Canadian Natural Gas

Review of 1998 & Outlook to 2005

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Natural Gas Division
Energy Resources Branch
Energy Sector
Natural Resources Canada

Foreword

Canadian Natural Gas: Review of 1998 & Outlook to 2005 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, including demand, supply, storage, gas flows, prices, transportation capacities, as well as Canadian gas export volumes, prices, and revenues.

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

The *Review & Outlook* was redesigned this year for easier reading. The conclusions are summarized in the Executive Summary. The balance of the report provides further details through tables, graphs, and short explanations on each subject area. All prices are shown in US dollars unless otherwise indicated.

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).

To obtain a copy of this report, call (613) 992-9612 or fax your request to (613) 995-1913. The report is also available at www.nrcan.gc.ca/es/erb/ngd/, as are other Natural Gas Division reports.

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Executive Summary

Executive Summary

1998 In Review

Entering 1998, the outlook for North American oil and gas producers was promising. Prices were fairly high; natural gas was at $2.58/MMBtu (December NYMEX close), and crude oil was $18.30/barrel (West Texas Intermediate). While the 1997/98 winter had been a warmer than normal “El Niño” event, the upcoming winter was predicted to be a colder “La Niña” winter.

Gas demand was forecast to rise by 2% per year, mainly due to growing demand for gas for electric power generation. Gas prices were expected to remain strong, and gas-directed drilling was high as a result. In Canada, natural gas prices, at $1.24/MMBtu, were still much lower than NYMEX prices, but it was widely expected that new export pipeline capacity would narrow the price spread.

By the end of 1998, only the last prediction — of a narrowing Canada-US price differential — had materialized. Events combined to bring lower prices, lower demand, and lower gas drilling in 1998 than in 1997.

The first major event was the loss of over 500 Bcf of heating load, caused by another warm winter. Compounding this was a marked drop in industrial demand. US industrial demand fell 381 Bcf, while Canadian industrial demand fell 87 Bcf. In total, US gas demand fell by 683 Bcf, while Canadian demand fell by 192 Bcf.

Another key event in 1998 was the fall in world crude prices, and the dawning realization that they would remain low for some time. West Texas Intermediate (WTI) tested the $10/bbl level but averaged $14.40/bbl, 30% less than in 1997.

The crude oil price collapse had several effects: petroleum products became more competitive with gas in certain industrial markets, reducing gas demand; North American gas prices were dragged down; and cash flows were reduced for natural gas producers (most of whom have considerable oil production), causing reduced 1998 gas drilling and development activity.

A major background factor in gas markets in 1998 was the buildup of wellhead productive capacity that had occurred over 1996-98, particularly in the US Gulf Coast. High levels of gas drilling from 1996 through the first half of 1998 created wellhead capacity that was surplus to market needs.

Storage inventories swelled to reflect weak demand and production overcapacity. US gas in storage by January 1st, 1999 was 2,645 Bcf, 587 Bcf higher than the previous year. Canadian storage volumes also swelled, reaching 427 Bcf on January 1st, 1999, compared to 341 Bcf a year previous.

Surplus gas, weak demand, high storage levels, and low oil prices pulled US gas prices down in 1998. Average NYMEX gas prices in 1998 were 19% lower than in 1997. While the peak NYMEX settlement price in 1997 (in January) was $4.00/MMBtu, the 1998 peak (in July) was only $2.36/MMBtu.

With weaker prices, US gas drilling fell dramatically. By the end of 1998, Gulf offshore gas drilling was down 36% from peak levels reached in 1997. As in other periods of weak gas prices and low drilling, production was flat or falling in the high-cost areas of the US Gulf Coast and Midcontinent (rising 1 Bcf and falling 132 Bcf, respectively), while production in the low-cost Rockies and Western Canada areas increased by 172 and 110 Bcf, respectively.

Canadian gas prices (i.e. the AECO spot price) entered 1998 at $1.24/MMBtu (Cdn$1.68 per Gigajoule), which was less than half of the December 1997 NYMEX price. This changed in late 1998 with the completion of the 690 MMcf/d expansion of the Northern Border pipeline and the 320 MMcf/d expansion of TransCanada PipeLines Ltd. (TCPL).

The Canadian gas market situation switched from one of a known surplus to a perception that domestic gas buyers would have to compete with US buyers for limited Canadian supplies. Canadian gas prices began to be determined in the US, in US dollar terms, rather than in Canada.

The NYMEX/AECO gas price differential reflected this, narrowing dramatically over the year. In December 1997, the AECO price was $1.34 lower than the NYMEX price. By December 1998, AECO was only $0.23 lower than NYMEX.

Ordinarily, this would have implied a sharp increase in Canadian prices, but the “re-linking” of Canadian and US gas prices occurred at a time of falling US prices. The net effect was that Canadian prices were only 2% higher in 1998 than in 1997 on a US$/MMBtu basis. The weakening Canadian dollar however, meant that in $Cdn/GJ (the basis for most domestic gas purchases), Canadian prices rose 9%, from Cdn$1.75 to Cdn$1.92.

The tightening of gas supply in Alberta in late 1998 may have been as much a matter of perception as reality. In 1998, Alberta gas storage was full, and gas supplies were sufficient to meet domestic demand and fill export pipeline capacity. For example, despite the large increase in Northern Border’s capacity, the pipeline's load factor has remained at about 97% since its expansion.

In addition, measurements of gas well productive capacity by the Alberta Energy & Utilities Board show that the large margin between productive capacity and demand is being maintained.

Unlike their US counterparts, Canadian producers continued to drill large numbers of gas wells in 1998. Total Canadian gas completions in 1998 were 4,600 wells, similar to 1997. That number would probably have been higher except that producer cash flows fell due to lower oil prices, which put a drag on gas activity.

In 1998, Canadian gas export volumes to the US rose 6%, or 188 Bcf. Although export pipeline capacity increased by 1 Bcf/day in 1998, this capacity did not come online until late in the year. Exports increased primarily by using existing capacity throughout the year at even higher load factors than in 1997. Exports now represent 54% of Canadian gas production, the highest percentage in history.

Although domestic Canadian gas prices rose in 1998 to meet US price levels, the US price decline meant falling prices and netbacks for Canadian exporters. Average export prices at the international border fell to $1.91/MMBtu, a drop of 10% from 1997. Netbacks likewise fell 10% to $1.58/MMBtu.

On average in 1998, export netbacks remained well above netbacks for gas sales within Canada, which were $1.26/MMBtu. This year, the US Northeast provided the highest netbacks to Canadian producers, averaging $1.67/MMBtu. However, with the narrowing of the Canada-US price differential, by November 1998 domestic netbacks reached parity with export netbacks.

Overall, the impact of higher volumes and rising domestic prices overwhelmed the impact of lower export prices, and plant gate revenues to Canadian producers rose slightly to Cdn$12.3 billion in 1998, from $12.1 billion in 1997.

Near Term Outlook (to 2000)

In the near term, a rapid change in market conditions is possible. The recent lows in US oil and gas prices have drastically reduced gas drilling and excess productive capacity. US gas prices are now vulnerable to a sharp upward shift. A return to normal winter weather would add about 180 Bcf to North American demand — colder than normal weather would add even more. Finally, increases in world oil prices (which appear to be happening) could lead to certain industrial consumers switching back to gas.

This price spike scenario could be intensified if US gas storage operators decide to fill storage to lower levels than last year. Operators were stung last year by receiving prices for gas withdrawn from storage that were lower than original purchase prices.

Medium Term Outlook (to 2005)

Our medium term outlook (to 2005) has changed only slightly from last year. Our working hypothesis — shared by many in the gas industry — is that demand will continue to rise by about 2% per year, driven mainly by increases in the Utility Electric Generation (UEG) and industrial sectors. The largest increases in annual demand will occur in the US Gulf Coast, Canada, US Northeast, Midwest, South Atlantic, and West.

Most of the additional supply is expected to come from three areas: the Gulf Coast (annual production rising 1,858 Bcf over the 1998–2005 period), Canada (increasing 1,553 Bcf), and the Rockies (increasing 780 Bcf). Regarding gas flows along pipelines, our base scenario is as follows:

Increased **Rockies** production will satisfy most incremental demand in the US West (520 Bcf) and in the Rockies itself (166 Bcf). Canadian pipeline capacity to the US West is already relatively full, and no new capacity is expected. Besides, during 1998 the US West was the lowest netback export market for Canadian gas producers.

Higher production from the **Gulf Coast** will satisfy all incremental demand in the South Atlantic (615 Bcf), in the Gulf Coast itself (748 Bcf), and in the Midcontinent (108 Bcf), and will also replace the loss of 407 Bcf of Midcontinent production. In total, these areas will absorb virtually all of the projected increase in Gulf Coast production.

Higher production in **Canada** will satisfy increased gas demand in the Midwest (795 Bcf), Northeast (791 Bcf), and Canada (785 Bcf). Pipelines from Western Canada to the Midwest, Northeast, and Eastern Canada are being built to capture markets in these areas.

On the price side, the Gulf Coast (NYMEX) is expected to continue to be the benchmark North American gas price. The Gulf Coast is a high-cost supplier, and is the marginal supplier to most North American markets. Gulf coast gas is the last gas that must be purchased to balance the market, and thus sets the marginal price in the market.

Executive Summary

As long as a market area requires some supply from the Gulf, the gas price in that market will be linked to the Gulf price. We expect prices in the US West, Midwest, Northeast, Gulf Coast, and South Atlantic to continue to be driven off Gulf Coast pricing.

Canadian supply is expected to to be a price taker in Midwest and Northeast markets, as those markets will continue to need some Gulf Coast gas. Depending on supply development, prices in the Canadian market could maintain the linkage to US prices established in late 1998, or could again fall below US prices. This would happen if additions to Canadian supply capacity again result in capacity greater than the sum of all exit pipelines plus Canadian demand.

A sampling of expert gas price forecasts shows US prices (NYMEX or wellhead) rising from an average of $2.11/MMBtu in 1998 to $2.60 (nominal) in 2005. Canadian prices are expected to rise from an average of $1.36/MMBtu (Cdn$1.92/GJ) in 1998 to $2.26/MMBtu (Cdn$2.74/GJ) by 2005.

Canadian gas exports are once again entering a period of sharp growth, due to recent and continuing pipeline construction. We expect exports to reach 3.9 Tcf by 2005.

With higher exports, continued domestic gas demand growth, and stronger US gas prices, the outlook is for strong growth in Canadian producer revenues. Revenues could be lower if domestic prices again become de-linked from US prices.

Producer plant gate revenues from export and domestic gas sales are expected to climb from Cdn$12.3 billion in 1998 to $19.7 billion by 2005.

Similarly, revenues to the Canadian pipeline sector will proportionally increase, due to higher throughput volumes.

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In 1998, total North American gas demand fell 875 Bcf, or 4%, compared to 1997. Canadian demand fell 192 Bcf, or 7%.

The largest demand loss was in the so-called "core market", due to warm winters of 1997/98 and 1998/99. The core market is composed of the residential and commercial sectors (space and water heating).

US industrial demand fell substantially (381 Bcf, or 4%) in 1998, following flat demand in 1997.

As with last year, US UEG (electric generation) demand was the only bright spot, showing growth of 291 Bcf, or 10%. UEG demand grew 9% in 1997.

Table 1:
North American Natural Gas Demand

	1998 (Bcf)	1997 (Bcf)	Difference (Bcf)	Change (%)
US Residential	4,506	4,984	-478	-9.6
US Commercial	3,085	3,223	-138	-4.3
US Industrial	8,462	8,843	-381	-4.3
US Electric Utility	3,259	2,968	291	9.8
US Gas Used in Operations	1,975	1,954	21	1.1
Domestic US Demand	**21,289**	**21,972**	**-683**	**-3.1**
US LNG Exports	66	62	4	6.5
US Exports to Mexico	50	38	12	31.6
Total US Gas Disposition	**21,405**	**22,072**	**-667**	**-3.0**
Cdn Residential	612	627	-15	-2.3
Cdn Commercial	399	413	-14	-3.5
Cdn Industrial	993	1,080	-87	-8.1
Cdn Electric Generation	170	184	-14	-7.6
Cdn Other	411	472	-61	-13.0
Total Cdn Demand	**2,585**	**2,777**	**-192**	**-6.9**
TOTAL N.A. DEMAND	**23,874**	**24,749**	**-875**	**-3.5**
TOTAL N.A. DISPOSITION	**23,990**	**24,849**	**-859**	**-3.5**

Sources: EIA Feb99 Natural Gas Monthly, NRCan/StatsCan Energy Statistics Handbook (Nov. and Dec. estimated). **NOTES:** Total North American gas disposition (23,990 Bcf) is 921 Bcf less than total North American supply (24,911 Bcf), due to accounting problems and storage changes. Canadian demand includes reprocessing shrinkage (taking ethane from pipeline gas).

The map at right shows the geographic location and sectoral type of gas demand in 1998.

The residential and commercial sectors have been combined into the core market.

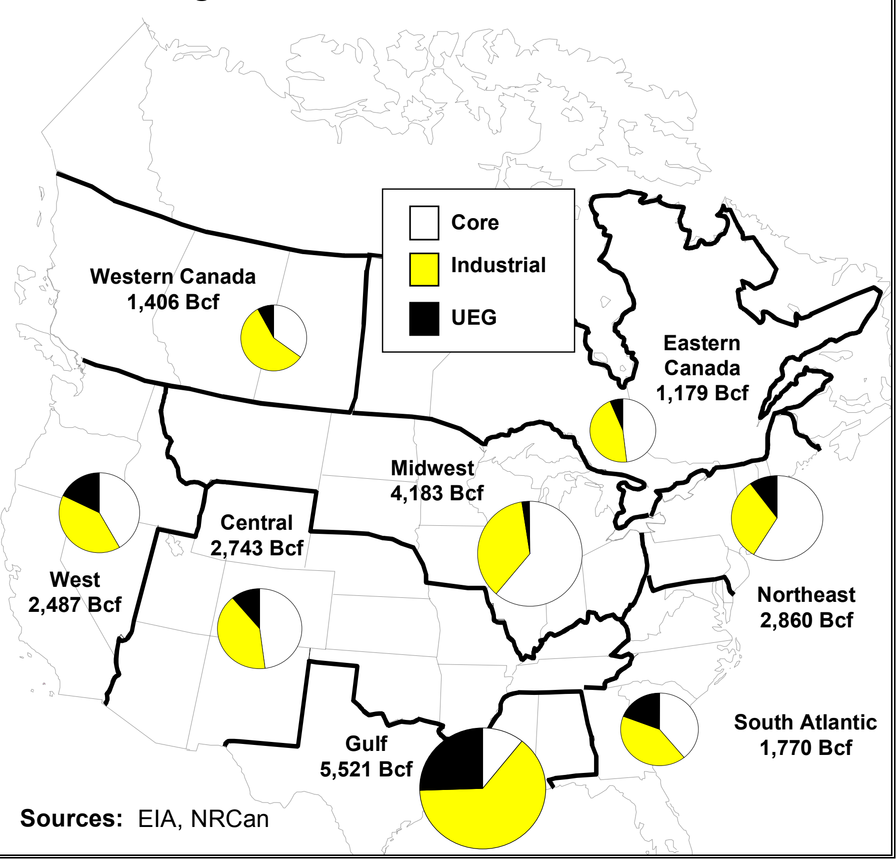
The top five geographic/sectoral gas demand loads are:

1) Gulf Coast industrial;
2) MW Core;
3) NE Core;
4) MW Industrial; and
5) Gulf UEG.

These account for 55% of North American end-use gas demand.

Note: US region totals are end-use demand only (excludes pipeline fuel), while Canadian region totals include all gas demand.

Figure 1: Gas Demand Distribution

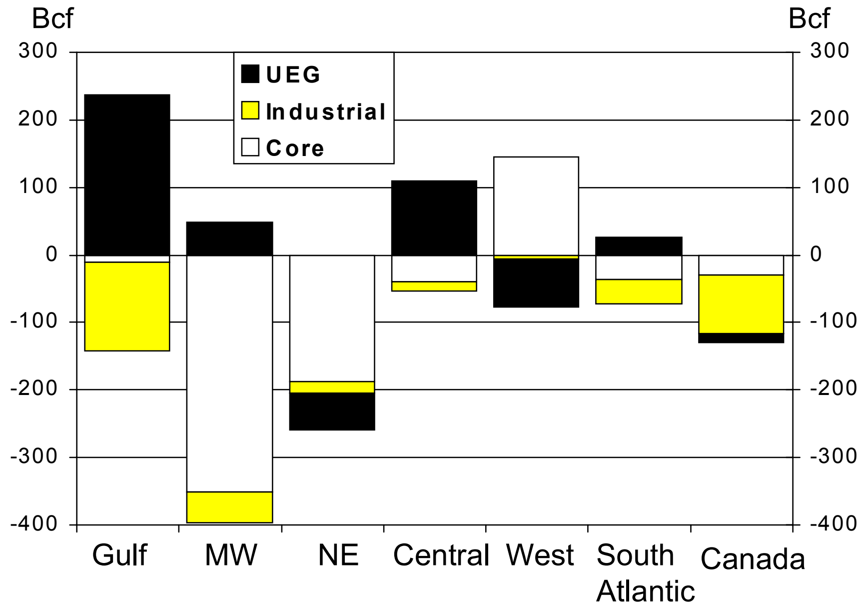


Sources: EIA, NRCan

In 1998, demand changes varied widely across regions and sectors. The largest changes were the loss of core market heating loads in the Midwest and Northeast, due to warmer winters in 1997/98 and 1998/99.
Core demand increased in the West due to colder weather, in marked contrast to events in the East.
Industrial demand fell in every region in North America. The major losses were in the Gulf, Canada, and Midwest.
UEG demand changes were generally positive — dramatically so in the Gulf (up 237 Bcf) and Central (up 109 Bcf) areas. UEG demand was down in the West due to increases in hydro generation, and down in the Northeast.
Demand in Canada was down across all sectors.

Figure 2:

Regional/Sectoral Demand Changes



Sources: EIA, NRCan. Note producer use & pipeline fuel is not shown.

The figure at right shows US heating degree days (HDDs) and core (residential and commercial sectors) gas demand.

US core demand is driven entirely by HDDs. Other factors (more efficient furnaces, new customers) balance each other out.

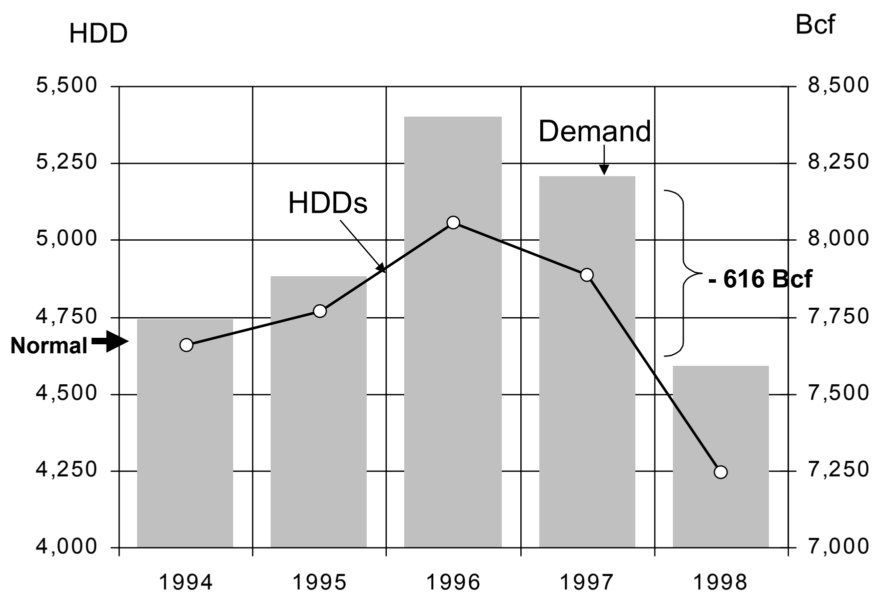
In 1998, US HDDs fell by 13%, due to warm winters in 1997/98 and 1998/99.

