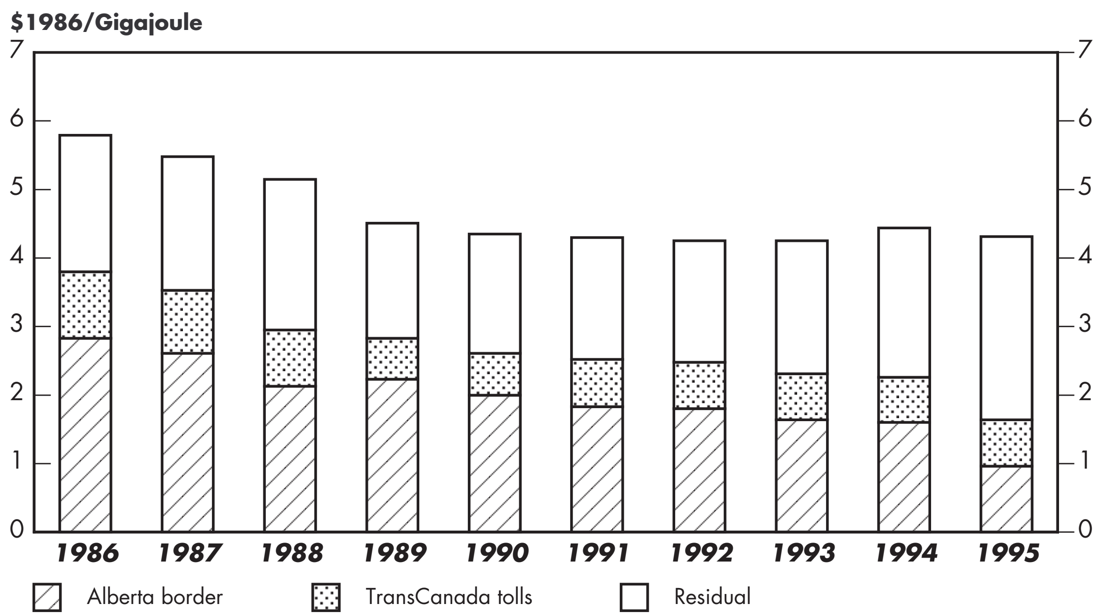


FIGURE 4.5

Ontario Commercial Burner-tip Prices

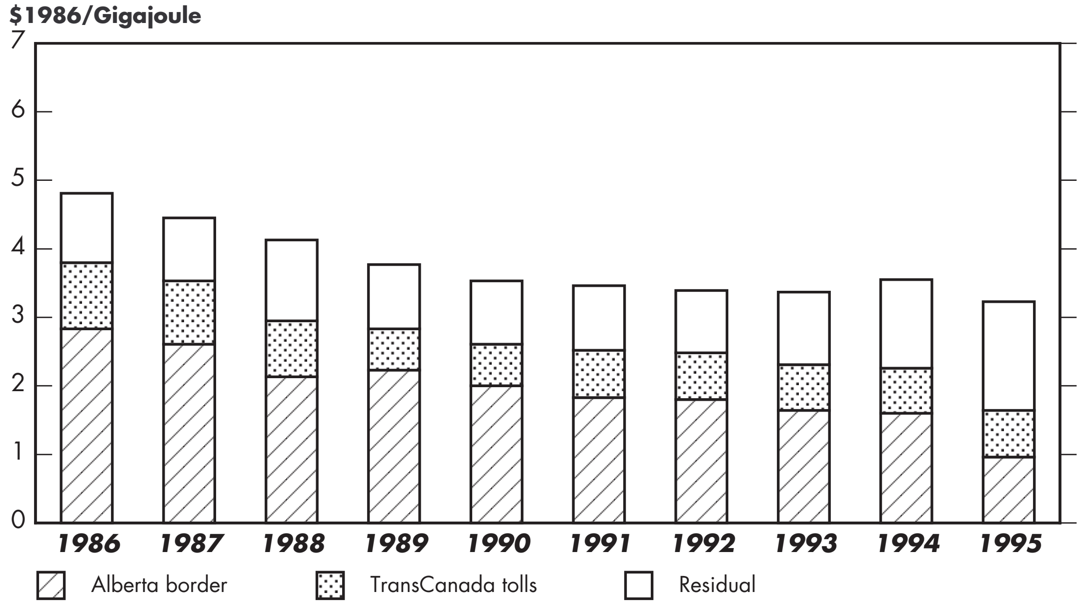
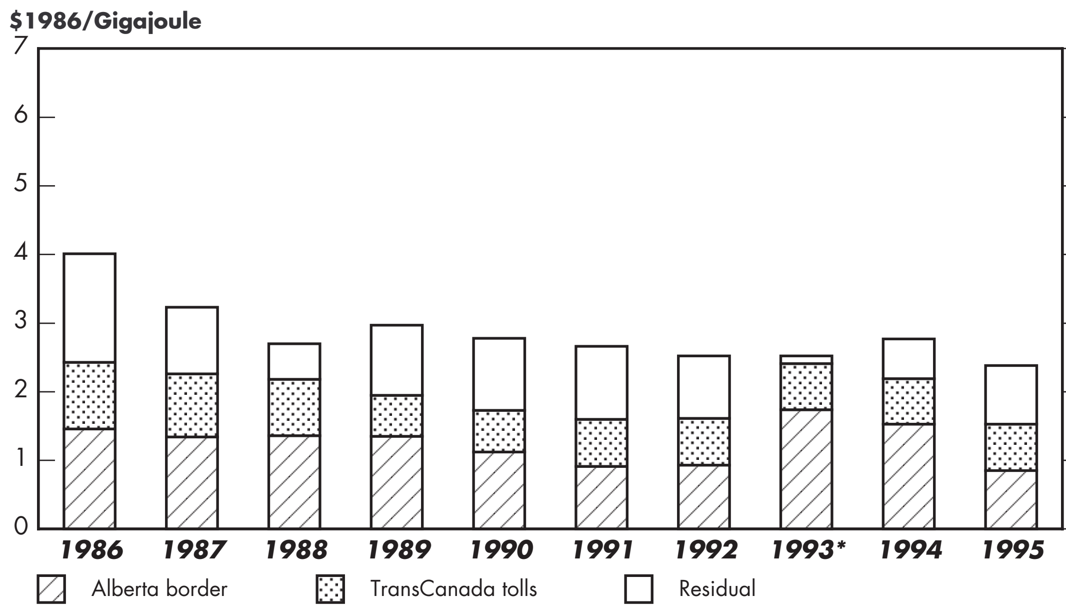


FIGURE 4.6

Ontario Industrial Burner-tip Prices



*The residual (distribution) charge for Ontario industrials appears to fall dramatically in 1993. This indicates a drawback with our methodology. The reason for the apparent decline in the residual is that the 30-day Alberta border price increased significantly, partly due to unusually cold weather. As we assumed that industrials always pay the 30-day price, this translated into a lower share of the burner-tip price being allocated to the residual. In fact, it is likely that actual gas prices paid by industrials were lower than shown because they purchase gas under a variety of contract terms, not only on a 30-day basis.

U.S. LDCs

U.S. LDCs are also adapting to changing market dynamics since the implementation of FERC Order 636. Recently, many LDCs have established guidelines or developmental programs to fully unbundle their distribution services to all customers. In early 1996, the New York Public Service Commission approved unbundling plans for eight LDCs operating in the state. Boston Gas Co. filed a natural gas services unbundling plan with its regulator in May 1996. In its plan, the LDC outlined its anticipated timetable to:unbundle sales and transportation for commercial and industrial customers by December 1996; unbundle sales and transportation for residential customers by November 1997; close gas sales to commercial and industrial customers by November 1998; and close gas sales to residential customers in November 2000. Although these examples may not be illustrative of activities currently taking place in every state, it demonstrates that the merchant role of LDCs likely will change dramatically over the next few years.

4.2 Export Markets

Canadian natural gas exports increased from 21 billion cubic metres (740 Bcf) in 1986 to 78 billion cubic metres (2.76 Tcf) in 1995. As a result of this dramatic increase in exports, the Canadian share of the U.S. gas market has expanded from 8 to 13 percent. The growth in exports was absorbed by a 32 percent increase in U.S. gas demand over the ten-year period and was accommodated by major Canadian pipeline expansions. In particular, the 1991 expansion of TransCanada, serving markets in the U.S. Northeast, and the 1993 expansion of ANG/Foothills and PGT pipelines serving California, greatly increased export potential.

