Natural Resources Canada Ressources naturelles Canada

Canadian Natural Gas

Market Review & Outlook

May 2001

Natural Gas Division
Energy Resources Branch
Energy Sector

Canada

Foreword

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

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

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

Structure of the Report

The main section of the report is composed of graphs, with limited text comments on the side. This is a structured look at market fundamentals (supply, demand, etc.) over the past year (2000), for the near term (the rest of 2001), and the long-term (to 2010). This analysis was done first. The executive summary was done last, and it takes the analysis done in the main section, and ties it into a cohesive narrative. The executive summary is all text – no graphs – and is presented at the front of the report.

Sources

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the United States (US). Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada (StatsCan). Some data for 2000 is still preliminary and contains problems, the major one being the large "balancing item" (unaccounted for gas) relating to the US. In 2000, because of data problems, supply is about 1 trillion cubic feet greater than demand, even after accounting for storage movements.

Natural Gas Division Website

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

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

Obtaining A Paper Copy

To obtain a paper copy of this report, call (613) 992-9612, or fax your request to (613) 995-1913, or email dboisjol@nrcan.gc.ca.

Questions and Comments

Comments are welcomed, and may be directed to John Foran at (613) 992-0287.

Rapport aussi disponible en français

Natural Gas Division

Staff Contacts:

Director
Jim Booth
(613) 992-9780
jbooth@nrcan.gc.ca

Secretary
Diane Boisjoli
(613) 992-9612
dboisjol@nrcan.gc.ca

Bruce Akins
(613) 943-2214
bakins@nrcan.gc.ca

Lynn Allinson
(613) 996-1690
lyallins@nrcan.gc.ca

Lisanne Bazinet
(613) 995-5849
lbazinet@nrcan.gc.ca

John Foran
(613) 992-0287
jforan@nrcan.gc.ca

Pat Martin
(613) 995-0422
pmartin@nrcan.gc.ca

David McGrath
(613) 995-8921
dmrgrath@nrcan.gc.ca

Fax: (613) 995-1913

17th Floor
580 Booth Street
Ottawa, Ontario
K1A 0E4

Email Notification
If you wish to receive email notification of new Natural Gas Division reports send an email to dboisjol@nrcan.gc.ca.

Canadian Natural Gas
Market Review & Outlook

TABLE OF CONTENTS

Executive Summary

Executive Summary

Review of 2000

Return of the missing demand

North American gas demand had grown steadily to 1997, at about 2.5% per year, but then fell 3.4% in 1998, and remained low in 1999 – below 1997 demand. Gas demand was low mainly due to mild winters, and weak residential and commercial gas consumption. In 2000, all this demand came back suddenly. Demand increased 1,240 Bcf, or 5%, as a result of a colder than normal November-December, and a 657 Bcf increase in gas used for power generation. Gas consumption in the US industrial sector for process heat or chemical feedstocks was 319 Bcf lower than last year.

Nov.-Dec. very cold

Of the 1,240 Bcf increase in North American demand last year, almost half occurred in the November-December 2000 period, in the residential and commercial sectors.

2000 – "A Perfect Storm"

This kind of sudden demand increase would have strained markets at any time, but in 2000, other factors made markets ripe for a price increase. The situation has been compared to the movie "A Perfect Storm" – everything that could have happened to increase prices, did happen.

Entering the 2000-2001 winter, North American supply was in a weakened state. Various factors had caused North American gas drilling to be low for several years. These factors included weak gas demand; NYMEX natural gas prices averaging only $2.24/MMBtu over 1995-1999; very weak crude oil prices in 1998 and 1999; and equity market disenchantment with oil and gas producers. As a result of the low drilling, there wasn't enough production capacity to handle the demand increase.

Weak supply and low storage going into winter

Storage balances were also low. Entering November 2000, North American gas storage stood at only 3,200 Bcf, 280 Bcf lower than the previous November, and one of the lowest levels ever.

Oil prices supported higher natural gas prices. If gas prices rise when oil prices are relatively low, gas demand falls, as some industrial and power generation customers switch to oil. This tends to moderate gas prices. However in November 2000, oil prices were high – $34 per barrel – and so switching to oil was not as easy an option.

NYMEX prices spike up to $10

With this backdrop, when cold weather hit in November 2000, prices skyrocketed. The benchmark NYMEX price went from the US$4 range in mid-summer to $10 in December.

Pacific region prices disconnect

In certain regional markets, the price increase was even more pronounced. In much of the Pacific coast of Canada and the US, the supply/demand balance was even tighter than the rest of North America, and spot month prices in California reached $15.48 in December, with even higher prices in the daily market. With pipeline capacity between much of the Pacific Coast and the rest of North America already full, Pacific prices could not be dampened by additional supply from the east. Thus, for several months, Pacific gas markets became disconnected from the broader North American natural gas market. This affected prices for many consumers in British Columbia.

Exports reach 3.6Tcf

Canadian natural gas exports to the US rose 244 Bcf, or 7%, to reach 3,593 Bcf in 2000. Volumes to the US West fell 20 Bcf, to the Midwest rose 51 Bcf, and to the Northeast rose 213 Bcf. Higher exports to the Northeast were mainly due to start-up of the Maritimes & Northeast pipeline and Sable Offshore Energy Project in January 2000.

Average export price US$3.85 per MMBtu

Export prices increased dramatically. Overall, export prices at the international border went from US$2.19/MMBtu in 1999 to $3.85 in 2000.

Average domestic price Cdn$4.81/GJ

Prices received for domestic gas sales also increased, with the AECO spot month index price rising from Cdn$2.77 per Gigajoule (1999 average), to $4.81 (2000 average). In American funds, prices rose from US$1.96/MMBtu (1999 average) to $3.40 (2000 average). Most Canadian sales prices are driven by the AECO market. Prices for some British Columbia sales are driven by the Huntingdon/Sumas market. Huntingdon prices averaged Cdn$5.92/GJ in 2000, up from $3.02 in 1999.

Producer netbacks and revenues almost double

Gas prices at different geographic points include varying pipeline transmission costs. Comparing plant gate netbacks eliminates the transportation component. Plant-gate netbacks were fairly similar across export markets, and similar to domestic netbacks. Average plant-gate export netbacks increased from about US$1.88/MMBtu in 1999, to reach $3.52 in 2000. Domestic netbacks were slightly lower. In December, export netbacks received from the US West market were higher than from other export markets, as a result of the disconnect in US West prices.

Higher domestic and export netbacks, and increased sales volumes, led to much higher revenues for producers. Revenues from export and domestic sales almost doubled in 2000, climbing from Cdn$16.7 billion in 1999 to hit $32.6 billion this past year.

Northern gas discussed

Large deposits of gas were found in Alaska and the Mackenzie Delta in the 1970s. While pipeline projects for these reserves had been proposed – and in the case of the Alaska Natural Gas Transmission System, approved – the projects were dormant for decades. As late as 1998, markets felt northern gas was not needed or economic in the foreseeable future. In 2000, with higher gas prices, this changed decisively. Producer and pipeline groups began seriously discussing northern pipeline projects.

2001 Outlook

North American gas demand in 2000 rose 1,240 Bcf overall, with a 553 Bcf increase in Canadian and US core markets (due to weather), and the other 687 Bcf was net of higher power generation demand, higher gas used in operations, and lower industrial gas use for process heat or feedstock.

Weather still key factor in 2001

If weather in 2001 returns to 1999 patterns, 553 Bcf of gas demand could disappear again. However, 2000 weather was more or less "normal" (corresponded to the 30 year average).

If 2001 weather is 5% colder than normal (i.e, like 1996), we could expect core gas demand in 2001 to be 250 Bcf higher than it was in 2000.

Gas-fired power generation rising

North American power generation demand rose a notable 657 Bcf (11%) in 2000. Power generation demand is rising steadily, as most new power generation capacity being constructed in recent years has been gas-fired. However, the big increase in 2000 had a lot to do with weather. Due to a lack of precipitation, US West hydro reservoirs are very low, hydro generation is down, and more gas is being burned in gas-fired units. If 2001 is wet in the west, some of this demand could disappear.

Obviously, gas demand in several sectors could swing by huge volumes one way or the other, depending on the weather. Thus, gas market prices will remain hard to predict.

Supply on rebound, but Western Canadian production growth is slow

On the supply side, production seems to be rising at a healthy rate – 3.6% in 2000. The rate of production increase also appears to be accelerating. Admittedly, this is based on statistics to date – statistics which are still preliminary. However, production capacity will clearly be in much better shape this coming winter than it was last year. Although Canadian production overall grew 3.4% in 2000, most of this was from Sable Island. Western Canadian production grew only 1.4% last year.

November storage levels will be key indicator

Looking at storage, entering the summer of 2001, North American storage remained low. Storage must be rebuilt to more normal levels in the months ahead. This will act as extra demand – an extra 480 Bcf – compared to last year. Storage balances will also be a good indicator of the relative strengths of gas production and demand growth. If storage balances catch up to normal levels by November, this will indicate that supply growth is catching up to demand, or demand is weakening, or a combination of the two.

Exports to increase again in 2001

In 2001, Canada to US gas exports should continue to increase, as a large new export pipeline (Alliance) was completed late last year. The limitation on exports is likely to be production capacity, rather than export capacity. Another factor affecting exports will be domestic demand (the higher it is, the less gas will be available to export). Exports are expected to rise another 200 Bcf in 2001, to reach 3.8 Tcf.

Executive Summary

Bottom line: weather will drive prices

Given all the above considerations, gas prices over the next year will continue to be driven mainly by weather, with supply capacity and storage balances an important part of the setting. This summer, the severity of heat waves will drive air-conditioning use and demand for gas for power generation. Rainfall will influence hydro power supply and gas demand for power generation. Next winter, cold weather or lack of it will affect gas demand. Oil prices will also be an important factor. If gas prices stay high, and oil prices weaken, gas demand could be lost to oil-based fuels.

2001 prices higher than 2000

A review of various recent price forecasts shows a range of forecast 2001 NYMEX prices from US$3.50/MMBtu to $5.00. These are average prices (Annual average of spot month closing prices). NYMEX prices averaged $3.89 in 2000. Over January-May 2001, NYMEX prices averaged US$6.31/MMBtu, but were falling as of writing of this report.

Similarly, 2001 price forecasts for AECO range from Cdn$5.85/GJ to $6.80. AECO prices averaged $4.81 in 2000. Over January-May 2001, AECO prices have averaged Cdn$9.03/GJ.

Outlook to 2010

Long-term forecast – the generally accepted view

Our longer term forecast is generated by reviewing forecasts by various organizations for gas demand fundamentals. We then use averages to derive what could be described as a consensus scenario. For example, we assume gas demand in 2010 will be equal to the average of selected demand forecasts for 2010.

US gas demand in 2010 is expected to reach 28 Tcf; Canadian demand 3.7 Tcf, for a North American total of 31.7 Tcf. This is an increase of 5.9 Tcf over 2000 demand. Most of this increase is expected to be for electric power generation (by utilities and by non-utilities generating power).

Future supply sources

This demand would be satisfied by: US gas production of 22.8 Tcf; Canadian production of 8.5 Tcf; and 0.55 Tcf of LNG imports to the US.

Incremental supply to 2010 is expected to come from: 1) the US – 3.4 Tcf; Canada – 2.5 Tcf; and LNG – 0.3 Tcf.

Scotian Shelf production is included in the Canadian production forecasts. The average of 3 forecasts shows Scotian Shelf production reaching 0.6 Tcf by 2010.

Most forecasters did not have northern gas in the US supply picture by 2010. However, forecasters are currently re-evaluating this issue.

Long-term prices to fall from current levels

US natural gas prices are expected to drop over the next 3 years, before rising slowly. Prices fall to US$3.05/MMBtu by 2003, and then reach $3.55 by 2010. Alberta prices fall to Cdn$3.50/GJ by 2003, and then reach $3.85 by 2010. Price expectations have risen considerably since last year's report.

As no further export pipeline projects are yet formally proposed, we assume Canadian export pipeline capacity is flat to 2010. We do not assume pipeline capacity in our forecast until it is well along in the regulatory process. Existing export capacity was used at 90% load factor in 2000, for exports of 3.6 Tcf. We assume exports reach 4.2 Tcf by 2010 – a 95% load factor.

Forecasters expect more export pipe capacity to be built

We recognize that additional pipeline capacity from Canada to the US is likely to be constructed in the 2001-2010 timeframe. The largest project would be a northern pipeline project or projects, involving Alaskan and/or Mackenzie Delta production. Given the preliminary nature of northern projects, we have not included any northern pipeline scenarios in our outlook. Depending on the progress of a project or projects (i.e., pipeline applications to regulators), we anticipate including northern pipeline capacity in future versions of this report.

Similarly, PanCanadian expects to have its Deep Panuke Scotian Shelf project on production by 2005. To date, there is no pipeline application filed, and so we have not included this project in our export forecast.

Our outlooks tend to under-estimate Canadian production and exports

Due to the above factors, our Canadian exports forecast and Canadian production forecast are best viewed as minimums. Canadian exports to the US, and Canadian production, are likely to be higher than our forecasts. We recognize that past versions of this report, dating back to 1989, have consistently underestimated Canadian production and exports, due to our method of estimating pipeline capacity.

A comparison of our pipeline-restrained forecast with other industry forecasts highlights this. The average of industry forecasts shows Canadian exports reaching 4.9 Tcf by 2010, compared to our estimate of 4.2 Tcf. Similarly, an average of industry forecasts shows Canadian production at 8.5 Tcf by 2010, compared to our outlook of 7.9 Tcf.

Producer revenues expected to peak in 2001

Given our conservative assumptions about Canadian production and exports, and industry price forecasts, producer plant-gate revenues from natural gas sales are expected to peak in 2001, at Cdn$41 billion. This is a remarkable increase in the past few years – revenues in 1998 were $12 billion. Revenues would then fall to $28 billion by 2005, then rise to $34 billion by 2010.

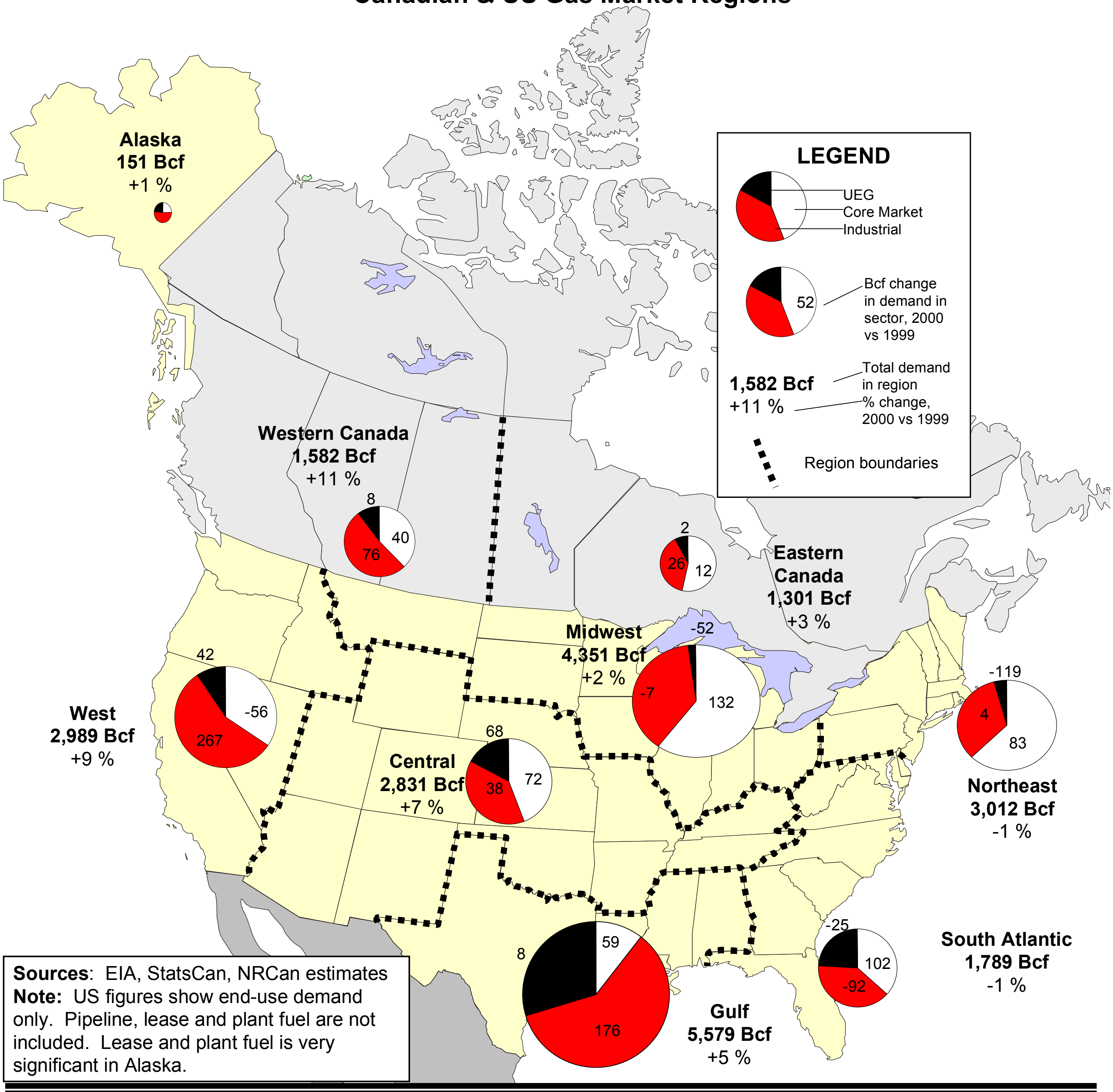
Uncertainty about supply, timing of the North

There is considerable uncertainty for the medium to longer-term, which is reflected in the lack of a strong consensus among forecasters. The main areas of uncertainty are: whether existing North American supply areas can produce 32 Tcf of gas by 2010; the level that gas prices fall to over the next few years; and, whether those prices result in development of a northern gas pipeline project or projects, to open a new supply source before the end of the decade.