Core demand fell by 8%, or 616 Bcf. This drop is equal to 3% of total US gas demand. This loss of heating load was **the** major factor in North American gas markets in 1998.

The extreme loss of demand was due to a warmer than normal year (1998) following a colder than normal year (1997). A return to normal (or 40-year average) weather in 1999 would result in a US core demand increase of about 150 Bcf over 1998 levels.

Figure 3:

US HDDs & Core Demand



Sources: EIA, NOAA

Industrial gas demand figures as measured by EIA include gas used for industrial power generation, also called "non-utility generation".

Over the 1990–96 period, demand grew strongly, by 200 to 250 Bcf per year. Some of the growth was for power generation.

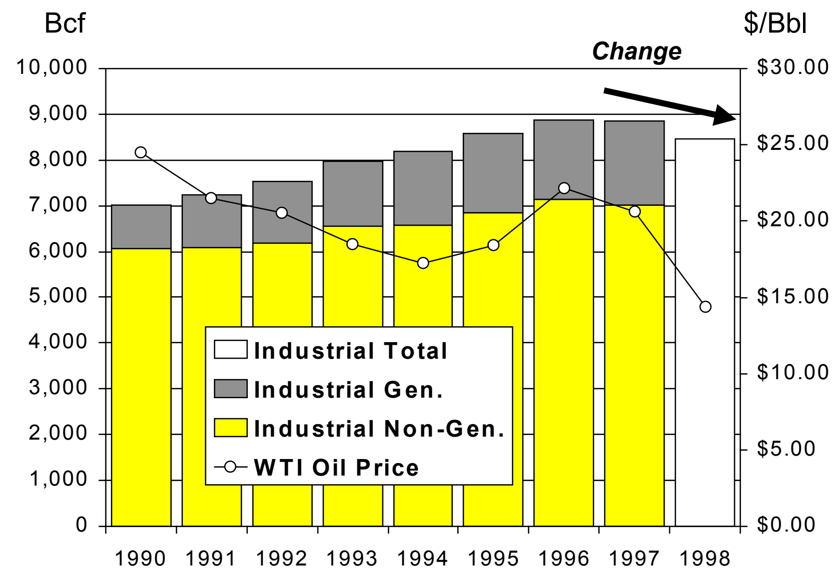
However, industrial gas demand growth has now stopped. US industrial demand has lost 408 Bcf from its peak in 1996.

The Gulf Coast accounts for 38% of total US industrial gas demand, and the largest industrial load losses in 1998 occurred there.

The single largest factor that can be identified to explain the loss in industrial load is the collapse of oil prices. WTI oil prices went from $21.31 per barrel in October 1997 to $11.31 in December 1998.

Figure 4:

US Industrial Gas Demand



Sources: EIA, PIRA

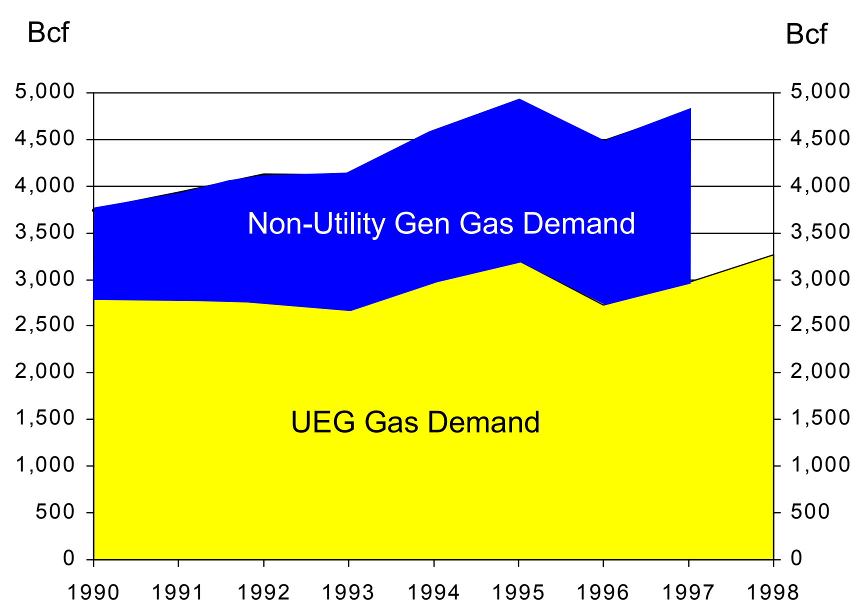
The gas demand figures used by EIA for power generation include only utility electric generation (UEG) and exclude industrial generation/non-utility generation.

The graph shows both UEG gas demand and non-utility generation demand. Most power generation demand growth has been non-utility. Industrial/non-utility power generation gas demand is shown here because it will be harder to separate it from UEG demand in the future. This is due to utilities selling power plants to non-utility companies and other factors. Non-utility demand for 1998 is not yet available.

UEG demand has now grown for the second straight year. Over 1996–98, UEG demand grew 527 Bcf, averaging 9% growth per year.

Figure 5:

US Power Generation Gas Demand



Source: EIA, PIRA

The industrial sector is by far the most important demand segment in Western Canada. This includes industries such as pulp and paper, mining and metalworking, fertilizer and cement production, petrochemicals (such as methanol and ethylene), enhanced oil recovery, bitumen mining, and oil refining.

Western Canadian gas demand was down 6% in 1998. Most of the reduction in demand occurred in the industrial sector. Core demand dropped slightly due to a 3% fall in HDDs.

The UEG sector (utility electric generation) includes all gas transformed into electricity.

Other refers to pipeline fuel and “reprocessing shrinkage”, which is a form of gas demand. Shrinkage occurs when straddle plants take ethane out of the pipeline gas.

Table 2:

Western Canadian Gas Demand Bcf

1998	Residential	Commercial	Industrial	UEG	Other	Total
January	42.1	23.9	62.7	8.5	36.7	**174.0**
February	31.1	17.7	46.1	6.3	29.7	**130.8**
March	33.4	18.8	49.7	6.8	33.1	**141.7**
April	16.6	10.1	49.4	8.3	23.1	**107.6**
May	14.8	9.0	43.4	7.4	21.7	**96.4**
June	13.3	8.0	40.0	6.7	19.5	**87.6**
July	7.7	4.3	40.5	8.9	26.2	**87.5**
August	7.8	4.3	41.4	9.0	29.0	**91.5**
September	8.3	4.5	43.3	9.4	28.3	**93.7**
October	20.9	12.1	45.8	7.8	26.2	**112.9**
November	28.9	16.6	48.3	8.7	28.3	**131.0**
December	37.8	21.7	52.2	9.6	29.9	**151.3**
Total 1997	260.9	151.5	604.8	102.9	371.0	**1491.2**
Total 1998	**262.7**	**151.1**	**562.8**	**97.5**	**331.8**	**1406.0**
Difference	1.8	-0.4	-42.0	-5.4	-39.2	**-85.2**
% change	**0.7%**	**-0.2%**	**-6.9%**	**-5.3%**	**-10.6%**	**-5.7%**

Source: Energy Statistics Handbook. November and December estimated.

The most important markets in Eastern Canada are core markets (residential and commercial sectors). In 1998, core demand fell 5%, due to a 19% drop in HDDs.

The next largest sector is the industrial sector, including pulp and paper, mining and metalworking, fertilizer and cement production, petrochemicals, auto and auto parts manufacturing, and other industries.

Gas transformed to electricity (UEG) fell 11%, due mainly to a rise in gas prices.

Other mainly refers to pipeline fuel. Other demand in some months is negative. This is due to measurement differences in the StatsCan data.

Total Eastern Canadian gas demand was down 8% in 1998.

Table 3:

Eastern Canadian Gas Demand Bcf

1998	Residential	Commercial	Industrial	UEG	Other	Total
January	55.4	38.4	46.4	6.1	8.9	**155.3**
February	48.8	33.2	40.8	5.5	7.6	**135.9**
March	50.1	34.6	42.3	5.6	7.8	**140.4**
April	29.3	19.6	43.1	7.3	-0.7	**98.7**
May	22.2	14.8	32.5	5.5	-0.5	**74.6**
June	17.1	11.8	25.9	4.1	-0.2	**58.7**
July	7.8	7.1	29.6	5.7	9.4	**59.6**
August	7.7	7.0	29.4	5.5	9.2	**58.8**
September	8.5	7.6	31.9	6.2	10.2	**64.3**
October	20.3	16.0	27.9	5.0	9.2	**78.4**
November	36.1	25.3	37.9	7.2	8.4	**115.0**
December	46.2	32.2	42.4	8.7	9.4	**139.1**
Total 1997	366.2	261.9	475.4	80.8	101.0	**1285.4**
Total 1998	**349.7**	**247.8**	**430.2**	**72.3**	**78.8**	**1178.7**
Difference	-16.5	-14.1	-45.3	-8.5	-22.2	**-106.7**
% change	**-4.5%**	**-5.4%**	**-9.5%**	**-10.5%**	**-22.0%**	**-8.3%**

Source: Energy Statistics Handbook. November and December estimated.

Review of 1998

Natural Gas Production

- Total 1998 Production
- Regional Gas Production
- US Gas Drilling
- Gulf Coast Gas Deliverability
- Gulf Coast Reserves Trends
- Western Canadian Gas Drilling
- Alberta Gas Deliverability
- Western Canada Reserves Trends

During 1998, total North American gas supply grew only 155 Bcf, or 0.6%. Production is driven by gas demand. With lower gas demand in 1998, production increases simply were not needed.

Given that demand fell, the production increase was due to year-on-year growth in storage inventories. There are also accounting problems — production net of storage changes does not match demand.

Due to the importance of regional prices, regional production statistics are shown.

Regional drilling and production statistics are also desirable given the vast differences in well productivity from region to region (for example, Midcontinent wells average only 125 Mcf/day, while Gulf offshore wells average 3,600 Mcf/day, or 29 times as much).

Table 4:
Total 1998 Production

	1998 (Bcf)	1997 (Bcf)	Difference (Bcf)	% Change
Gulf Onshore	6,829	6,684	145	2.2
Gulf Offshore	5,001	5,145	-144	-2.8
Total Gulf	11,830	11,829	1	0.0
US Midcontinent	2,332	2,464	-132	-5.4
US Rockies	3,161	2,989	172	5.8
Other US	1,605	1,622	-17	-1.1
Total US Production	**18,927**	**18,903**	**24**	**0.1**
Canadian Production	5,765	5,655	110	1.9
LNG & Mexican Imports	102	95	7	7.4
Supplementals	117	103	14	13.6
TOTAL N.A. SUPPLY	**24,911**	**24,756**	**155**	**0.6**

Sources: EIA March 1999 Natural Gas Monthly, StatsCan/NRCan, MMS. **Note:** Gulf Offshore includes only the Gulf of Mexico OCS. Data to November 1998 from MMS, December estimated. Canadian marketable production from StatsCan. StatsCan normally shows production net of reprocessing shrinkage. These figures are before reprocessing shrinkage.

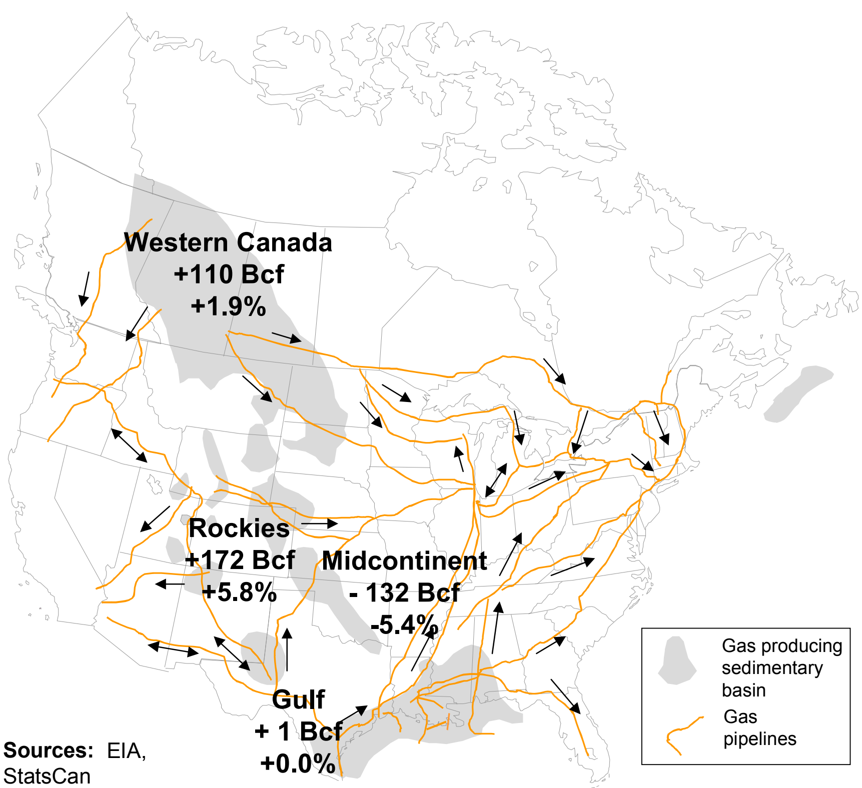
In 1998, Rockies producers (Colorado, Wyoming, Utah, and New Mexico) took advantage of enhanced pipeline access to markets (see pipeline section), and increased production by 172 Bcf, or 6%.

Midcontinent (Arkansas, Kansas, Oklahoma, Missouri) production fell 132 Bcf, or 5%. Given recent gas prices, producers in this area cannot replace production. Production has fallen substantially every year since 1993.

Western Canadian production increased only 110 Bcf (2%). Growth was hampered by a lack of export capacity and weak domestic demand.

Gulf (Texas, Louisiana, Alabama, and Mississippi) production was flat, due to weak demand and lower prices. With lower prices, producers in this region reduced drilling and production activity.

Figure 6: Regional Gas Production



Sources: EIA, StatsCan

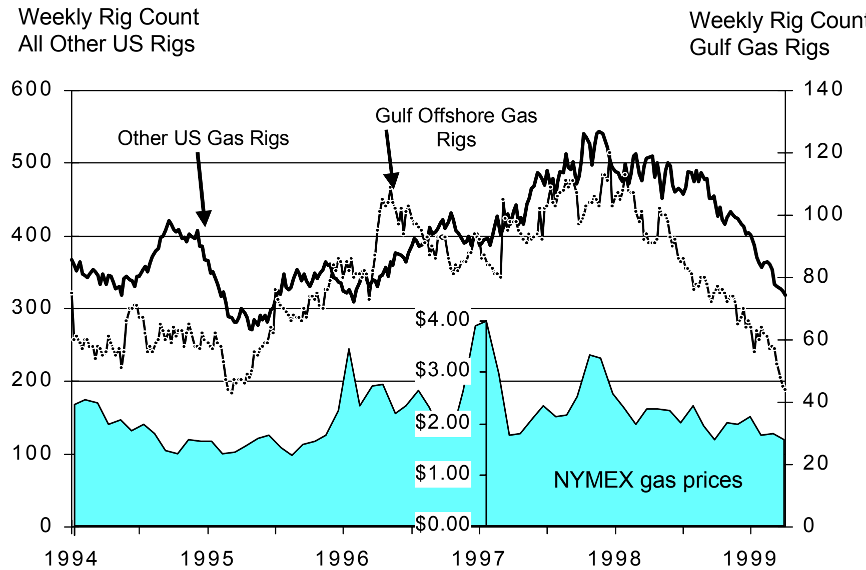
High gas drilling rates of 1996 and 1997 mean that a considerable oversupply was built during this period. In 1998, US gas drilling fell dramatically in response to lower prices.

Activity peaked in late 1997 with 110 gas rigs drilling in the Gulf Offshore and 540 rigs drilling in the rest of the US. Gas drilling by early 1999 was down about 40% from peak levels, close to the depressed levels of 1994 and 1995.

Production capacity from currently flowing gas wells declines rapidly (by up to 40% per year). This means that reduced drilling quickly results in lower production capacity.

The rapid drop-off in US gas drilling is now eroding the oversupply of gas in North America.

Figure 7: US Gas Drilling



Source: Baker Hughes

A supply surplus has been developing in the US since late 1996.

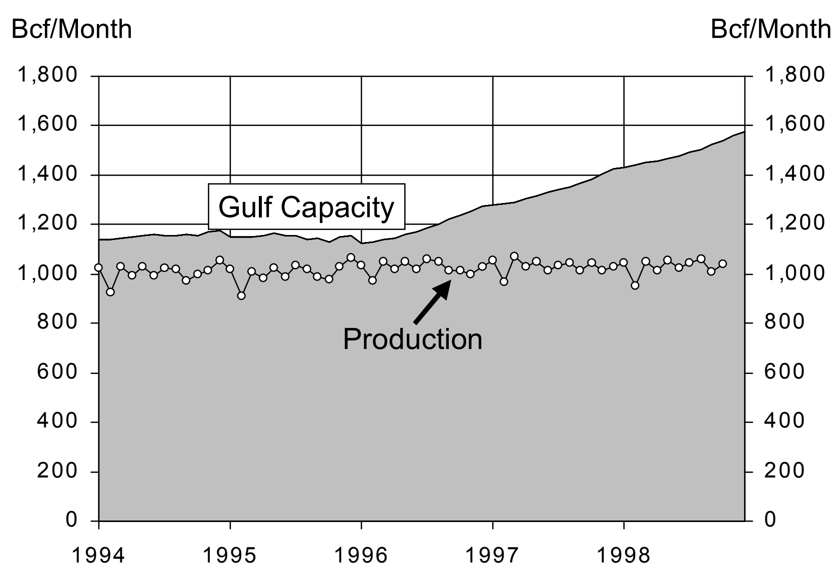
The figure at right shows EIA estimates of Gulf Coast gas production capacity. Numbers for 1996–98 were estimated by EIA from recent drilling trends. Gulf Coast capacity is shown since it accounts for over half of US production.

EIA's low capacity case is shown. Given the scale of the drilling slowdown, this case probably shows capacity numbers which are too high, particularly for 1998.

US gas drilling reached high levels by mid-1996, causing a rapid buildup in Gulf capacity.

This extra capacity was not needed by markets, and production was flat over the period.