Export Sales, Revenue and Netbacks - Regional Analysis

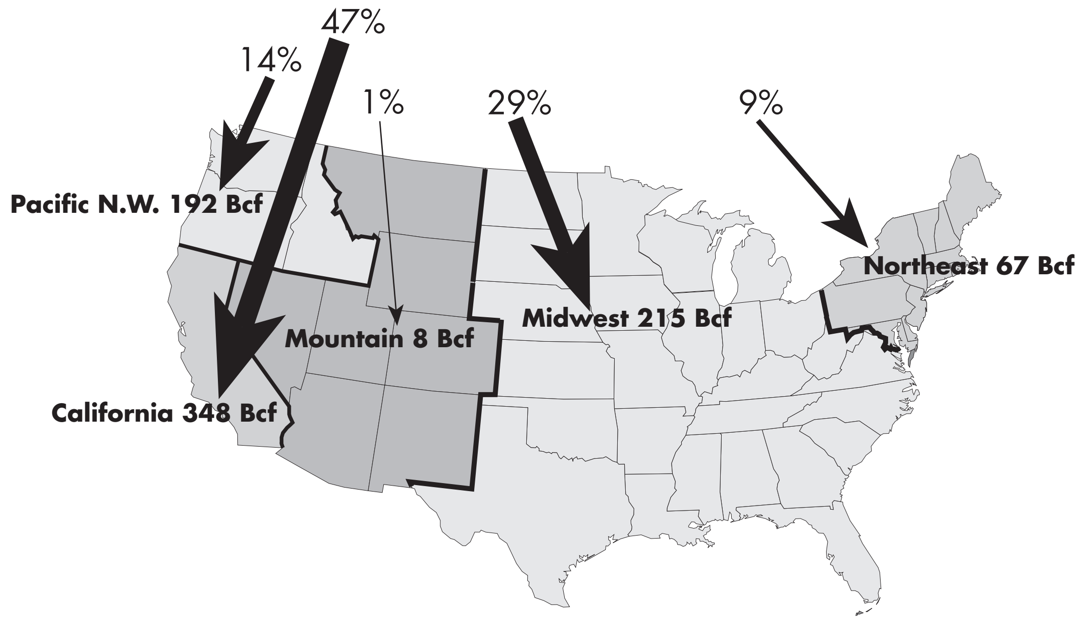
While the traditional export markets for Canadian natural gas have not changed over the past ten years, the share of total exports flowing to each region has become somewhat more balanced. As shown in Figure 4.7, in 1986 California was the largest region for Canadian sales, accounting for 47 percent of total export sales, followed by the Midwest at 29 percent, the Pacific Northwest at 14 percent, the Northeast at nine percent, and the Mountain region at one percent.

In 1995, the Midwest became the largest region for export sales, accounting for 34 percent of the total, followed closely by California at 27 percent and the Northeast at 24 percent (Figure 4.8). The share of sales to the Pacific Northwest and Mountain regions remained virtually unchanged at about 14 percent and 1 percent, respectively.

The growth in exports to the U.S. Northeast has been particularly important, adding value and diversity to many Canadian producers' and marketers' portfolios. Earlier exports which commenced in 1984 from TransCanada to Boundary Gas Ltd., a consortium of U.S. Northeast LDCs, helped pave the way for similar future arrangements. These include the current exports to Alberta Northeast Ltd. which involves 19 U.S. Northeast LDCs. TransCanada's 1991 expansion made these and other additional exports to the Northeast possible. As a result, the Northeast has been transformed from a relatively small market to a major one for Canadian gas which has been providing relatively high prices to producers.

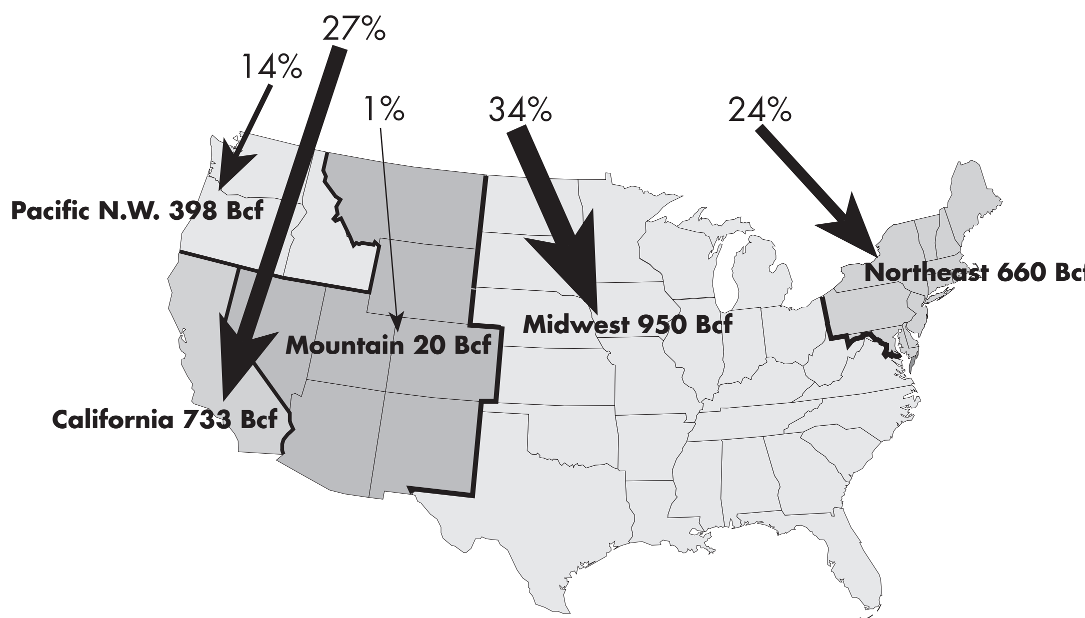
F I G U R E 4 . 7

Canadian Natural Gas Exports By Region - 1986



F I G U R E 4 . 8

Canadian Natural Gas Exports By Region - 1995



While the bulk of Canadian gas exports are still marketed in the traditional regions - the Pacific Northwest, California, the Midwest and the Northeast - a variety of arrangements have enabled Canadian gas sales to penetrate non-traditional North American export markets, such as Florida and Mexico.

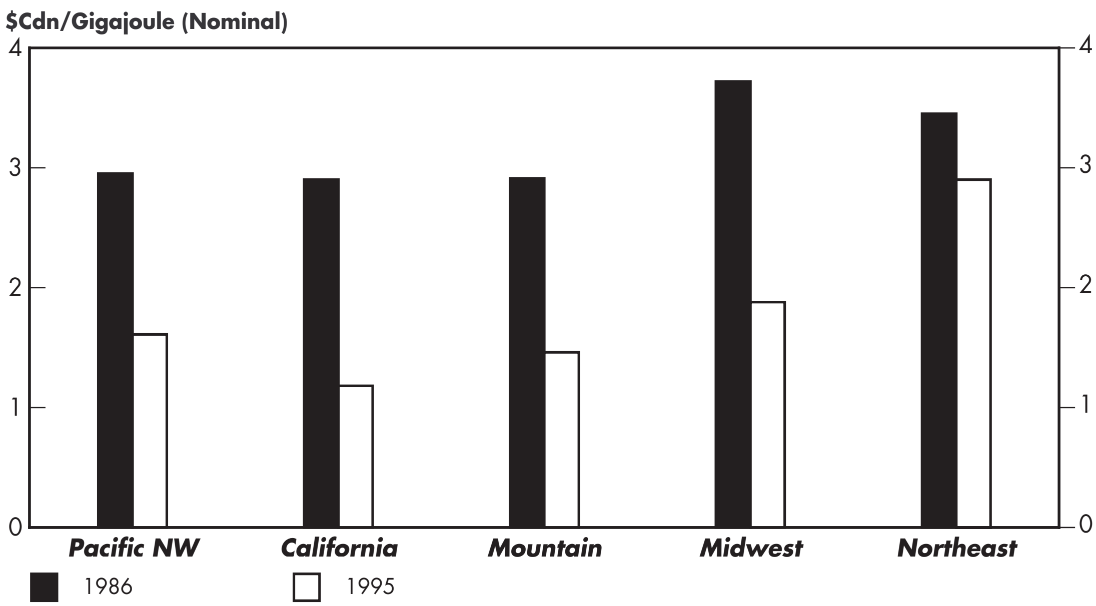
With the rapid growth in export volumes, export revenues have increased from $2.5 billion in 1986 to $5.6 billion in 1995. While volumes have shifted in the traditional export markets, the netback price relationships have also changed over the years. These changes will likely continue, reflecting regional supply and demand conditions in addition to the availability of pipeline capacity serving and/or leaving particular export regions.