Review of 2000

Natural Gas Demand

Figure 1
Canadian & US Gas Market Regions



Sources: EIA, StatsCan, NRCan estimates
Note: US figures show end-use demand only. Pipeline, lease and plant fuel are not included. Lease and plant fuel is very significant in Alaska.

The locations and scale of natural gas demand in North America are shown on the map. Also shown are the changes in demand compared to last year, by region and sector. Note that two market areas dwarf the others (US Gulf Coast and Midwest).

Core demand increases were important in the US Gulf, Central, Midwest, South Atlantic, and Northeast regions, and in Canada. Industrial demand growth was important in the West, Gulf and Canada, but Industrial demand fell in the South Atlantic. Utility power generation demand grew substantially only in the US Central and West areas.

The largest demand increases were the 267 Bcf and 176 Bcf in the US West and Gulf Coast Industrial sectors. Much of this was for power generation in the Industrial sector. (See Table 1 and Appendix 1)

Table 1
North American Gas Demand

	2000 (Bcf)	1999 (Bcf)	Difference (Bcf)	Change (%)
US Residential	4,927	4,726	201	4.3%
US Commercial	3,349	3,050	299	9.8%
US Industrial total [1]	9,406	9,001	405	4.5%
[industrial process use] [2]	*6,115*	*6,434*	*-319*	*-5.0%*
[non-utility power generation] [3]	*3,291*	*2,567*	*724*	*28.2%*
US Utility Electric Generation [4]	3,035	3,113	-78	-2.5%
US Gas Used in Operations	2,039	1,812	227	12.5%
Domestic US Demand	**22,756**	**21,702**	**1,054**	**4.9%**
Total US power generation [5]	6,326	5,680	646	11.4%
US LNG Exports	64	64	0	0.0%
US Exports to Mexico	110	61	49	80.3%
Total US Gas Disposition	**22,930**	**21,827**	**1,103**	**5.1%**
Cdn Residential	621	590	31	5.2%
Cdn Commercial	432	412	21	5.0%
Cdn Industrial	1,073	971	102	10.5%
Cdn Electric Generation	208	198	10	5.2%
Cdn Other	550	527	22	4.2%
Total Cdn Demand	**2,883**	**2,697**	**186**	**6.9%**
TOTAL N.A. DEMAND	**25,639**	**24,399**	**1,240**	5.1%
TOTAL N.A. DISPOSITION	**25,813**	**24,524**	**1,289**	5.3%

Sources: EIA Mar.2001 Natural Gas Monthly, Electric Power Monthly, StatsCan, NRCan estimates.
Notes: 1 - Industrial demand as reported in EIA Natural Gas Monthly. 2 - Calculated as Industrial demand less gas demand by non-utility generators. 3 - Gas demand by non-utility generators, Table 67, March 2001 EIA Electric Power Monthly. Most (but not all) non-utility generation is within the industrial sector. 4 - Gas consumed by Utility Electric Generators, as reported in Natural Gas Monthly. 5. Sum of non-utility and utility electric generation. See Appendix 1.

EIA's Natural Gas Monthly reports on 5 basic types of US gas demand. We have used other information sources to break out demand on the basis of economic activity. See table notes and Appendix 1.

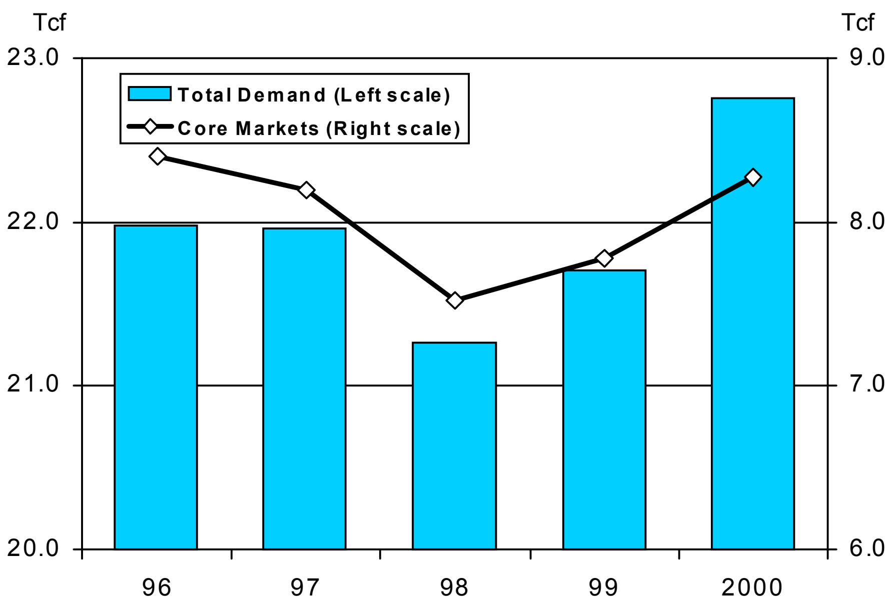
The largest increase in natural gas demand in the US was for power generation, which was up 11.4% from 1999 to 2000. All the increase was due to non-utility generators, most of which are in the industrial sector.

The residential and commercial sectors also saw large demand increases.

Gas used by the Industrial sector for heat and chemical feedstock fell heavily in 2000.

Electric utility demand declines partly reflect the sale of generation plants to non-utilities.

Figure 2
US Natural Gas Demand



Source: EIA

US demand in 2000 set a new record. This would not have happened without large core (residential and commercial) demand increases.

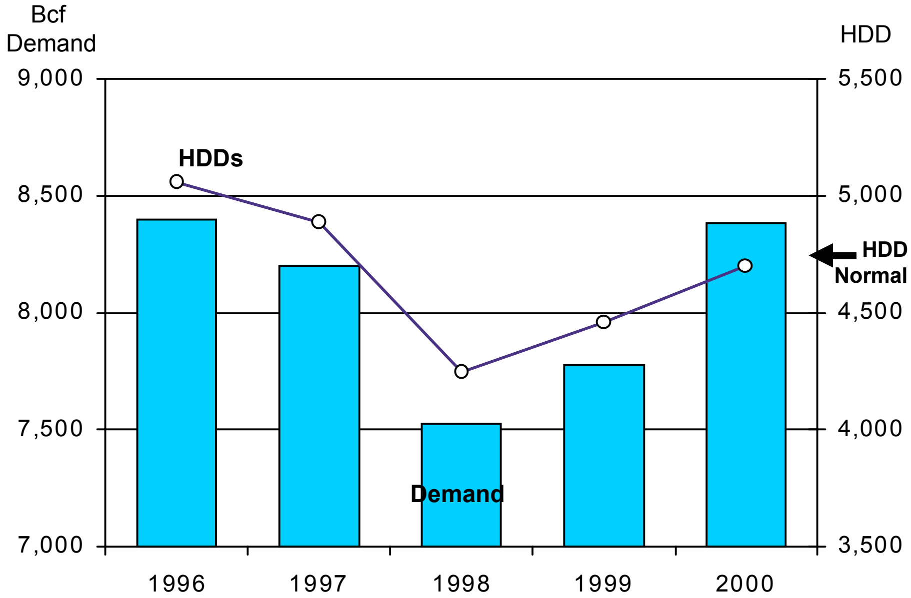
The increases of 2000 contrast with falling demand in the previous 3 years.

Weak demand in the 1997-1999 period was mainly due to falling requirements in core markets.

Core demand is almost perfectly correlated to heating degree days. Heating degree days had been low over the previous 2 calendar years, resulting in lower core demand.

For the year 2000 in total, HDD's returned to normal, resulting in a sharp increase in demand.

Figure 3
US Heating Degree Days & Core Demand



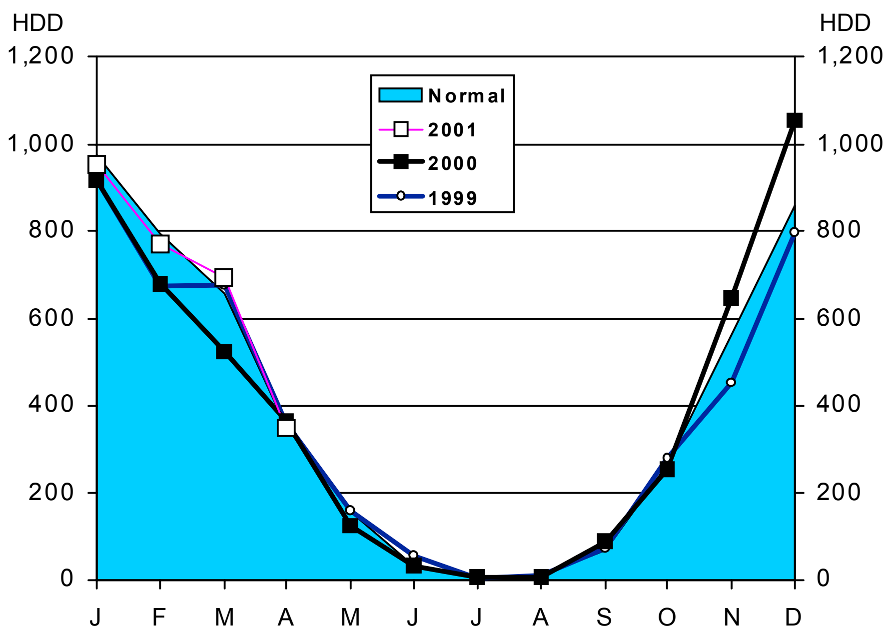
Sources: EIA, NOIAA

While year 2000 saw normal HDDs for the year overall, January through March were warmer than normal, and November and December were colder than normal.

The last two months of 2000 were much colder than last year, and in fact much colder than normal.

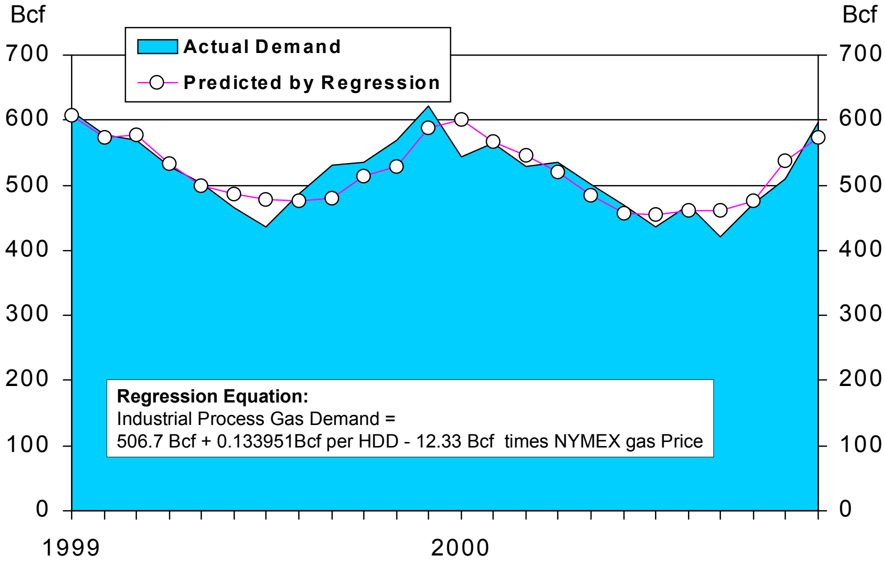
US core demand in November-December 2000 jumped 476 Bcf compared to the same period last year. So far in 2001, HDDs have been normal.

Figure 4
US Heating Degree Days By Month



Sources: EIA, NOIAA

Figure 5
Industrial Process[1] Gas Demand



Sources: EIA NGM, EPM **Note:** 1- Calculated as Industrial demand (NGM, Table 3) less Nonutility demand (EPM, Table 67).

"Industrial Process" demand includes industrial use of gas for process heat, space heating, and chemical feedstock. It does not include gas used for power generation in the industrial sector. See Appendix 1 for further detail.

Regression analysis indicates that industrial process demand is driven by Heating Degree Days and natural gas prices.

In 2000, the increase in HDDs was more than offset by higher gas prices, leading to a drop in demand in this sector.

Table 2
US Electric Generation
(Billion Kilowatt-Hours)

Year	Coal Billion Kw-Hrs	Nuclear Billion Kw-Hrs	Gas Billion Kw-Hrs	Hydro Billion Kw-Hrs	Oil Billion Kw-Hrs	Other Billion Kw-Hrs	Total Billion Kw-Hrs
1996	1,796	675	470	344	82	80	3,447
1997	1,844	629	497	355	93	77	3,494
1998	1,874	674	549	319	127	75	3,618
1999	1,884	728	570	313	124	87	3,706
2000	1,965	754	611	269	109	84	3,792
Difference	80	26	41	-44	-15	-3	86
% Change	4.3%	3.5%	7.3%	-14.1%	-11.8%	-3.5%	2.3%

Source: Electric Power Monthly, Table 3 and Table 58

As Table 2 shows, electricity generated from natural gas increased by 41 billion kilowatt-hours, or 7.3%, in 2000. Higher gas generation offset lower oil and hydro power generation. Hydro was affected by low precipitation in the US West, while oil was lower due to high oil prices. As a result, gas used in US power generation rose by 646 Bcf in 2000.

All the gas demand growth occurred in non-utility generation.

This is partly a result of power utilities selling generation assets to non-utility companies. In 2000, 75 US power generation plants were reclassified from utility to non-utility status.

This table reports provincial and total Canadian natural gas demand for the past year.

Total demand increased 7% in 2000 compared to 1999. The most significant increases occurred in Western Canada and in Yukon. However, Yukon demand represents only about 1% of total Canadian demand.

Natural gas demand in Manitoba and Ontario remained fairly stable in 2000.

Table 3
Natural Gas Demand by Province (Bcf)

2000	B.C.	Alberta	Sask.	Manitoba	Ontario	Quebec	Yukon	Total
January	34.6	101.8	28.1	13.5	134.6	29.5	1.8	**343.9**
February	32.2	91.6	23.7	10.9	131.9	26.5	1.7	**318.4**
March	31.7	90.1	22.5	9.2	108.2	24.0	1.3	**287.0**
April	23.9	77.8	18.9	7.5	88.7	20.8	1.8	**239.5**
May	25.1	68.9	16.0	5.0	61.0	15.6	4.1	**195.7**
June	19.3	67.4	11.3	4.6	53.0	12.4	3.9	**172.0**
July	19.8	68.6	13.2	3.9	43.7	12.8	2.0	**164.0**
August	20.3	67.7	14.5	3.7	48.3	13.2	3.7	**171.6**
September	19.8	72.2	14.5	4.5	48.2	13.5	3.6	**176.3**
October	24.7	87.9	20.2	6.8	59.2	17.6	3.5	**219.9**
November	35.0	92.3	25.5	9.4	78.1	21.6	4.0	**265.9**
December	36.5	99.5	29.0	13.9	119.1	26.8	4.3	**329.1**
Total 1999	284.6	900.7	223.8	90.0	958.9	218.1	21.1	**2,697.2**
Total 2000	**323.0**	**985.8**	**237.4**	**92.9**	**973.9**	**234.6**	**35.8**	**2,883.3**
Difference	38.4	85.1	13.6	2.9	14.9	16.5	14.7	186.1
% change	**13.5%**	**9.4%**	**6.1%**	**3.2%**	**1.6%**	**7.6%**	**69.7%**	**6.9%**

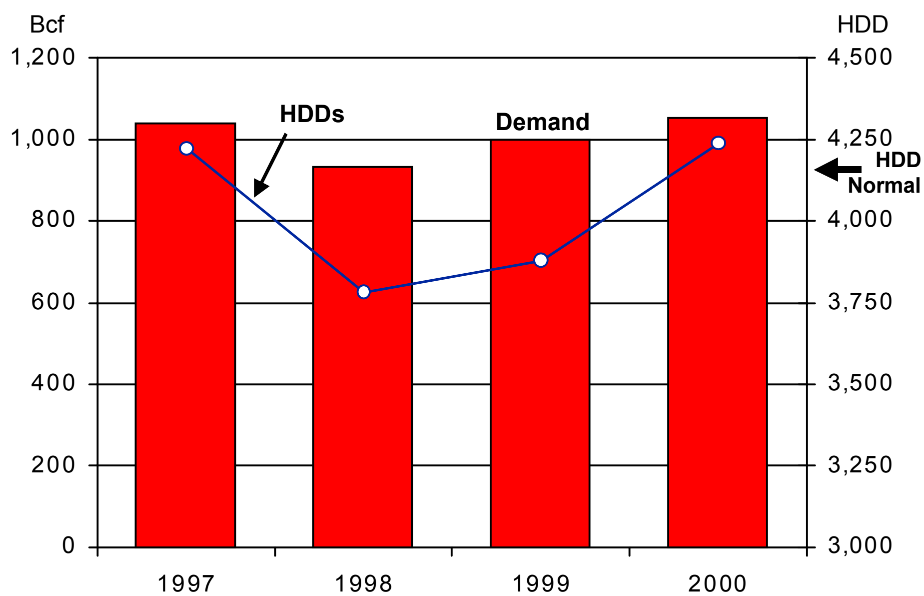
Sources: NRCan estimates, StatsCan

This figure illustrates core Canadian demand from 1997 to 2000.

