Canadian Natural Gas

Review of 1999 & Outlook to 2010

May 2000

Natural Gas Division
Energy Resources Branch
Energy Sector
Natural Resources Canada

Foreword

Canadian Natural Gas: Review of 1999 & Outlook to 2010 is an annual working paper prepared by the Natural Gas Division of Natural Resources Canada. It provides summaries of North American natural gas industry trends, and also reviews Canadian gas exports.

As natural gas advisors to the Minister of Natural Resources Canada, we publish this report to initiate dialogue with the industry and obtain feedback on our interpretations of natural gas issues. This report is also used as input for other NRCan reports such as *Canada's Energy Outlook*.

The objective of this report is to provide an understanding of the overall North American gas picture, in a format that can be quickly read.

Sources

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the United States (US). Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada (StatsCan). Data for 1999 is still preliminary and contains problems, the major one being the large "balancing item" (unaccounted for gas) relating to the US. In 1999, because of data problems, supply is almost 1 trillion cubic feet greater than demand, even after accounting for storage movements.

Natural Gas Division Website Upgrade

This report is available online at our website: www.nrcan.gc.ca/es/erb/ngd/. Other natural gas division reports, including previous versions of the review and outlook, are also available at this site.

The website was recently renovated. Older reports have been upgraded to Adobe Acrobat format. The reports now download much faster, and are easier to read and print. The free Adobe 4 software is required to read these reports.

Printed copies of this report are available, in black and white. The internet version is in full colour. Clients with colour printers can therefore generate a colour version of the report by printing the internet version.

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Questions and Comments

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Canadian Natural Gas
Review of 1999 & Outlook to 2010

TABLE OF CONTENTS

Executive Summary

Executive Summary

REVIEW OF 1999

Gas Demand

Gas demand weak for second straight year

North American natural gas demand remained in the doldrums in 1999. Having grown steadily from 1990 – 1997 at 2.5% per year, gas demand then fell 3.4% in 1998. During 1999, demand recovered somewhat, increasing 180 billion cubic feet (Bcf) (1%) to reach 24,039 Bcf. This was still less than the 1997 demand level.

Demand recovery entirely due to core market sectors

After falling 8% in 1998, the temperature-sensitive residential and commercial markets gained 3% in 1999, but remained at below-normal levels due to mild winter weather.

Industrial demand was flat in 1999, following a 2% drop in 1998. The lack of growth was due to low crude oil prices in early 1999 (causing industrials to switch from gas to oil) and to low petrochemicals prices (causing low demand for gas feedstocks).

US gas demand for electric generation fell 4% in 1999, mainly due to a cooler summer than 1998. Use of air conditioners in hot summer months causes electric power demand to peak, and this peak power is often generated using natural gas.

Within Canada, demand in the West (British Columbia, Alberta, Saskatchewan, Yukon) was flat, while demand in Eastern Canada rose 6%, mainly due to colder weather versus 1998.

Gas Supply

Weak North American gas production

Usually, weak demand results in weak prices. But in 1999, North American gas prices were up (in some areas dramatically), on perceptions of weak supply growth. Overall, North American supply rose 276 Bcf (1.1%). US production was flat. All of the increased supply came from Canada, liquid natural gas (LNG) imports, or Mexico.

LNG imports almost double, reach 161 Bcf

LNG imports to the two presently operational US regasification terminals (Lake Charles, Louisiana and Everett, Massachusetts) were up strongly in 1999, rising from 83 Bcf in 1998 to 161 Bcf this year. In previous years, these terminals received most LNG from Algeria, with minor amounts from Australia and the United Arab Emirates. In 1999, LNG cargoes were also received from Trinidad, Qatar, and Malaysia.

Essentially all US demand growth since 1994 has been met by increased imports, mainly from Canada.

Regional Supply Trends, Drilling, and Prices

We analyse four major gas supply regions (the Gulf Coast, Midcontinent, Rockies and Western Canada). Strong production growth in Western Canada and the US Rockies (248 Bcf or 3%) was offset by large declines (213 Bcf) in the mature areas of the Gulf Coast and Midcontinent.

Production strong in the west, but weak in the Gulf Coast and Midcontinent

The cause of Gulf/Midcontinent production declines was low crude oil and natural gas prices in those regions during 1998 and the first half of 1999. Production in these mature areas is only marginally economic. When natural gas prices are weak, producers cancel drilling programs. Low oil prices also have this effect, since gas production is often associated with oil, and because low oil prices leave producers with insufficient cash flows for gas drilling.

As a result, gas drilling in the mature US areas was very low, particularly during the first half of 1999. This did considerable damage to US production capacity. Although drilling has now recovered, the lag time between drilling and production means that higher US production will not occur until 2000.

US production flat due to weak drilling in mature areas

The ability of US Gulf Coast and Midcontinent producers to continue current levels of production is increasingly being questioned. During 1999, the US Energy Information Administration (EIA) released its annual report on changes to US proved gas reserves. Gulf Coast reserves fell 2.6 trillion cubic feet (Tcf) (3%) during 1998. This may foreshadow future production problems in the region.

Rockies prices up 15%, Canadian producer prices up 44%

In contrast, producers in the US Rockies and Western Canada producing areas saw totally different dynamics in 1999. Although Gulf Coast gas prices (NYMEX) rose only 5% in 1999, prices in the Rockies rose 15%, and prices in Western Canada rose 44%. As a result, gas drilling in Canada set new records in 1999, when approximately 6,300 gas wells were completed. The previous record was 5,300 wells, in 1994.

Canadian gas drilling sets new record

Price increases in the Rockies and Canada moved these regional prices almost to parity with Gulf prices in 1999. In the past, Gulf prices had typically been much higher. This convergence of prices was due to major pipeline expansions in 1998. New pipeline capacity eliminated local gas surpluses in the Rockies and Western Canada, which had been depressing local prices. Currently, all North American gas market prices track each other, and are spread over a very narrow range.

Gas Flows

We analyze gas flows between the four producing regions and five consuming regions (the US West, Midwest, Northeast, South Atlantic and Eastern Canada).

More Canadian Exports to Midwest

In 1999, gas flow patterns continued to evolve, with Western Canada sending more gas to the Midwest. Other pipeline corridors seeing increasing flows are

Gulf Coast producers exiting Midwest market, focussing on South Atlantic

the Gulf Coast to South Atlantic route, and the Rockies to US West route. One pipeline corridor being used less is the Gulf/Midcontinent to Midwest route. This is due to a number of factors: new Midwest supply from Canada, falling production in the Gulf and Midcontinent leaving less gas to ship north, and rising demand in the South Atlantic, which gets all of its gas from the Gulf.

Canadian East Coast offshore gas production begins

The major pipeline project completed during 1999 was the Maritimes & Northeast Pipeline, from the new gas fields of the Sable Island area to markets in Nova Scotia, New Brunswick, and the US Northeast. The pipeline began operations on the last day of 1999. The pipeline has one gas supplier – the Sable Offshore Energy Project. Capacity from the gas processing plant is 530 million cubic feet per day (MMcf/d). At the Canada-US border, export capacity on the pipeline is 360 MMcf/d. The project was flowing about 280 MMcf/d from the processing plant to the US Northeast by March 2000.

Canadian Gas Exports

A large part of our report is dedicated to analysis of Canadian gas exports. Exports from Western Canada to the US Midwest increased 202 Bcf (18%), taking advantage of large capacity expansions of late 1998 (Foothills/Northern Border, TransCanada).

To some extent, this was offset by falling exports to the US West via the Huntingdon and Kingsgate export points, where export volumes fell 70 Bcf (5%).

Exports to the US Northeast were up 107 Bcf (15%). Although new capacity to the Northeast was added during 1999 (Maritimes & Northeast, Portland Natural Gas Transmission System), most was not available until late in the year. The increase in Northeast exports was the result of higher load factors on existing capacity through the Iroquois and Niagara Falls export points.

Canadian gas exports rise 238 Bcf (8%)

In total, Canadian natural gas exports reached 3,349 Bcf in 1999, an increase of 238 Bcf (8%) over 1998. Canadian producer sales to domestic buyers reached 2,630 Bcf, up 2%. Gas exports now account for 56% of Canadian production.

Canadian producer netbacks identical across all regional markets

Unlike previous years, there was little difference in producer netbacks from sales to the different markets. The average Canadian producer plant gate netback for all sales (domestic and export) was approximately US$1.87, up 28%. The high netbacks balooned Canadian producer plant gate revenues from an estimated $12.3 billion ($Cdn) in 1998 to $16.6 billion in 1999, a 35% increase.

OUTLOOK TO 2010

Our outlook relies heavily on industry views, as represented by several forecasters. Our approach is to deduce a consensus outlook, and then examine whether this outlook is reasonable, what its risks are, and the implications for Canada.

Gas Demand

North American demand expected to reach 31.4 Tcf by 2010

Our US demand outlook is simply the average of five forecasts. We assume both US and Canadian demand grows 2.5% per year to 2010. In total, North America is assumed to require 31.5 Tcf of gas by 2010.

This figure is 7.4 Tcf higher than 1999 demand, and 6.6 Tcf greater than 1999 supply (1999 supply does not equal demand because of storage changes and measurement differences).

Gas Supply

Most incremental supply expected to come from Canada, Gulf Coast

Most of the additional gas required is expected to come from the Gulf Coast and Canada. Gulf Coast production would rise to 14.5 Tcf, an increase of 2.9 Tcf. We expect Canadian production to reach 7.6 Tcf by 2010, an increase of 1.7 Tcf over 1999 levels. The next biggest increments of supply would come from the US Rockies (increase of 1.3 Tcf), and other US regions (0.7 Tcf).

In our view, the main concern in this supply outlook is the ability of the US Gulf Coast to increase production on this scale. To reach production of 14.5 Tcf, Gulf Coast reserves would have to increase from 78 Tcf currently to about 95 Tcf. Given that Gulf reserves are falling, this seems a tall order.

Alternate scenario: less Gulf Coast supply, unexpectedly higher production from other regions

An alternate scenario would be that other supply sources make up any shortfall from the Gulf. These alternate supplies might include: a more dramatic than expected increase in Western Canadian production, given unprecedented producer cash flows and drilling in the region; additional LNG projects; an increase in Scotian Shelf production, over and above already announced projects; or increased gas imports from Mexico.

Towards the end of the period, currently uneconomic gas supply sources may be under consideration, such as Newfoundland offshore gas; Canadian coalbed methane; or Alaskan and Mackenzie Delta gas.

Gas Prices

Many industry observers expect US natural gas prices to approach $3.00/MMBtu by 2010

A range of industry views shows that US prices on average are expected to rise to almost US$3.00/MMBtu by 2010 (nominal dollars). Canadian prices, analysed similarly, are seen to more or less track US prices, but remain slightly lower and with a steadily widening differential to US prices.

Gas Flows

Based on the regional forecasts of demand and supply, we have calculated future natural gas flow patterns, and the implications for future pipeline construction.

Various pipeline corridors will have to be expanded

The corridors requiring large gas pipeline expansions would be the Gulf Coast to South Atlantic; Western Canada to US Midwest; and the Rockies to US West and/or Midwest. In addition, the US Northeast will need more incoming pipeline capacity, probably from the US Midwest, possibly from eastern Canada. A survey of planned pipeline projects shows that many of these capacity increases are already under construction or proposed.

Canadian Gas Exports

Canadian natural gas exports expected to reach 4.1 Tcf by 2010, with total Canadian production hitting 7.6 Tcf.

Our outlook for natural gas exports from Canada to the US is based on existing or pending export pipeline capacity. When the Alliance project is completed, Canadian gas export capacity to the US will reach 12 Bcf per day, or 4.4 Tcf per year. Given past experience with load factors, we expect exports to reach 4.1 Tcf by 2010, based solely on existing or under-construction pipeline capacity. At this point, the average export load factor on capacity would be 94%.

Along with domestic gas demand growth, this would bring the call on Canadian gas production to 7.6 Tcf by 2010. If additional export capacity were constructed before 2010, our Canadian export and production outlook could very well be low.

Review of 1999

Natural Gas Demand

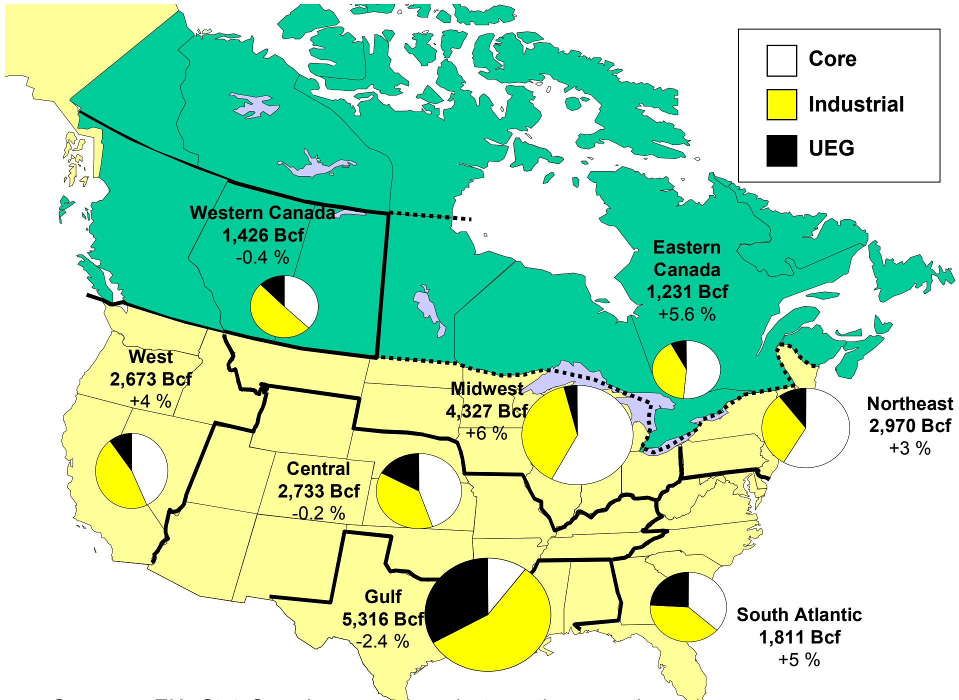
For analysis purposes, we divide the US and Canada into the regions shown on the map.

The pie charts illustrate the relative scale of gas demand by region, and the sectoral breakdown of demand within each region.

The largest gas loads in North America are, in descending order:

1) *Gulf Coast Industrial;*
2) *Midwest core;*
3) *Northeast core;*
4) *Gulf Coast Utility Electric Generation (UEG);*
5) *Midwest Industrial.*

Figure 1: US & Canadian Gas Demand by Region & Sector



Sources: EIA, StatsCan. In many cases, last months are estimated.

In 1999, total North American demand increased by 1% over 1998.

The only demand increase of any consequence was in the "core" market (residential and commercial sectors).

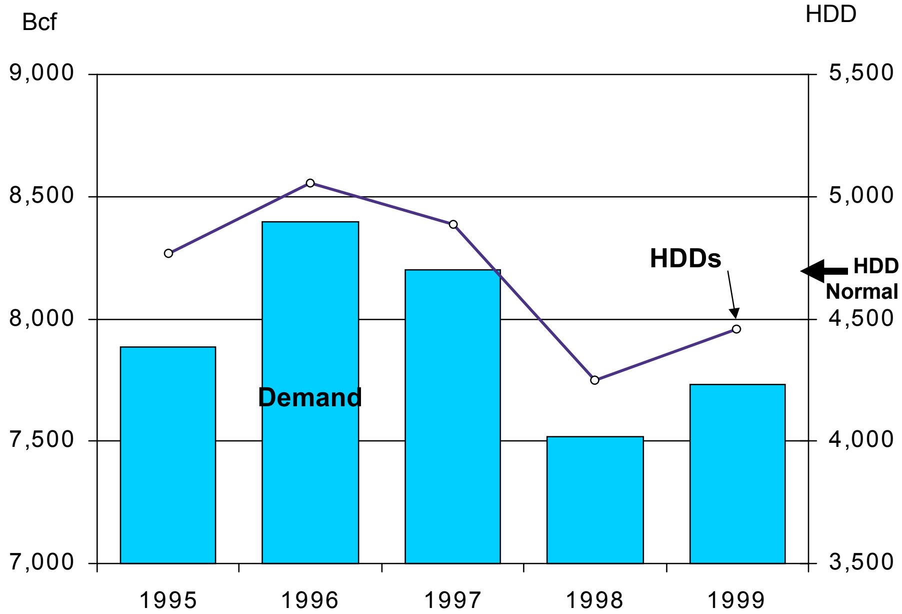
North American Industrial sector gas demand was flat, while US demand for electric generation dropped by 4%, in contrast to increases of 10% and 9% in 1998 and 1997 respectively.

Table 1
North American Gas Demand

	1999 (Bcf)	1998 (Bcf)	Difference (Bcf)	Change (%)
US Residential	4,666	4,520	146	3.2%
US Commercial	3,067	3,005	62	2.1%
US Industrial	8,653	8,686	-33	-0.4%
US Electric Utility	3,125	3,258	-133	-4.1%
US Gas Used in Operations	1,871	1,792	79	4.4%
Domestic US Demand	**21,382**	**21,261**	**121**	**0.6%**
US LNG Exports	64	66	-2	-3.0%
US Exports to Mexico	61	53	8	15.1%
Total US Gas Disposition	**21,507**	**21,380**	**127**	**0.6%**
Cdn Residential	576	552	24	4.3%
Cdn Commercial	394	382	13	3.4%
Cdn Industrial	987	981	7	0.7%
Cdn Electric Generation	215	214	1	0.5%
Cdn Other	484	470	15	3.1%
Total Cdn Demand	**2,657**	**2,598**	**59**	**2.3%**
TOTAL N.A. DEMAND	**24,039**	**23,859**	**180**	0.8%
TOTAL N.A. DISPOSITION	**24,164**	**23,978**	**186**	0.8%

Sources: EIA Natural Gas Monthly, StatsCan, NRCan estimates **Notes:** Total North American disposition is less than total North American supply due to accounting problems and storage changes. Canadian demand includes reprocessing shrinkage (taking ethane from pipeline gas).

Figure 2
US Heating Degree Days & Core Demand



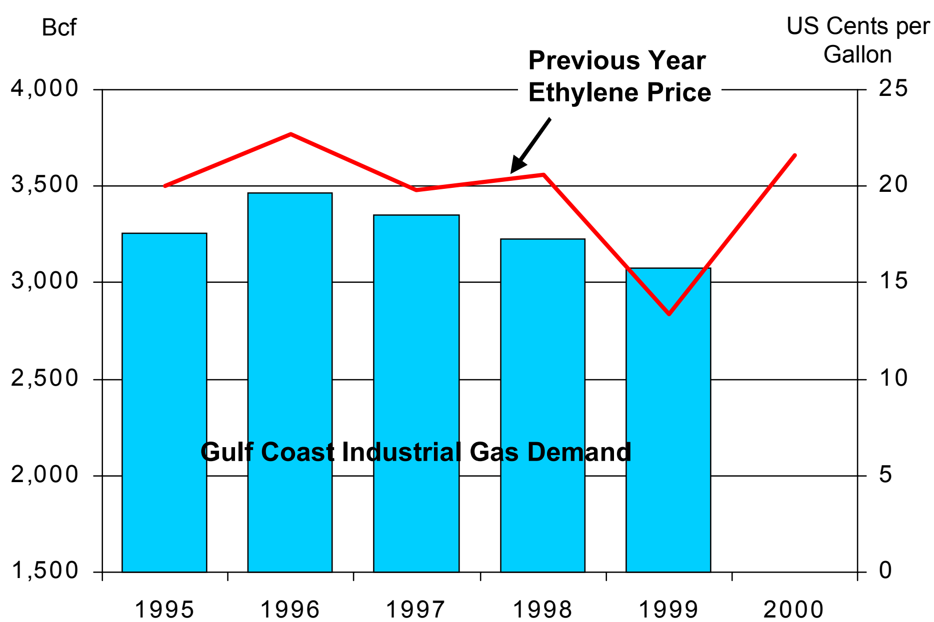
Sources: EIA, NOIAA

Changes in heating degree days (HDDs) explain demand fluctuations in core markets (residential and commercial sectors).

HDDs increased by 5% in 1999 compared to 1998, leading to an increase in gas demand of 208 Bcf.

However, total US HDDs still remained 6% below "normal" in 1999.

Figure 3
US Gulf Coast Industrial Demand



Sources: EIA, Purvin & Gertz

Overall US Industrial demand fell by 217 Bcf since 1996 – entirely due to a 389 Bcf decline in the Gulf Coast (Texas, Louisiana, Mississippi and Alabama).

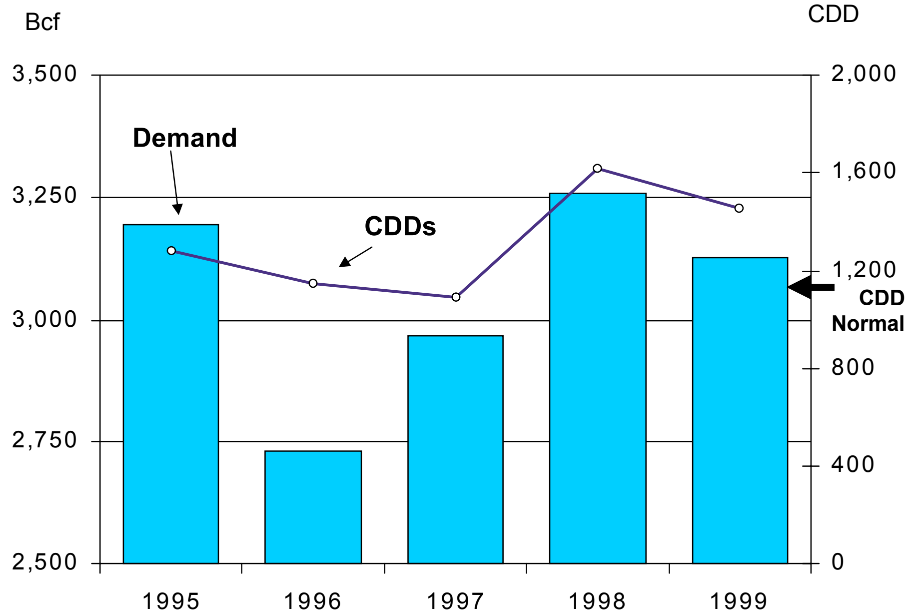
Most Gulf industrial gas demand occurs in the petrochemical and oil refining industries. Low chemical product prices and high gas prices relative to oil were driving factors.

In the Utility Electric Generation (UEG) sector, peak electricity demand occurs as air-conditioners are turned on. Peak electric demand is typically supplied by gas-fired peaking plants.

Warmer than normal summers in 1998 and 1999 have led to high gas demand in this sector in the past 2 years.

Gas demand in this sector is also increasing due to new gas-fired generating stations.

