Natural Resources Canada
Ressources naturelles Canada

Canadian Natural Gas

2001 Market Review & Outlook

June 2002

Natural Gas Division
Energy Resources Branch
Energy Sector

Canada

Foreword

The *Canadian Natural Gas 2001 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 (2001), for the near term (the rest of 2002), and the long-term (to 2010). This analysis was completed first. The executive summary was prepared last, and uses the analysis completed 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 2001 is still preliminary and contains problems, a major one being the large "balancing item" (unaccounted for gas) relating to the US. In 2001, because of data problems, US supply is about 450 billion cubic feet greater than demand, even after accounting for storage movements.

Natural Gas Division Website

This report is available online at our website: http://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.

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Questions and Comments

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

Sommaire aussi disponible en français

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From one extreme to another

The year 2000 saw 5% demand growth, low storage, and steadily rising prices, peaking at US$10 at Henry Hub. In 2001, everything reversed – a 5% demand loss, storage full, and steadily falling prices.

Industrial demand collapse

The major story for North American gas markets[1] in 2001 was the collapse of gas demand. North American gas demand fell by 5%, or 1.3 Tcf, in 2001. This was the biggest gas demand loss in North America since 1982. Most of the losses occurred in the industrial sector, in particular, in gas used for process heat or petrochemical feedstock. This type of gas consumption, i.e., "industrial process" gas demand, fell 20%.

15-month recession

The collapse of demand in the industrial sector was tied to two intertwined factors: extremely high gas prices in 2001, and an economic recession that began in October 2000 and only appears to be ending in January 2002. Significant increases in energy prices were contributing causes to the recession.

In 2001, gas prices averaged US $4.27/MMBtu for the NYMEX futures contract, and CDN $5.91/GJ in the Alberta spot month market. Prices in the previous 5 years had averaged US $2.69 (NYMEX) and CDN $2.51 (Alberta). At 2001 prices, many industrial plants were unprofitable, and suspended operations, some permanently.

As measured by the US industrial production index, the recession was the worst one since 1982.

Industrial gas demand losses were concentrated in the US Midwest (-199 Bcf), South Atlantic (-101 Bcf), and Northeast (-112 Bcf).

Core demand falls due to mild weather

The start of the 2001/2002 winter was almost the exact opposite of the one before. November and December 2000 were the coldest in US history, while November and December 2001 were amongst the warmest. Canada experienced a situation similar to that of the US in the previous two winters. As a result, core demand fell 4% or 224 Bcf in 2001.

The only sector seeing a gas demand increase in North America in 2001 was the power generation sector, where gas consumption increased by 5% or 323 Bcf.

West out of sync: cold weather, higher demand

Regionally, most of North America saw lower gas demand. The exception was the US West, which was in the throes of a regional energy crisis in 2001, mainly the result of low water levels and reduced hydroelectric power generation. As a result, gas use for power generation increased. The west was also out of sync with the rest of North America in terms of winter heating. The west was cold in

[1] In this report, the North American gas market refers to Canada and the US.

2001 and core demand was up - the opposite of trends elsewhere.

On the supply side, North American gas supply increased 1.8%. US production rose 1.9% or 365 Bcf, while Canadian production increased 1.7% or 104 Bcf. The increase in production was somewhat disappointing however, given that drilling had increased in the US by 33% (total US gas-directed rig count) and in Canada by 25% (total gas completions).

Sluggish production growth for such high levels of drilling

There are two possibilities to explain the dichotomy between high gas drilling and relatively weak increases in gas production. One is that the large number of wells drilled did find considerable gas, but production is slow in coming, perhaps due to lags in getting wells connected to pipelines. This is the more optimistic scenario in terms of gas supply - more gas is coming, but just has not arrived yet.

The other scenario is more pessimistic for gas supply. This scenario would explain slow gas production growth with poor results from drilling. The conclusion in this case would be that very high levels of drilling are needed simply to match declines from existing wells, and significant increases in production will require even more drilling.

Strong gas reserves additions in 2000

More light can be shed on this question by examining proved reserve changes. If high levels of gas drilling are finding more gas, this should be indicated by increases in reserves. Reserves changes during 2001 will only become available in late 2002. However, reserves changes during 2000 were positive. In 2000, North American reserves increased nearly 4%, or 8.7 Tcf. US proved reserves increased 6%, while Canadian reserves fell 2%. The increase in reserves argues for the scenario that even more gas production is coming; it just has not arrived yet.

As gas drilling in 2001 was significantly higher than in 2000, proved reserves should increase again when 2001 numbers become available.

Higher LNG imports

Positive stories for gas supply growth included LNG imports, and Canada's east coast offshore. LNG imports to the US rose slightly to 238 Bcf, while production from the Sable Offshore Energy project reached 180 Bcf on the year.

Storage full

Natural gas storage is in some sense the memory of the gas market. In 2001, storage dynamics were almost the complete opposite of 2000. Injections reached record levels in the 2001 injection season, the result of increases in production, and even bigger declines in demand. By June 2001, gas in storage had surpassed year-ahead levels, and by November 2001, reached new highs. With the relatively mild 2001/2002 winter, storage balances remained high in spring 2002.

Weakening prices

While the winter of 2000/2001 saw prices hitting US $10/MMBtu on NYMEX and CDN $13/GJ in Alberta, the winter of 2001/2002 saw much more moderate prices. NYMEX ranged from $2.01 - $3.20, while Canadian prices ranged from

$2.79 - $3.94. Particularly important causes of lower prices were mild winter weather in November and December 2001, lower core market demand, low oil prices, low industrial gas demand, and high storage balances.

North American gas markets, which had been fairly well integrated for years, also disconnected for several months in late 2000 and early 2001, with huge regional differences in prices developing.

West becomes disconnected from other markets – insufficient gas supply access

Very high gas prices in California, the Pacific Northwest, and British Columbia were the result of low rainfall in the region, which dramatically lowered the availability of hydropower. Gas-fired power was needed to make up the power shortfall, driving up gas demand. At the same time, higher levels of gas demand could not be satisfied, as gas pipeline capacity into the region was already full. These factors drove gas prices in California and British Columbia to the US $14/MMBtu range in early 2001.

Trapped gas in the Rockies

The US Rockies saw the opposite situation. Gas became trapped in the Rockies, as gas production capacity outgrew exit pipeline capacity. As a result, Opal Wyoming prices were for several months in 2001 over US $1/MMBtu lower than NYMEX prices, and more than US $6/MMBtu lower than California prices.

New Canadian gas export volume and revenue records

Canadian natural gas producers and exporters had a record year for volumes and revenues. Although prices weakened during 2001, 2001 prices still averaged out at record highs. Gross export volumes increased 4% to hit 3,728 Bcf. Net exports fell very slightly to 3,500 Bcf. With record prices, export plant-gate revenues increased 21%, to CDN $22.8 billion. While domestic sales volumes fell, revenues increased 10% due to higher prices, reaching CDN $14.8 billion. Total plant-gate revenues, including export and domestic sales, also set a new record, at CDN $37.6 billion.

Import volumes become significant in 2001

Canadian natural gas imports nearly tripled in 2001, reaching 228 Bcf, primarily as a result of gas being re-imported into Canada via the Vector Pipeline. As a result of the increasing significance of imports, it is now important to measure net exports. Although gross exports were up in 2001, net exports fell slightly to 3,500 Bcf.

Short-Term Outlook

Storage overhang will weigh heavily on market

Perhaps the largest single factor in the North American gas market over the short-term (to mid 2003) will be the large gas storage inventory. Gas in storage as of April 2002 is well above seasonal normals. As a result, the amount of gas necessary for injections this summer in order to reach normal November fill levels is lower than in previous years. In other words, “storage demand” will be low this summer. This is a certainty. Most other important variables hinge on weather and are uncertain in the extreme.

Executive Summary

Demand gains from power sector may be muted in 2002

Generally, gas demand for power generation has been rising between 6%-10% per year, as more gas-fired power plants are constructed. This is a structural feature of gas markets, unrelated to weather, and could add several hundred Bcf to North American gas demand in 2002. However, the high gas prices of 2001 and financial community concerns relating to Enron will blunt this structural growth in 2002, as power companies have postponed many gas-fired power plants.

Rainfalls and temperatures always a wild card

Weather can also swing gas demand for power generation. While low rainfall/snow-pack left hydro reservoirs in the west low during 2001, a return to normal fill levels would mean increases in hydropower, and reduce the call on gas for power generation. This could swing gas demand for power generation downward by several hundred Bcf.

Temperatures could similarly swing gas demand upward by several hundred Bcf in core markets. The risks of this are mainly upward, as calendar 2001 was fairly warm during the winter heating months. Still, mild weather in November and December 2002, coupled with high storage, could combine to depress gas prices.

Finally, industrial process gas demand fell 1.3 Tcf in 2001. If this demand all returned suddenly, prices would increase. However a sudden return of this demand is unlikely.

Industrial gas demand recovering slowly

Industrial process gas demand is strongly correlated to US industrial production, and is also affected by weather. The US Federal Reserve tracks US industrial production, publishing data on a monthly basis, with a one-month lag. The US industrial production index began to swing downward in July 2000, and continued to fall through December 2001. For the first quarter 2002 as a whole, industrial production increased at an annual rate of 2.5 percent.

However, both the industrial production index and industrial process natural gas demand are still well below 2000 levels.

Both power generation and industrial gas use are vulnerable to fuel switching. Thus, world crude oil prices will also be a factor in natural gas demand and prices in the short-term.

On the supply side, weaker US gas prices since the latter half of 2001 have drastically reduced US gas drilling. Early in 2002, US gas drilling is well below last year's levels, which will have a negative impact on gas production and supply. Consequently, gas prices become vulnerable to an upward shift.

In March 2002, gas prices increased dramatically, the result of expectations of supply around weak drilling, and the influence of current high oil prices, themselves due to tensions in the Middle East. Rising gas prices of late may induce higher drilling.

Supply factors that could depress prices may include an increase in short-term supply from the states of Wyoming, Colorado and Utah as a result of various project proposals designed to increase pipeline capacity out of the US Rockies. There are currently three projects under construction with a total expansion capacity of 570 MMcf/d, all of which are expected to be in service by the summer of 2002. Another supply influence would be higher LNG imports. All four of the US LNG receiving terminals will be operating in 2002.

Additional supply expected to come from the US Rockies

In summary, in the short-term, weather effects could easily overwhelm all other factors, and cause higher or lower gas demand and prices. However if weather is normal, gas demand will rise considerably, since 2001 weather was mild, and since industrial gas demand is recovering.

Outlook to 2010

Our longer-term forecasts of gas demand fundamentals are generated by reviewing forecasts of various organizations. 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.

Long-term forecast – the general view

US gas demand in 2010 is expected to reach 28 Tcf; Canadian demand 3.8 Tcf, for a North American total of 31.8 Tcf. This is an increase of 7.8 Tcf over 2001 demand. Most of this increase is expected to be for electric power generation (by utilities and by non-utilities generating power).

This demand would be satisfied by: US gas production of 22.9 Tcf; Canadian production of 8.1 Tcf; and 1.2 Tcf of LNG imports to the US. Compared to expectations last year (0.6 Tcf of LNG imports by 2010), LNG is now seen as a much more important component of future North American gas supply.

Future supply sources

Incremental supply to 2010 is expected to come from: 1) the US - 3.6 Tcf; Canada - 1.9 Tcf; and LNG – 1.0 Tcf.

Scotian Shelf production is included in the Canadian production forecasts. The average of 3 forecasts shows Scotian Shelf production reaching 0.63 Tcf by 2010.

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

Price expectations have increased somewhat compared to last year

US natural gas prices are expected to fall to US $2.74/MMBtu next year (2002), and then reach the $3.50 range by 2005. Alberta prices fall to CDN $3.57/GJ next year, and then reach the $4.40 range by 2004. Price expectations have increased somewhat since last year's report.

Several expansions of Canadian export pipelines are now proposed, and are included in our outlook. We do not assume pipeline capacity in our forecast until it is well along in the regulatory process. Existing export capacity was used at 84% load factor in 2001, for gross exports of 3.7 Tcf. We assume exports reach 4.4 Tcf by 2010 – equal to a 93% load factor on pipeline capacity.

We recognize that additional pipeline capacity from Canada to the US, over and above the capacity assumed in our outlook, could be constructed in the 2003-2010 timeframe.

Many forecasts do not include northern gas supply during period to 2010

The largest project would be a northern pipeline project or projects, involving Alaskan and/or Mackenzie Delta production. There is no confirmed schedule for constructing a pipeline to date. 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.

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, could 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.

Canadian exports to US hit 4.4Tcf by 2010

We have compared our pipeline-restrained forecast with other industry forecasts. The average of industry forecasts shows Canadian gross exports reaching 4.5 Tcf by 2010, compared to our estimate of 4.4 Tcf. Similarly, an average of industry forecasts shows Canadian production at 8.1 Tcf by 2010, compared to our outlook of 7.9 Tcf.

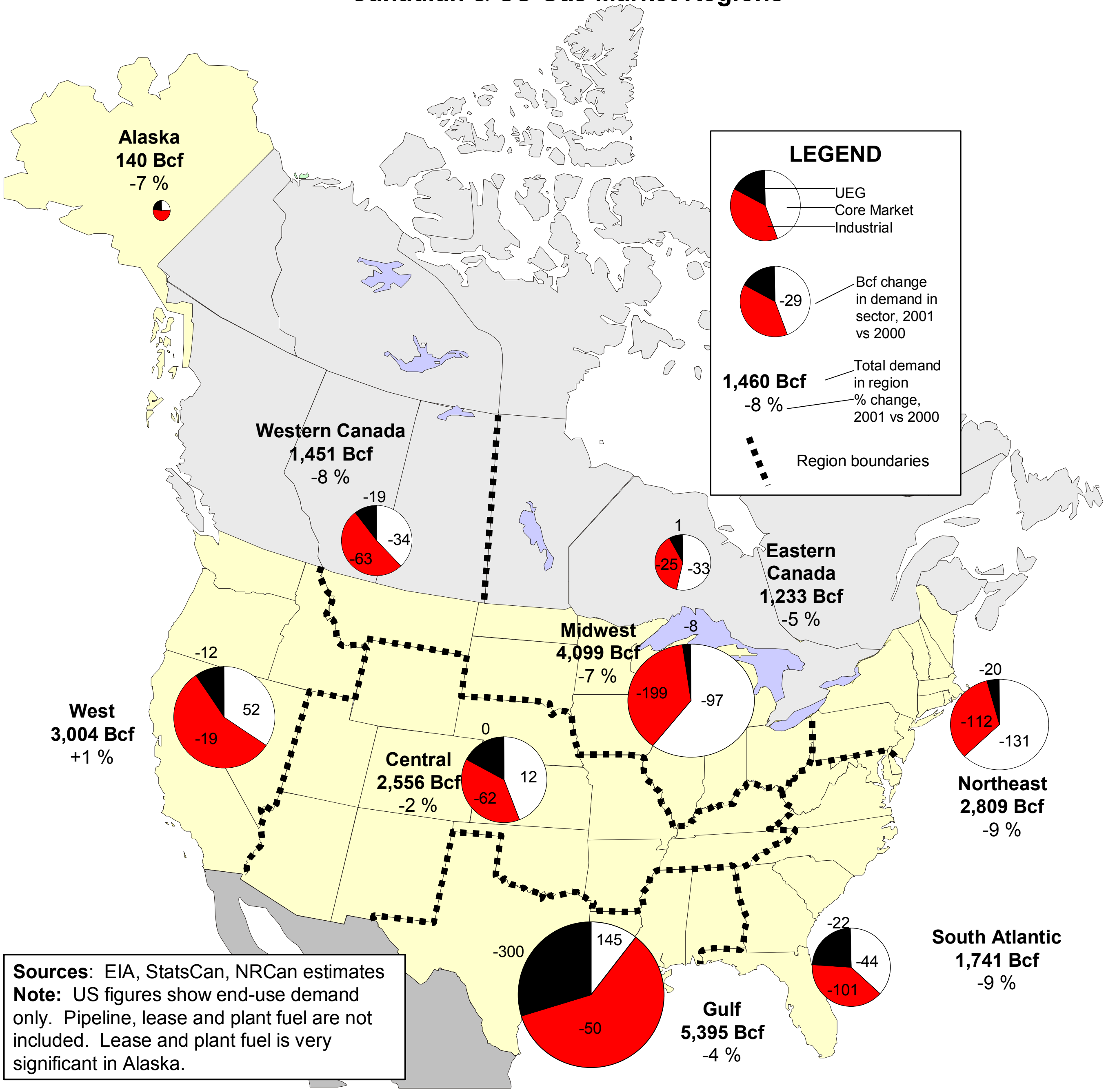
2001 was a peak year for producer revenues

Given our assumptions about Canadian production and exports, and industry price forecasts, producer plant-gate revenues from natural gas sales are not expected to regain peak 2001 levels over the outlook period. Revenues are expected to reach CDN $36.8 billion by 2010, below the CDN $37.6 billion level of 2001.

Review of 2001

Natural Gas Demand

Figure 1
Canadian & US Gas Market Regions



The locations and scale of natural gas demand in North America[1] are shown on the map. Also shown are the changes in demand compared to last year, by region and sector.

In 2001, the largest demand growth in North America occurred in the US West. Demand decreases were significant in the US Gulf, Midwest, South Atlantic, and Northeast regions of the United States. Demand also fell significantly in Western Canada. Core demand and industrial demand decreased significantly in the Midwest and Northeast regions. The largest loss in demand occurred in the industrial sector, falling by 543 Bcf. Power generation demand fell substantially in the US Gulf region.

The largest demand increases were the 52 Bcf and 145 Bcf in the US West and Gulf core sectors.

1- Mexico is of course part of North America, but is not covered in detail in this report.

Table 1
North American Gas Demand

	2001 (Bcf)	2000 (Bcf)	Difference (Bcf)	Change (%)
US Residential	4,814	4,992	-178	-3.6%
US Commercial	3,247	3,226	21	0.7%
US Industrial total [1]	8,969	9,512	-543	-5.7%
[industrial process use] [2]	*4,973*	*6,225*	-1,252	-20.1%
[non-utility power generation] [3]	*3,996*	*3,287*	709	21.6%
US Utility Electric Generation [4]	2,675	3,043	-368	-12.1%
Total US power generation [5]	6,670	6,330	340	5.4%
US Gas Used in Operations	1,766	1,774	-8	-0.5%
Domestic US Demand	**21,471**	**22,547**	**-1,076**	**-4.8%**
US LNG Exports	66	66	0	0.0%
US Exports to Mexico	140	105	35	33.3%
Total US Gas Disposition	**21,677**	**22,718**	**-1,041**	**-4.6%**
Cdn Residential	585	621	-36	-5.8%
Cdn Commercial	407	438	-31	-7.0%
Cdn Industrial	996	1,083	-87	-8.1%
Cdn Electric Generation	251	268	-17	-6.4%
Cdn Other	445	462	-16	-3.6%
Total Cdn Demand	**2,684**	**2,872**	**-188**	**-6.5%**
TOTAL N.A. DEMAND	**24,155**	**25,419**	**-1,264**	-5.0%
TOTAL N.A. DISPOSITION	**24,361**	**25,590**	**-1,229**	-4.8%

Sources: EIA March 2002 Natural Gas Monthly and 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 68, 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 Appendices.

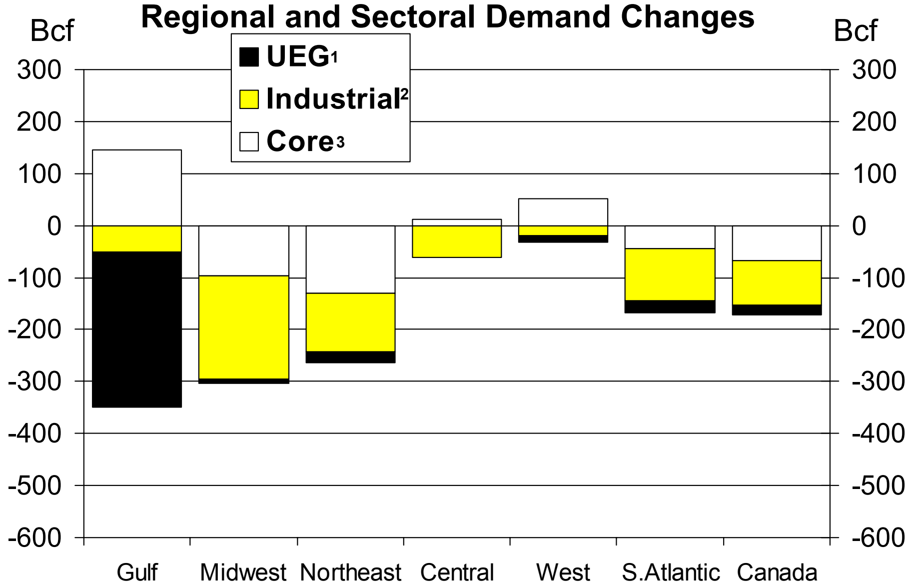
North American gas demand fell by 5% in 2001.

The residential and commercial sectors saw fairly large demand decreases – 224 Bcf in total.

US gas used by the industrial sector for heat and chemical feedstock completely collapsed – a drop of 1,252 Bcf or 20% in 2001, after falling 2% in 2000. The drop was the result of high gas prices making gas use for industrial manufacture uneconomic, combined with a weakening economy.

Overall, US power generation demand rose by about 5%.

Figure 2
Regional and Sectoral Demand Changes



Sources: EIA, NRCan **Notes:** Producer use & pipeline fuel is not shown. 1-Gas demand by Utility Electric Generators as reported in NGM. 2-Industrial demand as reported in NGM (includes non-utility gas demand). 3-Core is residential + commercial as reported in NGM

In 2001, North American gas consumption fell by 5%.

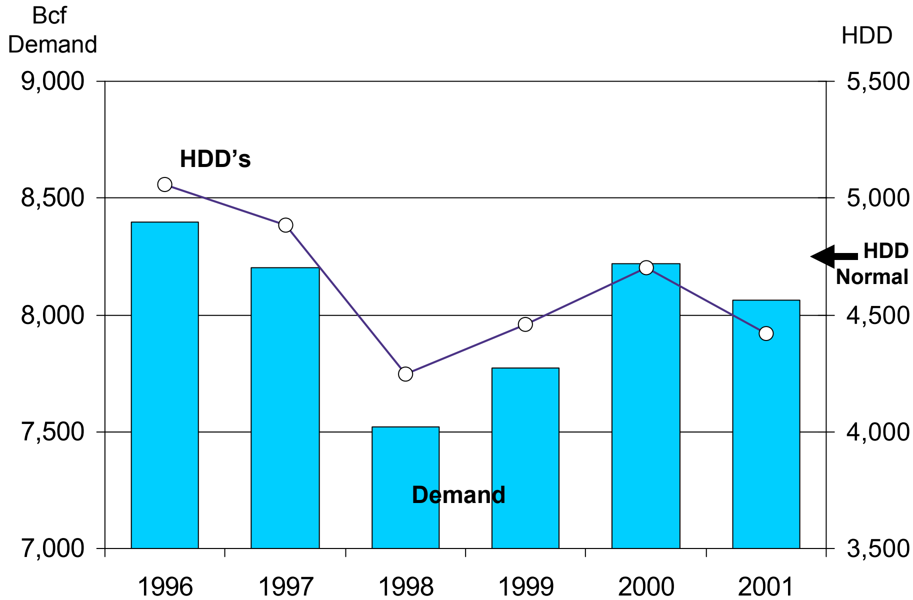
Core demand dropped in most regions, as shown on the left. Core demand rose in the US West and Gulf Coast as a result of colder winter months there during 2001.

Industrial demand fell in every region. The major losses occurred in the US Midwest, Northeast and South Atlantic, and Canada.

