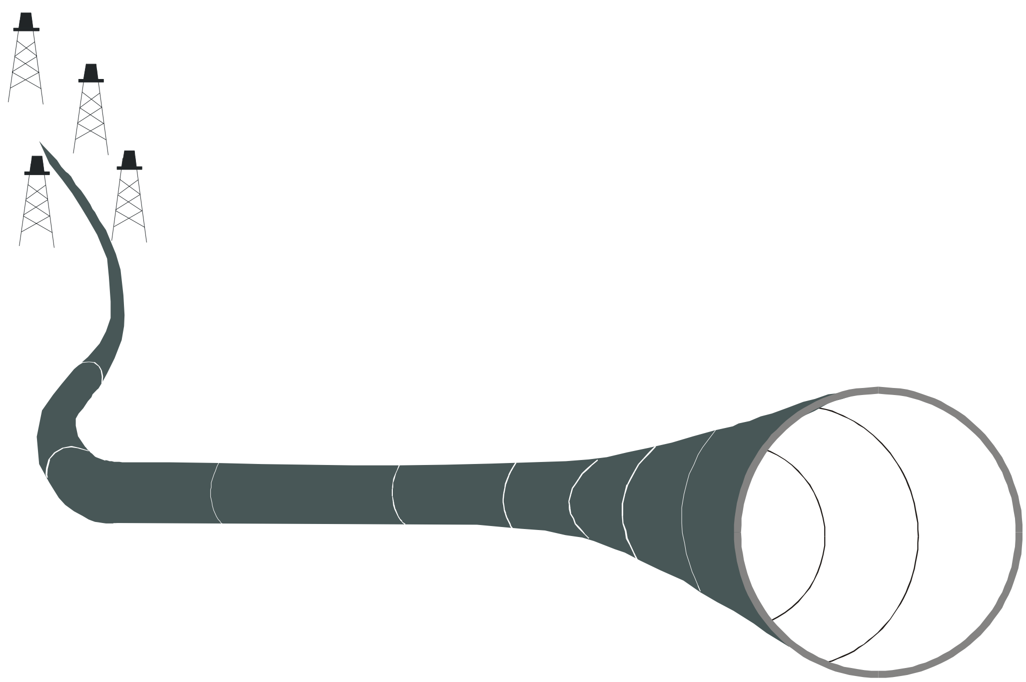
Canadian Natural Gas: Review of 1996 & Outlook to 2002

April 1997



Natural Gas Division
Energy Resources Branch
Natural Resources Canada

CANADIAN NATURAL GAS:
REVIEW OF 1996 & OUTLOOK TO 2002

TABLE OF CONTENTS

Foreward

Canadian Natural Gas: Review of 1996 and Outlook to 2002 is an annual publication of the Natural Gas Division of the Energy Resources Branch, Natural Resources Canada. It provides summaries of North American natural gas industry trends, including supply, demand, storage, gas flows, prices, transportation capacities, as well as export volumes, prices, and revenues. The report is based on a calendar year, as opposed to a gas contract year.

Our report this year has a more regional focus, and we have added analyses of three new regions: the U.S. Gulf Coast, Western Canada, and Eastern Canada. These changes were made to address the two principal issues in the Canadian natural gas industry today -- the future of natural gas price differentials and the need for large expansions of natural gas pipeline capacity.

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the United States. Our main sources of statistical data were the National Energy Board (NEB), the U.S. Energy Information Administration (EIA), and Statistics Canada (StatsCan).

Due to resource constraints, our report does not contain a *Regulatory Update* section this year. We hope to reinstate this section next year.

To order a copy of this report, call 613-992-9612, or fax us at 613-995-1913. Our mailing address is: Natural Gas Division, Energy Resources Branch, Natural Resources Canada, 17th floor, 580 Booth Street, Ottawa, Canada, K1A 0E4. To view other Natural Gas Division reports, visit our website at http://www.es.nrcan.gc.ca/erb/ngd/homepage/home.html.

Our primary reason for publishing this report is to maintain a required level of expertise within the division. Accordingly, your questions and comments on this report are appreciated. General comments may be directed to John Foran at 613-992-0287. Questions relating to specific sections may be directed to the authors below:

John Foran, 613-992-0287; email: jforan@nrcan.gc.ca
Supply, Storage, Gas Flows, Prices, U.S. Midwest & Gulf Coast regions

Michel Chénier, 613-992-8377; email: mchenier@nrcan.gc.ca
Demand, U.S. Northeast & Western regions

Martin Lamontagne, 613-992-4985; email: mlamontagne@nrcan.gc.ca
Western & Eastern Canadian regions

David McGrath, 613-995-8921; email: dmcgrath@nrcan.gc.ca
Export & Domestic Gas Sales, Export & Domestic Sales Forecasts

Executive Summary

Review of 1996

Canadian Export & Domestic Gas Sales

- Prices for Canadian natural gas rose substantially at the end of 1996. International border prices for exported gas rose from US$1.48/MMBtu during 1995 to US$1.91 in 1996, an increase of 29%. Domestic prices increased by similar percentages.

- Volumes increased only 4%, or 194 Bcf, reflecting limited additions of pipeline capacity, and existing capacity already nearly full. Export capacity rose less than 1%, and export volumes only 3%. Export volumes had averaged 12% annual growth over 1985 to 1995. Domestic sales increased 4%.

- Natural gas export revenues soared 33% to Cdn$7.4 billion, a new record. Higher revenues mainly reflected higher prices. Revenues from domestic sales increased by similar percentages.

North American Natural Gas Markets

- The largest supply increase came from the U.S. Gulf Coast, which produced an additional 406 Bcf compared to 1995. Offshore deepwater projects are fueling renewed optimism for the Gulf Coast. Canadian production increased 169 Bcf, with most sent to domestic markets. U.S. Rockies production increased 148 Bcf, as pipeline flows were reversed to send more gas east.

- Price increases occurred against a backdrop of North American demand growth of only 2%, less than the average growth rate - 3% - of the past five years. U.S. utility electric generation demand collapsed, falling 461 Bcf, mainly due to higher gas prices and availability of hydropower.

- Prices in 1996 were driven up mainly by low storage inventories, and by the lack of sufficient take-away pipeline capacity from low-cost supply regions (Western Canada, U.S. Rockies). Faced with higher demand in 1996, gas buyers were forced to buy incremental supplies from higher-cost supply regions (Gulf Coast).

- Natural gas price differentials widened over the year, particularly between Western Canadian and U.S. markets. The so-called "integrated" North American natural gas market has become balkanized in the last five years, due to production growth occurring mostly in the west (Western Canada and the U.S. Rockies), while demand growth has occurred in the east and south (the U.S. Midwest, Northeast, South Atlantic, and Gulf Coast). By December 1996, New York gas prices were US$3.67/MMBtu *higher* than Alberta prices.

- U.S. Rockies prices reached parity with Gulf Coast prices late in the year. Because Rockies prices drive prices in the U.S. West, U.S. West prices were carried up as well.

- Large price differentials make it very profitable to hold natural gas pipeline capacity along certain routes. This is driving pipeline expansion proposals such as Alliance, Nexus, Pony Express, Voyageur, Millennium, and Independence, most of which run from western supply regions to eastern markets.

Outlook To 2002

North American Natural Gas Markets

- The outlook assumes the Gulf Coast will be the major incremental supplier of natural gas to 2002, with annual production increasing by 1,489 Bcf. However the high Gulf Coast production decline rate and need for continued high prices to drive high levels of drilling pose risks to this view.

- Continued growth in supplies from Western Canada and the U.S. Rockies is widely expected. Our outlook assumes additional annual production of 1,154 Bcf from Canada to 2002, with 12% of that from the offshore east coast. We expect U.S. Rockies production to increase by 454 Bcf to 2002.

- There is a general consensus for 1.9% annual U.S. gas demand growth to 2002, concentrated in the electric generation and industrial sectors. Demand increases will be highest in the U.S. Midwest, Northeast, and Southeast.

- Pipelines are being proposed or are under construction to bring additional gas to U.S. Midwest and Northeast markets. These markets will not be able to absorb all planned increases, and a battle for market share is emerging. The price to earn markets will be to sponsor pipeline capacity expansion, which involves risks.

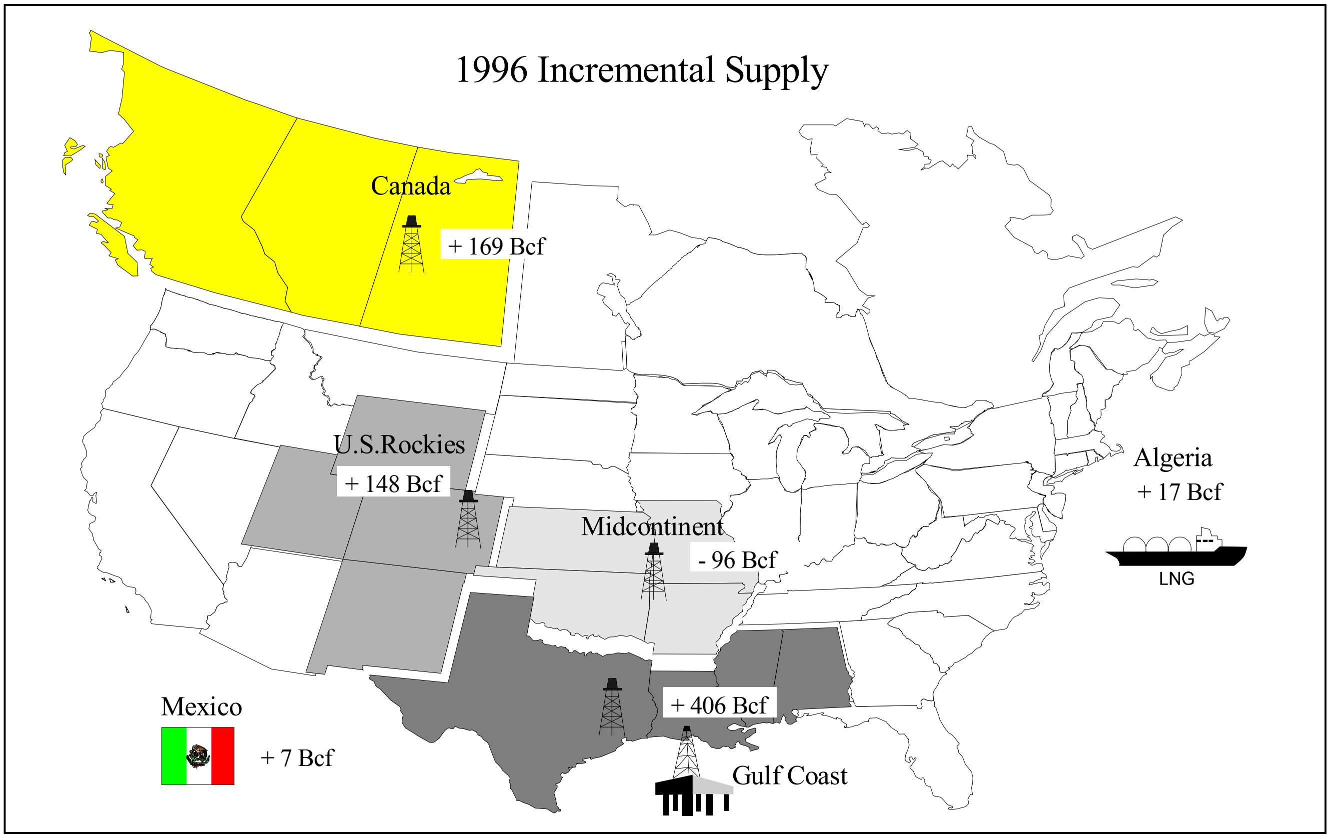
- The U.S. West will also require considerable incremental gas over the outlook period. This could be supplied from the U.S. Rockies and Gulf Coast regions, which have excess pipeline capacity to this market, or could involve more pipeline construction from Canada.

Canadian Export & Domestic Gas Sales

- It is expected that 2.7 Bcf per day of incremental gas pipeline capacity from Canada to the U.S. will be constructed by 2002. Canadian natural gas production is expected to rise from 5.4 Tcf in 1996 to 6.6 Tcf in 2002, reflecting growth in export sales of 0.8 Tcf and domestic sales growth of 0.3 Tcf. It is anticipated that Canadian natural gas exports to the U.S. will reach 3.6 Tcf by 2002.

- Most experts now expect U.S. prices to remain relatively flat, while Canadian prices are expected to rise towards U.S. levels as new pipelines are built, integrating Canadian and U.S. markets. Assuming these views are correct, revenues from sales of Canadian gas should increase by an even higher percentage than volume increases.

Review of 1996
North American Supply



North American natural gas supply grew 2.6% during 1996. We divide North America into supply regions as shown above. As indicated, the bulk of the increase, 406 Bcf (66%), came from the onshore and offshore regions of the U.S. Gulf Coast. Canada and the U.S. Rockies, as has been typical over the past five years, also contributed significant incremental supplies.

Midcontinent supply declined 96 Bcf or 4%, which has also been typical of the past five years. LNG and Mexican gas imports into North America doubled in 1996, but are minor, providing only 0.2% of total supplies. Details are provided in Table 1.

U.S. Gulf Coast

The U.S. Gulf Coast region, as defined here (see Figure 1), includes the salt dome basins of

Figure 1: U.S. Gulf Coast Producing Region

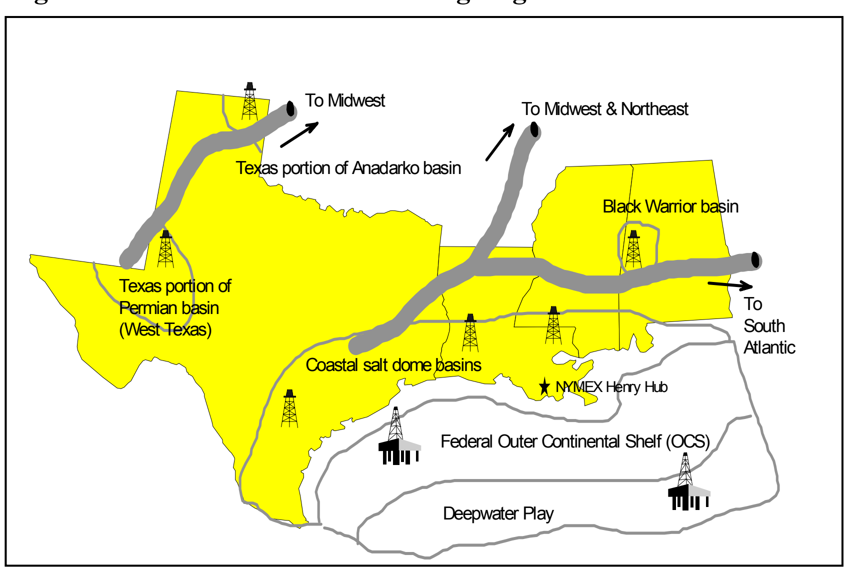


Table 1: North American Natural Gas Supply

	1996 (Bcf)	1995 (Bcf)	Difference (Bcf)	% Change	% of Total Increase	% N.A. Supply
U.S. Gulf Coast	11,925	11,519	406	3.5	66.1	48.7
U.S. Midcontinent	2,482	2,578	-96	-3.7	-15.6	10.1
U.S. Rockies	3,052	2,904	148	5.1	24.1	12.5
Other U.S.	1,560	1,597	-37	-2.3	-6.0	6.4
Total U.S. Production	19,019	18,598	421	2.3	68.6	77.7
Canadian Production	5,401	5,232	169	3.2	27.5	22.1
LNG Imports	35	18	17	96.1	2.8	0.1
Mexican Imports	14	7	7	95.7	1.1	0.1
TOTAL N.A. SUPPLY	24,469	23,855	614	2.6	100.0	100.0

onshore and offshore Alabama, Louisiana, Mississippi, and Texas as well as those parts of the Permian and Anadarko basins within these states. About 40% of Gulf production originates in the offshore Outer Continental Shelf (OCS).

Of the supply areas examined in this report, the U.S. Gulf Coast is one of the highest cost suppliers. This is due to the maturity of exploration and production activity in the area. Production increases generally depend on high prices. In years when prices are low, production in this region usually stagnates or declines almost immediately. For example, relatively low gas prices in late 1994 and early 1995 resulted in low gas drilling in the Gulf Coast, and production fell slightly during 1995.

Continued drilling is needed to maintain Gulf production, since the area operates at very high rates of take (about 1/6th of proved reserves are produced each year). This results in a high decline rate, in the order of 25% per year (i.e., without drilling new wells, production would decline 25% in one year).

For 1996, prices in the U.S. Gulf Coast (NYMEX Henry Hub) were up 58% over 1995 levels, averaging US$2.59 per MMBtu for the year. As shown in Figure 2, this price increase led to very high levels of gas-directed drilling in the offshore Gulf (onshore drilling, not shown, also increased). The 406 Bcf supply increase in the U.S. Gulf Coast was the result of these high drilling levels.

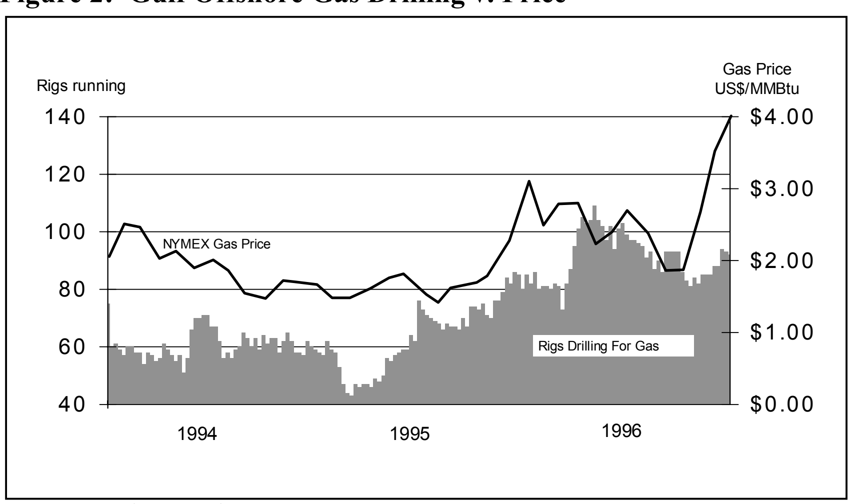
High drilling rates in the Gulf Coast have an immediate impact on gas production. Typically, any Gulf wellhead deliverability developed can be sold, as pipeline capacity going out of the region is not a constraint.