Figure 4
US Cooling Degree Days and UEG Demand



Sources: EIA, NOAA

Canadian gas demand by province is shown in Table 2.

Manitoba demand increased dramatically in percentage terms, due to a program to connect rural areas to gas distribution facilities, and a rebound in hog production.

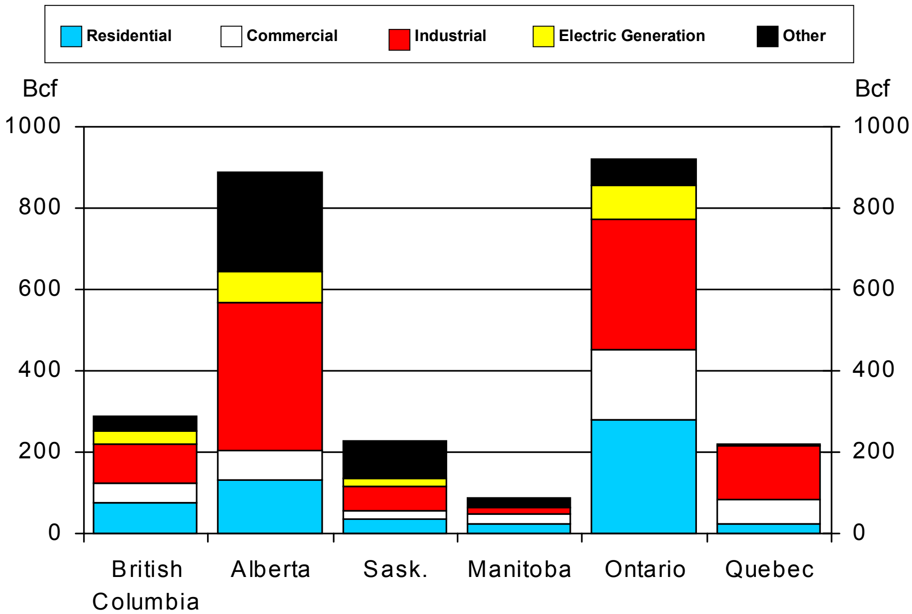
Alberta demand decreased in all sectors, which was mostly due to a warmer winter compared to 1998.

Table 2
Natural Gas Demand by Province
(Bcf)

1999	B.C.	Alberta	Sask.	Manitoba	Ontario	Quebec	Yukon	Total
January	36.0	98.0	26.5	13.1	136.6	29.0	2.1	**341.3**
February	32.8	82.3	21.4	9.4	110.7	24.2	1.5	**282.4**
March	31.2	88.7	23.9	8.5	114.5	24.6	1.8	**293.2**
April	23.1	71.0	18.5	7.1	73.1	19.3	2.0	**214.1**
May	20.2	67.4	16.2	5.0	61.1	14.9	1.9	**186.7**
June	17.5	58.3	12.4	4.1	41.6	11.6	1.3	**146.9**
July	15.5	60.9	11.7	4.4	51.8	11.8	2.0	**158.0**
August	14.2	57.5	14.7	4.9	46.3	12.2	2.0	**151.9**
September	15.8	60.1	14.3	5.0	46.1	12.5	1.8	**155.5**
October	22.4	76.7	20.5	8.6	56.1	16.2	2.0	**202.5**
November	24.5	79.5	19.7	8.2	71.9	19.6	1.6	**225.1**
December	35.4	88.5	26.8	10.9	110.8	24.9	2.0	**299.2**
Total 1998	287.0	912.3	215.7	79.1	873.6	213.2	17.4	**2,598.3**
Total 1999	**288.6**	**888.9**	**226.7**	**89.3**	**920.6**	**220.8**	**22.2**	**2,657.0**
Difference	1.6	-23.4	11.0	10.2	47.0	7.6	4.7	58.7
% change	**0.6%**	**-2.6%**	**5.1%**	**12.9%**	**5.4%**	**3.6%**	**27.2%**	**2.3%**

Sources: StatsCan, NRCan estimates

Figure 5
Canadian Gas Demand by Province & Sector



Sources: StatsCan, NRCan estimates

Figure 5 shows the provincial/sectoral breakdown of Canadian natural gas consumption.

Alberta and Ontario dominate Canadian gas use.

Other demand is mainly pipeline fuel, reprocessing shrinkage and a balancing figure.

Table 3
Sectoral Demand by Province
(Bcf)

		Residential	Commercial	Industrial	UEG	Other	Total
British	1999	74.9	49.1	97.5	31.6	35.5	**288.6**
Columbia	1998	73.2	47.7	98.8	32.6	34.8	287.0
Alberta	1999	131.9	70.5	364.6	78.1	243.9	**888.9**
	1998	137.1	73.0	376.9	80.4	244.9	912.3
Saskatchewan	1999	37.6	19.4	59.0	19.3	91.4	**226.7**
	1998	36.9	19.2	54.0	18.2	87.3	215.7
Manitoba	1999	23.6	25.4	15.6	0.0	24.5	**89.3**
	1998	21.5	23.1	13.1	0.0	21.3	79.1
Ontario	1999	281.7	168.9	320.4	86.3	63.3	**920.6**
	1998	260.0	161.5	308.9	83.0	60.2	873.6
Quebec	1999	24.5	61.2	130.3	0.0	4.8	**220.8**
	1998	22.4	57.1	128.9	0.0	4.7	213.2
Yukon	1999	1.2	0.0	0.0	0.0	20.9	**22.2**
	1998	0.9	0.0	0.0	0.0	16.5	17.4
Total 1998		552.0	381.6	980.6	214.3	469.7	2598.3
Total 1999		**575.6**	**394.4**	**987.4**	**215.3**	**484.3**	**2657.0**
Difference		23.5	12.8	6.8	1.0	14.6	58.7
% change		**4.3%**	**3.4%**	**0.7%**	**0.5%**	**3.1%**	**2.3%**

Sources: StatsCan, NRCan estimates

Table 3 shows the same information as the above graph, but in tabular form.

To better understand pipeline dynamics and regional gas prices, it is necessary to examine gas demand on a regional basis.

Demand in Western Canada was flat in 1999 vs 1998, while demand in Eastern Canada rose 6%.

Overall, Canadian gas demand was up 59 Bcf, or 2%.

Table 4
Canadian Natural Gas Demand
(Bcf)

1999	Western Canada (BC, AB, SA, YK)	Eastern Canada (MN, ON, QC, NB, NS)	Total Canada
January	162.6	178.7	341.3
February	138.1	144.3	282.4
March	145.6	147.6	293.2
April	114.6	99.5	214.1
May	105.7	81.0	186.7
June	89.5	57.4	146.9
July	90.0	68.0	158.0
August	88.5	63.4	151.9
September	92.0	63.6	155.5
October	121.6	80.9	202.5
November	125.4	99.8	225.1
December	152.7	146.5	299.2
Total 1998	1432.4	1165.9	2598.3
Total 1999	**1426.4**	**1230.6**	**2657.0**
Difference	-6.1	64.8	58.7
% change	**-0.4%**	**5.6%**	**2.3%**

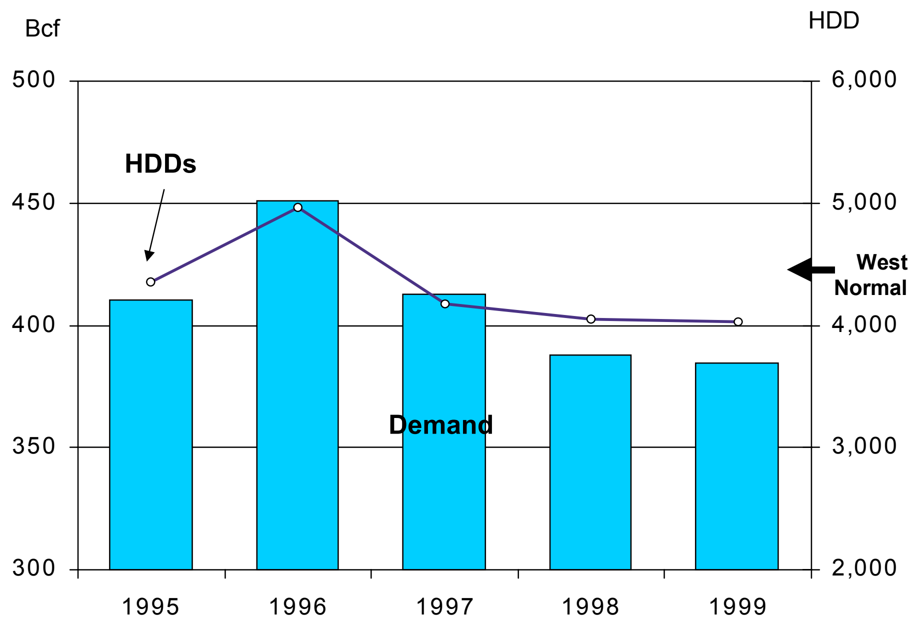
Sources: StatsCan, NRCan estimates

As in the US, Canadian residential and commercial natural gas demand depends primarily on the number of heating degree days.

In Western Canada overall, core gas demand fell 1% due to a 1% decline in HDDs.

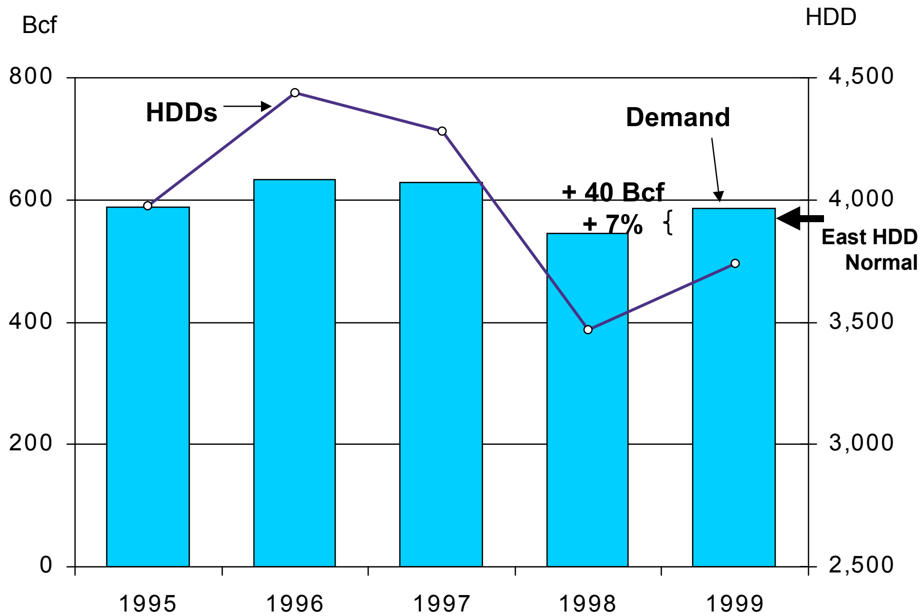
British Columbia HDDs increased by 9% over 1998, while HDDs dropped by 1% and 2% in Saskatchewan and Alberta respectively.

Figure 6
Core Western Canadian Demand
& Heating Degree Days



Sources: StatsCan, NRCan estimates

Figure 7
Core Eastern Canadian Demand
& Heating Degree Days



Sources: StatsCan, NRCan estimates

HDDs increased by 8% in 1999 in Eastern Canada, while core demand increased by 7%.

Ontario experienced the strongest increase in HDDs, a 10% rise compared to 1998.

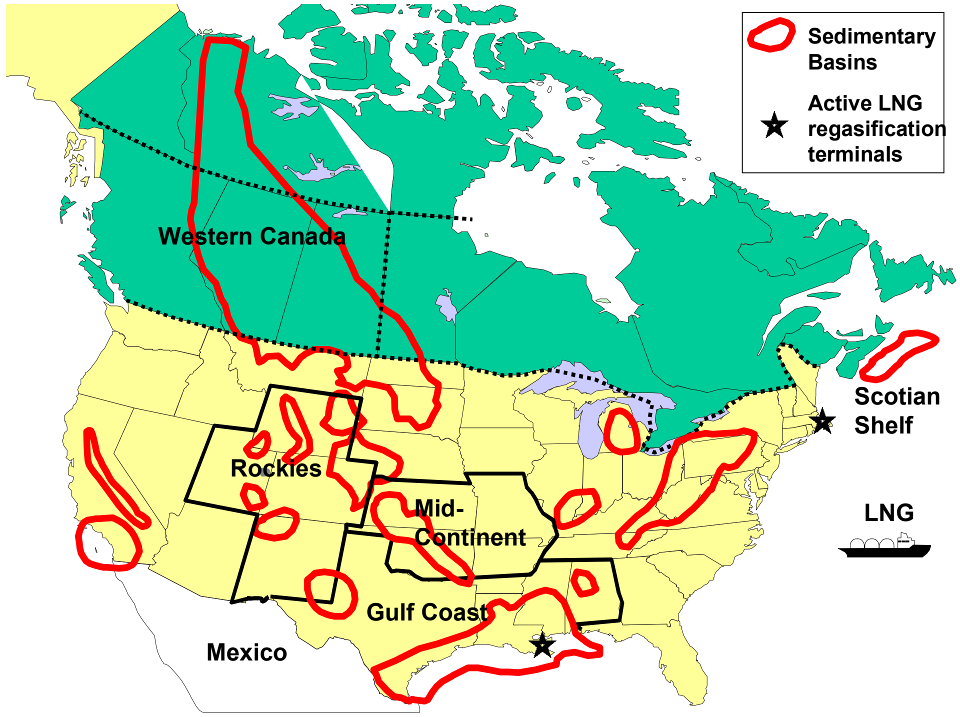
Review of 1999

Natural Gas Production

The accompanying map shows our breakdown of Canadian and US gas supply regions.

The Scotian Shelf is a new gas supply region, which includes the Sable Island development.

Figure 8
Canadian & US Gas Supply Regions



North American gas supply rose only slightly in 1999, increasing by 1%.

The largest regional change was a 135 Bcf decline in Gulf Coast production. This was counterbalanced by a similar sized increase in Canadian production.

In percentage terms, Mexican imports increased the most – 276% – but from a very small base.

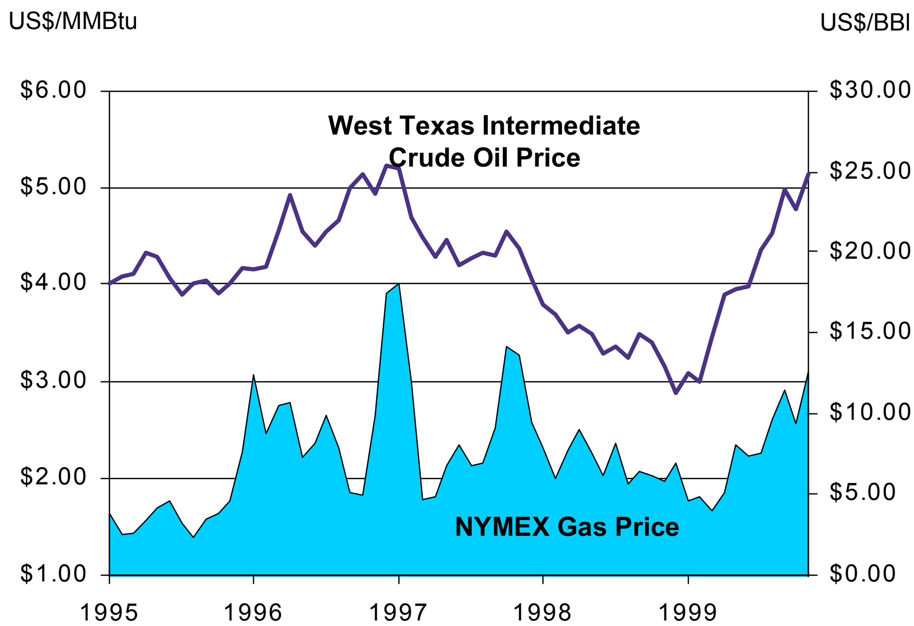
LNG imports almost doubled, also from a small base.

Table 5
North American Gas Supply
(Bcf)

	1999 (Bcf)	1998 (Bcf)	Difference (Bcf)	Change (%)
Gulf Onshore	6,642	6,719	-76	-1.1%
Gulf Offshore	4,964	5,022	-58	-1.2%
Total Gulf	11,606	11,741	-135	-1.1%
US Midcontinent	2,219	2,297	-78	-3.4%
US Rockies	3,146	3,050	96	3.2%
Other US	1,749	1,620	129	8.0%
Total US Production	**18,721**	**18,708**	**13**	**0.1%**
Canadian Production	5,932	5,780	152	2.6%
LNG	161	83	78	94.0%
Mexican Imports	55	15	40	275.9%
Supplementals	95	102	-7	-6.9%
TOTAL N.A. SUPPLY	**24,964**	**24,688**	**276**	**1.1%**

Sources: EIA March 2000 Natural Gas Monthly, StatsCan, MMS, NRCan estimates.
Notes: Gulf Offshore includes only the Gulf of Mexico OCS. StatsCan normally shows production net of reprocessing shrinkage. These numbers are before shrinkage, i.e., larger numbers.

Figure 9
Crude Oil & Natural Gas Prices

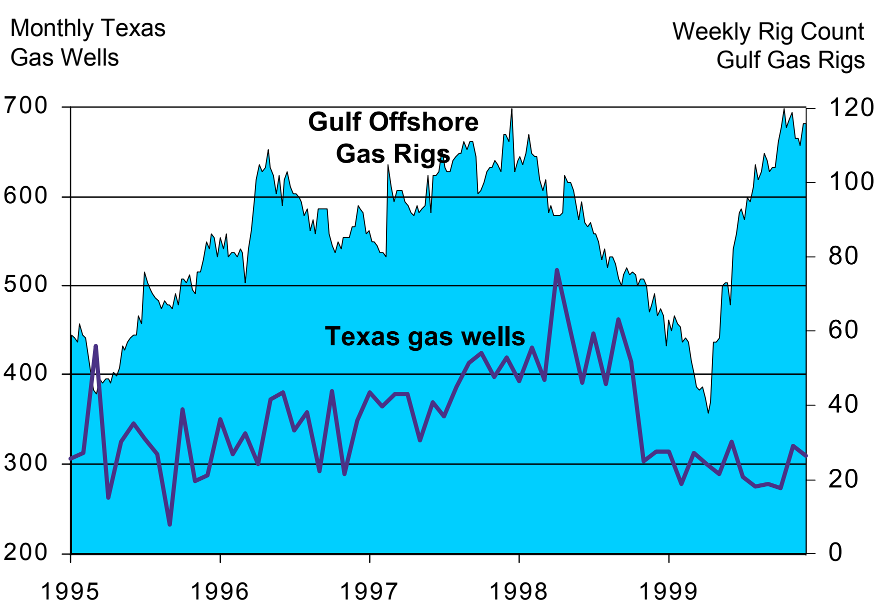


Sources: Friedenberg, Federal Reserve Bank

Gulf Coast producers' incentives to drill began to suffer in mid-1997, as both crude oil and gas prices fell.

Low crude oil prices also affect natural gas development in the Gulf, since gas is often associated with oil, particularly in the Gulf deepwater offshore.

Figure 10
Gulf Coast Gas Drilling



Sources: Baker Hughes, Texas RRC

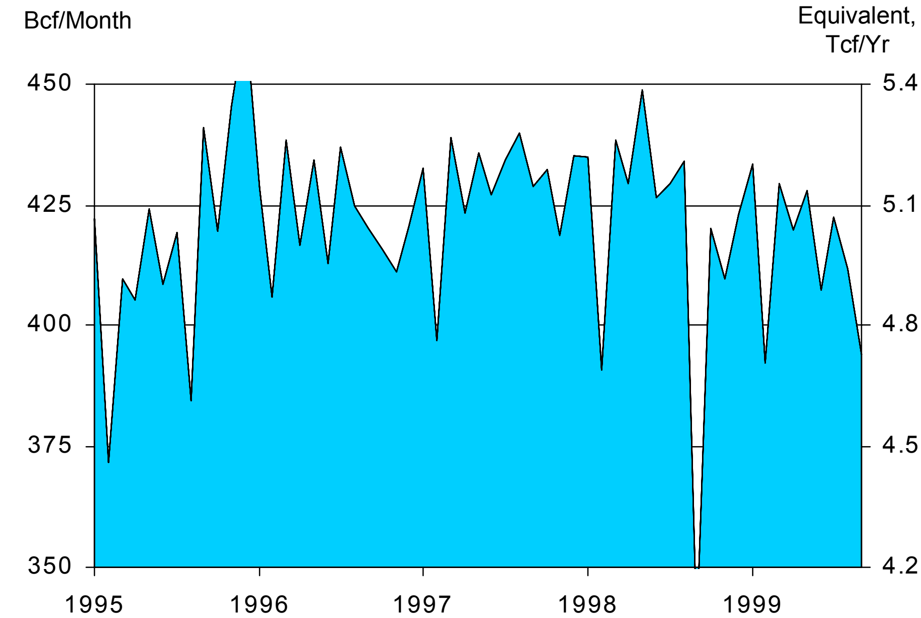
With cashflows very low due to low oil and gas prices, Gulf Coast drilling declined significantly. Gulf offshore gas drilling (the federal offshore of Texas, Louisiana, and Alabama) in 1999 was 11% lower than in 1998.

In Texas, onshore gas completions in 1999 were 27% lower than in 1998.

Given the high decline rates in the Gulf Coast (new wells will commonly lose 40% of original productive capacity in the first year), lower drilling almost immediately reduces production.

The federal offshore production data from the US Minerals Management Service shows how Gulf offshore production declined with lower drilling.

Figure 11
Gulf Coast Offshore Gas Production

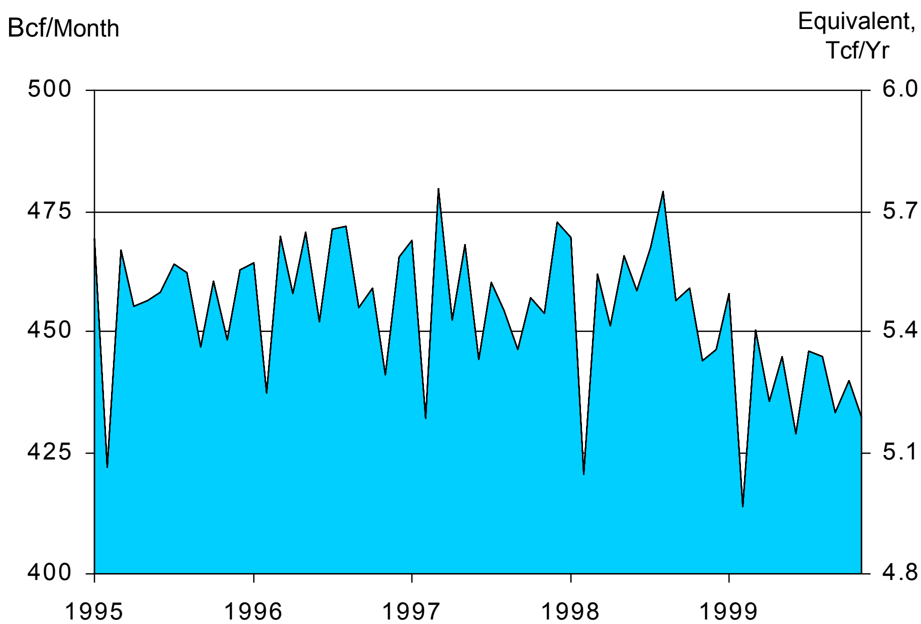


Source: MMS

Similarly, the Texas Railroad Commission's preliminary production numbers show an even more pronounced production decline for the Texas onshore.