Total core demand in 2000 surpassed core demand in the previous three years, due to a return to normal weather patterns.

The past three winters and past 2 calendar years were warmer than normal, while the 2000/01 winter started out severely colder than the previous three.

Figure 6
Heating Degree Days & Core Canadian Demand



Sources: NRCan estimates, StatsCan

Table 4
Canadian Demand by Sector
(Bcf)

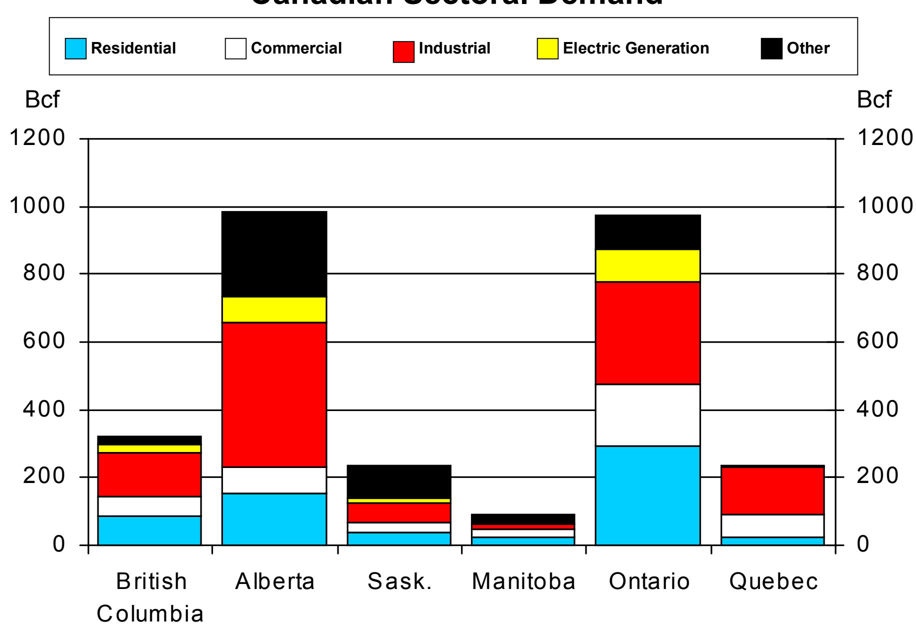
2000	Residential	Commercial	Industrial	UEG	Other	Total
January	96.3	68.4	118.9	20.1	40.3	**343.9**
February	89.7	63.3	109.2	18.7	37.5	**318.4**
March	78.6	55.5	98.2	16.6	38.1	**287.0**
April	47.0	32.3	96.6	20.7	42.9	**239.5**
May	37.2	25.3	77.3	16.5	39.4	**195.7**
June	32.0	21.5	67.3	14.3	36.9	**172.0**
July	17.6	11.7	74.2	15.1	45.5	**164.0**
August	18.6	12.4	77.5	16.0	47.0	**171.6**
September	18.6	12.5	78.0	16.0	51.2	**176.3**
October	47.5	32.9	75.1	14.3	50.0	**219.9**
November	59.8	41.7	90.2	17.3	56.9	**265.9**
December	77.6	54.7	110.5	22.3	64.0	**329.1**
Total 1999	589.6	411.7	971.0	197.5	527.4	**2697.2**
Total 2000	**620.5**	**432.3**	**1073.0**	**207.8**	**549.8**	**2883.3**
Difference	30.9	20.5	102.0	10.2	22.4	186.1
% change	**5.2%**	**5.0%**	**10.5%**	**5.2%**	**4.2%**	**6.9%**

Sources: NRCan estimates, StatsCan

Canadian demand increased in all sectors in 2000. Industrial demand increased the most in 2000, over 10% compared to 1999. This follows two consecutive years of declines.

Similar to the industrial sector in the US, Canadian industrial demand is related to gas prices, HDDs, and/or crude oil prices. While industrial demand in the US decreased due to the increase in gas prices, there appears to be a slight lag in the response to higher prices in the Canadian industrial sector.

Figure 7
Canadian Sectoral Demand



Source: StatsCan

Figure 7 illustrates demand for gas in each sector and province for 2000.

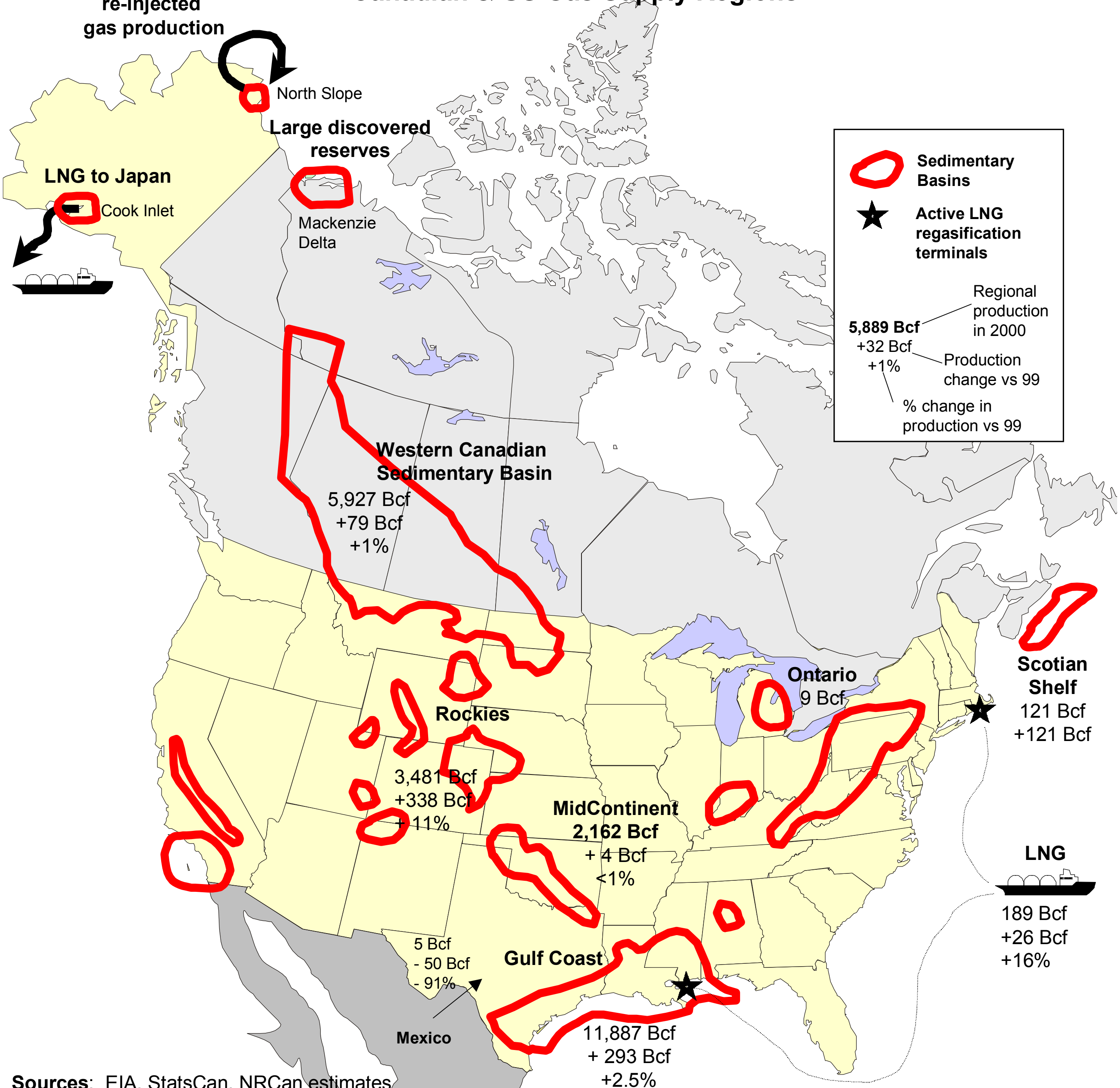
The industrial sector represents about 37% of total Canadian consumption.

The other most important market in Canada is the core sector, which includes space heating for residential and commercial buildings. Core demand increased by 5% in 2000 relative to 1999. The largest core sector is in Ontario.

Review of 2000

Natural Gas Production

Figure 8
Canadian & US Gas Supply Regions



Sources: EIA, StatsCan, NRCan estimates

The map shows the major natural gas-producing basins of North America. In 2000, the big additional supplies came from the US Rockies, Gulf Coast, and Canada's Scotian Shelf.

Western Canadian production, which grew 1.3% last year, was fairly weak again this year, growing 1.4% in 2000.

Production in the very mature Midcontinent region was flat.

LNG imports to the US were up, but the increase did not amount to significant volumes of gas.

US imports of Mexican gas fell 50 Bcf compared to last year.

Table 5
North American Gas Supply (Bcf)

	2000 (Bcf)	1999 (Bcf)	1998 (Bcf)	% Change 99 vs 98	% Change 00 vs 99
Total Gulf	11,887	11,594	11,834	-2.0%	2.5%
US Midcontinent	2,162	2,158	2,297	-6.1%	0.2%
US Rockies	3,481	3,143	3,051	3.0%	10.8%
Other US	1,791	1,729	1,526	13.3%	3.6%
Total US Production	**19,320**	**18,623**	**18,708**	**-0.5%**	**3.7%**
Canadian Production	6,057	5,857	5,780	1.3%	3.4%
LNG	208	164	83	97.6%	26.8%
Mexican Imports	6	55	15	263.3%	-89.7%
Supplementals	99	98	102	-3.9%	1.0%
TOTAL N.A. SUPPLY	**25,690**	**24,797**	**24,688**	**0.4%**	**3.6%**

Sources: EIA March 2001 Natural Gas Monthly, StatsCan, MMS, NRCan estimates.
Notes: Gulf Offshore includes only the Gulf of Mexico OCS. Canadian production is marketable gas plus reprocessing shrinkage, source StatsCan.

North American gas supplies rose by 893 Bcf, or 3.6%, in 2000. This was a much better production performance than last year.

The largest amount of new production came from the US Rockies, followed by the US Gulf Coast and Canada.

Imports from Mexico fell to almost nothing, while LNG increased moderately in absolute terms.

Table 6
North American Gas Drilling Indicators

	2000 (Wells)	1999 (Wells)	1998 (Wells)	% Change 99 vs 98	% Change 00 vs 99
Gulf Onshore (1)	4,860	3,566	4,907	-27%	36%
Gulf Offshore (2)	117	80	91	-12%	47%
Total Gulf (3)	553	380	517	-27%	46%
US Midcontinent (3)	125	72	106	-32%	75%
US Rockies (3)	143	89	110	-19%	60%
Other US (3)	97	84	120	-30%	16%
Total US (4)	**918**	**624**	**853**	**-27%**	**47%**
Canada Shallow (5)	5,860	3,858	2,014	92%	52%
Canada Deep (6)	3,053	2,432	2,561	-5%	26%
Total Canada (7)	**8,913**	**6,290**	**4,575**	**37%**	**42%**

Sources: Texas RRC, Baker Hughes, Daily Oil Bulletin, NEB.
Notes:
(1) Texas onshore gas completions only. This is the major portion of Gulf Onshore drilling.
(2) Average weekly gas-directed rig count (Baker-Hughes). Number of wells not available.
(3) Average total weekly rig count including oil-directed and gas-directed rigs.
(4) Average weekly gas-directed rig count during the year.
(5) East and SE Alberta gas wells, plus Saskatchewan gas wells.
(6) Rest of Alberta gas wells, plus all British Columbia gas wells.
(7) Total number of Western Canada gas wells.

Various drilling statistics are shown in the table. (Gas well numbers are not available in many areas).

North American gas drilling in 2000 was up strongly, and at new record levels, in most regions. This is a positive signal for future supply.

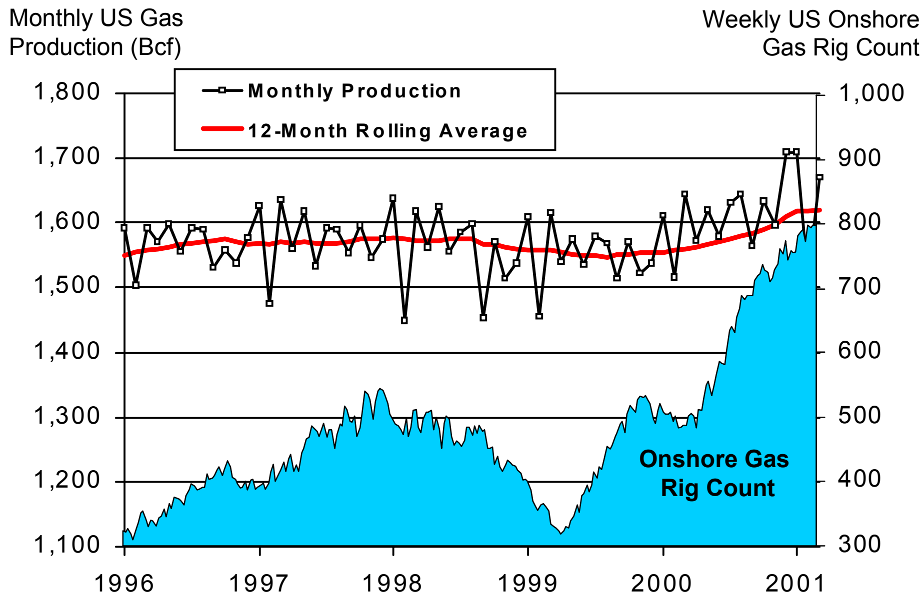
Note that last year, drilling only increased in the shallow regions of Western Canada. All other regions showed drilling declines.

The recovery in US onshore gas drilling is even more dramatic when looking at monthly detail.

US onshore gas drilling is far above previous record levels. Offshore drilling is also above former record levels, but only slightly.

These high rates of drilling appear to be having a positive impact on US gas production, as shown in the figure.

Figure 9
US Production & Drilling Trends



Sources: Baker Hughes, EIA

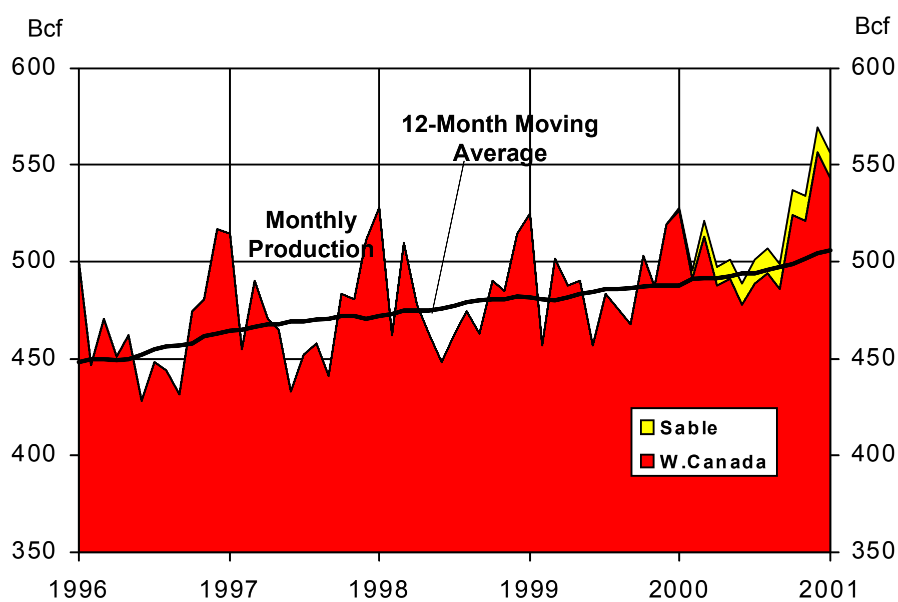
Canadian natural gas production is also rising; 3.4% in the last 12 months.

Most of the production increase is due to startup of the Sable offshore energy project in 2000.

In 2000, production from Western Canada increased by 1.4%.

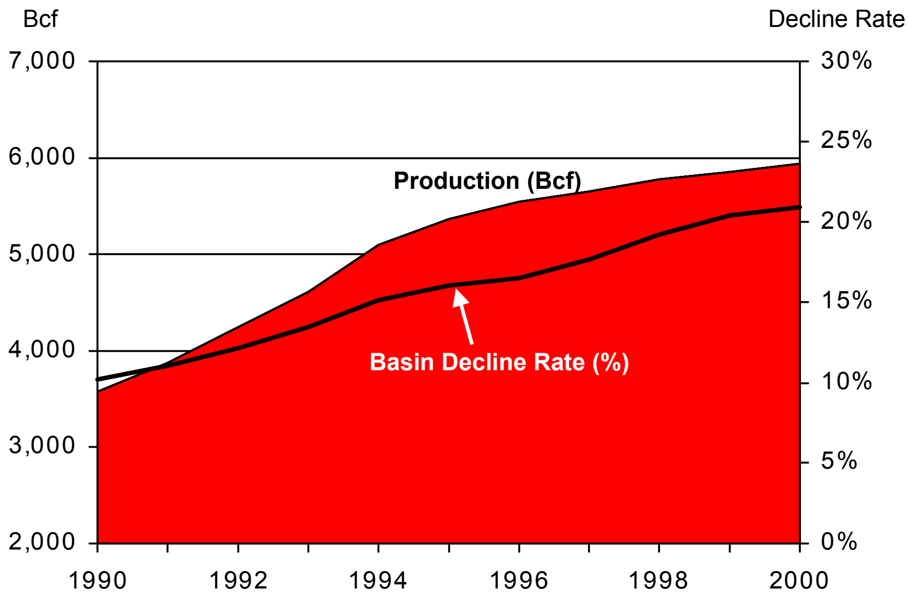
With Sable stabilizing in 2001 vs 2000, any production growth in 2001 will have to come from Western Canada.