Gulf Deepwater Offshore

Gulf Coast production increases also reflect development of a few very large deepwater (>1,500 foot water depth) offshore production projects over the past few years. During 1996, there were 11 producing deepwater projects, with a total combined production of 155 Bcf per year (1.3% of total Gulf Coast production). These are capital intensive (up to $1 billion), projects which take years to conceive and develop. Due to the long lead times, month-to-month price changes do not affect decisions to proceed. Some ventures are also being driven by oil production, with the gas being secondary.

These projects would not be economically possible without

Figure 2: Gulf Offshore Gas Drilling v. Price



Source: Baker Hughes

cutting edge technologies such as 3-D seismic, tension leg platforms, and subsea completion technologies.

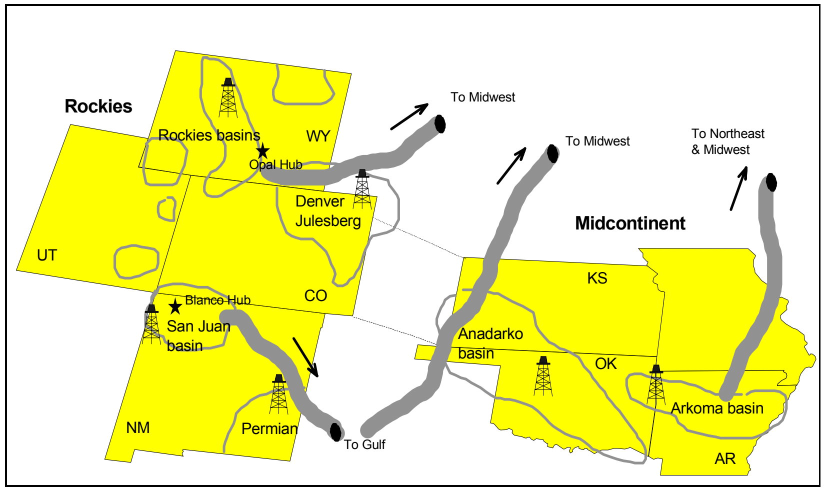
Another important development was the interim rule issued in March 1996 for deepwater royalty relief. The Minerals Management Service will forego royalties on specific volumes of initial production from qualifying wells. The production exemptions will be large -- 102 to 507 Bcf -- for wells in 200 metres to over 800 metres of water.

U.S. Rockies

The U.S. Rockies producing region of New Mexico, Utah, Wyoming, and Colorado (see Figure 3) includes numerous basins, the most important being the coalbed methane dominated San Juan basin.

The situation in the U.S. Rockies is quite different than that in the Gulf Coast. Rockies production is less dependent on gas prices. The area is a low cost producer, and production has increased 930 Bcf (44%) over the past five years. Production has increased even during periods of low prices, and despite local prices which have been consistently lower than those available to Gulf Coast producers (pipeline bottlenecks cause gas to back up in the Rockies, keeping local prices low).
The area operates at a low rate of take (about 1/13th of reserves are produced each year), leading to relatively low decline rates. As a result, periods of reduced drilling

Figure 3: U.S. Rockies & Midcontinent Producing Regions



do not immediately cause lower production.

Considerable potential exists for increasing production from this region. However, further development and production is limited by the current lack of exit pipeline capacity.

During 1996, reversal of flows on the El Paso and Transwestern Pipeline systems allowed further production flows from the San Juan basin eastwards into the Gulf Coast. This was the main factor allowing U.S. Rockies production to increase 148 Bcf (5%) over last year.

A related factor was the desire of San Juan producers to maximize production from coalbed methane wells. Coalbed wells which qualify for the section 29 tax credit will receive a tax credit of approximately $0.90/MMBtu until the end of the year 2002. No new wells can qualify, but by adding field compression, producers can accelerate production from existing qualifying coalbed wells.

U.S. Midcontinent

The Midcontinent region of Arkansas, Kansas, Missouri, and Oklahoma (see Figure 3), contains the Arkoma and Anadarko basins, and appears to be a region in long-term production decline. Improving technology is not offsetting the effects of increasing resource maturity in this area. Production fell 96 Bcf during 1996, continuing a pattern of production decreases since 1989. Over the past five years, annual production has fallen 263 Bcf, or 2% a year.

Western Canada

The Western Canada producing region of British Columbia, Alberta, and Saskatchewan is shown in Figure 4. Like the U.S. Rockies, Western Canada is a low-cost producing region.

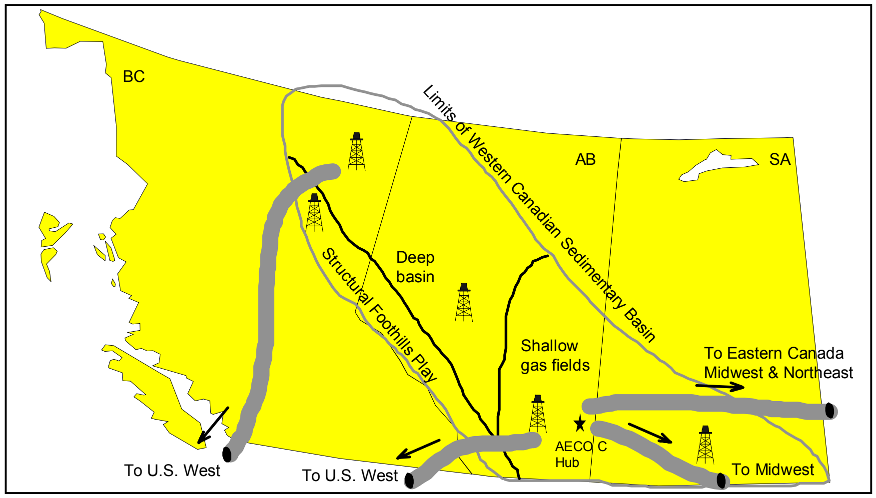
Like the Rockies, the area operates at a relatively low rate of take, and has potential for increased production. Further development and production is currently limited by take-away pipeline capacity.

Following very large exit pipeline capacity expansions in the early 1990s (Northern Border, Iroquois, PGT), drilling in Western Canada increased dramatically during 1993 and 1994 (see Figure 5), as production was developed to fill the expansions.

With no major pipeline expansions since 1993, drilling during 1995 and 1996 settled at a rate of roughly 3,400 gas wells per year (drilling data shown in Figure 5 is quarterly).

During 1996, production increased 169 Bcf, mainly due to higher Canadian gas demand.

Figure 4: Western Canada Producing Region

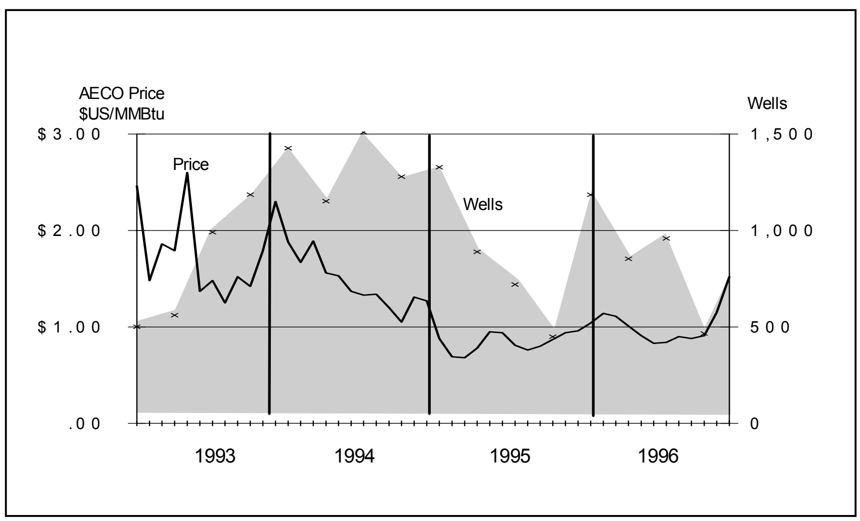


LNG & Mexican Imports

U.S. imports of LNG during 1996 remained below levels of the early 1990s due to continuing renovation of Algerian liquefaction plants.

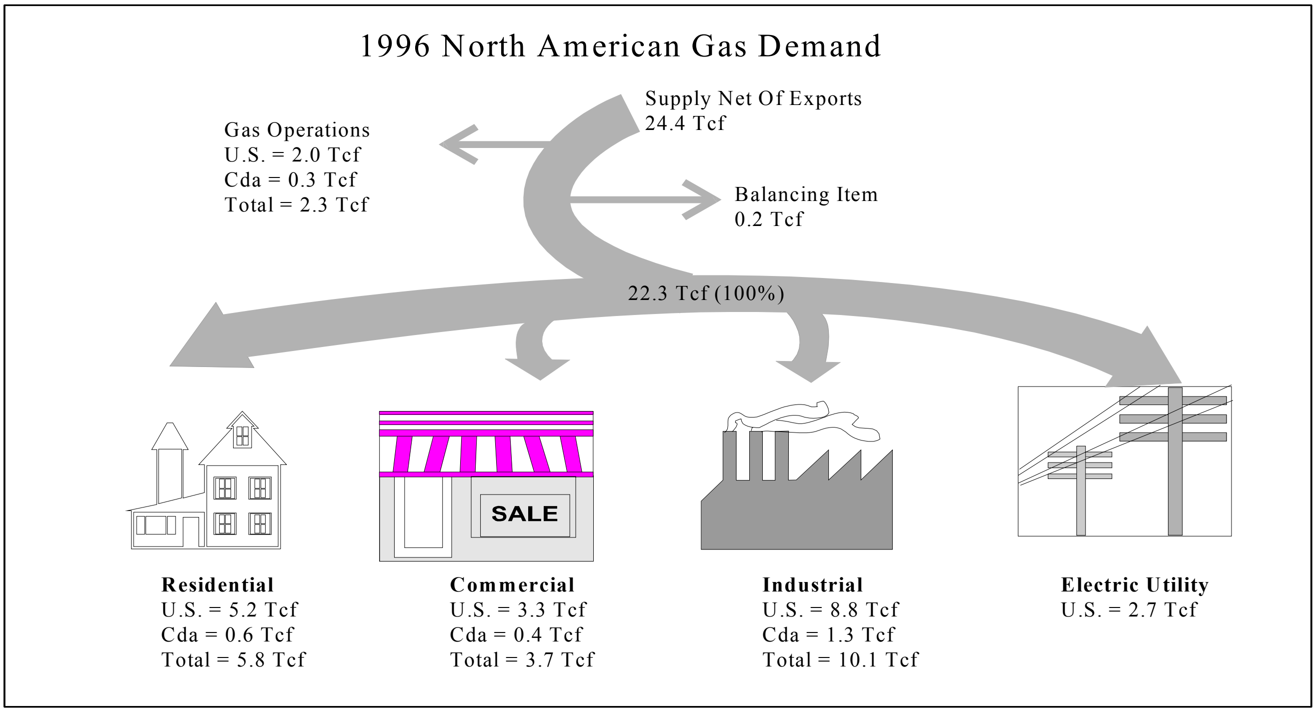
Imports of Mexican gas doubled, despite a loss of production capacity associated with an explosion at the Cactus gas processing plants in southern Mexico.

Figure 5: Canadian Gas Wells & Prices



Sources: Daily Oil Bulletin, Friedenberg

Review of 1996
North American Demand

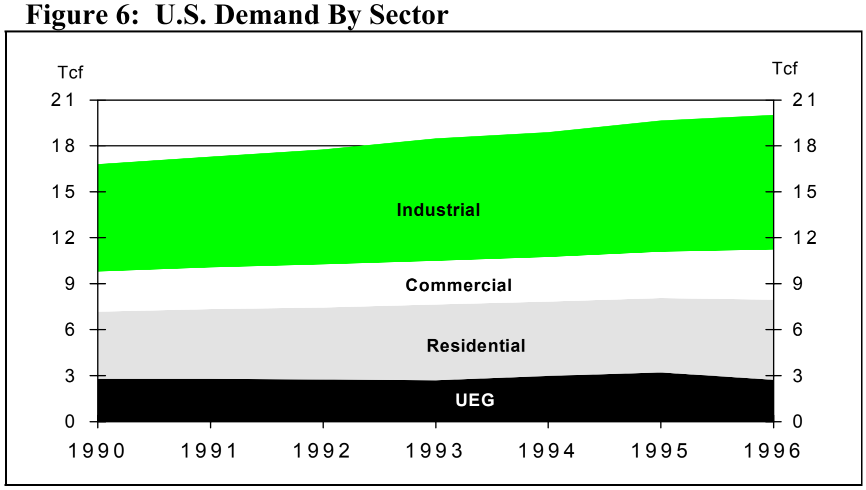


North American demand by sector is shown in the graphic above. In 1996, demand grew 2.3% over 1995 levels. The bulk of demand growth (80%) occurred in the residential sector. The 441 Bcf increase in residential demand was almost exactly offset by a 461 Bcf drop in U.S. utility electric generation (UEG) demand. Regionally, the U.S. Midwest and Gulf Coast accounted for the largest demand increases. Further details are shown in Table 2.

Demand By Sector

Total U.S. demand increased 1.9% to 22.0 Tcf in 1996. This represents an all-time high for gas consumption, equalling the previous record set over 20 years ago in 1972. Consumption increased in all sectors except for the UEG sector (see Figure 6), which declined significantly. In Canada, demand growth outpaced the 2% U.S. rate.

Figure 6: U.S. Demand By Sector



Source: EIA

Canadian demand grew 5.1%, for total demand of 2.6 Tcf in 1996. Canadian demand grew in all sectors, but the largest increase occurred in the residential and

Table 2: North American Natural Gas Demand & Disposition

	1996 (Bcf)	1995 (Bcf)	Difference (Bcf)	Change (%)	% Of Total Increase	% of N.Am. Demand
U.S. Residential	5,224	4,850	374	7.7	72.5	21.2
U.S. Commercial	3,280	3,031	249	8.2	48.3	13.3
U.S. Industrial	8,790	8,580	210	2.4	40.7	35.7
U.S. Electric Utility	2,736	3,197	-461	-14.4	-89.4	11.1
U.S. Gas Used in Operations	1,963	1,920	43	2.2	8.3	8.0
Domestic U.S. Demand	21,993	21,578	415	1.9	80.5	89.3
U.S. LNG Exports	68	65	2	3.5	0.4	0.3
U.S. Exports to Mexico	33	61	-28	-46.3	-5.5	0.1
Total U.S. Gas Disposition	22,094	21,705	389	1.8	75.4	89.7
Cdn. Residential	617	558	58	10.4	11.3	2.5
Cdn. Commercial	443	409	34	8.4	6.7	1.8
Cdn. Industrial	1,309	1,278	31	2.4	6.0	5.3
Cdn. Other	256	252	3	1.4	0.7	1.0
Total Cdn. Demand	2,624	2,497	127	5.1	24.6	10.7
TOTAL N.A. DEMAND	24,617	24,075	542	2.3	105.1	100.0
TOTAL N.A. DISPOSITION	24,718	24,202	516	2.1	100.0	100.4

Sources: EIA, StatsCan

commercial sectors, mainly reflecting colder than normal temperatures in 1996.

Residential/Commercial

The residential and commercial sectors are both largely driven by weather related factors. The most important determinant of actual consumption over the year is regional temperature, measured by the total number of heating degree days. In the winter months, weather drives demand for space heating purposes. New customer additions also increase demand, but are typically offset by efficiency gains from equipment upgrades and replacements.

In 1996, winter temperatures varied from region to region, as shown in Table 3. Due to mild weather, heating degree days were 12% less than normal in the U.S. West region, while in the U.S. Midwest, the largest consuming region, degree days were 105% of normal levels. On average, degree days across the U.S. were 102% of normal, reflecting colder than normal temperatures.

Colder winter temperatures in most regions offset warmer temperatures in the Western U.S. This was the main cause of the increase in U.S. residential consumption of 8%, or 374 Bcf, and the U.S. commercial sector increase of 8%, or 249 Bcf.

In Canada, temperatures were even lower below normal than in the U.S. In 1996, heating degree days were 12% higher than in 1995, with colder temperatures recorded in both Western and Eastern Canada.

These cold weather conditions in Canada were the primary cause of the 10% (58 Bcf) demand increase in the residential sector, and the 8% (34 Bcf) increase in commercial sales.

Industrial

Total sales to the U.S. industrial sector increased 2.4% (210 Bcf) in 1996 to reach 8.8 Tcf. This was the tenth consecutive year of steady growth. The U.S. Energy Information Administration, or EIA, our source for U.S. demand data, includes non-utility generation (NUG) in the industrial sector. NUG demand has been a major factor in the growth of industrial demand.

"Traditional" industrial natural gas consumption (i.e., excluding NUGs) is closely linked to the performance of the U.S. economy. Sustained growth in overall U.S. industrial output contributed to an increased use of natural gas in the manufacturing sector.

Table 3: Heating Degree Days – U.S. & Canada

Year	Month	Northeast	Midwest	West	Gulf	U.S. Average	East Canada	West Canada
1995	Jan	1958	1200	466	521	875	663	692
	Feb	2196	1130	698	379	800	699	578
	Mar	1524	768	364	289	578	508	533
	Nov	1539	913	247	301	630	516	577
	Dec	2263	1208	440	510	899	721	754
1996	Jan	2359	1294	471	600	978	827	884
	Feb	2090	1107	375	416	803	723	617
	Mar	1884	1025	336	396	736	673	619
	Nov	1595	917	325	309	660	552	678
	Dec	1771	1068	452	453	802	641	837
1997	Jan	2312	1330	484	620	976	na	na
	Feb	1693	958	387	413	709	na	na
	1995	9480	5219	2215	2000	3782	3975.16	4356
	1996	9699	5411	1959	2174	3979	4455.02	4961
	% chge	2.3	3.7	-11.6	8.7	5.2	12.1	13.9
1996 as a % of normal		100.6	104.5	89.1	98.9	101.7	na	na

Notes: Canadian heating degree days from StatsCan, provincial figures, volume weighted. Canadian degree days between April-October not shown, but included in yearly totals. U.S. figures from EIA.