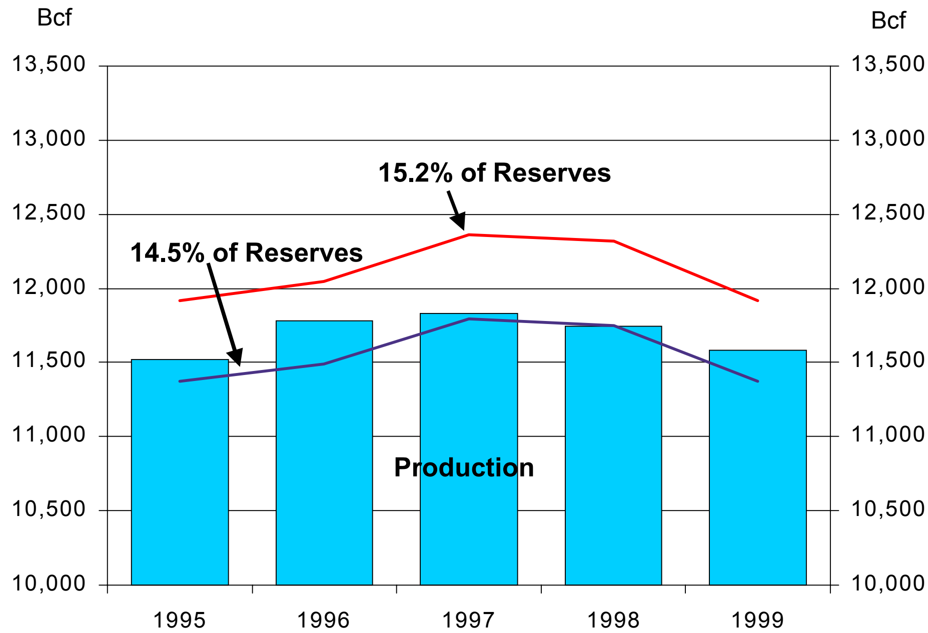
These two areas, the Gulf Coast offshore and the Texas onshore, account for about half of total US natural gas production.

Figure 12
Texas Onshore Gas Production



Source: Texas RRC

Figure 13
Gulf Coast Reserves & Production Correlation



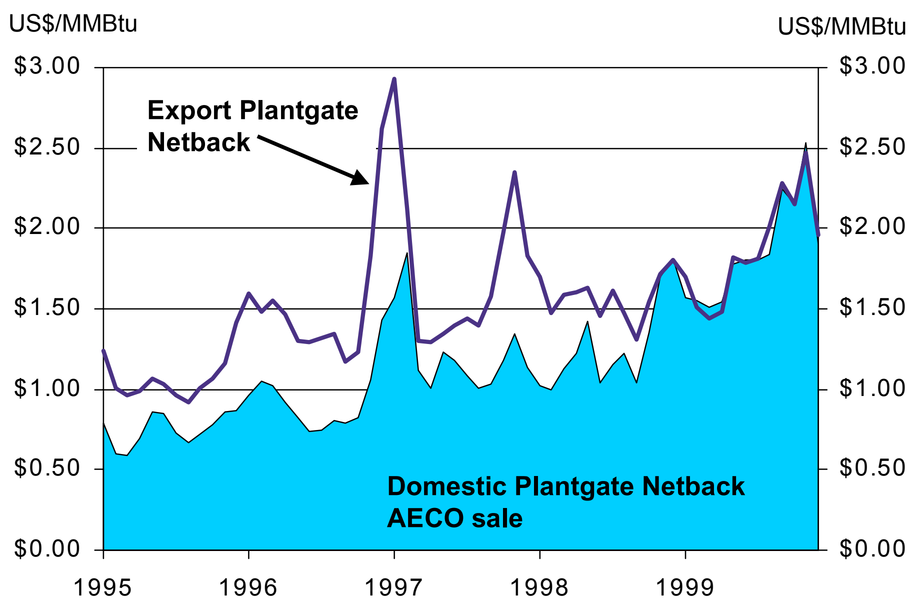
Source: EIA. Includes TX, LA, AL, MS, onshore & offshore

Figure 13 shows production (bars) plus lines equal to 14.5% and 15.2% of Gulf proved gas reserves at the start of each year.

Gulf Coast production tracks proved reserves, and varies between 14.5% – 15.2% of reserves.

In 1998, Gulf reserves fell from 81.0 Tcf to 78.4 Tcf. Given low drilling in 1999, it is expected that Gulf reserves fell again during 1999. This has negative implications for future Gulf production.

Figure 14
Canadian Producer Netbacks



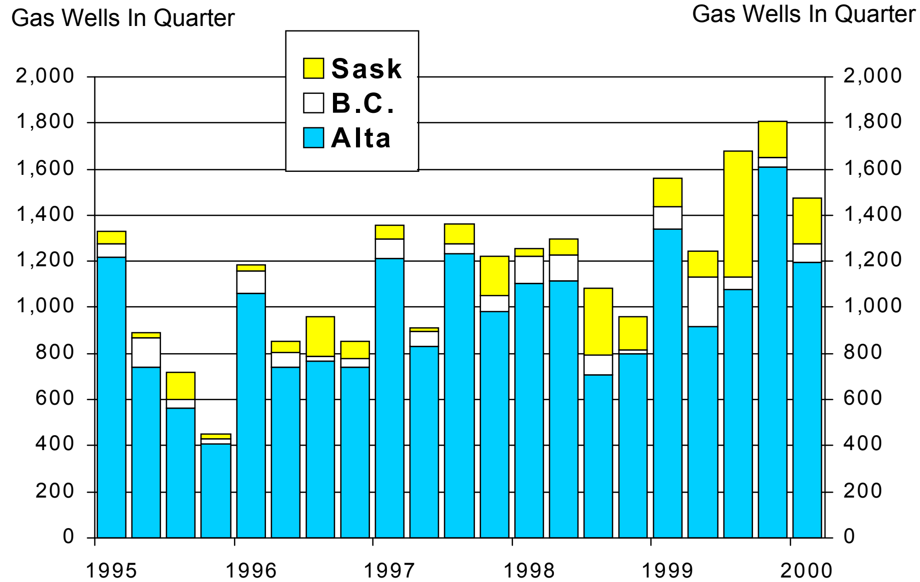
Sources: Friedenberg, NEB

Whereas US producers faced lower prices for natural gas in 1999, for Canadian producers the situation was the opposite.

Beginning in late 1998, plantgate netbacks from gas sales to the Canadian domestic market reached parity with export netbacks (due to pipeline expansions – see last year's report). With both domestic and export netbacks high, Canadian producers had tremendous incentive to drill gas prospects.

Figure 15
Canadian Gas Well Drilling

In 1999, the Canadian industry drilled a record 6,300 gas wells, easily surpassing the previous record of 5,300 in 1994.

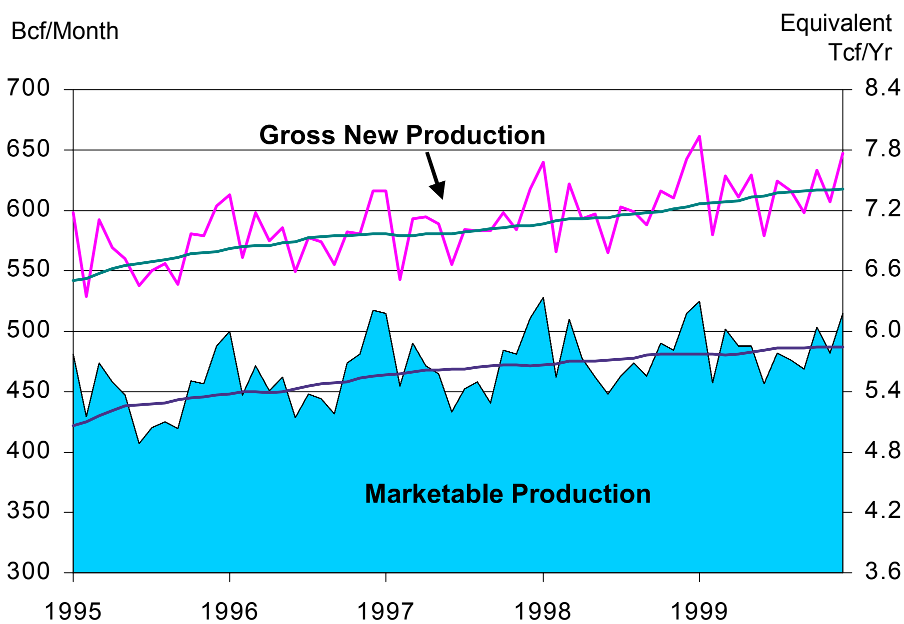


Source: Nickles Daily Oil Bulletin

Figure 16
Monthly Canadian Gas Production

As a result of high drilling, Canadian gas production climbed to 5,932 Bcf in 1999, 152 Bcf higher than 1998.

Figure 16 shows gross new production (before gas plant shrinkage, re-injection, and producer use) as well as marketable production. Rolling averages of both monthly series are also shown.



Source: StatsCan

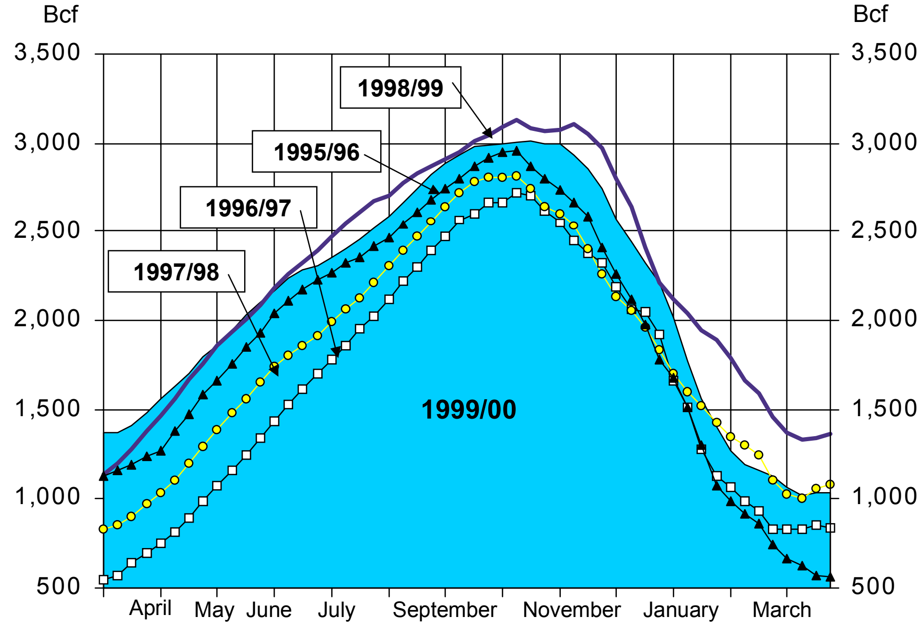
Review of 1999

Natural Gas Storage

In the US, the 1999/2000 storage injection period (April – October) began with storage balances at an unusually high level, mainly due to the mild winter of 1998/99.

Balances stayed relatively high (higher than any of the previous 4 years, except for 1998/99) throughout the withdrawal season (November – March), and entering the summer injection season. However, storage balances are below last year's level, and will require more injections than last summer in order to reach fill levels by November, 2000. The normal fill level is 2.6 – 3.0 Tcf.

Figure 17
US Gas In Storage

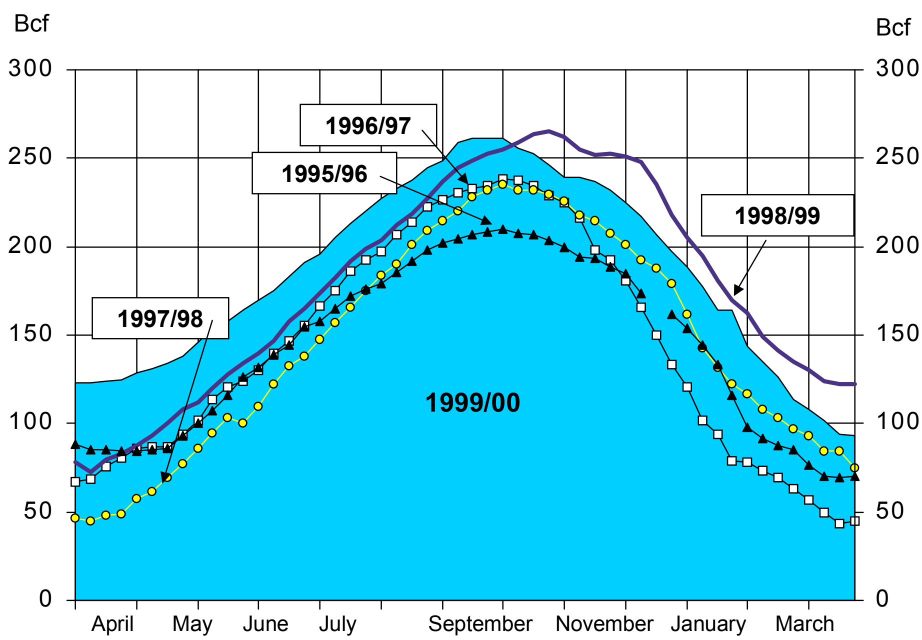


Source: AGA

In Canada, we focus on Western Canadian storage, since it has more direct impacts on gas markets.

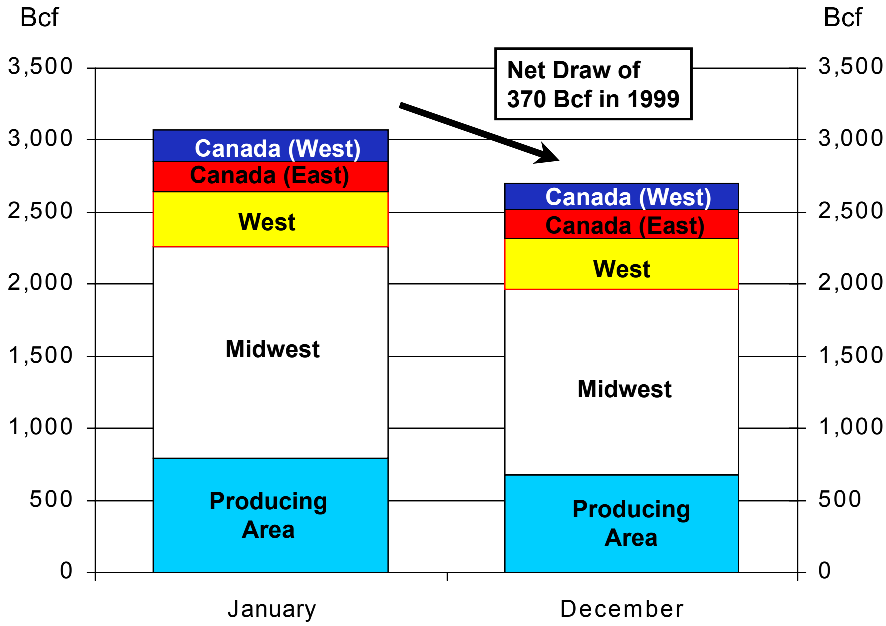
The Western Canadian storage experience tracked that of the US in 1999/2000.

Figure 18
Western Canada Gas Storage



Source: CGA

Figure 19
Storage Changes During 1999

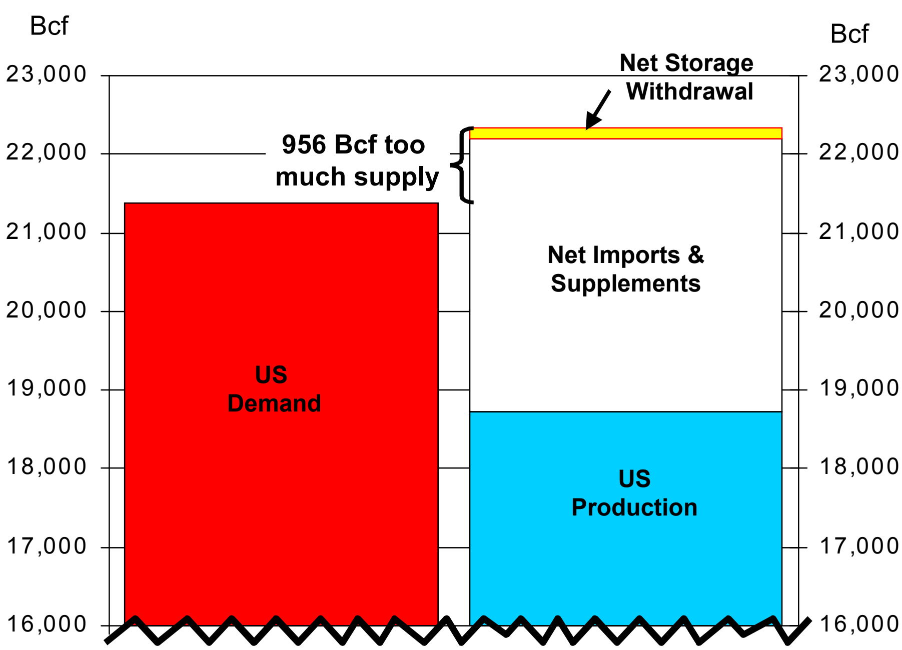


Sources: AGA, CGA

On Jan 1st, 1999, there was, according to AGA and CGA estimates, 3,072 Bcf of gas in North American storage. By Dec 31st, there was only 2,702 Bcf. Thus, during calendar year 1999, there was a net storage draw of 370 Bcf.

During 1998, the opposite happened – there was a net storage build of 674 Bcf.

Figure 20
US Demand/Supply Imbalance



Source: EIA March 2000 Natural Gas Monthly

Supply and demand figures should be equal, once storage movements are accounted for, but US preliminary numbers typically don't balance.

Current EIA figures show a negative 956 Bcf "balancing item" for 1999 – supply is higher than demand.

At the time of finalizing our report last year, 1998 US supply was 259 Bcf higher than demand. When EIA finalized their numbers in October 1999, US production was 269 Bcf lower than the initial figure.

This year, we expect US production to be revised downward, and demand to be revised upwards.

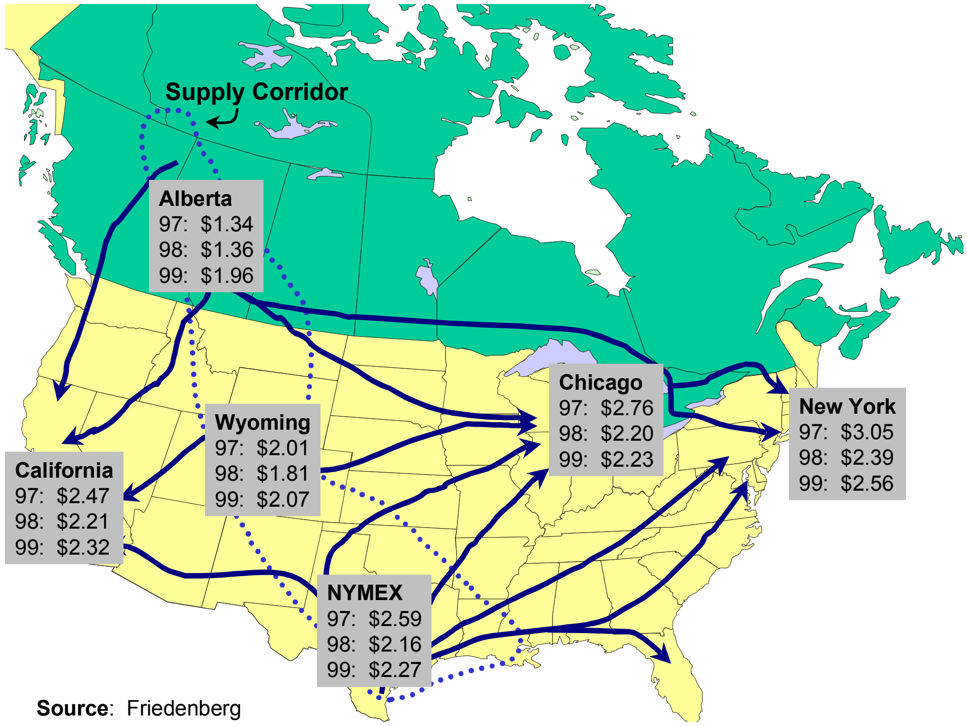
Review of 1999

Natural Gas Prices

Figure 21
Canadian & US Gas Prices
(US$/MMBtu)

Figure 21 shows recent prices for several major gas markets in North America, as well as main pipeline routes.

The Gulf Coast (NYMEX) is the benchmark North American gas price. The NYMEX is the strongest influence on all other market prices. In 1999, NYMEX prices increased 5%. NYMEX prices are still lower than 1997 levels, which were unusually high.



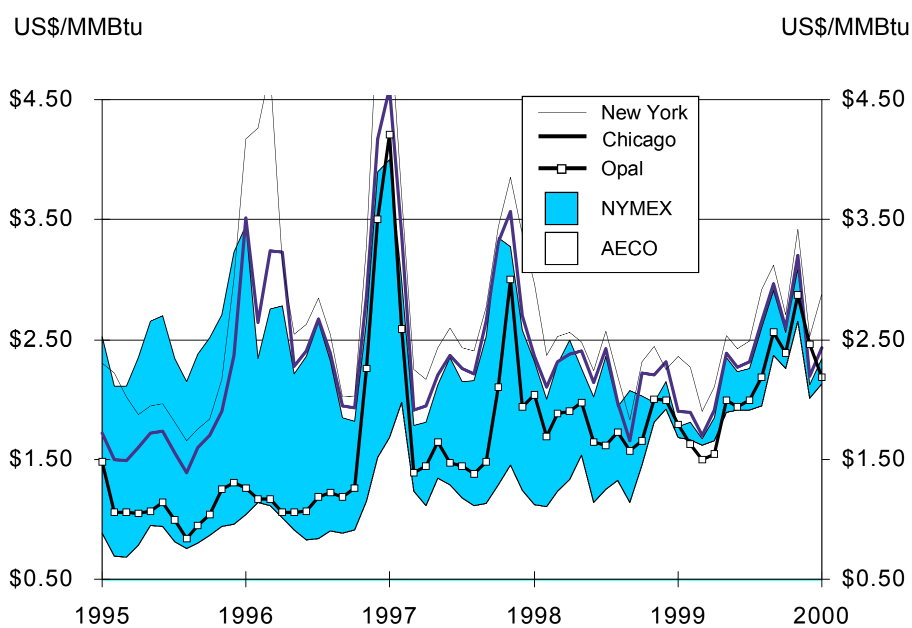
Source: Friedenberg

Figure 22
Regional Gas Price Trends

Figure 22 shows monthly spot prices in various markets. In the mid-1990s, prices in the US Rockies and Western Canada were much lower than prices in the Gulf and in market centres.