Export prices in the post-deregulation era are essentially set in the marketplace where the gas is sold. Once transportation and other costs are deducted from these prices, the resulting price is the netback at various points upstream of the sale. As market prices are determined in U.S. dollars, Canadian export netbacks are also influenced by the exchange rate. The fall in the Canadian dollar vis-a-vis the U.S. dollar over the past ten years has stemmed some of the deterioration of export prices.

Figure 4.9 shows export prices, as measured at the international border, for the major export markets in 1986 and 1995.[27] Through the late 1980s and early 1990s, California yielded premium prices for Canadian natural gas exports. During this time, California experienced high gas demand which helped support market prices. This was partially the result of drought conditions which had lowered the availability of hydro, usually the least expensive electric power source. In addition, the relative proximity of this state to the WCSB translated into lower transportation costs and

FIGURE 4.9

Natural Gas Export Prices by Region



*Prices are calculated at the international border and include the cost of transportation to the export point.

[27] Prices measured at the export border include the costs of transportation in Canada. Thus, exports to the U.S. Northeast, which require more transportation in Canada than exports to California, for example, will yield higher border prices. Border prices are used because reliable field-gate prices for sales in all export markets are not available.

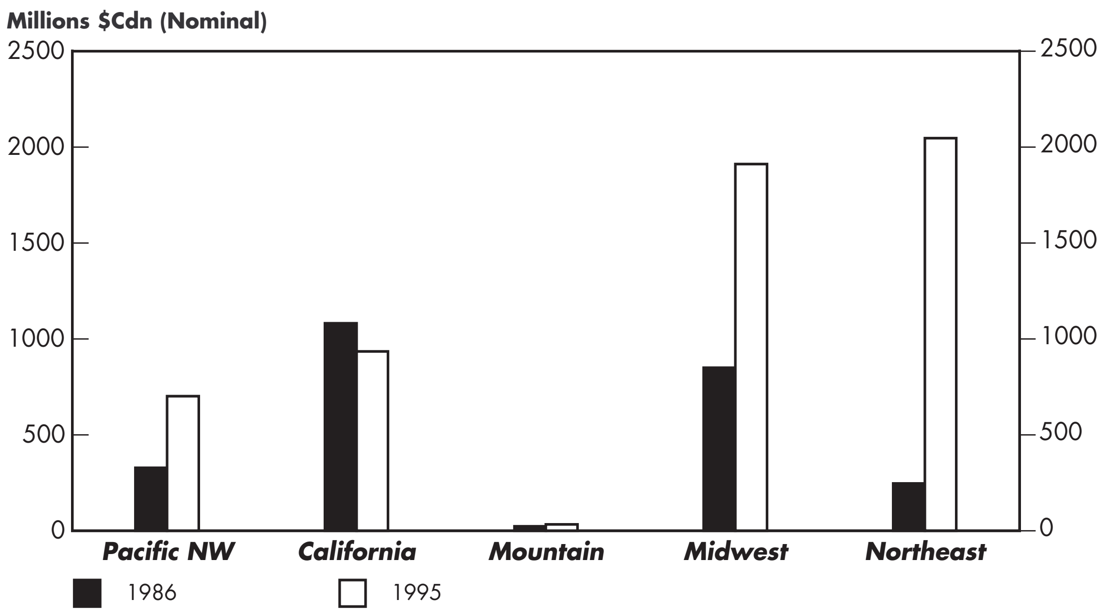
relatively higher netbacks. The existing PGT system was operating at close to 100 percent capacity which, in part, reflected the competitiveness of Canadian supplies compared to other supply sources for California. Following the construction of new pipeline capacity to California in 1993/94 and a return to more-normal hydro conditions, market prices and netbacks from sales to this market fell.

In 1986, exports to the Midwest provided the highest netbacks at both the international border and the field-gate, while sales to the U.S. Northeast yielded the lowest field-gate netbacks. By 1995, the Northeast market yielded the highest netbacks at both the field-gate and the international border despite the higher costs to transport gas there from the WCSB. The prices of many exports to the U.S. Northeast are either tied to indices of U.S. Northeast energy prices or are escalated annually according to agreements, and tend to yield premium values. More recently, there has been a trend to link the export prices to market-sensitive gas prices. In 1995, exports to the U.S. Northeast generated more revenue than sales to other U.S. export markets even though this market is third in terms of volumes of sales (Figure 4.10).

The Midwest provided the second highest netbacks in 1995, while exports to California yielded the lowest field-gate netbacks. The California market has become intensely competitive over the past few years, with abundant gas supplies carried on recently-expanded pipelines. At the same time, the return to more normal hydro conditions has caused demand for gas to soften. In addition, the higher incremental transportation rates that were levied on the PGT expansion shippers further reduced netbacks on exports to California.[28]

F I G U R E 4 . 1 0

Natural Gas Export Revenues by Region



*Revenues are calculated at the international border and include the cost of transportation to the export point.

[28] Following the PGT expansion in late 1993, the FERC decided to establish an incremental tolling methodology on the PGT system. All new volumes were charged a toll to recover the incremental costs of building the expansion. Pre-expansion shippers paid a toll which was based on the historical depreciated cost of the older system, a rate which was less than half of the incremental toll.

Export Customers

Interstate pipeline companies are no longer the predominant purchasers of Canadian gas exports. This came about as a result of the FERC's Order 636 and its regulatory predecessors, which fully unbundled pipeline sales and transport functions, and directed pipelines to shed their merchant function. Several of the contracts between Canadian exporters and pipeline companies were restructured under a variety of new arrangements.

Currently, the largest purchasers of Canadian gas exports are U.S. marketing companies, accounting for 47 percent of total exports in 1995. This gas is resold to a variety of other customers, ranging from LDCs to small end-users. Some of these marketers are affiliated with or wholly owned by Canadian companies.

In the last decade, there has been rapid growth in gas exports to electricity generation markets. This can be attributed to two main factors. The first is technical advances in natural gas combined-cycle generation which has resulted in improved efficiency of generating electric power from gas, lower capital costs, and reduced emissions. The second factor relates to U.S. federal government initiatives that repealed legislation which restricted the use of natural gas by electric utilities and industrial customers and, along with several states, encouraged the development of non-utility power production. Consequently, natural gas has captured the largest share of the incremental market for fuels for electric power generation. As of 1995, exports to electricity generation markets were estimated to account for 10 to 15 percent of total exports.

LDCs have stepped into the role of purchaser in a large number of cases where contracts were previously held by pipeline companies. U.S. LDCs purchased 33 percent of total Canadian exports in 1995 compared to only 11 percent in 1986. As noted earlier in this chapter, the roles of LDCs are undergoing many changes.

4.3 Gas Sales Practices

Gas sales practices rapidly changed after the introduction of open access and direct sales in the mid-1980s. Many smaller marketing entities were formed in response to the new sales opportunities in the marketplace. The traditional role of aggregators has eroded, with producers shifting to marketing some, or all, of their own gas or using other marketing companies. In 1986, aggregator/pipeline companies marketed 90 percent of total export volumes while in 1995 aggregators marketed only about 45 percent.

In recent years, improved access to price information through published sources and electronic gas trading, and generally more efficient markets, have reduced marketing margins. Consequently, several marketing companies have found it difficult to compete, resulting in a trend to mergers to create larger companies. A number of "mega-marketers" or larger marketing entities have been established which usually have corporate affiliations on both sides of the border. With the continued rationalization of the industry, and a view to increase value-added services,energy marketers or "Btu traders" have also emerged. These companies are capable of providing a variety of integrated energy services.

Several large pipeline companies have realigned their corporate structures to increase their presence in marketing activities. Others have become more involved further downstream in LDC activities, such as Westcoast's ownership of Union Gas and Centra Gas.