In contrast to 1996, the price of competing fuels, most notably residual fuel oil (RFO), did not affect gas consumption in the industrial sector in most areas of the U.S. Residual fuel oil prices increased in step with gas prices throughout most of 1996. As a consequence, there was no incentive to switch from gas to RFO during 1996.

Regionally, industrial consumption fluctuated significantly. Most notable was a 162 Bcf increase in Gulf Coast industrial demand due to economic growth and the increased use of natural gas by industrials for generating their own electricity.

Canadian industrial sales were also up 2.4%, despite a 10% drop in industrial power generation sales. The decline in power generation sales reflects an improvement in water conditions on the West Coast. Traditional industrial demand was mainly driven by economic growth and the cost competitiveness of natural gas versus fuel oil.

Utility Electric Generation

The electric generation sector is by far the most volatile of all U.S. demand sectors. Weather affects demand in several ways.

In the summer months, total cooling degree days influences electricity generation demand for air cooling purposes. Dry weather may reduce hydro-electric generating capacity, and increase gas-fired generation.

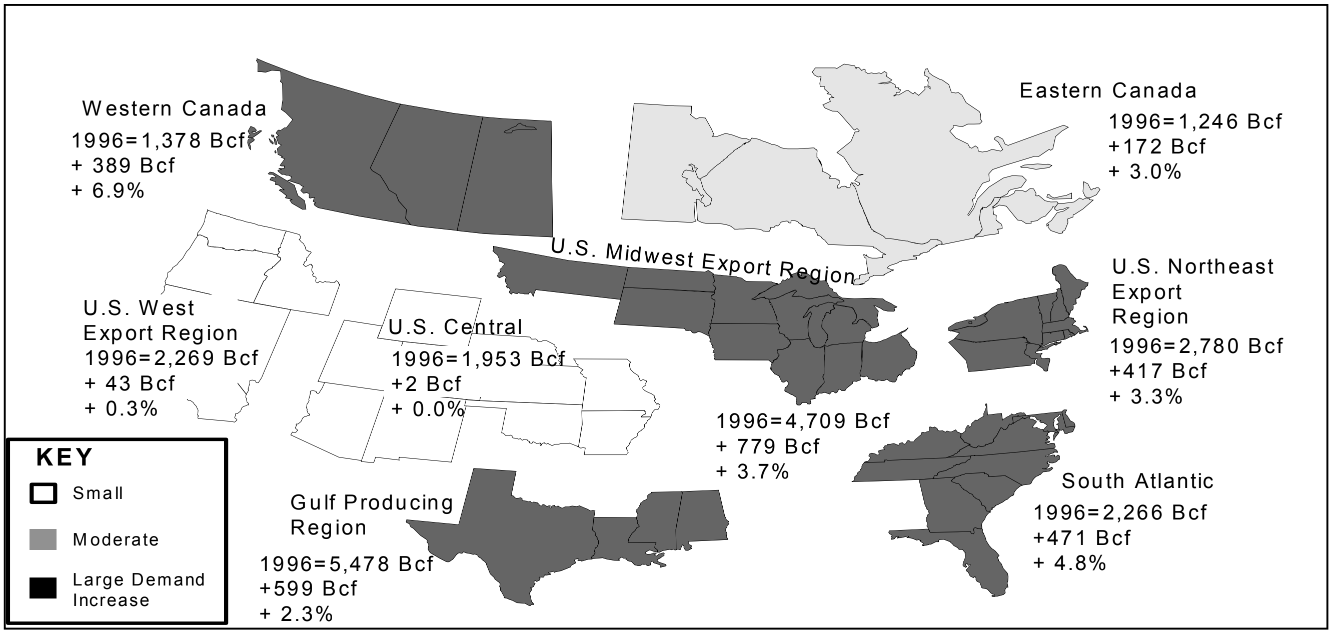
Prices for competing fuels also influence gas consumption in this highly price sensitive sector.

Total UEG gas consumption in 1996 decreased by 14% to 2.7 Tcf, due to a combination of higher gas prices, cool weather in the summer months, and abundant hydro-electric capacity in the U.S. West.

The significant decrease in natural gas consumption for electricity generation purposes is probably not a sustainable trend. An abundant supply of unusually low-cost natural gas in 1995 prompted utilities to switch from residual fuel oil to natural gas, making 1995 UEG consumption unusually high. U.S. UEG demand has experienced sustained growth in the 2 - 5% range for the last ten years.

Geographically, UEG consumption decreased in all regions of the U.S., reflecting U.S.-wide increases in natural gas prices.

Figure 7: Regional Demand Trends, 1991-1996



The decrease in consumption was more pronounced in areas where dual-fuel generators are located, most notably the U.S. Northeast, where consumption decreased 37% to 256 Bcf in 1996, down from over 400 Bcf the previous year.

The Gulf Coast region, by far the largest UEG consuming region, was less affected by high prices and associated fuel switching. Sales to the UEG sector in the Gulf Coast decreased 6.9%.

Geographic Demand Trends

A focus on the geographic location of demand growth is very useful, since Canadian gas has pipeline access only to certain markets. The geographic location of natural gas demand growth is also a major factor in determining regional gas prices and price differentials. Thus, for Canadian producers, marketers, pipelines, or consumers deciding on pipeline capacity additions (whether constructing new capacity or signing long term contracts to pay demand charges on new capacity), geographic demand trends are an important consideration.

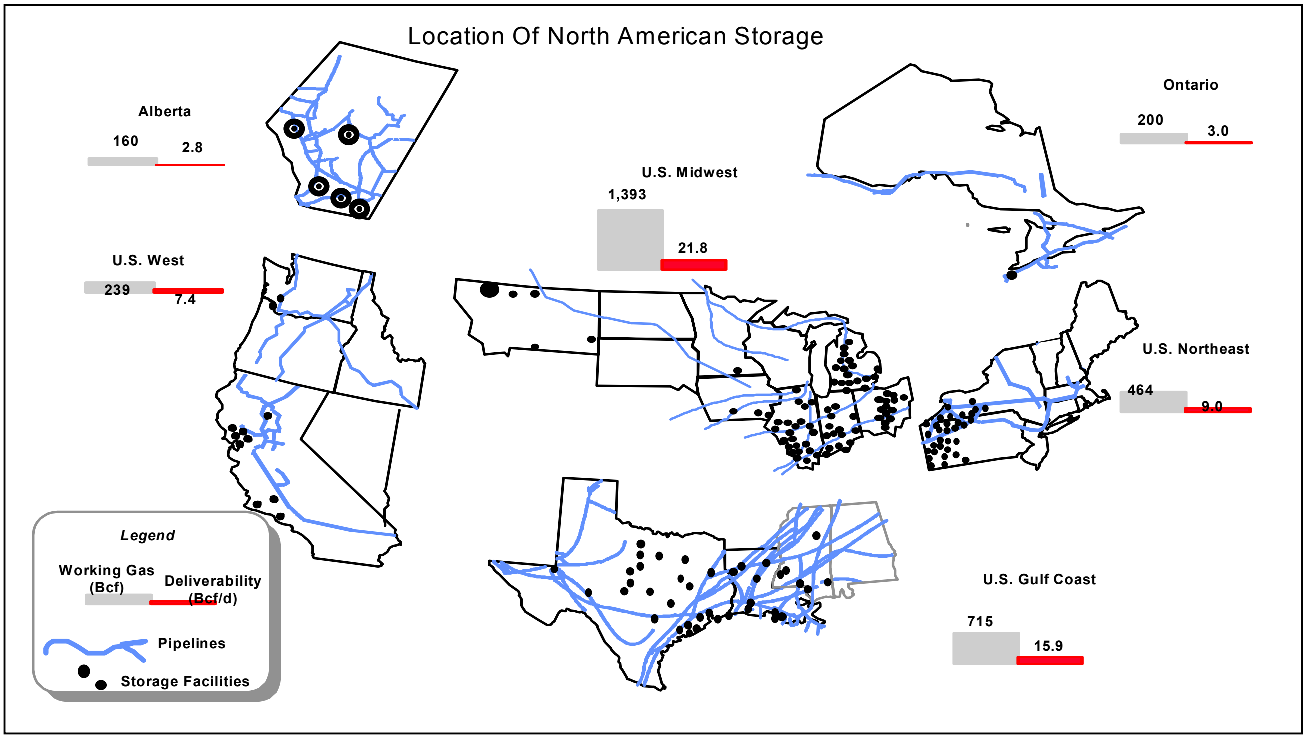
Figure 7 shows the end-use demand breakdown in North America as of 1996, the change in demand by area over 1991-1996, and the average annual demand growth rate over this period.

This regional demand breakdown is quite striking. There has been virtually no gas demand growth in the U.S. West in the past five years.

Most of the demand growth in North America over the past five years has been in the eastern and southern U.S. (Midwest, North-east, Gulf Coast, and South Atlantic).

This regional pattern of gas demand growth has contributed to the east/west natural gas pricing split, where gas prices in eastern markets have been much higher than those in western markets. It also explains the large number of natural gas pipeline proposals for west to east capacity.

Review of 1996
Storage



Source: NRCan, Natural Gas Division

Storage plays a very large role in North American supply, demand, and price dynamics. Most storage is located in the large demand centres of eastern North America (the U.S. Gulf Coast, U.S. Midwest, and U.S. Northeast).

Storage is used to balance production capacity (which is fairly constant) with demand (which is heavily weather-sensitive). The major storage flows are into storage during the injection season (April through October) and out during the withdrawal season (November through March). Smaller storage inflows and outflows also occur hourly and daily to balance hourly and daily demand fluctuations with pipeline capacities, or to deal with temporary pipeline shutdowns. The amount of usable gas remaining in storage is termed working gas.

Storage levels, withdrawals and injections are inextricably linked to gas prices in highly complex ways. Storage decisions are based on previous events (which have left storage levels high or low) and on expectations of future demand and prices. Just as storage decisions are highly dependent on price expectations, flows in and out of storage are a large component of month-to-month supply or demand, and have a significant feedback effect on natural gas prices.

flowing gas into and out of storage involves operating costs (compression fuel) and capital costs (gas inventory cost, amortization of storage facilities). These storage costs must be offset by gas price savings or profits for storage to be economically useful.

Thus, gas is usually injected to storage when prices are low and withdrawn when prices are high. Conversely, prices are often high when the working gas in storage is low, and vice-versa.

Storage analysis is best performed market by market. For example, low storage volumes in the Midwest U.S. may not affect San Juan gas prices. However, overall North

American gas prices are usually directed by storage, i.e., when North American storage is low, this tends to strengthen prices; when storage is fuller than normal, prices are weakened.

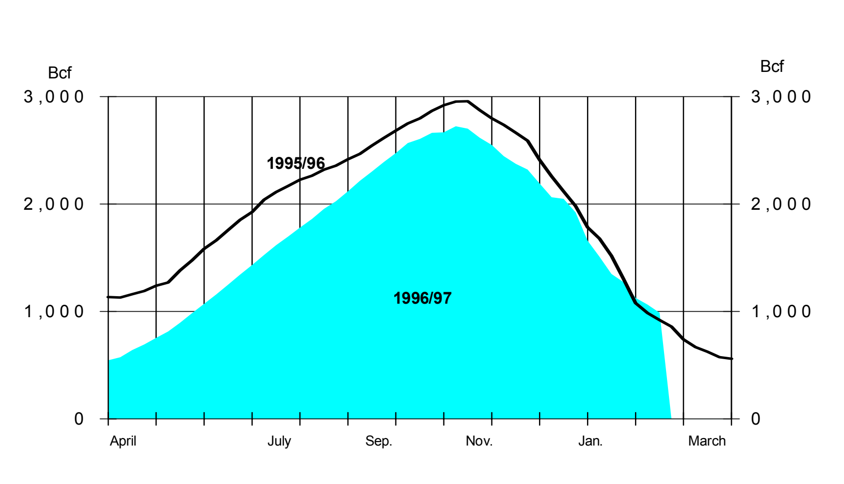
With the withdrawal season continuing past the end of the year, storage does not lend itself to analysis by calendar year. The logical end of a storage analysis period is the end of the withdrawal season in March.

U.S. Storage
Figure 8 shows U.S. working gas storage levels over the past two injection/withdrawal seasons. Last year (1995/96), U.S. working gas levels peaked at 2,958 Bcf. This year, working gas reached only 2,725 Bcf before withdrawals began. However, the pace of storage withdrawals dropped in 1996, with the result that for the last half of the withdrawal season, U.S. storage levels were approximately equal to those of last year.

As noted in the previous section, U.S. heating degree days during 1996 were 2% higher than in 1995, but December 1996 through February 1997 was warmer than last year. This allowed operators to slow storage withdrawals, and bring working gas levels back in line with levels of the previous year.

The effect of this weather/ storage situation on U.S. gas prices is shown in Figure 9. The low working gas levels in

Figure 8: Total U.S. Storage Balance



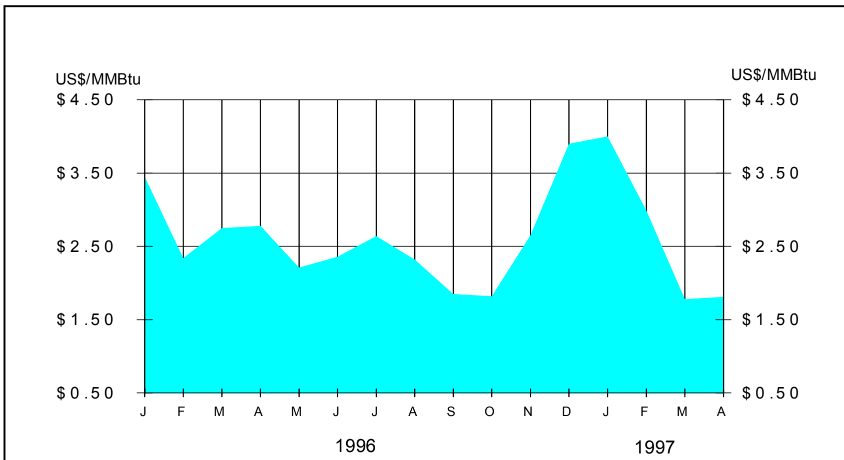
Source: AGA

November 1996 led to a price runup, resulting in gas prices on NYMEX peaking at $4.00 per MMBtu for the January contract. With the withdrawal season over, prices fell dramatically by April 1997.

Canadian Storage
Most Canadian storage is located in Ontario (44%) and Alberta (39%). Canadian storage affects Canadian gas market prices in the same way as for U.S. storage.

The main Canadian gas market is in Alberta, where most volumes destined for Canadian consumers are bought and sold. The pricing point is on the NOVA pipeline system within Alberta, and is commonly at AECO C, the largest Alberta storage facility. There is no large-scale Ontario spot gas market. Most Ontario gas users purchase their gas in Alberta and contract for pipeline capacity to transport it to

Figure 9: 1996 NYMEX Henry Hub Gas Prices



Source: Friedenberg

Ontario. (See the Appendix sections on Eastern Canada and Western Canada for a detailed explanation).

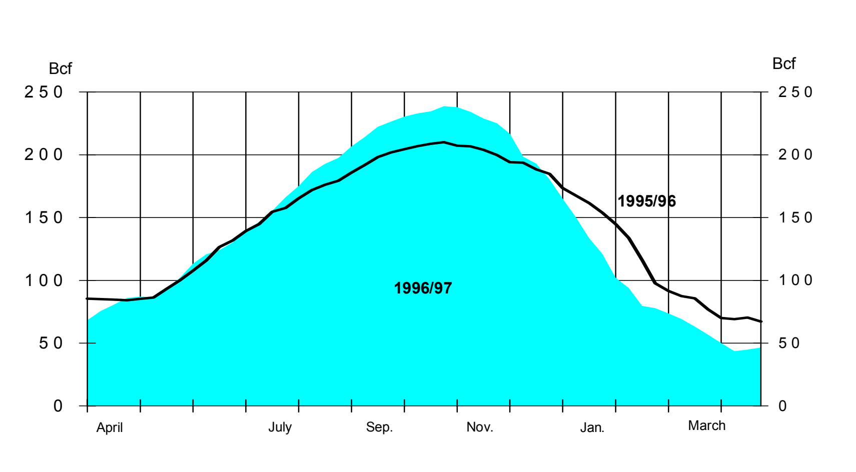
Figure 10 shows Western Canadian working gas storage levels over the past two injection/withdrawal seasons. Last year (1995/96), working gas levels peaked at 210 Bcf. This year, with storage capacity expansions, working gas reached 239 Bcf, 14% higher.

However, the pace of storage withdrawals was considerably more rapid than last year, with the result that Western Canadian storage levels fell to 1995/96 levels by December, and below last year's levels by January 1997. The rapid pace of withdrawals and the resultant rapid storage declines were caused mainly by extremely cold temperatures and high gas demand in Western Canada. Alberta heating degree days were 13% higher than last year.

The combination of high local demand, limited additional production capacity, and low storage inventories resulted in Western Canadian gas prices (AECO) rising above last year's levels by December 1996 (see Figure 11). Prices peaked in February at CDN$2.50/GJ or US$2.00/MMBtu before settling to levels more typical of the past two years.

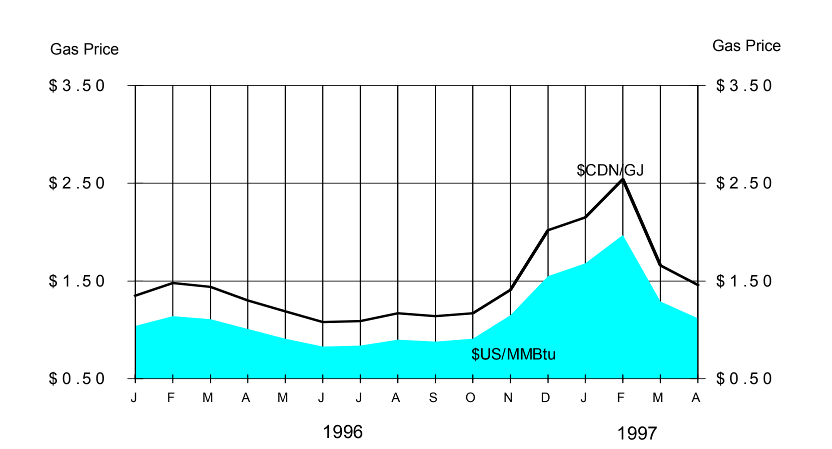
High Western Canadian gas prices during the latter part of 1996 were also partly caused by high demand from U.S. markets. While Canada-to-U.S. export sales were up only 3% in 1996, exports during November and December were up 9% and 6%, respectively.