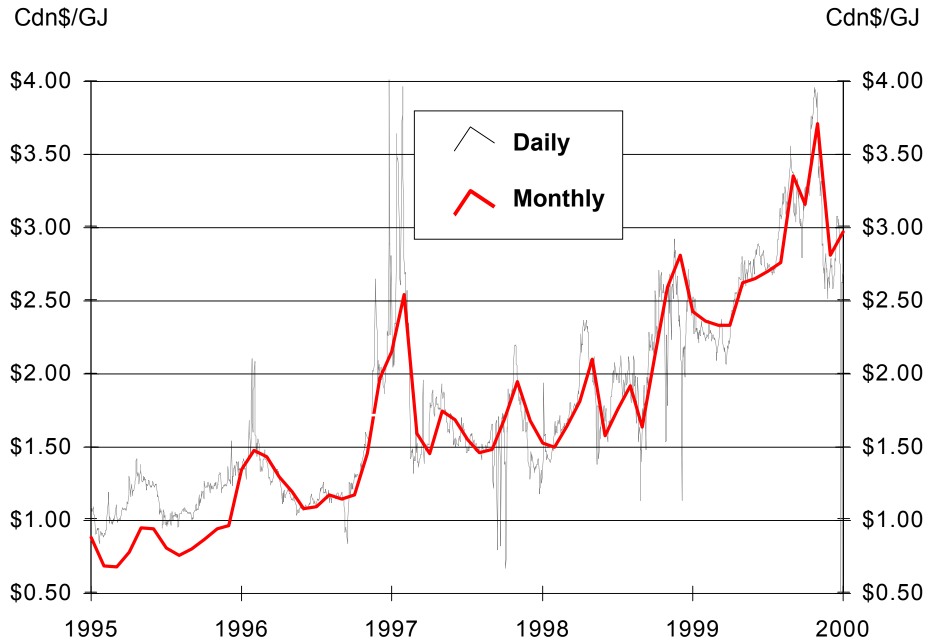
Lower prices were due to local gas surpluses.

As pipeline construction proceeded, surplus production capacity was bled off, and prices converged.



Source: Friedenberg

Figure 23
Canadian (AECO) Gas Prices

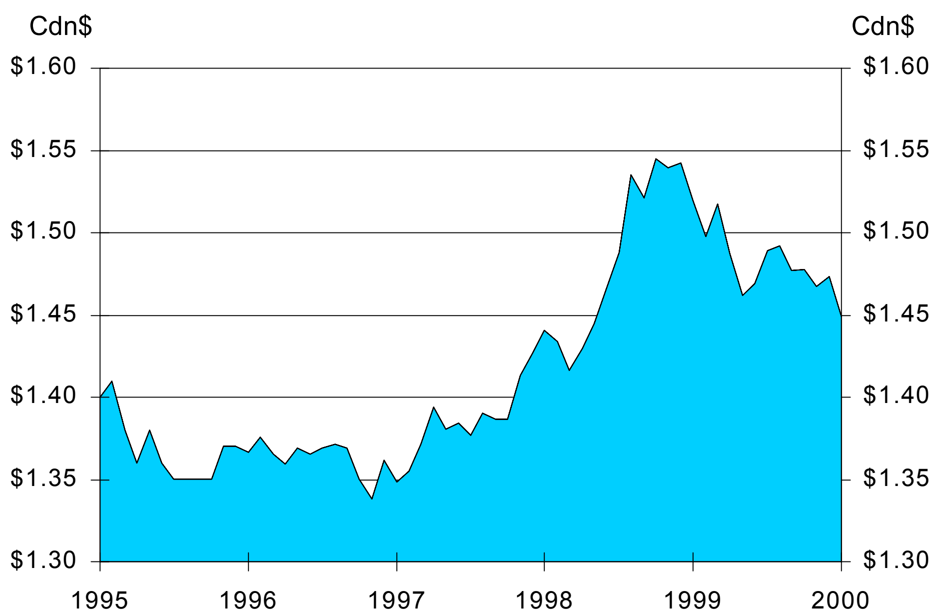


Sources: Enerdata, Friedenberg

Although NYMEX gas prices increased only 5%, Canadian prices increased 44% in 1999.

The main cause for the large increase was the construction of export pipeline capacity in late 1998 (see last year's report for a fuller explanation).

Figure 24
US/Canada Exchange Rates



Source: Bank of Canada. Canadian dollars required to purchase one US dollar.

The figure shows how many Canadian dollars were required to purchase one US dollar. Given the influence of US gas market prices on all gas prices in North America, when US currency appreciates, this also raises the price of natural gas in Canada.

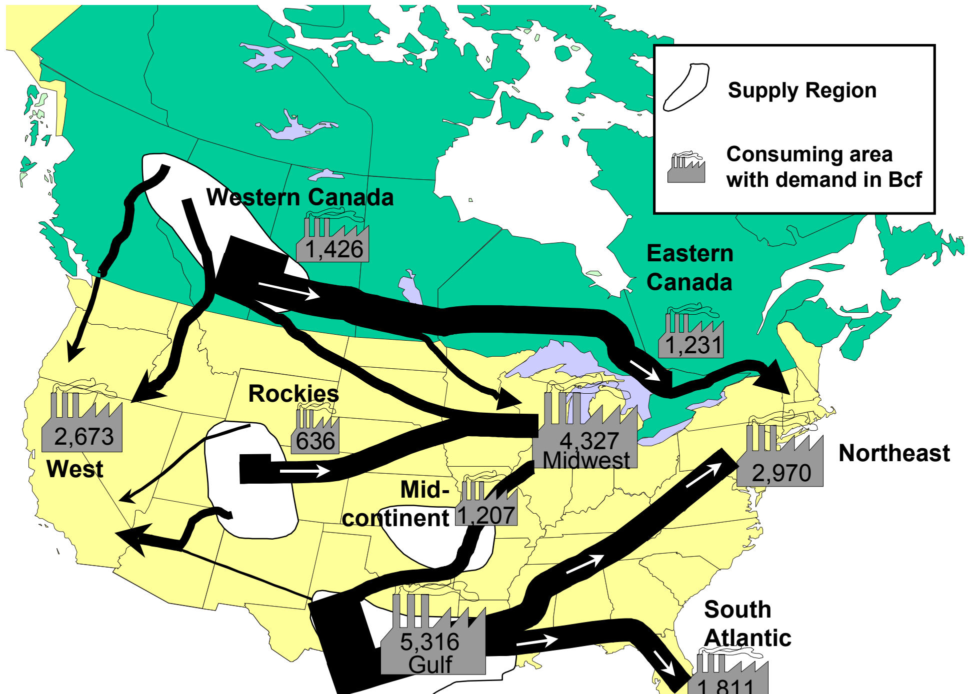
This factor tended to increase gas prices in Canada in 1997-98, but stabilized in 1999.

Review of 1999

Gas Flows
& Pipeline Capacity

The North American pipeline grid is extremely complex. To give a rough idea of the major flows, Figure 25 shows gas demand in several major markets, and main pipeline corridors (stylized). The corridor width is approximately proportional to gas volumes moved. Direction of flow is also shown.

Figure 25
Natural Gas Pipeline Flows
(Bcf)



Sources: EIA, StatsCan, NRCan. In many cases, last months are estimated.

Table 6 shows the calculation of natural gas flows during 1999, and the change from 1998.

These calculations are only estimates of gas flows, as the effects of storage have not been considered.

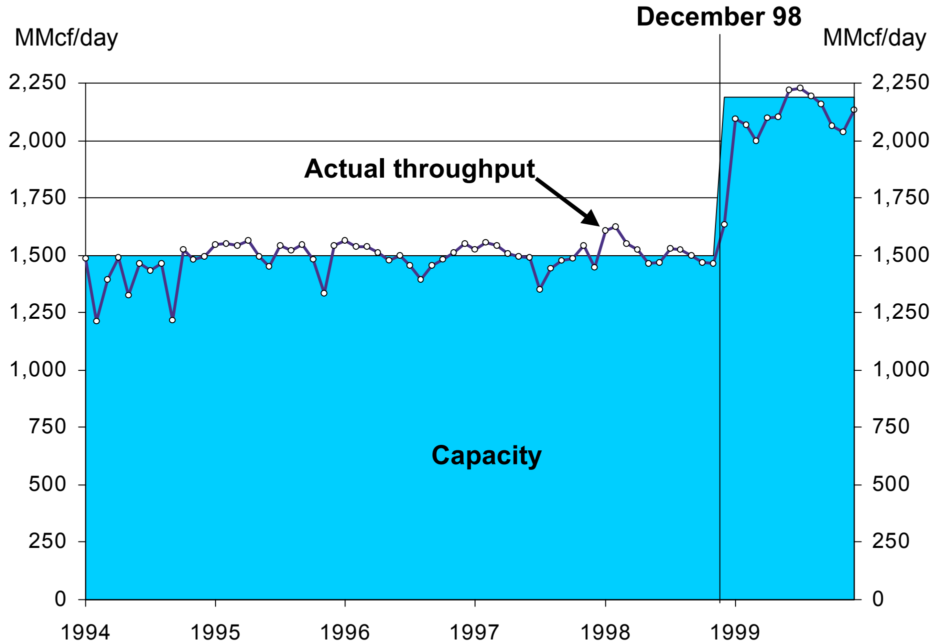
The most striking change was the large increase in gas required in the Midwest. Some of this requirement was probably met by a year over year net storage withdrawal.

Table 6
Inter-Regional Natural Gas Flows
(Bcf)

	1999 Production	1999 Demand	1999 Outflows	1998 Outflows	Outflows Difference
Producing Areas:					
Gulf	11,606	5,316	6,290	6,295	**-5**
Midcontinent	2,219	1,207	1,012	1,046	**-34**
Rockies	3,146	636	2,510	2,435	**75**
Western Canada	5,905	1,426	4,479	4,312	**167**
Total Producing	**22,876**	**8,585**	**14,291**	**14,088**	**203**
Market Areas:	**1999 Production**	**1999 Demand**	**1999 Inflows**	**1998 Inflows**	**Inflows Difference**
West	359	2,673	2,314	2,223	**91**
Midwest	438	4,327	3,889	3,636	**253**
Northeast	84	2,971	2,887	2,792	**95**
South Atlantic	4	1,811	1,807	1,722	**85**
Eastern Canada	27	1,231	1,204	1,130	**74**
Total Market	**912**	**13,013**	**12,101**	**11,503**	**598**

Note: US demand excludes pipe, lease fuel, etc. US figures estimated from EIA data. Gas outflows from a supply region such as the Gulf or Western Canada are calculated as production less internal demand. Inflows to market regions are calculated as demand less internal production. Storage effects ignored.

Figure 26
Flows Through Monchy Export Point

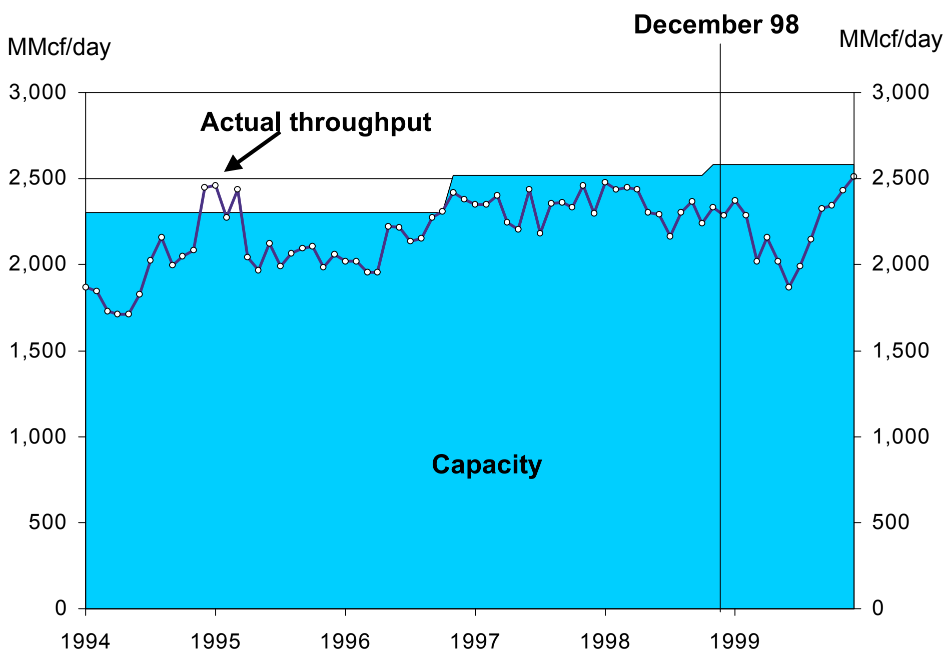


Sources: NEB, Foothills Pipeline

Gas flows through the Monchy export point increased considerably in 1999, taking advantage of the Foothills/Northern Border pipeline capacity expansion, which occurred in December 1998.

As shown in Figure 26, the Monchy export point was used at essentially full capacity since the expansion.

Figure 27
Flows Through Kingsgate Export Point



Sources: NEB, Foothills Pipeline

To some extent, the increased flows across Monchy were achieved via a reduction in flows across other export points, mainly Kingsgate, which exports to the US West.

Kingsgate flows dropped from the 2,400 MMcf/d level before the Monchy capacity expansion, to 1,868 MMcf/d in June 1999. However, Kingsgate flows recovered by the end of 1999.

Details on the major gas pipeline capacity increases in 1999 are shown in Table 7.

The major project, Maritimes & Northeast, was completed too late in the year to have any impact on 1999 gas flow patterns.

Table 7
Natural Gas Pipeline Construction, 1999

Project Name	Sponsors	Origin	Passes Through	Destination	Length (Miles)	Began Operating	Capacity (MMcf/d)
Maritimes & Northeast	Westcoast, Duke Mobil, NS Power	Sable Island, NS	NB, ME, NH	Dracut, MA	650	12/31/99	530
Portland Natural Gas Transmission System	PNGTS & TQM	East Hereford, QC	NH	Wells, ME	136	02/25/99	163
Columbia Gorge Expansion	Northwest Pipeline	Stanfield, OR		Sumas, WA		11/01/99	50

Notes:

Martimes and Northeast Pipeline flows gas from the new fields of the Sable Offshore Energy Project, to markets in Nova Scotia, New Brunswick, and the U.S. Northeast. The pipeline began operations on the last day of 1999. Capacity from the gas processing plant is 530 MMcf/d. At the Canada – U.S. border, export capacity on the pipeline is 360 MMcf/d. The project was flowing about 300 MMcf/d by March, 2000.

Portland Natural Gas Transmission System (PNGTS) brings Western Canadian gas to Wells, Maine. From this point pipeline interconnections exist to other markets in the U.S. Northeast.

The **Columbia Gorge** project allows the Northwest Pipeline increased capacity to flow gas north. Mostly, flows are southward.

Review of 1999

Canadian Export & Domestic Sales

Exports to the US Midwest increased by 18% in 1999, and by 15% to the US Northeast. Exports to the West fell 5%.

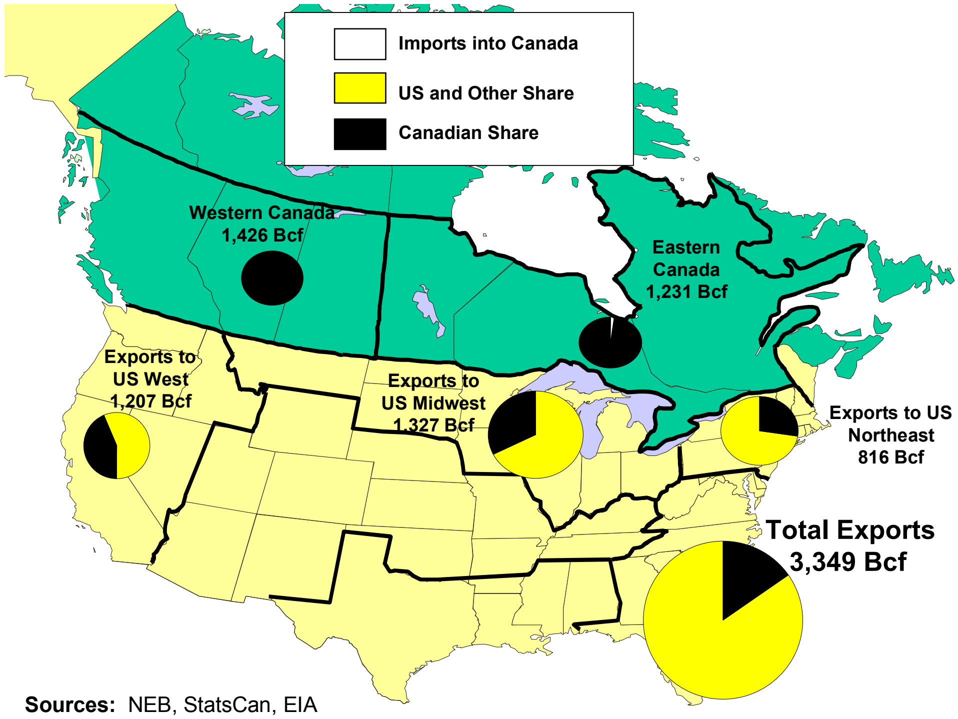
Canadian exports accounted for 16% of total natural gas consumption in the US in 1999.

The market share of Canadian natural gas was highest in the Western US, at 44%. In 1998, it was 50%.

In the Midwest, Canadian gas market share was 32% in 1999, up from 28% in 1998.

It also increased in the US Northeast, from 25% in 1998 to 28% in 1999.

Figure 28
Canadian Natural Gas Market Share



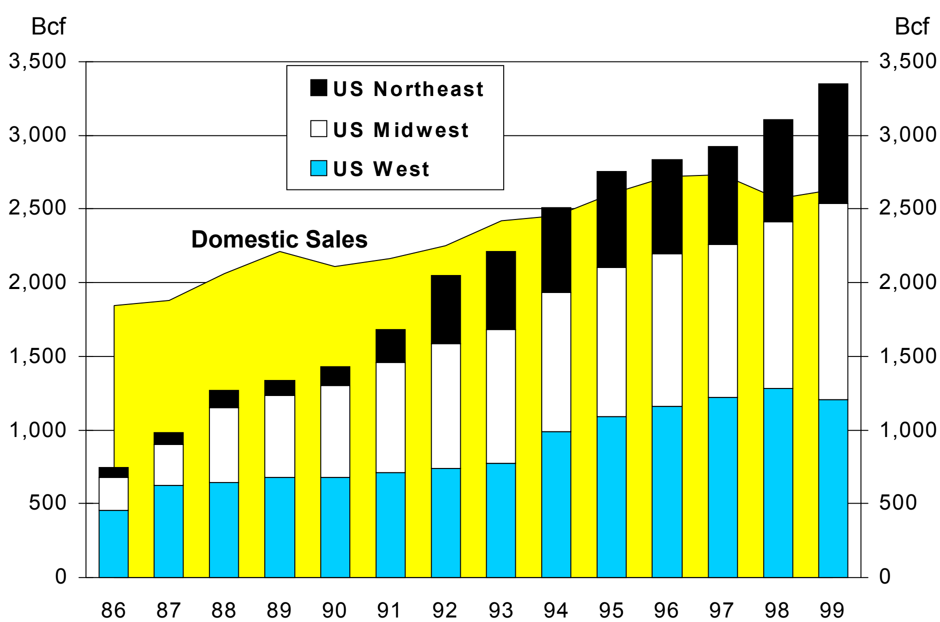
Sources: NEB, StatsCan, EIA

Canadian export sales continue to increase relative to domestic sales. Exports now account for 56% of Canadian production.

Exports increased 8% compared to a 2% increase in domestic sales in 1999.

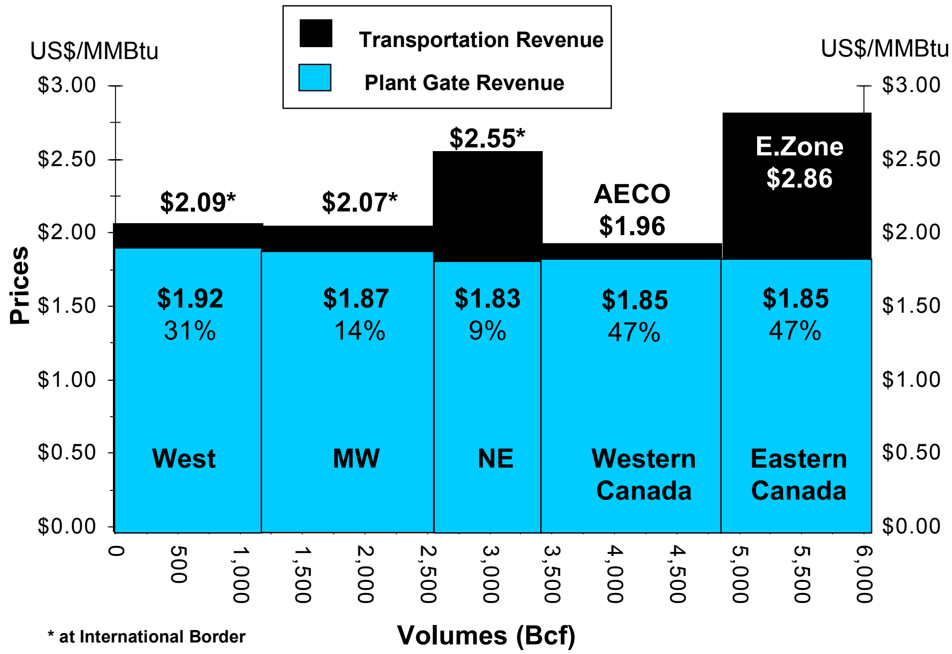
72% of natural gas is exported through National Energy Board-approved short-term orders.