Besides the dramatic decline on the Gulf Coast (down 300 Bcf), UEG demand changes were insignificant in 2001.

Figure 3

US Heating Degree Days & Core Demand



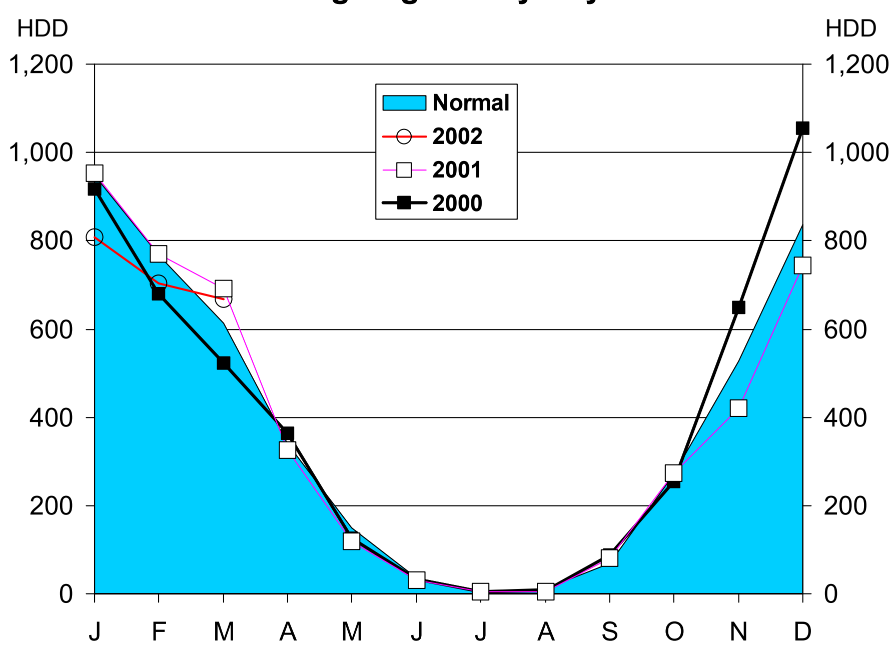
Sources: EIA, NOIAA

Core demand is almost perfectly correlated to heating degree days. Heating degree days had soared last year, resulting in higher core demand.

For the year 2001 in total, HDD's fell back, resulting in a sharp decrease in demand.

Figure 4

US Heating Degree Days By Month



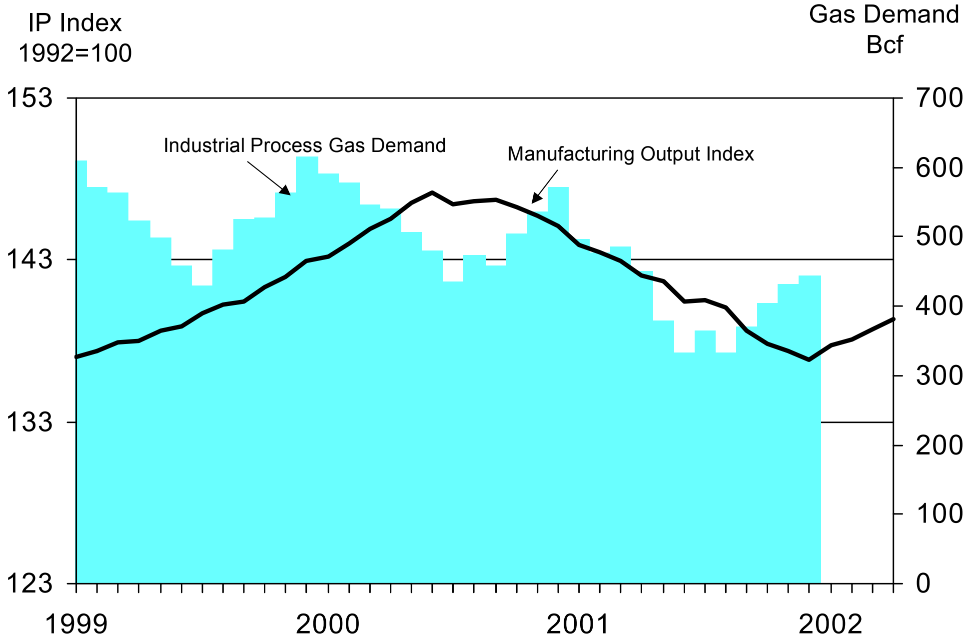
Sources: EIA, NOIAA

The last two months of 2000 were much colder than normal.

HDD's decreased by 6% in 2001 compared to 2000, primarily as a result of warmer-than-normal weather in November and December 2001.

Although not depicted in this graph, Canadian heating degree days followed a similar pattern to that of the US in 2001. Canada experienced 394 fewer HDD's or a decrease of 9% in 2001.

Figure 5
US Industrial Output & Gas Demand



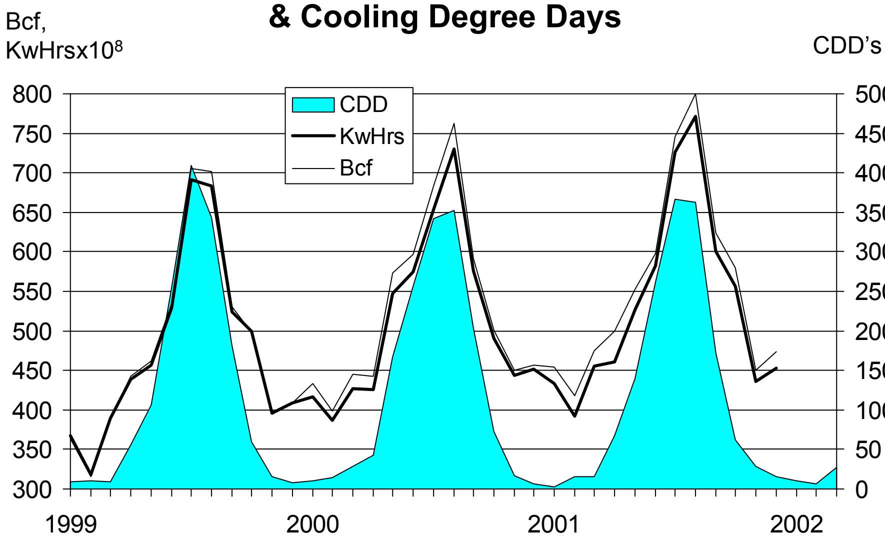
Sources: US Department of Commerce Statistical Release G-17, EIA

We define US "Industrial Process" demand as use of gas for process heat, space heat, and chemical feedstock. Industrial sector power generation is not included. See Appendices 1 and 2 for further detail.

Industrial process gas demand is linked to US manufacturing and weather. The US Federal Reserve tracks manufacturing by an index, which fell from July 2000 through December 2001. For the first quarter 2002 as a whole, the index increased at an annual rate of 2.5 percent.

However, both the index and industrial process natural gas demand are still well below 2000 levels.

Figure 6
Power Generation Gas Demand (Bcf), Gas-Fired Power Generation (kWhx10^8), & Cooling Degree Days



Sources: EIA (NGM, EPM). **Note:** 1- Calculated as UEG demand (NGM, Table 3) plus NonUtility demand (EPM, Table 68).

US power generation gas demand (including generation by the industrial sector) is shown in the figure, along with the quantities of power generated by gas-fired facilities, and US cooling degree days (CDD's).

On average, 10 Bcf of gas is needed to generate 1 BkWh of electricity.

Although summer heat, as measured by CDD's, drives power demand, gas use is rising even when CDD's are not.

See Appendix 2 for further detail on the US power generation sector.

Increased thermal power generation (gas, oil, coal, nuclear) was needed in 2000, due to very low hydro reservoir water levels. Gas and coal were favoured, since oil prices were high.

In 2001, hydro fell again, meaning thermal generation increased again. Gas was less favoured though, since oil prices had fallen, while gas prices had risen.

Table 2
US Electric Power Generation

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
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	85	3,704
2000	1,968	754	612	273	109	84	3,800
2001	1,943	767	640	211	128	88	3,777
Difference	-25	14	28	-62	19	4	-23
% Change	-1.3%	1.8%	4.6%	-22.7%	17.5%	5.1%	-0.6%

Source: EIA Electric Power Monthly, Table 3 and Table 58

Table 3 reports eastern Canadian natural gas demand by province and sector for 2000 and 2001.

In eastern Canada, the core market (residential and commercial) is the most important demand sector, accounting for almost 50% of total eastern gas demand.

Gas demand totalled 1233 Bcf in 2001, a decrease of nearly 5% compared with 2000.

Large decreases in Quebec, particularly in the industrial sector, are to blame for falling gas demand in 2001. Many Quebec industrial gas users have the ability to switch to oil. With high gas prices in 2001, many did.

Note that there is some gas demand in Nova Scotia and New Brunswick, but figures are not yet available.

Table 3
Eastern Canadian Natural Gas Demand (Bcf)

Province	Sector	2001	2000	Difference	% Change
Manitoba	Residential	21.3	23.6	-2.3	-9.8%
	Commercial	22.9	25.3	-2.5	-9.7%
	Industrial	15.5	16.9	-1.4	-8.4%
	Power	0.0	0.0	0.0	0.0%
	Other	24.9	27.1	-2.2	-8.0%
	Total Manitoba	**84.6**	**92.9**	**-8.3**	**-8.9%**
Ontario	Residential	294.2	302.0	-7.8	-2.6%
	Commercial	187.5	192.0	-4.5	-2.4%
	Industrial	342.2	342.0	0.3	0.1%
	Power	101.7	100.4	1.3	1.3%
	Other	30.2	28.6	1.6	5.5%
	Total Ontario	**955.8**	**965.0**	**-9.2**	**-1.0%**
Quebec	Residential	21.9	26.1	-4.3	-16.4%
	Commercial	56.2	67.6	-11.4	-16.8%
	Industrial	102.7	126.2	-23.4	-18.6%
	Power	0.0	0.0	0.0	0.0%
	Other	11.9	14.7	-2.8	-18.8%
	Total Québec	**192.7**	**234.6**	**-41.9**	**-17.8%**
E.Canada Total	Residential	337.4	351.7	-14.5	-4.1%
	Commercial	266.6	284.9	-18.4	-6.4%
	Industrial	460.4	485.1	-24.6	-5.1%
	Power	101.7	100.4	1.3	1.3%
	Other	67.0	70.4	-3.4	-4.8%
	Total E. Canada	**1233.1**	**1292.4**	**-59.3**	**-4.6%**

Sources: NRCan estimates, StatsCan

Table 4
Western Canadian Natural Gas Demand (Bcf)

Province	Sector	2001	2000	Difference	% Change
British Columbia	Residential	72.2	76.6	-4.4	-5.7%
	Commercial	47.8	50.8	-3.0	-5.8%
	Industrial	112.7	120.5	-7.8	-6.5%
	Power	36.4	39.7	-3.2	-8.2%
	Other	32.1	33.2	-1.1	-3.2%
	Total B.C.	**301.2**	**320.8**	**-19.6**	**-6.1%**
Alberta	Residential	138.5	154.3	-15.8	-10.3%
	Commercial	68.5	76.1	-7.7	-10.1%
	Industrial	368.1	421.8	-53.7	-12.7%
	Power	89.9	103.9	-14.0	-13.5%
	Other	205.3	229.6	-24.3	-10.6%
	Total Alberta	**870.3**	**985.7**	**-115.4**	**-11.7%**
Saskatchewan	Residential	36.8	38.6	-1.8	-4.6%
	Commercial	24.6	26.2	-1.7	-6.3%
	Industrial	54.8	56.0	-1.2	-2.2%
	Power	22.5	23.7	-1.3	-5.3%
	Other	89.3	92.8	-3.6	-3.8%
	Total Sask.	**228.0**	**237.3**	**-9.3**	**-3.9%**
Yukon	Residential	0.2	0.1	0.1	59.5%
	Commercial	0.0	0.0	0.0	0.0%
	Industrial	0.0	0.0	0.0	0.0%
	Power	0.0	0.0	0.0	0.0%
	Other	51.4	35.6	15.9	44.5%
	Total Yukon	**51.6**	**35.7**	**15.9**	**44.4%**
W. Canada Total	Residential	247.7	269.6	-21.9	-8.1%
	Commercial	140.9	153.1	-12.3	-8.0%
	Industrial	535.6	598.3	-62.7	-10.5%
	Power	148.8	167.3	-18.5	-11.1%
	Other	378.1	391.2	-13.1	-3.4%
	Total W.Canada	**1451.1**	**1579.5**	**-128.5**	**-8.1%**

Sources: NRCan estimates, StatsCan

This figure illustrates demand for gas by sector in the western Canadian provinces.

The industrial sector is the most important demand segment in western Canada, representing more than 35% of total western gas demand.

Industrial gas demand includes gas used for heat, power or chemical feedstock by the manufacturing sector. Also included in industrial demand are the mining, forestry and construction sectors. See Appendix 3 for Canadian gas demand definitions.

In 2001, industrial and power generation demand declined by about 12% each.

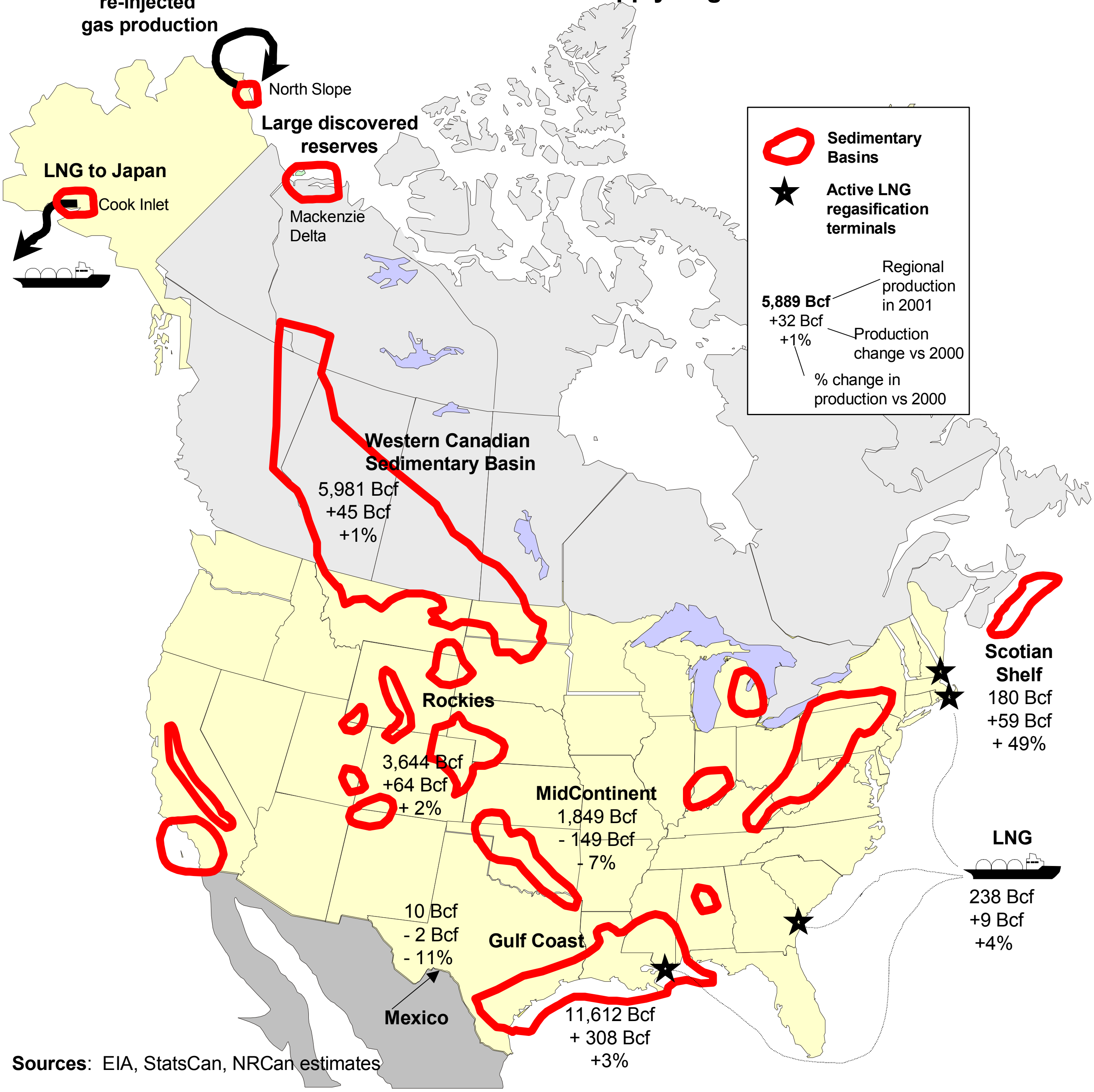
The most significant demand decline occurred in Alberta, where 115 Bcf of gas demand was lost, mostly in the industrial sector. High gas prices were the major cause of the loss in demand. This included the closure of a large methanol plant in Medicine Hat.

Demand for gas in Yukon increased by nearly half. However, Yukon demand represents only about 1% of total demand.

Review of 2001

Natural Gas Production

Figure 7
Canadian & US Gas Supply Regions



Sources: EIA, StatsCan, NRCan estimates

The map shows the major natural gas-producing basins of North America[1]. In 2001, the big additional supplies came from the US Gulf Coast, the Rockies, and Canada's Scotian Shelf.

Western Canadian production, which grew 1.4% last year, was weaker this year, growing only 0.7%, despite a 20% increase in shallow drilling, and a 41% increase in deep drilling.

Rockies production was restrained by inadequate exit pipeline capacity, and grew only 2%.

LNG imports to the US were up 4%. Total LNG volumes remain minor, but LNG is an important source of incremental supply to North America.

1- Mexico is of course part of North America, but is not covered in detail in this report.

Table 5
North American Gas Supply (Bcf)

	2001 (Bcf)	2000 (Bcf)	1999 (Bcf)	% Change 00 vs 99	% Change 01 vs 00	Bcf Change 2001 vs 2000
Gulf Onshore	6,534	6,349	6,749	-5.9%	2.9%	185
Gulf Offshore	5,078	4,956	5,056	-2.0%	2.5%	123
Total Gulf	11,612	11,304	11,805	-4.2%	2.7%	308
US Midcontinent	1,849	1,998	2,006	-0.4%	-7.4%	-149
US Rockies	3,644	3,581	3,272	9.4%	1.8%	64
Other US	2,247	2,104	1,749	20.3%	6.8%	142
Total US Production	**19,352**	**18,987**	**18,832**	**0.8%**	**1.9%**	**365**
Western Canada[1]	5,981	5,936	5,857	1.4%	0.7%	45
Scotian Shelf	180	121			49.4%	59
Total Canada	**6,161**	**6,057**	**5,857**	**3.4%**	**1.7%**	**104**
LNG	238	229	163	40.0%	4.0%	9
Mexican Imports	10	12	55	-78.7%	-11.3%	-2
Supplementals	77	86	98	-12.4%	-10.5%	-9
TOTAL N.A. SUPPLY	**25,839**	**25,371**	**25,005**	**1.5%**	**1.8%**	**469**

Sources: EIA March 2002 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) 1 - Includes minor Ontario production.

North American gas supplies rose by 469 Bcf, or 1.8%, in 2001. This was a slightly better production performance than the 1.5% of last year.

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

Imports from Mexico remained low, while LNG increased slightly.

Table 6
North American Gas Drilling Indicators

	2001 (Wells)	2000 (Wells)	1999 (Wells)	% Change 00 vs 99	% Change 01 vs 00
Gulf Onshore (1)	5,787	4,580	3,568	28%	26%
Gulf Offshore (2)	119	117	80	47%	2%
Total Gulf (3)	706	553	380	46%	28%
US Midcontinent (3)	160	125	72	75%	28%
US Rockies (3)	181	143	89	60%	27%
Other US (3)	131	97	84	16%	34%
Total US (4)	**954**	**720**	**496**	**45%**	**33%**
Canada Shallow (5)	8,225	6,855	4,579	50%	20%
Canada Deep (6)	2,946	2,092	1,712	22%	41%
Total Canada (7)	**11,171**	**8,947**	**6,291**	**42%**	**25%**

Sources: Texas RRC, Baker Hughes, Daily Oil Bulletin.
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) Alberta West of 4th meridian gas wells, plus Saskatchewan gas wells.
(6) Alberta W5 & W6 meridian 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 2001 was up strongly again, and at new record levels, in most regions. This is a positive signal for future supply.

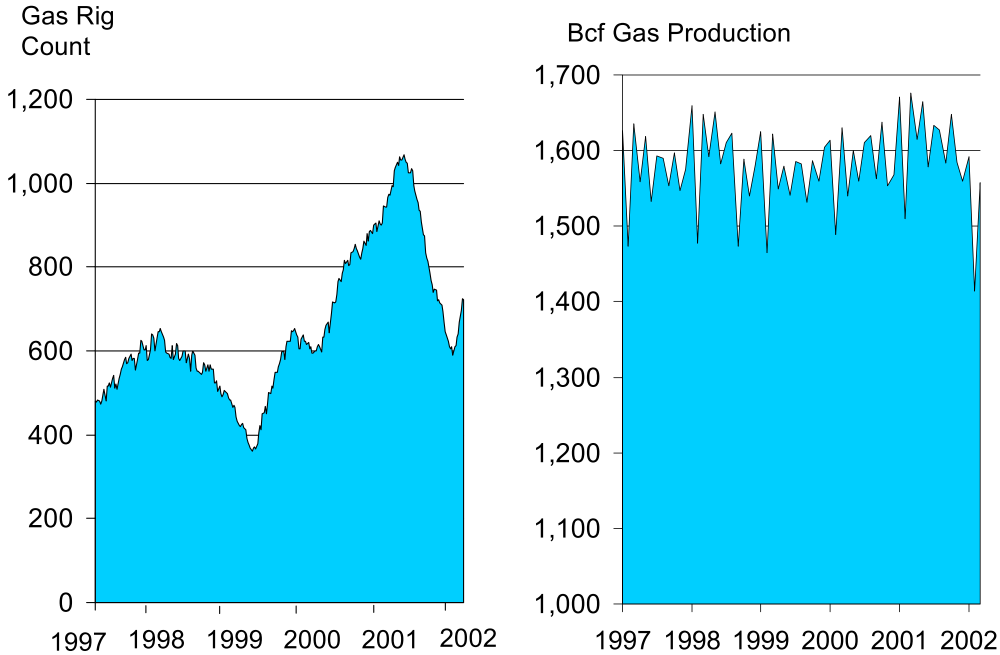
During 2001, drilling in the shallow, low productivity regions of Western Canada accounted for almost 75% of all Canadian gas drilling.

US gas production is quite stable. While gas demand can vary by as much as 5% year to year, US production is usually within 2% of the previous year level.

US production was slowly falling until about January 2000 – the result of low drilling in 1998 and 1999. US production is now rising slowly, due to a fairly long period of significantly above-normal gas drilling.

Note that it is difficult to see the increase in US production (2% in 2001), even though the US gas rig count rose a very obvious 33%.