Figure 10: Western Canadian Storage Balance



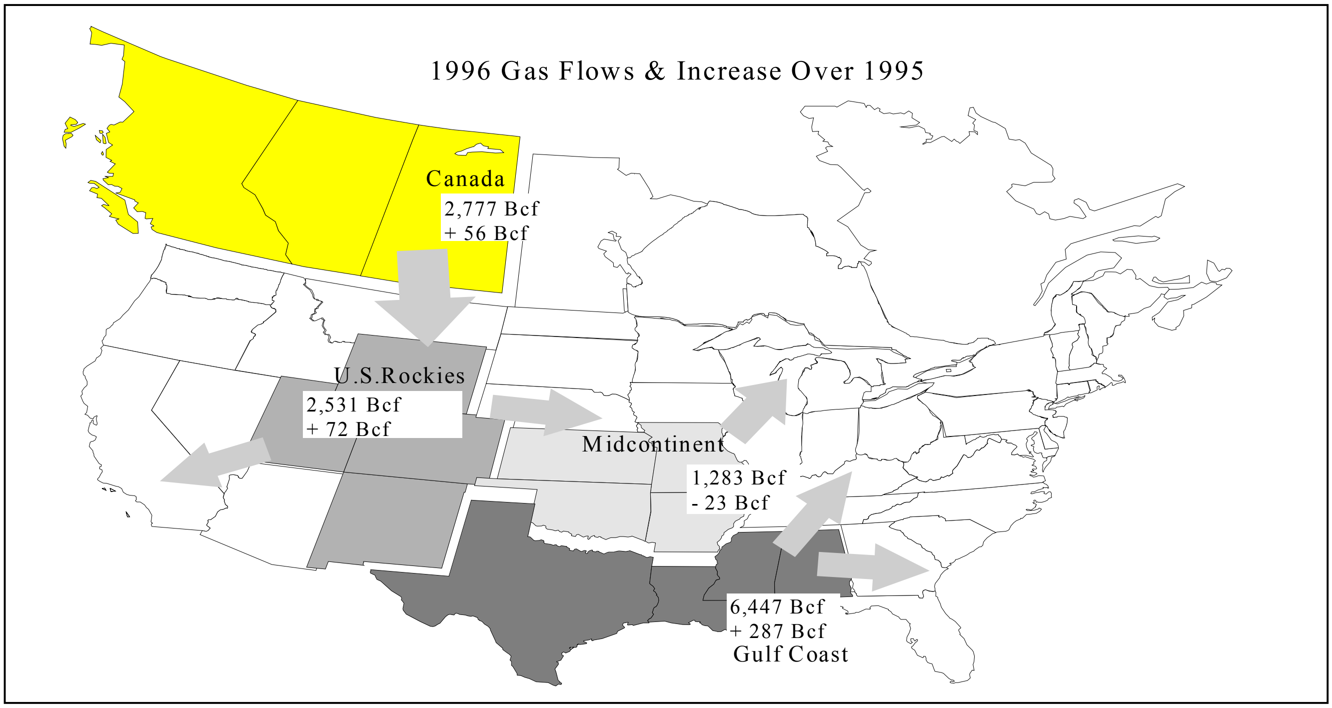
Source: CGA

Figure 11: 1996 AECO C Gas Prices



Source: Friedenberg

Review of 1996
Pipeline Capacities & Gas Flows



The concept of gas flows is useful in explaining and evaluating regional gas prices, price differentials ("basis"), and gas pipeline dynamics. In this section, net gas flows out of any region are calculated as production less gas demand within that region. These flows are shown in the graphic above.

By looking at changes in net gas flows, we can determine where supply flows are increasing or falling. This has implications for regional prices and price differentials. Details on the calculation of gas flows by region are shown in Table 4. Note that the exports from Canada to the U.S. shown in the graphic above are *net* exports.

Regional Changes
The big change in gas flows during 1996 was the 287 Bcf increase in gas flowing out of the U.S. Gulf Coast. This increase is not surprising, given that Gulf Coast production increased by 406 Bcf during the year. Flows out of the Gulf would have increased even more, but demand within the Gulf rose by 118 Bcf, absorbing some of the increased production.

Although gas production in the Midcontinent fell 96 Bcf, internal demand also fell, resulting in a decline of only 23 Bcf for flows out of the region. Increased flows out of the Gulf or Midcontinent are not restricted by pipeline capacity, as large pipeline corridors to the Midwest and Northeast usually have excess capacity in all but peak periods.

In the U.S. Rockies, where production increased by 148 Bcf, demand also increased, resulting in exports out of the region increasing by 72 Bcf.

Finally, in Western Canada, the 169 Bcf increase in production was mainly absorbed by increased Canadian demand. Net gas flows from Canada to the U.S. were only 56 Bcf higher than last year (Note: gross exports, discussed in the next section, were 87 Bcf higher).

Table 4: North American Natural Gas Flows

	1996 Prod. (Bcf)	1996 Demand (Bcf)	Net Exports 1996 (Bcf)	Net Exports 1995 (Bcf)	Difference (Bcf)	Change %
Gulf Coast	11,925	5,478	6,447	6,160	287	33.3
Midcontinent	2,482	1,199	1,283	1,306	-23	8.6
U.S. Rockies	3,052	521	2,531	2,459	72	4.4
Canada	5,401	2,624	2,777	2,721	56	4.6

Gas Price Differentials

In today's deregulated North American natural gas market, gas price differentials drive gas flows. For example, if gas is worth $1.00/MMBtu more in one market than another, and if the transportation cost is less than $1.00/MMBtu, then gas will flow to the higher-priced market until all pipeline capacity is used up, or until the price differential is bid away.

If enough gas can flow from the lower-priced market to the higher-priced market, prices in the two markets will adjust until the high market price is equal to the low market price plus transportation costs. At this point, the two markets are integrated.

In certain North American regions, natural gas flows are periodically or habitually restricted by natural gas pipeline capacity (see Figure 12). Prices between points cannot integrate. Because of this effect, North America is currently in what could be called the era of very large differentials.

Gas flows out of Canada are not restricted by productive capacity at the wellhead, but by export pipeline capacity. When trapped gas at the wellhead backs up in the Western Canadian market, prices are kept low relative to other markets.

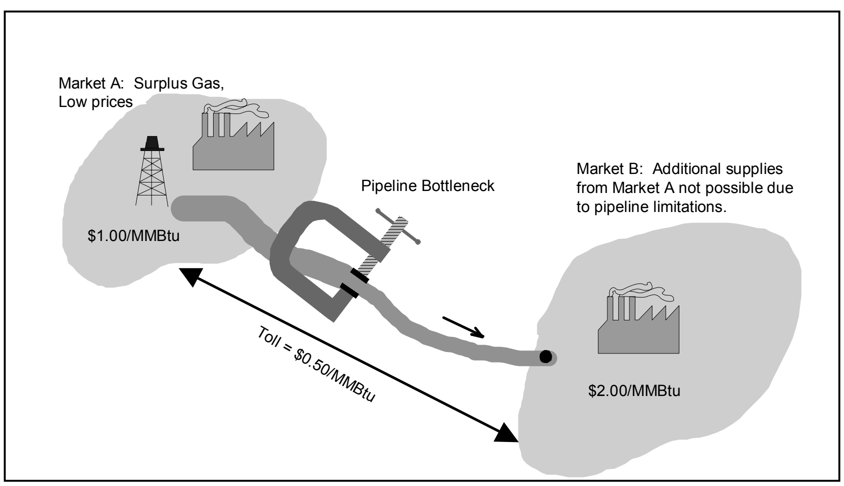
Pipeline capacity bottlenecks out of Canada and the Western U.S. have been main factors in causing large price differentials in the North American gas market.

The effects of these bottlenecks are reflected in regional natural gas prices over time. Figure 13 shows spot (1-month) gas prices at four major natural gas markets: the AECO C storage hub in Alberta, the San Juan basin in New Mexico, the Henry Hub in Louisiana, and Chicago. The Chicago and NYMEX markets are well integrated, and prices have tracked one another over 1995 and 1996.

During 1995, U.S. Rockies and Western Canadian prices were not strongly correlated to prices on NYMEX or at Chicago.

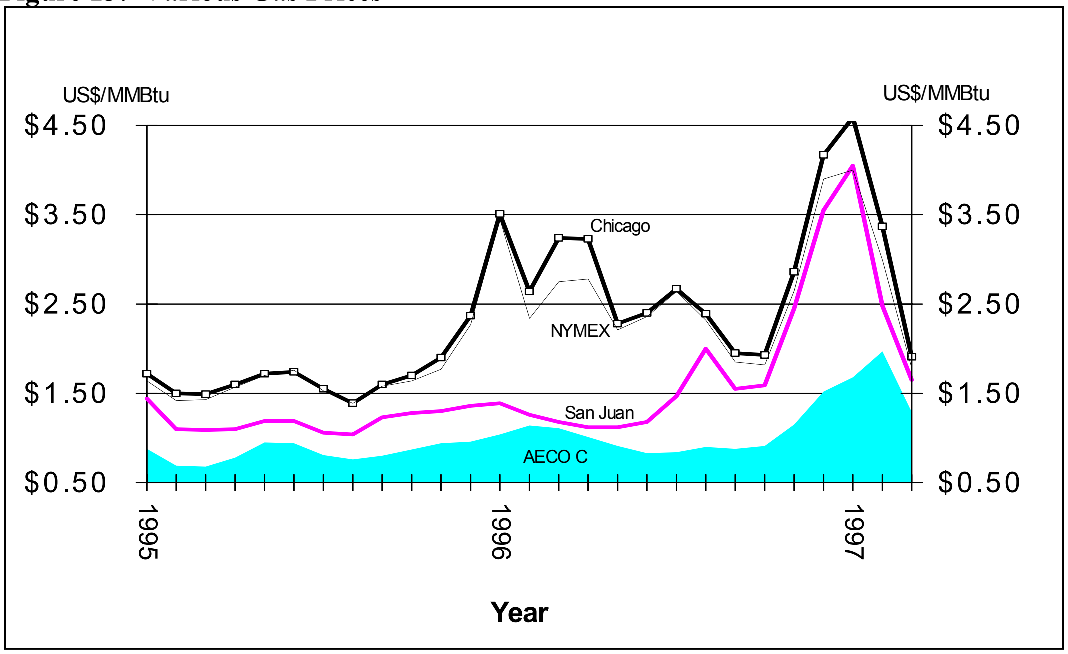
Beginning in mid-1996, San Juan prices reconnected with those at NYMEX/Chicago. It appears that pipeline capacity added on the El Paso and Transwestern pipelines was sufficient to bring the total exit pipeline capacity up to the San Juan supply capacity. This may be a temporary phenomenon. If the demand available to San Juan producers drops, or if the supply increases again, San Juan prices may once again become disconnected from Gulf Coast prices.

Figure 12: Markets Unable To Integrate



Western Canadian gas prices continued to be disconnected from U.S. market prices throughout 1996. This is illustrated in Figure 14, which shows the difference in gas prices between various U.S. markets and the AECO spot price, for the months of August and December, 1996. All U.S. spot market prices were higher than AECO in August 1996, and then became progressively more disconnected from AECO prices.

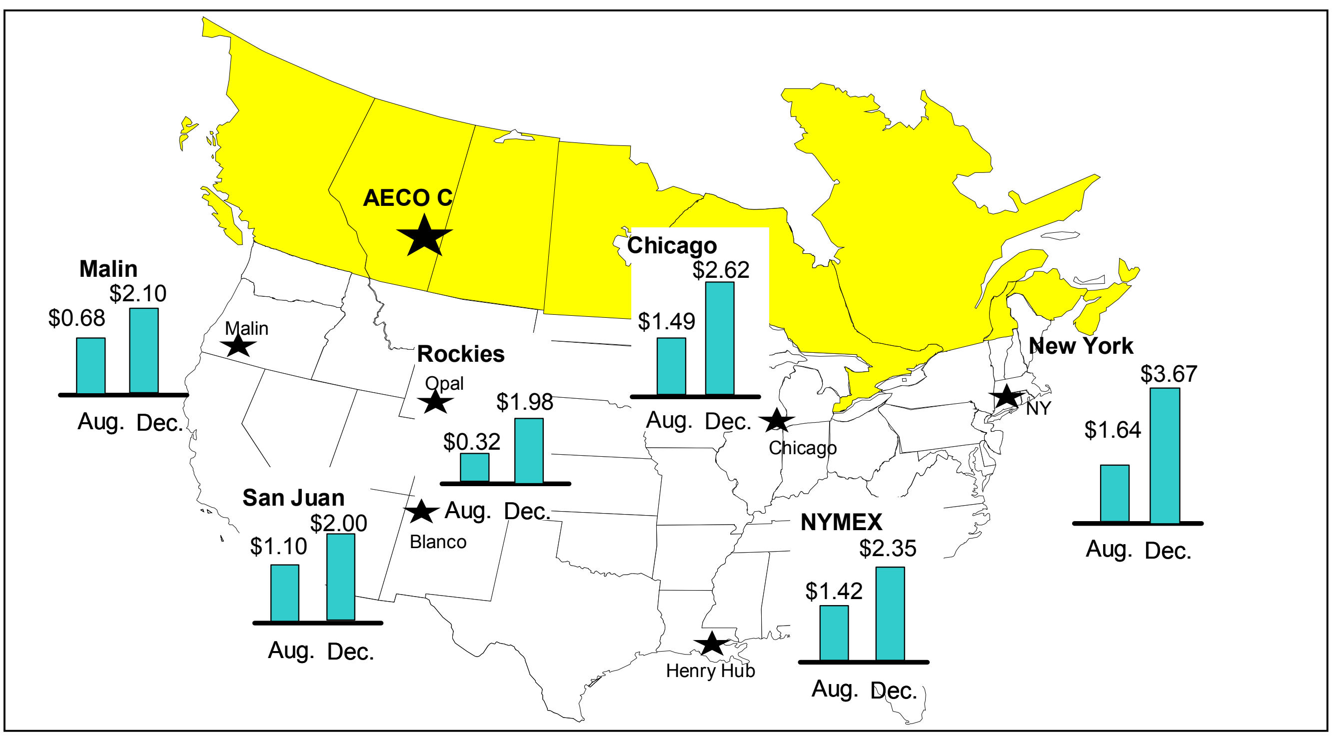
Figure 13: Various Gas Prices



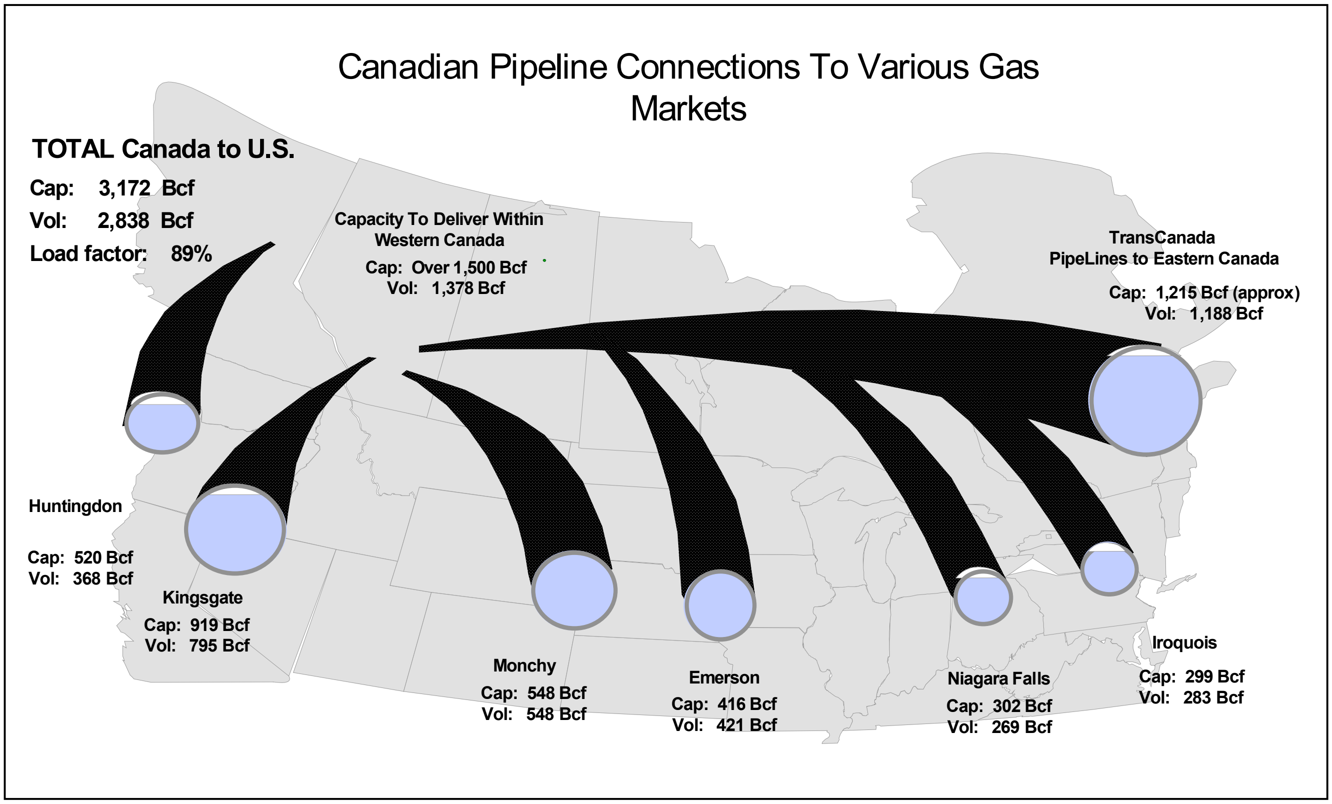
Source: Friedenberg

By the end of 1996, these differentials were much greater than the pipeline transmission cost from AECO to the relevant U.S. market. This is driving the current push to expand pipeline capacity out of Western Canada.