Figure 29
Domestic & Export Sales



Sources: NEB, StatsCan, NRCan estimates

Figure 30
Regional Prices & Volumes

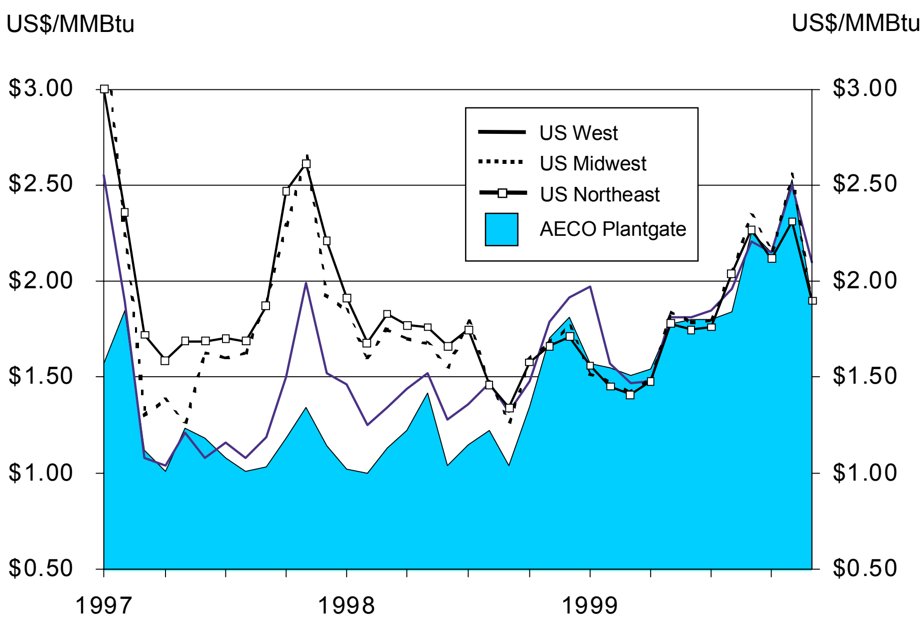


Sources: NEB, Friedenberg, StatsCan, NRCan estimates

The figure shows netbacks and the percent change from 1998 (lower bars), international border prices (top bars), and volumes (width of bars, horizontal scale on bottom in Bcf) for Canadian sales to various markets.

Reflecting the convergence of regional market prices, netbacks from sales to various markets also converged.

Figure 31
Plant Gate Netback Price Trends



Sources: NEB, Friedenberg

Convergence of netbacks occurred in late 1998, with the addition of export pipeline capacity.

There is now little difference in producer netbacks among the various markets.

Although the benchmark US gas price, NYMEX, increased only 5% in 1999, the average price (at the international border) of Canadian natural gas exports rose 14%.

In Canada, the average AECO spot price (the key Canadian market price) was 44% higher in 1999 than in 1998.

Table 8
Domestic & Export Prices

	International Border Export Prices					Canadian Markets		
1999 Month	**West US/MMBtu**	**MW US/MMBtu**	**NE US/MMBtu**	**Average US/MMBtu**	**Average Cdn/GJ**	**AECO Cdn/GJ**	**AECO US/MMBtu**	**Huntingdon US/MMBtu**
January	$2.14	$1.72	$2.28	$2.01	$2.89	$2.43	$1.68	$2.94
February	$1.75	$1.70	$2.19	$1.84	$2.61	$2.36	$1.66	$1.76
March	$1.65	$1.62	$2.10	$1.76	$2.53	$2.33	$1.62	$1.48
April	$1.66	$1.69	$2.18	$1.79	$2.53	$2.33	$1.65	$1.52
May	$1.99	$2.05	$2.51	$2.14	$2.97	$2.62	$1.89	$1.92
June	$2.00	$2.00	$2.50	$2.12	$2.96	$2.65	$1.91	$1.90
July	$2.04	$2.00	$2.51	$2.14	$3.01	$2.70	$1.91	$1.93
August	$2.12	$2.24	$2.76	$2.32	$3.28	$2.76	$1.95	$2.20
September	$2.38	$2.54	$2.99	$2.58	$3.62	$3.36	$2.37	$2.52
October	$2.31	$2.35	$2.83	$2.44	$3.42	$3.16	$2.26	$2.39
November	$2.66	$2.77	$3.02	$2.80	$3.89	$3.71	$2.65	$2.94
December	$2.26	$2.07	$2.60	$2.29	$3.19	$2.81	$2.01	$2.27
1999 Average	**$2.09**	**$2.07**	**$2.55**	**$2.19**	**$3.09**	**$2.77**	**$1.96**	**$2.15**
1998 Average	$1.64	$1.90	$2.45	$1.92	$2.70	$1.92	$1.36	$1.60
% change	**27.37%**	**9.12%**	**4.01%**	**14.47%**	**14.51%**	**44.37%**	**44.20%**	**34.43%**

Sources: NEB, Friedenberg, NRCan estimates

Export netbacks are defined as international border prices less pipeline transportation costs from the gas processing plantgate to the international border. Export netbacks averaged $1.88 in 1999, 19% higher than in 1998.

Canadian netbacks were estimated by subtracting the pipeline transmission tolls from spot prices.

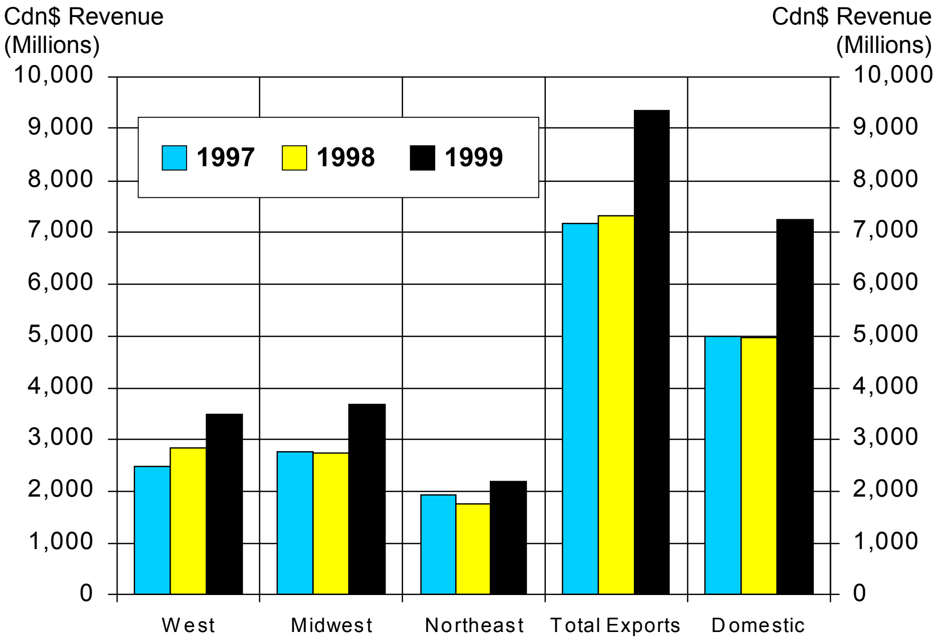
Canadian netbacks increased 47% in 1999. Domestic netbacks are now in line with export netbacks.

Table 9
Domestic & Export Plant Gate Netbacks

	Export Plant Gate Prices					Canadian Markets		
1999 Month	**West US/MMBtu**	**MW US/MMBtu**	**NE US/MMBtu**	**Average US/MMBtu**	**Average Cdn/GJ**	**AECO Cdn/GJ**	**AECO US/MMBtu**	**Huntingdon US/MMBtu**
January	$1.97	$1.52	$1.56	$1.70	$2.45	$2.27	$1.57	$2.63
February	$1.57	$1.47	$1.45	$1.51	$2.14	$2.20	$1.55	$1.50
March	$1.47	$1.42	$1.41	$1.44	$2.07	$2.18	$1.51	$1.23
April	$1.48	$1.49	$1.48	$1.48	$2.09	$2.18	$1.54	$1.27
May	$1.81	$1.84	$1.78	$1.82	$2.52	$2.47	$1.78	$1.65
June	$1.81	$1.79	$1.75	$1.79	$2.49	$2.51	$1.80	$1.63
July	$1.85	$1.80	$1.76	$1.81	$2.55	$2.54	$1.80	$1.66
August	$1.96	$2.05	$2.04	$2.01	$2.85	$2.60	$1.84	$1.92
September	$2.21	$2.34	$2.27	$2.28	$3.19	$3.16	$2.25	$2.22
October	$2.15	$2.16	$2.12	$2.15	$3.01	$3.00	$2.15	$2.10
November	$2.50	$2.55	$2.31	$2.47	$3.44	$3.52	$2.53	$2.63
December	$2.10	$1.85	$1.90	$1.96	$2.74	$2.65	$1.90	$1.98
1999 Average	**$1.92**	**$1.87**	**$1.83**	**$1.88**	**$2.64**	**$2.61**	**$1.85**	**$1.87**
1998 Average	$1.47	$1.64	$1.67	$1.58	**$2.22**	$1.78	$1.26	$1.34
% change	**30.67%**	**13.75%**	**9.07%**	**18.95%**	**18.95%**	**46.76%**	**47.27%**	**39.51%**

Sources: NEB, Friedenberg, NRCan estimates

Figure 32
Plant Gate Revenues



Sources: NEB, Friedenberg, StatsCan, NRCan estimates

The combination of increases in natural gas exports, Canadian demand, and prices has led to record levels of revenue to Canadian producers.

Export revenues increased 28% in 1999, and domestic revenues increased 46% – an incremental $4.3 billion (Canadian) of revenue.

Western Canadian gas producers have never seen these kinds of cashflows. This partly explains the high levels of gas drilling seen in recent months.

Outlook to 2010

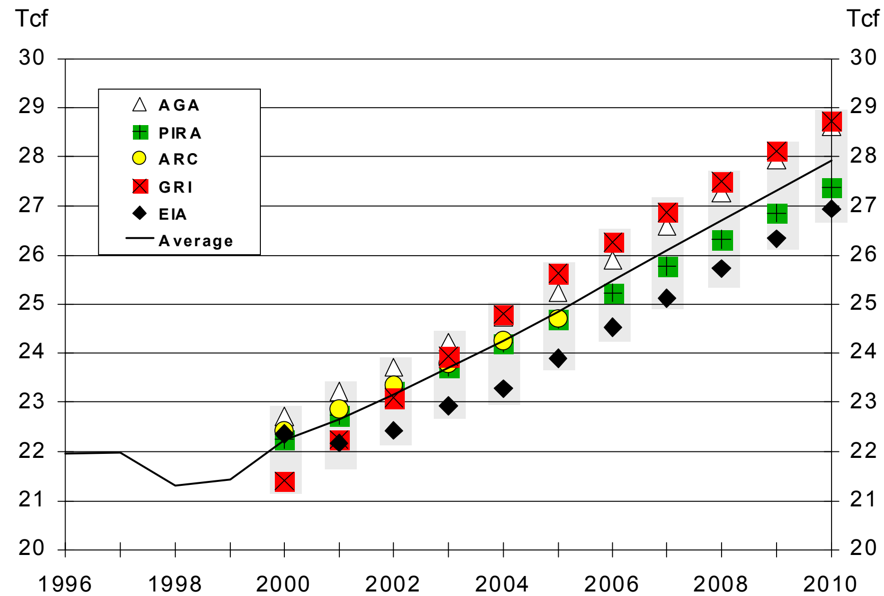
Natural Gas Demand

Figure 33 shows five forecasts of US gas demand, along with the average of the five forecasts.

The average of the forecasts shows US gas demand at 28 Tcf by 2010. This represents an average increase of 2.5% per year.

Note that the five forecasts are fairly consistent. The difference between the highest forecast and the lowest is 1.6 Tcf by 2010.

Figure 33
US Gas Demand Forecasts



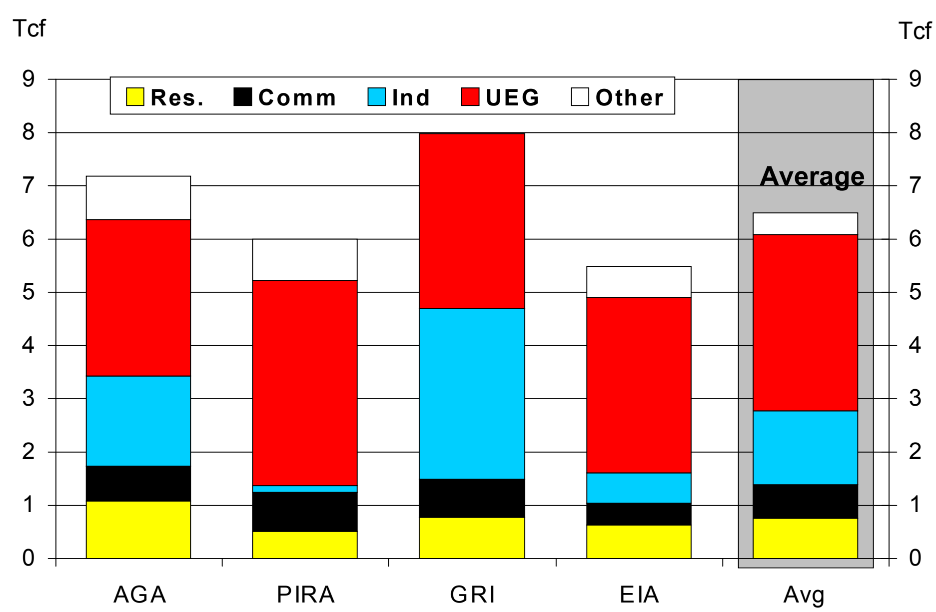
Sources: AGA, PIRA, ARC, GRI, EIA

Figure 34 shows the sectoral breakdown of incremental gas demand for each forecaster.

Specifically, in each sector, the actual 1999 demand is subtracted from the individual forecaster's 2010 forecast.

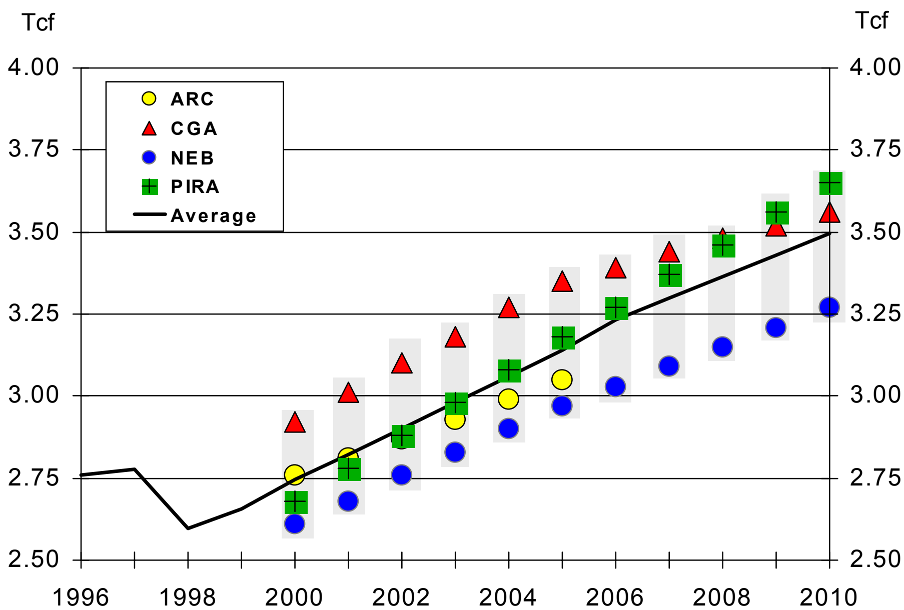
The difference between forecasters at the high end the total demand range (GRI, AGA) and those at the low end (PIRA, EIA) appears to be due to differing expectations about the industrial sector.

Figure 34
Sectoral US Gas Demand Forecasts



Sources: AGA, PIRA, GRI, EIA **Note:** All forecasts put cogen in industrial sector, other non-utility generation is in UEG sector.

Figure 35
Canadian Gas Demand Forecasts



Sources: CGA, ARC, NEB Case 1, PIRA

Figure 35 shows four forecasts for Canadian gas demand. The average shows Canadian demand reaching 3.5 Tcf by 2010. This is an average increase of 2.5% per year.

Table 10
Regional Demand Outlook

	Actual 1999 Demand Bcf	1994-99 Annual Growth %	Growth Rate to 2010 %	Incremental Demand 99-2010 Bcf	Demand Forecast 2010 Bcf
Gulf Coast	5,316	0.8%	1.8%	1,172	6,488
Midcontinent	1,207	-0.5%	1.8%	262	1,469
Rockies	636	2.7%	3.1%	253	889
West	2,673	2.7%	2.7%	906	3,579
Midwest	4,327	0.4%	1.8%	923	5,250
Northeast	2,971	2.2%	2.7%	1,007	3,978
US South Atlantic	1,811	3.4%	4.1%	1,010	2,821
Other US	571	-6.7%	2.5%	177	748
Total US End-Use	19,512	1.1%	2.4%	5,709	25,221
US Pipe fuel, etc.	1,870	0.8%	3.4%	831	2,701
Total US Demand	**21,382**	**1.1%**	**2.5%**	**6,540**	**27,922**
Canadian Demand	**2,657**	**1.7%**	**2.5%**	**837**	**3,494**
Total North America	**24,039**	**1.1%**	**2.5%**	**7,377**	**31,416**
Exports to Mex., Jap.	**125**	**5.4%**	**0.0%**	**0**	**125**
Total Gas Required	**24,164**	**1.1%**	**2.5%**	**7,377**	**31,541**

Source: NRCan **Note:** Demand growth rates seen over the1994-99 period are somewhat low due to abnormally mild 1999 weather. Demand growth rates over other periods (e.g., 1993-97) were higher.

Together with US gas demand, this results in a forecast of US and Canadian gas demand of over 31.4 Tcf by 2010. North America would need an additional 7.4 Tcf of gas by 2010.

In order to analyze regional gas price and flow dynamics, we also assess regional demand, using past demand trends as well as expert forecasts. Our regional demand assumptions are shown in Table 10.

Outlook to 2010

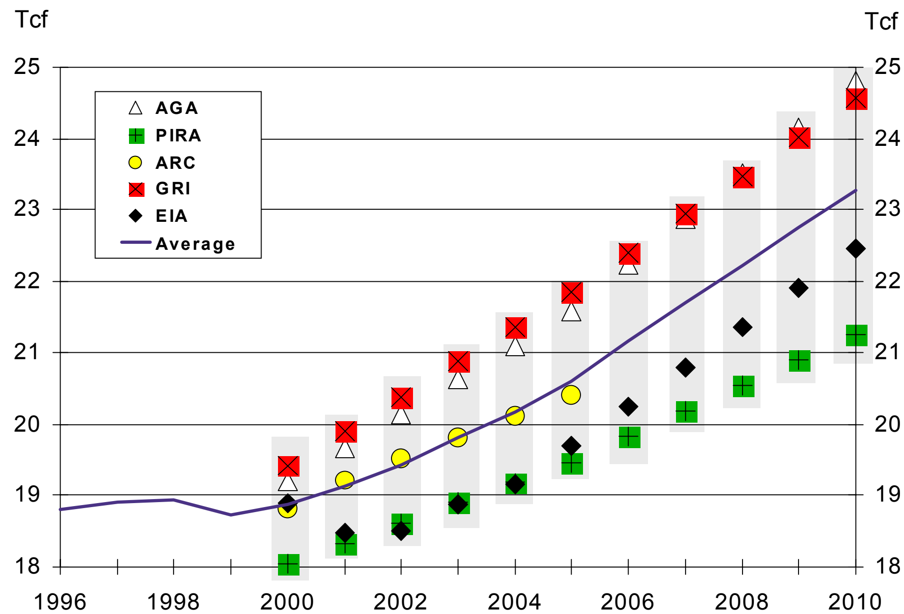
Natural Gas Supply

Figure 36 shows five forecasts for US gas production. The average sees US production increasing 2% per year over the period.

For the first time since we have been doing this report, some forecasters see US production falling in the medium term.

The range in forecasts suggests uncertainty about US supply among industry observers.

Figure 36
US Gas Production Forecasts



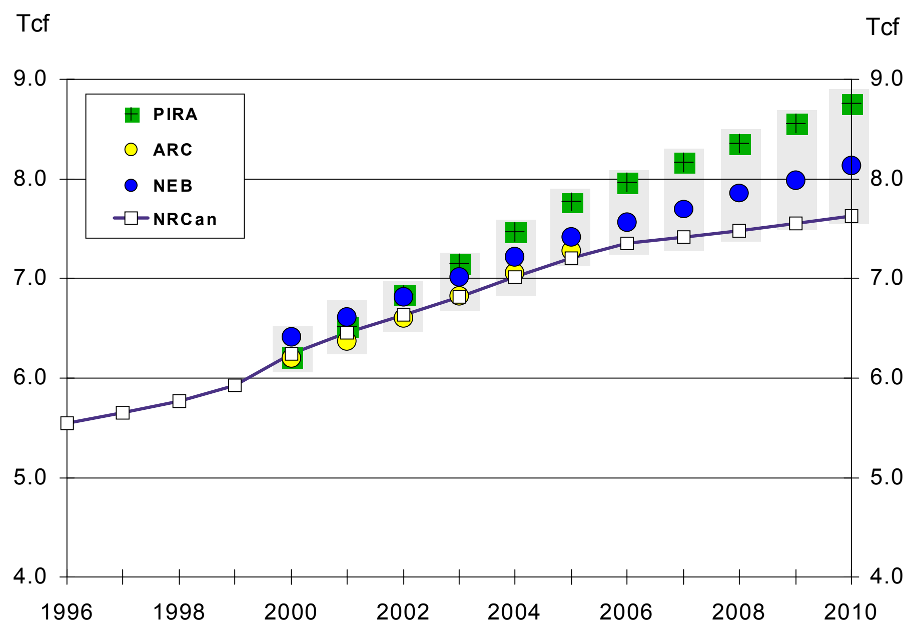
Sources: AGA, PIRA, ARC, GRI, EIA **Note:** Does not include supplementals.

Figure 37 compares our forecast of Canadian gas production with the forecasts of 3 other organizations.

We expect production to reach 7.6 Tcf by 2010. This represents an average annual increase of 2.3%.

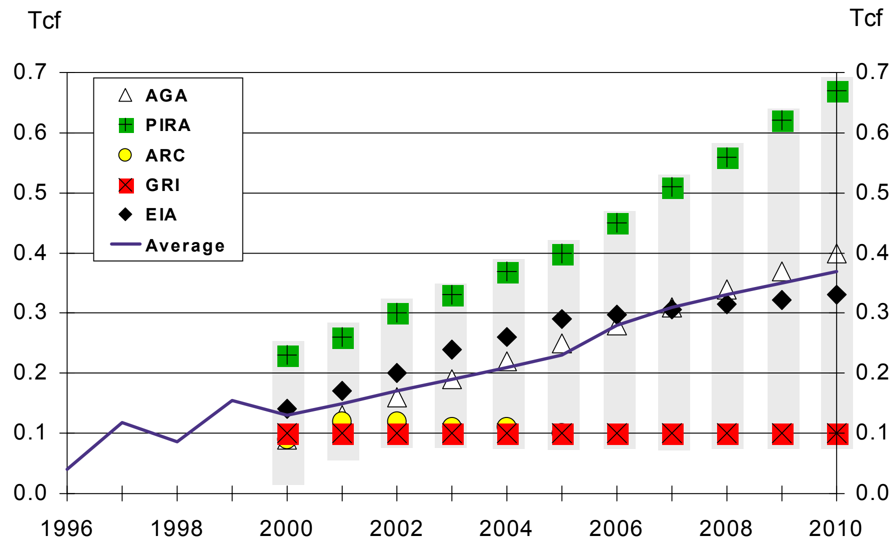
Our forecast (NRCan) is based on existing or under construction pipeline capacity. If more capacity is constructed, our forecast will be low. See page 48 for additional detail on how the NRCan Canadian production forecast is generated.