Figure 8
US Production & Drilling Trends

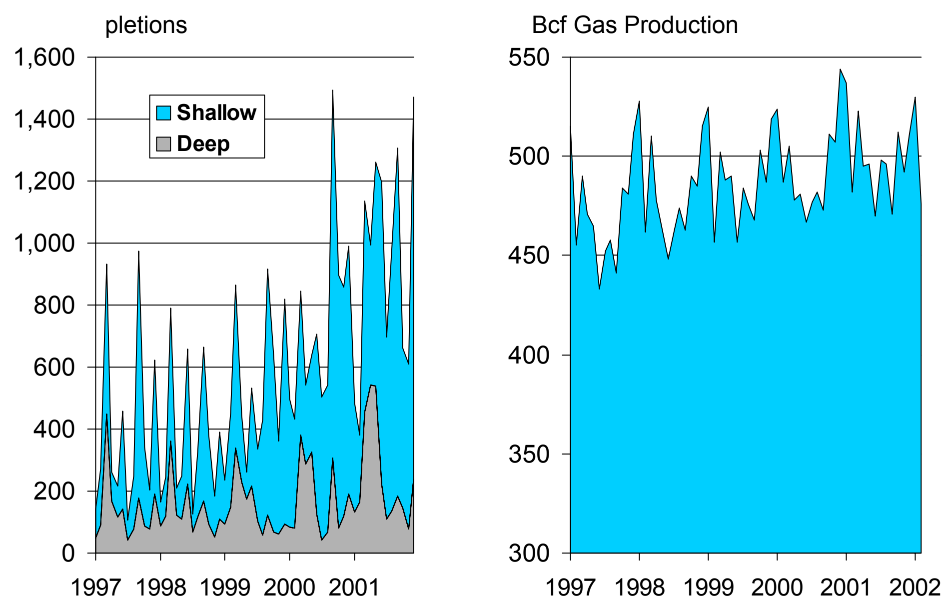


Sources: Baker Hughes, EIA

Annual Western Canadian gas production growth in recent years has averaged 2.1%. This fell to 0.7% in 2001. Maintaining production growth has required higher and higher gas drilling levels. While gas well drilling was averaging around 300 wells per month in 1997, by last year (2001) this had grown to 1,000 wells per month.

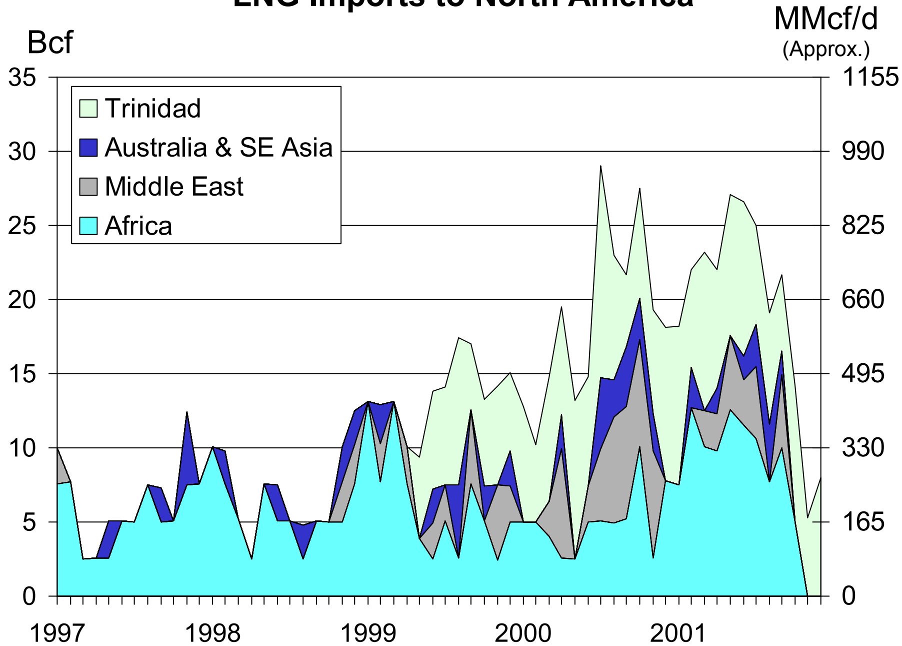
Most of the increase in drilling over the past 5 years has been in the shallow parts of the WCSB. However, deeper drilling did increase 41% in 2001.

Figure 9
Western Canadian Sedimentary Basin (WCSB) Production & Drilling Trends



Sources: StatsCan, Daily Oil Bulletin

Figure 10
LNG Imports to North America

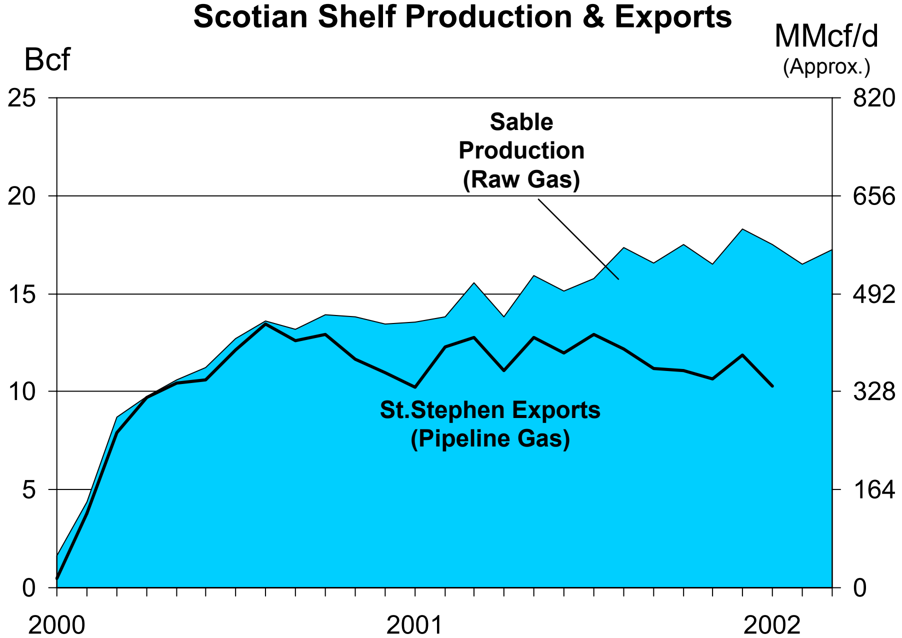


Source: EIA

LNG imports in 2001 averaged 652 MMcf/d. In 2001, LNG was imported via 3 receiving terminals, the CMS Trunkline Gas Company's Lake Charles Louisiana facility, the Tractebel Everett Massachusetts facility, and the recently re-opened El Paso Elba Island facility. The facilities combined had import capacity of over 1 Bcf per day.

LNG imports would probably have been higher in 2001, but for a ban on LNG tankers entering Boston Harbour from September 26th through October 16th. The ban was instituted following the terrorist attacks of September 11th.

Figure 11
Scotian Shelf Production & Exports



Sources: CNSOPB, NEB **Note:** St. Stephen exports are preliminary, and are expected to be revised upwards.

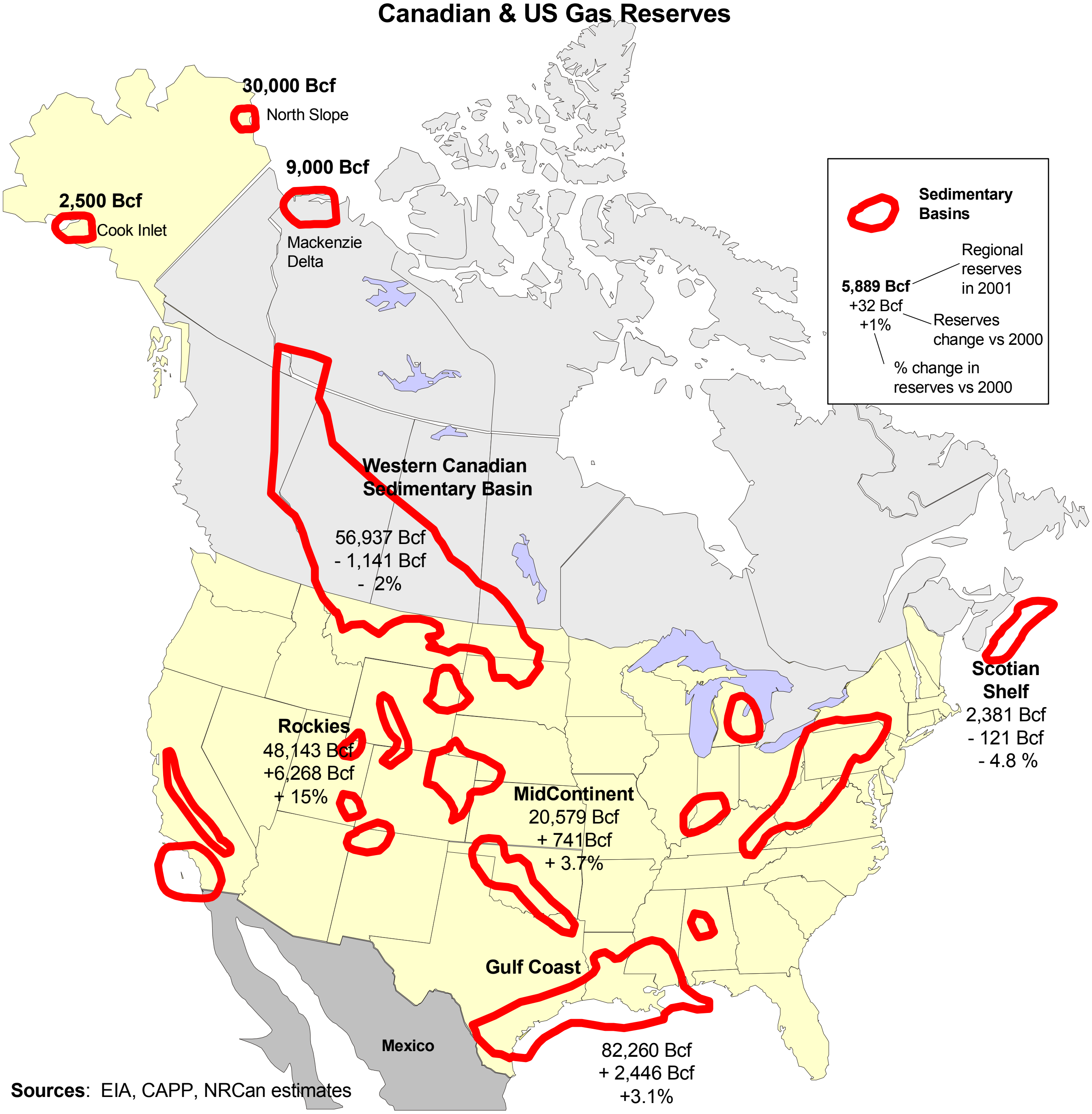
A single project which has similarly accounted for a large amount of the growth in North American gas supply in the past 2 years is the Sable project offshore Nova Scotia. In 2001, Sable production neared the full capacity level (550 MMcf/d) specified by the project's owners.

As shown in the figure, most of the gas is exported to the Northeast US.

Review of 2001

Natural Gas Reserves

Figure 12
Canadian & US Gas Reserves



Sources: EIA, CAPP, NRCan estimates

The map shows proved reserves in the major natural gas-producing basins of North America[1].

- In 2001, reserves increased dramatically (6%) in the US, due to a combination of high drilling in conventional areas, deepwater Gulf of Mexico successes, and the identification of large coalbed methane reserves in the US Rockies.

Western Canadian Sedimentary Basin (WCSB) reserves continued their downward trend. This is mainly an ongoing adjustment, as a result of deregulation. The 1980s regulated era forced producers to maintain much higher reserves than necessary for production. With deregulation, producers allowed reserves to fall towards the minimum levels needed for desired production.

1- Mexico is of course part of North America, but is not covered in detail in this report.

Table 7
North American Reserves

	Jan. 1, 2001 (Bcf)	Jan. 1, 2000 (Bcf)	Jan. 1, 1999 (Bcf)	% Change 00 vs 99	% Change 01 vs 00	Bcf Change 2001 Vs 2000
Gulf Onshore[1]	56,088	54,363	51,993	4.6%	3.2%	1,725
Gulf Offshore	26,172	25,451	26,422	-3.7%	2.8%	721
Total Gulf	82,260	79,814	78,415	1.8%	3.1%	2,446
US Midcontinent	20,579	19,838	21,375	-7.2%	3.7%	741
US Rockies	48,143	41,875	38,906	7.6%	15.0%	6,268
Other US	26,445	25,879	25,345	2.1%	2.2%	566
Total US Reserves	**177,427**	**167,406**	**164,041**	**2.1%**	**6.0%**	**10,021**
Western Canada	56,937	58,078	59,089	-1.7%	-2.0%	-1,141
Scotian Shelf	2,381	2,502	2,502	0.0%	-4.8%	-121
Other Canada [2]	415	429	436	-1.5%	-3.3%	-14
Total Canada	**59,733**	**61,010**	**62,027**	**-1.6%**	**-2.1%**	**-1,277**
TOTAL N.A. Reserves	**237,160**	**228,416**	**226,068**	**1.0%**	**3.8%**	**8,744**

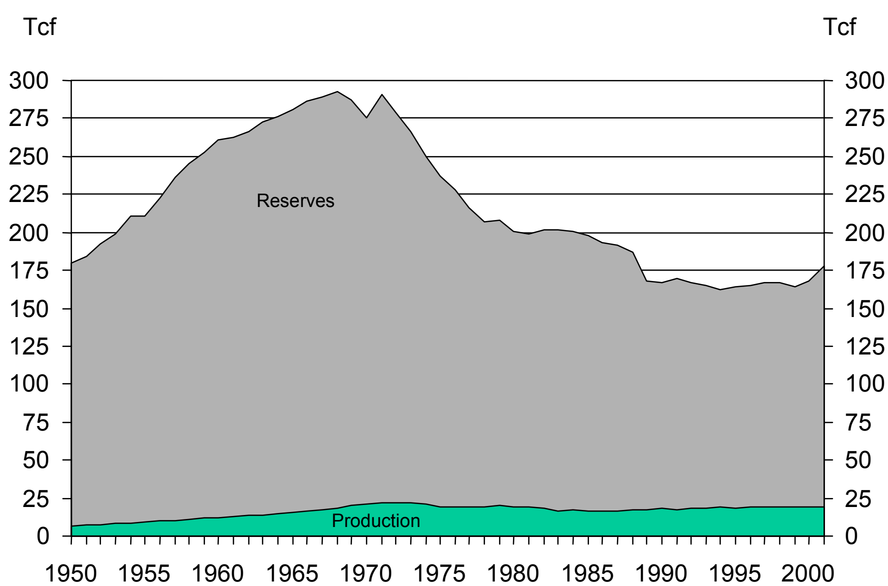
Sources: EIA US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2000 Annual Report (US data), and Canadian Association of Petroleum Producers (Canadian data).
1. Gulf Onshore includes all reserves in Texas, Louisiana, Mississippi, and Alabama onshore, plus the state offshore reserves of those states.
2. Mainly Ontario.

Reserves are those quantities of gas in known accumulations, which are economic to produce at current or anticipated economic and technical conditions. Reserves are usually drilled.

Reserves data for any year comes out almost one full year later. For example, reserves changes during 2000 were released in December (US) and September (Canada). The latest reserve figures show reserves as of January 1st, 2001.

January 2001 North American reserves were 3.8% higher than they were in January 2000. This was due to increases in the US.

Figure 13
Total US Gas Reserves



Sources: EIA

A comparison of proved reserves and production over time provides an indication of the maturity of an area.

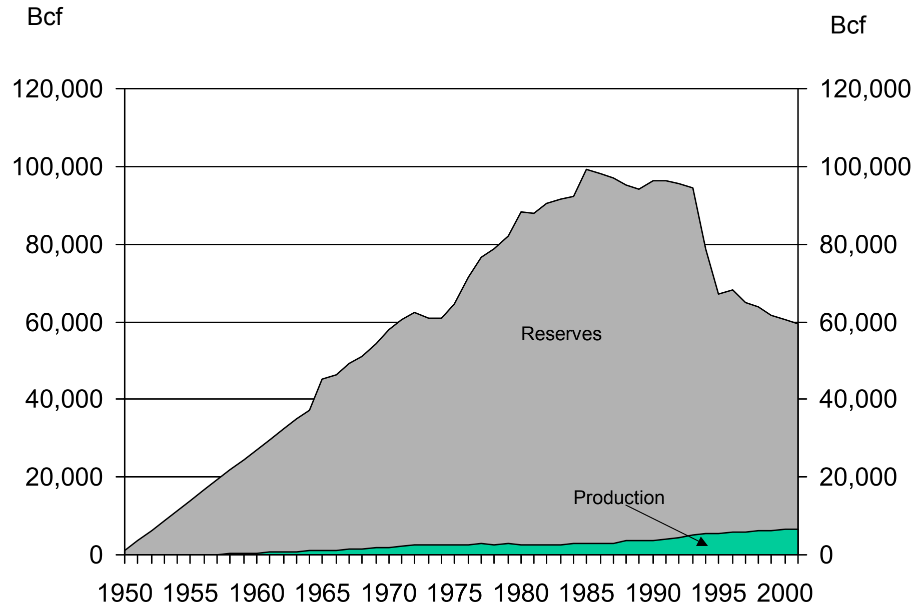
As shown in the figure, US reserves peaked in 1970. Following this peak, US reserves declined rapidly. Since 1990 however, US reserves have been stable.

Although there are numerous basins in the US, at various stages of maturity, in general it may be said that the US gas production industry is now in a mature, stable, sustainable phase, where reserves and production are fairly flat.

A similar comparison of WCSB gas reserves shows a different maturity. WCSB reserves peaked in 1983, and fell very quickly to 1994. Part of this drop was due to large negative revisions, which removed old reserves that had been on the books for some time. Canadian reserves are still dropping, though the declines appear to be slowing.

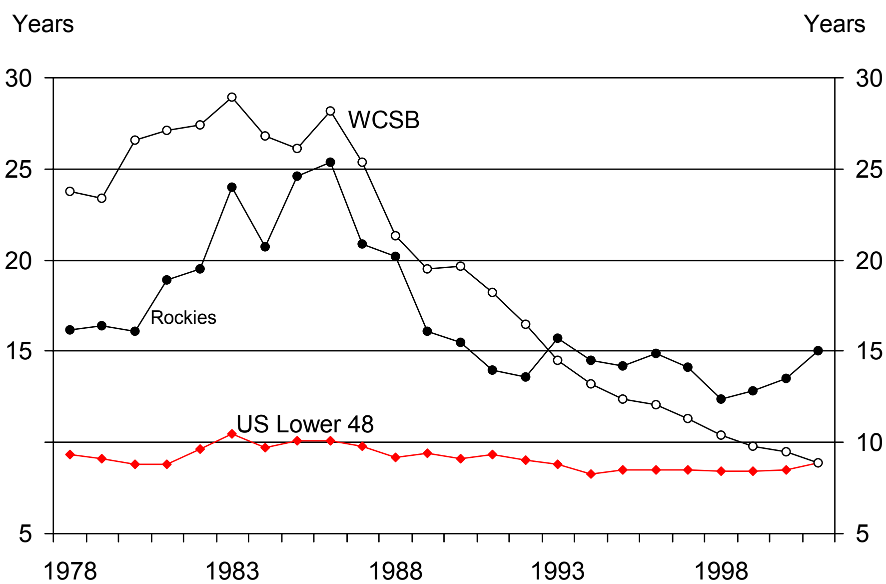
WCSB production in recent years has continued to increase, but the percentage increase is a bit less each year. The WCSB appears to be at the stage the US was in during the late 1970s, when US production began to flatten out.

Figure 14
Total Canadian Gas Reserves



Source: CAPP

Figure 15
Reserves to Production Ratios



Sources: EIA, CAPP

Another indication of the maturing nature of the WCSB is its reserves to production ratio.

By this year, the WCSB had the same R/P ratio as the US lower 48 states.

The only major supply region which remains quite immature is the US Rockies, specifically, Colorado, Wyoming, and Utah.

Review of 2001

Natural Gas Storage

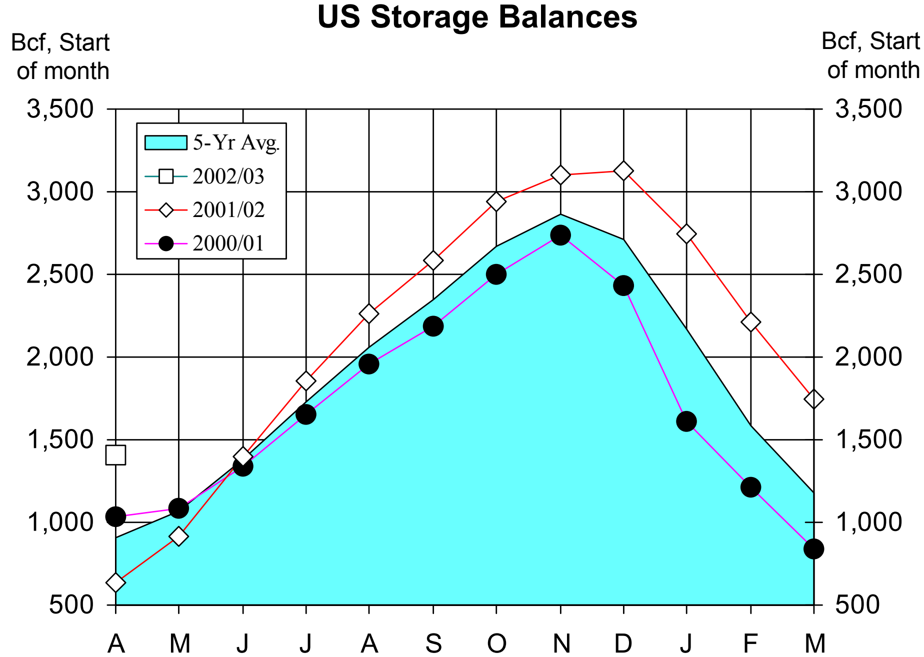
The storage situation in 2001 was almost a complete reversal of 2000. US storage injections during summer 2001 were extremely strong, leaving November 2001 storage at record highs.

Since November and December were very mild, storage balances fell very little, leaving a large year-on-year storage surplus, which seems likely to persist through to spring.

This means less gas will need to be injected before November 2002 in order to reach typical November levels in the 2.7 – 3 Tcf range.

Figure 16

US Storage Balances



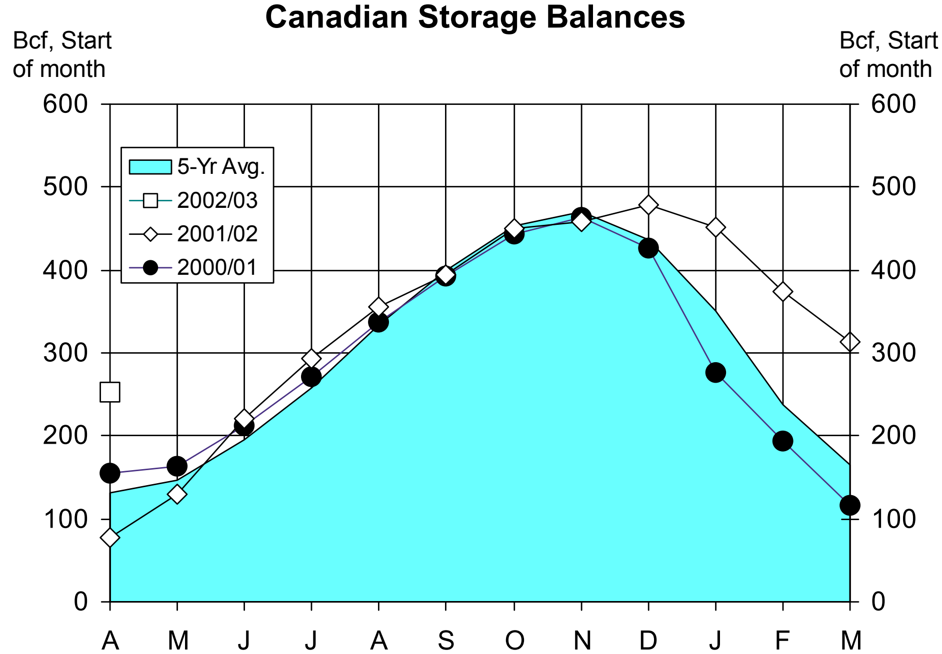
Source: NRCan estimates from AGA weekly data.