Figure 14: Spot Markets Relative to AECO C: 1996 $US/MMBtu Differential



Review of 1996
Canadian Export & Domestic Gas Sales



Canadian gas sales enjoyed a banner year in 1996. Total volumes rose 3.6%, but the greatest change was in prices and revenues, which saw increases in the order of 21% to 44% .

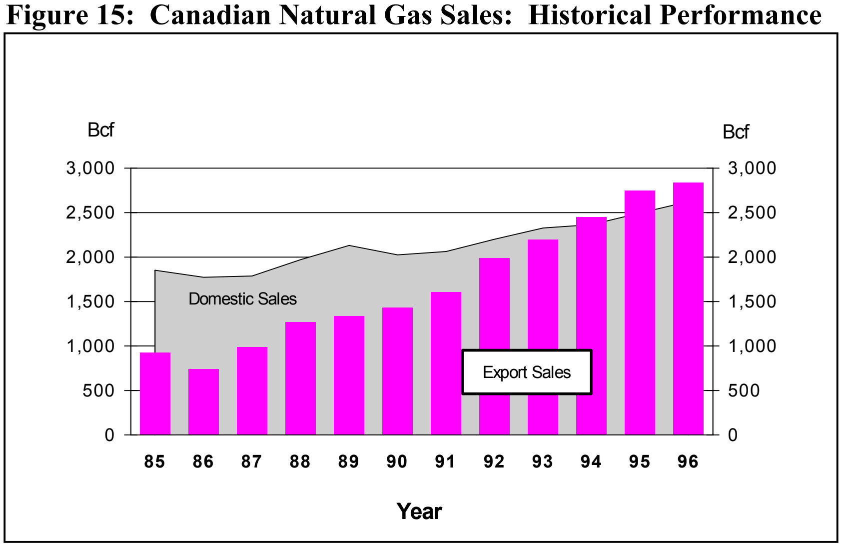
Pipeline Capacity

Canadian pipeline capacity to markets expanded only marginally during the year. The main pipeline capacities and volumes are shown in the graphic above. During 1996, the only expansions were a 76 MMcf/d increase in TCPL capacity to Eastern Canada, and approximately 41 MMcf/d at the Iroquois export point.

Sales Volumes

With minimal additions to capacity, and given that capacity was already being used at near maximum levels last year, 1996 volume increases did not match those of previous years. This is evident in Figure 15, which shows export volumes growing at an average annual rate of 12% over 1985-95, but slowing to 3% in 1996.

Figure 15: Canadian Natural Gas Sales: Historical Performance



Canadian gas sales during 1996 are shown in Table 5. Total sales volumes increased by 3.7%, or 194 Bcf, during 1996.

Table 5: Total 1996 Canadian Export & Domestic Sales

Year	Month	Firm Exports (Bcf)	Interruptible Exports (Bcf)	Total Exports (Bcf)	Canadian Sales (Bcf)	Total Sales (Bcf)
1996	January	205	42	247	272	519
	February	187	39	225	224	450
	March	175	57	232	234	466
	April	166	59	224	202	427
	May	173	63	236	197	433
	June	161	62	223	173	396
	July	179	52	231	183	414
	August	180	56	237	182	419
	September	166	66	233	187	420
	October	175	68	243	216	459
	November	186	58	244	243	486
	December	198	64	262	268	530
Total 1996		2,151	686	2,837	2,581	5,418
Total 1995		**2,185**	**565**	**2,750**	**2,474**	**5,224**
Bcf Change		**-34**	**121**	**87**	**107**	**194**
% change		-1.6	21.5	3.2	4.3	3.7
% of Total Increase		**-17.7**	**62.6**	**44.9**	**55.1**	**100.0**

Sources: NEB, StatsCan

In contrast to past years, the majority of the increase in 1996 sales was due to domestic markets, where sales increased 4%. Sales to export markets increased 3%.

Load Factors

The minimal expansion of the Canadian pipeline system was reflected in the load factors experienced throughout the year. Export capacity was used at an average 89% load factor in 1996, while domestic capacity to Eastern Canada was used at even higher load factors.

The only export point with a relatively low load factor was Huntingdon. However, there is little scope for significantly increased exports across Huntingdon without adding further pipeline capacity. Huntingdon includes three short user-dedicated lines with a total of 138 Bcf/yr of capacity. These lines were deliberately built with excess capacity, and this excess cannot be used to flow to other customers. This lowers the load factors across Huntingdon.

Another factor is the nature of markets downstream of Huntingdon. These markets have little gas storage compared to markets downstream of other export points. As a result, these markets need excess pipeline capacity on an average annual basis in order to meet winter peaks.

The combination of strong prices and high load factors led to the announcement of several proposals for substantial new capacity in the near future.

Term & Class of Sales

The pattern of Canadian export sales continues to move away from firm sales and long-term export licences.

Of total export sales in 1996, 61.7% were short-term (under two years) versus only 53% in the previous year. [Note: this does not refer to the gas supply contract term, but the term of the export arrangement (either a long-term licence or a short-term order)].

In 1996, 76% of exports were sold under firm delivery arrangements, while 24% occurred via interruptible pipeline capacity. In 1995, the proportion was 80% firm, 20% interruptible.

Exports using firm pipeline transportation fell 2% versus the previous year, while those using interruptible transportation increased 21%.

Most sales to Canadian markets occurred under firm pipeline transportation arrangements.

Sales Prices

Table 6 shows the average international border prices for the three U.S. export markets. These figures are obtained from information filed with the National Energy Board (NEB).

Similar price information for Canadian markets is not readily available. Instead, Table 6 shows spot month prices at the two most important gas pricing points for Canadian gas sales: the AECO C price (the Alberta market, which drives Eastern Canada and Saskatchewan prices), and the Huntingdon/ Sumas price (the largest British Columbia market).

Canadian markets from Alberta and eastward are mainly priced relative to AECO. Most eastern Canadian customers purchase gas in Alberta at a price reflecting the AECO price. This gas is then moved to eastern Canadian markets by the customer, resulting in a delivered price equal to AECO plus the regulated pipeline transmission toll.

The AECO price shown in Table 6 is a one-month term price. Some customers may be buying gas at higher or lower prices, where contracts are of different lengths (hourly, daily, 1-year, etc.). For more information on Canadian markets, see the Appendix.

Most British Columbia sales reflect the Huntingdon price. As with AECO, sales occur at different prices when contracts are longer or shorter term.

Higher Prices In 1996

Domestic and export prices were both up significantly in 1996. In Canada, the average AECO spot price of US$1.02/MMBtu represented an increase of 22% over 1995. Price increases for sales to the U.S. were highest in the Midwest (41%), followed by the Northeast (27%) and the West (24%).

Both domestic and export prices experienced sharp increases at the end of the year, as a result of various factors, including: low storage in the U.S.; severe winter weather in Canada; colder than normal weather in the U.S. Midwest; the lack of take-away pipeline capacity from low cost supply regions; and the need to obtain incremental supplies from the high cost Gulf Coast region.

Higher prices led to higher netbacks.

Plant Gate Netbacks

Plant gate netbacks from U.S. sales, as well as plant gate netbacks from spot month sales at Huntingdon and AECO are also shown in Table 6. These latter two netback figures are considered to be roughly indicative of netbacks for domestic sales, and useful for comparing to export netbacks.

Sales Revenue

Price increases accounted for most of the gains in domestic and export sales revenues in 1996. The revenue data discussed below and shown in Table 7 is reported to the NEB, and is revenues in Canadian dollars at the international border. These figures therefore include revenues for pipeline transmission from the production region to the border.

Export sales revenues increased by 33%, based on a volume increase of only 3.1% for all U.S. markets. Revenues from sales to the U.S. Midwest increased by 44% to $2.9 billion on a volume increase of only 2.5%. In the West, a volume increase of 6.2%, combined with increased prices, pushed revenues up by 31% to $2 billion. Despite a slight decline in volumes sold in the Northeast market

Table 6: 1996 Prices (US$/MMBtu)

Year	Month	International Border Prices			Canadian Markets		Plant-Gate Netbacks				
		West	MW	NE	AECO	Huntingd.	West	MW	NE	AECO	Huntingd.
1996	January	1.17	2.08	3.03	1.04	1.23	0.99	1.85	2.14	0.94	0.97
	February	1.17	1.89	3.06	1.14	1.18	0.96	1.63	2.12	1.03	0.92
	March	1.17	2.06	2.99	1.11	1.15	0.98	1.81	2.08	1.00	0.90
	April	1.01	2.08	2.93	1.01	0.93	0.79	1.81	2.01	0.90	0.68
	May	0.97	1.84	2.73	0.91	0.93	0.78	1.58	1.83	0.81	0.68
	June	0.97	1.88	2.71	0.83	0.90	0.77	1.60	1.77	0.73	0.65
	July	1.01	1.99	2.77	0.84	0.96	0.82	1.67	1.79	0.74	0.71
	August	1.18	1.88	2.61	0.90	1.01	0.98	1.56	1.68	0.80	0.76
	September	1.11	1.59	2.44	0.88	1.02	0.91	1.29	1.50	0.78	0.77
	October	1.18	1.65	2.47	0.91	1.11	0.98	1.36	1.52	0.81	0.86
	November	1.72	2.33	3.09	1.15	2.08	1.50	2.06	2.11	1.04	1.79
	December	2.47	3.18	3.69	1.52	3.35	2.25	2.90	2.80	1.41	3.01
1996 Average		1.28	2.05	2.89	1.02	1.32	1.07	1.77	1.96	0.91	1.06
1995 Average		**1.03**	**1.45**	**2.28**	**0.84**	**1.03**	**0.72**	**1.13**	**1.36**	**0.74**	**0.78**
% change		24.3	41.4	26.8	21.6	27.8	48.6	56.6	44.1	24.3	35.3

Sources: NEB, Friedenberg

(volumes fell 0.9%), sales revenues rose by 25% to exceed $2.5 billion.

Over the year, the Canadian dollar/US dollar exchange rate remained stable and had no significant effect on sales revenues.

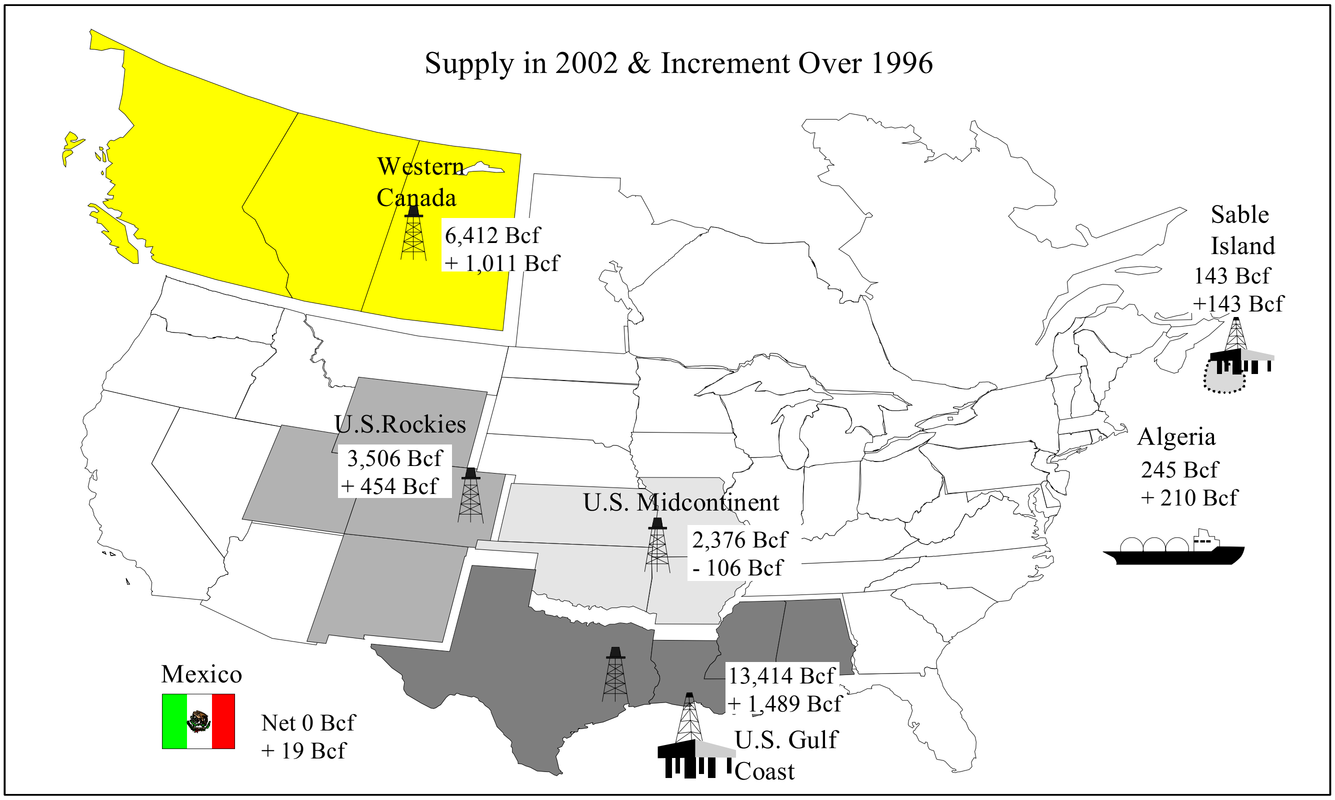
The pattern was the same in Canadian markets. Revenues from domestic gas sales rose approximately 25%. The revenue increase was mainly due to higher prices, as sales volumes increased only 4.3%.

Table 7: 1996 Export Sales Revenue

Year	Month	West	MW	NE	Total
		Cdn$Millions			
1996	January	152	250	265	667
	February	144	214	225	583
	March	141	254	218	613
	April	117	243	211	571
	May	128	217	201	546
	June	122	211	179	513
	July	140	223	184	546
	August	163	211	195	568
	September	150	183	166	499
	October	167	196	167	530
	November	242	266	221	729
	December	358	414	302	1,074
1996		**2,024**	**2,882**	**2,533**	**7,439**
1995		**1,549**	**2,002**	**2,028**	**5,579**
% change		**30.6**	**44.0**	**24.9**	**33.3**

Source: NEB

Outlook to 2002
North American Supply



Incremental natural gas supplies for North America to the year 2002 will come from U.S. production, Canadian production, LNG and other supplies. Our estimates of North American supply sources, and the differences from 1996, are shown in the graphic above.

Our approach in determining this outlook is as follows.

First, the forecasts of various agencies for U.S. and Canadian supply and demand were examined. We assumed that U.S. and Canadian demand will occur according to the average forecasts of the experts surveyed (see page 23 for detail). In short, U.S. and Canadian gas demand will total 27,596 Bcf in 2002. We also assumed U.S. LNG exports of 60 Bcf per year would continue.

Second, Canadian gas exports to the U.S. were determined. Our export forecast of 3,609 Bcf in 2002 is driven by estimates of export pipeline capacity (see page 32).

Third, we assumed that all Canadian gas demand would be satisfied by Canadian supplies. This yields a forecast for total Canadian production of 6,555 Bcf in 2002, equal to exports plus Canadian demand.
Fourth, based on the average of several expert forecasts, future U.S. supplies from LNG and other sources were estimated (245 Bcf in 2002).

Finally, supply from Canada and LNG were subtracted from forecast North American demand, to yield an estimate of required U.S. production. Based on this analysis, required U.S. production will be 20,856 Bcf in 2002.

Domestic U.S. Gas Supply
U.S. demand increased at an average 3% annual rate over the past five years, while domestic production increased by only 1.5%. Higher imports of Canadian gas made up the shortfall. If U.S. production continued at a 1.5% average

annual growth from 1996 to 2002, U.S. domestic production would reach roughly 21 Tcf in 2002.

Figure 16 shows various forecaster views of U.S. production to 2002. The average expectation is for U.S. production growth to continue its recent annual growth rate, and reach 21.1 Tcf by 2002.

In summary, the average expectation for U.S. production, combined with our estimate of Canadian and LNG exports to the U.S., would be adequate to meet forecast U.S. gas demand.

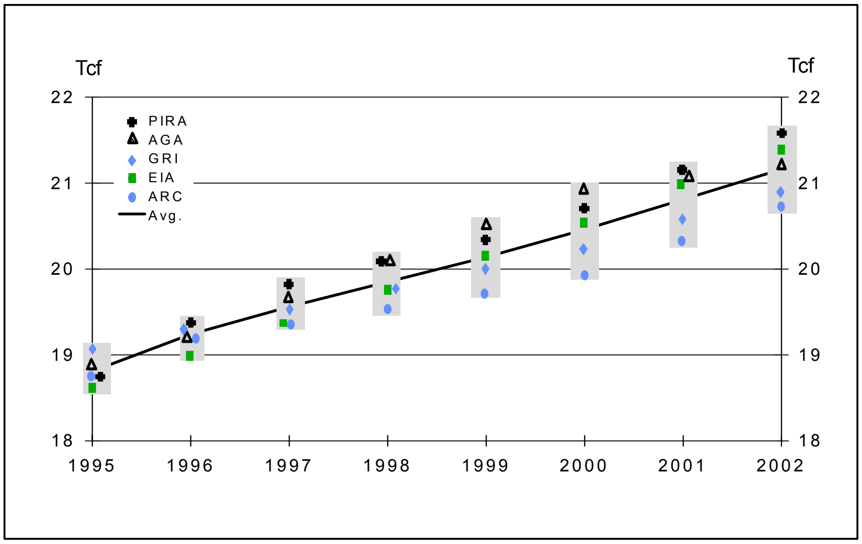
Regional Supply Outlook

Today's North American gas market is a collection of numerous regional markets with their own supply, demand, and price dynamics. Many of the major decisions made in the gas industry relate to regional gas markets, rather than to North America as a whole.

For example, gas consumers, producers, and pipelines must decide whether it will be profitable to build or contract for pipeline capacity between two gas markets. Pipeline capacity will be valuable if a large price differential exists between the two markets. Regionally disaggregated outlooks for supply and demand are valuable in helping to determine whether large price differentials will in fact continue.