The Increasingly Short-term Nature of the Market

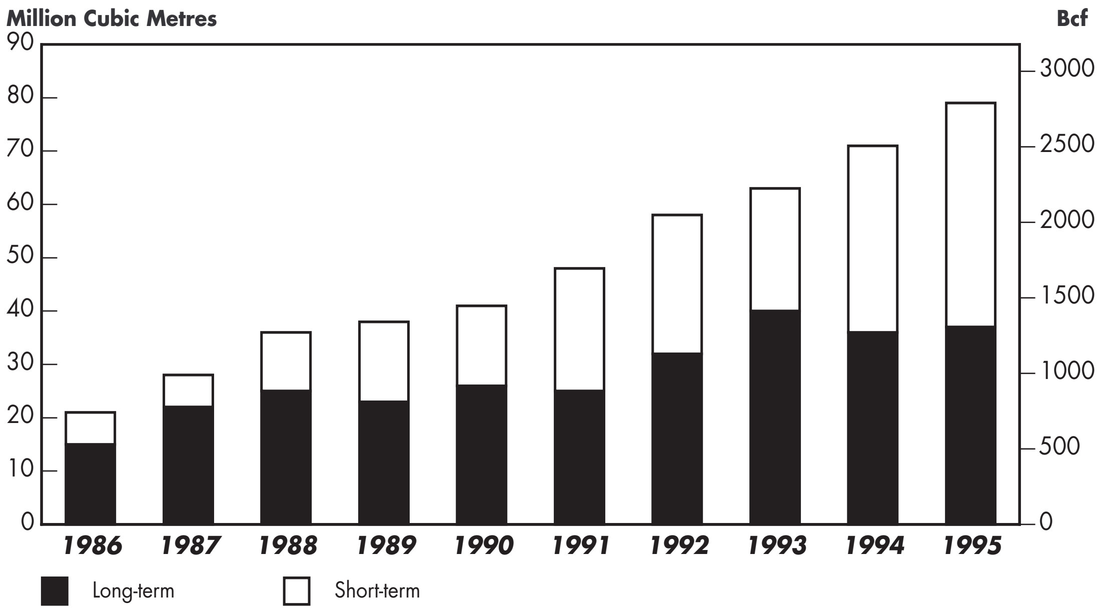
Prior to deregulation, natural gas was sold almost entirely by merchant pipelines to LDCs under long-term contracts with specific contract provisions. In the last ten years, gas buyers have become less concerned about security of gas supply and more concerned about minimizing the costs of their gas purchases. Not surprisingly, there has been a shift to shorter-term sales in the gas market. For example, there has been a steady movement by Canadian gas exporters to sales under short-term export orders. Whereas short-term exports accounted for only 30 percent of exports in 1986, they accounted for 53 percent of total exports in 1995 (Figure 4.11).[29]

Sales of an interruptible nature (short-term or spot sales that can be interrupted according to the terms of the contract) have also increased. Buyers and sellers find that they can increasingly take advantage of various market opportunities, including day-to-day transactions, using back-stopping arrangements with storage when necessary. Interruptible export sales comprised 21 percent of total export volumes in 1995, compared to 2 percent in 1986.[30]

In the late 1980s, active spot markets began to develop at various locations in North America, some of which later turned into market hubs.[31] By 1995, spot markets had a large influence on the pricing of gas throughout the market. The pricing in many sales contracts, including long-term contracts, is market-responsive and is often determined according to indices of monthly spot prices in the relevant market region.

F I G U R E 4 . 1 1

Short-term and Long-term Gas Exports



[29] Exports for terms less than two years are approved as short-term orders and are generally processed in less than 48 hours from receipt of application. Export applications for terms longer than two years require the Board to hold a public hearing (either oral or written) prior to issuing an export licence.

[30] Expansion of storage in North America over the past ten years has helped accommodate these opportunities by providing producers with more inventory flexibility to release supplies when market conditions are favourable.

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

The efficiency of spot markets has been enhanced by the establishment of a number of futures contracts. These include the NYMEX futures contracts at the Henry Hub in Louisiana, at Keystone in Texas and the newly-launched Alberta contract, as well as the Kansas City Board of Trade contract at the Waha hub in Texas. The price of natural gas is very volatile and these futures contracts, and associated derivatives, provide an important means by which buyers and sellers can protect themselves from adverse price fluctuations.[32]

Perhaps even more importantly, the futures contracts improve price transparency throughout the market. All participants can now quickly determine the relative value of natural gas at different points, gas will flow to its highest value end-use. Efficient spot markets help ensure that short-term supply/demand imbalances are quickly corrected.

Although there has been rapid growth in short-term sales and the spot market, long-term sales still comprise a large proportion of the total. Pricing provisions in long-term gas sales contracts have become very flexible and are often tied to short-term indices, with the effect that export prices follow, at least in part, developments on the spot market.[33]

Integration of the Canada/U.S. Natural Gas Market

In a fully-integrated competitive natural gas market, the price of gas in one region should differ from the price of gas in other regions only by the cost of transportation. Price movements in one region should tend to be reflected in parallel movements in other regions. Evidence from the North American experience over the last ten years indicates that the gas market has indeed become increasingly integrated since the deregulation of natural gas prices and the introduction of open access to pipelines.[34]

The degree of integration between the various market and supply regions in Canada and the U.S. varies over time as demand shifts, new gas supplies are developed and new pipeline facilities are constructed (Figure 4.12). Prior to 1993, the Alberta market was not well-integrated with the larger Canada/U.S. market. Excess supply conditions in western Canada created intense gas-on-gas competition, resulting in prices which were largely determined by intra-provincial market conditions. Following the construction of new pipeline capacity to carry gas to extra-provincial markets, constraints on the flow of western Canadian gas to other regions were removed and, throughout 1993 and 1994, the Alberta market was well-integrated with the rest of the Canada/U.S. market.

In 1995, the link between the western and eastern halves of the market began to weaken and, by the winter of 1995/96, a clear split between the two regions had developed. The extent of this split was highlighted in February 1996 when prolonged cold weather in the east resulted in prices reaching an average of $US 4.62/MMbtu at Henry Hub while the price at Empress averaged only $US 1.15/MMbtu. Prices in western U.S. regions also remained low, indicating that the Alberta market was still closely linked with these market regions.

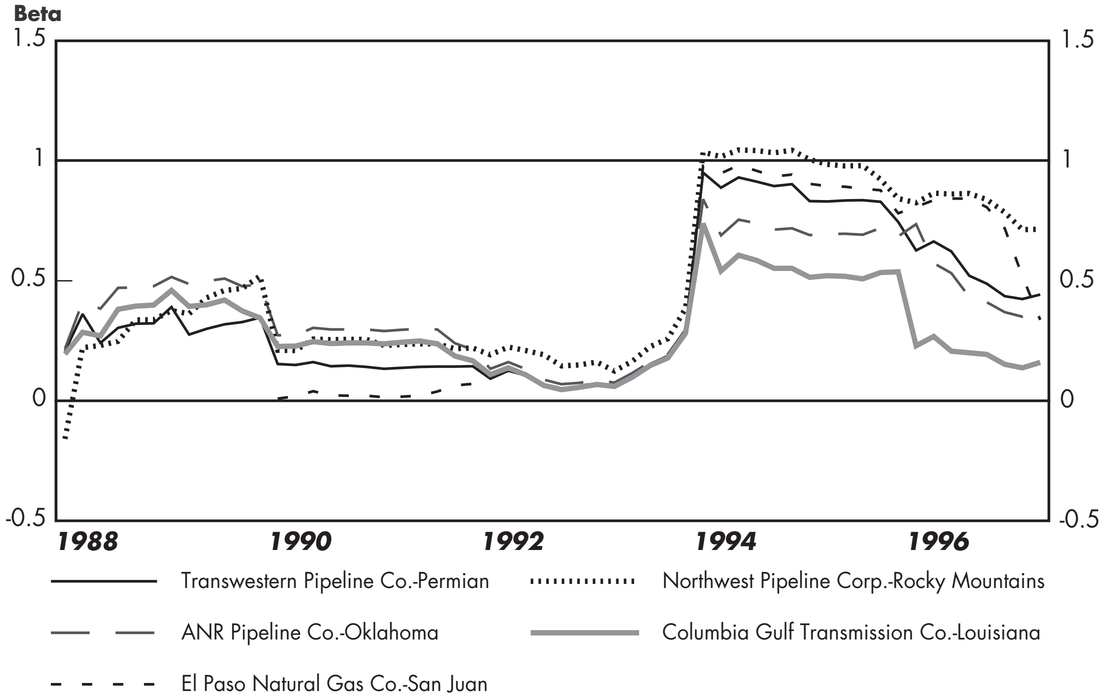
32 See Appendix IV for a review of the hedging instruments available to the Canadian gas industry to reduce the risk associated with price volatility.