Figure 10
Canadian Production Trends



Sources: CNSOPB, StatsCan. **Note**: seasonality of Canadian production is partly due to upstream storage being included in production - wellhead production is flatter.

Figure 11
WCSB Production & Decline Rates



Sources: StatsCan, NRCan estimates.

One reason for the weak production growth in Western Canada during 1999 and 2000 was higher decline rates on existing production.

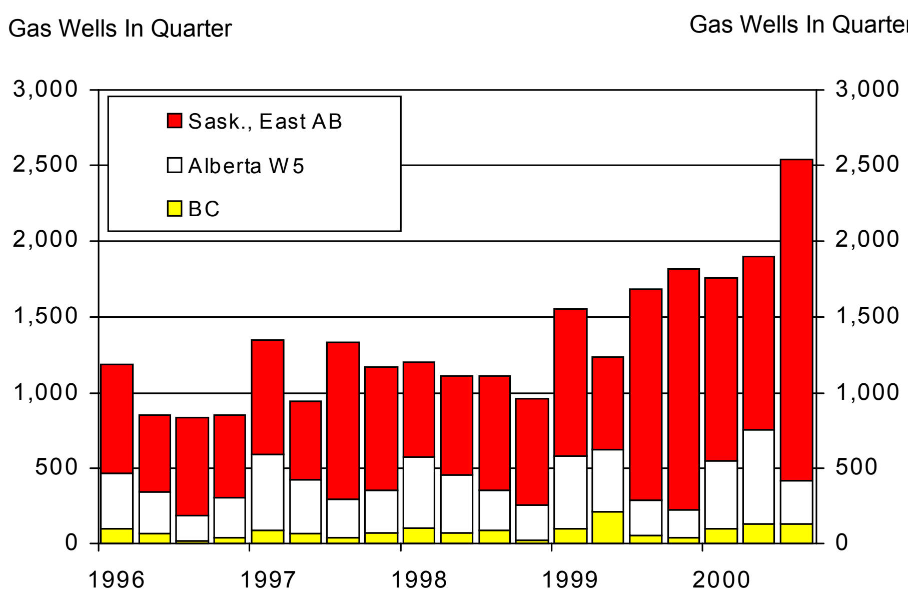
Rapid Canadian production growth in the 1990s was achieved by increasing production from existing wells.

As wells were opened up, their decline rates increased.

Compared to the early 1990s, more new wells and more drilling are now needed to replace wells which decline faster.

This is the "treadmill effect" – you have to run harder to stay in the same place.

Figure 12
Western Canada Gas Drilling



Source: Nickles Daily Oil Bulletin

The other main reason for the weak production growth in Western Canada was the location of drilling.

Most drilling in 2000 occurred in the eastern areas of the basin.

Wells in the east (all Saskatchewan and east of the fifth Meridien in Alberta) are relatively poor producers, yielding on average about 0.1 Bcf in their first year of production.

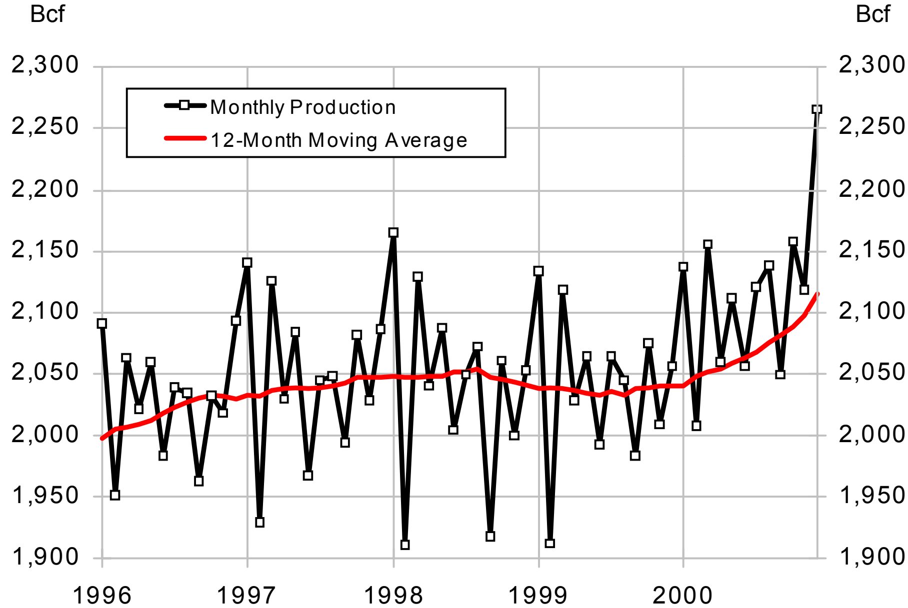
Wells on the west side of the basin yield about 1 Bcf in their first year of production.

So far in 2001, drilling seems to be shifting to the west, which should result in a better production response.

In summary, a recovery in North American natural gas production seems to be well under way.

Gas drilling is at record levels in most supply regions. Production in 2000 increased 3.6%. Further, production growth appears to have accelerated during 2000.

Figure 13
US + Canadian Production Trend



Sources: EIA, StatsCan

Review of 2000

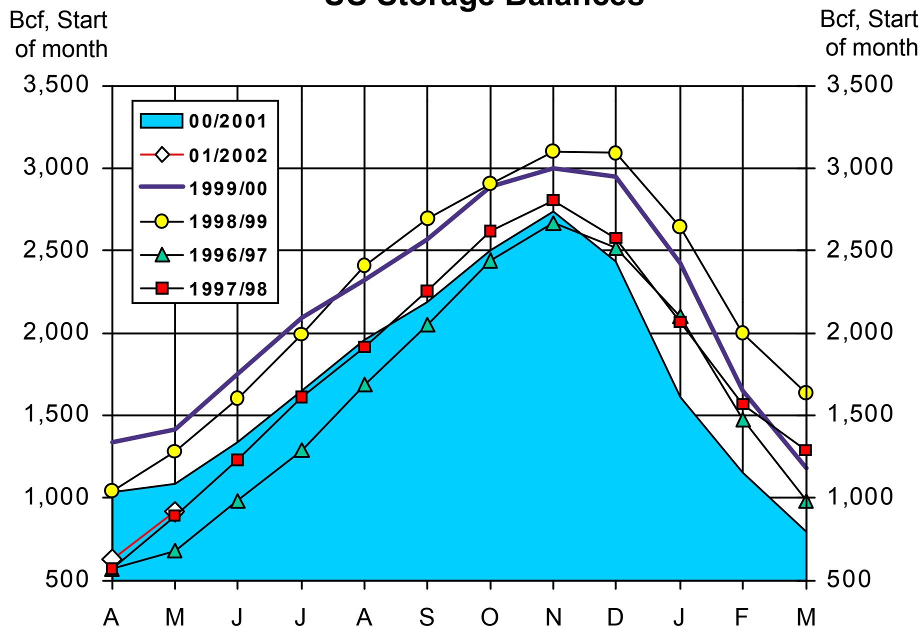
Natural Gas Storage

Natural gas storage is the barometer of the market. US storage injections during summer 2000 were weak. November 2000 storage was lower than November levels of previous years.

Since November and December were very cold, storage balances fell quickly, resulting in extremely low storage through January-March.

At least 2.2 Tcf must be injected this summer to reach normal fill levels in the 2.7 Tcf range by November.

Figure 14
US Storage Balances

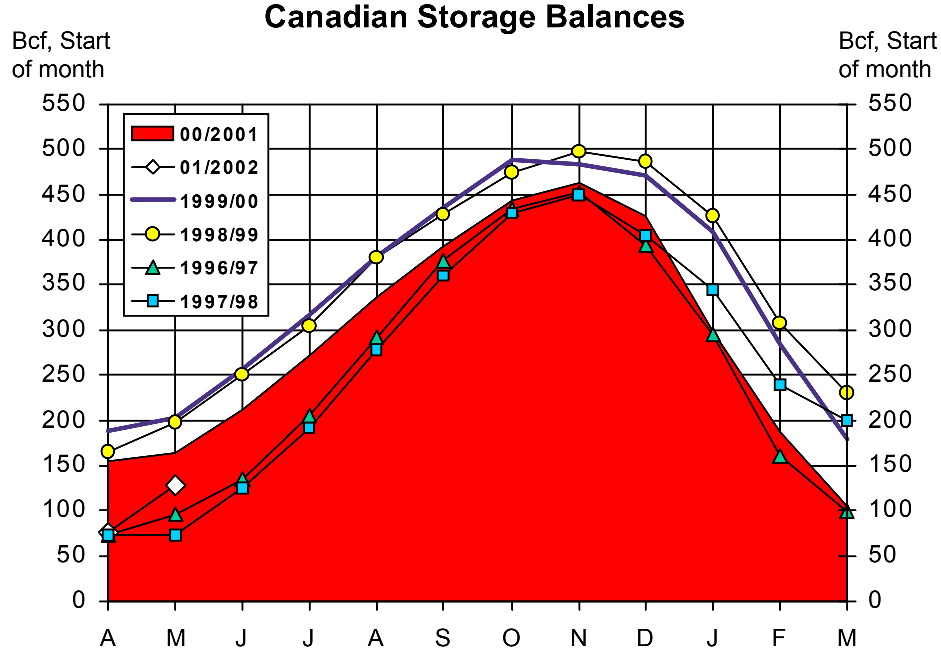


Source: NRCan estimates from AGA weekly data

Canadian storage injections during summer 2000 were also weak, resulting in comparatively low storage by November 2000.

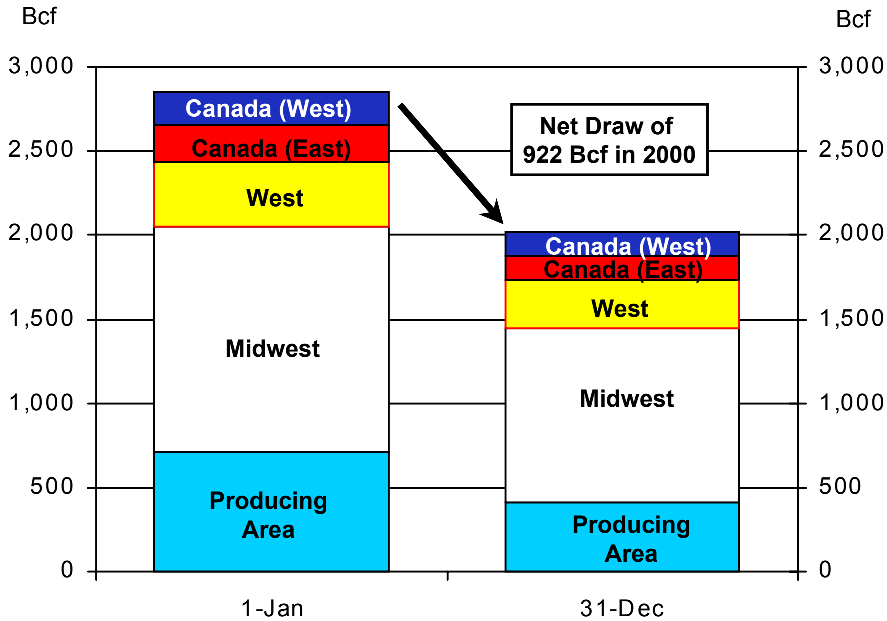
Going into the summer 2001 injection season, Canadian storage balances remain low. About 400 Bcf will have to be injected to reach normal levels by November 2001.

Figure 15
Canadian Storage Balances



Source: NRCan estimates from CGA weekly data

Figure 16
Storage Changes During 2000



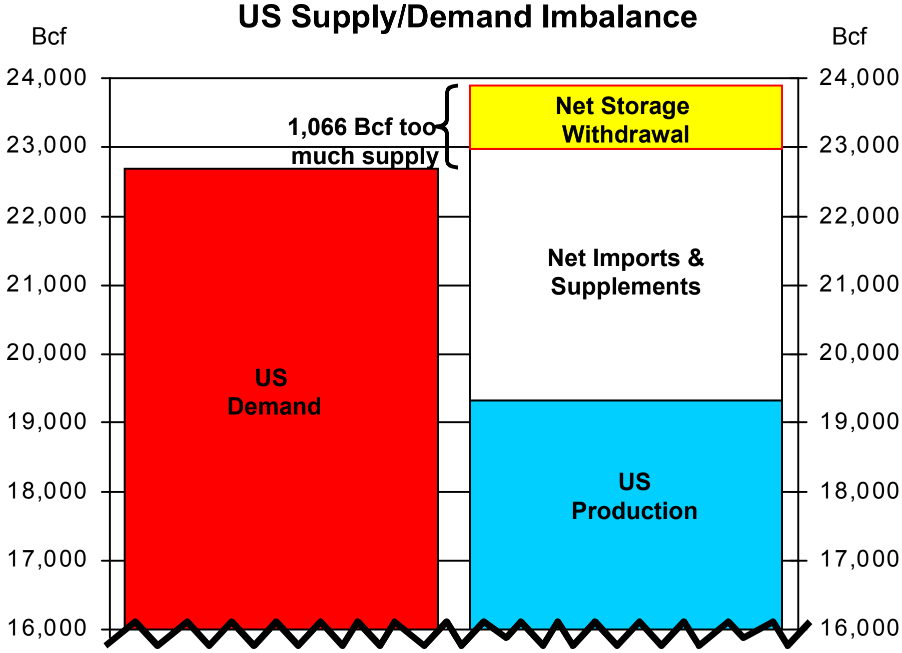
Sources: AGA, CGA

On Jan 1st, 2000, the AGA and CGA storage surveys showed 2,830 Bcf of gas in North American storage. By Dec 31st, there was only 1,907 Bcf. Thus, during calendar year 2000, there was a net storage draw of 922 Bcf. This was the largest single source of incremental "supply" in 2000.

This follows a net draw of 370 Bcf last year.

Storage balances at the start and end of year are particularly important in reconciling unequal annual demand and supply figures.

Figure 17
US Supply/Demand Imbalance



Source: EIA March 2001 NGM

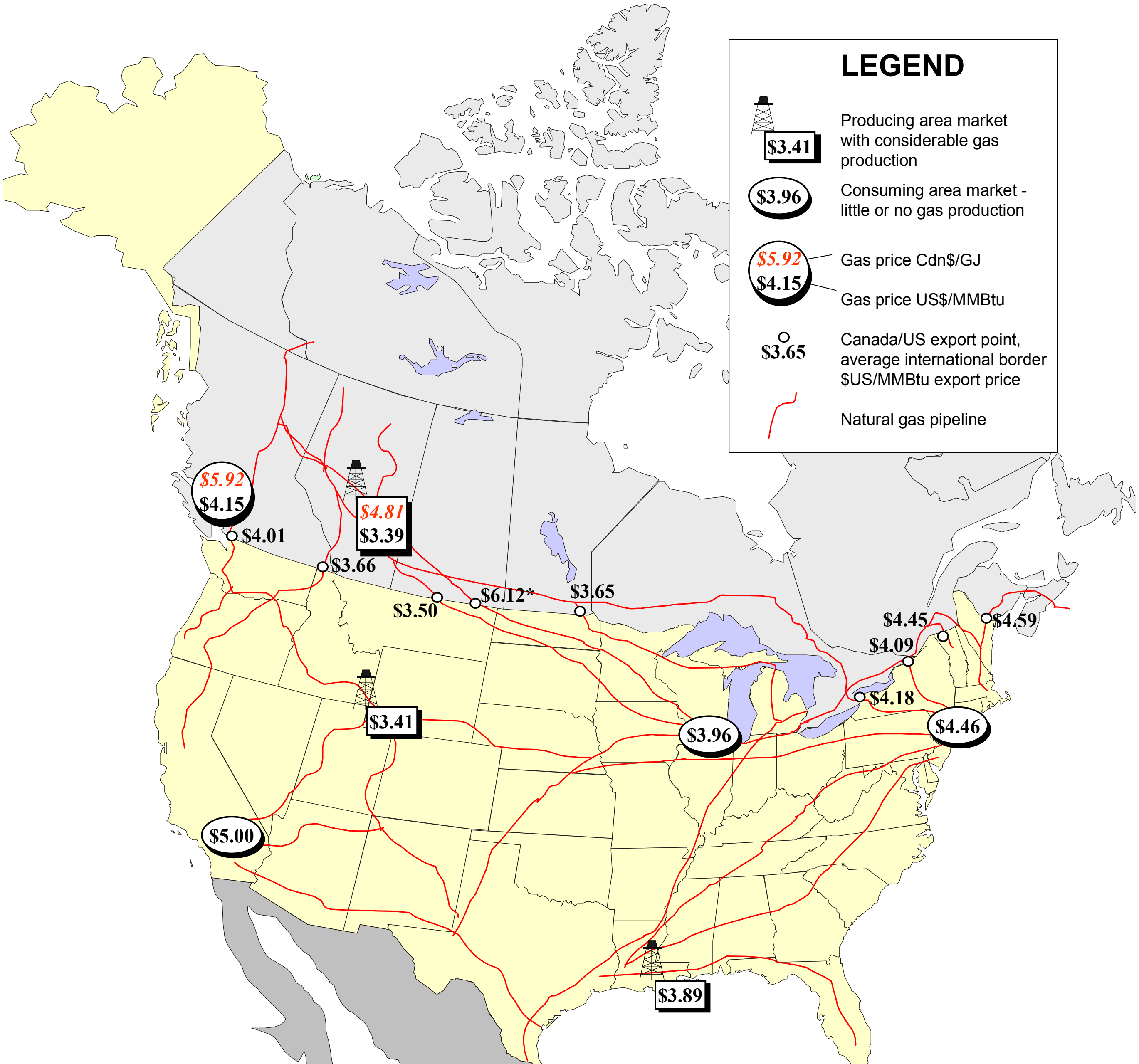
Supply and demand figures should be equal, once storage movements are accounted for, but US preliminary numbers typically don't balance.