Canadian storage injections during summer 2001 were also strong, resulting in comparatively high storage by November 2001.

Going into the summer 2002 injection season, Canadian storage balances remain very high. As with the US, less gas will be required for storage injections before next winter than was the case last year.

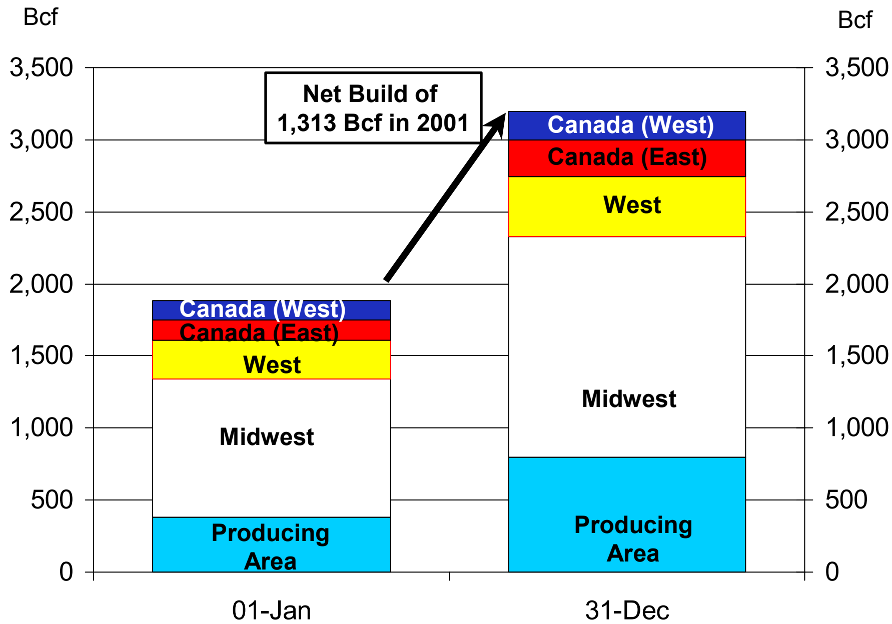
Figure 17

Canadian Storage Balances



Source: NRCan estimates from CGA weekly data.

Figure 18
Storage Changes During 2001



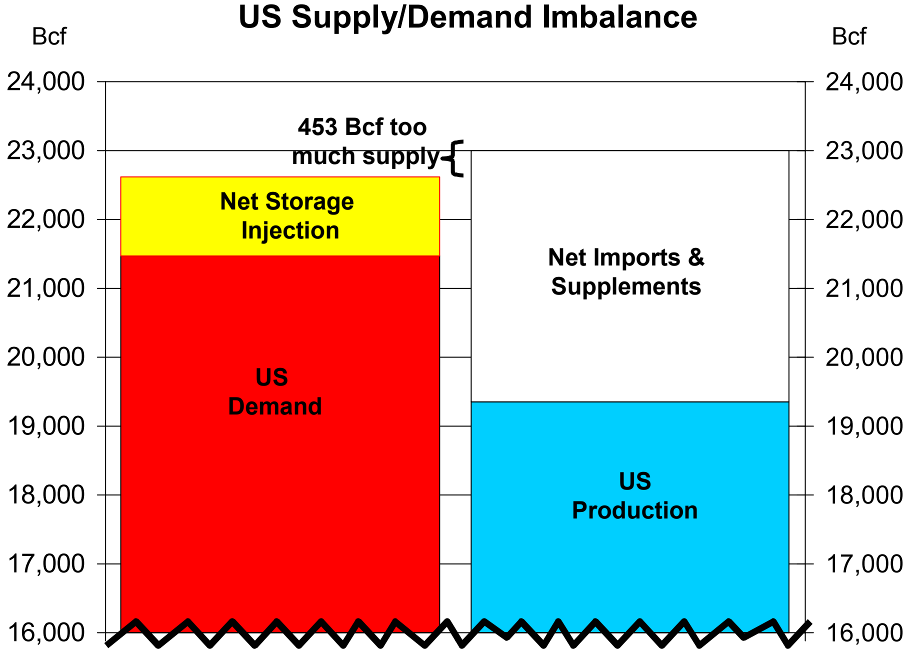
Sources: AGA, CGA

On Jan 1st, 2001, the AGA and CGA storage surveys showed 1,886 Bcf of gas in North American storage. By Dec 31st, there was 3,199 Bcf. Thus, during calendar year 2001, there was a net storage build of 1,313 Bcf. This was the largest single source of incremental "demand" in 2001.

This follows a net draw of 944 Bcf last year.

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

Figure 19
US Supply/Demand Imbalance



Source: EIA Natural Gas Monthly, March 2002

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

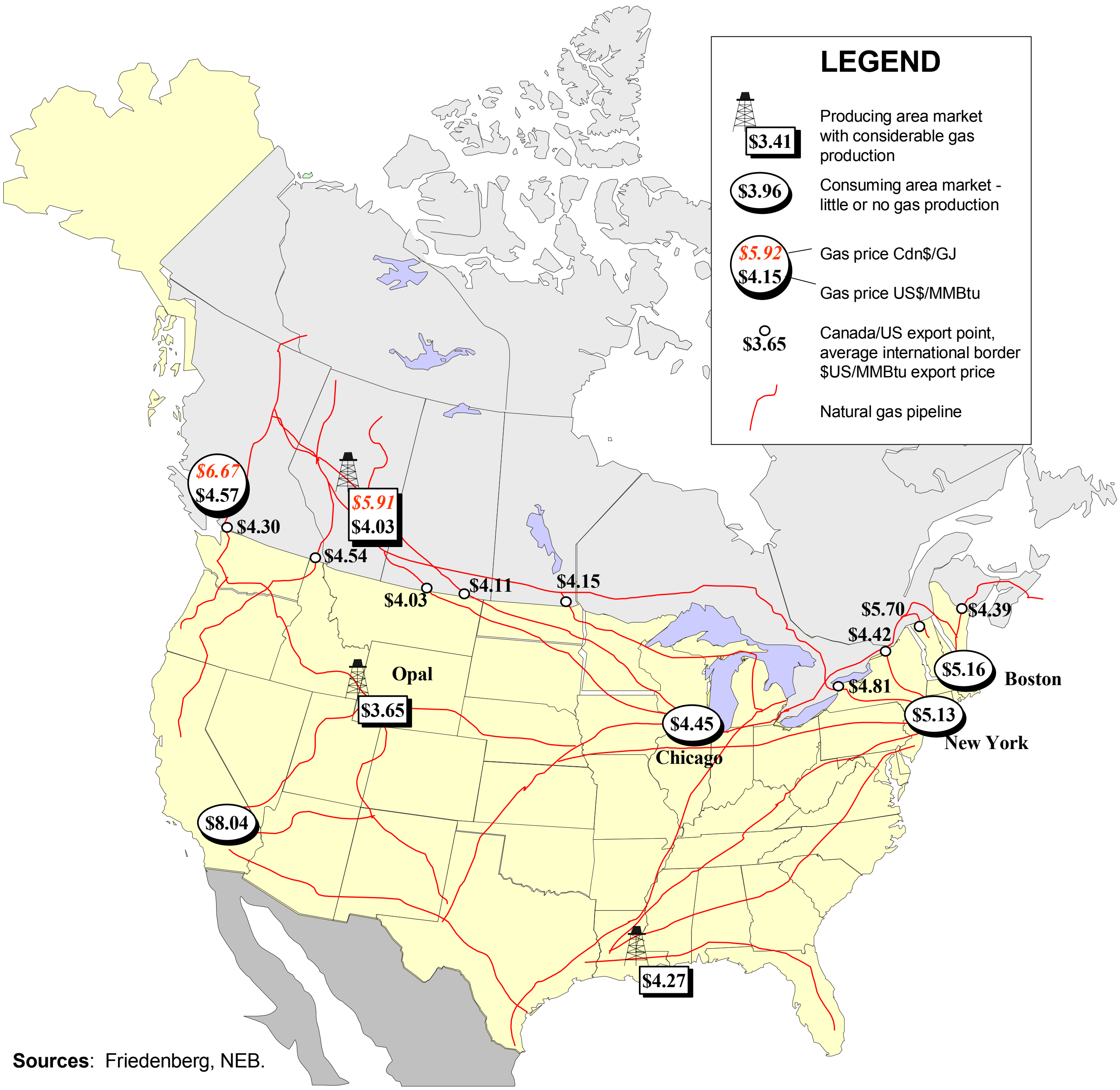
Current EIA figures show a negative 453 Bcf "balancing item" for 2001 – supply is higher than demand.

This is fairly typical. The balancing item was –230 Bcf in 1995, 217 in 1996, 61 in 1997, -334 in 1998, -897 in 1999, and –827 in 2000.

Review of 2001

Natural Gas Prices

Figure 20
Canada/US Natural Gas Prices



Sources: Friedenberg, NEB.

The map shows various North American natural gas spot-month market prices. Prices shown are the annual average of 12 monthly prices, except for prices at export border points, which are volume-weighted average prices.

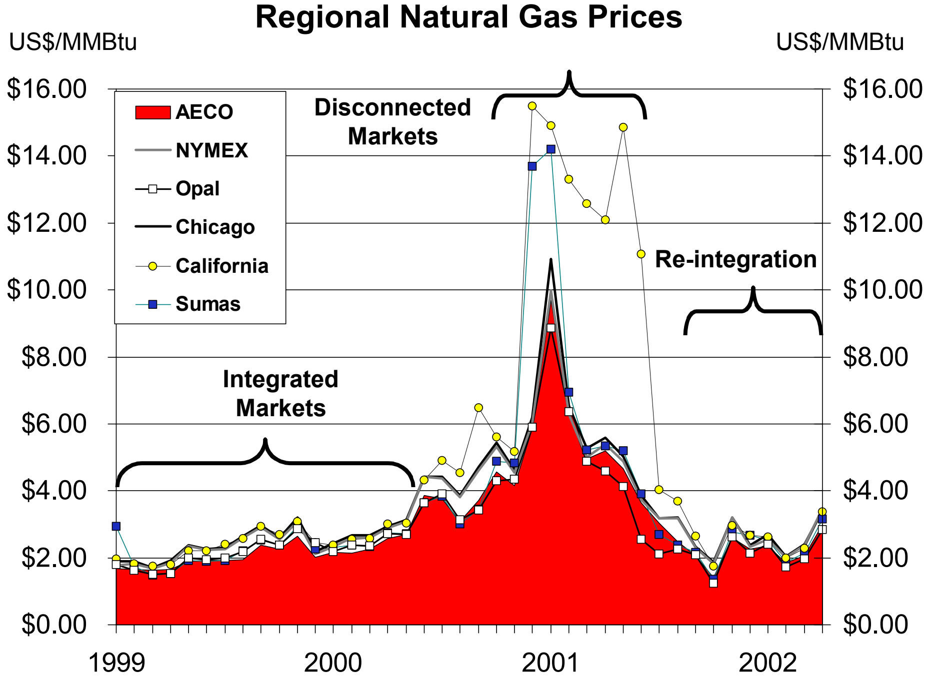
In 2001, gas demand in western North America soared, to the point where pipeline capacity from supply areas to the east was insufficient. As a result, prices in western North America de-linked from those in the rest of North America, and were higher, particularly in California.

The opposite situation occurred in the US Rockies. In the Rockies, production capacity exceeded exit pipe capacity, trapping gas and causing relatively low prices.

Although gas prices fell through 2001, on average 2001 prices were the highest on record.

Figure 21

Regional Natural Gas Prices



Source: Friedenberg

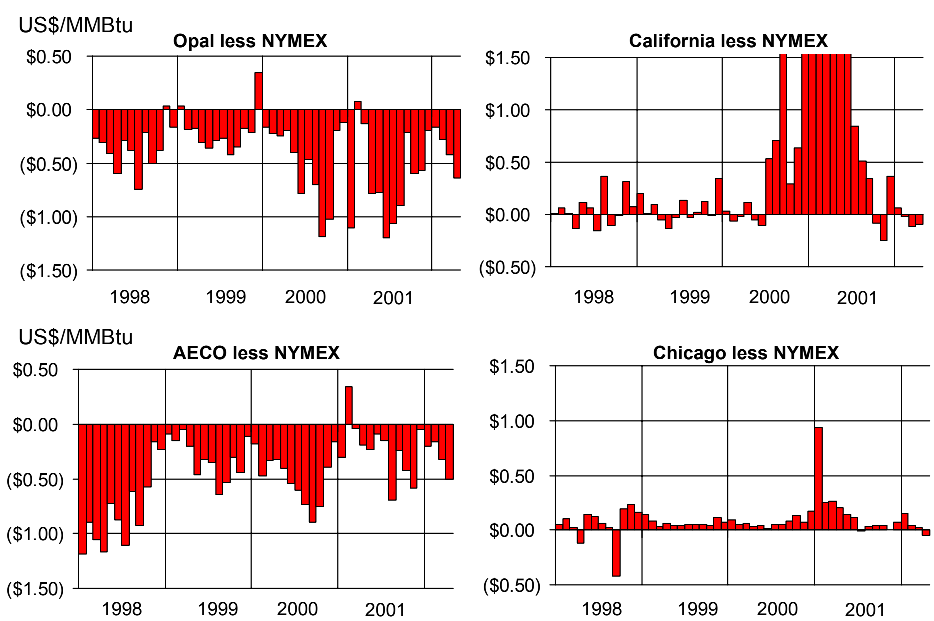
As noted in last year's report, the winter of 2000/2001 was "A Perfect Storm", in terms of natural gas prices. Numerous factors were all tending to cause high gas prices.

Beginning in January 2001, most of these factors turned, sending prices lower.

Particularly important was mild winter weather in November and December 2001, and massive demand losses in the industrial sector (see Review of 2001- Natural Gas Demand).

Figure 22

Natural Gas Price Differentials



Source: Friedenberg

Along with high prices, last winter also saw an extended period of high price differentials in the west.

Price differentials were high in the Midwest, but only for one month – January 2001.

As with prices overall, price differentials now seem to be back to normal ranges.

The Rockies differentials are strongly negative, indicating that gas is trapped there, due to insufficient exit pipeline capacity.

Crude oil prices influence natural gas prices. In 2000, crude oil prices were high – in the $30 per barrel range. This tended to support high natural gas prices, as natural gas and oil products are substitutes in industrial and power generation facilities.

In 2001, crude prices fell to the $20 per barrel range by year-end.

In 2002, prices are up again, to the $25 per barrel range.

Figure 23

Daily Crude Oil Prices

Source: EIA. Cushing, Oklahoma West Texas Intermediate spot price.

Canadian and US natural gas markets are strongly linked, with prices generally moving together. Thus, exchange rate changes affect Canadian gas prices.

This factor has for several years been increasing the price in Canadian dollars of natural gas.

To illustrate, if the Canada/US exchange rate in 2001 had been equal to the 1997 exchange rate, the average 2001 Canadian gas price would have been Cdn$5.61/GJ, rather than $5.91/GJ, as was actually the case.

Figure 24

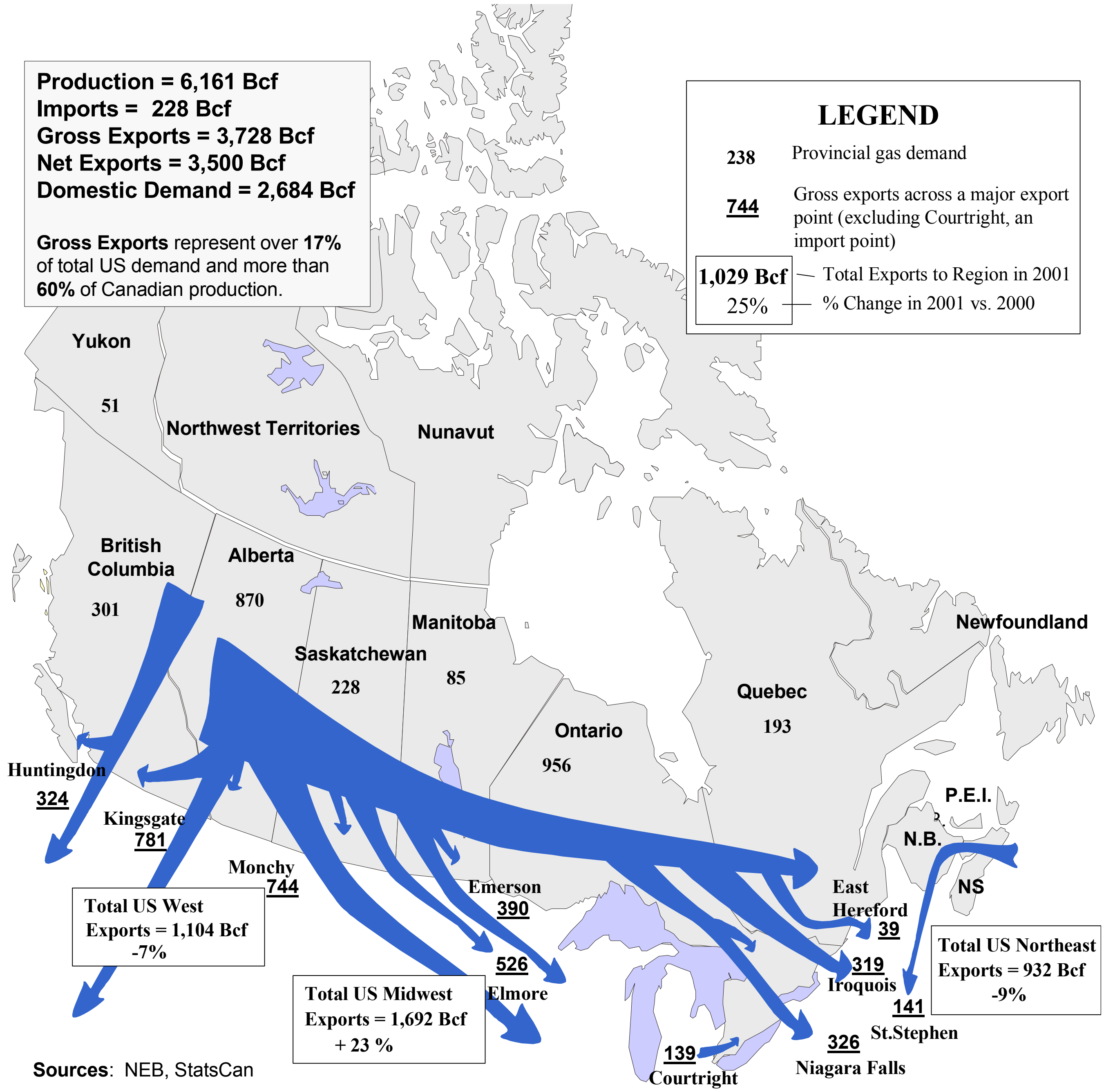
Canada/US Exchange Rates

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

Review of 2001

Canadian Export
& Domestic Sales

Figure 25
Domestic and Export Markets



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 228 Bcf of natural gas in 2001, which represented about 8% of Canadian demand.

For the US however, Canadian gross exports represented 17% of total US natural gas consumption.

In 2001, gross Canadian exports reached a record of 3.7 Tcf. However, net exports were slightly lower due to a significant increase in imports.

Gross export volumes in 2001 were distributed as follows: 45% to the Midwest, 30% to the West and 25% to the Northeast. The Midwest market accounted for all of the increase in exports, reflecting the volumes of gas transported by the Alliance Pipeline.

Table 8
Total Canadian Gas Sold

	2001 (Bcf)	2000 (Bcf)	1999 (Bcf)	% Change 00 vs 99	% Change 01 vs 00	Bcf Change 2001 Vs 2000
US West Gross Exports	1,104	1,189	1,207	-1.5%	-7.1%	-85
US Midwest Gross Exports	1,692	1,379	1,327	3.9%	22.7%	313
US Northeast Gross Exports	932	1,023	816	25.4%	-8.9%	-91
Total Gross Exports	3,728	3,591	3,349	7.2%	3.8%	137
Imports from US	228	80	50	59.9%	183.2%	147
Net Exports	**3,500**	**3,511**	**3,299**	**6.4%**	**-0.3%**	**-11**
Western Canada Demand	1,451	1,580	1,431	10.4%	-8.1%	-129
Eastern Canada Demand	1,233	1,292	1,267	2.0%	-4.6%	-59
Total Canadian Demand	**2,684**	**2,872**	**2,698**	**6.5%**	**-6.5%**	**-188**
Net Exports	3,500	3,511	3,299	6.4%	-0.3%	-11
Canadian Demand	2,684	2,872	2,698	6.5%	-6.5%	-188
Total Canadian Gas Sold	**6,184**	**6,383**	**5,997**	**6.4%**	**-3.1%**	**-199**

Sources: Export and import flows from NEB. Canadian demand from StatsCan. **Notes:** Gross exports are gas flows into the US from Canada which were identified as exports. This differs from some gas going into the US Great Lakes pipeline, which flows uninterrupted back into Canada. This gas is not considered to be an export or an import - it is Canadian gas sold to the domestic market. Net exports are gross exports less imports. Total Canadian gas sold equals net exports plus Canadian demand. See Appendix 4.

Because imports from the US became significant this past year, we now list both gross exports and net exports to the US.

Gross exports to the US went from 3,591 Bcf in 2000 to 3,728 Bcf in 2001, an increase of 4 %.

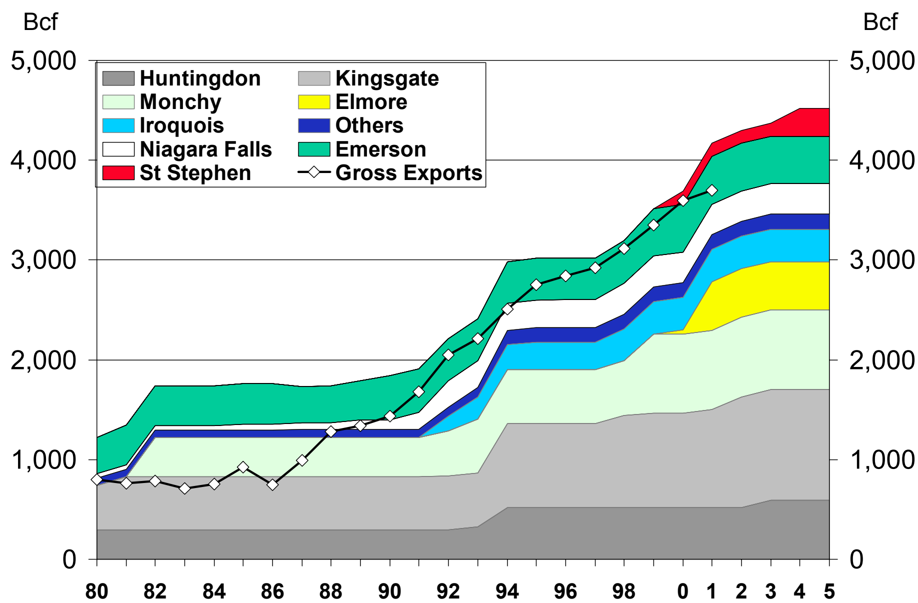
However, net exports fell, from 3,511 Bcf last year to 3,500 Bcf in 2001.

Imports, most of which occur via the Vector pipeline, reached 228 Bcf in 2001, more than doubling from last year.

Total Canadian gas sold fell by 3%.

See Appendix 4 for further detail on Canadian natural gas exports.

Figure 26
Pipeline Capacities by Canadian Export Point



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

Pipeline capacity had increased significantly in 2001, with the first full year of service of the Alliance pipeline (Elmore export point).

Export capacity also increased by 98 MMcf/d at Kingsgate, BC.