33 For a review of contracting practices in long-term Canadian gas export contracts, see the Board's upcoming report Long-Term Canadian Natural Gas Contracts - An Update, to be released within the next few months.

34 For a more in-depth analysis of North American natural gas market integration, see the National Energy Board's December 1995 publication, Price Convergence in North American Natural Gas Markets.

FIGURE 4.12

Integration of the Canada/U.S. Natural Gas Market



Most recently, available pricing data for 1996 suggest that the Alberta market is much less-closely linked with the western U.S. producing regions (Figure 4.12). This link may be weakening, in part, because additional volumes of natural gas from the San Juan and Permian basins in the western U.S. have begun to flow to eastern U.S. markets. Further, there may be increased constraints, relative to productive capacity, on pipeline take-away capacity in Alberta.

Although construction of new pipeline capacity can help integrate regional markets, it is likely that some degree of regionalization will continue to exist in the Canada/U.S. gas market. The existence of this regionalization has been recognized by the launching of western-based futures contracts, including the NYMEX Alberta-based futures contract.

Despite some regionalization of markets, the homogeneous nature of natural gas has allowed for the development of a larger more competitive natural gas market. Natural gas exchanges can be performed to accommodate a sales contract without the physical delivery of a particular supplier's gas. Instead, arrangements can be made between suppliers to deliver gas to various markets in exchange for having their particular markets served. It is now possible for marketers based in Calgary to sell Canadian gas to markets in Florida even though the gas will not physically flow there. Thus, the Canada/U.S. market is much more integrated that it was a decade ago.

Domestic and Export Natural Gas Prices

Another indicator of the integration of the Canada/U.S. natural gas market is provided by a review of average prices paid for Alberta gas by Canadian buyers and U.S. buyers (Figure 4.13). A premise of the Board's MBP is that, in an open unregulated gas market, all buyers should have access to Canadian-produced gas on similar terms and conditions, including price. The figure

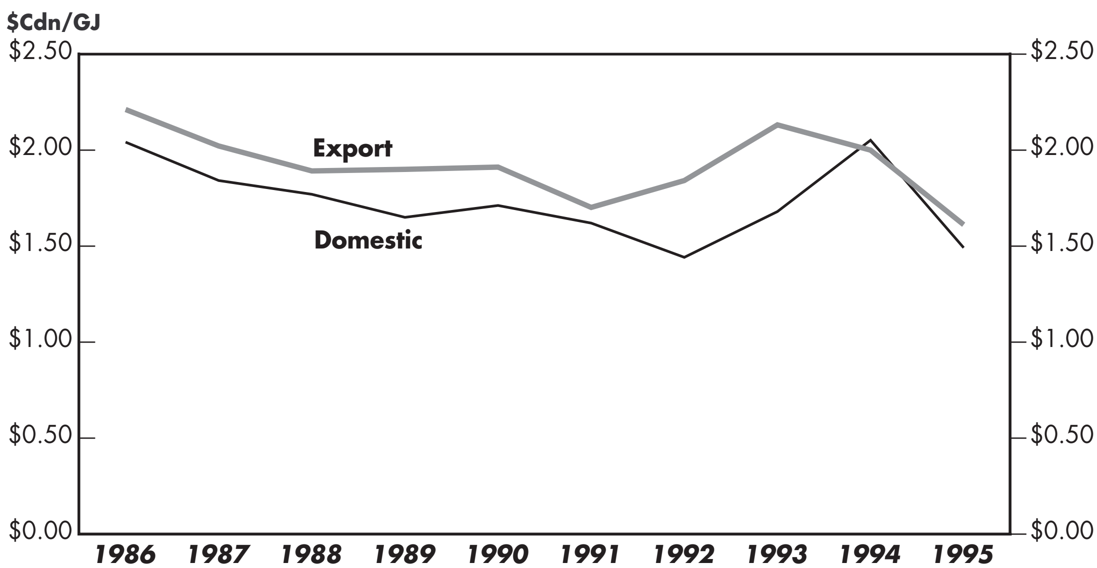
indicates that Canadian buyers have enjoyed lower prices for Alberta-produced gas over most of the last decade, although there has been a convergence in the last two years.

One of these reasons for the divergence in prices earlier in the period was differing price expectations within the various markets, resulting in fixed prices for specified terms, in absence of the large degree of price discovery which exists today. In addition, eastern Canadian LDC prices were essentially fixed at the Alberta border while export prices were determined at various points (typically along the international border) and used a variety of pricing mechanisms including indices linked to a basket of fuel prices. Exchange rate differentials also played a larger role in causing the two price lines to diverge than would have been the case if the prices used for Canadian and export sales were based in U.S. dollars.

Currently, the indices used are primarily in U.S. dollars, resulting in fewer differences in the two prices due to exchange rate differences. This, combined with a few other domestic sales based on similar indices, have helped bring domestic prices closer to export prices (as measured at the Alberta border).

F I G U R E 4 . 1 3

Average Annual Alberta Border Prices



*Domestic prices include intra-Alberta sales.

Source: Alberta Department of Energy

4.4 Interaction Between Transportation and Gas Markets

The price of natural gas varies from region to region due to changes in local supply and demand conditions which are caused by such things as weather fluctuations. When the price rises in one region, it is a signal that it needs more gas. Gas sellers will want to sell gas in the high price region to profit from the higher prices. The change in relative prices between regions, the price differential, provides an important signal to market participants about the value of transportation between regions across the continent.

The entire Canada/U.S. gas market is affected by changes in price differentials. Gas marketers re-align their sales portfolios, shift priorities and adjust the flow of gas in response to changing local prices. Similarly, gas purchasers try to access the lowest cost supply regions to minimize their cost of acquiring gas. To access the most advantageously-priced markets, market participants bid to acquire transportation capacity. The difference in spot gas prices between two locations will affect the level of the bids for transportation, thereby establishing a key link between the transportation and sales markets. Due to this link, the transportation system plays an integral part in the dynamics of the natural gas market. Parties who hold transportation capacity have the option either to use their capacity to move gas themselves or to sell it to another party who values it more highly. Thus, sales of pipeline capacity rights take place in conjunction with numerous gas market deals.

Persistent patterns in price differentials can also lead to longer-term market adjustments. For example, prior to 1993 the California gas market was one of the highest-priced markets on the continent. In 1991, the price of gas at the California border was $US 0.50/Mcf higher than the NYMEX price and $US 0.98/Mcf higher than the Alberta price. In response to the persistently high price differentials and in anticipation of growth in demand, a number of pipeline projects were completed in 1992 and 1993, including the ANG/Foothills-PGT expansion. As a result of the increase in gas supplies available to the state, the California market price fell relative to other markets. In 1995 the California border price was $US 0.26/Mcf lower than the NYMEX price, a change of over $US 0.75/Mcf in the differential from 1991.Similarly, the California price was only $US 0.49/Mcf higher than the Alberta price, half the 1991 differential.

In summary, in response to changing regional prices, there will be a series of adjustments in both the gas market and the market for transportation. This provide market participants with more options to adjust their sales/purchase portfolios and creates considerable flexibility in the gas delivery system. A major benefit of this flexibility is that gas sales and physical deliveries constantly adjust to minimize the cost of getting gas to consumers while providing profit opportunities to gas marketers. From time to time, capacity constraints between two regions arise, resulting in some loss of flexibility. However, even within these temporary constraints, the use of the pipelines system is still optimized.

4.5 Summary and Current Issues

There have been fundamental changes in the natural gas market in the last decade. Natural gas has emerged as a commodity that can be traded on a short-term basis in a highly transparent spot market. The efficiency of the gas market has been enhanced by the development of a spot market and associated futures markets, and by improvements in the gas transportation system.

The importance of aggregators as gas sellers has diminished as marketing companies have taken up a large share of the gas sales market. Although there was a proliferation of small marketing companies in the years immediately following deregulation, more recently larger “mega-marketers” are playing a larger role in gas trading. Several pipeline companies continue to be very active in gas trading, primarily through marketing arms.

There has been steady growth in gas consumption in Canada during the last ten years, with the most rapid growth occurring in the industrial sector. The steep fall in prices at the wellhead translated into lower prices for industrial gas users. However, prices to end-users in the residential and commercial sectors in eastern Canada only fell modestly, in part due to increases in distribution costs.