Current EIA figures show a negative 1,066 Bcf "balancing item" for 2000 – supply is higher than demand.

Review of 2000

Natural Gas Prices

Figure 18
Natural Gas Prices

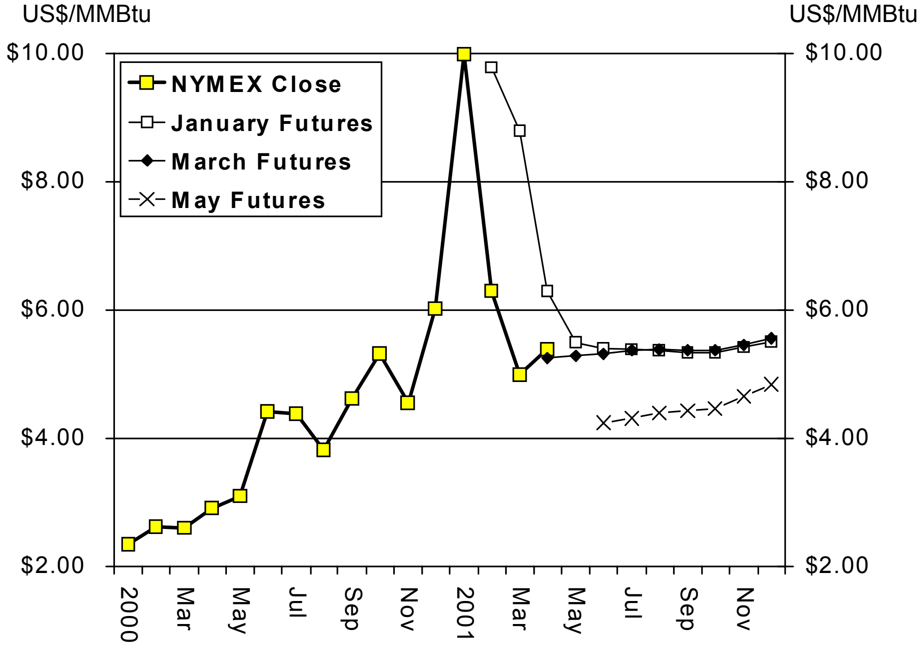


Source: Friedenberg, NEB. ***Note:** Elmore exports are only for a portion of 2000 - affects year price average.

The map shows various North American natural gas spot-month market prices. Prices shown are the annual average of 12 monthly prices. Average export prices at Canada/US export points are also shown.

Markets remained fairly well integrated, as generally there was sufficient pipeline capacity to keeps markets linked. The exception was the Pacific coast. Demand factors specific to the Pacific coast led to higher demand in November and December 2000. However, there was insufficient pipeline capacity to increase flows from the east. As a result, Pacific prices disconnected from those in the rest of North America.

Figure 19
NYMEX Contract Prices



Sources: Friedenberg, Gas Daily

The benchmark NYMEX gas settlement price is shown.

Natural gas prices increased dramatically in 2000. Prices started going outside of normal boundaries by mid-year, and peaked in January 2001.

The levels reached in 2000 for gas prices signalled a new era in North American natural gas pricing.

The figure also shows the market price of gas for forward month delivery as of the beginning of January, March, and May. Note that price expectations are constantly changing.

Figure 20
Natural Gas Price Drivers

Driver	Status of Driver in 2000	Caused Gas Price in 2000 To Be:	Status of Driver in 2001
Crude Oil Prices[1]	High ($30.30)	High	Lower ($27.40ytd)
Heating Degree Days	High	High	2000 was normal
Cooling Degree Days	High	High	Normal is lower
Hydro Capacity	Low in west	High	Hydro is still low
Gas-fired Power Cap.	Growing	High	Still rising
Storage	Very low	High	Not known yet
Gas Supply	Up 3.6%	High	Up 3.6%?
Gas Demand	Up 5.1%	High	?
Drilling in previous year	Low	High	High
Pipeline Capacity	Low to Pacific[2]	High in Pacific	Still low to Pacific

Notes: 1 - Crude price shown is WTI in US dollars per barrel from Friedenberg. 2 - Pipeline capacity to the US West was reduced in August 2000 by the explosion of the El Paso Pipeline.

In many ways, 2000 was "A Perfect Storm", in terms of natural gas prices. Numerous factors were all tending to cause high gas prices.

Looking to the rest of 2001, many of these influences for high gas prices have changed.

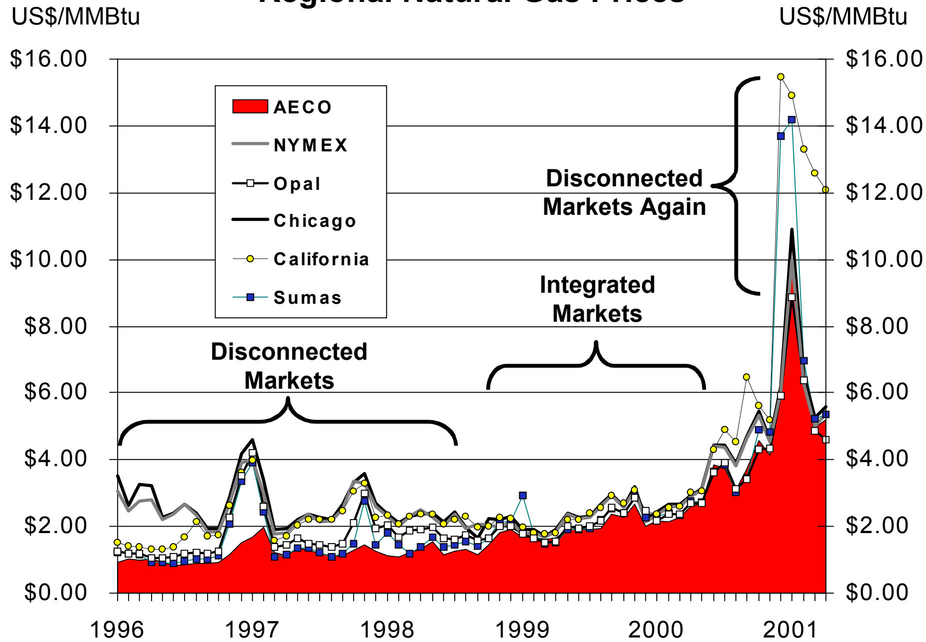
Other factors are driven by the weather and are impossible to predict.

Note that although supply increased 4% in 2000, this was not enough to prevent high prices, since demand increased 5%, and given that storage was low.

North American gas prices had converged by late 1998, as adequate pipeline capacity had, by that time, linked markets.

In late 2000, demand growth in areas bordering the Pacific resulted in demand exceeding pipeline capacity into the region. Pacific prices disconnected from prices in the rest of North America. Until more pipeline capacity is built, Pacific markets remain vulnerable to higher prices than other regions.

Figure 21
Regional Natural Gas Prices

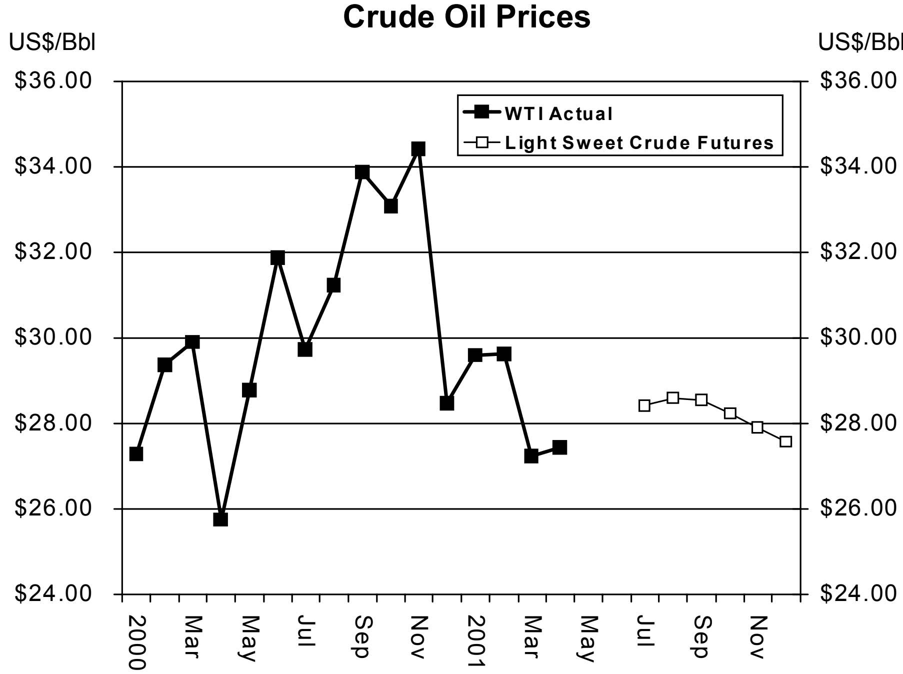


Source: Friedenberg

Crude oil prices influence natural gas prices. In 2000, crude oil prices were high, tending to support high gas prices.

In 2001, crude prices are falling. Indicators from the futures market are that crude prices will continue to fall to the end of the year.

Figure 22
Crude Oil Prices

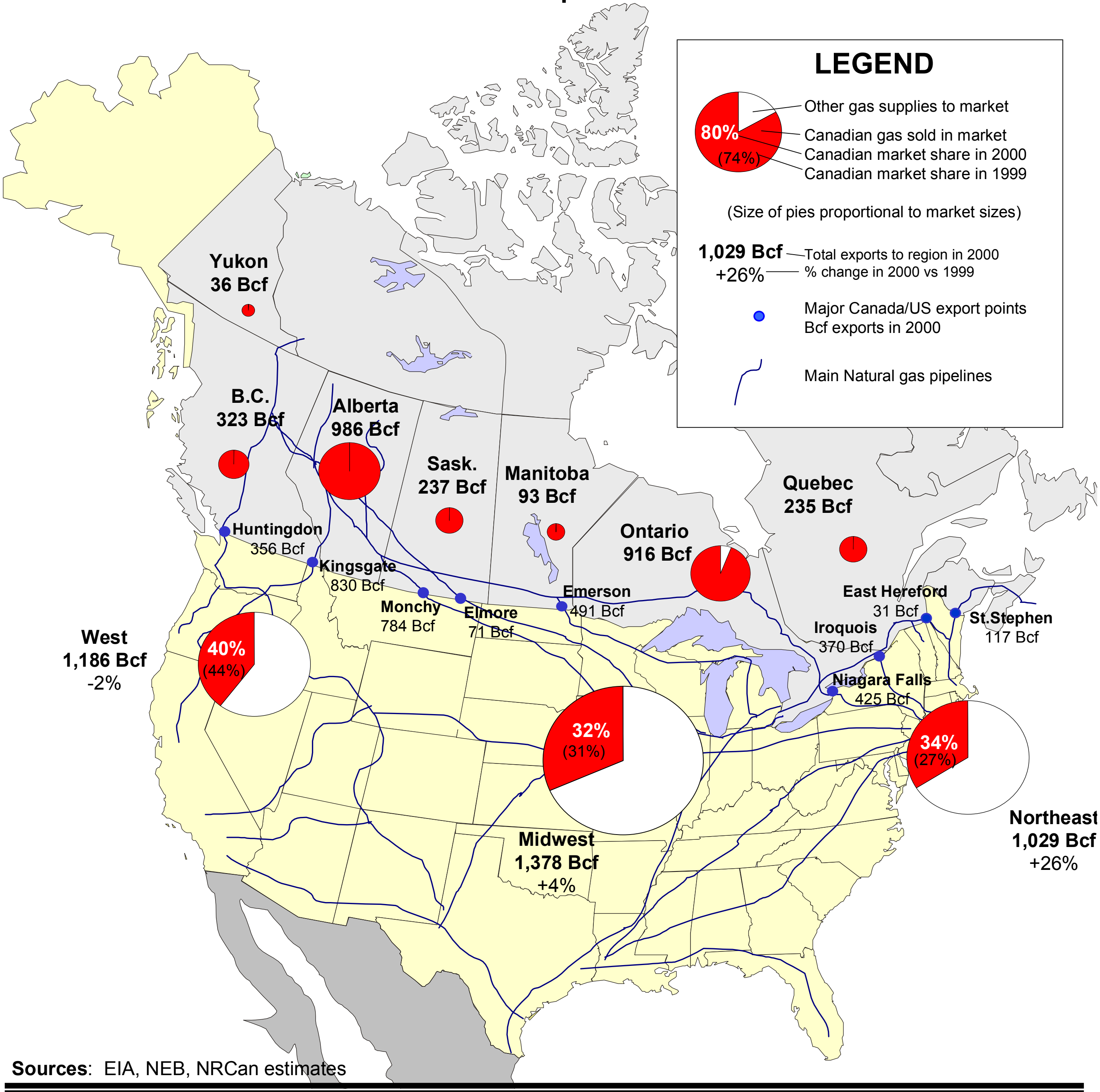


Sources: Friedenberg, Globe & Mail

Review of 2000

Canadian Export & Domestic Sales

Figure 23
Domestic & Export Markets



Sources: EIA, NEB, NRCan estimates

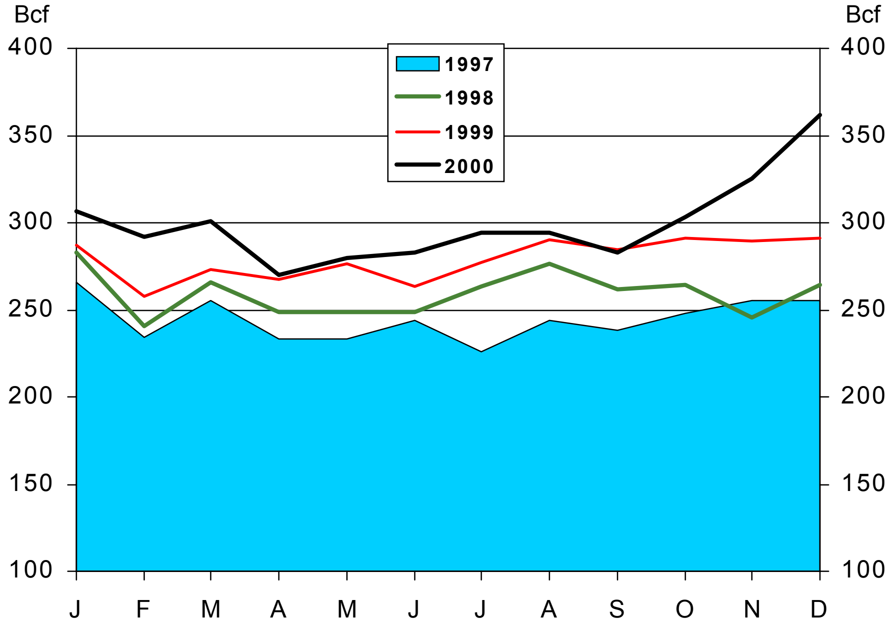
The location and scale of Canadian natural gas sales are shown on the map.

The majority of Canadian natural gas demand is satisfied by Canadian production. Canada imported 57 Bcf of natural gas in 2000, which represented about 2% of Canadian demand.

For the US however, Canadian exports represented 16% of total US natural gas consumption.

Exports from Canada to the US Northeast increased 26% in 2000, due to the completion of the Sable Offshore Energy Project (off the coast of Nova Scotia) and the Maritimes & Northeast Pipeline in late 1999.

Figure 24
Monthly Natural Gas Export Trends

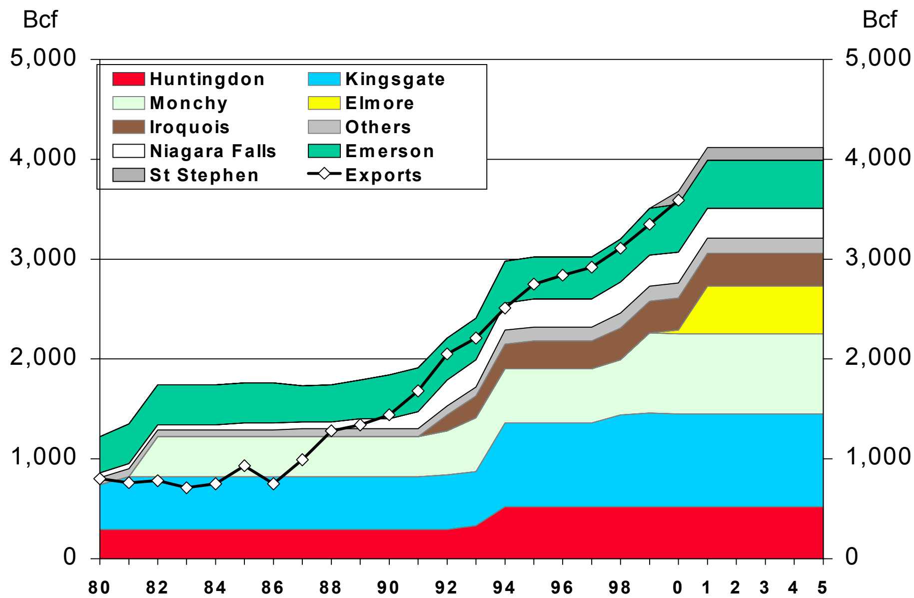


Source: NEB

Exports to the US went from 3,350 Bcf in 1999 to 3,593 Bcf in 2000, an increase of 7%. Our forecast done last year was a little lower, 3,470 Bcf.