Load factors dropped from 89% in 2000 to 84% in 2001.

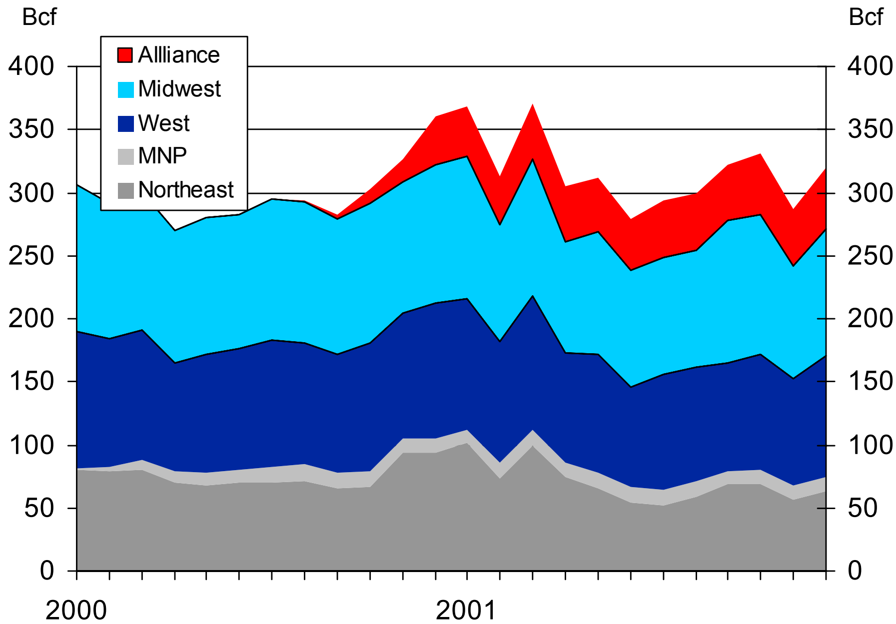
Capacity in 2002 is expected to increase by 360 MMcf/d at Kingsgate; in 2003 by 200 MMcf/d at Huntingdon, and in 2004 by a 400 MMcf/d expansion at St. Stephen.

Regionally, Midwest gross exports increased the most in 2001. The 23% increase or the additional 313 Bcf in 2001 can be largely attributed to a full year of throughput on the Alliance Pipeline (Elmore export point).

Increases in exports to the Midwest were offset by decreases in exports to the US West and Northeast, which fell by 85 Bcf and 91 Bcf, respectively.

Figure 27

Regional US Gross Exports



Source: NEB

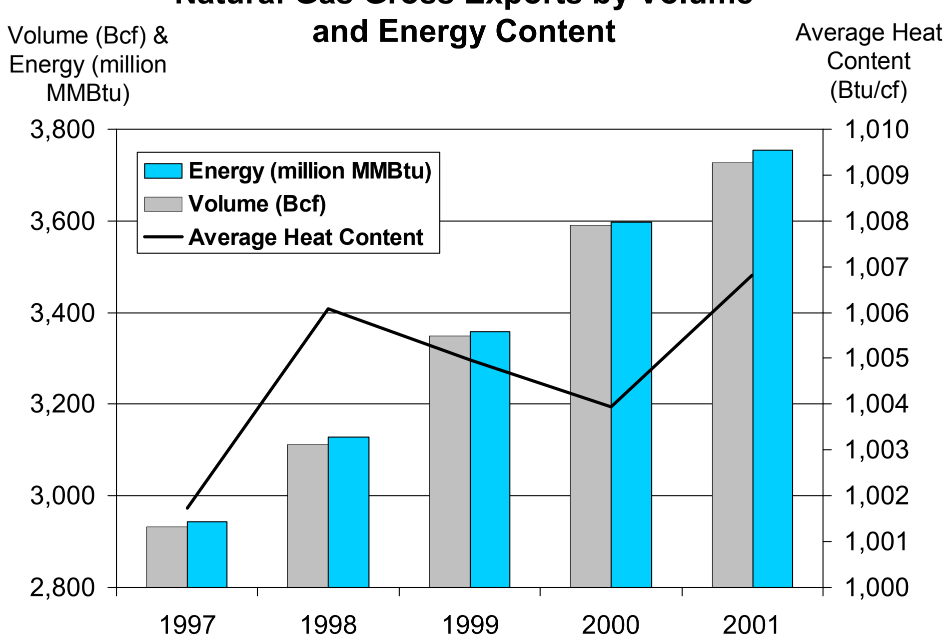
In the US, energy is commonly expressed in terms of million British thermal units (MMBtu). One MMBtu is approximately equal to one Mcf. The common sales unit in Canada is a Gigajoule (GJ), which is approximately equal to 0.948 MMBtu.

Typically, the higher the average heat content, the greater will be the difference between energy and volume of gas exported.

With the advent of high Btu gas exports on the Alliance Pipeline, the total amount of energy exported has risen slightly more than the volume of gas exported.

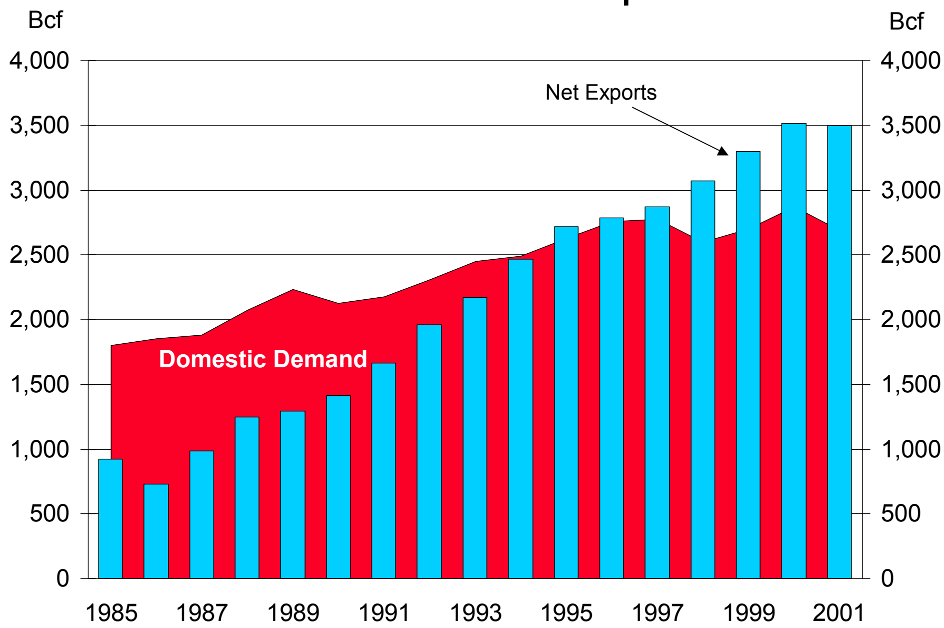
Figure 28

Natural Gas Gross Exports by Volume and Energy Content



Source: NEB

Figure 29
Domestic Demand & Net Exports



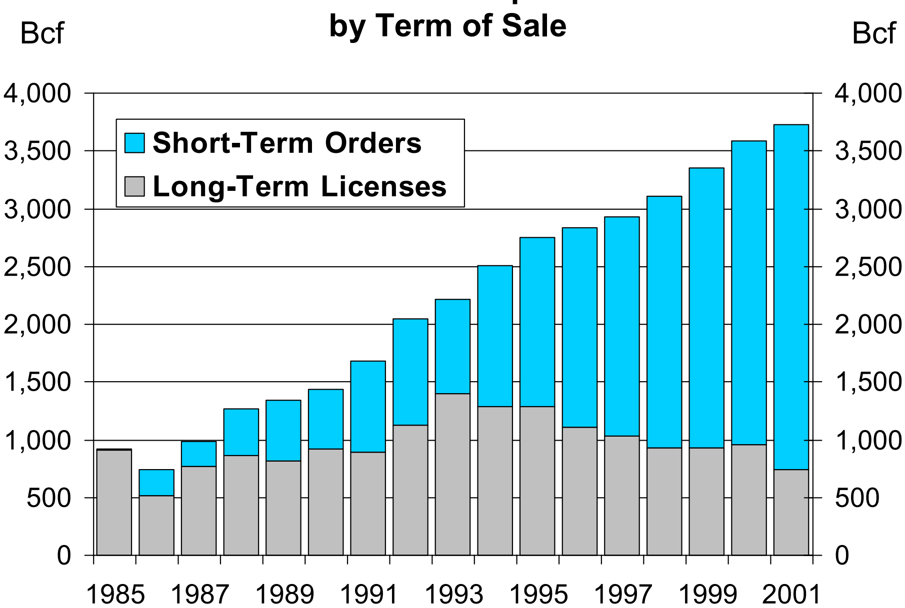
Sources: NEB, NRCan estimates, StatsCan

The domestic market reported a decline in sales in 2001. Domestic demand decreased 188 Bcf or 7% due to a weakening economy and warmer weather.

In 2001, net exports decreased by 11 Bcf, the first decline since 1986.

Net export sales represented more than 55% of total Canadian natural gas sold in 2001.

Figure 30
Natural Gas Gross Export Volumes by Term of Sale



Source: NEB

The NEB must approve the terms of an export arrangement, via either a long-term license or a short-term order (2 years or less).

The contractual structure of Canadian exports continues to shift towards short-term contracts and away from long-term licenses.

In 2001, the proportion of Canadian gas exported under short-term orders increased substantially to about 80% from 73% in 2000.

The increase in short-term orders during 2001 is largely due to increased volumes on the Alliance and MNP systems.

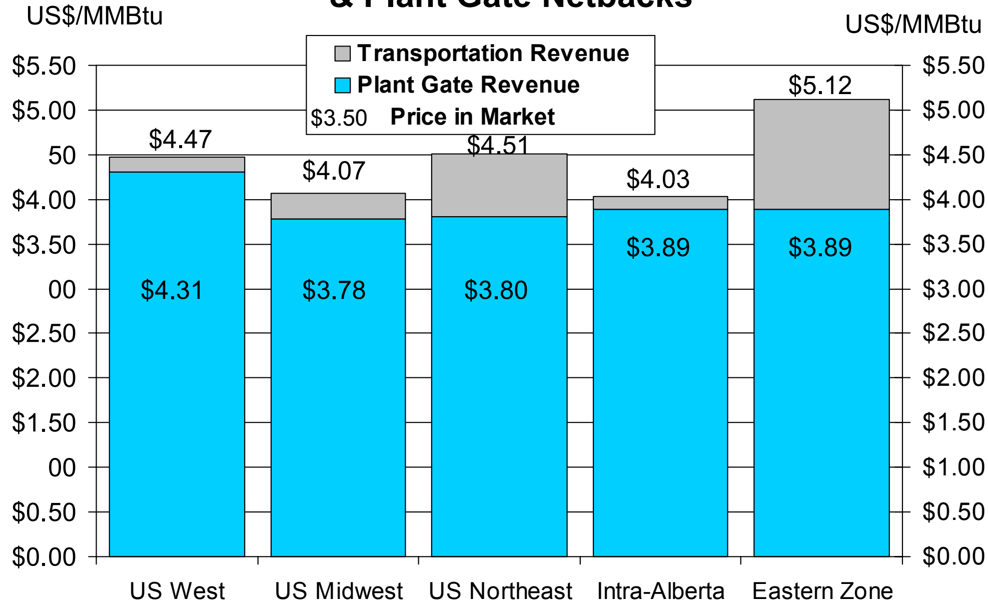
The figure shows natural gas prices for various markets. For the export markets, the price shown is the international border price.

Subtracting transportation costs from market prices (the top numbers) yields plant-gate netbacks (the lower numbers).

The US West saw the highest plant gate netbacks in 2001. Netbacks from other markets were roughly similar.

Figure 31

Gas Prices, Transportation Costs & Plant Gate Netbacks



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.

International border export prices and Canadian domestic prices closely tracked the NYMEX price in 2001.

Natural gas prices in the export market averaged US$4.30/MMBtu in 2001, an increase of 12% over 2000.

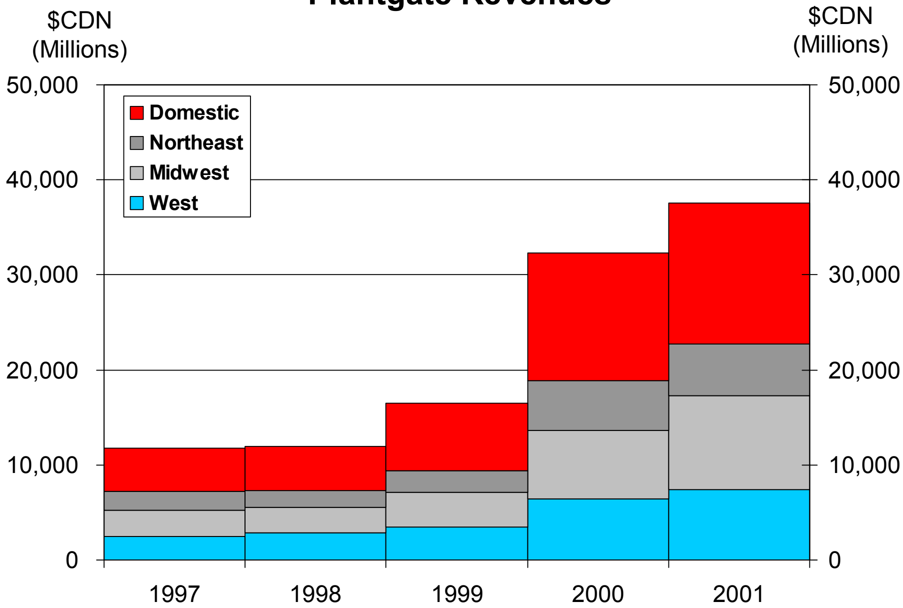
In Canada, AECO spot prices in US$/MMBtu were 19% higher in 2001.

Table 9
Domestic & Export Prices

	International Border Export Prices				US Prices	Canadian Markets			
	West	MW	NE	Average	NYMEX	AECO	AECO	Huntingdon	Westcoast St 2
nth	US/MMBtu	US/MMBtu	US/MMBtu	US/MMBtu	US/MMBtu	Cdn/GJ	US/MMBtu	US/MMBtu	US/MMBtu
January	$9.90	$9.11	$8.87	$9.26	$9.98	$13.78	$9.55	$14.20	$9.88
February	$6.96	$6.02	$5.99	$6.30	$6.29	$9.57	$6.63	$6.95	$7.21
March	$5.54	$4.97	$4.94	$5.15	$5.00	$7.32	$4.96	$5.21	$4.93
April	$5.48	$5.16	$5.07	$5.24	$5.38	$7.66	$5.19	$5.34	$5.24
May	$5.42	$4.58	$4.58	$4.84	$4.89	$6.81	$4.66	$5.19	$4.98
June	$4.24	$3.69	$3.90	$3.89	$3.74	$5.28	$3.61	$3.90	$3.77
July	$2.83	$2.99	$3.44	$3.05	$3.18	$4.40	$3.03	$2.70	$2.55
August	$2.64	$2.94	$3.42	$2.97	$3.17	$3.58	$2.45	$2.38	$2.40
September	$2.27	$2.17	$2.81	$2.35	$2.30	$3.05	$2.06	$2.17	$2.11
October	$1.78	$1.90	$2.65	$2.04	$1.83	$2.10	$1.41	$1.37	$1.34
November	$2.63	$2.80	$3.17	$2.85	$3.20	$3.94	$2.61	$2.76	$2.72
December	$2.65	$2.38	$2.97	$2.61	$2.32	$3.39	$2.25	$2.67	$2.40
2001 Average	**$4.47**	**$4.07**	**$4.51**	**$4.30**	**$4.27**	**$5.91**	**$4.03**	**$4.57**	**$4.13**
2000 Average	$3.77	$3.70	$4.15	$3.85	$3.89	$4.81	$3.40	$4.15	$3.34
% change	**19%**	**10%**	**9%**	**12%**	**10%**	**23%**	**19%**	**10%**	**24%**

Sources: Friedenberg, NEB, NRCan estimates

Figure 32
Plantgate Revenues



Sources: Friedenberg, NEB, NRCan estimates. **Notes:** Domestic plant gate revenue is an estimate only. See Table 14, p.54 for further detail.

The combination of increases in gross exports and higher prices led to new record levels of revenue to Canadian producers.

Total export plant gate revenues increased by 16% in 2001. Higher revenues were mostly the result of higher export prices in early 2001.

Seventy-two percent of additional export revenues were generated in the US Midwest, where all of the additional gas was exported in 2001, and where prices also rose by the largest percentage.

Short-Term Outlook

In the short-term (to 2003), natural gas prices are expected to be driven by the factors listed at right.

This section compares the state of these drivers in 2001 to normal or past extreme levels.

This can give an idea of the market's tendencies in the short-term.

Figure 33
Natural Gas Price Drivers

Demand Side

- ❑ Heating Degree Days (weather)
- ❑ Storage Balances (past injections and past weather)
- ❑ Oil prices (driven partly by weather)
- ❑ Industrial Output/Industrial gas demand (demand partly weather-driven)
- ❑ Need for gas-fired power (weather: precipitation into hydro reservoirs, summer cooling degree days, winter heating degree days. Restrictions on burning other fuels like oil or coal due to pollution concerns can also be a factor.)

Supply Side

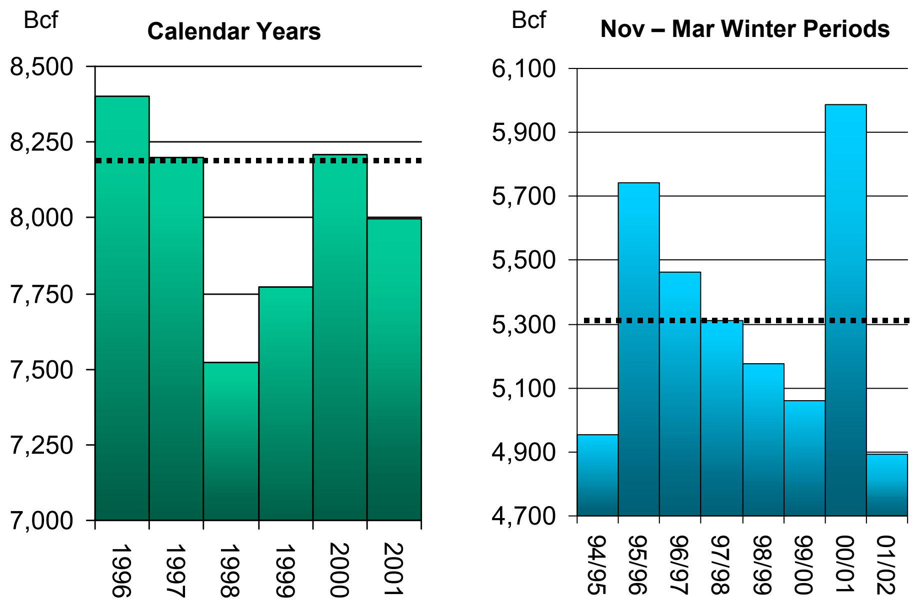
- ❑ Gas Production capacity (past drilling, completion, and work-over levels)
- ❑ Recent Drilling levels
- ❑ Storage Balances
- ❑ Underutilized reserves (e.g. US Rockies)
- ❑ Pipeline construction from new or underutilized supply areas
- ❑ Weather-related reductions (e.g. well freeze-offs, hurricane shut-ins)

Starting with the demand side, it has been several years since North America has had a truly cold calendar year, and high core market demand. Normal annual US core demand would be in the 8,200 Bcf range (dashed line).

For November through March winter seasons, 2000/01 was cold, and 2001/02 was warm. Normal US winter core demand is about 5,300 Bcf (dashed line).

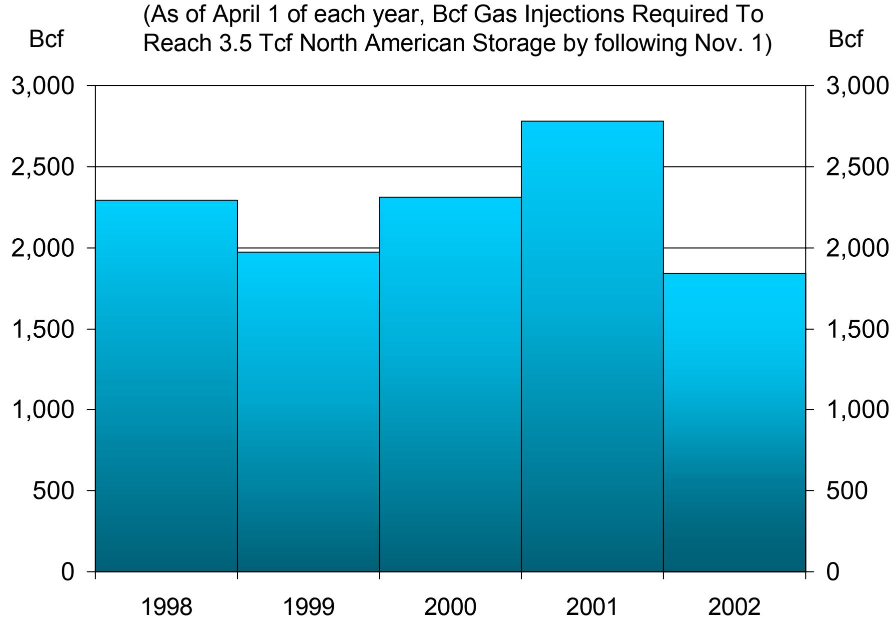
With both the 2001 calendar year and last winter seeing less core demand than normal, odds are that core demand will rise in 2002, and for the 2002/03 winter.

Figure 34
US Core Market Demand



Source: EIA

Figure 35
North American Storage Injection Demand:
(As of April 1 of each year, Bcf Gas Injections Required To Reach 3.5 Tcf North American Storage by following Nov. 1)



Sources: AGA, CGA

Given North American gas storage levels on April 1st, 2002, only 1,844 Bcf must be injected into storage in order to reach 3.5 Tcf in North American storage by November 1, 2002. This compares to 2,750 Bcf, which was required as of April 1, 2001.

"Storage demand" will be a lot less this summer than in previous years.

Storage demand for the summer of 2003 could be entirely different.

Table 10
Non-Core Natural Gas Demand Factors

Industrial Demand	2000	2001	2002Ytd
Average US Industrial Index, 1992=100	146	140	138[1]
US Average NYMEX Gas Prices, $/MMBtu	$3.89	$4.27	$2.75[2]
US Industrial Process Gas Demand, Bcf	6,225	4,973	na[3]
Canadian Industrial Gas Demand, Bcf	1,083	996	na
Power Generation Demand			
US Cooling Degree Days	1,512	1,511	na
US Hydro Generation, Billion KwHrs	273	211	na[4]
US Power Gen Gas Demand, Bcf	6,330	6,670	na
Canadian Power Gen Gas Demand, Bcf	268	251	na
Fuel Switching			
US Average NYMEX Gas Prices, $/MMBtu	$3.89	$4.27	$2.75[2]
US Residual Fuel Oil Prices, $/MMBtu	$3.77	$3.13	$2.69[5]
Gas less oil differential	$0.12	$1.14	$0.06

Sources: EIA, US Dept. of Commerce, Friedenberg, NOAA.
Notes: 1- In first 1/4 2002, rose at annual rate of 2.5%. 2 - As of May, 2002. However, June prices are $3.75. If they remain at that level, the average price for 2002 will be $3.33. 3 - Some recovery in demand is widely expected. 4 - Due to wetter weather in the west, some recovery in hydro is expected. 5 - As of May, 2002.

Non-core natural gas demand (industrial and power generation sectors) is driven by a variety of factors. Price-driven fuel switching occurs in these sectors as well.