Figure 37
Canadian Gas Production Forecasts



Sources: NEB Case 1, PIRA, ARC

Figure 38
LNG Supply Forecasts



Sources: AGA, PIRA, ARC, GRI, EIA **Notes:** AGA forecast was LNG imports net of LNG exports to Japan. Assumed 50 Bcf/yr LNG exports over period. PIRA forecast was LNG imports plus supplemental gases. Assumed supplements of 110 Bcf/yr over period. Forecasts thus adjusted to be on gross LNG imports basis.

An average of various forecasts sees LNG imports to the US reaching 0.37 Tcf (374 Bcf) by 2010.

There are also minor amounts of supply from supplemental sources (propane air mixtures, etc) and via pipeline imports from Mexico. These are expected to remain minor over the outlook period.

Table 11
Regional Supply Outlook

	Actual 1999 Supply Bcf	Annual 1994-99 Growth %	Annual 1996-99 Growth %	Growth Rate to 2010 %	Production Forecast 2010 Bcf	Incremental Supply 99-2010 Bcf
Gulf Coast:						
Non-OCS	6,642	-0.3%	-0.2%	2.0%	8,293	1,651
Gulf OCS	4,964	0.5%	-0.9%	2.0%	6,198	1,234
Gulf Total	11,606	0.0%	-0.5%	2.0%	14,490	2,884
Rockies	3,146	2.2%	3.3%	3.2%	4,449	1,303
Midcont.	2,219	-3.7%	-4.2%	-1.3%	1,914	-305
Other US	1,749	1.2%	2.2%	3.0%	2,421	672
Total US	**18,720**	**0.0%**	**-0.1%**	**2.0%**	**23,274**	**4,554**
Canada	**5,932**	**3.4%**	**2.2%**	**2.3%**	**7,626**	**1,694**
LNG	**161**	**25.9%**	**59.1%**	**8.0%**	**374**	**213**
Other	150	**4.9%**	**6.8%**	**5.4%**	**267**	**117**
TOTAL	**24,963**	**1.0%**	**0.8%**	**3.4%**	**31,541**	**6,578**

Source: NRCan **Note:** Other US includes minor producing states like Alaska. Other is supplemental gaseous fuels plus imports from Mexico. 2010 supply set equal to 2010 demand. However, 1999-2010 supply change not equal to demand change due to 99 supply/demand differences. Other is supplementals and imports from Mexico.

Table 11 shows our assumptions about how North American demand in 2010 would be met.

Assumptions about regional production are also shown. These are based on past trends and expert advice.

The major regional sources of incremental supply to north America over the outlook period are expected to be the Gulf Coast (annual production up 2,884 Bcf by 2010), followed by Canada (up 1,694 Bcf) and the Rockies (up 1,303 Bcf).

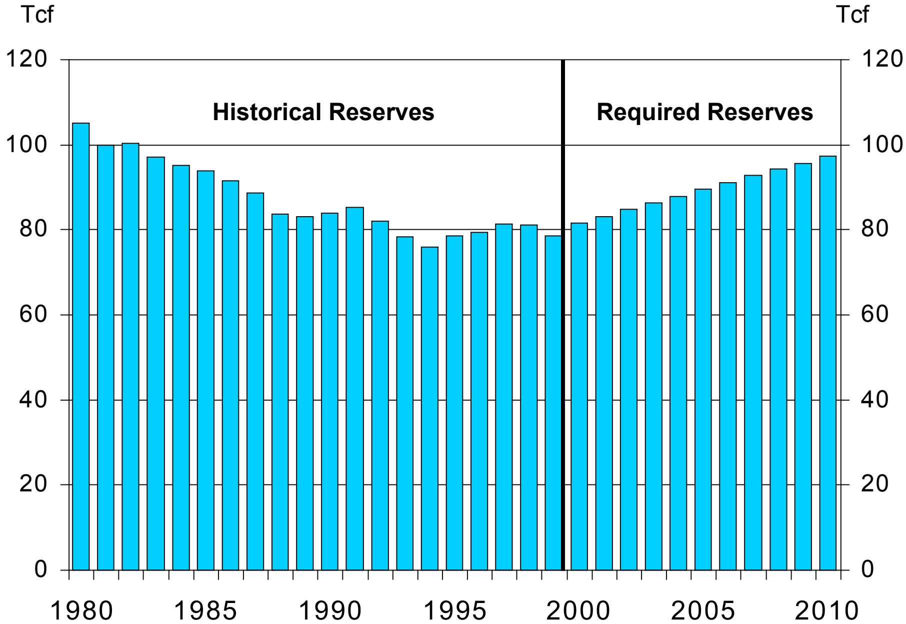
Some of these regional production figures may be difficult to achieve.

Gulf Coast production has typically ranged between 14.5% - 15.2% of proved reserves.

Under that assumption, for Gulf production to reach 14,490 Bcf by 2010, proved reserves would have to climb from 78 Tcf as of January 1, 1999, to 95 Tcf by 2010.

Past reserve trends do not provide support for reserves growth on this scale.

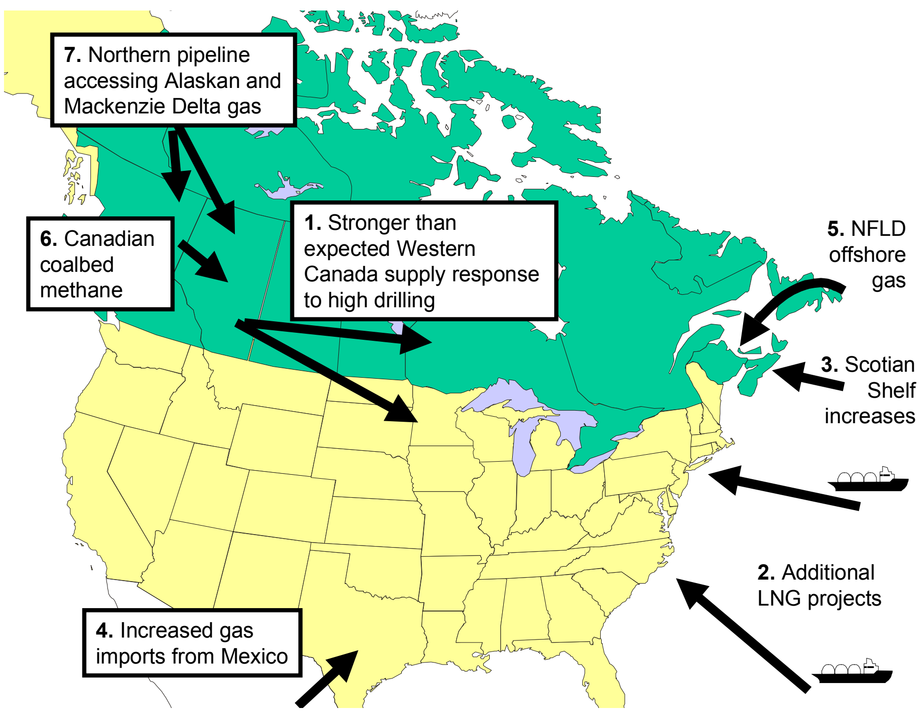
Figure 39
Gulf Coast Proved Gas Reserves



Source: EIA (historical data)

Another option for supply would be that incremental production comes from other sources, taking up any shortfall left by the Gulf. Figure 40 outlines some of these possible supply sources.

Figure 40
Possible Alternative Supply Sources

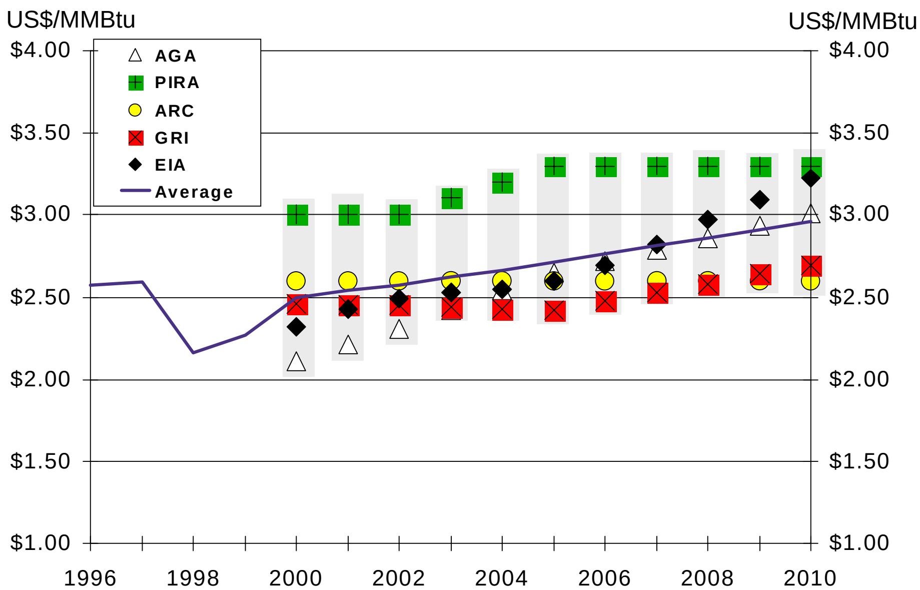


Outlook to 2010

Natural Gas Prices

Figure 41
US Gas Price Forecasts

A range of industry views shows that US prices (nominal dollars) on average are expected to rise to $2.96/MMBtu by the end of the period.



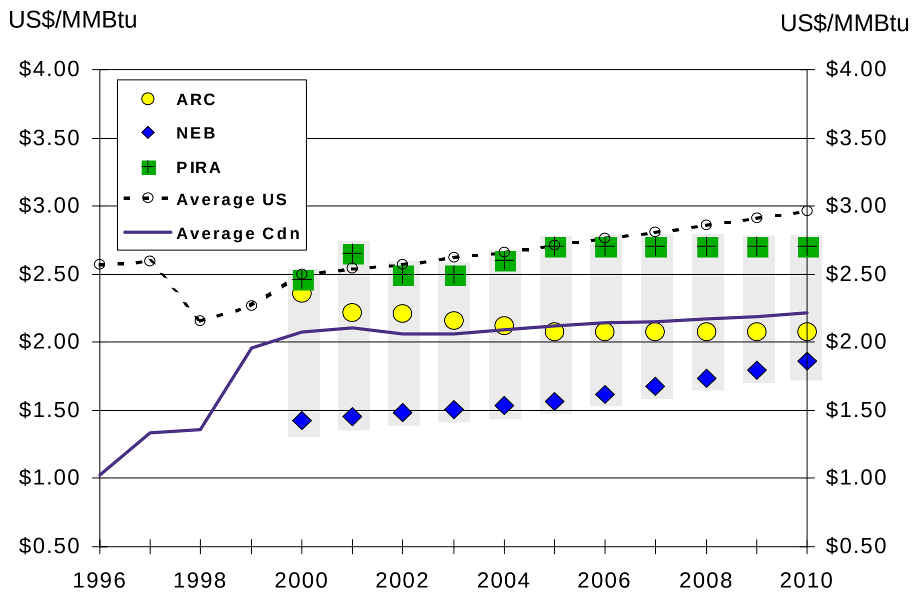
Sources: AGA, PIRA, ARC, GRI, EIA **Note:** Gulf Coast prices, except AGA, which is a field price. Some original forecasts in constant dollars, converted to nominal using forecaster's assumed inflation rate. 1995-99 are NYMEX actuals.

Figure 42
Canadian Gas Price Forecasts

Canadian gas prices, according to a selection of forecasts, are expected to be more or less flat in nominal terms.

The average US price track is also shown on the figure for comparison. This gives a sense of future Canada/US gas price differentials.

This implies AECO /NYMEX differentials widening to $0.59/MMBtu by 2005, $0.74/MMBtu by 2010.



Sources: PIRA, ARC, NEB Case 1 **Note:** ARC and NEB were plantgate forecasts, added $0.12US/MMBtu. PIRA=AECO. Forecasts in nominal dollars, ARC assumes 2% annual inflation. 1995-99 prices are AECO actuals.

Outlook to 2010

Gas Flows
& Pipeline Capacity

Certain gas flow patterns are implied by the regional demand and supply outlooks of previous sections of this report.

These are shown in Table 12. Most producing and market areas will need additional pipeline capacity in the following 11 years.

Table 12
Future Gas Flow Patterns, Bcf

Producing Areas: (Outflows)	1999 Outflows	2010 Production	2010 Demand	2010 Outflows	99-2010 Outflows Difference
Gulf	6,290	14,490	6,488	8,002	1,712
Midcontinent	1,012	1,914	1,469	445	-567
Rockies	2,510	4,449	889	3,559	1,049
Western Canada	4,479	7,435	1,887	5,548	1,069
Total Producing	**14,291**	**28,288**	**10,733**	**17,555**	**3,264**
Market Areas: (Inflows)	**1999 Inflows**	**2010 Production**	**2010 Demand**	**2010 Inflows**	**99-2010 Inflows Difference**
West	2,314	497	3,579	3,082	768
Midwest	3,889	606	5,250	4,644	755
Northeast	2,887	116	3,978	3,861	974
South Atlantic	1,807	6	2,821	2,815	1,008
Eastern Canada	1,204	191	1,607	1,416	212
Total Market	**12,101**	**1,416**	**17,234**	**15,818**	**3,717**

Source: NRCan **Notes:** increase in supply region outflows not equal to increase in demand region inflows due to 1999 supply/demand differences. (Recall that initial 1999 supply figures exceed demand figures). Increase in Eastern Canada production due to Sable Island. Eastern Canadian production in 1999 was 27 Bcf (from Ontario).

Given the flows anticipated above, we next examine proposed North American pipeline projects.

The major project is Alliance, scheduled for completion in late 2000.

Other areas of pipeline activity are: the US Rockies; the Gulf Coast to South Atlantic corridor; and the US Midwest to Northeast corridor.

The numbers on the map correspond to the projects numbered in Table 13.

Figure 43
Proposed Pipeline Projects

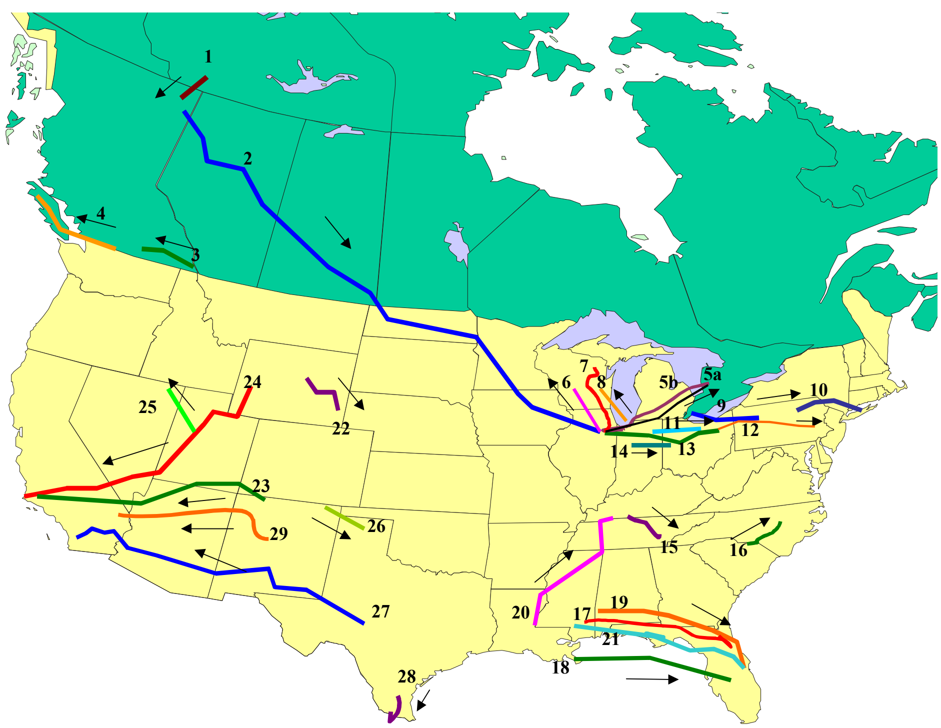


Table 13: Pipeline Project Proposals

Project Name	Sponsors	Origin	Destination	Length (Miles)	Start Date	Capacity (MMcf/d)
Western Canadian Projects						
1. Shiha Pipeline Project	Paramount Berkley	Ft. Liard, NWT	Maxhamish Plant, B.C.	15	not available	106
2. Alliance Pipeline	Ft. Chicago, Enbridge, Coastal, Williams	Fort Saskat-chewan, B.C.	Jolliet, Illinois	1,900	10/01/00	1,325
3. Southern Crossing	BC Gas	Yahk, BC	Oliver, B.C.	193	not available	275
4. Georgia Strait Crossing	Williams	Sumas, Washington	Vancouver Island	85	2002	100
Midwest - Ontario - Northeast Projects						
5a. Tristate	CMS, Westcoast	Chicago Hub	Dawn Hub	344	11/01/00	650
5b. Vector	Enbridge, MCN, Westcoast	Chicago Hub	Dawn Hub	329	11/01/99	1,000
6. Guardian Pipeline	CMS Energy, Wicor, Viking	Jolliet Illinois	N. Illinois and S. Wisconsin	149	11/01/02	750
7. Horizon Pipeline	KN Energy	Chicago Hub	N. Illinois and S. Wisconsin	129	11/01/01	800
8. Peoples/ Coastal	Peoples Energy & Coastal Corp	St. John Indiana	Wisconsin	130	11/01/01	1,400
9. Millenium	Columbia, TransCanada, St. Clair	Dawn, ON	Mt. Vernon, NY	560	not available	714
10. Market Link	Transco	Leidy Hub	NY City	700	11/01/01	700
11. N. Border Project 2000	N. Border Pipeline Co.	Channahon, Illinois	North Ayden, Indiana	34	not available	350
12. Independence	ANR, Transco, Nat. Supply Corp.	Defiance, Ohio	Leidy, Penn.	397	11/01/00	916
13. Supply Link	ANR Pipeline Co.	Chicago Hub	Defiance, Ohio	73	11/01/01	750
14. Crossroad (expansion)	Crossroads Pipeline	North Hayden Indiana	Indiana, Ohio	25	11/01/00	600
Southwest US - Gulf Coast - South Atlantic Projects						
15. Volunteer	Columbia Gulf, AGL, MCN	Portland, Tennessee	Chattanooga, Tennessee	270	11/01/01	500
16. Palmetto	Palmetto Interstate pipe	Aiken County, SC	Robeson County, NC	175	04/01/02	300
17. Buccaneer Pipeline	Williams	Mobile Bay, Alabama	Central Florida	420 (offs.) 250 (ons.)	04/02/02	950
18. Gulf Stream	Coastal Corp	Mobile Bay, Alabama	W. Palm Beach, FL	700	06/01/02	1,130
19. FGT - Phase 4	Florida Gas Trans (FGT)	Gulf of Mexico	Florida	205	05/01/01	275
20. Mainline '99	Columbia Gulf	Rayne, LA	Leach, Tenn.	335	11/01/00	335
21. Sawgrass Energy	Duke Energy Corp.	Mobile Bay, Alabama	Florida	600	01/01/03	1,000
US Rockies - California Projects						
22. Medicine Bow Lateral	Coastal/ WIC	Glenrock Wyoming	Cheyenne Wyoming	150	01/12/99 to 03/11/01	192
23. Southern Trails	Questar	South Colorado	Long Beach, California	700	06/01/00	406
24. Kern River Exp.	Williams	Opal, Wyoming	Long Beach, California	150	11/01/02	300
25. Ruby Pipeline	Coastal Paiute	Uinta City, UT	Northern NV	400	11/01/00	250
26. Dumas Gas Transmission	El Paso Natural Gas Co.	Van Bremmer Canyon	Dumas, Texas	185	07/01/01	175
27. El Paso All American Pipeline	El Paso Natural Gas Co.	McCamey, Texas	Emidio Stn, Bakersfield, CA	1,088 (existing oil pipeline)	03/01/00	300
28. Coral Mexico Pipeline	Tejas, Coral	Southern Texas	Mexico Border	97	10/01/00	300
29. Gallup Expansion	Transwestern	Blanco Hub, New Mexico	California Border	2	05/01/00	140

Alliance is the major project listed in the table. Alliance will have major impacts on North American gas flow patterns, and on future pipeline construction.

Several projects anticipate additional gas flows from the US Midwest to Northeast.

The Gulf Coast to South Atlantic corridor has been steadily expanding, and more projects are planned.

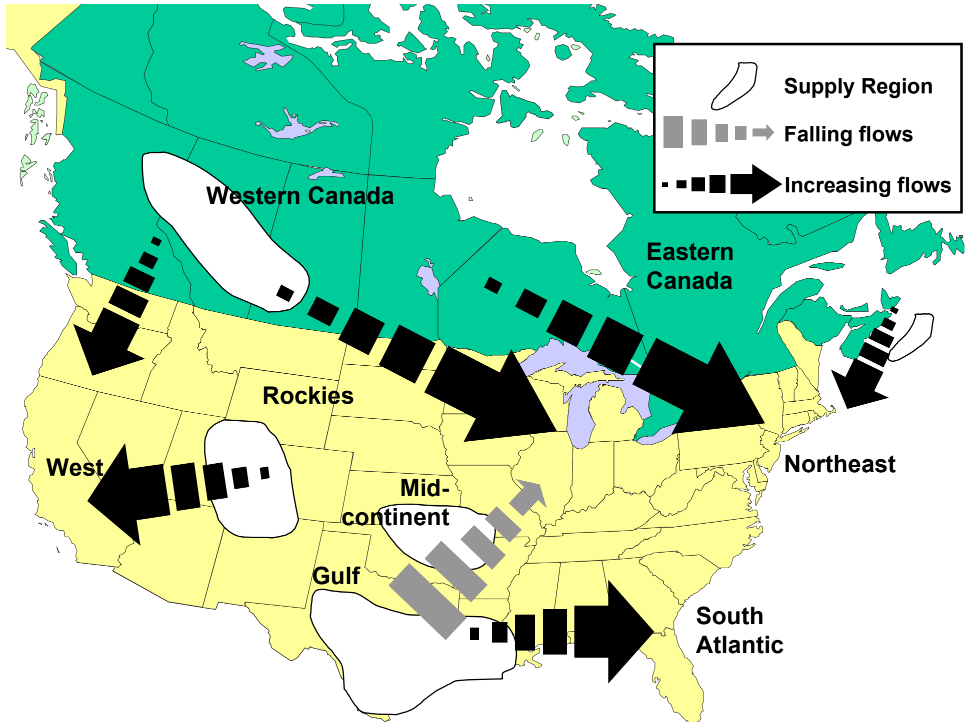
The Rockies to California corridor is also seeing considerable expansion activity.