Figure 8: Gulf Coast Gas Deliverability



Source: EIA

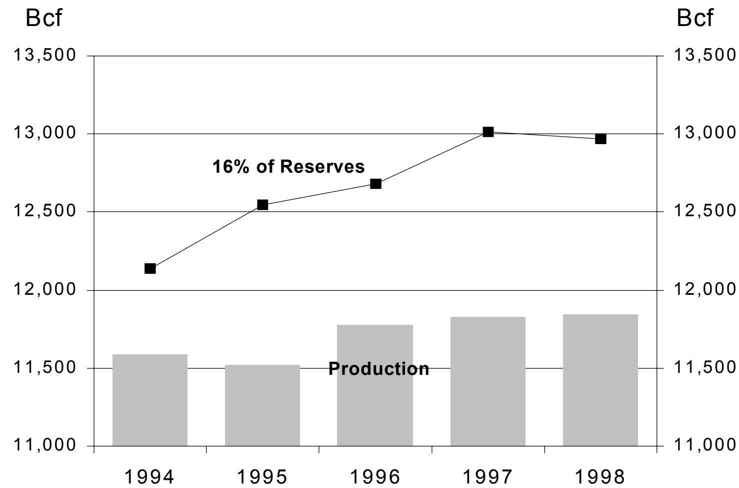
Another way to look at gas supply is via proved reserves trends. Proved reserves include gas in already drilled wells and are the volumes of gas expected to be recoverable under current or anticipated technological and economic conditions.

The table shows total Gulf reserves, reserves added, and production. Also shown is the ratio of reserves to production and the percentage of reserves which are produced each year. Gulf production has never exceeded 16% of reserves. This may be a rough indication of the productive capacity of Gulf reserves.

As the graph shows, Gulf reserves have been rising fast enough so that production remains well below “reserves capacity” (i.e., production remains less than 16% of reserves).

Figure 9: Gulf Coast Reserves Trends

Year	Jan.1 Reserves (Bcf)	Avg. Weekly Gas Rigs	Reserves Added (Bcf)	Dry Prod'n in Year (Bcf)	R/P Ratio (Years)	% Reserves Produced in year
1994	75,873	61	14,134	11,587	6.5	15.3%
1995	78,420	63	12,364	11,520	6.8	14.7%
1996	79,264	91	13,845	11,780	6.7	14.9%
1997	81,329	99	11,549	11,829	6.9	14.5%
1998	81,049	89	na	11,830	6.9	14.6%



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

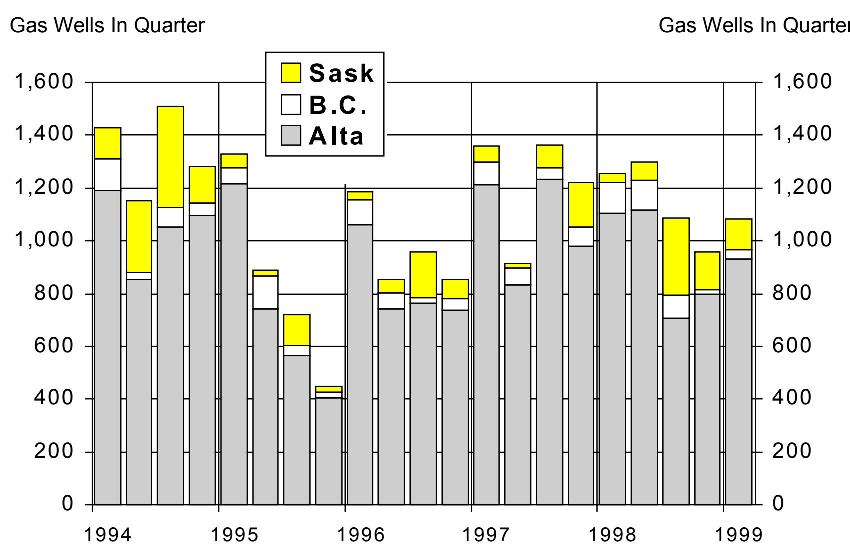
In 1998, Canadian gas drilling totalled 4,600 wells, similar to 1997, and close to all-time high levels. The most gas wells ever drilled was in 1994, when over 5,000 wells were completed.

Gas drilling would probably have been higher, if not for weak oil prices, which dramatically cut producer cashflows and hindered equity and debt financing. As a result, some producers have had difficulty finding cash to invest in gas drilling.

But given a choice in the low oil price environment, firms with both oil and gas properties have chosen to drill for gas instead of oil. Oil well drilling dropped by over 40% in 1998.

Figure 10:

Western Canadian Gas Drilling



Source: Nickles Daily Oil Bulletin

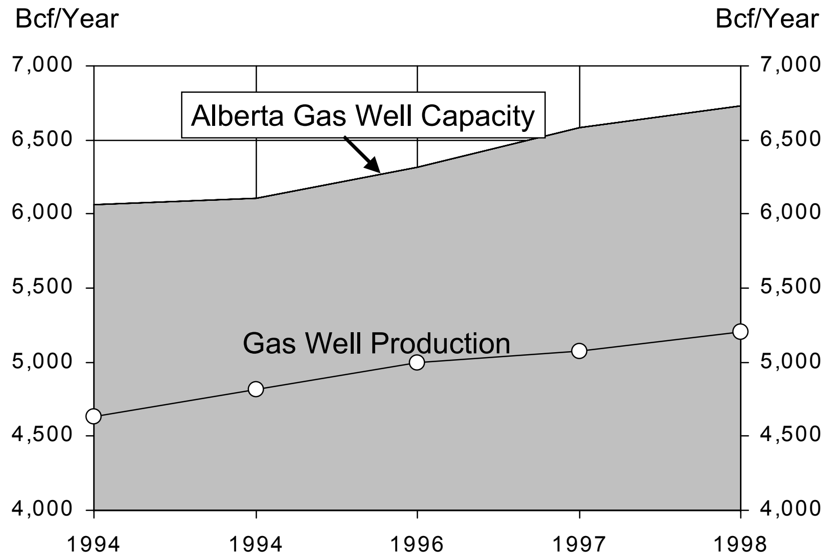
Alberta raw gas production increased 12% from 1994–98. However, capacity increases appear to have kept pace with production.

The figure at right compares Alberta gas well productive capacity to actual production rates. Volumes are on a "raw gas" basis, i.e., before processing shrinkage.

Productive capacity is determined by the Alberta Energy and Utilities Board in the following manner. First, the average production rate of each Alberta gas well, for those hours when it was in production, is calculated. Then, it is assumed all wells could produce at their average rate for the full year.

Due to pipeline expansions, Canadian gas production is expected to rise about 600 Bcf in 1999. This will bring Alberta considerably closer to production capacity.

Figure 11: Alberta Gas Deliverability



Source: Alberta Energy and Utilities Board

Canadian gas reserves have fallen by more than 6 Tcf since 1994. This was due to reserves originally booked in the 1970s and 1980s being downgraded. These negative revisions took 6.7 Tcf off the books between 1995–97.

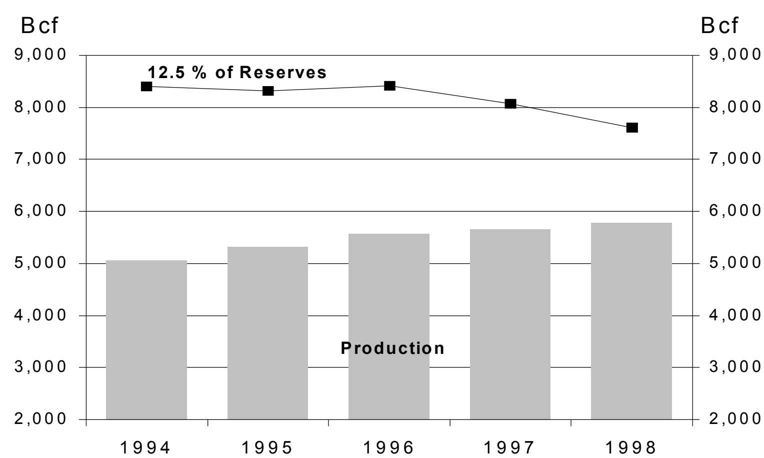
Before negative revisions, reserves added over 1994–97 were about equal to production. Reserves fell entirely due to revisions to old fields. Additions to reserves shown are before revisions.

The graph shows a line equal to 12.5% of Canadian reserves (i.e., an 8-year reserves-to-production ratio). This line approximates the production capacity of Canadian reserves. Canadian reserves are still of sufficient size to support increased production. If production began to exceed 7.5 Tcf per year, higher reserves levels would be necessary.

Figure 12: Western Canada Reserves Trends

Year	Jan.1 Reserves (Bcf)	Gas Wells Drilled	Reserves Added (Bcf)	Dry Prod'n in Year (Bcf)	R/P Ratio (Years)	% Reserves Produced in year
1994	67,313	5,333	3,980	5,098	13.2	7.6%
1995	66,195	3,324	6,977	5,321	12.4	8.0%
1996	67,352	3,664	5,534	5,564	12.1	8.3%
1997	64,213	4,819	5,040	5,652	11.4	8.8%
1998	60,600	4,600	na	na	na	na

Notes: Includes Alberta, Saskatchewan and British Columbia. Converted from cubic metres @ $1M^3 = 35.30096\ FT^3$. CAPP production numbers are slightly different from StatsCan.



Source: CAPP

Review of 1998

Natural Gas Storage

- US Gas Storage
- Western Canada Gas Storage

Figure 13 shows the weekly volumes remaining in gas storage over various injection/withdrawal seasons. Gas is pumped underground over the April – October period and withdrawn from November – March.

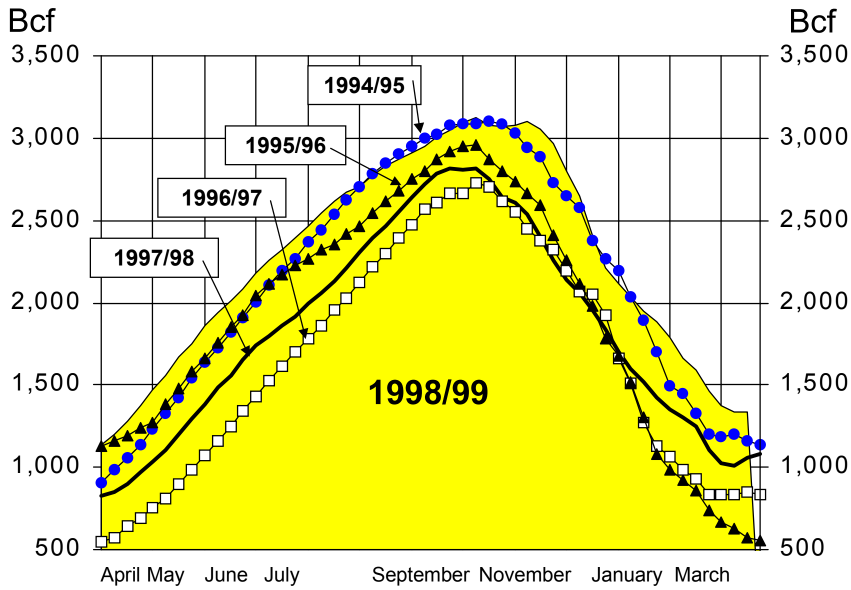
Since the 1994/95 storage year, US operators have been generally getting by with less storage — filling storage less each year and pulling storage down to lower volumes at the end of each withdrawal season.

In 1998/99, operators filled storage to high levels not seen since 1994/95. Anticipation of a La Niña winter (colder than normal) may have accounted for this activity.

However, the 1998/99 winter was warmer than normal, and by the end of the withdrawal period, US gas in storage was still at very high levels.

Figure 13:

US Gas Storage



Source: AGA

Western Canadian storage has the largest impacts on Canadian markets and prices. Eastern Canadian storage is just as large, but Eastern Canada is not a major gas market pricing point yet.

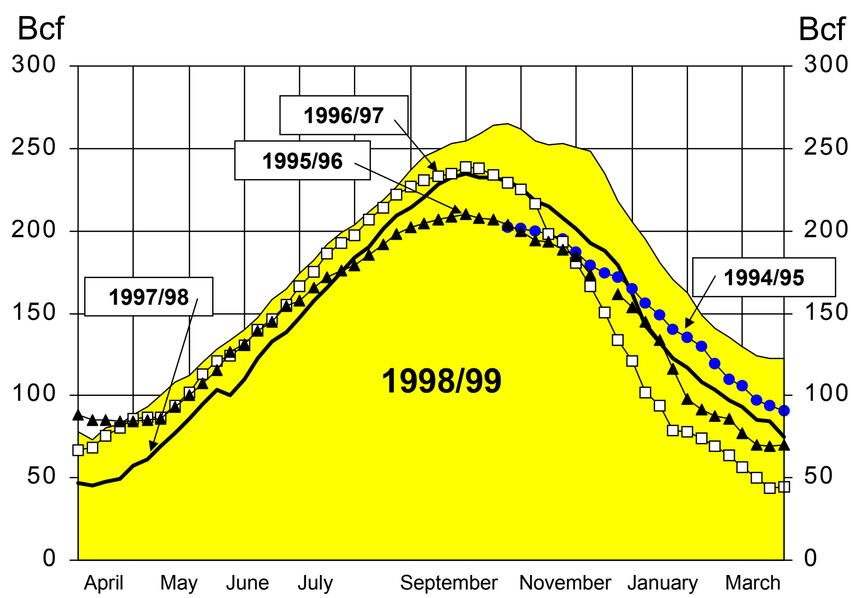
In Western Canada, gas in storage reached new record highs in 1998. This reflected, in part, the addition of some new capacity.

Full storage is another indication of surplus gas production capacity. Under the 1998/99 weather pattern, Canadian producers filled all exit pipelines and still had supply available to fill storage.

Nearing the end of the withdrawal season, there were still historically high amounts of gas in Canadian storage. This will tend to moderate gas prices in the near term. It also makes it easier for producers to fill the Northern Border and TCPL expansions of late 1998.

Figure 14:

Western Canada Gas Storage



Source: CGA

Review of 1998

Natural Gas Prices

- NYMEX Henry Hub & Alberta Monthly Gas Prices
- Alberta Monthly & Daily Gas Prices
- Canada/US Exchange Rates
- Regional Gas Price Trends

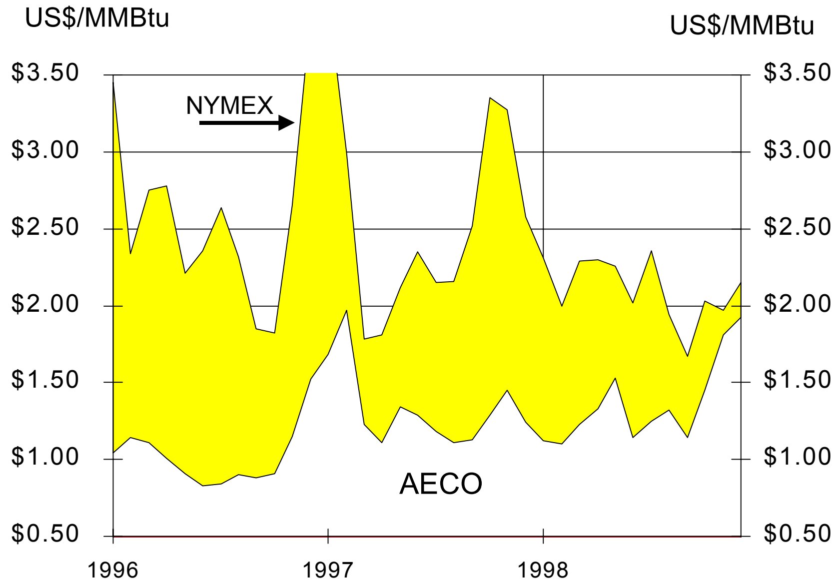
Average 1998 Henry Hub prices were ***19% lower*** than in 1997. Good prices in the previous two years led to high drilling levels and additional supply development (especially in the deepwater Gulf Offshore). This extra supply, combined with a huge drop in demand due mainly to weather, led to the price decline.

Prices in Alberta, on a US$/MMBtu basis, were flat in 1998, averaging $1.36 compared to $1.34 last year. Alberta prices are closer to NYMEX prices than in the previous four years.

This is due to recent large pipeline expansions. Now, to balance Canadian supply and demand, some Canadian customers must outbid US buyers, and cause some pipe to the US to remain unfilled. This dynamic has forced a strong linkage between US gas market prices and prices in Alberta.

Figure 15:

NYMEX Henry Hub & Alberta Monthly Gas Prices



Source: Canadian Natural Gas Focus

The graph at right shows Alberta gas prices on a Cdn$/Gigajoule basis. Both daily and monthly market prices are shown.

In Cdn$/GJ, gas prices in Canada rose to $1.92 average in 1998, up from $1.75 in 1997, for an increase of over 9%.

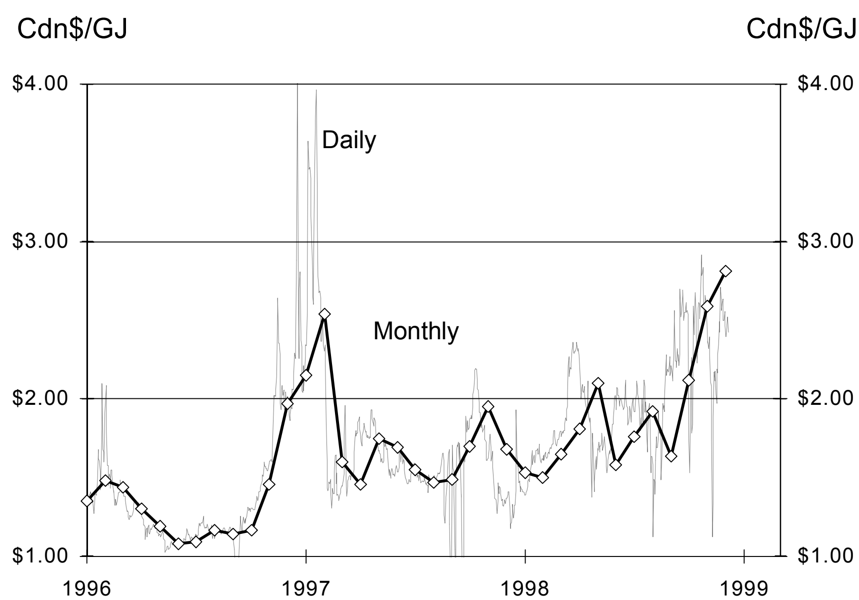
Gas prices in Canada, on a Cdn$ basis, are being pushed by three factors:

1) the strong link to US prices which kicked in in late 1998;
2) falling US prices; and
3) strong exchange rate movements.

Note: Daily price is AECO/NOVA Inventory Transfer price from Enerdata; monthly price is AECO from Canadian Natural Gas Focus.