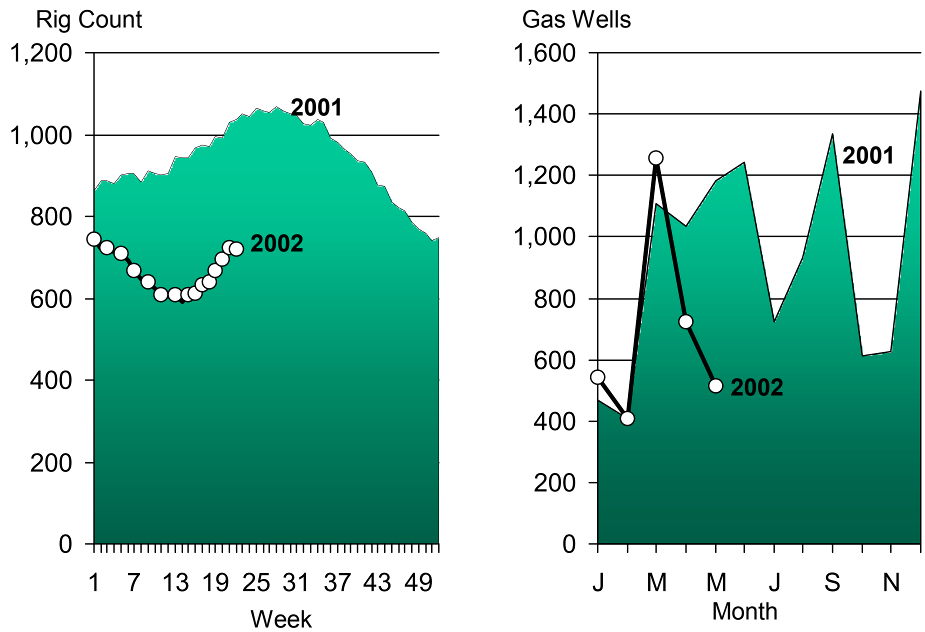
Due to the lower gas prices in 2002, and the improved gas/oil price differential, it seems likely that some recovery of non-core natural gas demand in 2002 will occur.

Turning to the supply side, US and Canadian gas drilling early in 2002 is below last year's levels.

The slowdown in drilling is generally considered negative for gas supply and positive for gas prices.

However, gas prices have risen of late, which may prompt higher drilling.

Figure 36
US & Canadian Gas Drilling Trends



Sources: Baker Hughes, Daily Oil Bulletin

Various projects to increase pipeline capacity out of US Rockies states of Wyoming, Colorado, and Utah are proposed, applied for, or under construction. These states are thought to have untapped production capacity (given weak Rockies prices and the 10% production increase in the above 3 states in 2001).

There will be 4 LNG receiving terminals operating in the US in 2002, with a total receipt/sendout capacity of about 1,050 Bcf per year. This is considerably higher than recent LNG import levels.

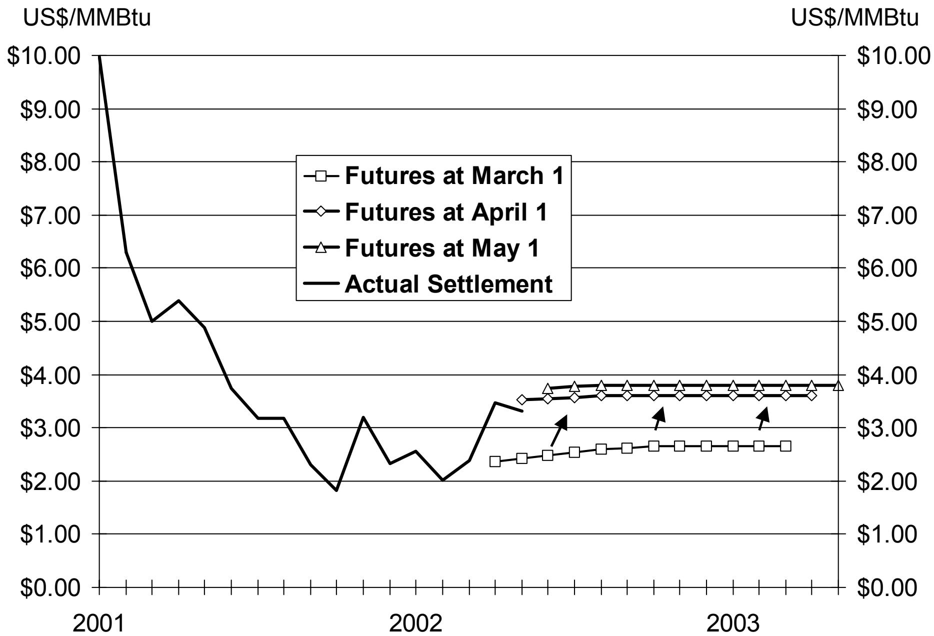
Table 11
Possible Short-Term Increased Supply

Company	Receipt Point	Delivery Point	Expansion Capacity (MMcf/d)	In-service Date	Status
Trailblazer	Wyoming	Nebraska	324	Mid-2002	In construction
Kern River 2002	Wyoming	California	125	May 2002	In construction
Kern River 2003	Wyoming	California	900	May 2003	Applied to FERC
Colorado Interstate	Colorado	Colorado	282	NA	Approved by FERC
Western Frontier	Colorado	Kansas	540	Nov. 2003	Applied to FERC
Southern Trails	Utah	California	120	July 2002	In construction
TOTALS			**2,291**		

LNG ing erminal	Company	Bcf Receipts in 2001	Regas Design Capacity (Bcf/Year)	Sendout Capacity (MMcf/d)	In-service Date
Everett	Tractebel	NA	160	450	Operating
Cove Point	Williams	NA	365	1,000	Mid-2002
Elba Island	El Paso	NA	160	438	Operating
Lake Charles	CMS	NA	365	1,000	Operating
OTALS		**135**	**1,050**	**2,888**	

Source: EIA. Note: Everett receipts were 99 Bcf in 2000.

Figure 37
Futures Prices



Source: Friedenberg

The short-term outlook for natural gas prices, as seen by the buyers and sellers participating in the NYMEX futures market, is as shown in the figure at left. Note that future gas settlement prices at different dates are shown.

Over the month of March 2002, gas price expectations jumped significantly, due to the run-up in oil prices over the same period, returning industrial demand, high gas demand for power, and lower US gas drilling.

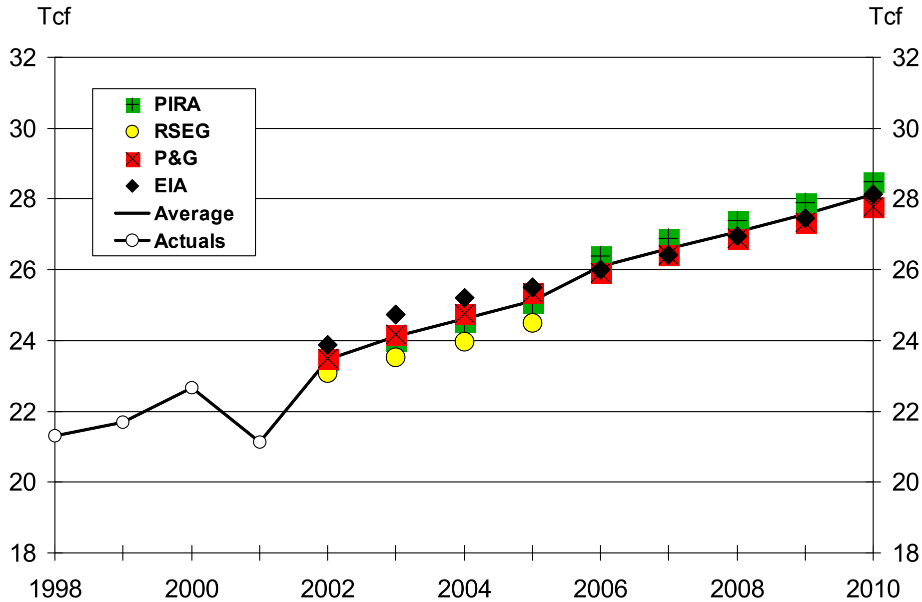
Outlook to 2010

Natural Gas Demand

Figure 38 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.

Figure 38
US Natural Gas Demand Forecasts

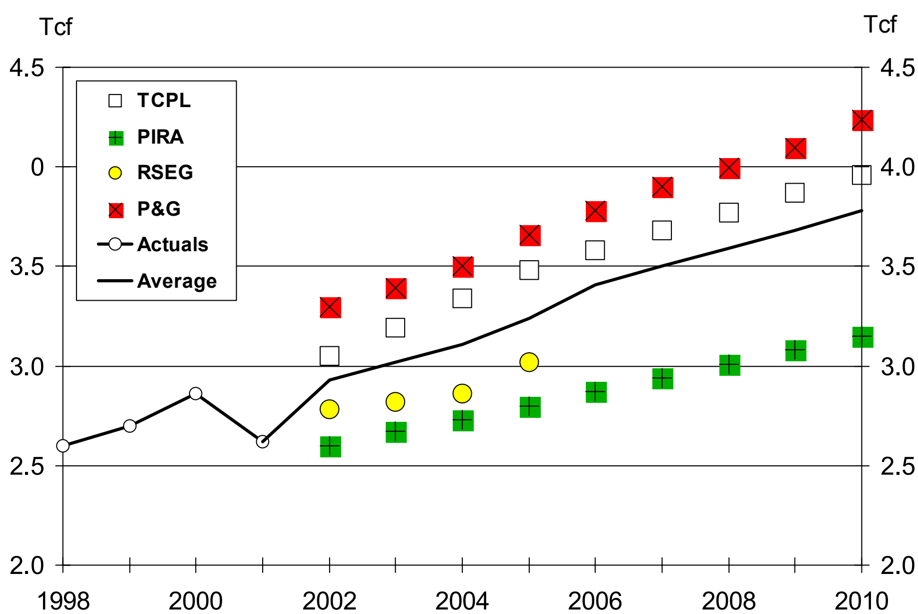


Sources: RSEG, EIA, PIRA, P&G **Note:** Historical numbers from EIA.

Figure 39 shows four forecasts for Canadian gas demand. The average shows Canadian demand reaching 3.8 Tcf by 2010. This is an average increase of 3.8% per year.

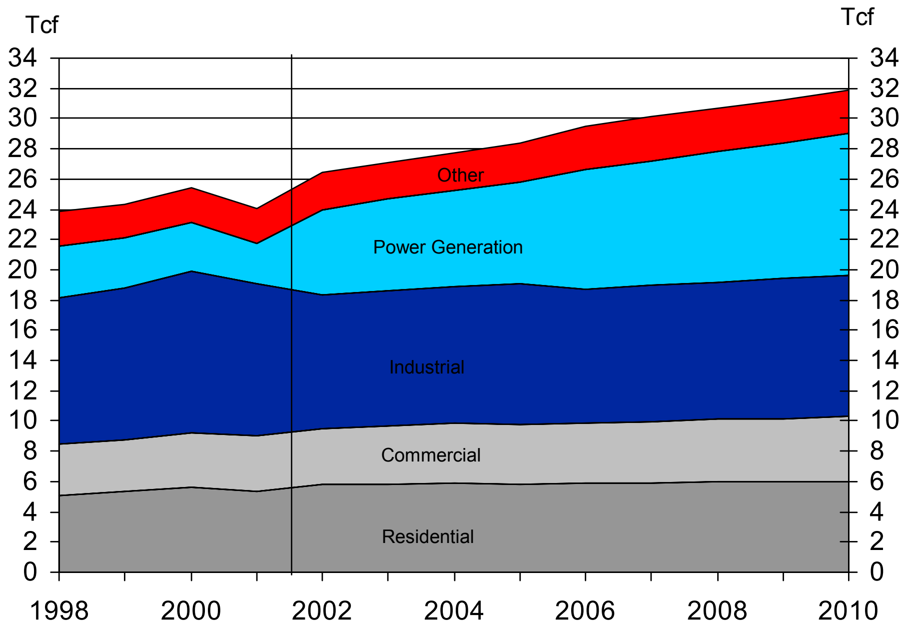
Figure 39

Canadian Demand Forecasts



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

Figure 40
North American Natural Gas Demand Growth



Summing US and Canadian gas demand, this results in a forecast of North American gas demand of 31.8 Tcf by 2010. As shown in the figure at left, almost all of the growth is due to power generation.

Given actual gas demand of 24 Tcf in 2001, this forecast implies that North America will need an additional 7.8 Tcf of gas supply by 2010.

Outlook to 2010

Natural Gas Supply

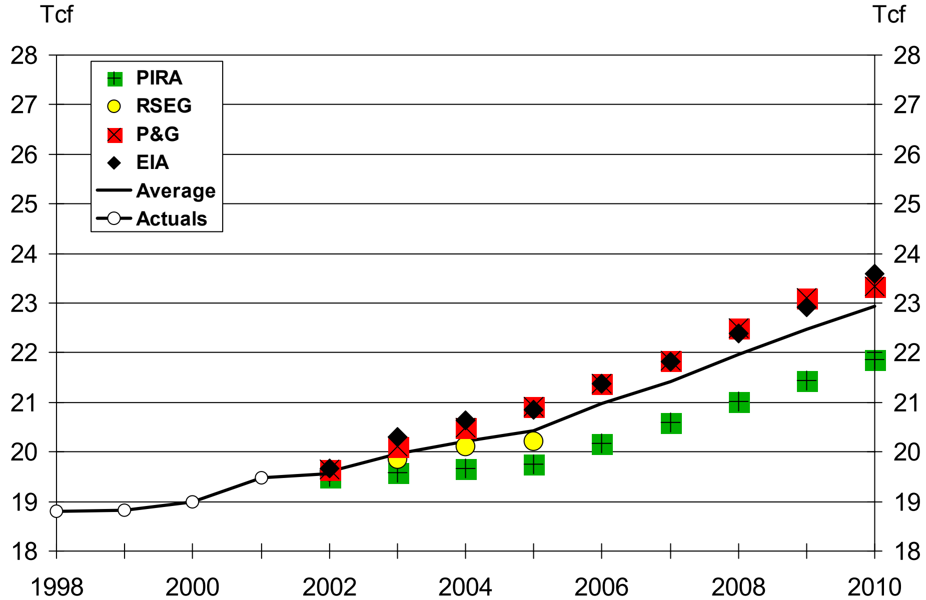
Figure 41 shows four forecasts for US gas production. The average sees US production increasing to 22.9 Tcf or 1.9% per year over the period.

There are considerable differences in opinion about US gas production. Some forecasts have northern gas in the mix to 2010.

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

Figure 41

US Natural Gas Production Forecasts



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

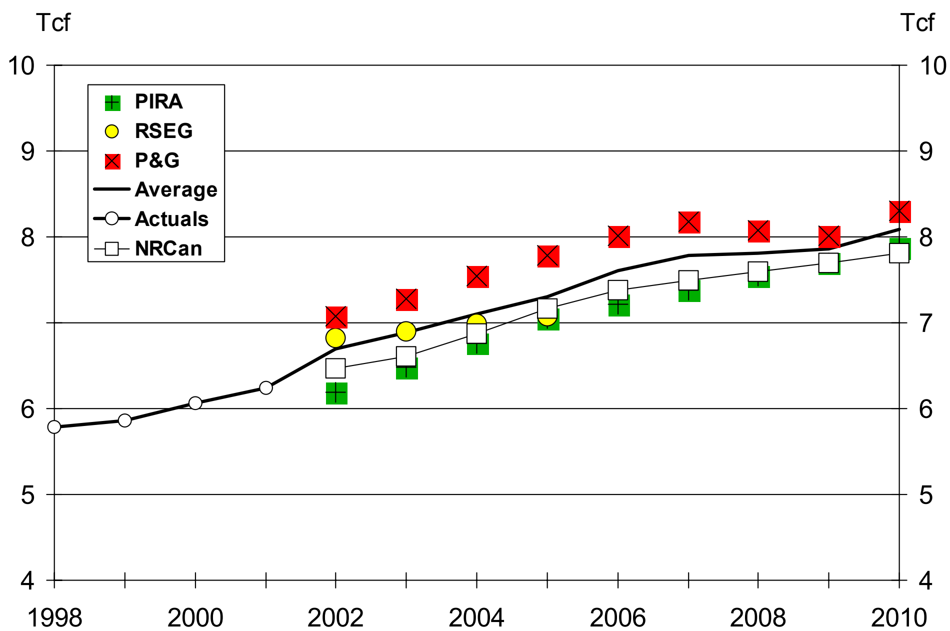
Figure 42 compares our forecast of Canadian gas production with the forecasts of 3 other organizations. The average of the forecasts (excluding NRCan) shows Canadian production reaching 8.1 Tcf by 2010.

We expect production to reach 7.9 Tcf by 2010. This represents an average annual increase of 2.8%.

Our forecast (NRCan) is based on existing or under construction pipeline capacity. If more capacity is constructed, our forecast will be low. See page 53 for additional detail on how the NRCan Canadian production forecast is generated.

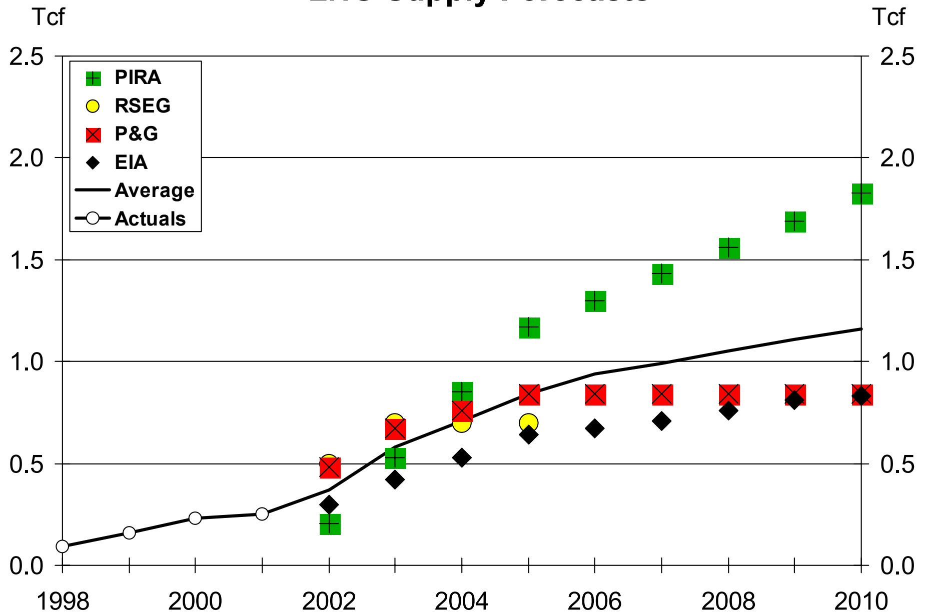
Figure 42

Canadian Natural Gas Production Forecasts



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

Figure 43
LNG Supply Forecasts

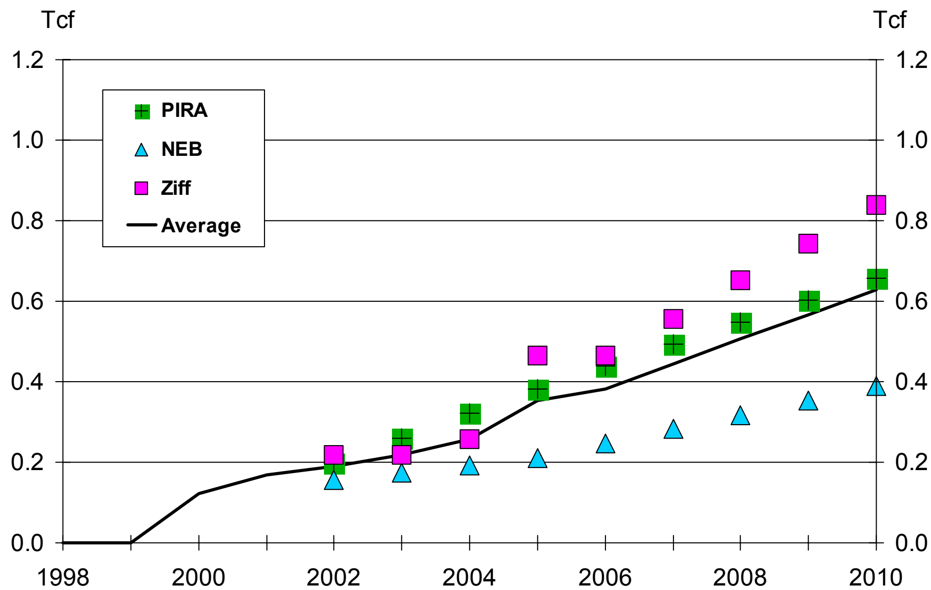


Sources: RSEG, EIA, PIRA, P&G **Note:** Historical numbers from EIA.

An average of various forecasts sees LNG imports to the US reaching 1.16 Tcf (1,116 Bcf) by 2010.

Sharper LNG import growth is partly due to re-activation in 2001 and 2002 of the Elba Island and Cove Point LNG receiving terminals.

Figure 44
Scotian Shelf Supply Forecasts



Sources: NEB, PIRA, Ziff **Notes:** Historical numbers from CNSOPB. PIRA and Ziff forecasts done in 2001 and 2002, respectively. NEB forecast dates from 1999.

Like LNG, Scotian Shelf production, while small in absolute terms, is an important source of incremental North American gas supply. Several production forecasts for the Scotian Shelf in total are shown.

The higher production forecasts reflect several announcements. First, the Sable Offshore Energy Project is developing the Alma and South Venture fields, with projected production starts of 2003 and 2004. Secondly, PanCanadian has announced plans to start production from its Deep Panuke discovery by 2005.

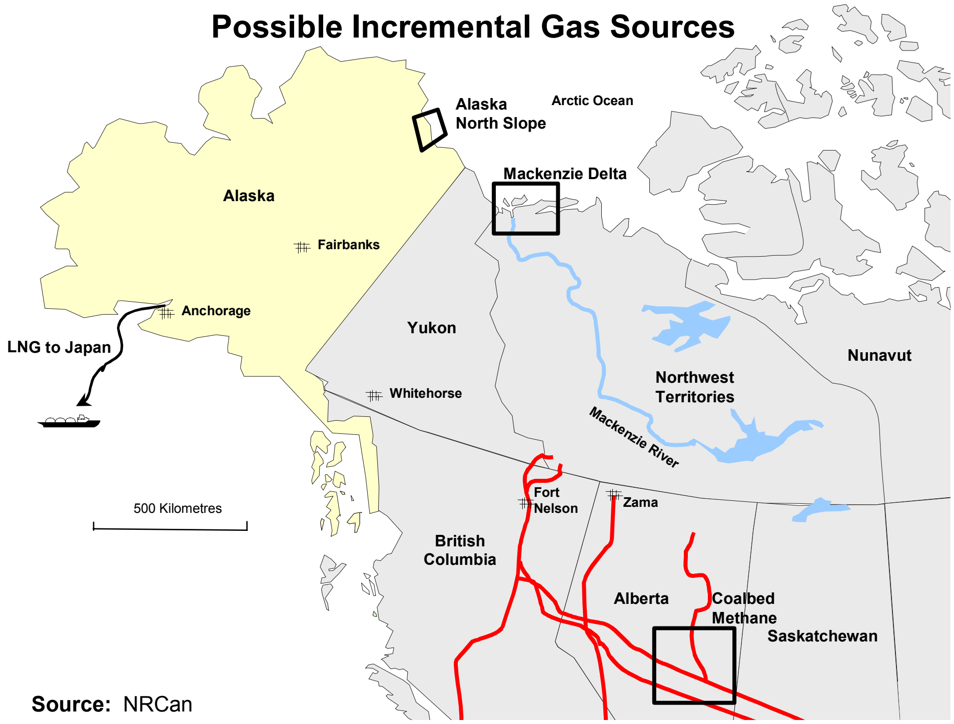
Other possible sources of gas supply include northern gas and Canadian coalbed methane (CBM).