The jump in exports in November and December 2000 is mainly due to the commissioning of the Alliance Pipeline and high US demand.

Figure 25
Pipeline Capacities by Canadian Export Point



Sources: NEB, NRCan estimates, Pipeline Companies, Regulatory Filings

Higher exports were achieved as a result of expanded export pipeline capacity.

Load factors on export capacity remained at about the 90% full level, but with higher capacity, exports increased.

Capacity increases in 2000 included the start-up of Maritimes & Northeast (St Stephen export point), plus one month of full capacity on Alliance (Elmore export point).

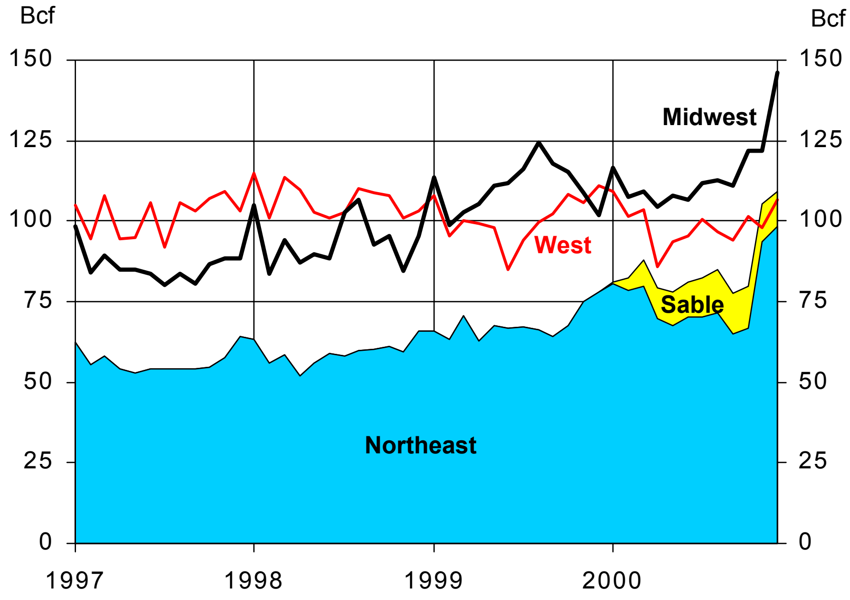
Capacity in 2001 will be higher again, as Alliance will be operating in all 12 months of the year.

Regionally, Northeast exports increased the most in 2000. Of the 213 Bcf increase, 117 Bcf was attributable to Sable production.

Midwest exports increased by 51 Bcf, partially displacing exports to the US West, which fell 20 Bcf.

Midwest exports should increase dramatically in 2001 as capacity on the new Alliance pipeline will be available for the entire year.

Figure 26
Regional US Exports



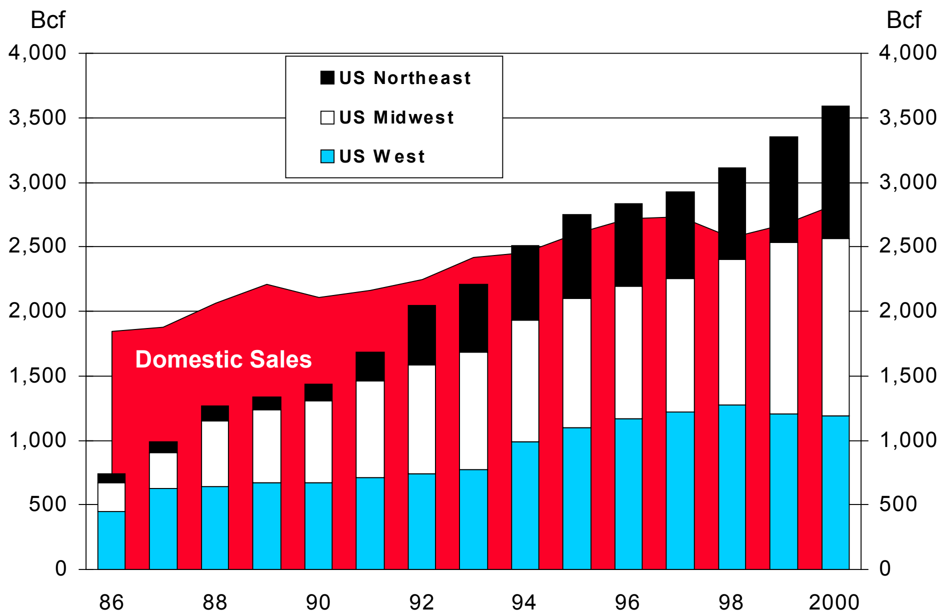
Source: NEB

Both domestic and export markets showed increases in sales in 2000. Domestic sales increased 157 Bcf, mainly due to colder weather.

In total, export sales increased 244 Bcf.

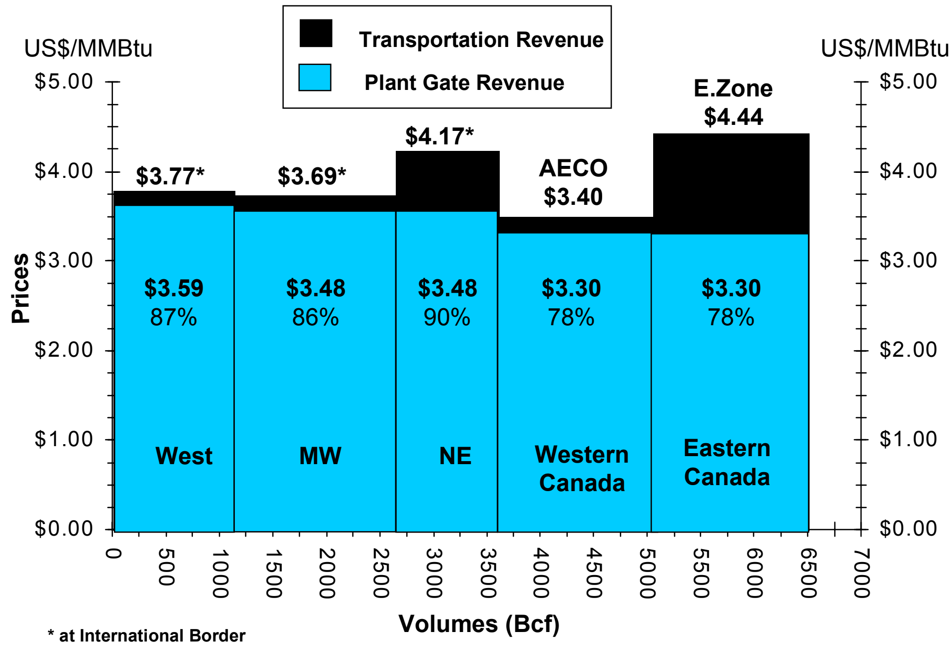
Exports represented 56% of total Canadian natural gas sales in 2000.

Figure 27
Domestic & Export Sales



Sources: NEB, NRCan estimates, StatsCan

Figure 28
Regional Prices & Volumes



* at International Border

Sources: Friedenberg, NEB, NRCan estimates, StatsCan. **Notes:** Eastern zone price is a net-forward price, i.e., AECO plus 100% load factor tolls to the eastern zone.

The figure shows netbacks and the percent change from 1999 (lower bars), international border prices (top bars), and volumes (width of bars, horizontal scale on bottom in Bcf) for Canadian sales to various markets.

All sales prices were up substantially in 2000.

Table 7
Domestic & Export Prices

	International Border Export Prices				US Prices	Canadian Markets			
2000 Month	**West US/MMBtu**	**MW US/MMBtu**	**NE US/MMBtu**	**Average US/MMBtu**	**NYMEX US/MMBtu**	**AECO Cdn/GJ**	**AECO US/MMBtu**	**Huntingdon US/MMBtu**	**Westcoast St 2 US/MMBtu**
January	$2.26	$2.22	$2.81	$2.39	$2.34	$2.97	$2.16	$2.31	$2.18
February	$2.29	$2.40	$2.98	$2.52	$2.61	$2.94	$2.14	$2.39	$2.24
March	$2.31	$2.40	$3.00	$2.55	$2.60	$3.14	$2.27	$2.32	$2.22
April	$2.67	$2.64	$3.19	$2.81	$2.90	$3.59	$2.58	$2.75	$2.59
May	$2.80	$2.84	$3.42	$2.99	$3.09	$3.82	$2.69	$2.73	$2.62
June	$3.38	$3.83	$4.30	$3.81	$4.41	$5.40	$3.86	$3.65	$3.85
July	$3.71	$3.85	$4.26	$3.91	$4.37	$5.26	$3.76	$3.83	$3.68
August	$3.26	$3.51	$4.06	$3.58	$3.82	$4.33	$3.08	$3.02	$2.95
September	$3.77	$4.18	$4.63	$4.17	$4.62	$5.24	$3.72	$3.44	$3.38
October	$4.49	$4.70	$5.25	$4.78	$5.32	$6.53	$4.56	$4.89	$4.64
November	$4.78	$4.38	$4.94	$4.68	$4.54	$6.06	$4.15	$4.83	$4.67
December	$9.12	$6.29	$6.32	$7.14	$6.02	$8.45	$5.86	$13.69	$5.11
2000 Averag	**$3.77**	**$3.69**	**$4.17**	**$3.85**	**$3.89**	**$4.81**	**$3.40**	**$4.15**	**$3.34**
1999 Averag	$2.09	$2.07	$2.55	$2.19	$2.27	$2.77	$1.96	$2.15	$1.94
% change	**80%**	**78%**	**64%**	**76%**	**71%**	**74%**	**73%**	**93%**	**72%**

Sources: Friedenberg, NEB, NRCan estimates

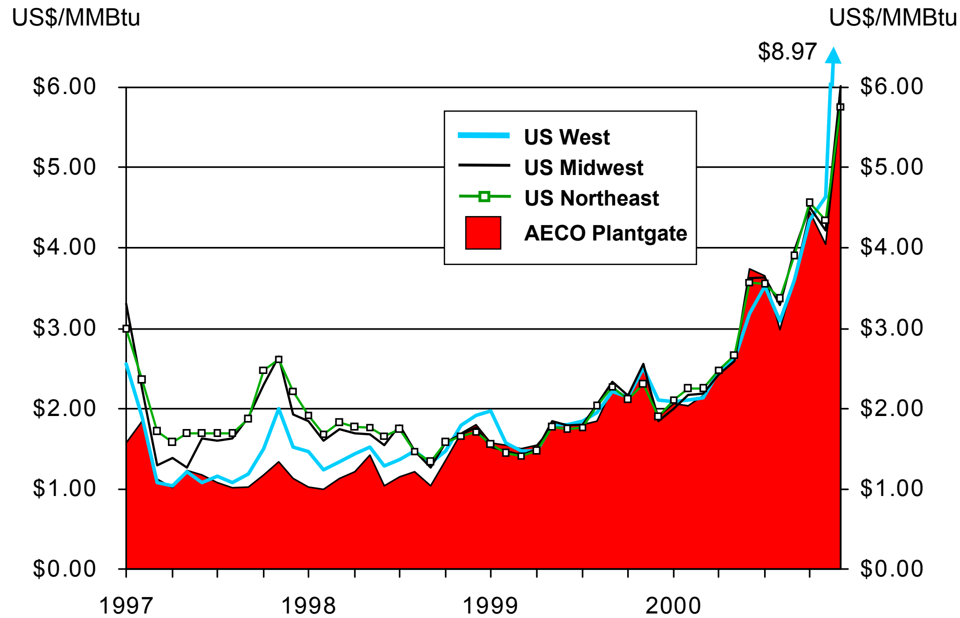
International border export prices generally followed the trend of the NYMEX price. Exports to the US West were at even higher prices in November and December 2000.

Domestic prices similarly tracked NYMEX, for the most part. However, prices at Huntingdon tracked US West prices in November and December, and were higher. BC consumers generally buy some of their gas at prices reflecting the Huntingdon market or Westcoast Station 2.

Netbacks had converged in late 1998, with the addition of export pipeline capacity.

In 2000, netbacks stayed similar, but rose dramatically with the higher prices.

Figure 29
Plant Gate Netback Price Trends



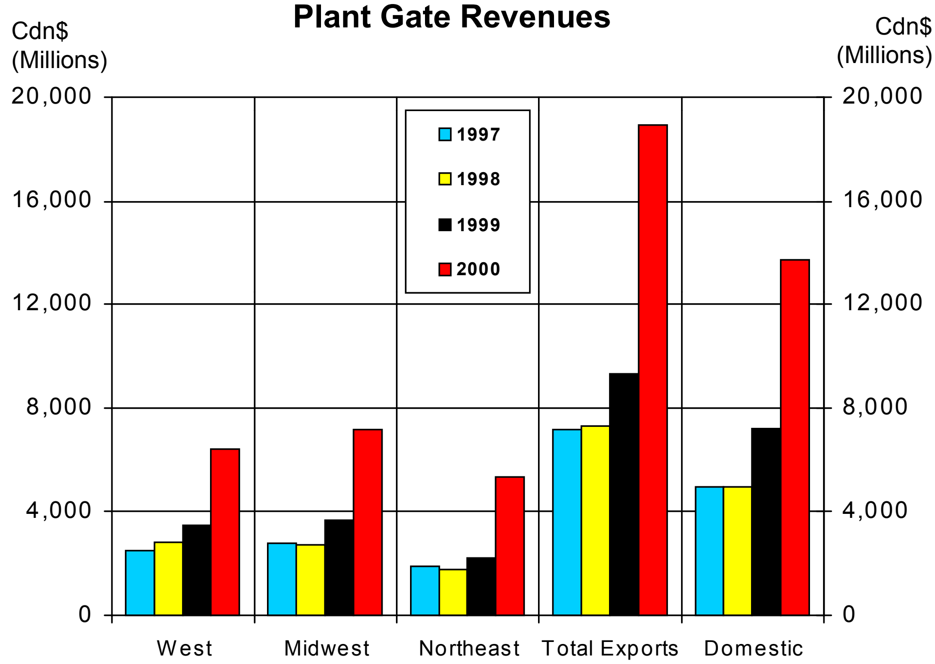
Sources: Friedenberg, NEB, NRCan estimates

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

Export plant-gate revenues more than doubled in 2000, as did domestic revenues.

High western Canadian gas producer cashflows partly explain the high levels of gas drilling seen in recent months.

Figure 30
Plant Gate Revenues



Sources: Friedenberg, NEB, NRCan estimates, StatsCan

Outlook to 2010

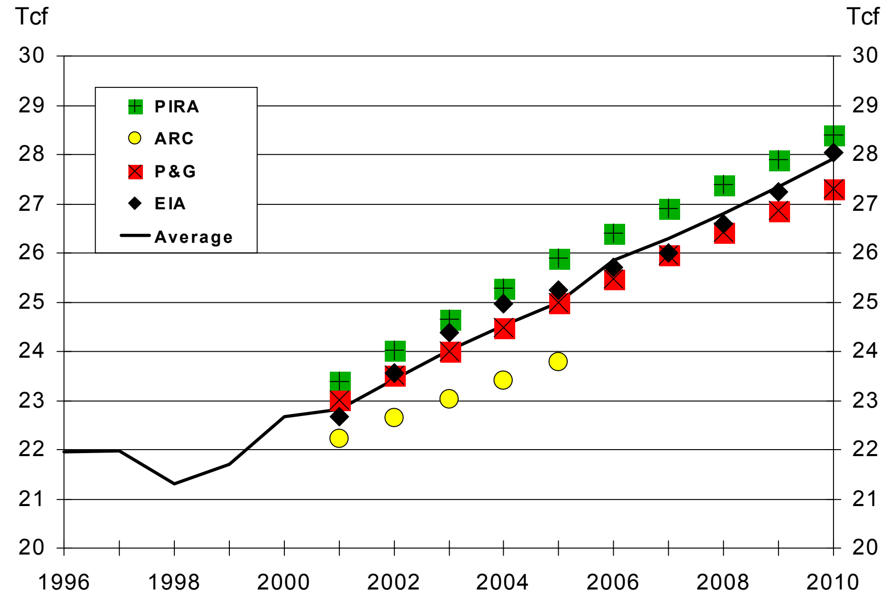
Natural Gas Demand

Figure 31 shows four forecasts of US gas demand, along with the average of the forecasts.

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

Note that the four forecasts are fairly consistent. For 2010, the difference between the highest forecast and the lowest is only 1.1 Tcf, or 4%.