Figure 16:

Alberta Monthly & Daily Gas Prices



Sources: Enerdata, Canadian Natural Gas Focus

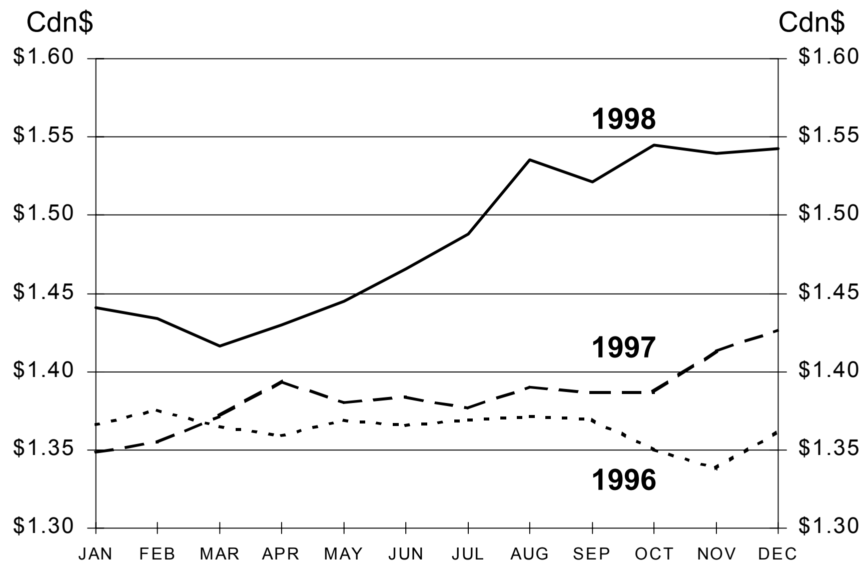
With the stronger link between Canadian gas prices and US prices which developed in 1998, this meant that Canadian gas prices were really being determined in the US, in US dollars.

In 1998, the US dollar gained strength over the Canadian dollar. This meant that Canadian buyers had to pay more for natural gas in 1998, solely due to exchange rate movements.

The effect can be seen in the following example. If Canadian gas prices are driven by the price in US markets (a US dollar price), and that price was US$2.00/MMBtu during 1997, this would mean a Canadian price of Cdn$2.62/GJ using the 1997 exchange rate. With the 1998 exchange rate, the price would be Cdn$2.81/GJ, or 7% higher.

Figure 17:

Canada/US Exchange Rates



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

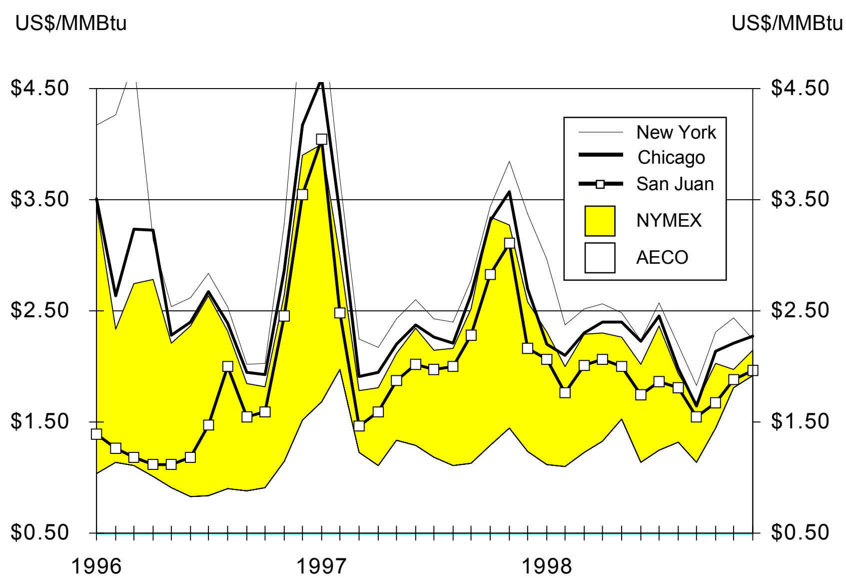
Regional gas price differentials underwent compression in 1998. In the mid-1990s large gas price differentials existed. These disappeared in 1998.

With large gas pipeline expansions occurring over the past five years, supply areas which had seen bottlenecked supplies, local gas surpluses, and very low prices are now well connected to the broader North American market.

For example, in early 1996 both San Juan (Western US) and Western Canadian gas prices were much lower than Eastern US prices. This is no longer the case.

Figure 18:

Regional Gas Price Trends



Source: Canadian Natural Gas Focus

Review of 1998

Gas Flows
& Pipeline Capacity

- Outflow From Supply Areas
- Major Pipeline Projects
- Gas Flows Along Pipeline Routes
- Northern Border/Foothills

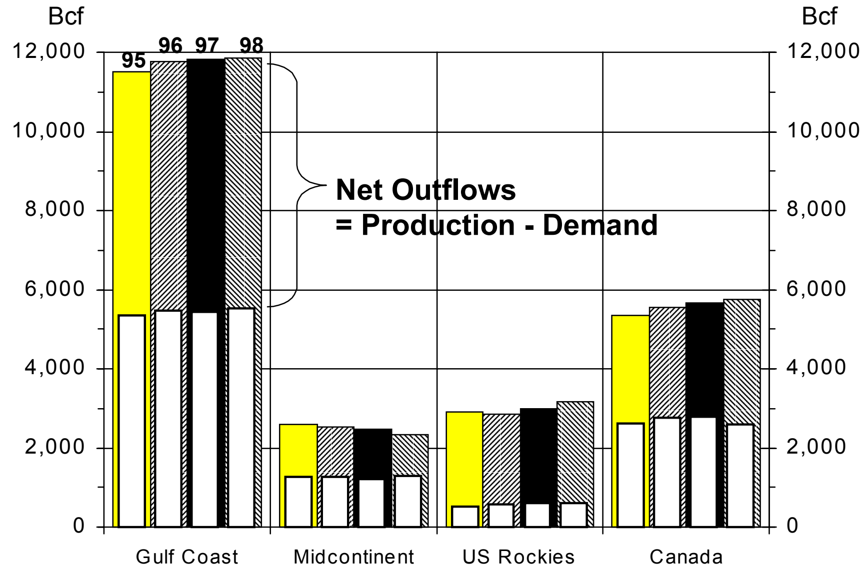
Net gas outflow is the positive difference between production and consumption within a supply region.

The biggest change in net outflows during 1998 was the additional 302 Bcf of gas flowing out of Canada. The increase of 10% over 1997 outflows was much greater than the increase in production, due to lower Canadian demand.

Some of this increased outflow replaced declining outflows and production from the Midcontinent, which flows mainly to the US Midwest and Northeast. Outflows from the Midcontinent fell by 17% in 1998.

Outflows from the US Rockies increased by 8%, or 177 Bcf, while Gulf Coast outflows decreased by 94 Bcf.

Figure 19:
Outflow From Supply Areas



Sources: EIA, StatsCan

Over 4.4 Bcf per day of additional capacity from major pipeline expansions was scheduled to come online in 1998.

Foothills/Northern Border was the largest pipeline expansion in 1998, adding 690 MMcf/d of new capacity from Alberta to Chicago on December 22, 1998.

TransCanada added 320 MMcf/d of new capacity, of which 232 MMcf/d was for exports. Some of this was required for expansions taking place further downstream, such as on the Portland Natural Gas Transmission System and on TransQuébec and Maritimes.

Construction was completed early in 1999 on the TQM Extension, adding 142 MMcf/d of new capacity to southeast Quebec and the US Northeast. Capacity on the pipeline is expected to increase to 210 MMcf/d by the end of 1999.

Table 5: Major Pipeline Projects

		Project Name	Capacity (MMcf/d)	Status
Canada	1	Foothills/Northern Border Pipeline	690	In service Dec 98
	2	TCPL 1998 Expansions	320	In service
	3	ANR/Foothills Expansion (PG&E GT-NW)	64	FERC conditionally authorized Aug 98
		New Canadian capacity:	**1,074**	
NE	5	PNGTS	178	In service
Gulf	6	Nautilus	600	In service
	7	Manta Ray Lateral	300	In service
	8	Discovery (Williams)		In service
	9	Gemini Expansion (Destin)	1,000	Under construction
	10	Mobile Bay Expansion (Williams)	350	In service
		New Gulf capacity:	**2,250**	
Rockies	11	Front Runner	254	FERC certificated Jul 98
	12	Front Range	269	In service
	13	TransColorado Pipeline	300	In service
	14	Powder River Basin (CIG)	52	In service
	15	Campo Lateral (CIG)	100	In service
		New Rockies capacity:	**975**	
		Total new capacity:	**4,477**	

Sources: Foster Natural Gas Report, Natural Gas Week, pipeline companies.

The map shows major pipeline routes and the directional flow of gas. Also shown is the change in 1998 in outflows from the supply regions.

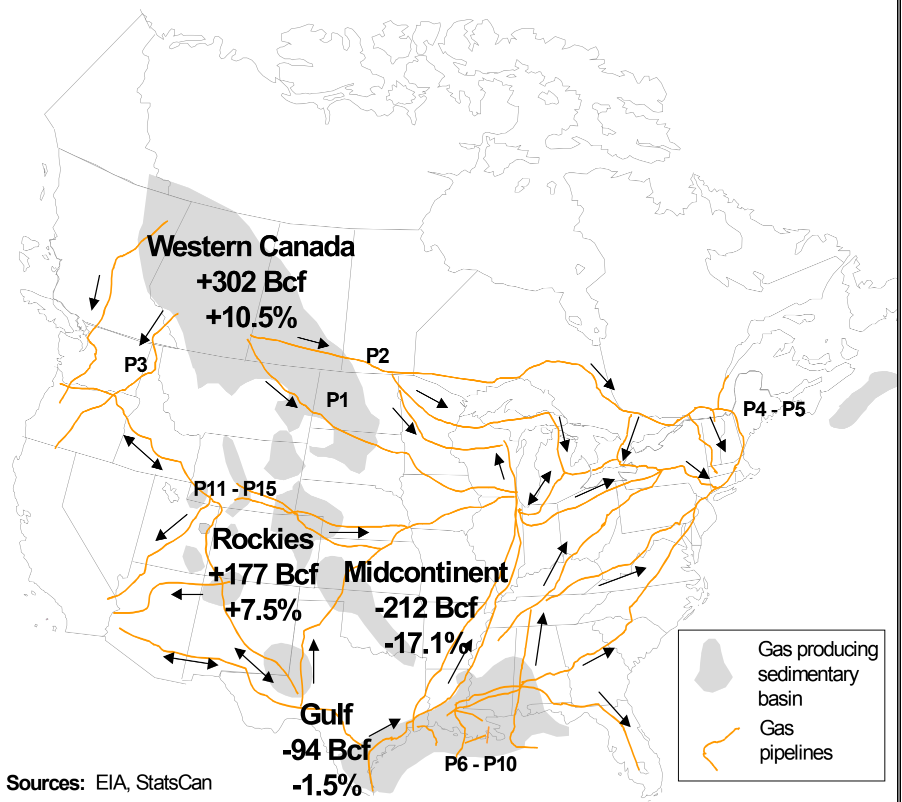
Pipeline projects listed in Table 5 are shown on the map; for example, P1 is the Foothills/ Northern Border expansion of Table 5.

Most pipeline projects stem from supply areas, and are intended to allow higher net outflows.

The exception is the Gulf Coast. Flows out of the Gulf are generally not restricted by pipeline capacity due to the large corridors to the West, Midwest and Northeast. Gulf projects in 1998 were all offshore gathering type projects.

The addition of new capacity from Western Canada and the US Rockies will allow higher net outflows from these areas in the future.

Figure 20: Gas Flows Along Pipeline Routes



Sources: EIA, StatsCan

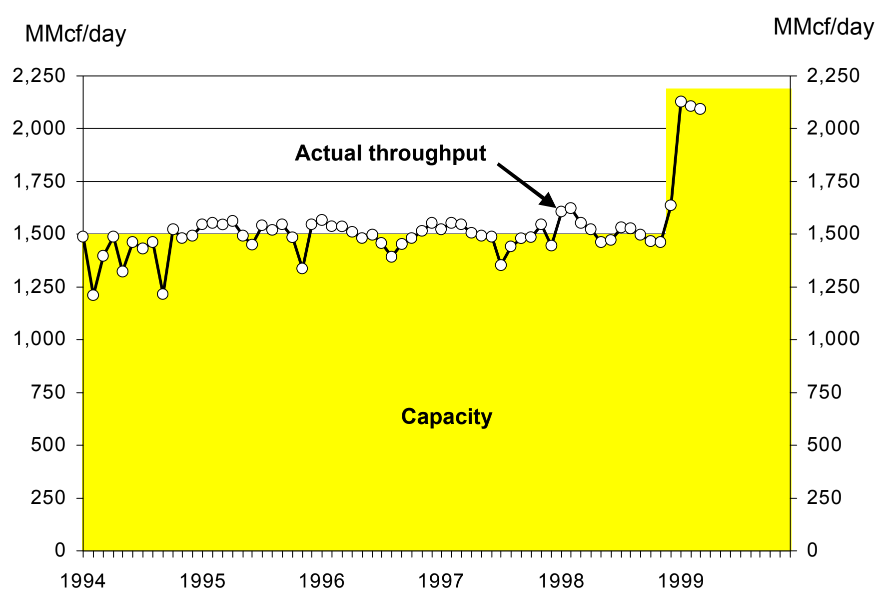
This graph shows daily pipeline capacity through the Monchy, Saskatchewan export point, as well as exports through that point.

The Foothills/Northern Border system had, since 1995, been used at essentially full capacity. In 1997, the pipeline was used at a load factor of 99%. More impressive is the load factor of 101% from January to November 1998.

In the first full month (January 1999) of operations after the large December 1998 expansion, an average of 2,129.7 MMcf/d flowed through Monchy, representing a load factor of 97%.

Figure 21:

Northern Border/Foothills



Sources: NEB, Foothills Pipeline

Review of 1998

Canadian Export & Domestic Sales

- Domestic & Export Sales
- Regional Prices & Volumes
- Domestic & Export Prices
- Domestic & Export Plant Gate Netbacks
- Plant Gate Revenues

Despite limited new export pipeline construction (until late in the year), export sales increased by 188 Bcf, or 6.4%, to reach 3.1 Tcf in 1998. Export sales are now 555 Bcf greater than domestic sales and account for 54% of Canadian production.

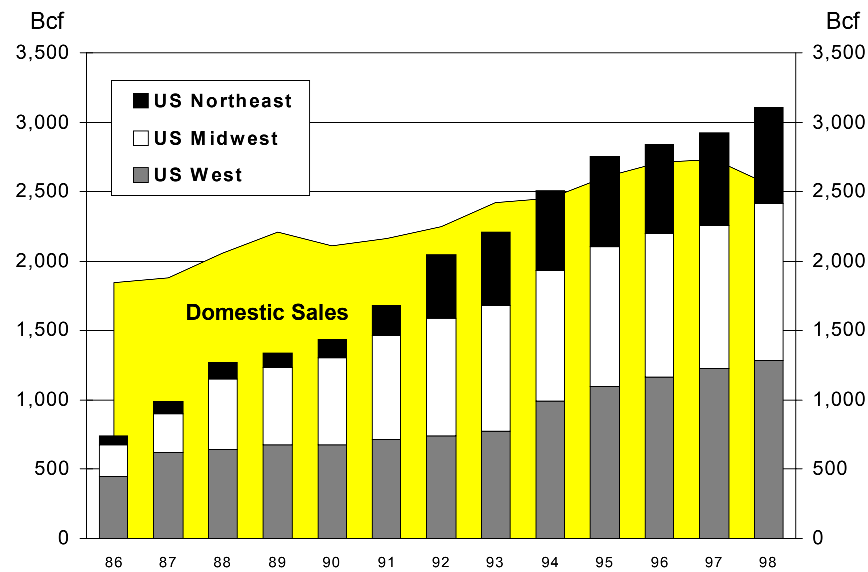
Exports grew by the following amounts: Midwestern US 9%, reaching 1,127 Bcf; US West 5%, reaching 1,287 Bcf; and Northeast 5%, reaching 699 Bcf.

Growth in exports offset a 6.4% drop in domestic sales, caused mainly by warm weather, especially in Eastern Canada.

The shift continued towards export orders and away from licences. Short term orders now account for 71% of all export sales. The National Energy Board (NEB) must approve all exports, via either long-term licences or short-term orders.

Figure 22:

Domestic & Export Sales



Sources: NEB, StatsCan, NRCan estimates

The figure on the right shows average annual export gas prices at the international border, and average annual domestic prices at AECO in Alberta and at TCPL's eastern zone of Ontario and Quebec. These are the top row of prices on the chart.

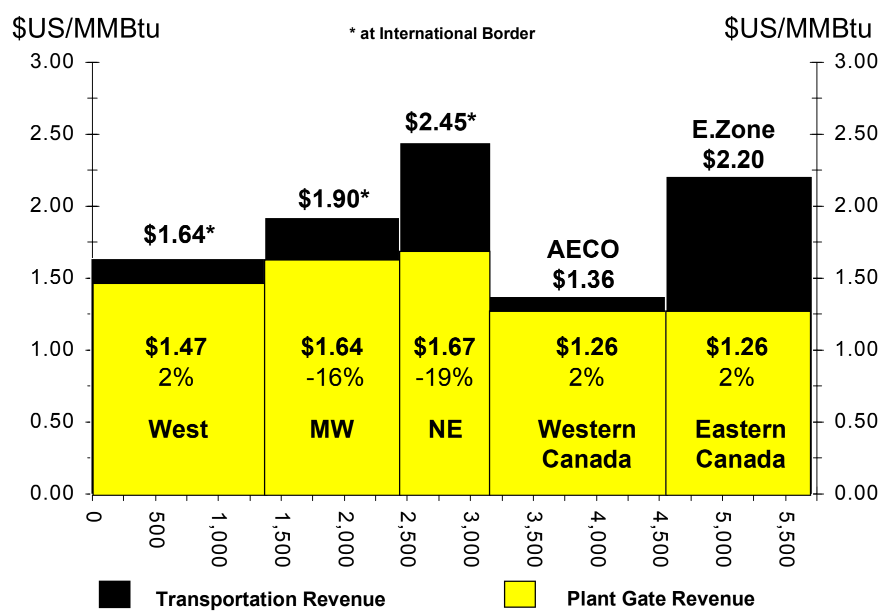
The corresponding plant gate netbacks from these sales are also shown (the lower prices on the chart), as well as the percent change in netbacks from last year.

The width of each bar is proportional to sales volumes. Thus, the area of each bar is proportional to sales revenue. The lower part of each bar is plant gate revenues to producers, while the upper bar is revenue to pipelines.

Prices for the three major export markets are drawn from information filed with the NEB. Canadian prices are derived from the Alberta trading hub (AECO) spot price.

Figure 23:

Regional Prices & Volumes



Sources: NEB, Friedenberg, StatsCan, NRCan estimates

Export and domestic price data is shown in detail on the right.

Natural gas prices in the export market were 10% lower in 1998 than last year.

The average price for Canadian gas sold to the US Northeast fell 15.5% in 1998, to $2.45/MMBtu, after averaging over $2.89 the previous two years.

Export prices to the Midwest fell 14.8% in 1998, following increases of 40% and 10% in 1996 and 1997 respectively.

In Canada, AECO spot prices in terms of US$/MMBtu were 2% higher in 1998. Due to exchange rate changes, Cdn$/GJ spot prices increased by 10%.

Canadian prices at Huntingdon/ Sumas (the largest British Columbia market) were 6% lower (US$ basis) than in 1997.