There has been spectacular growth in Canadian gas exports in the last ten years, as exports almost quadrupled from the 1986 level. Export revenues climbed to $5.5 billion in 1995, more than twice the 1986 level. The U.S. Northeast has emerged as a major market for Canadian natural gas exports, accounting for 24% of sales in 1995 and yielding the highest netbacks of any market. The higher netbacks are partly due to a split that has emerged in the Canada/U.S. gas market, with the western part of the market characterized by oversupply and lower prices, with the reverse being true in the eastern part of the market.

Despite the recent split in pricing between eastern and western markets, the North American gas market has become increasingly integrated over the past decade. The use of futures contracts and the growth in spot market sales is tending to harmonize sales and purchasing practices in Canada and the U.S. Another indication of this integration is the fact that prices paid by domestic and U.S. buyers at the Alberta border have converged in the last two years.

Available data indicate that Canadians who purchase gas from Alberta have paid prices which have been equal to or less, on average, than prices paid by export buyers for Alberta-sourced gas. This, along with increased competition and wide choice of supply, indicates that the gas market has been generally working so that Canadian requirements for natural gas have been satisfied at fair market prices. While the domestic gas market has functioned well since deregulation, provincial regulatory bodies still have to make some important decisions about the future role of LDCs within a deregulated market, including the extent to which their services will be unbundled.

There are a number of issues facing gas producers and marketers, not the least of which is perceived limitations in capacity on Canadian pipelines to the international border. The ongoing lower gas prices in western Canada relative to the U.S. Midwest and Northeast make these markets increasingly attractive.

The current initiative in the United States to deregulate electric power markets eventually could have a large impact on the gas export market. However, there is currently a great deal of uncertainty as to the speed with which electric power markets will be opened and as to the short-term and long-term implications for gas sales in these markets. Natural gas, of course, will have to compete with other fuels for its share of the electric power market.

PREVIOUS NATURAL GAS MARKET ASSESSMENT REPORTS BY THE BOARD

1. **Natural Gas Market Assessment**, October 1988

   This report provides a description of the structure and functioning of the Canadian natural gas market following gas price deregulation and the implementation of open access on Canadian pipeline systems.

2. **Natural Gas Market Assessment**, October 1989

   This report provides an update of the structure and functioning of the Canadian natural gas market, covering the major changes since the October 1988 report. It also includes a short-term assessment of the outlook for supply, demand and prices in the market.

3. **Natural Gas Market Assessment, Long-Term Canadian Natural Gas Contracts**, August 1992

   This report provides a comprehensive description and analysis of the changes which occurred in natural gas contracting practices for sales of Canadian gas into both domestic and export markets from 1985 to 1991.

4. **Natural Gas Market Assessment, Canadian Natural Gas Market Mechanisms: Recent Experiences and Developments**, November 1993

   This report describes the response of the natural gas market, on the part of both Canadian gas buyers and sellers, to deliverability difficulties which arose, particularly during the 1992/93 winter period.

5. **Natural Gas Market Assessment, Natural Gas Supply, Western Canada: Recent Developments (1982-1992); Short-Term Deliverability Outlook (1993-1996)**, November 1993

   This report summarizes then-recent developments in Canadian gas supply and provides an analysis of short-term gas deliverability for the years 1993-96.

6. **Natural Gas Market Assessment, Price Convergence in North American Natural Gas Markets**, December 1995

   This report uses a unique statistical analysis to assess the extent to which the Canadian and U.S. natural gas markets became integrated in the post-deregulation era.

PRICE SIGNALS FOR PIPELINE EXPANSIONS

The secondary market can provide useful information about the need for future pipeline expansions. Price differentials, the difference in the price of gas between two locations, provide a market measure of the value of transportation between two locations. If the price differential consistently exceeds the regulated toll on a pipeline, then the shipper that holds capacity on that pipeline can regularly benefit by transporting gas to the higher-priced location. From a shipper's perspective, the willingness to subscribe to a new pipeline expansion will depend on current and expected future price differentials compared to the actual and expected pipeline toll.

The price differentials between the Alberta border and other areas in North America tell an interesting story, particularly in the months of late 1995 and early 1996. To illustrate the major North American consuming regions for Canadian gas, three specific delivery points are examined: Malin for the California market; Chicago for the U.S. Midwest market, and Niagara for the eastern market. All three of these markets can be serviced by natural gas from the WCSB through existing pipelines.

Figure A.1 shows the spot price differential between Kingsgate, British Columbia and Malin on the Oregon-California border. The firm regulated tolls on PGT are also shown. The two lines labelled FTS-1 and T-3 represent the tolls paid by pre- and post-expansion shippers respectively. Since the expansion of the PGT pipeline to Malin in December of 1993, the regulated toll has exceeded the spot price difference by an average of $US 0.08/MMBtu for pre-expansion shippers and $US 0.28/MMBtu for post-expansion shippers.

The spot price differential between Chicago and Alberta has exhibited far greater volatility as can be seen in Figure A.2. However, the pattern of large swings in the differential observed in the early 1990s looks as if it has subsided recently. Since January 1995, the Chicago differential has averaged $U.S. 1.09/MMbtu compared to the toll via TransCanada, Viking and ANR which averaged $U.S. 0.66/MMbtu, and the toll via Foothills, Northern Border, Natural, which averaged $U.S. 0.76/MMbtu.