However, of the organizations whose forecasts are shown in Figure 16, only PIRA

Figure 16: U.S. Gas Production Forecast



disaggregates its U.S. production forecast by supply region. The regional forecasts of U.S. production discussed below and shown on the map at the beginning of this section were developed after considering PIRA's analysis, the analysis contained in our *Gas Supply Trends 1996 - 2002* report, and further information as outlined below.

Gulf Coast

The Gulf Coast is the most important U.S. supply region, and accounted for about 63% of U.S. production in 1996. As discussed in the supply review section (page 1), Gulf drilling and production follow price trends. As prices are likely to be volatile, predicting future production from the Gulf will be difficult.

Another difficulty in predicting Gulf production is related to the Gulf's role as the swing supplier in North America. High or low gas demand may not affect Canadian exports or U.S. Rockies flows to the Midwest, since these flows are not as price sensitive, and routinely occur at levels near pipeline capacity. However, Gulf Coast production is more likely to swing with price and demand changes.

The Gulf also has the advantage that higher Gulf production will (to a certain extent) not require additional long-haul pipeline capacity, as excess capacity currently exists to Midwest and Northeast U.S. markets.

Gulf Coast Deepwater

It is possible that a fundamental change has occurred in the U.S. Gulf Coast offshore. The introduction of the Deepwater Royalty Relief Bill may completely change the economics of gas production in the deepwater Gulf. This will depend on exactly how much gas production will qualify for royalty relief and under what conditions. These details remain unclear.

There is no doubt that considerable incremental production from the deepwater Gulf is being planned. These are long term projects, which are likely to proceed irrespective of gas price changes. In total, approximately 350 Bcf/year of deepwater production is expected by 1997, 616 Bcf by 1998, and 821 Bcf by 1999. The latter number would equal 7% of current Gulf production.

Incremental deepwater production does not necessarily mean that overall Gulf production will also rise. Other Gulf production will continue to account for over 90% of total Gulf production, and has a rapid decline rate (up to 25% per year).

This rapid decline rate means that high levels of drilling are necessary to maintain production. High levels of Gulf drilling require fairly high prices. At NYMEX prices below $2/MMBtu, Gulf drilling has historically been much lower than current levels (see page 2).

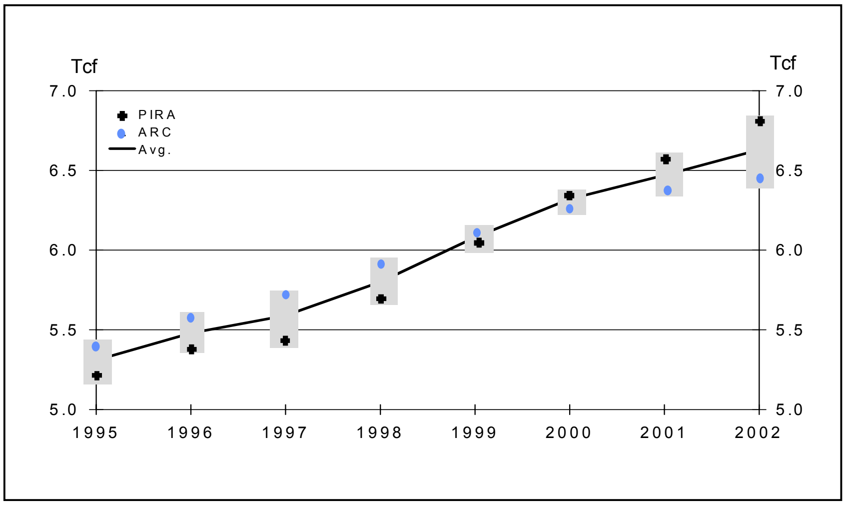
In short, the outlook for Gulf Coast production is highly uncertain, as it depends on gas prices, which are in turn influenced by many factors, including demand growth and whether pipeline expansions from western regions occur.

U.S. Rockies
The situation is totally different in the U.S. Rockies. We concur with PIRA that much higher U.S. Rockies production is likely. However, additional production in the U.S. Rockies area will require exit pipeline capacity expansions. The outlook section on Gas Flows (page 25) will discuss this further.

Midcontinent
Both PIRA and our analyses conclude that Midcontinent production will slowly decline. In recent years, production in this area has been declining steadily. Midcontinent production is expected to lose 106 Bcf of annual production between 1996-2002.

Canadian Production
Figure 17 shows the PIRA and ARC Financial forecasts of Canadian gas production. Canadian gas production has grown by an average annual rate of 7% over the past five years. The average PIRA/ARC expectation for the next six years is a much lower growth rate of 3.5%. This prediction is identical to our calculation of future Canadian production.

Figure 17: Canadian Gas Production Forecast



As with the U.S. Rockies, for any significant Canadian production growth to occur, pipeline expansions are necessary, as current exit pipeline capacity is full.

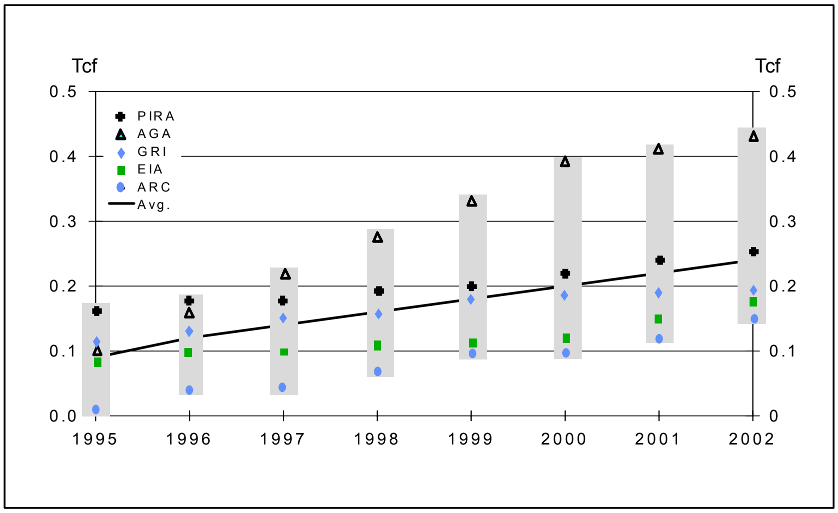
Over the outlook period, production is expected to begin at the Sable Offshore Energy Project. We expect this to result in 143 Bcf of annual gas production by 2002, distributed between U.S. and Canadian markets.

Other Supplies

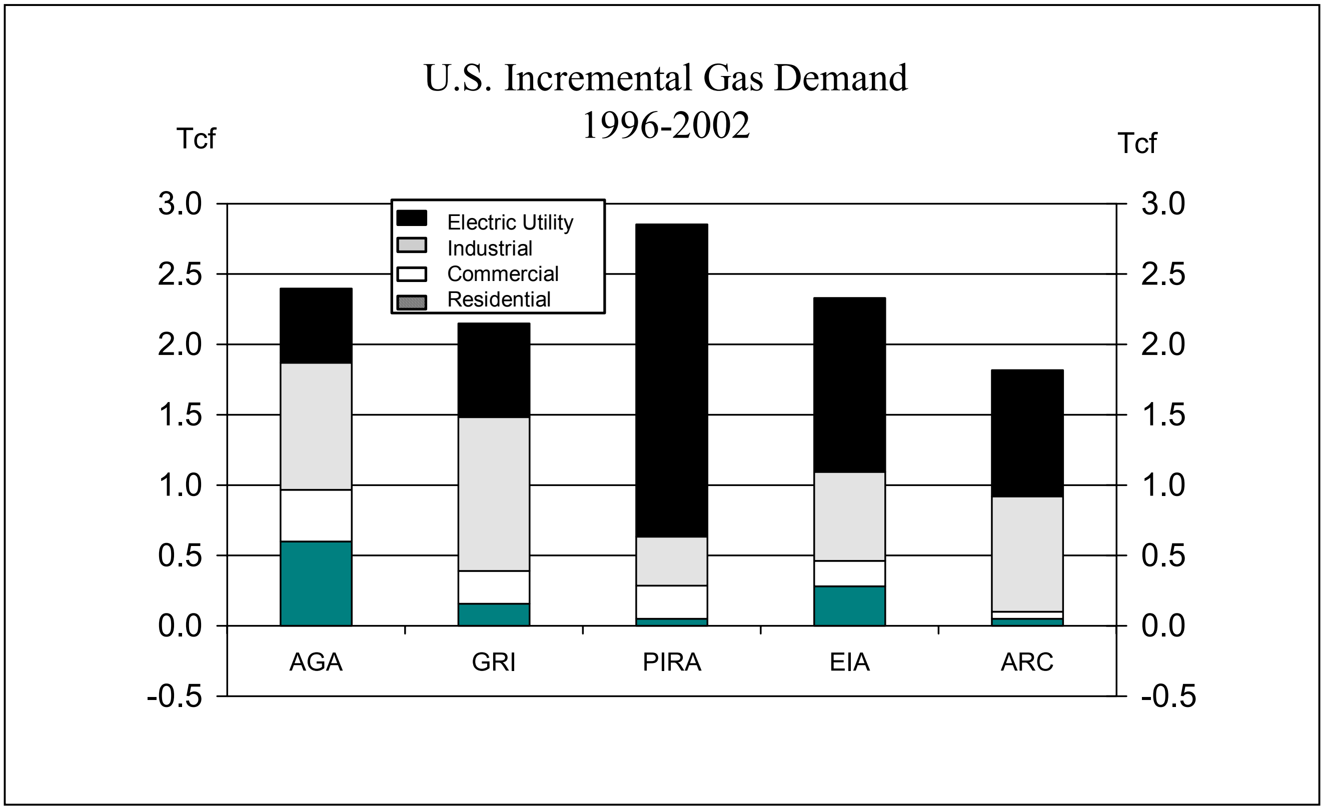
We expect other U.S. supplies not identified above (i.e., from states with minor production such as Alaska, California, Michigan, New York, etc.) will contribute 1,560 Bcf per year to North American supply (same amount as in 1996).

Figure 18 shows the forecasts of five organizations for LNG imports into the U.S. There is a wide range of values predicted, from 140 Bcf to 440 Bcf in year 2002. Our outlook assumes 245 Bcf of LNG exports to the U.S. by 2002 (this is the average of the forecasts shown in Figure 20). Higher Algerian LNG exports to the U.S. are widely expected, as renovations of Algerian gas liquefaction plants are expected to be completed later this year. These renovations had resulted in lower LNG exports to the U.S. in 1996.

Figure 18: U.S. LNG Import Forecast



Minor amounts of Mexican gas currently enter the Canada/U.S. gas market. Over the outlook period, most forecasters expect these volumes to remain minimal.



The above graphic shows various forecasts of U.S. natural gas demand by sector. This year, the forecasters are more or less in agreement: U.S. gas demand will increase by 1.8 to 2.9 Tcf by year 2002, and the bulk of demand growth will occur in the industrial and electric generation sectors. (Note: In the above graphic, PIRA's UEG sector includes NUG, whereas for the other forecasters, NUGs are included in industrial.)This consensus was not the case last year, when the effects of the ongoing restructuring of the electricity industry on natural gas demand were interpreted differently by forecasters.

The forecaster views on U.S. natural gas demand by year are presented in Figure 19. The average of the five forecasts is shown as a line. The average growth rate shown is 1.9% per year. U.S. gas demand over the past five years has averaged 3.0% per year growth.

Figure 19: U.S. Gas Demand Forecast

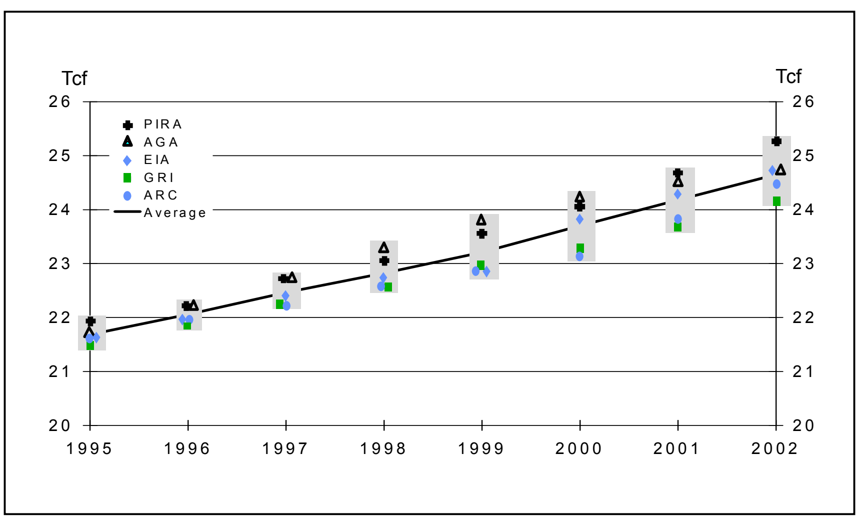
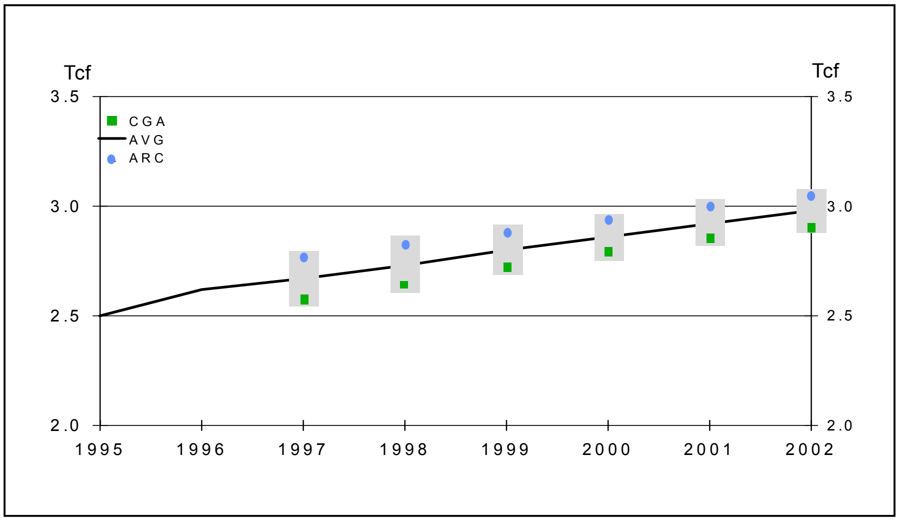


Figure 20 shows the Canadian Gas Association (CGA) and ARC Financial forecasts for Canadian natural gas demand. The average expectation is for Canadian gas demand to grow at a 2.2% average annual rate. Over the past five years, Canadian gas demand growth has averaged 4.9% per year.