Table 6:
Domestic & Export Prices

	International Border Export Prices					Canadian Markets		
1998 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	$1.62	$2.09	$2.68	$2.03	$2.77	$1.53	$1.12	$1.81
February	$1.44	$1.89	$2.52	$1.84	$2.50	$1.50	$1.10	$1.43
March	$1.52	$1.97	$2.63	$1.92	$2.57	$1.65	$1.23	$1.17
April	$1.62	$1.99	$2.62	$1.95	$2.65	$1.80	$1.33	$1.39
May	$1.70	$1.96	$2.58	$1.99	$2.73	$2.10	$1.53	$1.68
June	$1.47	$1.82	$2.44	$1.82	$2.53	$1.58	$1.14	$1.38
July	$1.54	$2.04	$2.52	$1.95	$2.75	$1.76	$1.25	$1.43
August	$1.63	$1.71	$2.19	$1.78	$2.59	$1.92	$1.32	$1.55
September	$1.49	$1.53	$2.07	$1.63	$2.36	$1.64	$1.14	$1.41
October	$1.65	$1.84	$2.31	$1.87	$2.73	$2.12	$1.45	$1.65
November	$1.97	$1.96	$2.42	$2.07	$3.02	$2.64	$1.81	$2.15
December	$2.09	$1.97	$2.42	$2.13	$3.11	$2.81	$1.92	$2.12
1998 Average	**$1.64**	**$1.90**	**$2.45**	**$1.91**	**$2.69**	**$1.92**	**$1.36**	**$1.60**
1997 Average	$1.65	$2.23	$2.89	$2.13	$2.80	$1.75	$1.34	$1.71
% change	**-0.08%**	**-14.83%**	**-15.47%**	**-10.26%**	**-3.73%**	**9.82%**	**2.00%**	**-6.40%**

Sources: NEB, Friedenberg, NRCan estimates

Export and domestic plant gate netbacks are shown in detail in this table.

Export plant gate netbacks are equal to international border export prices minus transmission costs for moving gas from the plant gate to the international border.

Regulated pipeline transmission tolls were subtracted from Huntingdon and AECO spot prices to estimate netbacks for domestic sales.

Lower export prices resulted in lower plant gate netbacks for producers. The Northeast and Midwest were the best markets for producers.

Producer netbacks from domestic sales remained below those from US markets for most of the year. However, in the latter two months of 1998, domestic and export netbacks were similar.

Table 7:
Domestic & Export Plant Gate Netbacks

	Export Plant Gate Prices					Canadian Markets		
1998 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	$1.46	$1.85	$1.91	$1.70	$2.32	$1.39	$1.02	$1.54
February	$1.25	$1.60	$1.68	$1.47	$2.00	$1.36	$1.00	$1.17
March	$1.34	$1.75	$1.83	$1.59	$2.13	$1.51	$1.13	$0.92
April	$1.44	$1.70	$1.76	$1.60	$2.17	$1.66	$1.22	$1.13
May	$1.52	$1.68	$1.75	$1.63	$2.23	$1.95	$1.42	$1.41
June	$1.28	$1.55	$1.66	$1.46	$2.03	$1.44	$1.04	$1.13
July	$1.36	$1.78	$1.75	$1.61	$2.27	$1.62	$1.15	$1.18
August	$1.46	$1.47	$1.45	$1.46	$2.13	$1.77	$1.22	$1.30
September	$1.32	$1.27	$1.33	$1.31	$1.88	$1.50	$1.04	$1.16
October	$1.48	$1.59	$1.58	$1.54	$2.26	$1.97	$1.35	$1.40
November	$1.80	$1.68	$1.67	$1.73	$2.52	$2.49	$1.70	$1.88
December	$1.91	$1.76	$1.72	$1.81	$2.65	$2.65	$1.81	$1.85
1998 Average	**$1.47**	**$1.64**	**$1.67**	**$1.58**	**$2.22**	**$1.78**	**$1.26**	**$1.34**
1997 Average	$1.44	$1.95	$2.06	$1.76	**$2.31**	$1.61	$1.23	$1.43
% change	**1.78%**	**-15.63%**	**-18.88%**	**-10.42%**	**-3.88%**	**10.28%**	**2.39%**	**-6.63%**

Sources: NEB, Friedenberg, NRCan estimates

The graph on the right depicts plant gate revenues (millions of Cdn$) from each export region, from total exports and from domestic sales.

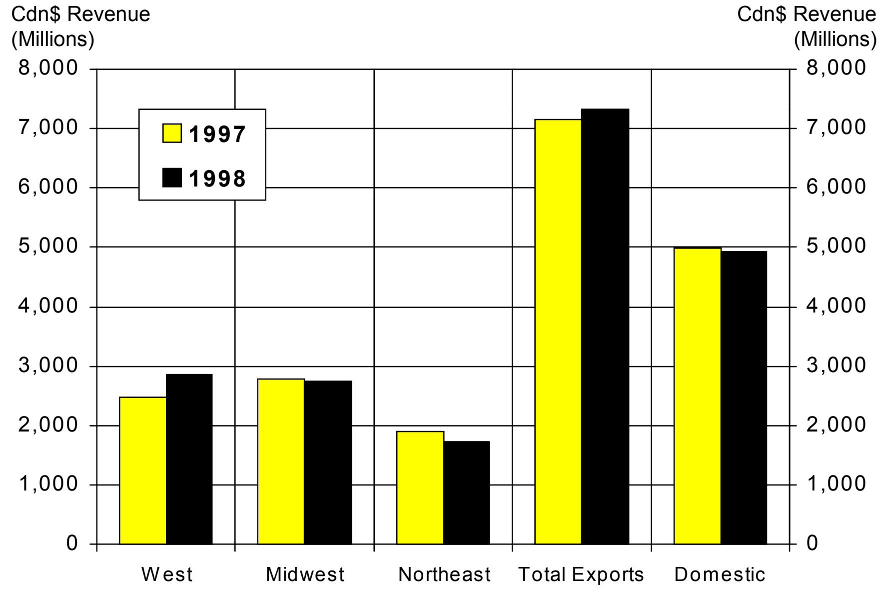
Growth in US export volumes in 1998 more than offset a drop in prices. Export revenues increased to Cdn$7.3 billion, up 2.4%. US West revenues increased by Cdn$379 million, or 15%. Midwest export revenues fell slightly — Cdn$37 million, or 1%; Northeast revenues fell Cdn$169 million, or 9%.

Revenues from domestic sales fell 1%, or Cdn$51 million. An increase in prices partly counterbalanced a drop in domestic sales volumes.

Overall, revenues for Canadian producers from all markets increased 1% to Cdn$12.3 billion from Cdn$12.1 billion in 1997.

Figure 24:

Plant Gate Revenues



Sources: NEB, Friedenberg, StatsCan, NRCan estimates

Outlook to 2005

Natural Gas Demand

- US Gas Demand Forecasts
- Canadian Gas Demand Forecasts
- 1998–2005 US Demand Growth By Sector
- Regional Demand Outlook

Five forecasts of US natural gas demand are shown, as well as the average. For 1996–98, the line shows actual US demand, from EIA's Natural Gas Monthly report.

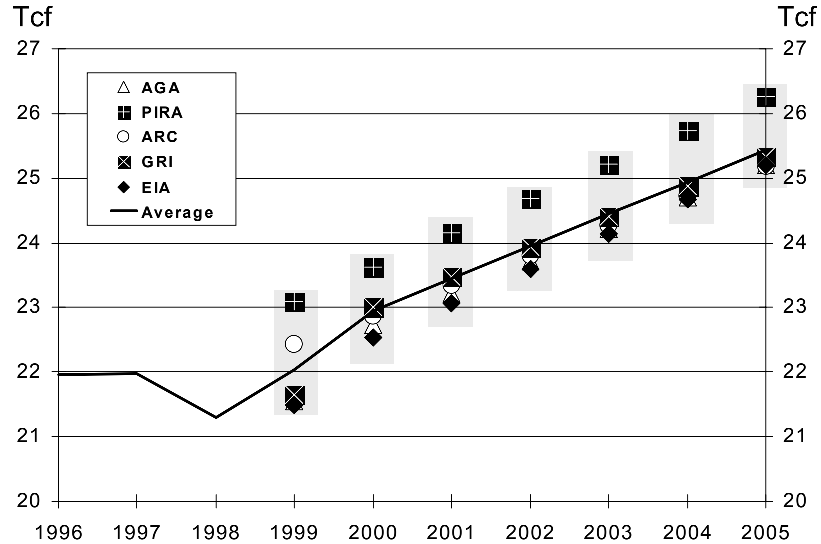
The average line shows annual growth of 2.6% from 1998–2005. US gas demand growth over the past five years was 1%[1].

Compared to our report last year, forecasters have lowered their gas demand outlook for 2005 by 540 Bcf. This slightly more pessimistic view of future gas demand appears to be warranted, given recent disappointing demand growth in the industrial sector (see Natural Gas Demand, Review of 1998 section).

This forecast of US demand, combined with forecast Canadian demand (see below) sees the North American gas market reach 29 Tcf by 2005.

Figure 25:

US Gas Demand Forecasts



Sources: AGA, PIRA, ARC, GRI, EIA

Three forecasts of Canadian natural gas demand are shown, as well as the average. For 1996–98, the line shows actual Canadian demand, from Statistics Canada reports.

The average line shows annual growth of 3.9% from 1998–2005. Growth over the past five years was 1.1%[1].

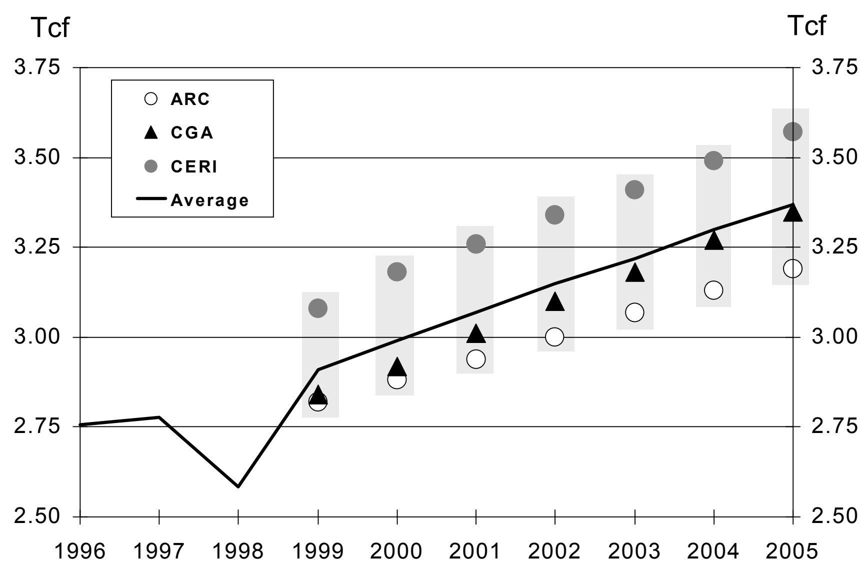
Compared to our report last year, forecasters have raised their Canadian gas demand outlook for 2005 by about 180 Bcf.

One major event to consider in this regard is the expected access of New Brunswick and Nova Scotia to natural gas, commencing in 1999. Gas supply contracts have already been signed to allow conversion of some power plants and industrial sites from oil to gas use.

[1]**NOTE:** 1993–98 growth rates were skewed by unusual 1998 demand.

Figure 26:

Canadian Gas Demand Forecasts



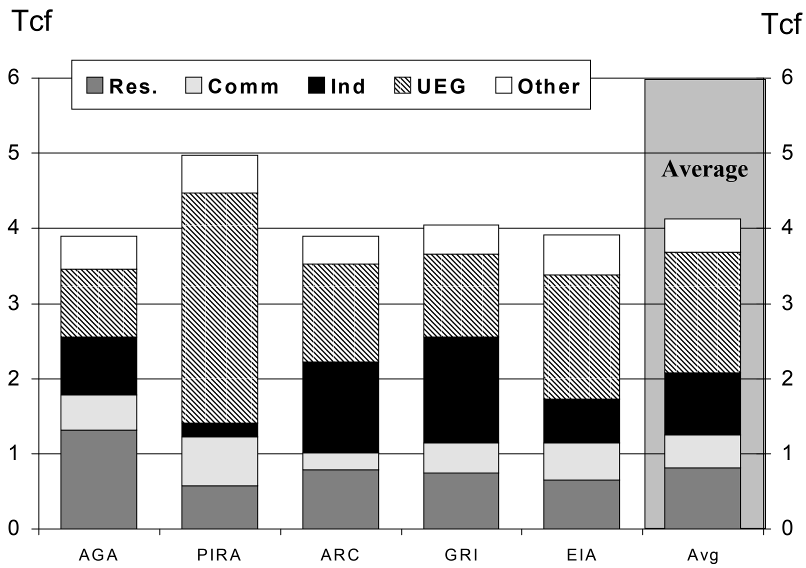
Sources: CGA, ARC, CERI.

The big increases in demand are expected to occur in electric generation using gas and in the industrial sector. Using the average of the forecasters, these two sectors account for 59% of gas demand growth over 1998–2005. UEG demand is expected to grow 1.6 Tcf; industrial demand 0.8 Tcf.

Note: *Historical* figures published by EIA put gas demand by industrial cogenerators and non-utility generators in the industrial sector. However, all *forecasts* now put industrial cogen in industrial, but non-utility generation in the UEG sector. While confusing, the change is probably warranted. Increasingly, electric generation is becoming non-utility. Continuing to place this in the industrial sector would not be appropriate.

Figure 27:

1998–2005 US Demand Growth By Sector



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

Regional growth patterns will affect the value of capacity along certain gas pipeline routes and determine whether more capacity is built.
Good demand growth in the US Midwest and Northeast will drive major pipeline construction to these regions (i.e., Alliance, TCPL).
Growth in the South Atlantic, a region with no spare pipeline capacity, will drive new gas pipelines from the Gulf Coast.
The US West and Rockies also show high growth rates. To date, little incremental pipeline capacity to the West is planned, as the region has excess pipeline capacity. This capacity will be used at higher load factors in the future.

Table 8:

Regional Demand Outlook

	Actual 1998 Demand Bcf	1993-98 Annual Growth Bcf	Growth Rate to 2005 %	Incremental Demand 98-2005 Bcf	Demand Forecast 2005 Bcf
Gulf Coast	5,521	1.5%	1.6%	748	6,269
Midcontinent	1,302	1.0%	1.0%	108	1,410
Rockies	609	1.8%	3.1%	166	775
US West	2,488	1.3%	2.4%	520	3,008
US Midwest	4,182	-0.2%	2.2%	795	4,977
US Northeast	2,859	1.4%	3.1%	791	3,650
US South Atlantic	1,770	2.9%	3.8%	615	2,385
Other US	583	-6.3%	2.4%	122	705
Total US End-Use	19,314	0.9%	2.6%	3,864	23,178
US Pipe fuel, etc.	1,975	1.9%	1.7%	286	2,261
Total US Demand	**21,289**	**1.0%**	**2.6%**	**4,151**	**25,440**
Canadian Demand	**2,585**	**1.1%**	**3.9%**	**785**	**3,370**
Total North America	**23,874**	**1.0%**	**2.7%**	**4,936**	**28,810**
Exports to Mex., Jap.	**116**	**3.9%**	**1.0%**	**8**	**124**
Total Gas Required	**23,990**	**1.0%**	**0.7%**	**4,944**	**28,934**

Source: NRCan **Note:** The low demand growth rates seen over the1993-98 period are not representative, and were due to abnormal 1998 weather/demand. Demand growth rates over other periods (e.g., 1993-97) were much higher.

Outlook to 2005

Natural Gas Supply

- US Production Forecasts
- Regional US Production Outlook
- Gulf OCS Drilling Requirements
- Canadian Gas Production Forecasts
- Canadian Drilling Requirements
- Canadian East Coast Offshore

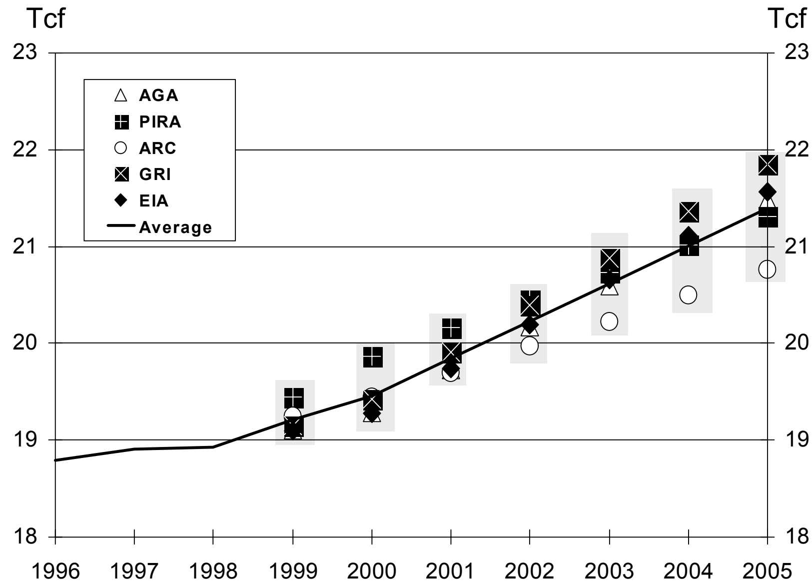
Five forecasts of US natural gas production are shown, as well as the average. For 1996–98, the line shows actual US production, from EIA's Natural Gas Monthly report.

The average line shows annual growth of 1.7% from 1998–2005. US gas production growth over the past five years was **much** less — only 0.9%.

Part of the reason for the low historical growth was the increase in imports from Canada over the past five years — rapid US production growth was not needed.

Given the demand outlook of the previous section, and the outlook for other supplies coming into the US (mainly pipeline imports from Canada), the production shown at right will be fully required by the US market.

Figure 28:
US Production Forecasts



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

Most US organizations are very bullish on production prospects for the Gulf Outer Continental Shelf (OCS), especially given the good results to date in the deepwater. For example, to 2005, government agencies (MMS and EIA) forecast OCS growth of 3.5% to 4.3%, while consultants (PIRA, Purvin & Gertz) forecast growth of 2%.

Most forecasters are also bullish on the Rockies — recent production growth rates support this view.

For the Gulf non-OCS (onshore, state offshore), consultants forecast growth of 2%, while EIA forecasts no growth.

In general, challenging rates of US production growth are called for. Lower past rates of growth raise some questions about how difficult it will be to achieve forecast high growth.