With no pipeline application to date, many forecasts to 2010 do not include northern gas.

There are several CBM pilot projects now operating in Alberta. Encana and partners are now testing 58 CBM wells in the Palliser block, and plan a further 250 wells for later in 2002. Encana expects well flow rates from 30 – 250 Mcf per day.

Figure 45

Possible Incremental Gas Sources



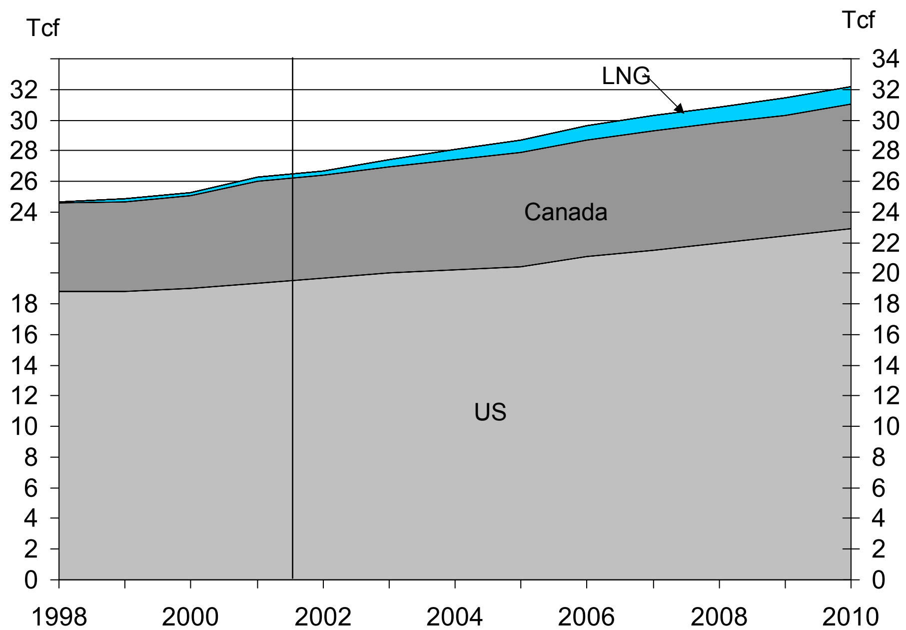
Source: NRCan

The current "consensus" view of North American gas supply is as shown in the figure at right.

However, given supply developments in coalbed methane, the arctic, and the Canadian east coast, we expect the supply picture to be in flux over the next few years.

Figure 46

North American Natural Gas Supply Growth



Outlook to 2010

Natural Gas Prices

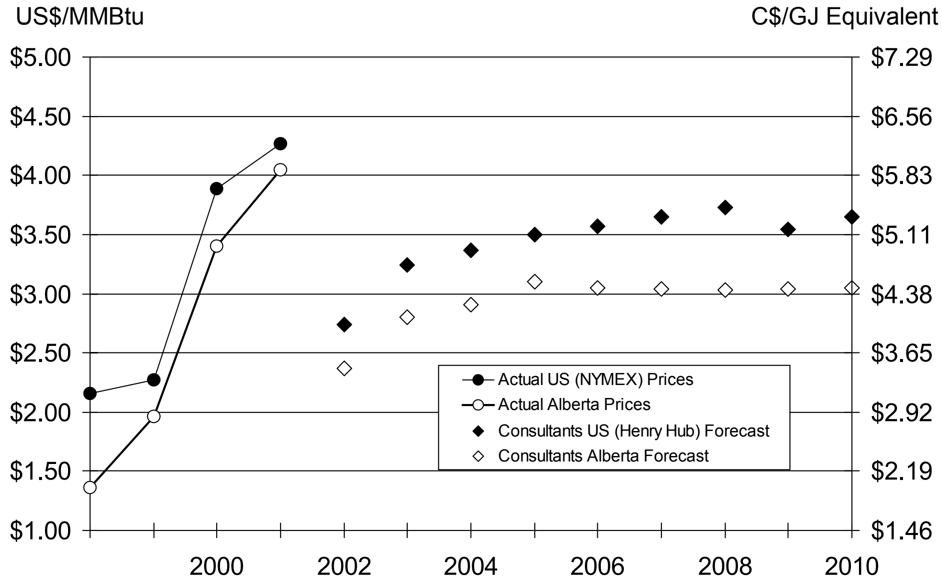
A range of industry views shows that US prices (nominal dollars) on average are expected to fall from peak 2000 and 2001 levels. Prices are expected to drop to the $2.75 range this year (2002), then rise at about 4% per year, to reach $3.65 by 2010.

Compared to our survey last year, US price expectations have risen again. Last year, the average price outlook for 2010 was $3.50.

Alberta prices meanwhile are expected to fall to US$2.37/MMBtu by 2002 (Cdn$3.57/GJ), and then rise to 2005, flattening out at about US$3.05/MMBtu or Cdn$4.40/GJ.

Figure 47

US & Canadian Price Forecasts

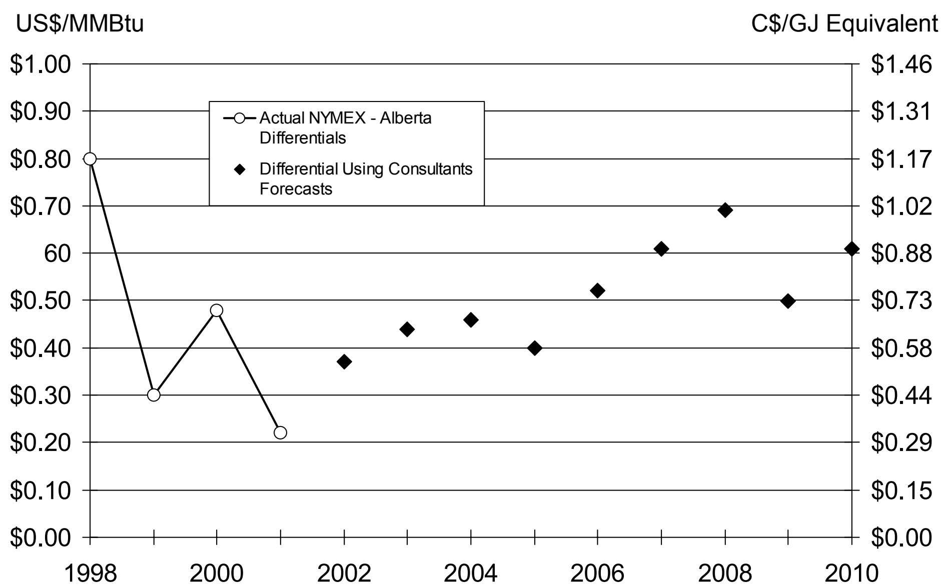


recast prices shown are averages of 3 consultants individual forecasts. Consultants used were troleum Industry Research Associates, Purvin & Gertz, and Ross Smith Energy Group. Nominal dollars.

The figure at right uses the average US and average Canadian price forecasts to calculate future gas price differentials. Differentials are expected to remain within the range observed over the past 4 years.

Figure 48

US - Canadian Price Differentials

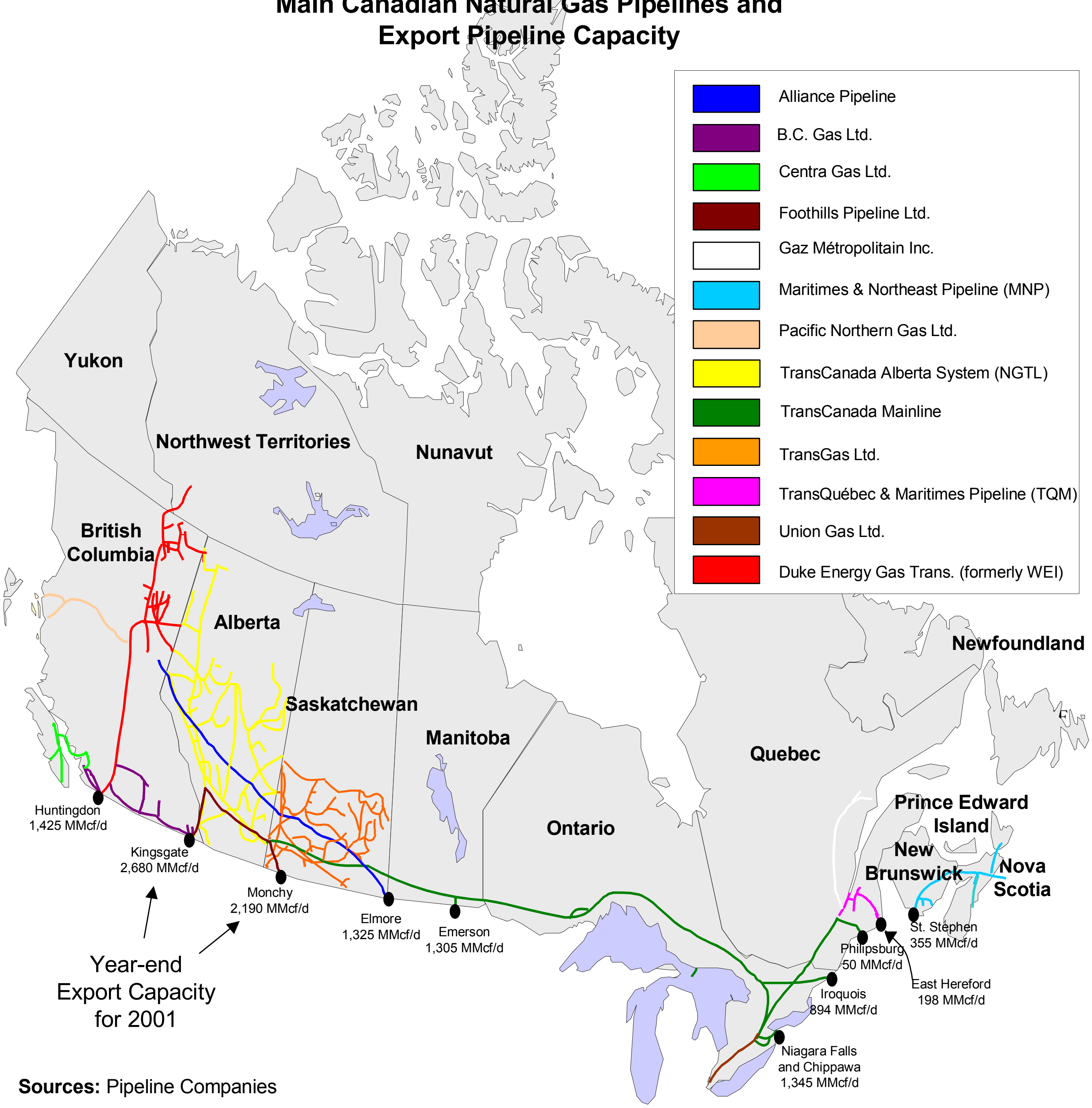


Note: Forecast differentials use averages of 3 consultants individual forecasts. Consultants used were Petroleum Industry Research Associates, Purvin & Gertz, and Ross Smith Energy Group. Nominal dollars.

Outlook to 2010

Canadian Export & Domestic Sales

Figure 49
Main Canadian Natural Gas Pipelines and Export Pipeline Capacity



Sources: Pipeline Companies

The location of Canadian natural gas pipelines (transmission and distribution) as well as year-end export capacity at major border points are presented on the map.

The Canadian gas market is served by seven major transmission pipelines (Duke Energy Gas Transmission, TCPL, Foothills, Alliance, Union, TQM and MNP), which also interconnect with the US pipeline network at nine major export points.

TransCanada Pipelines is one of the largest transporters of gas in North America. In 2001, the 'Alberta System' delivered 11.1 Bcf/day of gas.

Kingsgate (at the BC border) and Monchy (at the Sask. border) were the largest export points in terms of year-end 2001 capacities.

The newest export point is located at Elmore, Saskatchewan, on the Alliance Pipeline system, which commenced service in November 2000.

Table 12
Export Pipeline Capacity

(MMcf/d)	2000	2001		2002		2003		2004 - 2010	
	Year end Capacity	Expans.	Year end Capacity	Expans.	Year end Capacity	Expans.	Year end Capacity	Expans.	Year end Capacity
Huntingdon (Westcoast)[1]	1,045		1,045		1,045	200	1,245		1,245
Huntingdon (User Pipes)	380		380		380		380		380
Kingsgate (TCPL/Foothills/ANG)[2]	2,582	98	2,680	360	3,040		3,040		3,040
Total US West	**4,007**	**98**	**4,105**	**360**	**4,465**	**200**	**4,665**		**4,665**
Monchy (Foothills)	2,190		2,190		2,190		2,190		2,190
Emerson (TCPL)	1,305		1,305		1,305		1,305		1,305
Elmore (Alliance)[3]	1,325		1,325		1,325		1,325		1,325
Miscellaneous[4]	300		300		300		300		300
Total US Midwest	**5,120**		**5,120**		**5,120**		**5,120**		**5,120**
Iroquois (TCPL)	891		894		894		894		894
Niagara Falls (TCPL)	845		845		845		845		845
Chippawa (TCPL)	500		500		500		500		500
St. Stephen (MNP)[5]	355		355		355		355	400	755
E. Hereford (TCPL)	198		198		198		198		198
Cornwall (TCPL)	63		63		63		63		63
Napierville (TCPL)	61		61		61		61		61
Philipsburg (TCPL)	50		50		50		50		50
Highwater (TCPL)[6]	25		0		0		0		0
Total US Northeast	**2,973**		**2,966**	**360**	**2,966**		**2,966**	**400**	**3,366**
Total Capacity (Export)	**12,100**	**98**	**12,191**	**1,373**	**12,551**	**200**	**12,751**	**400**	**13,151**

Sources: Pipeline Companies. Note that 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.
Notes: 1 - Westcoast expansion scheduled to be completed November 1, 2003. 2 - TCPL expansion to be completed November 1, 2002. 3 - Alliance has authorized overrun capacity which is offered to firm shippers. This typically averages 212 MMcf/d. 4 - 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. 5 - St. Stephen export point typically flows at 387 MMcf/d, which is greater than contract capacity. Expansion scheduled for 1st quarter 2005.
6 - Highwater was shut down in February 2001.

Total physical export capacity reached 12,191 MMcf/d by the end of 2001.

The expansions shown in this table have all had formal applications filed with regulators. The largest is the 2004 expansion of MNP, to handle volumes from the Deep Panuke project. Additional expansions could occur.

Total export capacity currently cannot be filled due to insufficient gas supply. Pipeline capacity is seldom used at 100% load factors. In recent years, the best fill rate for total export capacity was about 95%. In 2002, export capacity load factors are expected to be about 85%, rising to 93% in 2010.

Table 13
Export Volumes and Domestic Sales

(Bcf)	1998	1999	2000	2001	2002	2003	2004	2005	2010
Huntingdon (Westcoast)	423	402	356	324	354	364	380	400	458
Kingsgate (Foothills/ANG)	854	805	833	781	850	880	900	930	930
Total US West	**1,277**	**1,207**	**1,189**	**1,105**	**1,204**	**1,244**	**1,280**	**1,331**	**1,388**
Monchy (Foothills)	558	773	784	744	759	775	799	799	799
Emerson (TCPL)	485	487	491	390	405	414	438	462	476
Elmore (Alliance)			73	526	510	510	510	510	510
Miscellaneous	82	67	31	32	20	24	44	49	77
Total US Midwest	**1,125**	**1,327**	**1,379**	**1,692**	**1,694**	**1,724**	**1,791**	**1,820**	**1,862**
Iroquois (TCPL)	318	357	363	319	326	326	326	326	326
Niagara Falls (TCPL)	305	361	423	326	324	324	324	324	324
Chippawa (TCPL)	44	44	37	54	41	43	44	46	55
St. Stephen (MNP)			117	141	141	141	221	300	300
E. Hereford (TCPL)		17	34	39	39	40	42	43	51
Cornwall (TCPL)	11	9	8	9	9	10	10	11	13
Napierville (TCPL)	17	19	19	33	27	22	22	22	22
Phillipsburg (TCPL)	5	6	8	6	6	7	7	8	10
Highwater (TCPL)	9	3	14	5					
Total US Northeast	**709**	**816**	**1,023**	**932**	**914**	**913**	**997**	**1,081**	**1,101**
Total Exports	**3,111**	**3,349**	**3,591**	**3,728**	**3,811**	**3,881**	**4,068**	**4,232**	**4,351**
Total Domestic Sales	**2,559**	**2,648**	**2,792**	**2,456**	**2,702**	**2,789**	**2,880**	**3,013**	**3,554**
Total Sales	**5,670**	**5,997**	**6,383**	**6,184**	**6,513**	**6,669**	**6,948**	**7,245**	**7,905**

Source: NRCan. **Note:** Domestic sales equal Canadian demand less imports. Imports assumed 228 Bcf/yr from 2002 to 2010.

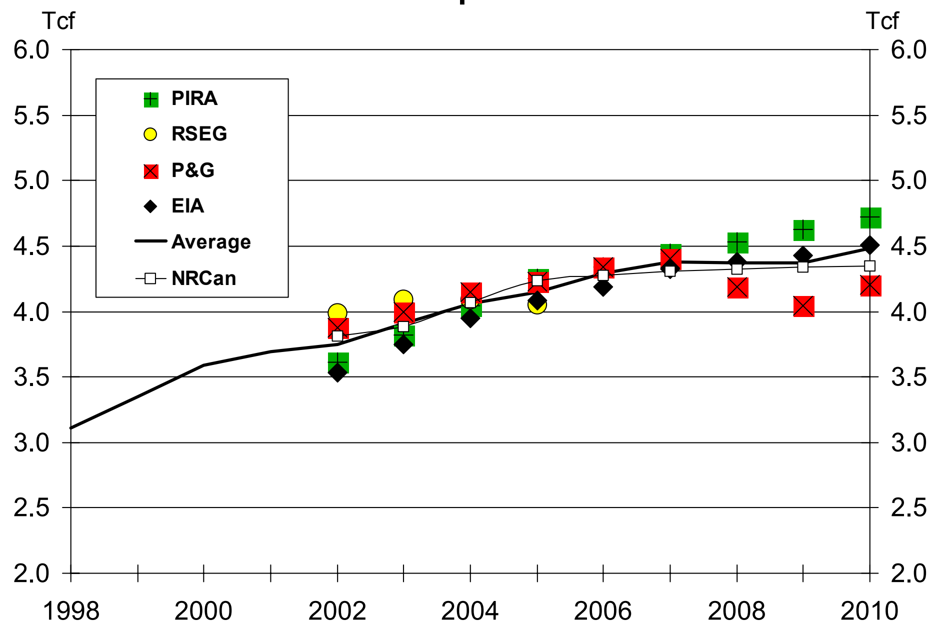
Table 13 shows our estimates of Canadian gas exports and domestic sales. This forecast assumes that the export pipeline capacity listed above is used at certain load factors. We estimate these load factors based on market factors, past load factors, etc.

We estimate that exports will reach 4.4 Tcf by 2010. Should additional expansions occur, over and above those assumed in Table 10, our export forecast could well be low.

Our export forecast (4.4 Tcf by 2010) is slightly less than the average of the forecasters we surveyed.

Our forecast does not assume any export pipeline capacity expansions to 2010, beyond those that have already been formally applied for to regulators.

Figure 50
Canadian Export Forecasts



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

Table 14 provides our estimates of producer plant gate revenues to 2010, given expected gas prices, export volumes, and domestic sales.

Total producer plant gate revenues increased 16% in 2001, hitting another new record. However, if price and volume forecasts prove correct, producer revenues will drop almost 40% in 2002, and will not regain 2001 levels over the outlook period.

Table 14
Export and Domestic Revenue Forecast

EXPORT SALES:	Gross 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	3,728	$4.27	$4.21	$3.94	$14,797	$22,759
2002	3,811	$2.74	$2.64	$2.34	$8,920	$14,159
2005	4,232	$3.50	$3.40	$3.10	$13,105	$20,801
2010	4,351	$3.65	$3.55	$3.25	$14,157	$21,451

OMESTIC SALES:	Domestic Sales (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	2,559	$1.36	$1.21	$3,116	$4,622	**$11,939**
1999	2,648	$1.96	$1.81	$4,815	$7,152	**$16,500**
2000	2,792	$3.40	$3.25	$9,074	$13,474	**$32,405**
2001	2,456	$4.03	$3.88	$9,531	$14,762	**$37,521**
2002	2,702	$2.37	$2.22	$6,011	$9,541	**$23,700**
2005	3,013	$3.10	$2.95	$8,887	$13,069	**$33,871**
2010	3,554	$3.05	$2.90	$10,292	$15,136	**$36,587**

Notes: Historical export information is from NEB data. Historical domestic netbacks and revenues are estimates only, and were calculated using Alberta prices, less US$0.15/MMBtu to yield a plantgate netback, which was then multiplied by domestic sales for a revenue estimate. Future domestic netbacks and revenues use forecast Alberta prices (see report) and were calculated similarly. Future export netbacks were assumed to equal forecast NYMEX prices (see report) less US$0.40. Resultant netback multiplied by forecast export sales. Exchange rate conversions assume $US0.63 per $Cdn for 2002-2005, $US0.66 per $Cdn for 2005-2010. Note domestic sales assumed to equal Canadian demand less imports.

Appendices

1. Industrial Sector Demand
2. Power Generation Sector Demand
3. Canadian Natural Gas Demand
4. Canadian Natural Gas Exports

Appendix 1: Industrial Sector Demand

INDUSTRIAL DEMAND DEFINITIONS

This appendix provides more detail on the collapse of natural gas demand in the industrial sector in 2001. In 2001, total gas demand in the US industrial sector was 9 Tcf, and in Canada, 1 Tcf.

The US industrial gas demand sector as defined by the US Energy Information Administration (EIA) is:

> 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 non-utility generators.

As noted in our report last year, this definition of industrial demand combines gas use for manufacturing with gas use for power generation.

In order to better understand gas market dynamics, we split US industrial gas demand into power generation demand and "Industrial Process" demand.

Industrial process demand includes only gas used by industrial companies for space heating, process heat, or petrochemical feedstock. This is calculated as:

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

US industrial process gas demand was 6.2 Tcf in 2000, but only 5 Tcf in 2001.

THE INDUSTRIAL DEMAND COLLAPSE OF 2001

The industrial sector, together with construction, accounts for the bulk of the variation in national output over the course of the business cycle.

During 2001, total US Industrial gas demand fell by nearly 6%, or 543 Bcf. This was a huge demand loss for the North American market. This volume is equal to the total amount of North American gas demand growth in a typical year.

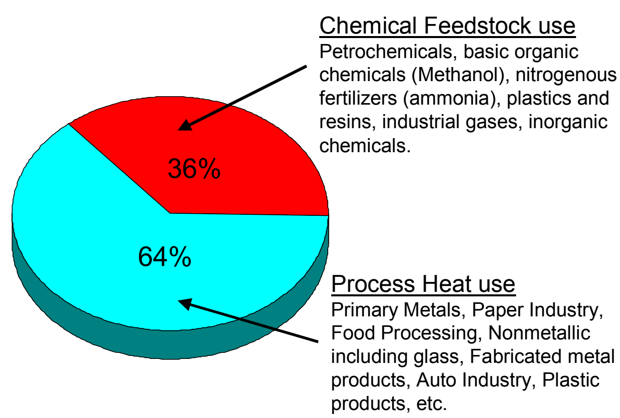
The numbers are even more dramatic when the effects of power generation in the industrial sector are removed. Industrial sector gas demand for power generation rose in 2001. Looking only at industrial process gas demand, the losses were startling. Industrial process gas demand fell 20%, or 1,252 Bcf.