Figure 20: Canadian Gas Demand Forecast

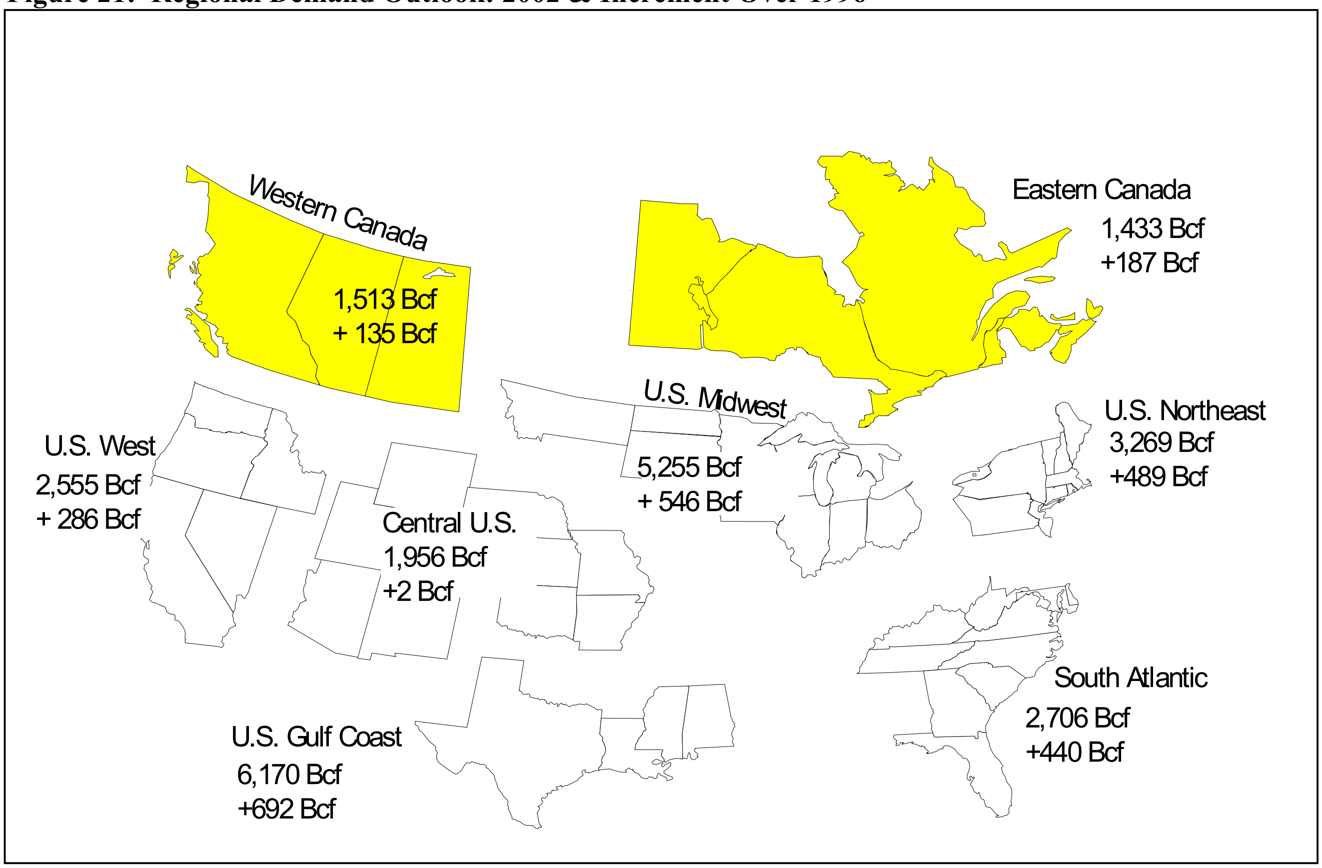


Regional Demand Outlook

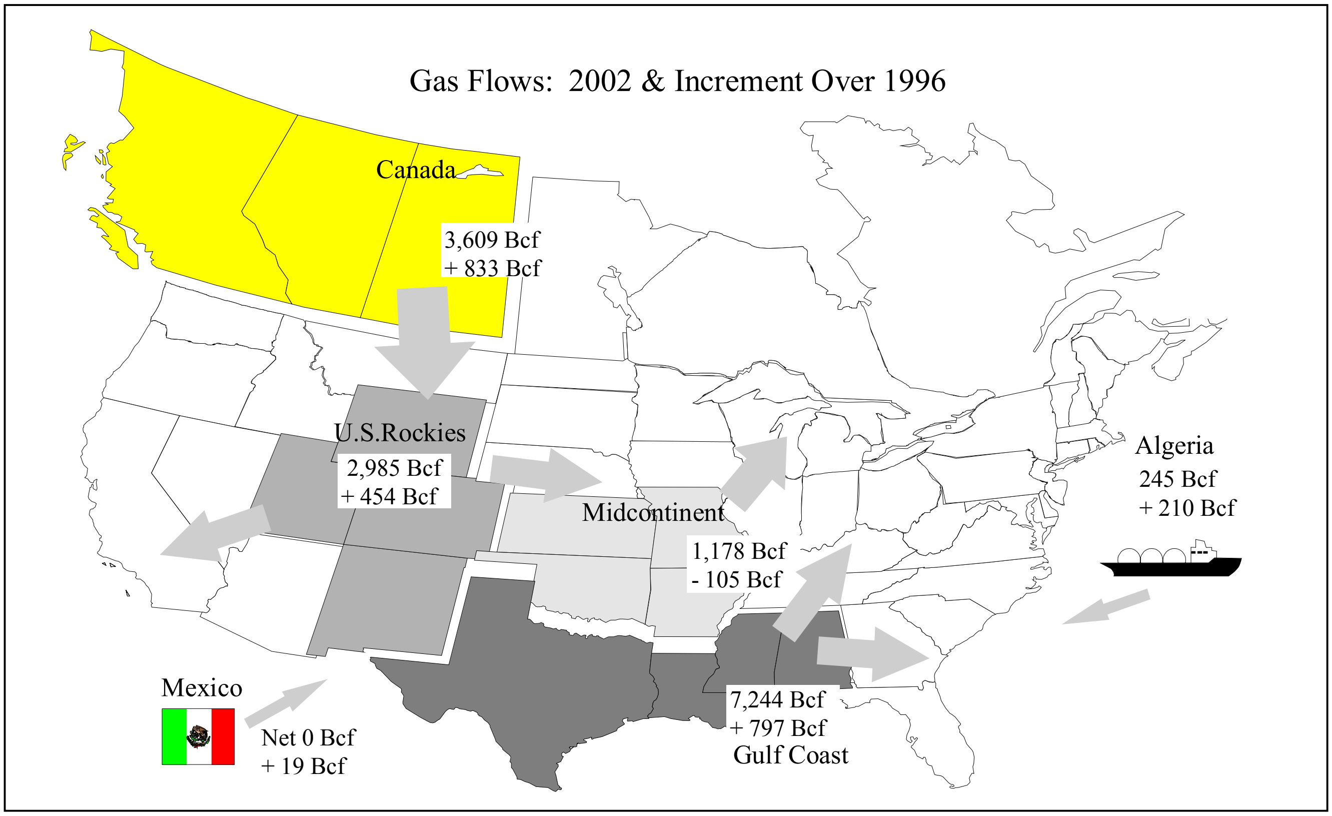
Figure 21 shows a regional gas demand outlook in map view. Estimates of future demand were determined after considering various expert forecasts for regional demand, and after considering past demand growth in each region. For further details on gas demand expectations by region, please see the Appendix.

Based on demand patterns of the past five years, most North American gas demand growth should occur in the eastern and southern U.S. (the Gulf Coast, Midwest, Northeast, and South Atlantic).

Figure 21: Regional Demand Outlook: 2002 & Increment Over 1996



Outlook to 2002
Pipeline Capacities & Gas Flows



The outlook for changes in gas flows from region to region depends on three elements: i) pipeline capacities; ii) the gas production outlook by region; and iii) gas demand outlook by region. The graphic above shows our estimate of how gas flows will change by year 2002. Table 8 illustrates how these changes were determined.

Production in 2002 was estimated by region (see page 19), as was demand by region (see page 23 and the appendix). Gas flows out of each supply region were calculated as regional production less internal demand.

Gulf Coast
Perhaps the main factor influencing Gulf Coast gas flows is the existence of excess pipeline capacity exiting the region in most periods. The Gulf Coast once produced almost 17,000 Bcf per year. As production declined (current production is less than 12,000 Bcf/yr), the region was left with excess pipeline capacity to the Midwest and other markets. Accordingly, the need for new pipeline construction to allow higher production is less pressing than in other supply regions.

As shown in Table 8, we anticipate Gulf production will increase to 13,414 Bcf, while demand will increase to 6,170 Bcf. This will result in net flows out of the Gulf increasing from 6,447 Bcf in 1996 to 7,244 Bcf in 2002, i.e., an increase of 797 Bcf.

Much of this increased outflow is expected to be required by neighbouring south Atlantic states (Maryland through Florida). Over the past five years, demand in the south Atlantic has grown by 471 Bcf, or 5% per year. Continued growth at a lower 3% per year rate would result in an additional 440 Bcf of demand in the region by 2002. Additional pipeline capacity from the Gulf to the South Atlantic will be required, such as the 245 MMcf/d Transco "Sunbelt Expansion" (from the

Table 8: North American Natural Gas Flows

	2002 Produced (Bcf)	2002 Demand (Bcf)	Net Exports 2002 (Bcf)	Net Exports 1996 (Bcf)	Difference (Bcf)	% Change
Gulf Coast	13,414	6,170	7,244	6,447	797	12.4
Midcontinent	2,376	1,198	1,178	1,283	-105	-8.2
U.S. Rockies	3,506	521	2,985	2,531	454	17.9
Canada	6,555	2,945	3,610	2,777	833	30.0

Gulf to the South Atlantic) recently approved by FERC, and expected to be in-service in November 1997.

Approximately 350 Bcf of incremental gas flows from the Gulf may target Midwest and/or Northeast gas markets.

U.S. Rockies

Higher production and net exports from the U.S. Rockies are also expected, as shown in Table 8. The incremental 454 Bcf of flows out of the U.S. Rockies will be absorbed in the U.S. West, U.S. Midwest, and U.S. Northeast.

Gas demand growth in the U.S. West has been minimal in the past five years. This has led to portions of the Transwestern and El Paso pipelines in New Mexico, which originally were built to flow gas west to California markets, being used to flow gas east to the Gulf Coast, and then on to other markets accessible from the Gulf (flow direction can be seen in Figure 22).

Several pipeline expansions are geared to increasing eastward flows from the Rockies. El Paso has received FERC approval for its "Hasavu Crossover" project (see Figure 22), which would increase San Juan-to-Texas capacity by 180 MMcf/d by second quarter 1997.

KN Interstate expects to receive FERC approval soon for its "Pony Express" project, a 255 MMcf/d conversion of an existing oil line from Wyoming to the Midwest.

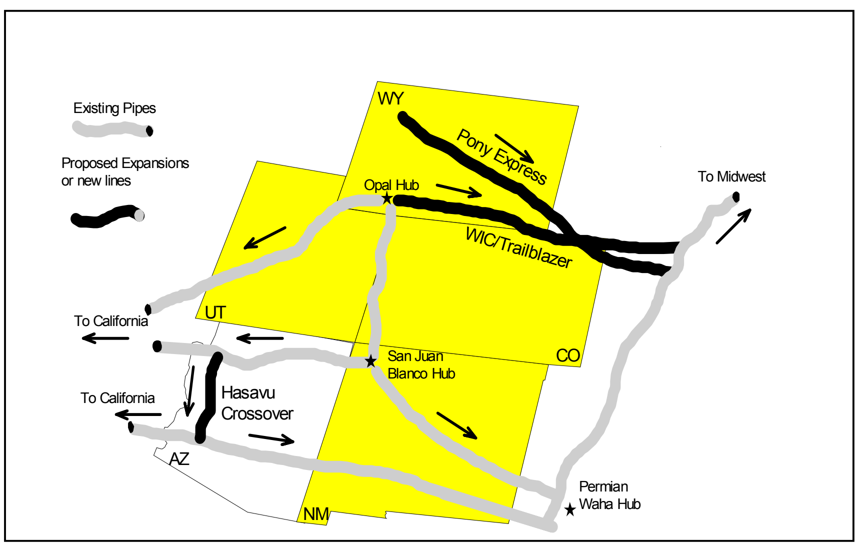
FERC has also granted preliminary approval for Wyoming Interstate and Trailblazer Pipeline expansions, which would increase capacities from the Western U.S. to the Midwest by 105 to 193 MMcf/d.

Other projects are also being proposed. Taken together, the Rockies projects previously listed could provide an additional 229 Bcf per year of exit pipeline capacity. More than this will be required, however, if the expected production and net exports are to occur. In short, the outlook for the Rockies is heavily dependent on pipeline capacity being constructed.

Canada

Our Canadian export forecast was used for Canada to U.S. gas flows. We anticipate that over the 1996-2002 period, Canadian gas exports to the U.S. West will increase by 87 Bcf; exports to the Midwest will increase by 503 Bcf; and exports to the Northeast will increase by 182 Bcf (See our export outlook section, page 32, for greater detail).

Figure 22: Proposed Rockies Pipeline Expansions



As with the U.S. Rockies, the outlook for Western Canada is heavily dependent on pipeline capacity being constructed. Some of the proposed expansions are shown in Figure 23.

Canadian gas is also expected to capture all demand growth in Eastern Canada (187 Bcf) and in Western Canada (135 Bcf).

See pages 33 and 34 for details on Canadian gas flows and pipeline capacities.

Conclusions

Higher production and net exports from the U.S. Gulf Coast are expected. Although much of the increased outflows (440 Bcf/yr) are expected to go towards satisfying market growth in the U.S. South Atlantic, some flows may target the U.S. Northeast or Midwest markets. The Gulf has existing excess pipeline capacity, but an accelerated pace of Gulf Coast drilling and production investment will be required.

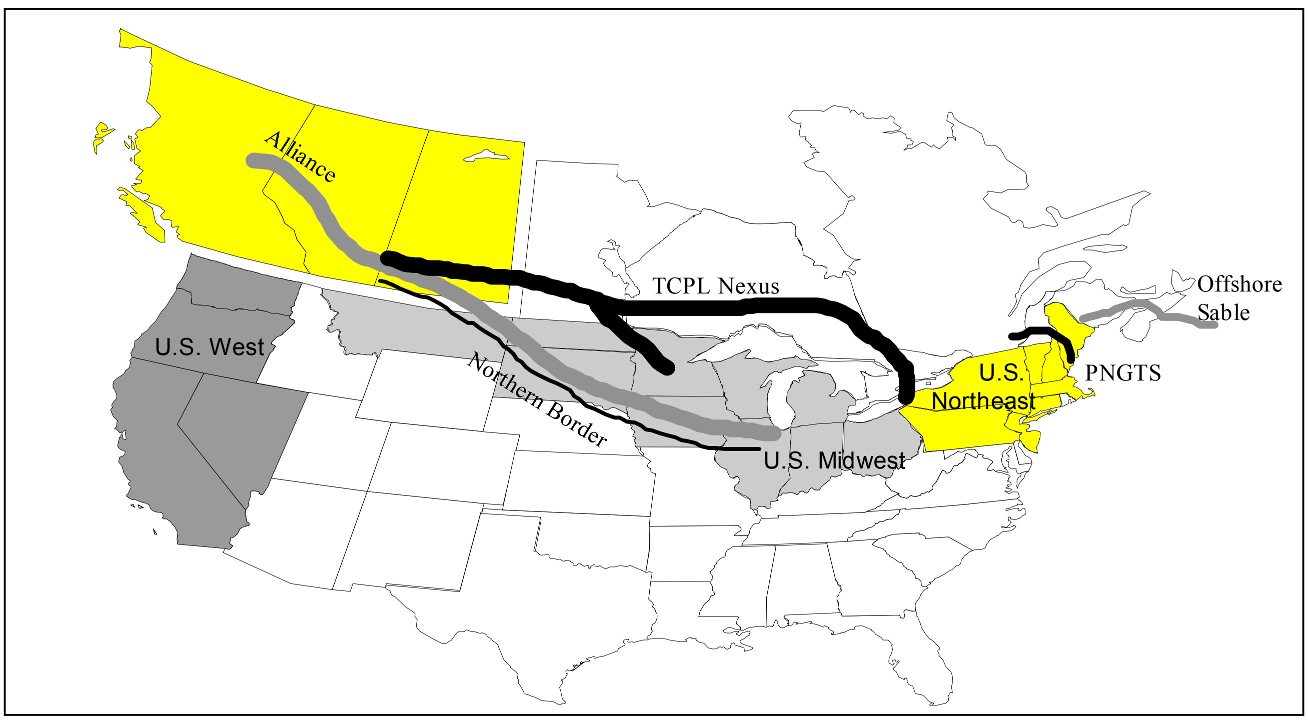
Increased outflows from the U.S. Rockies are also widely expected, and the pipeline projects which will support this incremental outflow are targeting increased sales to the Midwest market.

Finally, very large Canadian export pipeline expansions are also targeting the U.S. Midwest and Northeast markets.

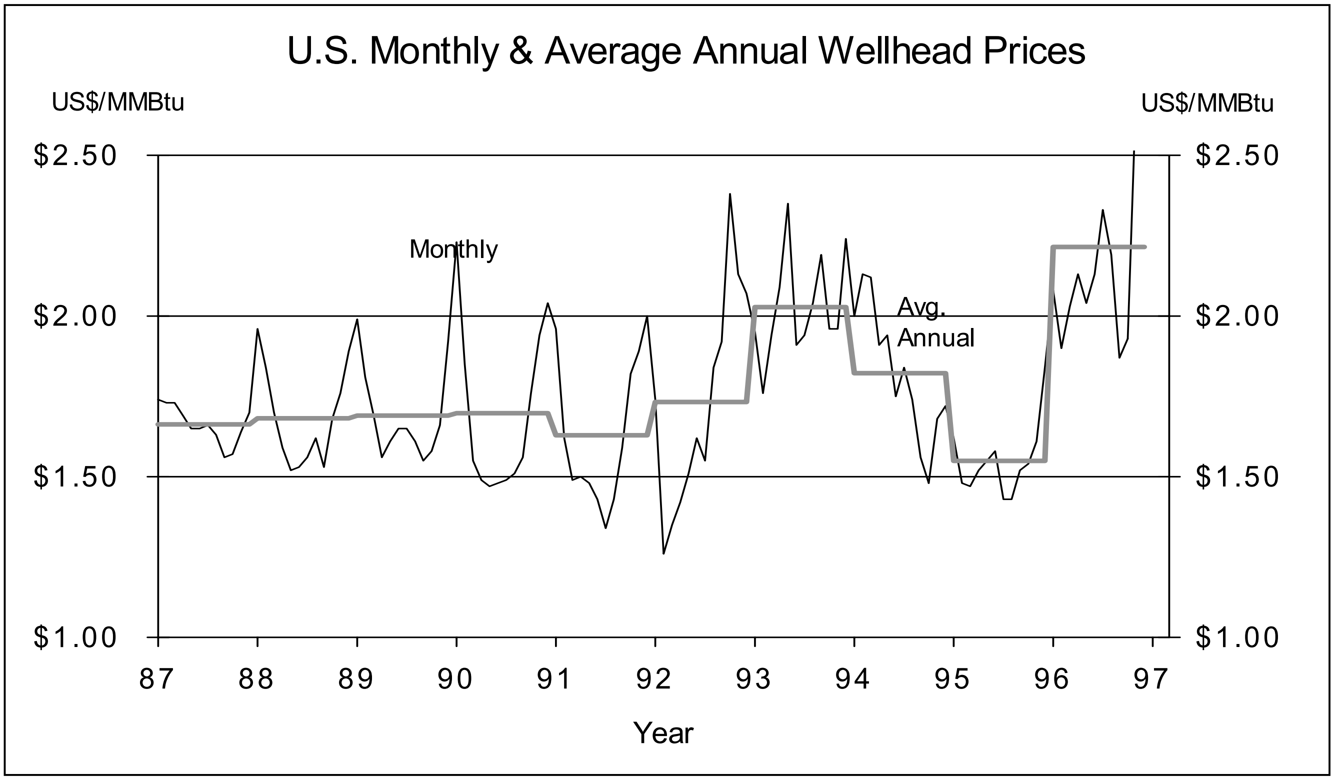
However, pipeline construction will largely determine which suppliers get incremental market growth in the U.S. Midwest and Northeast. Producers who sign long term transmission contracts with new or expanding pipelines will allow those pipelines to expand, resulting in increased sales. Once additional pipeline capacity is built, the Midwest and Northeast markets may not require all available capacity. A battle for market share in the U.S. Midwest and Northeast between U.S. Rockies, Gulf Coast, and Western Canadian supplies may result. Supplies priced lowest would get the market, and some pipeline capacity would lie idle.

Market share would be determined via gas commodity prices. Once excess pipeline capacity into a market region exists, the share of supply for each producing region in that market is mostly dependent on gas price competition, with the producers willing to accept the lowest prices capturing the market.

Figure 23: Proposed Canadian Pipeline Expansions



Outlook to 2002
Prices



Gas prices, on an average annual wellhead basis, have been extremely volatile over the past 10 years. Over the past five years, very large gas price differentials from one market to another have also developed.

U.S. Gas Prices
The graphic above shows historical monthly gas prices for the U.S. (average wellhead) since 1987, as well as the annual average of monthly prices.

On a monthly basis, gas prices have been extremely volatile over the full 1987-1997 period.

On an average annual basis, gas prices have been less volatile.

Stable Low U.S. Prices To 1992
From 1987-1992, annual gas prices varied over a narrow range, from US$1.63 to $1.73/MMBtu. This was a fairly stable period, which followed the big drop in prices in 1986 (deregulation of wellhead purchasing and pricing in Canada and the U.S. led to U.S. wellhead prices falling from $2.51/MMBtu in 1985 to $1.67 by 1987).