FIGURE A-1

Price Differential and Pipeline Tolls: Malin vs. Kingsgate

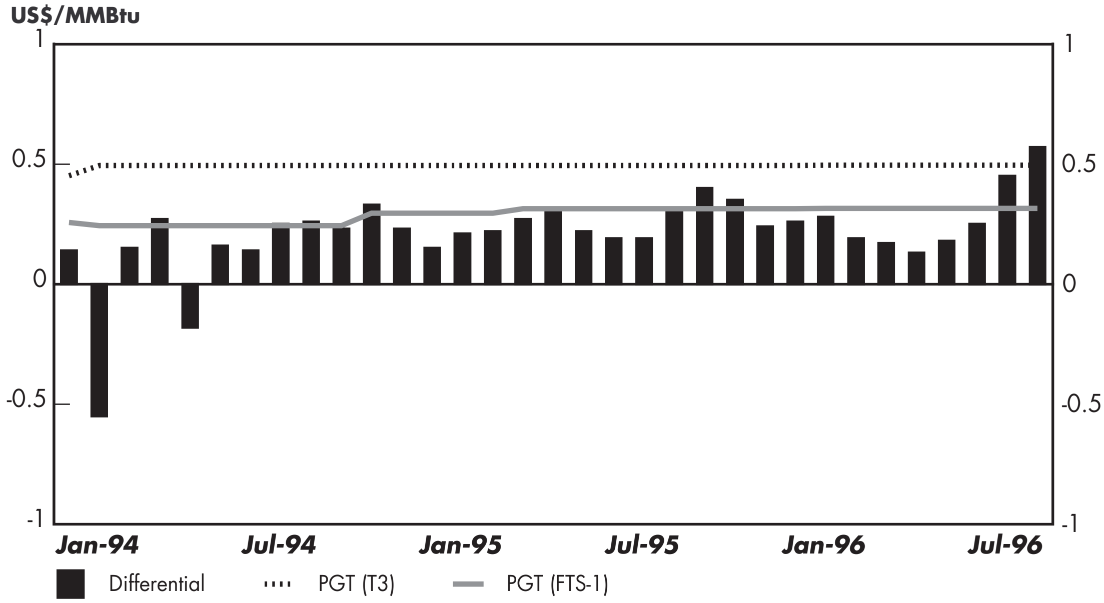


FIGURE A-2

Price Differential and Pipeline Tolls: Chicago vs. Alberta

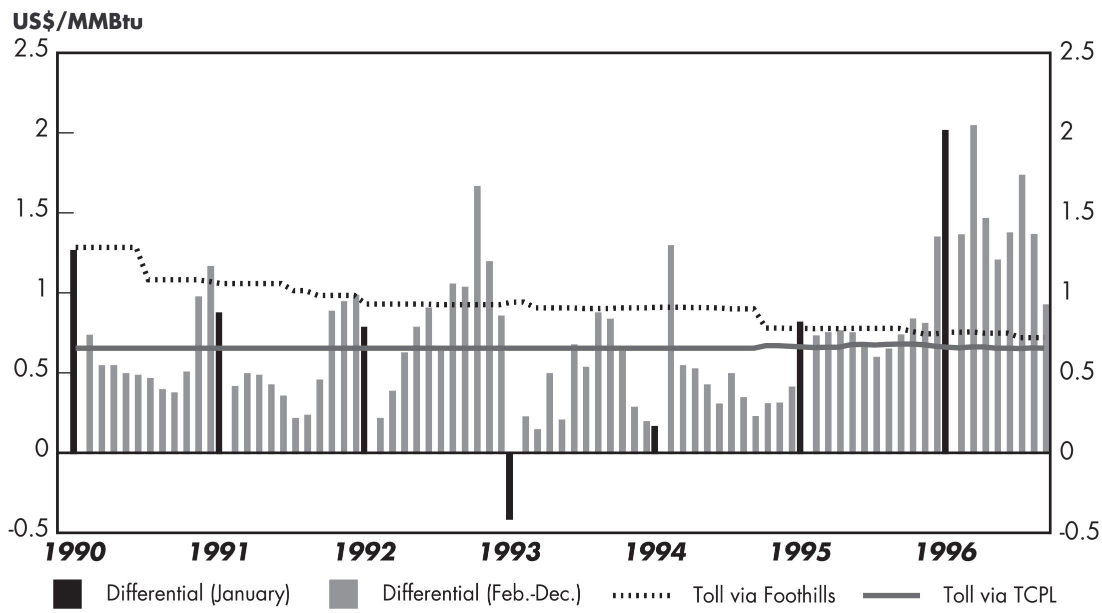


FIGURE A-3

Price Differential and Pipeline Tolls: Niagara vs. Alberta

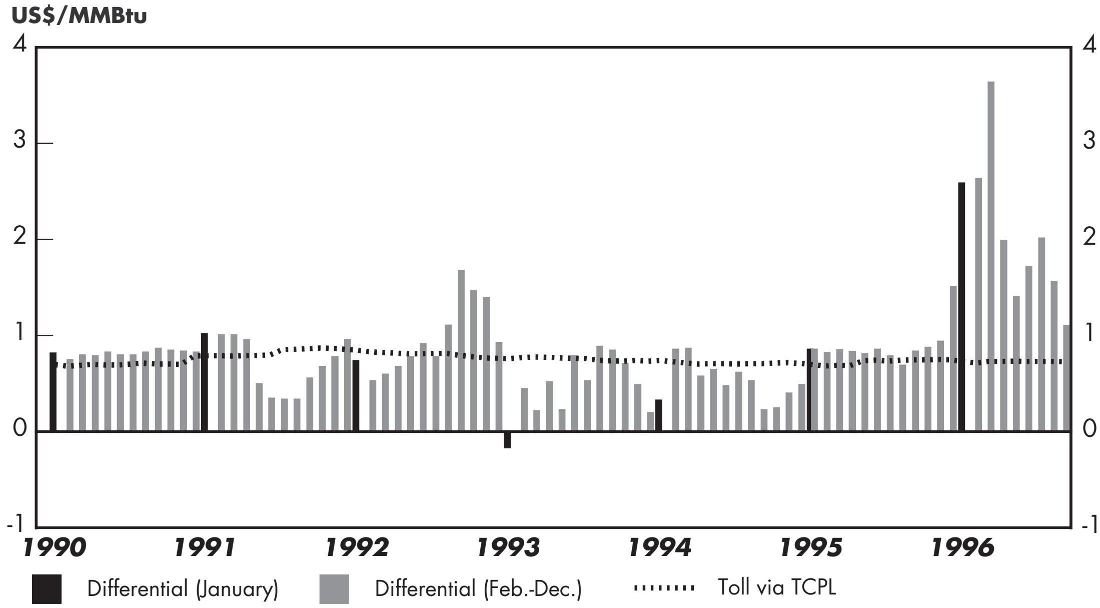


Figure A.3 illustrates the differentials in spot prices between the Alberta border and eastern markets, represented here by the Niagara export point at the Ontario-New York border.[35] Since 1990 the differential has averaged $US 0.87/MMBtu compared to the firm toll on TransCanada of $US 0.75/MMBtu. As in the Chicago market, the difference between the Niagara differential and the pipeline toll has increased recently. Since January 1995, the Niagara differential averaged $US 1.39/MMBtu compared to the average pipeline toll of $US 0.73/MMBtu. This is due to the extremely high spot prices in the east which resulted in a substantial widening of the differential since December 1995.

This simple analysis allows us to make a few conclusions. Since January 1995, the value of pipeline capacity going east has been greater than regulated pipeline tolls. In contrast, the value of capacity going to California has been less than regulated tolls. This suggests that it has been more beneficial to hold pipeline capacity to markets in the east. It should be noted, however, that roughly half of the gas exported from Canada is still moved under long-term contracts. Under these contracts, prices may be insensitive to short-term fluctuations in the spot market. However, persistent spot market conditions will influence any long-term contracts currently under negotiation or re-negotiation. Given that the value of capacity has exceeded the regulated toll to markets in the Midwest and Northeast, it should be of no surprise that all of the proposed pipeline expansions from Canada plan to access these markets.

[35] Niagara was chosen since it provides information on both Central Canadian markets as well as those in the U.S. Northeast. The same trend would be depicted for any of the other major eastern delivery points as shown for Niagara.

DEVELOPMENTS IN CORE MARKET POLICIES IN CANADA

British Columbia

In 1988, the Ministry of Energy, Mines and Petroleum Resources (MEMPR) issued a policy paper entitled "British Columbia Natural Gas Core Market Policy" and the British Columbia Utilities Commission (BCUC) established rules under which core customers could purchase gas supplies directly from producers and marketers. Commercial and residential customers required a diversified gas supply portfolio and an average rolling supply of 5 and 15 years, respectively. These requirements and problems with access to transportation on the Westcoast system created disincentives for core market customers to buy gas under direct purchase. By 1992, very few direct sales had taken place in the province.

In 1992, the MEMPR reviewed the core market policy and replaced it with a Domestic Supply Policy. Prior to implementing theses new rules, the BCUC held a generic hearing. The commission requires that sellers obtain a licence, post a gas delivery performance bond, comply with a code of conduct, maintain a four-year rolling supply and use a standard gas purchase contract. The LDCs were directed to make buy/sell arrangements available to core customers as of May 1, 1993 and make transportation service available by November 1993.

In 1994, the BCUC conducted a review of buy/sell deliveries to the core market. In 1995, it released its decision which effectively reduced the minimum supply requirement from four years to one year and allowed buy/sell deliveries to start at the beginning of any month on 60 days notice. These changes increased customer flexibility to select new supplies during the contract year.

Alberta

Alberta was the last province to allow direct sales for core customers. In 1993, the Alberta Department of Energy issued a discussion paper on proposals for an intra-Alberta core market policy. After extensive consultation with the industry, new regulations were enacted in 1995. Core customers now have the option of either continuing to be supplied by their LDC or purchasing from another supplier. Consumers served by rural co-operatives are not affected by the new regulations. In cases where the gas distribution system is municipally-owned, the decision to allow core direct sales will be made at the local level.

In 1995, Canadian Western Natural Gas and Northwestern Utilities Limited proposed that buy/sell and transportation service be available to core customers. The EUB approved these changes in early 1996 and some small direct sales have begun.

Licensing and bonding are required of direct sellers in Alberta and a code of conduct will be implemented in the near future.

Saskatchewan

There is no formal core policy in Saskatchewan. Core customers can purchase gas directly and transport the gas pursuant to a T-service. However, they must pay a premium fee for back-stopping arrangements on TransGas. Currently, there are no direct purchases made by the core market as the costs associated with direct sales offset any potential savings for these customers.

Manitoba

Currently, core customers can purchase gas directly under either a buy/sell arrangement or a T-service arrangement. ABMs operating in the province must be registered with the MPUB, pay a registration fee and must provide a minimum two-year rolling supply.

Ontario

Core customers in Ontario have been able to purchase gas directly from suppliers since shortly after deregulation under either a buy/sell arrangement or a T-service. By1991, direct sales to the core market in the province had expanded rapidly.