Table 9:
Regional US Production Outlook

	Actual 1998 Supply Bcf	Annual 1993-98 Growth %	Annual 1995-98 Growth %	Growth Rate to 2005 %	Production Forecast 2005 Bcf	Incremental Supply 98-2005 Bcf
Gulf Coast:						
Non-OCS	6,829	1.0%	0.5%	1.5%	7,579	750
Gulf OCS	5,001	1.4%	1.4%	2.9%	6,109	1,108
Gulf Total	11,830	1.1%	0.9%	2.1%	13,688	1,858
Rockies	3,161	4.6%	2.8%	3.2%	3,941	780
Midcont.	2,332	-3.5%	-3.3%	-2.7%	1,925	-407
Other US	1,604	0.1%	0.2%	2.0%	1,839	235
Total US	**18,927**	**0.9%**	**0.6%**	**1.8%**	**21,393**	**2,466**
Canada	**5,765**	**4.3%**	**2.5%**	**3.5%**	**7,318**	**1,553**
LNG/Other	219	1.6%	17.6%	0.2%	223	4
TOTAL	**24,911**	**1.6%**	**1.1%**	**2.2%**	**28,934**	**4,023**

Source: NRCan. LNG/Other includes supplementals, Mexican imports

Computing required drilling activity is a complex exercise. However, it appears US gas drilling activity will have to increase for US gas production forecasts to be realized.

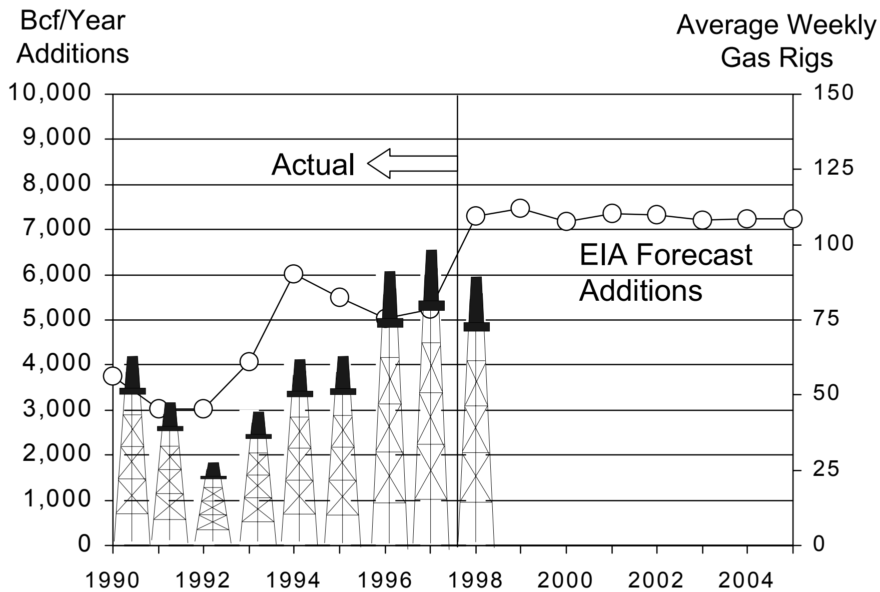
Shown at right (line on chart) is historical reserve additions in the Gulf OCS, as well as EIA's estimate of required Offshore reserve additions (from their Annual Energy Outlook 1999).

Also shown on the chart is the average weekly gas rig count (1994–98 from Baker Hughes, 1990–93 estimated).

To realize the reserve additions forecast, it appears that Gulf OCS gas drilling will have to increase.

Figure 29:

Gulf OCS Drilling Requirements

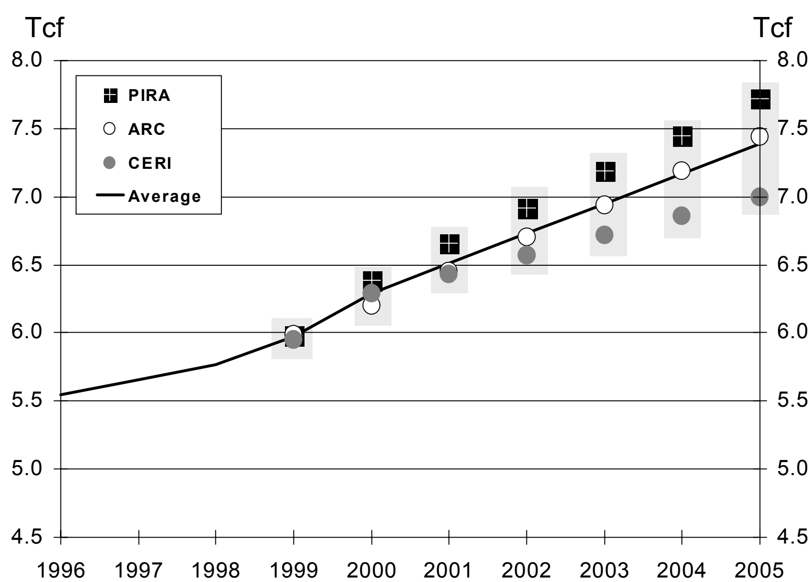


Sources: EIA, Baker Hughes

The production forecasts of several organizations are shown at right. On average, forecasters expect annual production growth of 3.6%. In the past five years, actual production growth was 4.3% per year. Only the US Rockies had a higher production growth rate.

Figure 30:

Canadian Gas Production Forecasts



Sources: CGA, PIRA, ARC

Canadian gas drilling activity will have to increase for the production forecast to be realized.

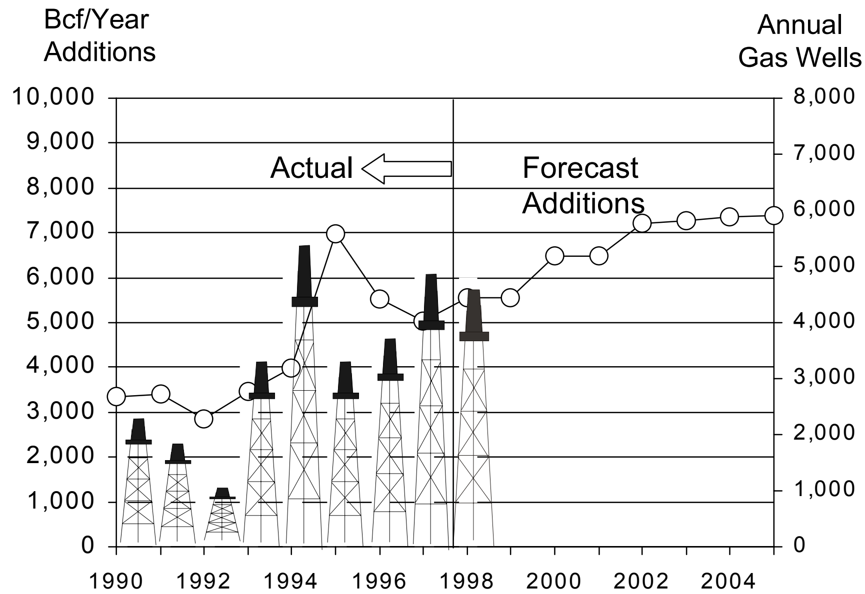
Shown at right (line on chart) is historical reserve additions (before revisions) in Western Canada, as well as annual gas drilling.

We estimate that Western Canadian reserve additions will have to increase to over 6,000 Bcf per year, from levels of about 5,500 Bcf in recent years.
This implies that increased gas drilling may be necessary — gas well completions in Western Canada may have to increase to the 5,500 well per year range. In 1998, Canadian gas drilling was 4,600 wells.

However, a change in the location of gas well drilling could have the same effect — more Foothills gas well drilling could allow higher reserves additions with fewer wells.

Figure 31:

Canadian Drilling Requirements



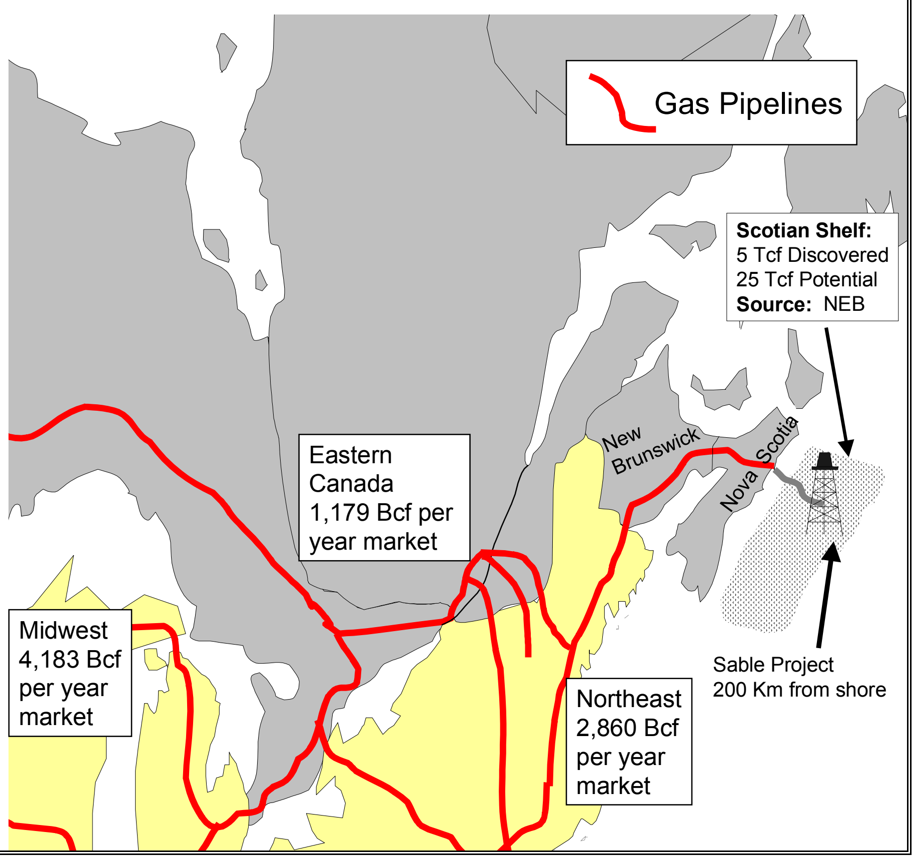
Sources: CAPP, NRCan

Note that production is also expected to start in the Canadian East Coast offshore (Sable Island area) in 1999. It is assumed that production will reach 530 MMcf/d (193 Bcf per year) quickly. It is generally thought that production from the Scotian Shelf could eventually increase, as new projects are identified and developed. However, given the lack of specific proposals, we have not speculated on the level or timing of production increases.

Further background is shown at right. The Scotian Shelf basin has discovered resources of 5 Tcf, and future potential of an additional 25 Tcf (NEB preliminary Supply/Demand Report).

As shown, this new basin is relatively well positioned, next to several large gas markets.

Figure 32: Canadian East Coast Offshore



Outlook to 2005

Natural Gas Prices

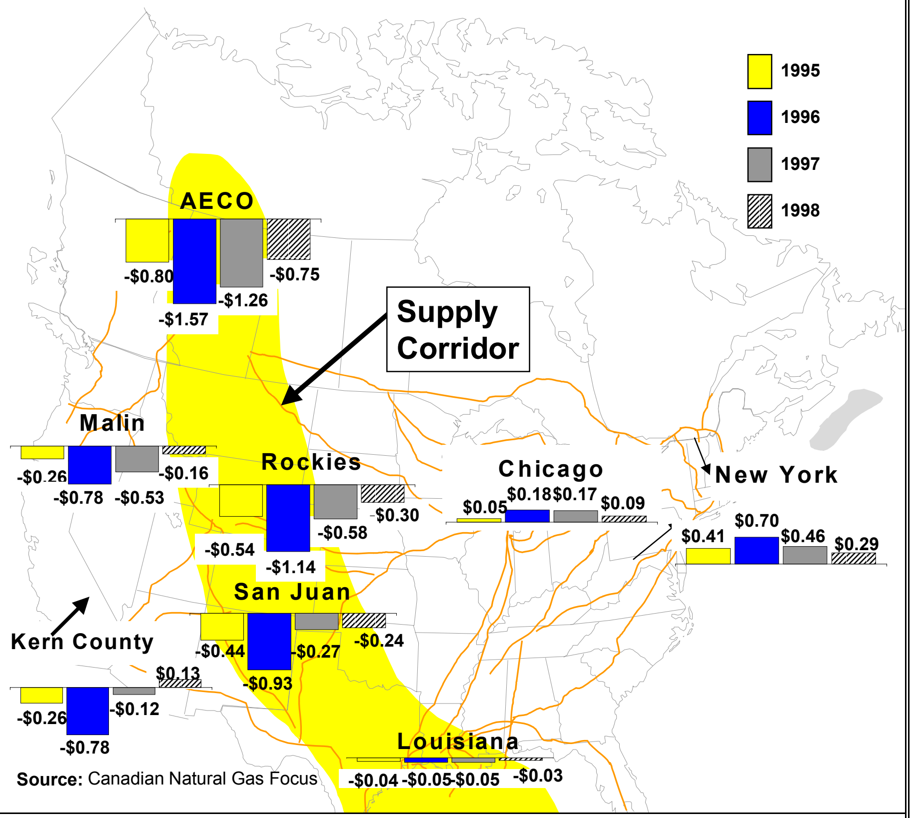
- Overall Price Framework
- Historical Gas & Oil Prices
- US Gas Price Forecasts
- Canadian Gas Price Forecasts

The map shows various gas market prices relative to NYMEX. For example, in 1995 the AECO price averaged \$0.80/MMBtu less than NYMEX, \$1.57 less in 1996, \$1.26 less in 1997, and \$0.75 less in 1998.

Gas supply is concentrated in a north/south corridor from Louisiana to Alberta. Supply costs and gas prices are lower as you proceed north. There are few north/south pipeline connections in this corridor.

Regions outside this corridor import gas, and pay supply prices plus pipeline costs. Prices in these market regions are driven by the marginal supplier. For example, Chicago and New York prices are Louisiana plus pipeline costs; Malin is AECO plus pipeline costs; and Kern County is San Juan plus pipeline costs.

Figure 33: Overall Price Framework



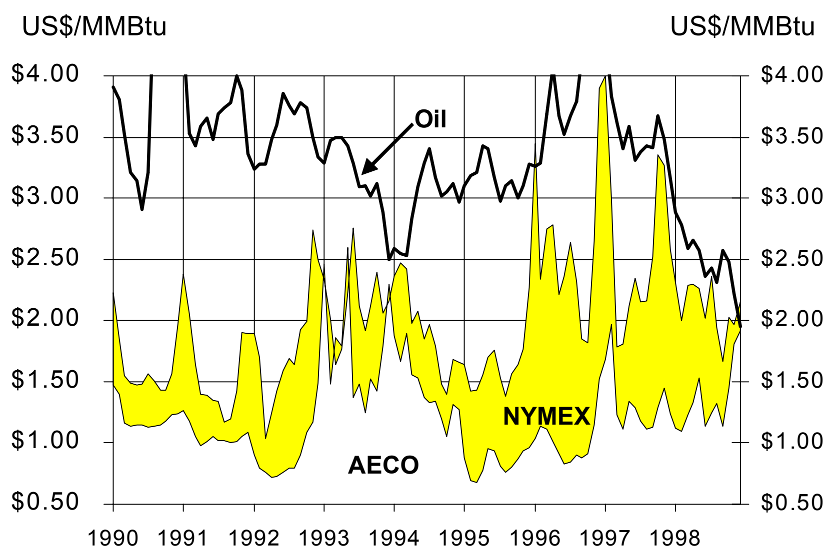
Source: Canadian Natural Gas Focus

The graph at right shows three monthly price tracks: West Texas Intermediate (at 5.8 MMBtu/bbl); gas at NYMEX; and gas in Alberta (AECO). A review of these three prices over the past nine years may provide some insight into the future.

For most of the 1990s, oil prices on a per MMBtu basis were far above gas prices. Good oil prices may have provided cashflows for gas development.

Things have changed. Gas prices in late 1998 were near parity with oil prices.

Figure 34: Historical Gas & Oil Prices



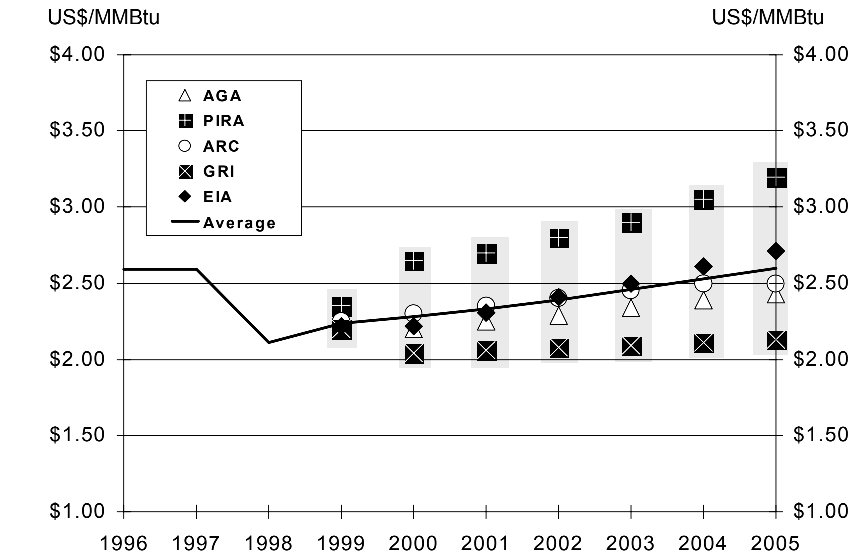
Sources: Canadian Natural Gas Focus, Federal Reserve Bank of Dallas

Last year, the average nominal dollar US gas price expected by our forecasters for 2005 was $2.41. This year, the number has increased to $2.60.

These forecasts were done in mid-to-late 1998. Forecasts by these same groups today would probably be different.

Figure 35:

US Gas Price Forecasts



Sources: AGA, PIRA, ARC, GRI, EIA **Note:** Field wellhead or Gulf prices. Some original forecasts in constant dollars, converted to nominal assuming 1.8% annual inflation. 1995-98 are NYMEX actuals.

Last year, the year 2005 price forecast by our group of forecasters averaged $2.05/MMBtu. This year, the corresponding figure is $2.26.

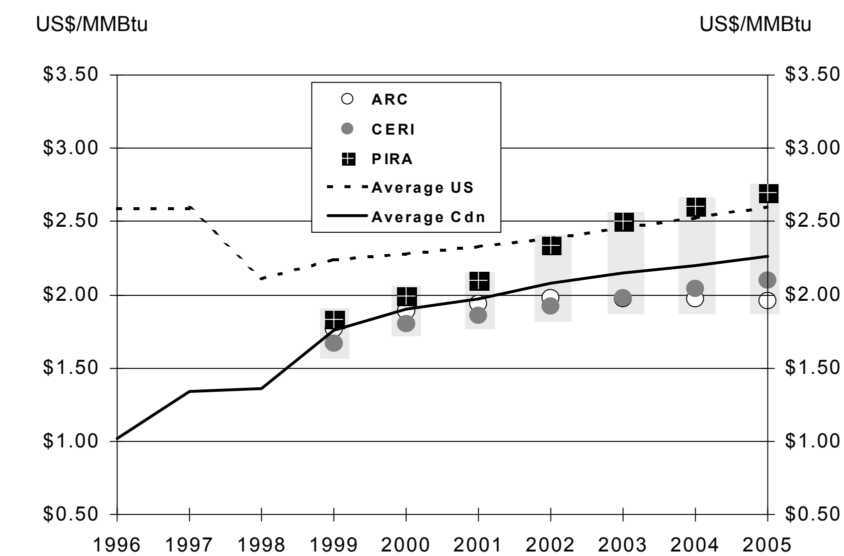
Forecasters expect a very strong link to remain between prices in US markets and Canadian prices.