Figure 31
US Natural Gas Demand Forecasts



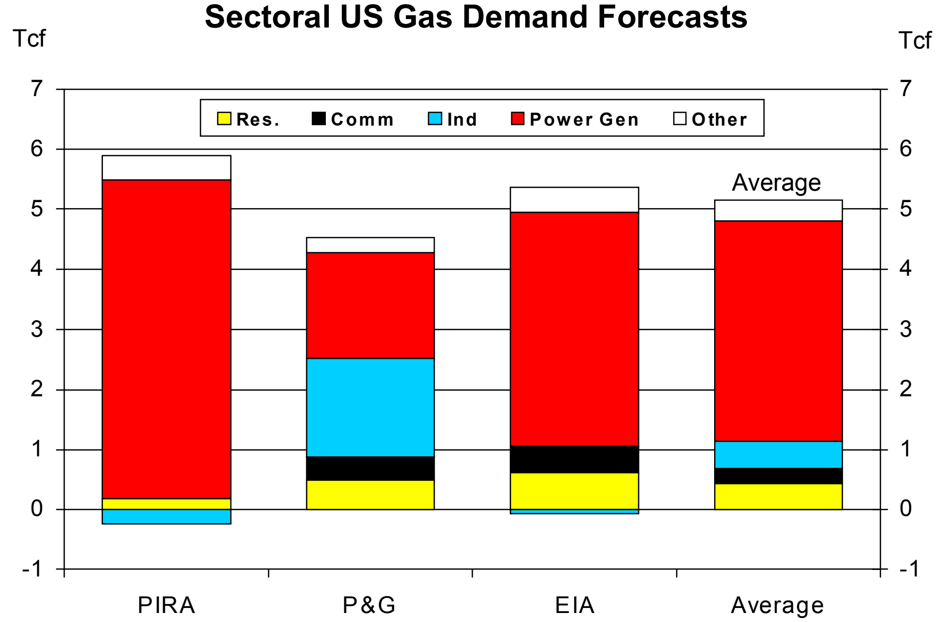
Sources: ARC, EIA, PIRA, P&G **Note:** Historical numbers from EIA.

This figure shows the sectoral breakdown of incremental gas demand for each forecaster.

Specifically, in each sector, the actual 2000 demand is subtracted from the individual forecaster's 2010 forecast.

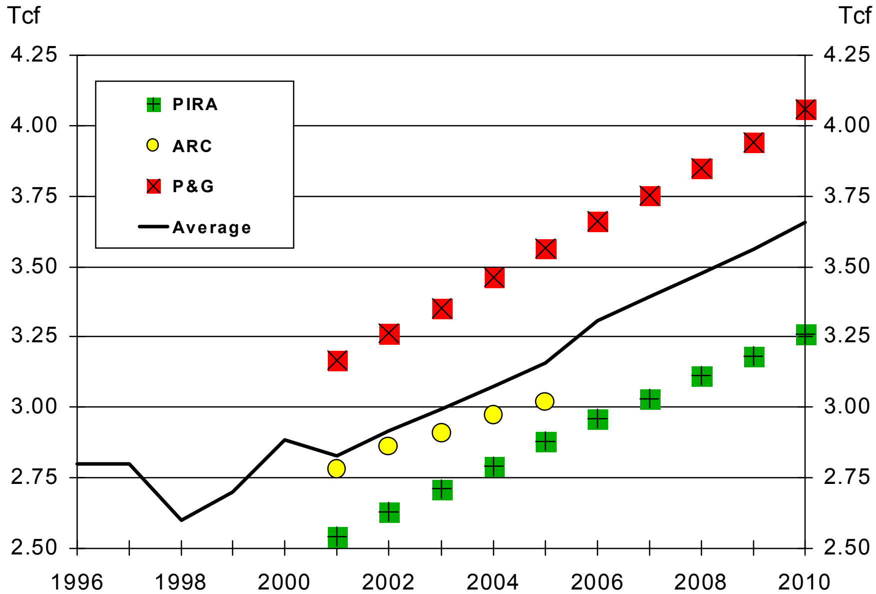
Most incremental US gas demand growth is expected to be used to generate electric power. Much of this is non-utility generation, which is classed by some forecasters as "Industrial" demand.

Figure 32
Sectoral US Gas Demand Forecasts



Sources: EIA, PIRA, P&G. **Note:** PIRA and EIA show incremental gas demand used for non-utility power generation in "Power Generation", while P&G places this demand in "Industrial".

Figure 33
Canadian Natural Gas Demand Forecasts



Sources: ARC, PIRA, P&G **Note:** Historical numbers from StatsCan.

Figure 33 shows three forecasts for Canadian gas demand. The average shows Canadian demand reaching 3.7 Tcf by 2010. This is an average increase of 2.5% per year.

Table 8
North American Demand Outlook

	Actual 2000 Demand Bcf	1995-2000 Annual Growth %	Growth Rate to 2010 %	Incremental Demand 2000-2010 Bcf	Demand Forecast 2010 Bcf
Total US Demand	22,756	1.1%	2.1%	5,159	27,915
Exports to Japan	64	-0.4%	0.0%	0	64
Exports to Mexico	110	12.3%	0.0%	0	110
Canadian Demand	2,883	3.0%	2.5%	773	3,656
Total North America	25,813	1.3%	2.1%	5,933	31,745

Together with US gas demand, this results in a forecast of US and Canadian gas demand of 31.7 Tcf by 2010. North America would need an additional 6 Tcf of gas by 2010.

Outlook to 2010

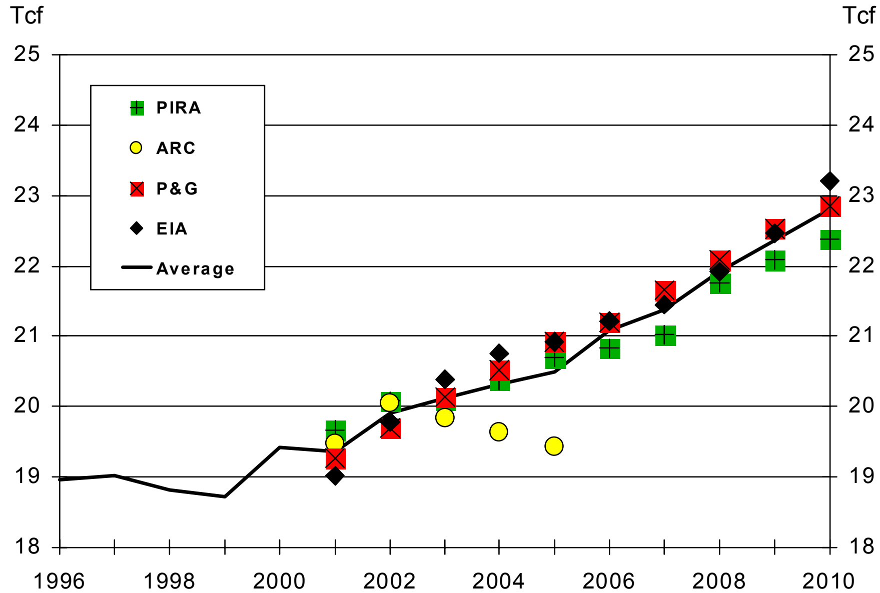
Natural Gas Supply

Figure 34
US Natural Gas Production Forecasts

Figure 34 shows four forecasts for US gas production. The average sees US production increasing 1.6% per year over the period.

There are considerable differences in opinion about US gas production. Some forecasts have northern gas in the mix to 2010, most do not.

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



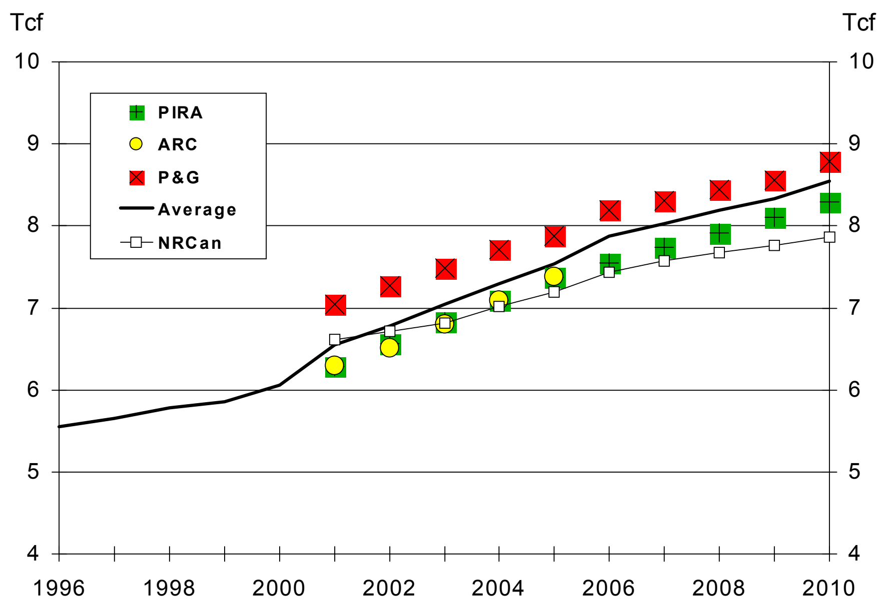
Sources: ARC, EIA, PIRA, P&G **Note:** Historical numbers from EIA. Includes supplements.

Figure 35
Canadian Natural Gas Production Forecasts

Figure 35 compares our forecast of Canadian gas production with the forecasts of 3 other organizations.

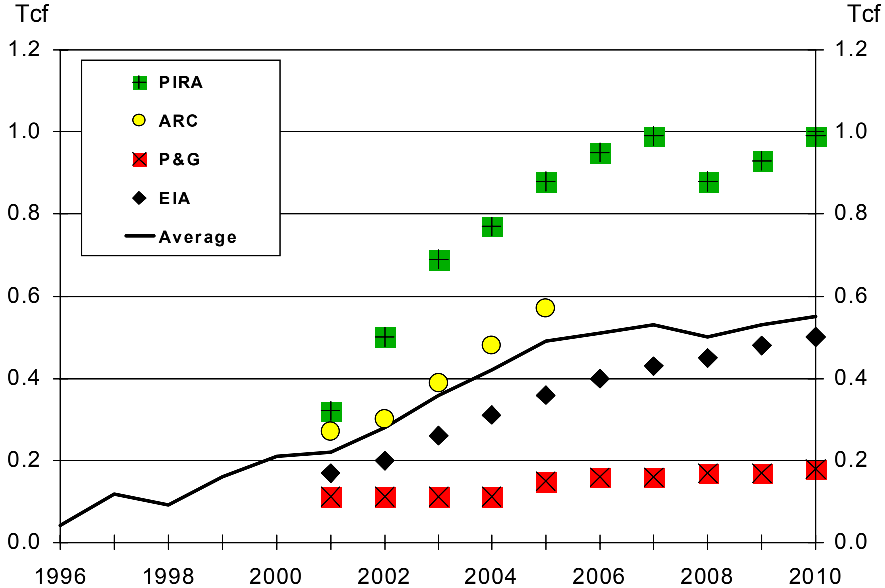
We expect production to reach 7.9 Tcf by 2010. This represents an average annual increase of 2.6%.

Our forecast (NRCan) is based on existing or under construction pipeline capacity. If more capacity is constructed, our forecast will be low. See page 40 for additional detail on how the NRCan Canadian production forecast is generated.



Sources: ARC, PIRA, P&G, NRCan. **Note:** Historical numbers from StatsCan.

Figure 36
LNG Supply Forecasts

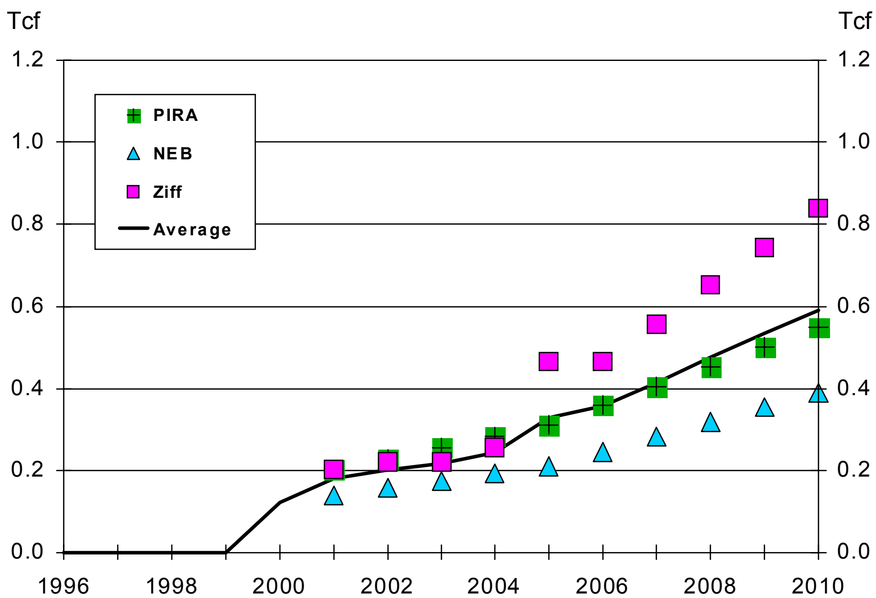


Sources: ARC, EIA, PIRA, P&G **Note:** Historical numbers from EIA.

An average of various forecasts sees LNG imports to the US reaching 0.6 Tcf (600 Bcf) by 2010.

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

Figure 37
Scotian Shelf Supply Forecasts



Sources: NEB, PIRA, Ziff **Note:** Historical numbers from CNSOPB.

The Scotian Shelf has rapidly become as important to the North American gas market as LNG. In its first full year of production, the Sable project produced approximately 121 Bcf (marketable gas). Sable has announced plans to increase production, while PanCanadian has announced plans to start production from Deep Panuke by 2005.

Several production forecasts for the Scotian Shelf in total are shown. It appears this area may grow as fast as LNG supply.

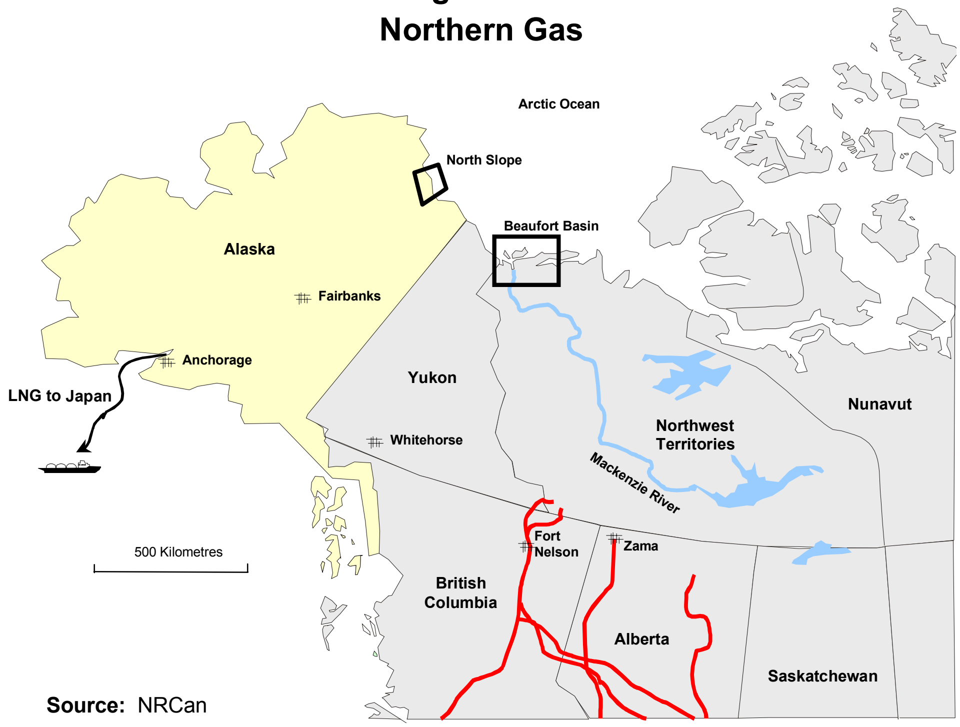
Finally, the largest increment of new gas supply could be northern gas. While no company has yet announced a project, companies are actively promoting and evaluating projects. Forecasters are divided about whether northern gas will arrive by the end of the 2001-2010 timeframe.

We know that some forecasters are currently re-evaluating their northern gas assumptions.

A northern gas project could be large – in the 4 Bcf per day range.

Alaska's North Slope currently has 7 Bcf per day of re-injected production.

Figure 38
Northern Gas



Source: NRCan

We would characterize today's market as in transition, while the market decides when and if northern gas will arrive. A northern gas pipeline would restructure most assumptions about North American gas demand, supply and prices.

Given that caveat, the current "consensus" view of North American gas supply is as shown in the Table. We expect this to be in flux over the next few years.

Table 9
North American Production Outlook

	Actual 2000 Supply Bcf	Annual 1995-2000 Growth %	Growth Rate to 2010 %	Incremental Supply 2000-2010 Bcf	Production Forecast 2010 Bcf
Total US	19,419	0.8%	1.6%	3,387	22,806
Canada	6,057	2.5%	3.5%	2,486	8,543
LNG	208	26.2%	10.3%	346	554
Mexico	6	6.0%	-3.5%	0	6
TOTAL	**25,690**	**1.3%**	**0**	**6,219**	**31,909**

Note: US includes supplements.

Outlook to 2010

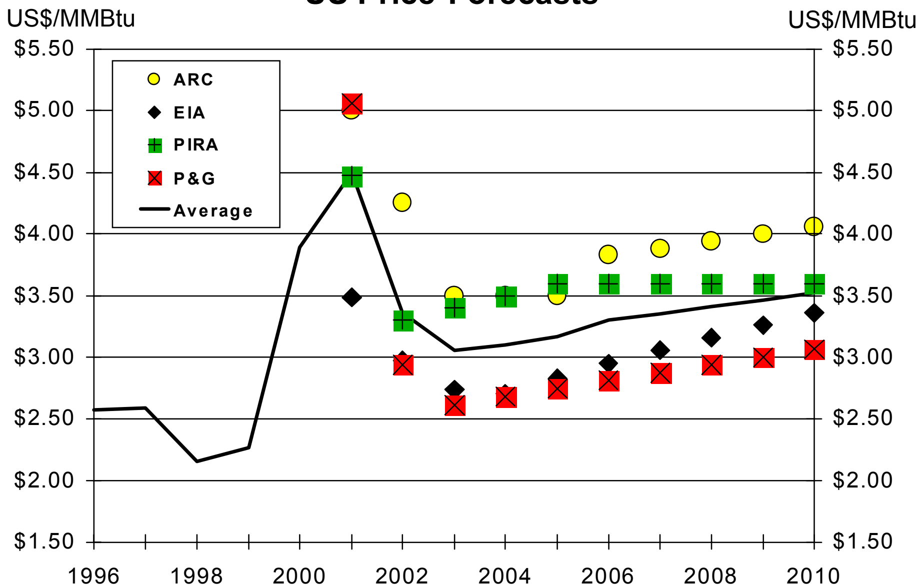
Natural Gas Prices

There is a huge amount of uncertainty with respect to weather, demand and northern gas. A range of industry views shows that US prices (nominal dollars) on average are expected to peak in 2001, then fall to the US$3.00 range by 2003, then slowly rise to $3.50 by the end of the period.