The three Ontario LDCs were concerned with the ability of core customers to make informed decisions with respect to security of supply. In 1992, Minimum Conditions of Supply (MCS) for core customers were implemented in the province as well as a code of conduct for gas ABMs. Negotiations regarding minimum conditions took place among interested parties under the auspices of the Ontario Natural Gas Association's Direct Purchase Committee. In 1993, a number of issues arose with respect to the implementation of the MCS and its impact on direct purchases. The OEB responded first by holding a workshop and then by calling a public hearing to examine issues relating to the direct purchase of natural gas.

In its 1993 Decision, the OEB found it did not have jurisdiction to require licensing and bonding of ABMs in Ontario. Furthermore, the OEB left a number of issues to be resolved among market participants. Subsequent to the 1993 hearing, a Direct Purchase Industry Committee comprised of LDCs and market participants was formed to address these outstanding issues. In 1994, the MCS were eliminated and new conditions of supply were adopted. Currently, ABMs have two options: one, provide 1-year firm supply and related transportation arrangements or, two, provide no supply security but undertake to use all reasonable means to mitigate potential impact on residential customers should there be a supply disruption. Moreover, a 1-year minimum term with 60-day notice was adopted for customers choosing to return to an LDC's system gas. The Committee agreed to establish a body to be responsible for developing a new code of conduct and a contract dispute mechanism.

Quebec

In 1993, the Régie du Gaz Naturel (Régie) held a public hearing to review the proposed natural gas policy presented by Gaz Métropolitain inc. In its Decision, the Régie abolished the umbrella buy/sell formula in place since 1988 and replaced it with a typical buy/sell arrangement. It also agreed that the proposed five-year minimum rolling supply commitment from suppliers to the core market was reasonable. Furthermore, a one-year minimum term with 60-day notice was adopted for customers choosing to return to LDC's system gas. Finally, the Régie encouraged market participants to form a committee to develop a code of conduct.

FINANCIAL INSTRUMENTS AND HEDGING

The spot price of natural gas is among the most volatile of all commodities.[36] As shown in Table A.1, the price of gas at Henry Hub had a volatility of 20.3 percent between September 1991 and December 1995, which is significantly greater than other commodity prices. The price of natural gas in Canada is even more unstable than in the U.S. with a volatility of 37 percent. The average deviation of the price of gas at Empress is ten cents higher than at Henry Hub ($U.S. 0.47/Mcf compared to $U.S. 0.37/Mcf).

TABLE A-1

Volatility of Commodity Prices - Sept. 1991 to Dec. 1995 (Standard Deviation Divided by Mean in Percent)

Natural Gas at Empress	Natural Gas at Henry Hub	Crude Oil WTI	Residual Fuel Oil Less than 1% S_2
37%	20.3%	10.6%	9.5%

As a result of this high price volatility, buyers and sellers are exposed to the risk of price movements. Even when buyers and sellers sign long-term contracts they may still be exposed the risk of price movements since these contracts are often linked to spot market prices. The greater the volatility of the price of gas the greater is the need to mitigate risk. A gas seller, for example, may need to guarantee an income stream from gas sales by locking in an acceptable price whereas a gas buyer would want to guard against paying too high a price. In both cases the process of protecting oneself from the effects of an adverse price movement is called hedging.

One of the key developments in the natural gas industry which has enhanced the ability of participants to hedge their risk was the start of futures trading on the NYMEX in 1990.[37] The NYMEX futures contract alone has provided only limited protection to Canadian producers who wish to hedge against price changes because of the existence of significant basis risk. In the case of the western producer, basis risk is the result of the unstable relationship between the price of gas in the west (ie. Alberta) and the NYMEX price.

[36] We measure the volatility of a commodity price as the standard deviation from the average price, divided by the average price over the time period being considered, and then converted to percent.

[37] A NYMEX futures contract is a commitment to deliver or take delivery of a specific quantity of gas at Henry Hub Louisiana, at a time in the future. A futures market serves two primary functions: it provides a means for price discovery into the future and allows parties to better manage risk, both of which increase the efficiency of the market.

More recently, both the Kansas City Board of Trade and NYMEX introduced new futures contracts with delivery points in west Texas which were designed to reflect market conditions in the west. Although it appears that these west Texas contracts may provide a better hedging alternative than the Henry Hub futures contract for Canadian producers, there still appears to be notable basis risk. In response to expressions of interest by a number of parties in establishing a futures contract with a delivery point in Alberta, the NYMEX applied and received approval from U.S. regulators for a futures contract with an Alberta delivery point. The Alberta contract began trading in September 1996.

In addition to using futures exchanges, there are other ways to hedge risk including physical hedging, over-the-counter instruments such as options or swaps, and the use of more exotic financial instruments such as "swaptions". While the use of basic derivative techniques is becoming more widespread in Canada, the use of other derivatives has been limited.

To conclude, hedging options provide an efficient way for gas buyers and sellers to mitigate the risk associated with adverse price movements. While the gas market has become highly competitive over the last number of years, there remains a fragmentation which limits the effectiveness of hedging tools such as the NYMEX for Canadian producers. The industry has been responding to these challenges by developing new products, such as over-the-counter instruments, as well as opening futures exchanges in new locations.

3-D Seismic	Gathering seismic data from artificially-created sound waves. The data are enhanced by a computer to form a three-dimensional representation of geological formations.
Basis Risk	The risk that the relationship between two prices (such as the Empress and NYMEX gas prices) will change in an unpredictable manner at some point in the future.
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.
Commodity Charge	A charge applied by a pipeline company to volumes actually transported. This charge recovers the variable costs of providing gas transportation service.
Cost of Service	The total cost of providing gas transportation service, including operating and maintenance expenses, depreciation, amortization, taxes and return on rate base. Generally, the cost of service of a pipeline is the same as its revenue requirement.
Demand Charge	The monthly charge which normally covers the fixed costs of providing gas transportation service. It is equivalent to a reservation charge and is based on the daily contracted volume. It is payable regardless of volumes actually transported.
Direct Sales	Gas purchase arrangements transacted directly between producers, brokers or marketers and end-users.
Eastern Zone	A tolling zone on TransCanada which includes the Central, Southwestern and Eastern Delivery areas. It roughly includes the area east of North Bay, Ontario up to Quebec City, including all of southern Ontario.
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.

Established Reserves Those reserves recoverable under current technology and present and anticipated economic conditions. Specifically, they include those reserves proven to exist by drilling, testing or production ("proved reserves"), plus a judgement portion of contiguous recoverable reserves that is interpreted to exist with reasonable certainty from geological, geophysical or similar information ("probable reserves"). Established reserves are typically comprised of proved reserves plus one-half probable reserves.

Field-gate The point where gas is delivered from a gas producing field, after it has been gathered and processed, to a transmission system (eg. NGTL). The field-gate is often used as a price reference point.

Firm Service Gas transportation service which provides a shipper with a guarantee that the contracted transportation capacity will be available and that service will not be interrupted, except in exceptional cases. Firm transportation provides shippers with the highest priority service.

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.

Incremental Tolls Tolls resulting from a toll design methodology that assigns capital and operating costs of new facilities to a cost pool separate from the costs of existing facilities. Tolls are designed so existing shippers pay a toll reflecting the cost of service associated with existing facilities; "new" shippers pay a toll reflecting the cost of service associated with new facilities.

Interruptible Service Gas transportation service that may be curtailed or interrupted by the pipeline on short notice. Interruptible service is typically offered when a pipeline has excess capacity on the system.

Merchant Pipelines Prior to deregulation, a pipeline which bought all gas delivered to its inlet, transported the gas and resold it in downstream markets.

Marketing Margins The per unit profit realized from the sale of 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.

Productive Capacity The estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities and potential losses due to plant turnarounds and operational problems.

Rate Base The amount of investment on which a return is authorized to be earned. It usually consists of plant in service, plus an allowance for working capital. This is sometimes referred to as the "net asset rate base".

Residential Customers The portion of the natural gas market consisting of private dwellings and larger residential units with individually-metered apartments.

Reserves Additions Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserves estimates for established pools.

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.

Swaption An agreement which gives the purchaser the option to buy a particular swap over a specified period of time.

Take-or-Pay Provision A contract provision whereby a purchaser agrees to pay for a specified volume of natural gas during a period whether or not the contract deliveries are taken.

Ultimate Potential An estimate, at a given point in time, of all the resources that may become recoverable or marketable, having regard for geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, other discovered resources and undiscovered recoverable resources.

Wellhead Price Used to specify a price reference or delivery point for natural gas. It is generally considered to be the price the producer receives after processing and gathering costs have been subtracted.