This demand was pushed out of the market by high natural gas prices. The questions now become whether some or all of this demand might return, how fast, and at what prices. In order to gauge these questions, this appendix examines what manufacturing industries use gas in the industrial sector, and how gas prices will affect gas demand in those industries.

GAS USED FOR PROCESS HEAT

Many industries use natural gas to generate heat for incinerating, heating, drying, or melting materials. Examples are the pulp and paper industry (drying paper), the wood products industry, the auto industry (drying paint), the iron and steel industry (heating scrap iron), glass industry (melting glass), food processing, waste incineration, etc. This type of gas use accounts for the lion's share of natural gas consumption in the industrial sector, as shown in the pie chart below. The other major gas use is for various sorts of chemical feedstocks.

US Industrial Gas Use Patterns



Source: US 1998 Manufacturing Energy Consumption Survey (MECS).

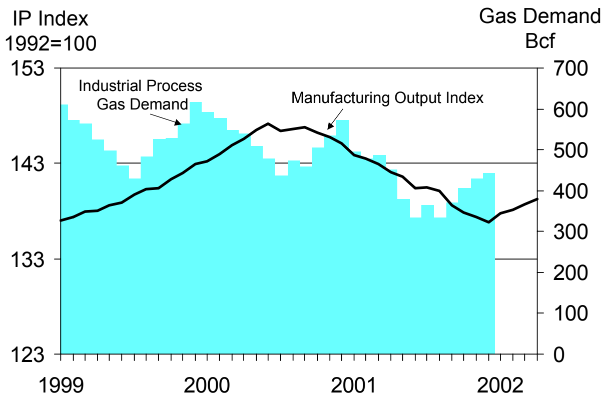
With the economic slowdown of 2001, many of the process heat using industries reduced gas consumption. This was exacerbated by high gas prices.

The US Federal Reserve collects data on US industrial production trends. The figure below compares US industrial process gas demand to the Federal Reserve's total industrial production index (1992 = 100), which can be found at www.federalreserve.gov/releases/G17/. Industrial production has been falling since mid 2000, was very low in 2001, and began to rise again in early 2002.

There is a clear link between the industrial production index and industrial process gas demand. Industrial process gas demand is also strongly affected by weather, rising in winter as factory heating demands rise.

Industrial production is now rising, but is still well below levels reached in 2000. As a result, industrial process gas demand is now starting to recover, but is also still well below 2000 levels.

US Industrial Output & Gas Demand



Sources: US Department of Commerce Statistical Release G-17, EIA

THE AMMONIA INDUSTRY

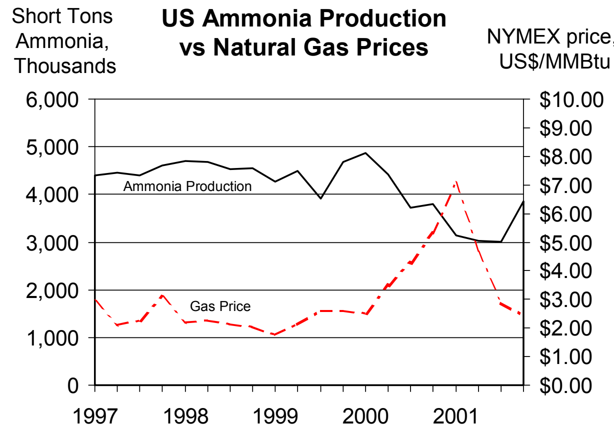
Natural gas is used to make anhydrous ammonia, a component of nitrogenous fertilizer. There were 39 operating plants in the US in 2001, and 10 plants in Canada, consuming roughly 750 Bcf of natural gas per year.

Ammonia production was hurt by high gas prices in 2000 and 2001. As a result, in early 2001, 40% of US ammonia capacity was shut down. Most plants re-opened by February 2001, but ammonia plants generally operated at low rates all year. In the past 3 years, 6 plants with about 2,000,000 tonnes per year of ammonia capacity were permanently closed. At conversion rates of 33 Mcf of gas required per tonne of ammonia, this equates to about 66 Bcf of gas demand.

As shown in the accompanying figure, as natural gas prices rose, US ammonia production fell dramatically in 2000 and 2001. US ammonia production dropped by over 1 million short tons in 2001. This equates to about 33 Bcf of natural gas demand loss.

As North American fertilizer plants closed, fertilizer prices rose. However, US imports of ammonia also

US Ammonia Production vs Natural Gas Prices



Sources: US Department of Commerce, Friedenberg. **Note:** Ammonia data is quarterly. Quarterly gas prices are averages of monthly data.

rose 29%, from 4,278 short tons to 5,513. Imports may have risen even more – information on US imports from Russia and Ukraine is suppressed.

To some extent, gas demand losses in the North American fertilizer industry may be permanent. Production is generally shifting to very large plants in areas of low cost gas supply, such as Trinidad, Qatar, Indonesia, and Malaysia.

THE METHANOL INDUSTRY

Natural gas is the main input for manufacture of methanol, which has widespread chemical use, including as feedstock for MTBE, a gasoline additive.

There are 18 methanol plants in the US, and 3 in Canada. Together, these plants have capacity of over 10 million tonnes per year of methanol.

At full capacity, these plants would consume about 280 Bcf of natural gas per year. However, some plants have shut down indefinitely, while others were shut down for at least part of 2001. Exact methanol production and gas consumption numbers are not known. However, in 2001 it was estimated that half of US methanol capacity may have shut down (source: Federal Reserve Bank of Dallas, January 2001). Thus, considerable gas demand losses occurred in this industry in 2001.

As with ammonia, methanol production is generally shifting from Canada and the US, to countries with very low cost natural gas feedstocks, such as Trinidad, Chile, Australia and New Zealand.

Appendix 2: Power Generation Sector Demand

POWER GENERATION GAS DEMAND DEFINITIONS

This appendix provides a general overview on the US power generation sector, with a focus on recent and emerging trends pertaining to natural gas-fired power generation.

The Energy Information Administration (EIA) defines Utility Electric Generation (UEG) as:

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

This does not include all power generation. The EIA defines industrial demand to include gas use for power generation by non-utilities (see Appendix 1). In order to better understand gas-fired power generation, we define 'Power Generation Gas Demand' as:

Power Generation Gas Demand = UEG Gas Demand (Natural Gas Monthly, Table 3) plus Non-Utility Gas Demand (Electric Power Monthly, Table 68).

Removing non-utility power generation from industrial demand and including it in power generation gas demand allows for a better understanding of gas market dynamics with respect to the power generation sector as a whole.

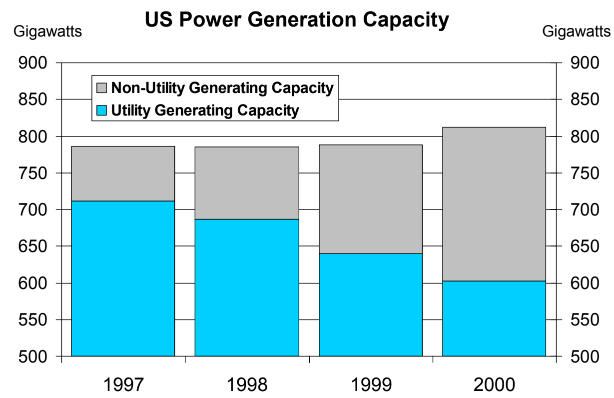
DEREGULATION AND STRUCTURAL CHANGE IN THE POWER SECTOR

The electric power industry is the latest to embark upon deregulation. Historically, regulated regional monopolies have generated, transmitted and distributed electric power in the US. In recent years, several states have acted to allow consumers to choose their power supplier. In light of the current restructuring of the electric industry, many electric utilities (since January 1998) have been in the process of selling their electric plants or spinning them off into unregulated subsidiaries.

Between 1997 and 2001, over 150,000 MW of utility capacity were either sold or transferred into the unregulated sector.

When this occurs, the gas demand data pertaining to specific power generation plants shifts from being captured in the Natural Gas Monthly (Table 3), to the Electric Power Monthly (Table 68). It is important to note this factor when comparing trends in utility electric generation demand – past data is not on the same basis as current data.

Today, non-utility capacity accounts for over 30% of total industry capacity, an increase of 21% from 1997. The majority of reclassifications have occurred in Illinois and Pennsylvania.



Source: EIA, Electric Power Annual **Note:** Data not yet available for 2001.

Today, utilities represent 70% of total generation. In 2001, utilities generated 2,661 billion kWh of electricity, a decrease of 355 billion kWh. Non-utilities generated 1,116 billion kWh of electricity, an increase of 330 billion kWh. Therefore, net generation decreased by 23 billion kWh or nearly 1%. At utilities, natural gas accounted for 10% of net generation. At non-utilities, gas represented about 35% of total generation. The breakdown of utility and non-utility classifications helps to show the transition of the power industry from a regulated business to that of an unregulated business.

Generating capability by energy source displays a geographical pattern: significant petroleum-fired capacity in the East, hydroelectric in the West and gas-fired capacity in the Coastal South.

GROWTH OF GAS-FIRED POWER GENERATION

The electric generation sector is the largest growth area in the natural gas industry, representing approximately 30% of total gas demand.

Between 1990 and 2000, gas-fired power generation has grown at an average annual rate of 5%, faster than the rate of growth of total power generation, which has grown at an average annual rate of 2% over the same period.

In the past decade, there has been a dramatic shift to natural gas for the generation of electricity.

Natural gas' share of total generation has increased from 12.5% in 1990 to 17% in 2001.

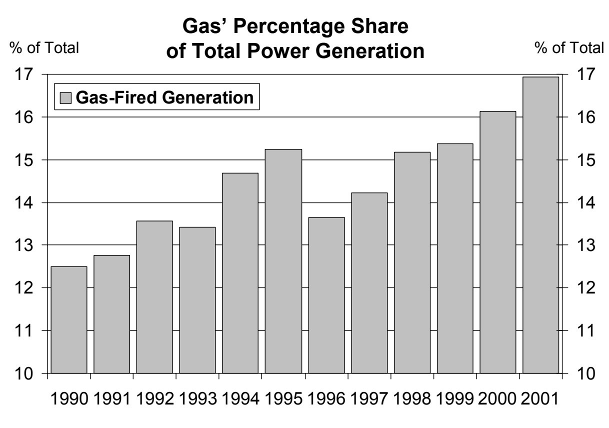
As a result, gas consumption for power generation has increased by more than 60% since 1990.

The gain in popularity in gas-fired electric generation over the past several years is a result of a combination of economic, environmental and technological factors. In fact, virtually all new generating capacity that has been added in the past five years has relied on gas and/or dual-fired turbines. Between 1995 and 2000, gas-fired capacity increased by 50,100 MW (Source: EIA). New capacity additions of 23,543 MW were added to the electric grid in 2000, with gas/dual-fired capacity additions accounting for about 22,238 or over 95% of all new capacity.

Combined-cycle gas turbines are the overwhelming choice in these new generating plants, offering high efficiency, low capital cost requirements and relatively short construction lead times. Moreover, gas-fired turbines are being used more frequently in order to comply with environmental regulations, which tend to preclude oil or coal units.

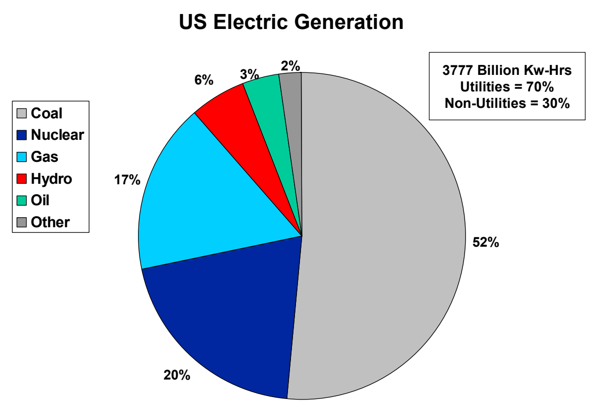
CURRENT STATE OF US POWER GENERATION SECTOR

Coal-fired generation leads the energy mix with 1,943 billion kilowatt-hours (kWh), or 52% of total generation. Nuclear generation accounts for 20% of total generation. Gas-fired generation is 640 billion



Source: EIA, Electric Power Monthly and Natural Gas Monthly

kWh or 17% of total generation. On average, 10 Bcf of gas is needed to generate one billion kWh of electricity. Petroleum-fired generation represents only 3% of total generation at 128 billion kWh. Hydroelectric generation is 211 billion kWh, or 6% of total generation. Other renewable energy sources including geothermal, biomass, wind, solar and photovoltaic total 88 billion kWh, or 2% of total US generation.



Source: EIA, Electric Power Monthly

US POWER GENERATION IN 2001

In 2001, total US net generation of electricity was 3,777 billion kilowatt hours, a decrease of 1% from 2000. A slowdown in the economy, especially in terms of a decline in demand for electric generation by industrial users and mild weather are responsible for a negative growth rate in the power generation sector in 2001.

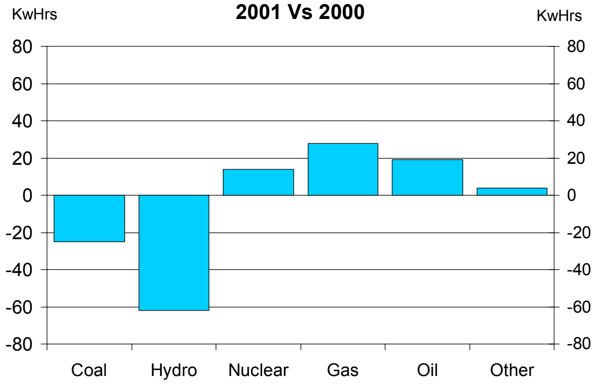
Increases in nuclear, petroleum and gas-fired generation were significantly offset by a decrease in hydroelectric generation.

A reduction in the availability of hydroelectric generation in 2001 came as a result of a drought that covered most of the western half of the US.

Gas-fired power generation increased by 4.6% or 340 Bcf in 2001, entirely as a result of increased use by non-utility generators.

Although gas-fired power generation was higher in 2001, the spike in gas prices between June 2000 and June 2001 had the tendency to reduce the use of gas for power generation. Generators with dual-fuel capability, which represented about 17% of total capability in 2000, provided producers with the opportunity to consume other less expensive alternatives such as coal or oil.

Change in Power Generation by Type, 2001 Vs 2000



Source: EIA, Electric Power Monthly

Furthermore, a weakening economy and milder weather in 2001 retarded demand for electricity, which in turn is dampening the need for generation plant construction.

Another factor is concern in the financial sector given the Enron affair. By the end of 2001, delays and cancellations of power plants, most of which were intended to be gas/dual-fired, totalled about 91,000 MW, or 18% of proposed new projects (Source: Wall Street Journal, January 4, 2002). Calpine Corporation, a large independent power producer that uses natural gas as its primary power source, has put 15,100 MW on hold until market forces can support such projects (Source: Engineering News-Record).

SHORT-TERM OUTLOOK FOR GAS-FIRED POWER GENERATION

Although many factors have been fuelling the construction of new gas-fired plants and the use of natural gas in power generation, recent trends including gas price volatility, a weakening economy, milder weather, along with the Enron debacle, have power producers rethinking exactly how much gas-fired generation is required. Furthermore, continued improvements in the use of alternative sources of power generation may partially displace the need for some gas-fired power generation.

One factor hampering the demand for gas-fired power generation in 2002 has come as a result of the fallout of Enron. Among the largest effects of the collapse of Enron, was the impact on investor confidence. Many investors have become leery of similar energy marketing and trading firms. In a bid to restore investor confidence and boost falling stock prices, many energy firms are sacrificing expansion plans in order to strengthen their balance sheets. In other words, growth is being sacrificed for liquidity. In January 2002, Mirant announced further cuts to its capital budgets for 2002 and 2003 of more than 50% for a combined US $2.9 billion in a bid to improve its cash flow (Source: Daily Oil Bulletin, February 14, 2002).

Another factor that would tend to reduce the need for gas-fired power generation would be increased demand for alternative sources of power. A resurgence of water levels at hydroelectric dams in 2002 would result in increased levels of generation from hydroelectric sources, thereby displacing some gas-fired generation. Also, increased annual capacity factors (fewer refueling outages) at nuclear plants have allowed a greater amount of electricity to be generated, also displacing some growth in gas-fired generation. Finally, large investments in pollution-reducing technologies for the use of coal in existing power plants will assure that coal remains the dominant source for power generation in the years ahead.

Although recent market conditions have resulted in the abatement of construction of new power plants, the long-term need for new power plants will be significant, particularly with an expected resurgence in the demand for electricity and the retirement of older, dirtier, less efficient power plants. Gas-fired generation is expected to dominate new capacity additions, as these new units will replace inefficient nuclear plants and less environmentally friendly oil- and coal-burning facilities. Furthermore, minimal new hydro capacity is anticipated due to concerns related to unpredictable weather and fish habitat. Although, gas price volatility and the collapse of Enron has raised some concerns, competitive electricity markets will still tend to favor more efficient, less capital-intensive natural gas as the fuel of choice for power generation.

Appendix 3: Canadian Natural Gas Demand

This appendix is intended to define specific terms used in this report (Table 1, pg 3), including:

- Residential Demand
- Commercial Demand
- Industrial Demand
- Electric Generation Demand
- Other

These terms relate **only** to Canadian natural gas demand. Our source for Canadian natural gas demand data is Statistics Canada, who in turn define the above sectors in the following manner:

Appendices

Residential Demand—Natural gas that is consumed for domestic purposes such as for water heating, cooking, clothes drying etc. Also included in residential demand is agricultural consumption.

Commercial Demand—Natural gas that is consumed by office buildings, hospitals, retail and wholesale trade outlets, school, hotels and restaurants and public institutions.

Industrial Demand—Natural gas that is used for both *energy use* and *non-energy use* is included in this category. *Energy use* includes natural gas that is consumed for heat, power or chemical feedstock by the manufacturing sector or those engaged in mining or other mineral extraction. The manufacturing sector is defined as including: pulp & paper, iron & steel, smelting & refining, cement, petroleum refining, chemicals and other manufacturing. Also included in industrial demand are the mining, forestry and construction sectors.

Natural gas and natural gas liquids (NGL's) are also used in the petrochemical and refining industries. Statistics Canada defines *non-energy use* as:

> the amounts of natural gas used for purposes other than fuel purposes. Includes products being used as petrochemical feedstock, anodes/cathodes, greases, lubricants, etc…

The greatest use as a petrochemical feedstock is in Alberta, where ethane is virtually the sole feed source for an extensive part of the Alberta economy. The estimates only take into account those plants located in Alberta and Ontario using natural gas as a feedstock. Gas used as a fuel associated with feedstock is represented under industrial chemicals.

Electric Generation Demand—Natural gas volumes used in the generation of electricity by both utilities and industry. The industrial sector generation of electricity may qualify as 'non-utility generation.' Most, but not all, non-utility generation is within the industrial sector.

Some non-utility electric generation is achieved via a cogeneration process. Cogeneration plants use natural gas to produce both *electric power* and *steam* (thermal output/process heat). In cogeneration, natural gas is used to power a turbine, which drives a power generator. The waste heat from the turbine is then used to provide the industrial heat requirement. Electric generation demand by industrial users is defined as including a portion of the gas consumed by cogeneration plants—the portion that is used to produce electric power.

Other—Natural gas demand (as reported in Table 1, pg. 3) in this category includes:

a. Transportation (Pipelines, Retail Pumps and Road Transport and Urban Transit)

> Natural gas is used for moving the gas along the pipeline – pipeline fuel. Natural gas turbines are the main source of propulsion for gas transmission pipelines, however some piston engines and electric motors are used.
>
> Natural gas is also used as a transportation fuel. Included are establishments engaged in truck transport services, transit systems, school buses, charter and sightseeing buses and taxis and limousines.

b. Statistical Difference = Net Supply - Producer Consumption - (Non-Energy Use + Energy Use)

Statistics Canada defines net supply, producer consumption and energy use in the following manner:

> Net Supply—The amount of natural gas 'available' after the amounts used in the transformation processes (electric generation) have been subtracted (i.e. Domestic Demand Minus Transformed to Electricity).
>
> Producer Consumption—Consumption by the producing industry of its own produced fuel.
>
> Energy Use—Transportation + Agriculture and Residential + Public and Commercial + Industrial.

Note: Statistical Difference includes a portion of the gas consumed by cogeneration plants—the portion that is used to produce useful thermal output (i.e. steam).

c. Reprocessing Shrinkage

This represents shrinkage of gas volumes due to ethane extraction.

Appendix 4: Canadian Natural Gas Exports

This appendix describes the methodology we use in calculating natural gas exports (Table 8, pg 29). We define the following terms:

- Gross Exports
- Imports
- Net Exports
- Canadian Gas Sold

Our source for Canadian natural gas export and import data is the National Energy Board (NEB). The NEB collects natural gas import and export data on a custody (physical movements) basis.

NRCan defines the above terms in the following manner:

Gross Exports–Natural gas flowing across the Canada-US border into to the US. It is important to recognize that these gas flows, **do not** include those export volumes that have been earmarked for re-import. For example, certain volumes flowing into the US at the Emerson export point flow uninterrupted back into Canada. This gas is neither considered an export nor an import. Gross exports are identified and reported by the NEB.

Imports–Natural gas flowing into Canada via the US pipeline network. Again, those Emerson volumes that are destined fro re-import into Canada **are not** included. Imports are identified and reported by the NEB.

Net Exports = Gross Exports – Imports

Canadian Gas Sold = Net Exports + Canadian Demand (Western Canada + Eastern Canada).

Canadian natural gas gross exports to the US reached 3,728 Bcf in 2001, breaking the previous high of 3,591 Bcf in 2000. The 4% growth in gross exports was due, in part, to the start-up of the Alliance Pipeline, which began operations in December 2000.

While large volumes of Canadian gas are exported to the US, until recently, only minor amounts of US gas were purchased by eastern Canadian consumers. Between 1995 and 2000, Canada imported an annual average of only 50 Bcf. Historically, imports represented only 2% of Canadian demand.

However, in 2001, natural gas imports nearly tripled to 228 Bcf, from 80 Bcf in 2000. The significant increase in Canadian imports was due to the Vector Pipeline, which became operational in December 2000. Vector Pipeline is a key link, supplying and transporting western Canadian and US natural gas to southern Ontario via interconnects with Alliance Pipeline and Northern Border Pipeline Company.

Today, buyers in Ontario are provided with the option of obtaining supply from the Western Canadian Sedimentary Basin (WCSB) through the Alliance and Vector pipeline systems as opposed to the historical route via the TCPL 'Canadian Mainline.'

Of the 228 Bcf imported into Canada, approximately 139 Bcf or 60% of the gas flowed through Courtright, an import point located near the hub at Dawn, Ontario. It is fair to assume that a proportion of the gas flowing into southern Ontario via the Vector Pipeline originated in Canada, and hence, should not be recorded either as an export or an import.

However, due to the large volumes of gas flowing through the Chicago hub, via numerous pipeline systems, it is impossible to determine how much Canadian gas flows back into Canada through Vector Pipeline. As a result, **gross export** volumes have become less significant, as they do not account for those volumes of Canadian gas that flow back into Canada via the Vector pipeline system.

An alternative approach to measure US demand for Canadian gas may be to calculate **net exports** (gross exports - imports) as opposed to gross exports. Although gross exports to the US increased by 4% in 2001, net exports fell to 3,500 Bcf from 3,511 Bcf the previous year. The calculation of net exports provides a more realistic representation of the amount of Canadian gas being supplied to the US.

Historically, the use of gross export volumes has been a valid tool for measuring US demand for Canadian natural gas. However, with the advent of higher natural gas imports, as a result of the Alliance and Vector pipeline systems, the way Canadian gas exports should be measured and interpreted is changing.

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