Juxtaposition of the US and Canadian price forecasts reveals a Canada/US gas price differential of only 34 cents US. This is lower than historical price differentials.

The NYMEX less Alberta price differential averaged 87 US cents in 1992, 35 cents in 1993 (after large export pipelines like PGT were completed), 48 cents in 1994, 80 cents in 1995, $1.57 in 1996, $1.26 in 1997, and 75 cents in 1998.

Figure 36:

Canadian Gas Price Forecasts



Sources: AGA, PIRA, ARC, GRI, EIA, CERI **Note:** ARC and CERI were plantgate forecasts, added $US 0.12/MMBtu. PIRA=AECO. Forecasts in nominal dollars, ARC assumes 2% annual inflation, CERI converted at 1.8%. 1995-98 prices are AECO actuals.

Outlook to 2005

Gas Flows
& Pipeline Capacity

- Required Gas Flows
- Increased Pipeline Flows 1998–2005
- US Midwest & Northeast
- Maritimes & Northeast

Based on the regional forecasts of demand and production contained in previous sections of this report, certain gas flows are implied.

The gas flows out of each supply region are calculated as forecast supply less forecast demand.

All major supply regions except the Midcontinent show increasing "outflows" of gas. Midcontinent production is falling while its demand is rising, so this region will send less and less gas beyond its borders. This will free up pipeline capacity which could be used to send Gulf Coast gas to the Midwest and Northeast.

For demand regions (most of which also have minor production), what is shown is the change in demand. Most of these increases in demand will have to be met by increased pipeline gas flows into these demand regions.

Table 10:

Required Gas Flows
Bcf

Supply Regions:	Production Forecast 2005	Demand Forecast 2005	Net Outflows 2005	Net Outflows 1998	Outflows Difference
Gulf Coast	13,688	6,269	7,419	6,309	1,110
Midcontinent	1,925	1,410	516	1,030	-514
US Rockies	3,941	775	3,166	2,552	614
Western Canada	7,125	1,680	5,445	4,339	1,106
Scotian Shelf	193	0	193	0	193
Total Increased Outflow from Supply Regions 1998-2005					**2,509**
Demand Regions:			**Demand Forecast 2005**	**Actual 1998 Demand**	**Demand Difference**
West			3,008	2,488	520
Midwest			4,977	4,182	795
Northeast			3,650	2,859	791
South Atlantic			2,385	1,770	615
Eastern Canada			1,691	1,179	512
Total Increase in Demand in Demand Regions 1998-2005					**3,233**

Source: NRCan. **Note:** increase in outflow not equal to increase in demand in demand regions due to growth in production in demand regions. Also due to supply/demand accounting problems. (Recall that 1998 production exceeded 1998 demand by 921 Bcf).

The map at right shows the major changes in pipeline gas flows assumed by our analysis.

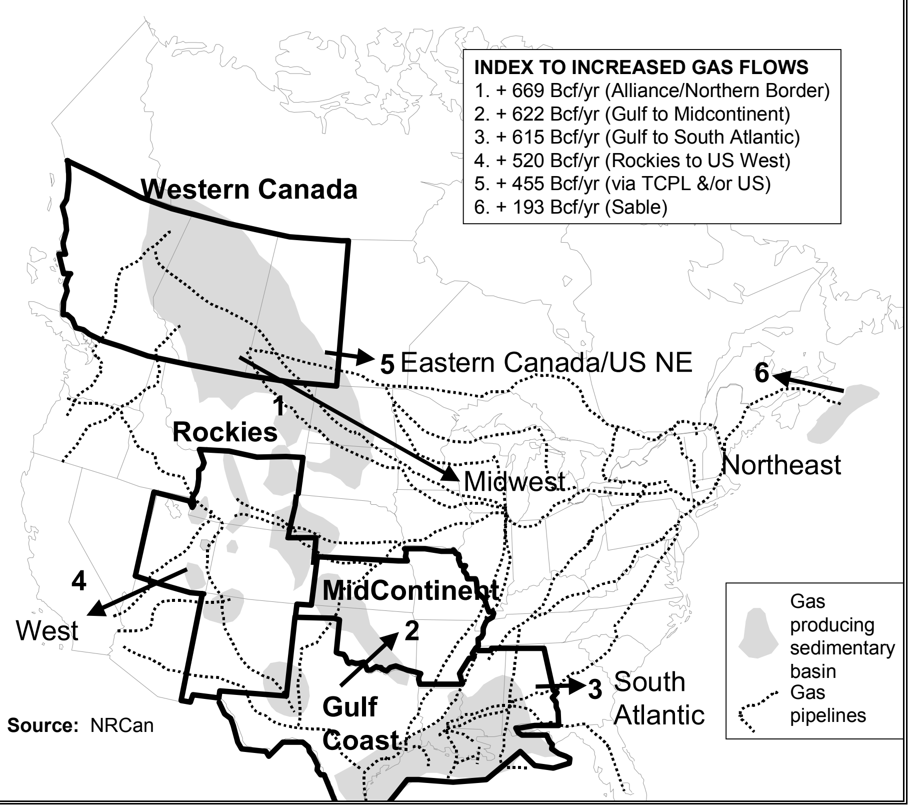
The increases in outflow from Canada were generated after considering specific pipeline expansion proposals.

In contrast, there is not enough new pipeline capacity yet proposed to take care of the forecast increases in outflow from the Rockies and Gulf Coast.

In addition to the major changes shown, other increases in pipeline flows will also be necessary.

Figure 37:

Increased Pipeline Flows 1998–2005



Source: NRCan

The Midwest already has more incoming pipeline capacity than local demand and is the target of further expansions. Pipeline flows into the region will have to adjust to the new capacity.

More gas will be coming into the Midwest via new projects and expansions (mainly Alliance and Northern Border).

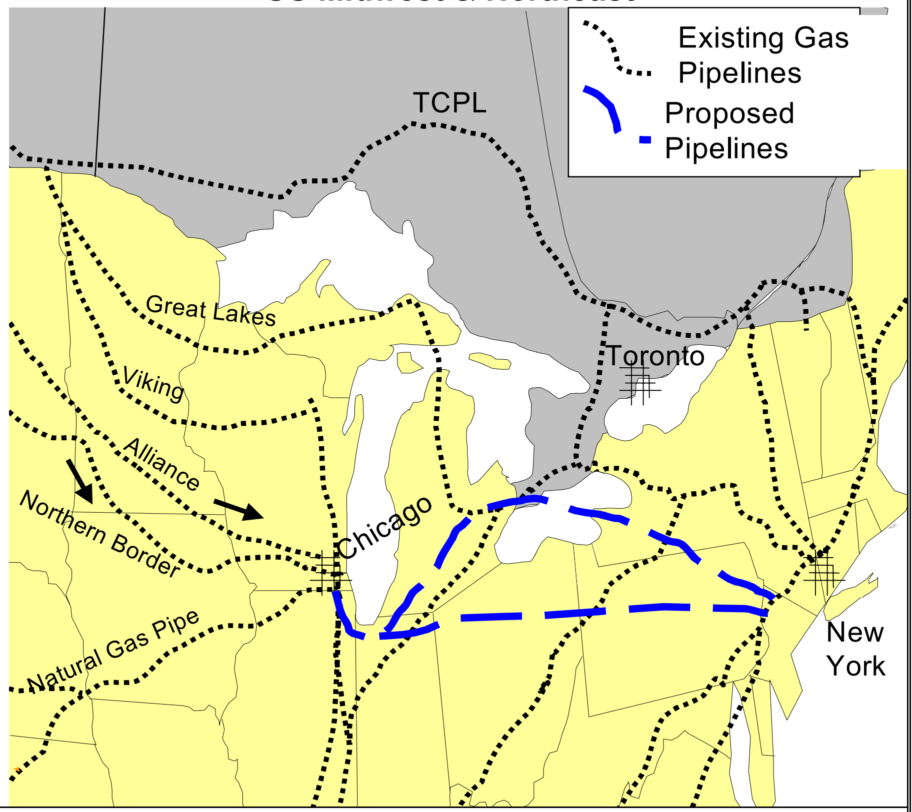
This gas will be partly accommodated by reduced flows northward from the Midcontinent and Gulf Coast.

The effect of more Canadian gas will be lower gas prices (relative to what would have otherwise occurred) in the Midwest. To the extent that the Midwest is part of the Gulf Coast/Midwest/Northeast "mega-market", this will tend to reduce prices in the Gulf as well.

If large MW-NE price differentials develop, MW to NE pipeline projects would be encouraged.

Figure 38:

US Midwest & Northeast

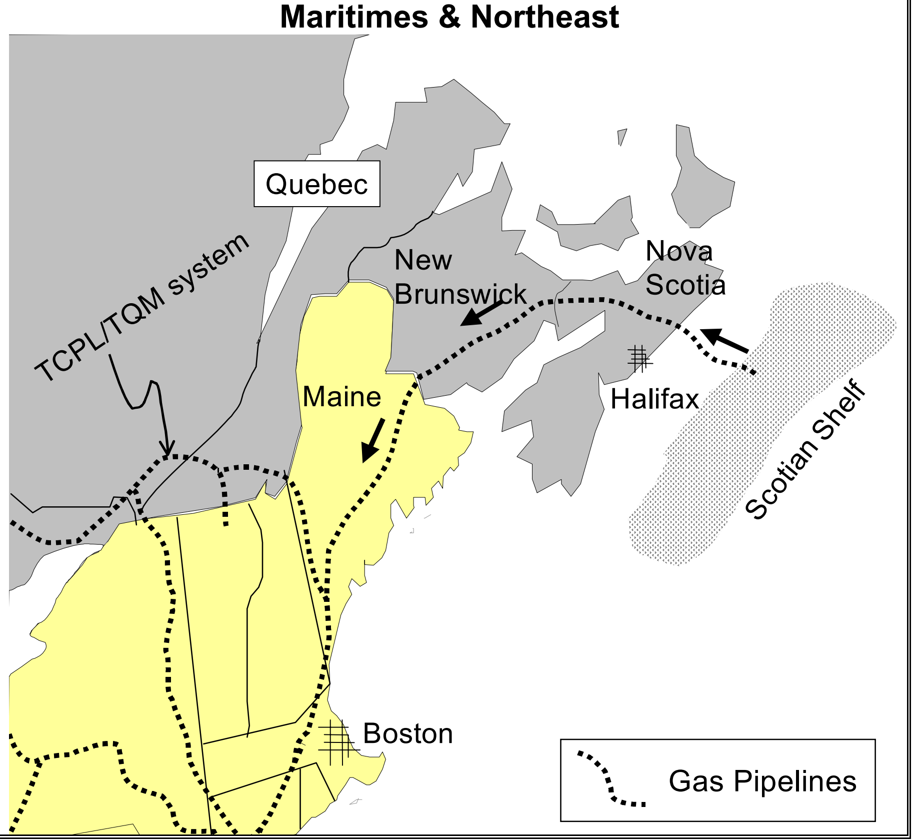


To date, the Canadian Maritime provinces and most of Maine have not had access to natural gas. With the Sable Offshore Energy Project and the Maritimes & Northeast pipeline, this will change. This will create new gas markets.
At this time it is unclear how much of Sable's initial 530 MMcf/d of planned production will stay in Nova Scotia and New Brunswick, and how much will be exported.

Depending on how quickly new gas fields are developed, the Scotian Shelf may eventually become a significant source of gas supply in the US Northeast. Scotian Shelf gas would compete with Western Canadian and Gulf Coast supplies.

Figure 39:

Maritimes & Northeast



Outlook to 2005

Canadian Export
& Domestic Sales

- Canadian Export Pipeline Capacity
- Export & Domestic Sales Outlook
- Export & Domestic Volumes
- Comparisons of Canadian Gas Export Forecasts
- Export & Domestic Revenue Forecast

The table at right shows recent and projected pipeline capacity through various export points. The forecast capacities are taken from regulatory filings by the pipelines.

After a 986 MMcf/d increase in export capacity in 1998, export capacity is forecast to increase again in 1999 and 2000.

In 1999, the big increase will be the Maritimes & Northeast Pipeline at St. Stephen, New Brunswick. Export capacity is shown at 360 MMcf/d.

In 2000, the big increase is the Alliance project. Big projects of this type are often late being built. The project's in-service date has already been postponed once.

Capacity to year 2000 only is shown. Past 2000, there are no projects proposed.

Table 11: Canadian Export Pipeline Capacity MMcf/d

	1997	1998		1999		2000	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
Huntingdon (NW Pipeline)	1,045		1,045		1,045		1,045
Huntingdon (User-pipes)	380		380		380		380
Kingsgate (Foothills/ANG)	2,518	64	2,582		2,582		2,582
Total US West	**3,943**	**64**	**4,007**		**4,007**		**4,007**
Monchy (Foothills)	1,500	690	2,190		2,190		2,190
Emerson (TCPL)	1,178	127	1,305	16	1,321	0	1,321
Fort Frances (TCPL)	26	0	26	1	27	0	27
Alliance						1,325	1,325
Miscellaneous	230	49	279		279		279
Total US Midwest	**2,934**	**866**	**3,800**	**17**	**3,817**	**1,325**	**5,142**
Iroquois (TCPL)	883	0	883	-22	861	0	861
Niagara Falls (TCPL)	798	47	845	0	845	0	845
Chippawa (TCPL)	500	0	500	-20	480	0	480
St. Stephen (MNP)				360	360	0	360
E. Hereford (TCPL)				190	190	0	190
Cornwall (TCPL)	63	0	63	0	63	0	63
Napierville (TCPL)	56	5	61	0	61	0	61
Phillipsburg (TCPL)	40	10	50	0	50	0	50
Highwater (TCPL)	31	-6	25	-25	0	0	0
Total US Northeast	**2,371**	**56**	**2,427**	**483**	**2,910**	**0**	**2,910**
Total Capacity (Export)	**9,248**	**986**	**10,234**	**500**	**10,734**	**1,325**	**12,059**

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.

Based on the capacities listed above, and on our estimates of likely load factors, we derived the export forecast shown at right.

Where large capacity increments are added, load factors on all export pipelines entering that market are assumed to fall. Load factors are then assumed to rise slowly over time.

In general we expect export load factors to remain high. The December 1998 690 MMcf/d Northern Border expansion, for example, is already running 97% full.

Thus, this table shows our Canadian production forecast. We expect Canadian gas production to reach 7.3 Tcf by 2005.

Table 12: Export & Domestic Sales Outlook Bcf

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Huntingdon (Westcoast)	372	433	432	437	442	447	453	458	463
Kingsgate (Foothills)	851	854	867	867	867	867	867	867	867
Total US West	**1,223**	**1,286**	**1,299**	**1,304**	**1,309**	**1,314**	**1,320**	**1,325**	**1,330**
Monchy (Foothills)	543	558	793	793	687	703	719	735	751
Emerson (TCPL)	430	486	477	482	482	482	482	482	482
Fort Frances (TCPL)	7	7	7	7	7	7	7	7	7
Alliance				105	416	426	435	445	455
Miscellaneous	53	75	100	100	100	100	100	100	100
Total US Midwest	**1,034**	**1,126**	**1,377**	**1,487**	**1,693**	**1,718**	**1,744**	**1,770**	**1,795**
Iroquois (TCPL)	294	307	299	299	299	299	299	299	299
Niagara Falls (TCPL)	290	305	305	305	305	305	305	305	305
Chippawa (TCPL)	32	44	44	44	44	44	44	44	44
St. Stephen (MNP)			20	118	118	118	118	118	118
E. Hereford (TCPL)			3	17	17	17	17	17	17
Cornwall (TCPL)	16	11	14	14	14	14	14	14	14
Napierville (TCPL)	18	17	18	18	18	18	18	18	18
Phillipsburg (TCPL)	6	5	7	7	7	7	7	7	7
Highwater (TCPL)	11	9							
Total US Northeast	**667**	**699**	**709**	**822**	**822**	**822**	**822**	**822**	**822**
Total Exports	**2,923**	**3,111**	**3,385**	**3,612**	**3,824**	**3,855**	**3,885**	**3,916**	**3,947**
Western Canada	**1,491**	**1,406**	**1,424**	**1,454**	**1,499**	**1,544**	**1,589**	**1,635**	**1,680**
Eastern Canada	**1,285**	**1,179**	**1,490**	**1,541**	**1,571**	**1,601**	**1,631**	**1,661**	**1,691**
Total Domestic Sales	**2,776**	**2,585**	**2,914**	**2,995**	**3,070**	**3,145**	**3,220**	**3,295**	**3,370**
Total Sales	**5,699**	**5,696**	**6,299**	**6,607**	**6,894**	**7,000**	**7,106**	**7,212**	**7,318**

Source: NRCan.

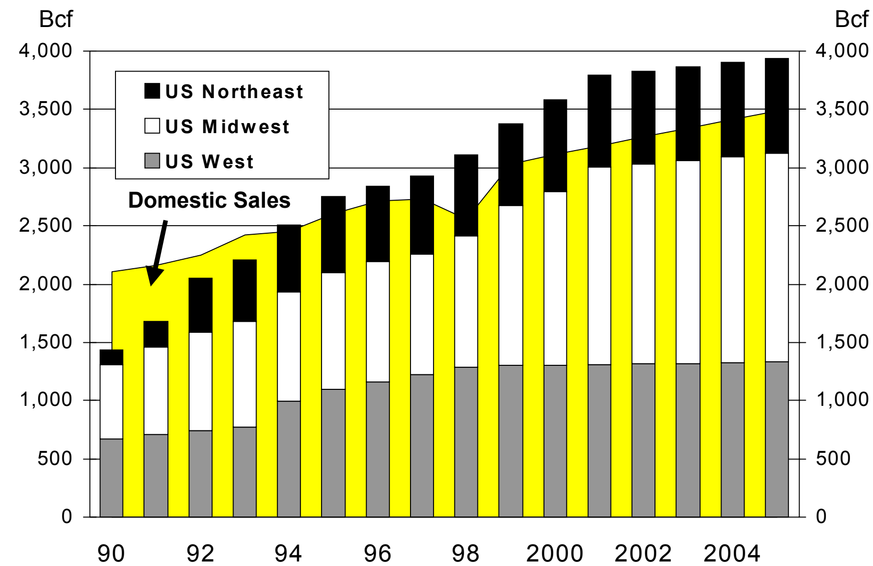
Our export forecast in graph form is shown at right. We expect exports to reach 3.9 Tcf by 2005.

Our domestic gas sales forecast is simply the Canadian gas demand forecast from the Demand Outlook section of this report. We assume that all Canadian gas demand is satisfied by Canadian production. This yields a domestic Canadian sales forecast of 3.4Tcf by 2005.

The sharp rise in exports to the US Midwest in 2001 represents the first full year of service on the proposed Alliance pipeline project.

Figure 40:

Export & Domestic Volumes



Sources: NEB, StatsCan, NRCan estimates and forecasts

Five expert forecasts of Canadian gas exports to the US are shown for comparison with our forecast. By 2005, the average of these forecasts shows Canadian gas exports at 3.8 Tcf, essentially the same as our forecast.