Figure 44: Emerging Gas Flow Patterns

The probable pattern of gas flow changes which emerges is shown at right.

Gulf Coast and Midcontinent flows to the Midwest are reduced over time, as more gas enters the Midwest from Canada.

Flows along most other pipeline corridors increase.



Outlook to 2010

Canadian Export & Domestic Sales

Total physical export capacity will reach 12,007 MMcf/d when the Alliance project is completed.

Total export capacity currently cannot be filled due to a lack of gas supply. Due to various constraints, capacity is seldom used at 100% load factors. In recent years, the best fill rate for total export capacity was about 90%.

Table 14
Export Pipeline Capacity

(MMcf/d)	1998	1999		2000		2001 - 2010	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
Huntingdon (NW Pipeline)	1,045		1,045		1,045	0	1,045
Huntingdon (User-pipes)	380		380		380	0	380
Kingsgate (Foothills/ANG)	2,582		2,582		2,582	0	2,582
Total US West	**4,007**	**0**	**4,007**		**4,007**	**0**	**4,007**
Monchy (Foothills)	2,190		2,190		2,190	0	2,190
Emerson (TCPL)	1,305	0	1,305		1,305	0	1,305
Alliance			0	1,325	1,325	0	1,325
Miscellaneous (see note)	300	0	300		300	0	300
Total US Midwest	**3,795**	**0**	**3,795**	**1,325**	**5,120**	**0**	**5,120**
Iroquois (TCPL)	883	8	891		891	0	891
Niagara Falls (TCPL)	845	-4	841		841	0	841
Chippawa (TCPL)	500	-19	481		481	0	481
St. Stephen (MNP)		360	360		360	0	360
E. Hereford (TCPL)		163	163		163	0	163
Cornwall (TCPL)	63	-27	36		36	0	36
Napierville (TCPL)	61	0	61		61	0	61
Phillipsburg (TCPL)	50	-3	47		47	0	47
Highwater (TCPL)	25	-25	0		0	0	0
Total US Northeast	**2,427**	**453**	**2,880**	**0**	**2,880**	**0**	**2,880**
Total Capacity (Export)	**10,229**	**453**	**10,682**	**1,325**	**12,007**	**0**	**12,007**

Sources: Pipeline Companies, Regulatory Filings Notes: Year-end MMcf/d capacity represents approximate contracted daily volumes that could be delivered on the last day of the year. Capacity additions are generally completed on November 1. Miscellaneous Midwest includes 9 export points with over 500 MMcf/d of capacity. These export points are not intended to be used at high load factors, and so we use a lower number in the table.

Table 15 shows our estimates of Canadian gas exports and domestic sales. This forecast assumes that the export pipeline capacity listed above is used at certain load factors. We estimate these load factors based on market factors, past load factors, etc.

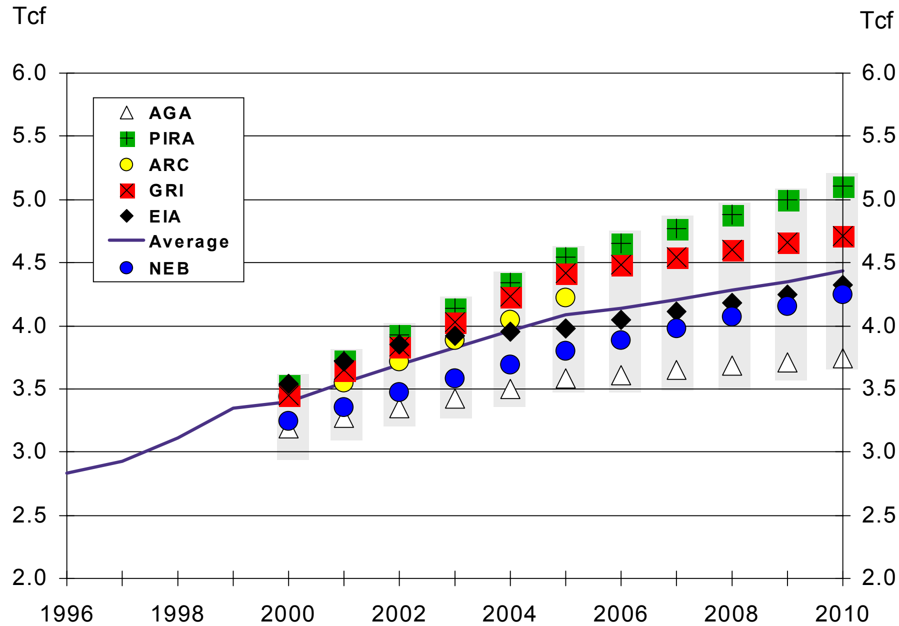
We estimate that exports will reach 4.1 Tcf by 2010. Currently, no additional export expansions are planned past 2000. Should further expansions occur, our export forecast may very well be low.

Table 15
Export Volumes and Domestic Sales

(Bcf)	1998	1999	2000	2001	2002	2003	2004	2005	2010
Huntingdon	423	402	412	422	433	443	454	464	473
Kingsgate (Foothills/ANG)	854	805	820	801	829	858	886	914	942
Total US West	**1,277**	**1,207**	**1,232**	**1,223**	**1,262**	**1,301**	**1,339**	**1,378**	**1,416**
Monchy (Foothills)	558	773	751	679	703	727	751	775	799
Emerson (TCPL)	485	487	453	405	419	433	448	462	476
Alliance			109	435	435	435	455	469	484
Miscellaneous	82	67	82	82	82	82	82	82	82
Total US Midwest	**1,125**	**1,327**	**1,395**	**1,602**	**1,640**	**1,678**	**1,736**	**1,789**	**1,841**
Iroquois (TCPL)	318	357	325	286	296	306	315	325	325
Niagara Falls (TCPL)	305	361	307	270	279	289	298	307	307
Chippawa (TCPL)	44	44	44	46	47	49	51	53	61
St. Stephen (MNP)			112	112	112	112	112	112	112
E. Hereford (TCPL)		17	21	21	22	22	23	24	26
Cornwall (TCPL)	11	9	9	9	10	10	10	11	12
Napierville (TCPL)	17	19	19	19	19	20	20	20	21
Phillipsburg (TCPL)	5	6	7	7	7	8	8	8	10
Highwater (TCPL)	9	3							
Total US Northeast	**709**	**816**	**843**	**770**	**792**	**815**	**837**	**859**	**875**
Total Exports	**3,111**	**3,349**	**3,470**	**3,595**	**3,694**	**3,794**	**3,912**	**4,026**	**4,132**
Western Canada	**1,432**	**1,426**	**1,347**	**1,394**	**1,441**	**1,488**	**1,535**	**1,582**	**1,704**
Eastern Canada	**1,138**	**1,204**	**1,428**	**1,461**	**1,493**	**1,526**	**1,559**	**1,592**	**1,790**
Total Domestic Sales	**2,570**	**2,630**	**2,774**	**2,854**	**2,934**	**3,014**	**3,094**	**3,174**	**3,494**
Total Sales	**5,682**	**5,980**	**6,244**	**6,450**	**6,629**	**6,807**	**7,006**	**7,199**	**7,626**

Source: NRCan

Figure 45
Export Volume Forecasts



Sources: AGA, PIRA, ARC, GRI, EIA, NEB

Our export forecast (4.1 Tcf by 2010) is near the average of the forecasters we surveyed.

Table 16
Export and Domestic Revenue Forecast

EXPORT SALES:	Export Volumes (Bcf)	Forecast US NYMEX Price (US$/MMBtu)	Export International Border Price (US$/MMBtu)	Export Plant Gate Netback (US$/MMBtu)	Export Plant Gate Revenues (Million US$)	Export Plant Gate Revenues (Million Cdn$)
1998	3,111	$2.16	$1.92	$1.58	$4,931	$7,317
1999	3,349	$2.27	$2.19	$1.88	$6,299	$9,348
2000	3,470	$2.50	$2.33	$1.98	$6,871	$10,104
2005	4,026	$2.71	$2.54	$2.19	$8,817	$12,966
2010	4,132	$2.96	$2.79	$2.44	$10,082	$14,827

DOMESTIC SALES:	Domestic Volumes (Bcf)	Forecast Alberta Price (US$/MMBtu)	Forecast PlantGate Netback (US$/MMBtu)	Domestic Plant Gate Revenues (Million US$)	Domestic Plant Gate Revenues (Million Cdn$)	**Total** Plant Gate Revenues (Million Cdn$)
1998	2,570	$1.36	$1.26	$3,348	$4,967	$12,284
1999	2,630	$1.96	$1.85	$4,877	$7,246	$16,594
2000	2,774	$2.08	$1.96	$5,438	$7,997	$18,100
2005	3,174	$2.12	$2.00	$6,347	$9,335	$22,301
2010	3,494	$2.22	$2.10	$7,337	$10,790	$25,617

Notes: Actual export revenues from NEB data. Actual domestic netbacks and revenues calculated using AECO, Huntingdon prices and subtracting published transmission tolls. Future revenues estimated as follows: Future export netbacks assumed to equal forecast NYMEX prices (see report) less US$0.52. Resultant netback multiplied by forecast export sales. Future domestic netbacks assumed to equal forecast Alberta prices (see report) less US$0.12. Resultant netback multiplied by forecast domestic sales. Future exchange rate assumed=$US0.68 per $Cdn.

Table 16 provides our estimates of producer plant gate revenues for the next 11 years, given expected gas prices, export volumes, and domestic sales.

Total producer plant gate revenues increased 35% in 1999. We expect revenues from all gas sales to continue to increase over the outlook period.

Appendix: Review of Selected Regulatory and Market Developments

- Retail Natural Gas Markets in Canada
- Natural Gas Distribution in the Maritimes
- Canadian Millennium Pipeline Project
- Amendments to TransCanada's Toll Schedules
- Changes to Alberta Tolls
- Natural Gas Development in the North
- Canadian East Coast Offshore: Status of Natural Gas Production
- Year 2000 Thank You

Retail Natural Gas Markets in Canada

This article reviews the status of retail natural gas markets in Canada.

Before the early 1990s, Canadian homeowners and small commercial enterprises (the core market) bought their natural gas from the company that delivered it to them - the local distribution company (LDC).

Producer pools sold gas to pipelines. Pipelines moved it to LDC gate stations, where LDCs bought the gas. LDCs then moved it on their systems to core customers, and sold it to them. The chain of gas movement and gas contracts was:

Producer pool -> Pipeline -> Distributor -> Customer

All activities in this chain were regulated: the price of gas, the price of pipeline services, and the price of LDC services. Core customers dealt only with the LDC, and paid one gas bill. The price for this gas service was regulated by the provincial authority.

Today, in most provinces, core customers can buy gas from the LDC, or have the option of purchasing gas from a producer, marketer, broker, or agent. Core customers are becoming known as the retail gas market.

Retail customers have two basic options for obtaining gas, as shown in Figure A-1.

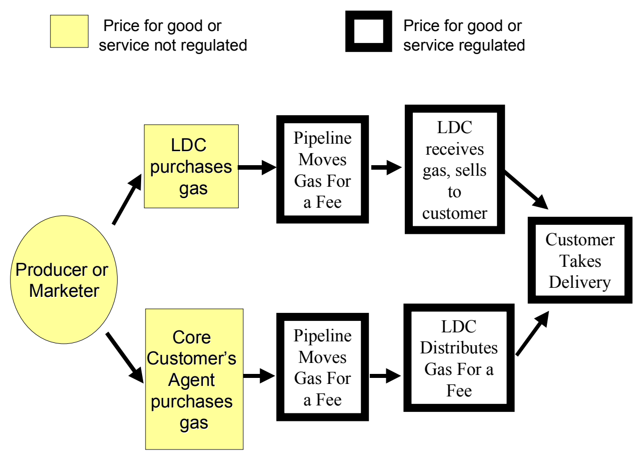
In the first option, the user can rely on LDC "system supply". This refers to the top path in Figure A-1. The LDC will buy the gas commodity (the gas molecules) from producers or marketers. This gas price is a market price; however it is subject to regulatory oversight, as explained below.

The LDC will then contract with pipelines to move the gas to the LDC gate station. The toll paid by the LDC to the pipeline is regulated, usually by the National Energy Board. The LDC then takes delivery of the gas from the pipeline at the LDC's gate station.

Finally, the gas is delivered to the core customer by the LDC. LDC rates include the gas price paid to the producer, the pipeline toll, costs for the use of the LDCs facilities (including load balancing using storage), plus a rate of return to the LDC on capital. LDC rates are regulated by provincial authorities. Rates are broken down into various components: the gas supply charge (the gas commodity), pipeline charges, and LDC charges.

The provincial regulator reviews the gas supply charge, and may not allow full recovery of this component if the gas purchase is deemed imprudent. The provincial regulator also restricts the type of gas contracts the LDC may enter into with producers. This generally means that LDCs purchase gas from producers under one-month "spot" contracts. Since the spot market price changes each month, the underlying gas price component of a core customer's gas rate may also change each month under the system supply option.

Figure A-1: Gas Industry Structure, 1999



LDCs must get provincial regulator approval for changes to rates. LDCs usually do not change their rates each month, even though gas prices change. Instead, LDCs use deferral accounts to handle discrepancies between the approved rate which the LDC is charging for the gas commodity, and the actual price paid in the supply area for the gas commodity. When the difference between the two becomes sufficiently large, the LDC will ask for a change in rates.

For core customers not wishing to use LDC system supply, the second option is the lower path in Figure A-1. A marketer, broker or agent purchases the gas commodity from producers, on behalf of the core consumer. This is called a "direct purchase". The price for acquiring this gas is a market price - not regulated. The gas is then transported by the pipeline and LDC as in the previous option. These components of cost remain regulated. The LDC may bill the customer for all costs, including the gas supply payment (which will be passed on to the marketer) or the latter may be paid directly to the marketer.

However, unlike the system supply option, there is no regulatory oversight of the gas supply charge. There are also no restrictions on the types of gas commodity contracts the marketer, agent or broker can enter into with producers. Often, the gas supply charge will be fixed for one, three, or five years.

In summary, retail gas consumers have basically two options – use system supply and pay a gas supply charge which essentially changes each month, or use marketers or brokers to pay a fixed gas supply charge. Fixed charges are usually higher than the current monthly rate available from the LDC. This reflects the value placed by markets on price certainty and insurance. If gas prices rise, fixed price contracts may allow the consumer to escape higher prices.

Originally (early 1990s), most direct sales to retail gas users occurred through "buy-sell" arrangements. With a buy-sell, the retail gas users (through their agents) would buy gas from producers or marketers at attractive prices. The retail user would then sell this gas to their LDC, at prices reflecting the LDCs average cost of gas purchases. The LDC would then deliver gas to the retail user and bill the user like a system supply customer.

Essentially, the retail user would make a profit on the gas commodity buy-sell, effectively lowering the retail user's gas price. Retail users could buy gas at lower prices than the LDCs average cost of gas purchases, because those purchases were dominated by long term, high priced contracts. Retail gas users would buy shorter-term gas, at lower prices. When LDCs switched to shorter-term gas purchasing, the attractiveness of buy-sells largely dissappeared.

Ontario

Ontario has the largest and most advanced retail gas market in Canada. Over half of the retail gas market purchases gas through marketers or brokers, rather than relying on LDC system supply. The large direct purchase penetration into the retail gas market occurred during the buy-sell era, driven by substantial gas savings that could then be achieved. (Certain regulatory requirements for transferring title to gas in Ontario made buy-sells more convenient than direct purchases. Changes to legislation in 1998 facilitated gas title transfers in Ontario, and now Ontario direct purchases for core markets need not be buy-sell arrangements.)

There are two main LDCs in Ontario (Enbridge Consumers Gas and Union Gas), plus several smaller LDCs. The Ontario Energy Board (OEB) regulates LDCs and gas markets in Ontario.

Early problems with retail natural gas sales included complaints about marketer sales practices and, in some cases, marketing companies failing to deliver gas supplies (for retail customers they had under contract) to the LDC. The affected LDCs delivered replacement gas to the retail customers, using LDC backstop supplies, but warned that penalty charges could apply to the retail customers.

In October 1998, Bill 35 (the Energy Competition Act, 1998), and the Ontario Energy Board Act (1998) received royal assent. This requires all gas marketers in Ontario to be licenced, and to follow a code of conduct. As of December, 1999, the OEB listed 20 licenced natural gas marketers on its website (www.oeb.gov.on.ca). The OEB has also designated the Ontario Energy Marketers Association (OEMA, website at www.oema.org) to resolve customer complaints.

Further market restructuring in Ontario is occurring, mainly involving certain LDC operations being removed from the regulated utility, and being operated as separate, non-regulated affiliates. This separation of activities is called unbundling. LDCs have transferred merchandise sales, rentals, and finance activities to non-regulated affiliates. LDCs would also like to take some storage assets out of regulation, and price storage services at market rates. To date, this has not been allowed.

Quebec

The main LDC in Quebec is Gaz Metropolitain, which is regulated by the Régie de L'Énergie du Quebec. Retail gas users may use Gaz Metropolitain system supply or purchase gas directly using brokers and buy/sell arrangements. In 1997, it was reported[1] that over 40% of retail gas users were direct purchases, rather than system supply. Gaz Metropolitain requires that brokers meet certain contract conditions before it will authorize buy/sells. On its website (www.regie-energie.qc.ca) the Régie de L'Énergie lists 22 marketers or producer-marketers as being active in Quebec.

Alberta

Alberta has one main LDC (Atco Gas), but also has several municipal LDCs, and rural gas co-operatives. The Alberta Energy and Utilities Board regulates LDCs and retail natural gas markets in Alberta.

Retail direct purchases were not allowed in Alberta until 1996, when Alberta enacted regulations allowing retail direct purchases. However, numerous conditions on sales to the retail market were imposed. These were included in the Gas Utilities Core Market Regulation, the Natural Gas Direct Marketing Regulation, and the Fair Trading Act.

Requirements for marketers included licencing, posting of a bond, a prohibition on sign-up fees, a requirement that customers be informed that the marketer was not affiliated with the LDC or the Government of Alberta, minimum codes, standards, and rules, and a requirement of firm gas supply and transportation, backed by a corporate warranty.

In 1999, it was reported[2] that marketers had signed up about 12,000 retail customers in Alberta. However, the LDCs retain most customers (790,000). Marketers offer prices, which are fixed for one to five years, while the LDCs offer prices that vary each month with the spot market. Unlike the case of Ontario, in Alberta LDCs retain the vast majority of retail gas customers.

Saskatchewan

Saskatchewan has one main LDC, SaskEnergy, which is a provincial crown corporation. SaskEnergy is regulated directly by the provincial government. The Saskatchewan cabinet reviews and approves SaskEnergy's rates.

As in Alberta, retail direct purchases were not common until recently. Retail gas customers in Saskatchewan may rely on SaskEnergy for gas supply (system supply), or may purchase gas directly from marketers or brokers. Consumers have had the latter option since November, 1998.

To date, the vast majority of retail customers remain with SaskEnergy's system supply.

British Columbia

The main LDC in British Columbia is BC Gas. BC Gas and the retail gas markets are regulated by the British Columbia Utilities Commission (BCUC).

As of May 1, 1993, retail direct purchases became possible in British Columbia. Brokers must be licenced, follow a code of conduct, and use contract types specified by the BCUC. To date, most retail gas users remain with BC Gas system supply.

Manitoba

The main LDC in Manitoba is Centra Gas Manitoba, which is regulated by the Manitoba Public Utilities Board (MPUB). Retail gas users may use system supply or direct purchases. Brokers must be registered with the MPUB. There are about 226,000 gas users in the province, 45,000 of whom purchase gas through brokers.

- JF

1 . Canadian Energy Research Institute, 1997 Survey of Residential Direct Sales of Natural Gas in Canada.
2 . Daily Oil Bulletin, September 16, 1999.

Natural Gas Distribution in the Maritimes

The development of offshore Nova Scotia natural gas and the onshore mainline pipeline has cleared the way for the provinces of Nova Scotia and New Brunswick to develop a licensing procedure for the distribution of natural gas to end use customers. Both provinces opted to grant exclusive distribution franchises to a province-wide distributor in 1999. This followed a selection process carried out earlier in 1999.

New Brunswick

In New Brunswick, the provincial government opted to strike a Select Committee on Energy to seek input from the public and industry on natural gas distribution issues. In its report to the provincial legislature, the Select Committee recommended that the government embark on a request for proposal (RFP) exercise from companies that had previously expressed interest in distributing natural gas in New Brunswick. The Government accepted the Committee's recommendation and invited 12 companies to submit a plan to develop natural gas distribution infrastructure in New Brunswick.

A selection committee comprised of independent experts and senior government officials reviewed the proposed plans. On September 7, 1999, following an evaluation of competitive bids, the government announced that Gas New Brunswick was chosen as the province-wide distribution company that would develop, construct, operate and maintain a natural gas pipeline network within New Brunswick. Gas New Brunswick is a joint venture between Enbridge

Inc, with a 63% interest and 28 New Brunswick investors which, in turn, control 37% of the venture.

Gas New Brunswick is expected to invest approximately $300 million over 20 years to construct a natural gas distribution system throughout the province. According to Gas New Brunswick, a total of 23 communities will receive natural gas service within the first five years. Details of Gas New Brunswick's development plan will be reviewed by the New Brunswick Utility Review Board in May 2000. Deliveries to end users are expected to begin in late 2000.

In addition to granting a province wide distribution licence, the New Brunswick government decided to grant single use franchises for large industrial customers that will be taking gas deliveries directly from the Maritimes & Northeast Pipeline. As well, local natural gas producers tapping into reserves within the province will be allowed to apply for a producer class franchise to distribute natural gas to specific customers located near their production area.

New Brunswick Gas will not be involved in the natural gas marketing business. The New Brunswick government adopted a fully unbundled model for its emerging natural gas industry. The commodity component of the natural gas service will be managed by natural gas marketers. Natural gas marketers will be certified by the provincial regulatory board.

Nova Scotia

Under the authority of the Gas Distribution Act, adopted in 1997, the Nova Scotia government mandated the Utility and Review Board (URB) to conduct a public review on gas distribution franchise applications.

In late 1998, the Nova Scotia government issued a policy statement entitled "Policy Statement on Maximizing Benefits from Natural Gas Delivery". This policy statement set out the government's objectives and conditions that would accompany any proposal to construct a natural gas distribution system in Nova Scotia. Two key elements of the policy were:

- That natural gas should be made available to a minimum of 62% of Nova Scotia households in all 18 counties throughout the province in the first seven years of operations.
- That rates should be identical for all natural gas users in the province.