Compared to our survey last year, US price expectations have risen dramatically. Last year, the average price outlook for 2010 was $2.96.

A northern pipeline could change price expectations again.

Figure 39
US Price[1] Forecasts

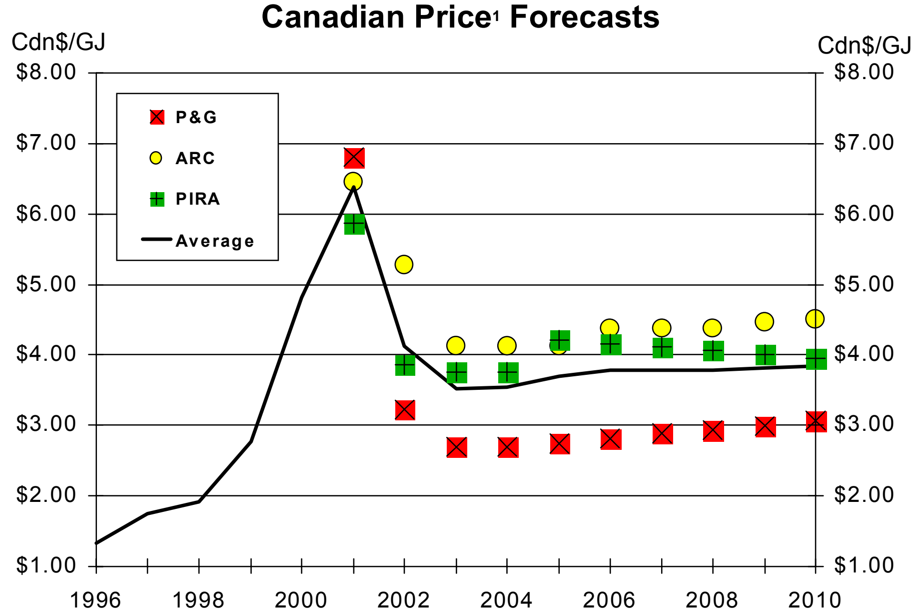


Sources: ARC, EIA, PIRA, P&G **Note 1:** 1996-00 are NYMEX actuals from Friedenberg. The forecast prices represent Gulf Coast Henry Hub prices, except EIA, which is an average US wellhead price. Some forecasts were converted from constant to nominal dollars.

Canadian gas prices, according to a selection of forecasts, are expected to peak in 2001, then fall to the Cdn$3.50/GJ range by 2003. Prices are then expected to rise slowly to about $3.85 by 2010.

As with the US, price expectations are much higher than last year. The average price forecast for 2010 was only $2.76 last year.

Figure 40
Canadian Price[1] Forecasts



Sources: ARC, PIRA, P&G **Note 1:** 1996-2000 are AECO actuals from Friedenberg. Forecast prices are AECO. Some prices converted from $US. ARC price was wellhead, added C$0.15/GJ (typical wellhead to AECO toll).

Outlook to 2010

Canadian Export
& Domestic Sales

Total physical export capacity reached 12,100 MMcf/d when the Alliance project was completed in December 2000.

Total export capacity currently cannot be filled due to a lack of gas supply. Due to various constraints, capacity is seldom used at 100% load factors. In recent years, the best fill rate for total export capacity was about 95%. In 2001, capacity is expected to be about 86%, rising to 95% in 2010.

Table 10
Export Pipeline Capacity

(MMcf/d)	1998	1999		2000		2001 - 2010	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
Huntingdon (Westcoast)	1,045	0	1,045	0	1,045	0	1,045
Huntingdon (User Pipes)	380	0	380	0	380	0	380
Kingsgate (Foothills/ANG)	2,582	0	2,582	0	2,582	0	2,582
Total US West	**4,007**	**0**	**4,007**	**0**	**4,007**	**0**	**4,007**
Monchy (Foothills)	2,190	0	2,190	0	2,190	0	2,190
Emerson (TCPL)	1,305	0	1,305	0	1,305	0	1,305
Elmore (Alliance)	0	0	0	1,325	1,325	0	1,325
Miscellaneous (see note)	300	0	300	0	300	0	300
Total US Midwest	**3,795**	**0**	**3,795**	**1,325**	**5,120**	**0**	**5,120**
Iroquois (TCPL)	883	0	883	8	891	3	894
Niagara Falls (TCPL)	845	0	845	0	845	0	845
Chippawa (TCPL)	500	0	500	0	500	0	500
St. Stephen (MNP)	0	360	360	0	360	0	360
E. Hereford (TCPL)	152	11	163	40	203	0	203
Cornwall (TCPL)	63	0	63	0	63	0	63
Napierville (TCPL)	61	0	61	0	61	0	61
Phillipsburg (TCPL)	50	0	50	0	50	0	50
Highwater (TCPL)	25	-25	0	0	0	0	0
Total US Northeast	**2,579**	**346**	**2,925**	**48**	**2,973**	**3**	**2,976**
Total Capacity (Export)	**10,381**	**346**	**10,727**	**1,373**	**12,100**	**3**	**12,103**

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

Table 11 shows our estimates of Canadian gas exports and domestic sales. This forecast assumes that the export pipeline capacity listed above is used at certain load factors. We estimate these load factors based on market factors, past load factors, etc.

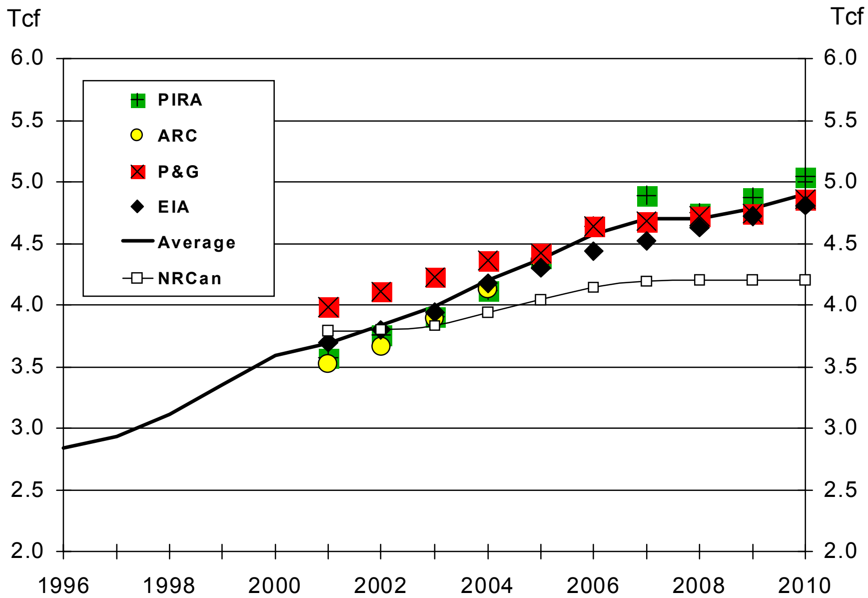
We estimate that exports will reach 4.2 Tcf by 2010. Currently, no significant additional export expansions past 2000 have been filed with regulators. Should further expansions occur, our export forecast will be low.

Table 11
Export Volumes and Domestic Sales

(Bcf)	1998	1999	2000	2001	2005	2010
Huntingdon (Westcoast)	423	402	356	385	408	473
Kingsgate (Foothills/ANG)	854	805	830	829	914	942
Total US West	**1,277**	**1,207**	**1,186**	**1,214**	**1,322**	**1,416**
Monchy (Foothills)	558	773	784	719	775	799
Emerson (TCPL)	485	487	491	429	462	476
Elmore (Alliance)			71	435	469	484
Miscellaneous	82	67	31	44	44	44
Total US Midwest	**1,125**	**1,327**	**1,378**	**1,627**	**1,750**	**1,803**
Iroquois (TCPL)	318	357	370	326	326	326
Niagara Falls (TCPL)	305	361	424	395	395	395
Chippawa (TCPL)	44	44	37	39	46	55
St. Stephen (MNP)			117	125	125	125
E. Hereford (TCPL)		17	31	32	35	38
Cornwall (TCPL)	11	9	8	9	11	13
Napierville (TCPL)	17	19	19	20	20	22
Phillipsburg (TCPL)	5	6	8	8	9	11
Highwater (TCPL)	9	3	14			
Total US Northeast	**709**	**816**	**1,029**	**953**	**967**	**985**
Total Exports	**3,111**	**3,349**	**3,593**	**3,794**	**4,040**	**4,204**
Total Domestic Sales	**2,570**	**2,669**	**2,826**	**2,829**	**3,155**	**3,656**
Total Sales	**5,682**	**6,018**	**6,419**	**6,623**	**7,195**	**7,861**

Source: NRCan

Figure 41
Canadian Export Forecasts



Sources: ARC, EIA, NRCan, PIRA, P&G **Note:** Historical numbers from NEB.

Our export forecast (4.2 Tcf by 2010) is considerably less than the average of the forecasters we surveyed.

This is likely due to these forecasters assuming that future pipeline expansions will occur.

Our forecast does not assume any export pipeline capacity expansions to 2010. Thus, our forecast is best viewed as a minimum exports forecast, since some pipeline expansions are probably likely.

Table 12
Export and Domestic Revenue Forecast

EXPORT SALES:	Export Volumes (Bcf)	US NYMEX Price (US$/MMBtu)	Export International Border Price (US$/MMBtu)	Export Plant Gate Netback (US$/MMBtu)	Export Plant Gate Revenues (Million US$)	Export Plant Gate Revenues (Million Cdn$)
1998	3,111	$2.16	$1.92	$1.58	$4,931	$7,317
1999	3,349	$2.27	$2.19	$1.88	$6,299	$9,348
2000	3,593	$3.89	$3.85	$3.52	$12,660	$18,931
2001	3,794	$4.50	$4.33	$3.98	$15,112	$22,223
2005	4,040	$3.19	$3.02	$2.67	$10,787	$15,863
2010	4,204	$3.55	$3.38	$3.03	$12,738	$18,733

DOMESTIC SALES:	Domestic Volumes (Bcf)	Alberta Price (US$/MMBtu)	PlantGate Netback (US$/MMBtu)	Domestic Plant Gate Revenues (Million US$)	Domestic Plant Gate Revenues (Million Cdn$)	**TOTAL Plant Gate Revenues** (Million Cdn$)
1998	2,570	$1.36	$1.26	$3,250	$4,820	**$12,137**
1999	2,669	$1.96	$1.85	$4,958	$7,365	**$16,713**
2000	2,826	$3.40	$3.30	$9,326	$13,714	**$32,646**
2001	2,829	$4.53	$4.41	$12,475	$18,346	**$40,570**
2005	3,155	$2.81	$2.69	$8,487	$12,481	**$28,344**
2010	3,656	$2.92	$2.80	$10,237	$15,054	**$33,787**

Notes: Actual export revenues from NEB data. Actual domestic netbacks and revenues calculated using AECO prices and subtracting published transmission tolls. Future revenues estimated as follows: Future export netbacks assumed to equal forecast NYMEX prices (see report) less US$0.52. Resultant netback multiplied by forecast export sales. Future domestic netbacks assumed to equal forecast Alberta prices (see report) less US$0.12. Resultant netback multiplied by forecast domestic sales. Assumed=$US0.68 per $Cdn for 2001-2010.

Table 12 provides our estimates of producer plant gate revenues for the next 10 years, given expected gas prices, export volumes, and domestic sales.

Total producer plant gate revenues increased 95% in 2000. We are seeing a phenomenal increase in producer revenues.

If price and volume forecasts prove correct, producer revenues will peak in 2001. However, revenues will remain relatively high over the outlook period.

Appendix

US Industrial & Electric Generation Gas Demand

US Industrial & Electric Generation Gas Demand

This appendix is intended to define several terms used in this report (e.g.Table 1, page 3), including:

- Industrial gas demand
- Industrial Process Gas Demand
- Non-utility generation demand
- Utility Electric Generation (UEG) Gas Demand
- Power Generation Demand

These terms relate to US natural gas demand only.

Our source of US demand information is the US Energy Information Administration (EIA). EIA defines Industrial gas demand as:

> gas used for heat, power, or chemical feedstock by manufacturing establishments or those engaged in mining or other mineral extraction, as well as consumers in agriculture, forestry, and fisheries. Also included in industrial consumption are natural gas volumes used in the generation of electricity by other than regulated electric utilities.

This industrial sector generation of electricity may qualify as "non-utility generation". Some non-utility generation is done via a cogeneration process. In cogeneration, gas is used to produce both steam (process heat) and electricity. Most non-utility generation is done by industrial sector companies, although some also occurs in the commercial sector.

We show US "Industrial demand", as defined by EIA, in Table 1 of this report.

Given that "Industrial demand" includes gas used for power generation, the above definition is limited in terms of helping to understand gas market dynamics. For example, it might be more useful to know the total amount of gas used in generating electricity, whether that generation occurred in regulated or non-regulated generating facilities.

Also, regulated generating facilities in the US are being sold to non-regulated entities. This means that gas consumed in one generating plant is classed as UEG demand one year, and as Industrial demand the following year. This makes year-to-year comparisons of gas demand difficult.

Accordingly, we have also calculated "Industrial Process" gas demand, which includes only gas used by industrial companies for space heating, process heat, or petrochemical feedstock. This is calculated as:

Industrial Process Gas Demand = Industrial demand (EIA Natural Gas Monthly) less Non-utility gas demand (Table 67, March 2001 EIA Electric Power Monthly).

Thus, "Industrial Process" gas demand includes gas consumed in the US Industrial sector for process heat, feedstock, or space heating. Note that "Industrial Process" demand as calculated above also includes a portion of the gas consumed by cogeneration plants – the portion that is used to produce useful thermal output (i.e., steam).

Cogeneration plants produce both electric power and steam. For its Electric Power Monthly, EIA attributed a portion of gas consumed by cogenerators to power generation, and a portion to useful thermal output. Only the gas used to produce power is included in Table 67 of the March 2001 EIA Electric Power Monthly. Note that in older versions of the Electric Power Monthly, Table 67 included all gas consumed in cogeneration plants.

EIA defines Utility Electric Generation (UEG) as:

> Includes all steam electric utility generating plants with a combined capacity of 50 megawatts or greater.

Similarly, since this does not include all electric generation, it has limited utility in understanding gas markets. Accordingly, we define "Power Generation gas demand" as:

Power Generation Gas Demand = UEG gas demand (EIA NGM), plus Non-utility gas demand (Electric Power Monthly, Table 67).

Bibliography / Sources / Acronyms

1. *Energy Update January 2001*, Advisory Research Capital (ARC), January 2001.
2. *Natural Gas Monthly*, Energy Information Administration (EIA), March 2001.
3. *Annual Energy Outlook 2000*, EIA, December 2000.
4. *Natural Gas Annual 1999*, EIA, October 2000.
5. *Electric Power Monthly,* EIA, March 2001.
6. *Energy Statistics Handbook*, Statistics Canada (StatsCan) and Natural Resources Canada (NRCan).
7. *Client Retainer Seminar 2000*, Petroleum Industry Research Associates (PIRA), October 2000.
8. *Consulting Studies,* Ziff Energy, 2000 & 2001.
9. *Consulting Studies,* Purvin & Gertz, 2000 & 2001.
10. *Statistical Handbook 1999,* Canadian Association of Petroleum Producers (CAPP).
11. *Climate Prediction Centre: Historical Degree Days*, National Oceanographic and Atmospheric Administration (NOAA) website: www.cpc.ncep.noaa.gov.
12. *Production Summary Statistics 2000,* Minerals Management Services (MMS) website: www.gomr.mms.gov.
13. *Export Statistics,* unpublished material provided by the National Energy Board (NEB).
14. *Baker Hughes Rig Counts,* Baker Hughes website: www.bakerhughes.com.
15. *Canadian Natural Gas Focus,* Brent Friedenberg Associates.
16. *Weekly Storage Reports,* Gas Daily, quoting surveys of US and Canadian storage volumes by the Canadian Gas Association (CGA) and the American Gas Association (AGA).
17. *Natural Gas Futures,* Gas Daily.
18. *Crude Oil Futures,* Globe and Mail.
19. *Canadian Energy Supply and Demand to 2025,* NEB, June, 1999.
20. *Natural Gas Transportation and Distribution, 55-002*, StatsCan.
21. *Supply and Disposition of Crude Oil and Natural Gas, 26-006,* StatsCan.
22. *Exchange Rates,* Bank of Canada website: www.bankofcanada.ca.
23. *Daily Oil Bulletin,* Nickle's website: www.dailyoilbulletin.com.
24. *Texas Petrofacts,* Texas Railroad Commission (RRC) website: www.rrc.state.tx.us.
25. *Sable Offshore Energy Production,* Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) website: www.cnsopb.ns.ca.