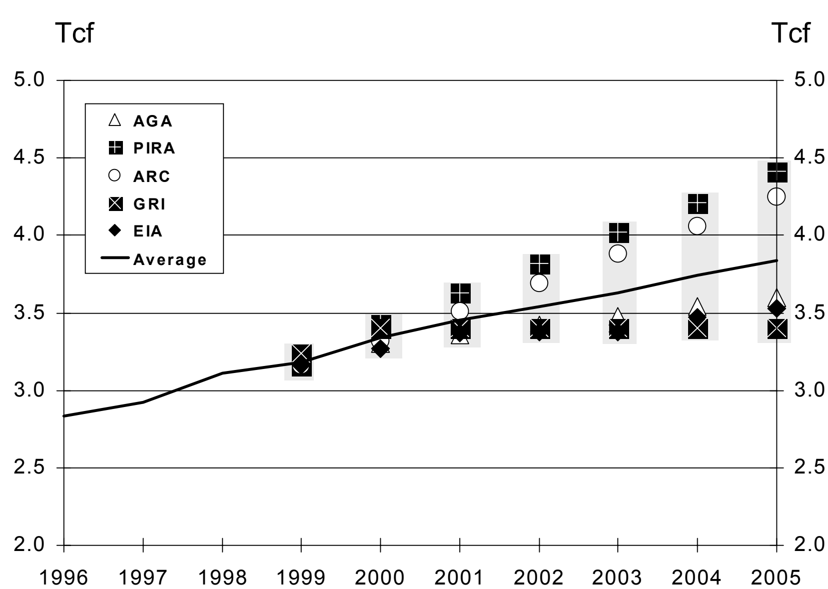
One factor which could reduce Canadian exports would be lower US gas demand. Even if US gas demand did fall, it is expected that higher cost US gas supply regions would absorb the brunt of the reduction in demand.

Another factor that could reduce Canadian gas exports would be the cancellation or postponement of a major pipeline project. However, all the projects used in our forecast have been approved by regulators and appear to be proceeding.

Finally, a lack of sufficient Canadian supply could reduce exports. However in the past, volume growth has been strong.

Figure 41:

Comparisons of Canadian Gas Export Forecasts



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

Based on forecast gas prices and volumes, future Canadian producer revenues can be estimated.

The estimates shown in the table at right assume that the past relationships between NYMEX prices and export revenues continue.

Similarly, the table assumes past relationships between AECO prices and domestic revenues continue to hold.

These relationships will change in the future. These revenue estimates will therefore be affected.

By 2005, export revenues are expected to rise by 43% to Cdn$10.5 billion, mainly due to volume increases. Domestic revenues are expected to increase 87% to Cdn$9.2 billion, due to a combination of volume and price increases. Total revenues are expected to rise 61% to Cdn$19.7 billion.

Table 13:
Export & Domestic Revenue Forecast

EXPORT SALES:	Export Volumes (Bcf)	Actual/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$)
1997	2,923	$2.59	$2.13	$1.76	$5,168	$7,149
1998	3,111	$2.11	$1.91	$1.58	$4,933	$7,321
1999	3,385	$2.24	$2.07	$1.72	$5,835	$8,841
2000	3,612	$2.28	$2.11	$1.76	$6,363	$9,357
2001	3,824	$2.33	$2.16	$1.81	$6,931	$9,902
2002	3,855	$2.39	$2.22	$1.87	$7,227	$10,037
2003	3,885	$2.46	$2.29	$1.94	$7,529	$10,174
2004	3,916	$2.53	$2.36	$2.01	$7,877	$10,364
2005	3,947	$2.60	$2.43	$2.08	$8,193	$10,504

DOMESTIC SALES:	Domestic Volumes (Bcf)	Actual/Forecast Alberta Price (US$/MMBtu)	Actual/Forecast Plant Gate Netback (US$/MMBtu)	Domestic Plant Gate Revenues (Million US$)	Domestic Plant Gate Revenues (Million Cdn$)	Total Plant Gate Revenues (Million Cdn$)
1997	2,732	$1.34	$1.23	$3,605	$4,991	$12,140
1998	2,557	$1.36	$1.26	$3,330	$4,940	$12,261
1999	2,914	$1.76	$1.64	$4,774	$7,233	$16,074
2000	2,995	$1.90	$1.78	$5,320	$7,823	$17,180
2001	3,070	$1.97	$1.85	$5,670	$8,100	$18,002
2002	3,145	$2.08	$1.96	$6,161	$8,557	$18,594
2003	3,220	$2.15	$2.03	$6,536	$8,833	$19,007
2004	3,295	$2.20	$2.08	$6,863	$9,030	$19,394
2005	3,370	$2.26	$2.14	$7,196	$9,225	$19,729

Notes: Actual export revenues from NEB data. Actual domestic netbacks and revenues calculated using AECO and Huntingdon prices and subtracting published transmission tolls. Future export revenues estimated as follows: Future export netbacks assumed to equal forecast NYMEX prices (see report, P.42) less US$0.52. Resultant netback multiplied by forecast export sales. Future domestic revenues estimated as follows: Future domestic netbacks assumed to equal forecast Alberta prices (see report, P.43) less US$0.12. Resultant netback multiplied by forecast domestic sales.

Regulatory Update

- Westcoast Energy Inc. — Framework for Light-Handed Regulation
- TCPL-NOVA Merger
- Industry Agreement on Natural Gas Pipeline Competition and Regulation
- NOVA's Proposed New Pricing Structure
- TCPL Contract Renewal Policy
- Ontario — New Competitive Framework
- Ontario Nuclear Situation
- Natural Gas Distribution in the Maritimes
- Energy Y2K & the Canadian Government

Regulatory Update

This section of the report provides a review of important developments in Canadian regulatory issues over the past year.

Westcoast Energy Inc. — Framework for Light-Handed Regulation

On June 25, 1998, the National Energy Board (NEB) approved an application for a framework for light-handed regulation by Westcoast Energy Inc. (Westcoast). Under the framework, Westcoast's tolls for gathering (Zone 1) and processing (Zone 2) services will be negotiated with shippers.

Briefly, the components of the framework are:

- an introduction which states that Westcoast and its stakeholders propose a new model of regulation to address increasing competition in the provision of gathering and processing services in British Columbia;
- a fair dealing policy which is intended to ensure that all parties desiring or obtaining service from Westcoast are treated fairly;
- a contracting practice which establishes the parameters under which Westcoast will negotiate individual agreements with shippers and provides that Westcoast will continue to offer service under standard contracts to those shippers who do not wish to negotiate individual contracts;
- a provision of market information and confidentiality of contracts which addresses the means by which information concerning the contracts negotiated between Westcoast and shippers will be made available to others;
- a complaint process which provides a process which will enable parties to resolve disputes without the necessity of applying to the NEB, i.e., resolutions of complaints by mediation, arbitration or, where required, by adjudication by the NEB;
- an asset utilization and disposition policy which establishes the principle that, as part of the proposal for light-handed regulation, Westcoast is responsible for the utilization, and loss or gain on disposition, of its gathering and processing facilities; and,
- an interconnection policy which is designed to further the competitive environment for gathering and processing services by enabling the owners of third-party facilities to interconnect with Westcoast's facilities in Zone 1 and Zone 2.

TCPL-NOVA Merger

On January 26, 1998, TransCanada PipeLines Limited (TCPL) and NOVA Corporation (NOVA) announced a merger agreement. NOVA is an integrated gas transmission and petrochemical company that ships more than 4 Tcf of gas per year, all within Alberta, through its subsidiary NOVA Gas Transmission Ltd. (NGTL).

TCPL receives gas from NGTL at the Alberta-Saskatchewan borders and transports it eastward to markets. At the time of the announcement, it was indicated that NOVA Chemicals, another NOVA subsidiary, would become an independent chemical company.

The companies identified the following as some of the potential benefits of the merger:

- preservation of Canadian ownership and control of domestic energy services organizations;
- contributing to the competitiveness of the Western Canadian Sedimentary Basin through lower costs and tolls and alignment of pipeline capacity planning;
- improved customer service;
- improved and expanded strategic planning; and
- enhanced coordination of regulated activities and consistent objectives for the realization of operating and capital cost savings.

The merger required and was granted regulatory approvals by the Alberta Energy and Utilities Board (AEUB), the federal Competition Bureau, and the US Federal Energy Regulatory Commission (FERC). Following approval by its respective shareholders, the Alberta Court of Queen's Bench approved the merger on June 30, 1998.

The combined company, which will carry the name of TransCanada PipeLines Limited, has assets of approximately $21.4 billion, and is the fourth largest energy service provider in North America. The two pipeline systems will continue to be regulated by the NEB and the AEUB in their respective jurisdictions.

Industry Agreement on Natural Gas Pipeline Competition and Regulation

On April 7, 1998, NOVA Gas Transmission Ltd. (NGTL), NOVA Corporation (NOVA), TransCanada PipeLines Limited (TCPL), the Canadian Association of Petroleum Producers (CAPP), and the Small Explorers and Producers Association of Canada (SEPAC) signed an accord to promote a competitive environment, greater customer choice and alignment of interests in the Western Canadian Sedimentary Basin.

The accord endorses three guiding principles:

- support for competition and greater customer choice;
- the need to construct competitive incremental pipeline capacity from Western Canada by both competitors and existing pipelines in a timely, safe and cost-effective manner; and
- the need for regulatory changes to provide existing and new pipelines equal opportunity to compete, recognizing that such competition is desirable and in the best interests of the industry.

NGTL, CAPP, SEPAC and TCPL agreed to pursue these guiding principles in 1998 by:

- implementing a pipeline interconnection policy to provide shippers with the option of reasonable access to competing transmission systems and to minimize duplication of facilities; developing several regulatory changes and a proposed regulatory framework for consideration by the National Energy Board and the Alberta Energy and Utilities Board; and
- developing a process to maintain adequate separation between pipeline companies regulated and non-regulated businesses.

NOVA's Proposed New Pricing Structure

On April 6, 1999, TransCanada PipeLines Limited (TCPL), through its subsidiary NOVA Gas Transmission Ltd. (NGTL), filed with the Alberta Energy and Utilities Board (AEUB) a new pricing proposal for gas transportation tolls on NGTL (NOVA Corporation and TCPL merged in 1998).

The latest filing continues a long process towards changes to gas transmission tolls within Alberta. This process began in 1996, when prices for NGTL transmission services were an issue during an AEUB hearing into NGTL's rates.

Important steps in this process were various agreements between TCPL/NGTL and its shippers: the April 1998 *Accord*; the October 1998 *Framework*; and the March 1999 *Memorandum of Understanding*. The latest filing is the result of these negotiations.

The proposed tolling system is based on a new receipt point pricing formula, and would replace the postage-stamp rate, which was introduced in 1980. Under postage-stamp rates, customers paid the same unit price for transportation of natural gas regardless of the distance transported. Currently, under the postage-rate system, customers pay approximately 28 cents per thousand cubic feet for gas delivered to Alberta's borders, and 14 cents for delivery within Alberta.

Under the new pricing system, the Alberta border rate would vary from $0.20 to $0.36/Mcf, while the intra-Alberta rate would vary from $0.06 to $0.22/Mcf.

The rates will reflect distances from border export points, and other factors. Rate discounts will apply if shippers sign longer-term contracts with NGTL, while premium rates will apply for shorter-term deals. A new renewal notice period is also anticipated. The proposal provides for the new pricing structure to be phased in over four years.

The proposal also envisions that NGTL would no longer build new laterals from gas processing plants to NGTL mainlines as part of its regulated business. Producers or third parties would have to build the laterals, and rates paid for use of the laterals would be unregulated (This is the current situation regarding gas gathering lines, which bring production from gas wells to gas processing plants). Some producers have already voiced opposition to the proposed change to laterals policy.

The AEUB is expected to hold a hearing into the proposal, and TCPL is hoping for a ruling by July 1999.

TCPL Contract Renewal Policy

No major developments occurred in 1998 with respect to new contract renewal policies on the TransCanada PipeLines Limited (TCPL) pipeline system. As a result, TCPL has not submitted anything to the National Energy Board for approval.

TCPL is still working with its shippers to develop a new policy with respect to this matter. TCPL would like to revise its current policy to provide the company with more time to react to and manage turned-back capacity. The changes would also be designed to reduce TCPL's risk. (For further background information on this issue, please see last year's report).

In this regard, the memorandum of understanding signed by TCPL and the Canadian Association of Petroleum Producers in March 1999, and the related NOVA Gas Transmission Ltd. (NGTL) toll hearing (see previous topic), obviously have some bearing on the TCPL contract renewal issue. The new tolling arrangement being sought for NGTL includes new contract renewal policies.

Ontario — New Competitive Framework

In October 1998, the Ontario Government passed the *Energy Competition Act* which established a new regulatory framework for the energy sector in Ontario. The enforcement of the new Act marked the end of the Ontario monopoly for power generation for Ontario Hydro, and the enhancement of competition in the natural gas sector.

The new Act provides a more open and transparent natural gas commodity market by eliminating certain gas transaction barriers. In particular, title transfers of natural gas within the province are now allowed. Previously, Ontario gas buyers had to take possession of gas outside Ontario and then move it to the province on contracted pipeline capacity. The new rules will allow purchasers to buy gas delivered to Ontario. This is expected to facilitate Ontario's development as a more liquid gas market and a reference gas pricing point. The Act will thus also increase customer choice, facilitate market-based pricing, and encourage competing suppliers to offer customers one-stop shopping for natural gas and electricity.

The new legislation will also protect small consumers against unfair practices by marketing companies. The Act will require marketers selling natural gas or electricity to small customers to obtain a license from the Ontario Energy Board (OEB), which will ensure consumer protection. According to the new Act, marketers in Ontario need to obtain a licence from the OEB effective March 1, 1999. Penalty provisions will apply to marketers who do not comply with the requirements.

The implementation of the *Energy Competition Act* should help to level the playing field between electricity and natural gas. It is intended to ensure reliable and safe supply of electricity and natural gas at the lowest possible prices for consumers.

Ontario Nuclear Situation

In 1997, Ontario Hydro announced its Nuclear Asset Optimization Plan (NAOP) which entailed performance improvement on the 12 newer units and lay-up of seven units at Pickering A and Bruce A. One unit at Bruce A was laid-up in 1996. The lay-up of the older units was due to management and resource difficulties, not technological difficulties. The eight units that are laid-up represent around 40% of the installed nuclear capacity in Ontario.

Ontario Hydro (now Ontario Power Generation Inc. due to electricity deregulation/restructuring), plans to bring the four units at Pickering A back into service starting in the year 2000. The four units at Bruce A should be brought back into service between 2003–2007.

The large amount of generating capacity laid-up raised speculation about whether natural gas generation would fill the void. To date, the impact on natural gas demand does not seem to be as great as some might have expected. There are several reasons for this: i) there is a large surplus of coal-fired capacity in Ontario; ii) oil prices were lower than expected; and iii) some gas pipeline capacity constraints exist. Moreover, the Ontario government recently authorized Ontario Power to increase its electric transmission capacity from the US. Additional imports of electricity from the US would be produced from coal fired plants, not natural gas.

Thus, the potential for a substantial increase in natural gas demand as a result the loss of Ontario nuclear generating capacity appears to be lower, and less certain, than originally expected. However, some Ontario power generation projects using natural gas were announced in 1998.

Natural Gas Distribution in the Maritimes

In November 1999, approximately 440 MMcf/d of natural gas from the Sable Offshore Energy Project (SOEP) offshore Nova Scotia is scheduled to flow through the Maritimes & Northeast Pipeline (MNP). MNP, which extends over 1,000 kilometres, will reach new markets in New Brunswick and Nova Scotia, and add to exports in the US Northeast.

The National Energy Board (NEB), in December 1997, approved the Canadian portion of the pipeline. Similarly, the Federal Energy Regulatory Commission issued a final certificate in July 1998 approving the US section of the MNP project. The pipeline is currently under construction.

To date, there are three pipeline laterals proposed to broaden the reach of the system: the Point Tupper (Cape Breton) lateral, the Halifax, Nova Scotia lateral, and the Saint-John, New Brunswick lateral.

- The NEB approved the Point Tupper lateral in January 1999. Construction of this lateral is expected to begin in May 1999 and be completed by fall, for an expected in service date in conjunction with MNP.
- NEB hearings regarding the 124 kilometre Halifax lateral will begin in May 1999. The Halifax lateral is expected to be in service in October 2000, rather than November 1999 as originally planned.
- No date has been set for NEB hearings regarding the Saint-John lateral.

The New Brunswick Department of Natural Resources and Energy will regulate the forthcoming distribution of natural gas within New Brunswick.

Three different types of provincially regulated distribution rates will be established. The largest number of customers will be under a province-wide distribution utility rate. The winner of the province-wide distribution franchise is expected to be determined by the end of July 1999.

For large volume users of gas, a (lower) single end use rate will be possible. This would involve the large user purchasing a single end use franchise. These large users would thus not be served by the province-wide distributor, but would receive gas directly from MNP.

Finally, there will be a producer class rate. There is minor gas production in New Brunswick, and gas exploration continues.

In Nova Scotia, the provincial government has guidelines in place to ensure that natural gas would be available to all counties in the province and to at least 62% of all households within seven years. The Utilities and Review Board will be conducting hearings regarding natural gas distribution in the spring, and will be providing recommendations to the provincial government thereafter.

Energy Y2K and the Canadian Government

The Government of Canada has taken a four-pronged approach to the Year 2000 (Y2K) computer problem. The Treasury Board is responsible for ensuring the government's own mission critical functions are Y2K ready. Industry Canada assists domestic industry (particularly small and medium businesses) to become Y2K aware and compliant. The Department of Foreign Affairs and International Trade handles international Y2K aspects, while National Defence is responsible for contingency planning.

To perform the contingency planning function, a special agency — the Canadian National Contingency Planning Group (NCPG) — has been created. The NCPG is assessing the Y2K readiness of all infrastructure that is critical to the health, safety and economic well-being of Canadians.

For the energy sector — electricity, oil and natural gas — the NCPG has engaged Natural Resources Canada (NRCan) to perform the necessary survey work. NRCan is doing this with the cooperation of five major energy associations. The National Energy Board will also use the survey results from regulated inter-provincial pipelines as part of its Y2K compliance program.

NRCan's first survey took place in January 1999 and included over 500 energy companies. Where companies were found not to be Y2K susceptible (these are primarily small electricity distributors), they are not included in the periodic re-surveys.

The NCPG will use the NRCan survey results (and the results of surveys on other critical infrastructures such as telecommunications, transport, healthcare, etc) to assess the risk posed by Y2K, and ultimately to prepare scenarios, contingency plans, and recommendations to the federal government.

Indications to date for the energy sector show a generally high level of Y2K remediation activity, particularly by the largest private companies and regulated utilities. Canadian energy companies typically plan to have mission critical systems "Y2K ready" in the second quarter of 1999, leaving the latter half of the year for refinements, repairing non-critical systems, and for updating and testing contingency plans for Y2K scenarios.

Other studies have indicated that the Canadian energy sector is at the forefront of Y2K remediation. For example, the North American Electricity Reliability Council reports Canadian electricity producers are leading in Y2K readiness in North America. The Gartner Group indicates that Canada's oil and gas Y2K readiness matches that of the US.

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