The government policy objective guided potential applicants and was used to screen applications by the provincial regulator.

Following a call for applications, in April 1999, the URB began its hearings to review applications to distribute natural gas in Nova Scotia. Two companies, Maritimes NRG, a Westcoast Energy/Irving partnership and Sempra Atlantic, a subsidiary of California based Sempra Energy applied for province-wide licenses while four other parties applied for region specific franchise rights.

In November 1999, following a 49-day public hearing process, where interested parties were given the opportunities to question the applicants and to provide evidence, the URB released its decision to award the province-wide franchise rights to Sempra Atlantic. Sempra's application was preferred to its competitor because it better met the province's policy objectives and that the applicant also guaranteed that the delivered cost of natural gas would be at least 5% less than the delivered price of heating oil. The Board rejected the four regional applications based on the high financial risk associated to them.

According to Sempra Atlantic, the total development cost of the distribution system is approximately $1.1 Billion. Natural gas service would be made available to over 50% of population by the end of the forth year, and to 78% of the province by the end of year seven. Deliveries to end users are expected to begin in late 2000.

Nova Scotia also adopted a fully unbundled regulatory model and further regulatory hearings will examine the issues surrounding the licensing of natural gas marketers in Nova Scotia as well as specific environmental and engineering issues relating to Sempra's development plan.

- MC

Canadian Millennium Pipeline Project

In December 1998, St. Clair Pipelines (1996) Ltd. applied to the National Energy Board (NEB) for a certificate of public convenience and necessity to construct and operate the Millennium West Pipeline. The proposed 36-inch pipeline would extend 74 kilometres (58 miles) from Dawn, Ontario to the shore of Lake Erie, near Patrick Point. In the same month, TransCanada applied to the NEB for a certificate to construct and operate the Lake Erie Crossing Pipeline. This proposed pipeline would extend 97 kilometres (60 miles) from a connection with the Millennium West Pipeline to the Canada/United States border near the middle of Lake Erie. At this point, the Lake Erie Crossing Pipeline would interconnect with the proposed Millennium pipeline in the United States.

Together, the Millennium West and Lake Erie Crossing pipeline projects are known as the Canadian Millennium Pipeline Project (Millennium Project). The facilities will have a capacity of 700 million cubic feet per day of natural gas. The companies also applied for related toll and tariff authorizations. The Millennium Project will deliver natural gas primarily form the Western Canadian Sedimentary Basin to the northeastern United States.

To coordinate the environmental assessment of the Millennium Project under the Canadian Environmental Assessment Act and the NEB Act, a Joint Panel Review, established by an agreement between the NEB and the Minister of the Environment, will be conducted. An oral hearing is scheduled for August 21, 2000 in London, Ontario.

- PM

Amendments to TransCanada's Toll Schedules

On October 29, 1999, TransCanada PipeLines Ltd applied to the National Energy Board (NEB) for approval to amend its interruptible transportation (IT) and short term firm transportation (STFT) tolls. The NEB held an oral public hearing in Calgary from January 18 to February 1, 2000.

Interruptible services are usually offered daily, to sell uncontracted pipeline capacity. STFT services are offered for terms ranging from 14 days to nine months, subject to availability. Unlike IT, STFT has the same priority as firm transportation, but neither IT nor STFT have contract renewal rights.

TransCanada's IT and STFT tolls are currently priced and allocated through a bidding process. IT bids were subject to a minimum bid equal to about 50% of the 100% load factor firm transportation (FT) toll along the same pipeline segment. This floor is a proxy for the incremental variable costs of providing IT services. For STFT, the minimum bid was the equivalent FT toll, which reflects the full cost of service.

TransCanada claimed that its IT and STFT toll floors were too low under conditions of excess pipeline capacity, since FT shippers could obtain essentially firm IT at half the cost of FT. TransCanada indicated that a higher IT "floor" would mitigate migration from FT to IT, but be competitive at the same time.

TransCanada's proposal would have allowed TransCanada the discretion to determine the minimum bid for IT and STFT prior to the bidding process. The floor for both IT and STFT would have been set between 65% and 100% of the equivalent FT toll from April 1 to October 31 and between 65% and 125% from November 1 to March 31.

During the hearing, various proposals were put forward. Most intervenors preferred that the IT and STFT floors remain at their current levels. Some suggested that the IT floor be raised to 80% or 100% of the FT toll. Others also suggested that the IT floor be calculated according to a formula based on gas prices, fuel costs and forecast IT volumes. One party supported TransCanada's IT application, while all parties opposed the STFT proposal.

On April 13, 2000, the NEB denied TransCanada's proposal for discretion to set the minimum price of these services. In its Reasons for Decision, the Board concluded that the current bidding mechanism is still appropriate and that the IT floor should represent a reasonable proxy for incremental variable costs. Also, the Board is of the view that "an IT floor price of 80% of the FT toll should maximize short-term services revenue on the TransCanada system without undermining the value of FT." Thus, the Board directed that the IT floor be raised and fixed at 80% of the FT toll, effective May 1, 2000. The STFT floor remains equal to the FT toll.

The NEB's Reasons for Decision on TransCanada's IT/STFT application are available on the Internet at: http://www.neb.gc.ca/regupd/decision/rh199.pdf .

On another note, the Incentive Cost Recovery and Revenue Sharing Settlement Agreement between TransCanada and its stakeholders expired on December 31, 1999. TransCanada's tolls will now be determined under the traditional cost-of-service method. Negotiations between TransCanada and its stakeholders on a comprehensive resolution of all pricing and services issues are ongoing.

- LB

Appendix

Changes to Alberta Tolls

In February 2000 the Alberta Energy Utilities Board (EUB) approved a new tolling design for the Nova Gas Transmission Limited (NGTL) system.

NGTL is the main natural gas pipeline system in Alberta, and moves over 80% of Western Canadian gas production. NGTL is now owned by TransCanada, and is also called TransCanada's "Alberta System".

The EUB accepted key elements of TransCanada's tolls submission. These eliminate the traditional postage stamp tolling design, in favour of one that charges different tolls for each of the system's receipt points (receipt point specific tolling).

The postage stamp tolling design had been in effect in Alberta since 1980. The contract structure for service on NGTL's system has traditionally separated receipt service from delivery service. Shippers contract for receipt service to put their gas into the system. There are separate delivery contracts to deliver gas off the system.

Under the postage stamp design, the toll was the same for all receipt points. This encouraged the development of natural gas reserves located far from Alberta consumption centres and export points.

As competition increased in the industry from the mid-1980s, the difference in treatment became more significant, and more of an irritant to some industry members. As a result, a number of pipeline proposals developed that were intended to bypass the NGTL system. Industry participants and the EUB became concerned that bypass proposals, while they were a logical response to the postage stamp toll design, ran the risk of being an economically inefficient development in the growth of the Alberta natural gas industry.

NGTL attempted to redress this situation through the development of "load retention rates" for two particular shippers. These lowered the tolls for these shippers, to reflect the proximity of their production to markets. NGTL then entered into negotiations with producers and other interested parties to develop a more durable solution to the bypass problem.

In late 1999, NGTL signed a memorandum of understanding (MOU) with the Canadian Association of Petroleum Producers (CAPP) which became the basis of its submission to the EUB.

The EUB allows companies to negotiate toll and tariff settlements with customers and other stakeholders and then submit them to the EUB to be accepted (or rejected). The MOU with CAPP was not submitted as a negotiated settlement. NGTL acknowledged that it did not meet the letter of the requirements of the EUB's Negotiated Settlement Guidelines, but did assert that the spirit of the Guidelines was satisfied.

In its findings on the NGTL submission, the Board accepted that the postage stamp toll had served its purpose and should be replaced:

> *"As a policy tool, the postage stamp tolling methodology has been, by extending the transportation network throughout the province, effective in enhancing the development of natural gas reserves. Given the significant expansion of the NGTL system over the past twenty years, the Board believes that to a great extent this goal has been accomplished. Therefore, it is now appropriate to determine whether other public interest issues should be considered paramount in the design of the NGTL tolls. Having considered the evidence and all of the issues discussed above, the Board concludes that the adoption of an alternative to the existing postage stamp rate structure is now in Alberta's public interest."*

Under the new toll design, receipt tolls will differ depending upon receipt point. The toll will reflect the distance from the receipt point to the Alberta export points and the diameter of the pipe from that point to the border. The toll design allocates NGTL's total revenue requirement among receipt points by calculating the relative costs of each point compared to an index of the average path covered by gas entering the system, and an index of the average costs associated with the facilities used in the system (taking into account pipe diameter, and related construction and operating costs). The new design also drops the commodity charge component. Tolls will be levied only on contracted volumes, regardless of the actual volumes shipped.

The EUB has also approved a 4-year transition period for the introduction of the new design. This is to allow shippers to adjust to any dramatic changes to the tolls that they have been charged in the past. A ceiling and floor will be established to limit the toll at any receipt point. The range between the two will be widened on January 1st of 2001, 2002, and 2003. When fully implemented, receipt point tolls will be within the range of 19.5 cents to 35.5 cents/Mcf.

The EUB determined that NGTL's proposal contains the attributes of proper rate design:

- Efficiency (It would promote innovation, respond to changing market dynamics, reflect cost causation, and provide proper price signals.)
- Effectiveness (The revenue requirement can be met without any socially undesirable expansion of the rate base.)
- Fairness (The design contains an appropriate apportionment of total cost of service among different ratepayers.)
- Simplicity, certainty, understandability, public acceptability and ease of administration.
- Freedom from controversy concerning proper interpretation.

The new tolling regime came into effect on 1 April 2000.

- DM

Natural Gas Development in the North

There have been two types of pipeline activity in northern Canada during the last 12 months. Natural gas producing and pipeline companies have developed relatively small, near-term projects to connect production in the southern Northwest Territories (NWT) to existing transportation systems. At the same time, potential pipeline sponsors have begun to study and discuss with governments large-scale projects that would be capable of transporting substantial production volumes from Alaska's Prudhoe Bay, as well as from Canada's Mackenzie Delta and the Beaufort Sea.

The near-term projects will expand incrementally the producing area of the Western Canadian Sedimentary Basin. On 26 January 2000, Chevron Canada announced that it had received all permits and approvals for a $21 million natural gas pipeline and associated well-site facilities. The line will connect two gas wells operated by Chevron and another owned by Ranger Oil to the Westcoast Energy Pointed Mountain gas plant in southwestern NWT. On 28 January 2000, the National Energy Board (NEB) approved construction of another project, the Shiha Pipeline. It is a 24 kilometre line linking production in the NWT to a proposed new gas processing plant at Maxhamish in northeast British Columbia.

At the same time, traditional industry members, and some newcomers, are beginning to develop proposals for large-scale projects capable of connecting gas reserves in northern Alaska and northern Canada to continental markets.

TransCanada Pipeline Limited (TCPL) is reviewing four options for delivering northern gas to southern markets. One of these is the Alaska Natural Gas Transportation System (ANGTS – see below). Canadian and US governments certificated ANGTS in the late 1970s. A separate, but related, project – the Dempster Lateral – would have to be approved by the National Energy Board and built to connect Canadian production to the system. A second TCPL option is a line directly from the Mackenzie Delta to northern Alberta. The third alternative the company is considering would combine a Mackenzie Valley line with a connecting offshore line from Prudhoe Bay to the Mackenzie Delta. The fourth option under consideration differs from the third only in that the Prudhoe Bay connection would be onshore, through the Yukon.

The Canadian sponsor of ANGTS is the Foothills group of companies (Foothills) owned by TCPL and Westcoast Energy Limited (Westcoast). Foothills holds a certificate to construct the Canadian portion of the line from the Alaskan border with the Yukon, south through Alberta and branching eastward to the US in Saskatchewan and westward in B.C. Only the southernmost portion of the system was ever completed - from Caroline, Alberta to the two export points. This "pre-build" system currently exports Alberta production. Foothills has had an application pending before the NEB since 1979 for the Dempster Lateral from the Mackenzie Delta to the ANGTS at Dawson. It would connect Canadian production to the main ANGTS line.

Arctic Natural Resources Company (ARC), a US-based group has discussed with governments, producers, and other interested parties its proposal for a pipeline to connect Alaskan gas production and Mackenzie Delta reserves to markets in Canada and the lower 48 states. The route currently under discussion would run from Prudhoe Bay along the Alaskan north slope and then offshore parallel to the Canadian coast in the Beaufort Sea, before turning southeast and following the Mackenzie river valley to the northeast corner of British Columbia, and ending in northern Alberta.

ARC would not own the pipeline, but would be project managers only. Local governments in both countries and organizations such as aboriginal band councils would be invited to participate. The capital cost would be financed by debt in the form of single A rated 20 year "municipal bonds."

On 28 February 2000, Imperial Oil Resources issued a press release announcing the formation of a group of producers to study the feasibility of developing Mackenzie Delta gas. The group also includes Gulf Canada Resources Limited, Shell Canada Limited, and Mobil Canada. The announcement states that the companies are in the early stages of conceptual development planning for onshore natural gas resources in the Mackenzie Delta.

In the early 1980s, interest in large-scale natural gas developments in the north subsided. It had originally developed in response to the international oil shocks of the 1970s and the perception that western Canadian reserves were rapidly depleting. Since that time, not only have commercial conditions changed but a number of land claims have been resolved. Northern public opinion has changed to the point that there now appears to be a greater receptivity to natural gas developments. This was made evident by a meeting of aboriginal leaders at Fort Liard, NWT in late January 2000. The participants signed a declaration that stated,

We the Aboriginal Peoples of the Northwest Territories agree in principle to build a business partnership to maximize ownership and benefits of a Mackenzie Valley pipeline.

- DM

Canadian East Coast Offshore: Status of Natural Gas Production

Nova Scotia Offshore

The Sable natural gas project and the associated Maritimes & Northeast Pipeline began flowing gas to markets on December 31, 1999. Production occurs within a large area offshore of Nova Scotia, which is generally called the "Scotian Shelf". This basin contains 3 trillion cubic feet (Tcf) of established natural gas reserves (proved reserves that are connected to pipelines), 2 Tcf of discovered resources (proved by drilling but not yet connected to pipelines), and 13 Tcf estimated undiscovered potential (not yet discovered).

The project started operations just over two years after receiving regulatory approvals from the National Energy Board. Production is gradually increasing as the project is brought on-line. The project's output is expected to reach 530 million cubic feet per day (MMcf/d) by the end of year 2000. In March 2000, production averaged 280 MMcf/d.

In the initial months of production, natural gas produced from the Sable gas fields will be delivered to markets in New England states. A lateral pipeline to the Point Tupper region of Nova Scotia will provide the first deliveries of natural gas to Canadian customers. This pipeline was constructed in 1999 and is awaiting final regulatory approval. Two additional lateral pipelines, the Halifax and Saint John pipelines, were reviewed and approved by the National Energy Board in 1999. Both pipelines are expected to be in-service in late 2000. The combined capacity of the three Canadian lateral pipelines is approximately 165 Mmcf/d and represents over 30% of the total planned output from the Sable project.

The Sable project is divided into two phases. Phase One included the construction of the main gas processing plant at Goldboro; the natural gas liquids fractionation plant at Point Tupper; offshore wells and platforms (Thebaud, which provides central gathering and dehydration facilities, North Triumph and Venture); and the onshore and offshore pipelines.

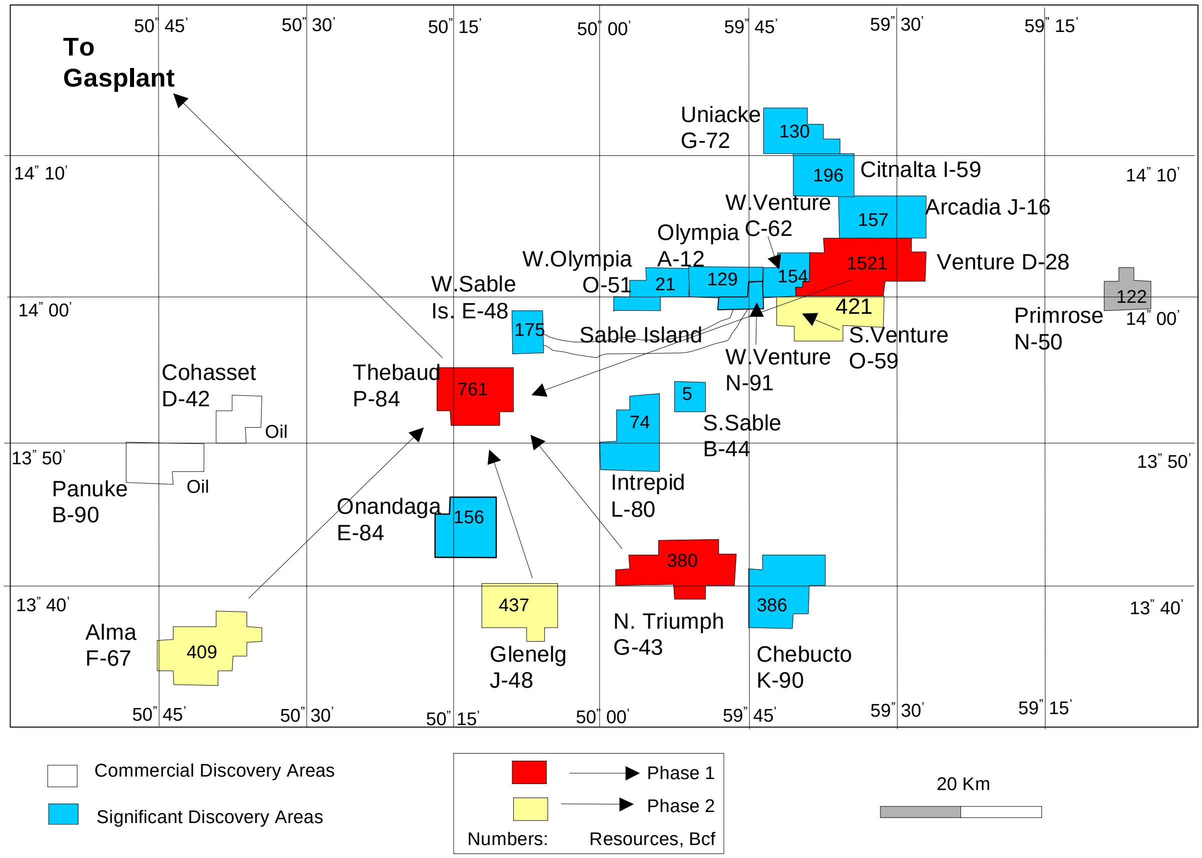
Phase Two is proposed for 2004-2010 and depends on the performance of Phase One. During Phase Two, another three platforms (Alma, Glenelg and South Venture) and remaining wells will be developed. Figure A-2 on the following page illustrates the total Sable project.

If Phase One wells are produced at 530 MMcf/d, production should begin to decline in about 15 years, and continue to decline until 2020-25. However, the project sponsors indicate a potential for new reserves to be established. In this scenario, production could be increased to about 630 MMcf/d and last until 2030-2035.

The subsea pipeline could flow to a maximum of 870 MMcf/d, but the existing Sable infrastructure would require significant additional investment to accommodate this throughput.

On February 24th, PanCanadian announced it had drilled two exploratory wells under the Panuke oil field close to Sable Island that tested more than 50 MMcf/d each. This discovery is not included in the 18 Tcf ultimate resource potential estimate. The size of the reserve has not yet been determined.

Figure A-2: Sable Project Area Map



Source: Canada Nova Scotia Offshore Petroleum Board

- LB/MC

Newfoundland Offshore

The Hibernia oil production platform, which lies 270 kilometres offshore Newfoundland, also currently produces large volumes of natural gas. However, this production is not connected to the North American pipeline grid.

Currently, the platform produces about 150 MMcf/d of solution gas per day, along with about 170,000 barrels of oil per day, from 7 wells. Of the natural gas, about 135 MMcf/d is reinjected into the reservoir to help facilitate oil recovery, and 15 MMcf/d is used to generate power on the platform. Most of the power requirement is to drive electric compressors, which are used to inject the gas back into the formation at high pressure. The power generation units on the platform are dual fuel capable (natural gas or diesel). The gas compression facilities have four stages of compression, with the lower stage being electric and the high stage being gas powered.

Due to the long distance from markets, there are no immediate firm projects to connect offshore Newfoundland gas to markets. However, this is being discussed as something that may occur in the future.

- JF

Year 2000 Thank You

When the federal government formed the National Contingency Planning Group (NCPG) in the fall of 1998, Natural Resources Canada (and ultimately the Natural Gas Division) was selected to be the federal government's window on the Y2K preparedness of the Canadian energy sector (electricity, crude oil / petroleum products, and natural gas).

Appendix

A problem like Y2K, with its potential for large-scale disruption, places on governments an enormous requirement for information gathering. While this information is needed for planning purposes, it is just as importantly required for reassuring various entities that the problem is being well-managed. For NRCan that meant communicating with the NCPG, the central agencies of the federal government, the various departments with operational responsibilities (Public Works, Industry Canada, Foreign Affairs), provincial government Y2K planners, international organizations (the IEA, G8, APEC), and the government of our principal export market, the United States.

NRCan is very grateful to the energy companies that participated in our Y2K readiness surveys, and to their associations for their co-ordination efforts. Our first survey reached over 500 companies, many of which were local electricity distributors who were subsequently removed from the survey when shown to have no Y2K exposure. At the end of our survey work in the fall of 1999, 110 companies were still participating.

All of our survey results were processed and forwarded to the NCPG for use in the NCPG's nation-wide risk assessment of all critical Canadian infrastructure. The NCPG used a modified Gartner methodology to determine whether a sector was behind or ahead of schedule in its Y2K remediation and contingency planning. Our results showed the energy sector to be consistently ahead of schedule, which resulted in a "low-probability-of-failure" designation in each of the NCPG's successive risk assessments. This was echoed by a Statistics Canada survey in early 1999 that showed the energy sector trailing only the highly computer-dependent financial sector in its Y2K readiness.

NRCan also thanks the energy associations for arranging a number of information sessions in Ottawa to keep federal and provincial government officials up to date on the energy industry's Y2K efforts and progress. These presentations provided a strong reassurance to governments, and shifted the focus of concern onto non-energy sectors that were not as advanced on Y2K.

Like Y2K staff throughout Canada that spent a long and uneventful night on 31 December 1999, the high point of NRCan's Y2K efforts came earlier in the year during the federal governments' contingency planning test in September 1999. "Exercise Validex" was a joint exercise of the NCPG and Emergency Preparedness Canada to test the federal government's ability to track Y2K events, analyse the impacts, and develop responses. Not surprisingly, many of the simulations during Exercise Validex were related to energy; not because energy supplies were expected to fail, but because the consequences would have been so widespread had this happened.

Again, our sincere thanks for all of the assistance we received from the energy industry in 1999 on Y2K.

- BA

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