This period of stable, low prices was due to the existence of excess proved reserves and productive capacity, which had been built up during the regulated era. In Canada, this was due to export regulation requiring large reserves, and in the U.S., this was due to incentive pricing and the Section 29 tax credit on coalbed methane and tight gas. Sufficient supplies were being brought on quickly enough to match demand growth and prevent prices from rising.

U.S. Price Volatility, 1993-1997
From 1993 to the present, annual gas prices have been in a different era, with much more volatility. Average annual gas prices have ranged from $1.55 in 1995 to $2.22 in 1996 (a range of $0.67/MMBtu).

We interpret this as a period when gas demand growth has overtaken the ability of supply areas to quickly bring on added supplies -- the large reserves and production capacity surpluses left over from the regulated era are now exhausted. It is a period of tighter balances between supply and demand.

Due to the lag time between higher demand and producer ability to bring on more production in response, prices show volatility on the upside.

Volatility on the downside occurs when demand falls, since producers are reluctant to shut in gas production capacity and slow to reduce drilling programs.

Given the above view of gas pricing dynamics, continued high gas price volatility is expected.

Expert U.S. Gas Price Forecasts

Figure 24 shows various expert forecasts of U.S. wellhead prices, all in constant dollars. Although these forecasts were the most recent we could obtain, they were done at different times during 1996 and 1997. This is thought to be one of the main reasons for the variance in the forecasts -- recent price changes seem to immediately alter long term price expectations. The average of these forecasts shows no growth in gas prices between 1996-2002. The range of prices for 2002 is $1.70 to $2.25/MMBtu.

Given the volatility factors inherent in today's gas markets, even this range of prices may not capture the actual range of future prices.

Canadian Gas Prices

It is important to define exactly what kind of gas prices are being discussed. There are two kinds of Canadian gas prices: i) the price in the Canadian market (e.g., an AECO C price), and ii) the price received for Canadian gas sold and priced in other markets.

To make these two kinds of prices comparable, it is necessary to subtract pipeline transportation charges from the gas price received in downstream markets. This results in an "Alberta netback" price to producers, which can then be compared to prices for gas sold in Alberta.

About half of Canadian gas sales occur in Canadian supply areas and are priced there, while the remainder occur in downstream U.S. markets. Due to exit pipeline bottlenecks, gas backs up in Alberta and other Canadian supply regions. This depresses prices for all domestic gas sales. For this reason, most gas sold in U.S. markets receives a higher netback than gas sold into the domestic market.

Figure 25 shows past Canadian gas prices at Empress, Alberta

Figure 24: U.S. Wellhead Gas Price Forecasts

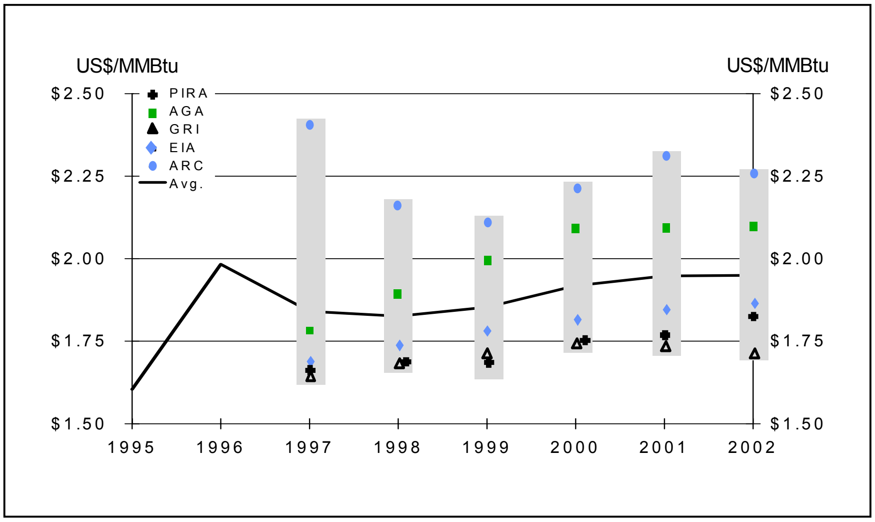
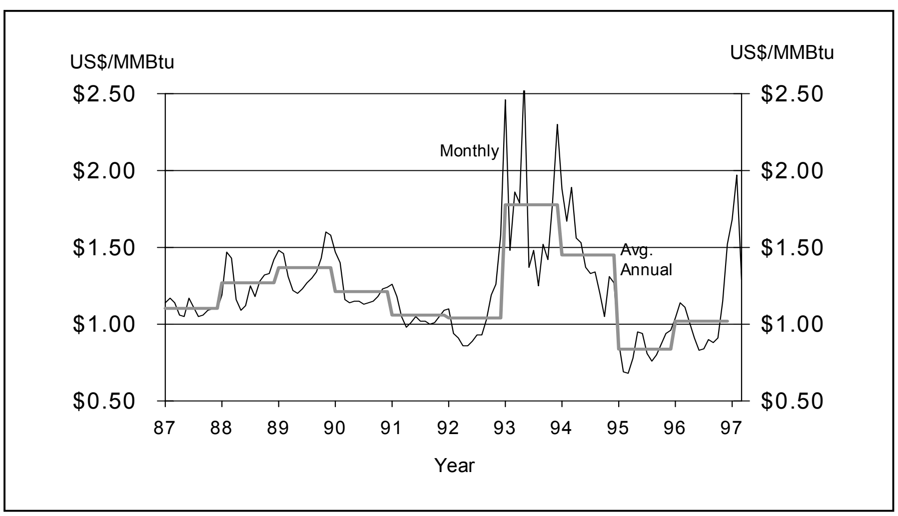


Figure 25: Canadian Monthly & Average Annual Prices



Sources: Enerdata, Friedenberg

(early years) and AECO C (1993-1997). Canadian gas prices have been even more volatile than U.S. prices. On an average annual basis, Canadian gas prices have ranged from US$0.83 to $1.78/MMBtu, a range of $0.95/MMBtu.

Stable Low Canadian Prices To 1992

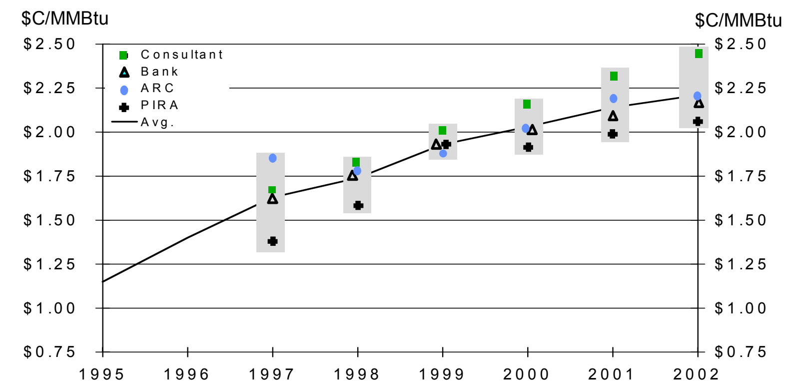
As in the U.S., the low price period from 1987 to 1992 mainly reflected deregulation, which allowed buyers to negotiate directly with suppliers for gas. Prices were kept low over this period due to the existence of ample reserves and (to a lesser extent) productive capacity left over from the regulated era.

Canadian Price Volatility, 1993-1997

Prices skyrocketed in 1993 due to two factors - rising U.S. prices, and large pipeline capacity additions in late 1992 and 1993 (Northern Border, Iroquois, PGT), which briefly allowed demand available to Canadian suppliers to equal productive capacity, reconnect-ing Alberta gas markets to U.S. markets. For a brief period, Canadian gas prices tracked U.S. prices.

By 1995, sufficient Canadian production had been developed for supply to once again overshoot available demand (local demand plus exit pipeline capacity). With gas-on-gas competition, Canadian prices dropped to about half of 1993 levels.

Figure 26: Canadian Plant Gate Gas Price Forecasts



Sources: Dobson Resource Management Ltd, PIRA.

Expert Canadian Gas Price Forecasts

Figure 26 shows the Canadian price forecasts of several experts. These are forecasts of average Alberta plant gate prices, in nominal dollars Canadian per MMBtu.

In contrast to the U.S. gas price forecasts, real growth in Canadian gas prices is widely predicted. The main reason for this view is that current Canadian gas prices are depressed relative to prices in U.S. markets, due to exit pipeline capacity limitations. Most forecasters anticipate that Canadian gas markets will, through the addition of pipeline capacity, reconnect with U.S. market prices to some extent. This will cause Canadian prices to rise, even if U.S. prices stay flat or fall marginally.

Regional Price Implications

The Gulf Coast is the marginal gas supplier to North American markets, and as such, has the most influence on gas prices in North America. Gas prices in the Gulf Coast, and in those markets which need Gulf Coast gas for their marginal supplies (South Atlantic, Midwest, Northeast) are the highest on the continent.

The Gulf Coast outlook will thus drive the overall North American gas price outlook.

U.S. West

Western U.S. prices are determined by the Rockies, the marginal supplier to the region. Rockies prices had been much lower than Gulf Coast prices, until reconnecting in 1996. The large gas reserves relative to production in the region argue for lower average prices for the Rockies (and thus, for the Western U.S.) than the Gulf.

U.S. Midwest

Midwest prices are determined by Gulf Coast prices. Currently, about 2,700 MMcf/d on average flows to the Midwest from the Gulf. Several large pipeline expansions from the Rockies and Western Canada to the Midwest are planned. However, the total incremental gas moved from these regions to the Midwest is unlikely to completely back out Gulf supplies. In general, Midwest pricing should continue to be driven by Gulf Coast markets.

U.S. Northeast
Northeast prices are also driven by Gulf Coast prices. Approximately 800 MMcf/d of incremental capacity from Canada to the Northeast is planned. However, this will not eliminate dependence by the Northeast on Gulf supplies, and so pricing in the region should continue to be driven by the Gulf.

Eastern Canada
Due to the fact that the majority of pipeline capacity from Western Canada to Eastern Canada is held by consuming interests, the bulk of Eastern Canadian supply is likely to continue to be purchased upstream. Eastern prices will tend to be equal to Western Canadian field prices plus the regulated cost of transporting the gas east.

Conclusions
The outlook for natural gas prices in each region will affect the outlook for revenues from gas sales to each region.

Overall, forecasters surveyed expect little growth in U.S. prices. Due to better linkages being developed between U.S. and Canadian markets, Canadian prices are expected to rise.

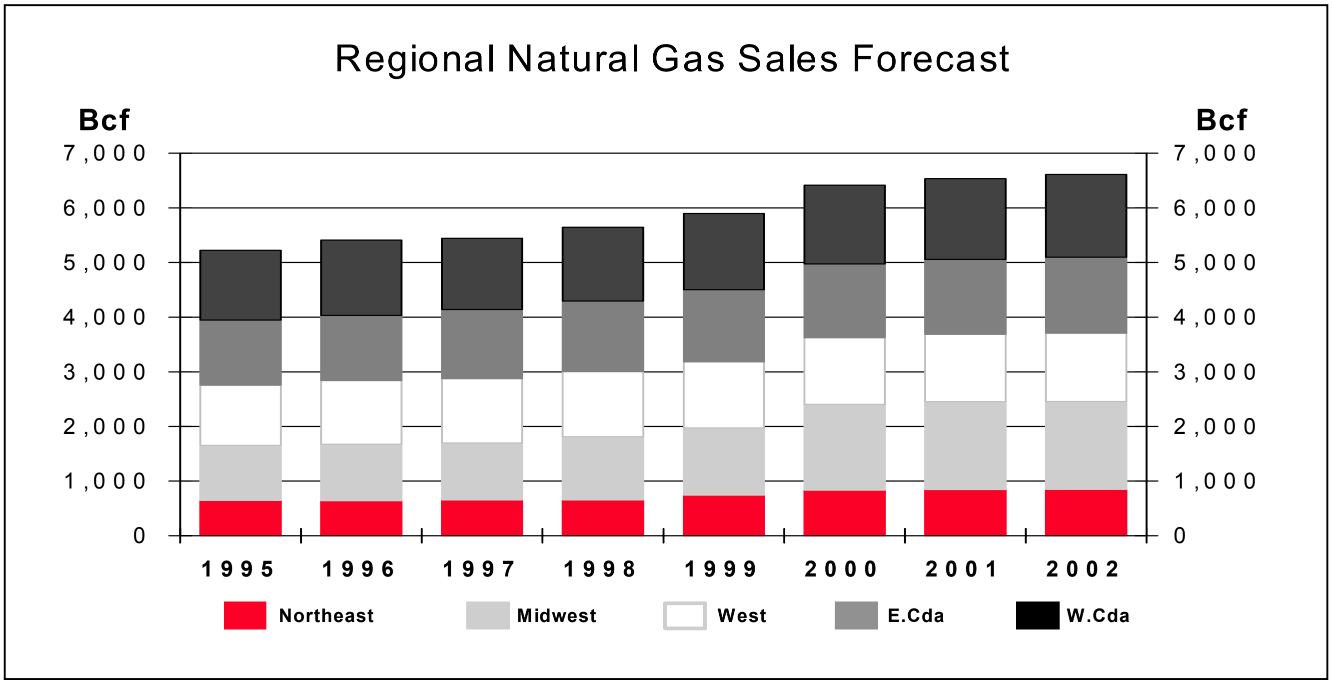
Given past patterns, year-to-year and month-to-month prices are expected to continue to be highly volatile and unpredictable.

We expect Canadian gas sales to U.S. Midwest and Northeast regions to continue to receive higher netbacks than sales to the U.S. West region. The reason for this view is our anticipation that U.S. Midwest and Northeast pricing will continue to be driven by Gulf Coast prices, and the Gulf is seen as a high cost supplier.

U.S. West prices are expected to be driven by its marginal suppliers, those being the San Juan and U.S. Rockies producers. Rockies production is thought to be lower cost. Rockies production is also periodically restricted by exit pipeline capacity, causing low local gas prices.

Prices for sales to Canadian markets are likely to be mainly driven by prices in local Western Canadian spot markets. These prices are widely expected to rise towards U.S. market prices as new pipelines are developed. However, prices may fall if supply development once again overshoots exit pipeline capacity. Further, prices are expected to remain lower than U.S. prices, due to the low-cost nature of Canadian gas supplies.

Outlook to 2002
Canadian Export & Domestic Sales Forecast



The graphic above shows our forecast of Canadian gas sales to various markets. We anticipate Canadian sales will grow from 5.4 Tcf to 6.6 Tcf by 2002. Incremental sales will be divided between Canadian and export markets. The biggest individual increase will occur in the year 2000, when substantial additional export capacity to the Midwest and Northeast U.S. is expected to be available.

A substantial increase in export pipeline capacity has occurred within the last five years, all of which has now been effectively fully utilized. Since 1985, the pattern in the Canadian industry has been that production and sales increase to fill the available pipeline capacity. At that point price and netback differentials among consuming markets signal the need for expanded capacity. These are the circumstances facing the industry today.

The primary determinant of Canadian gas sales over the next five years will be the availability of pipeline capacity. Pipelines linking Canadian supplies to U.S. and Eastern Canadian markets operated in almost every case at load factors in excess of 90% during 1996.

Our analytical method for estimating Canadian gas sales to export markets is mainly based on pipeline capacity. We obtain existing pipeline capacity figures for each export market from pipeline companies. We then estimate pipeline capacity additions over the 1996-2002 period, based on an evaluation of the expansion plans of pipeline companies. This yields a forecast of pipeline capacity to each export region, as shown in Table 9.

Capacity additions can be grouped into three categories: i) those most likely to be built, which have received regulatory approval; ii) the next most probable, which are currently under regulatory review; and iii) remaining projects, which appear to have market support, but have not yet applied to regulators and for which there may be alternative competing projects.

Table 9: Estimated Pipeline Capacity (MMcf/d)

	1996	1997		1998		1999		2000 - 2002	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
Huntingdon/Westcoast:									
Northwest Pipeline	1,045		1,045		1,045		1,045		1,045
User-dedicated	380		380		380		380		380
Kingsgate	2,518		2,518		2,518		2,518		2,518
Total U.S. West	3,943		3,943		3,943		3,943		3,943
Monchy	1,500		1,500	690	2,190		2,190		2,190
Emerson	1,139	39	1,178		1,178		1,178		1,178
New Project(s)						1,200	1,200		1,200
Miscellaneous	230		230		230		230		230
Total U.S. Midwest	2,869	39	2,908	690	3,598	1,200	4,798		4,798
Iroquois	818	25	843		843		843		843
Niagara Falls	827	39	866		866		866		866
St. Stephen (Sable) 1						478	478		478
E. Hereford (PNGTS)				152	152	58	210		210
Miscellaneous	233	48	244		244		244		244
Total U.S. Northeast	1,878	112	1,990	152	2,142	536	2,678		2,678
Total Capacity (Export)	**8,690**	**151**	**8,841**	**842**	**9,683**	**1,736**	**11,419**		**11,419**

Notes: Year-end MMcf/d capacity represents approximate contracted daily volumes that could be delivered on the last day of the year. Annual incremental capacity is usually completed at the start of the gas contract year (November 1). Excludes Winter Firm and Short-Haul Service to the International Border. 1 - Competing projects proposed. Total capacity shown. Part of this will be used for domestic markets.

Generally, we assume future pipeline capacity additions will occur if an application has been made to regulators (usually the National Energy Board or the Federal Energy Regulatory Commission).

We then calculate exports to each region, taking into consideration various factors, including: past exports across each border point, and the load factor at which each pipeline border crossing has been used; the demand outlook in the relevant export market; alternative supply basins (to Canadian supplies) in the export market; production outlook for these alternative supply basins; natural gas prices and price differentials between Canadian basins, the export market, and alternative supply basins; and other factors.

Our analytical method has worked well over the past seven years in forecasting exports. Most export pipeline capacity additions have had long lead times, and applications to regulators were made years before the capacity was built. This allowed us to predict capacity, and exports.

Typically, our forecasts of exports have been slightly low. There are two reasons for this: some pipeline expansions have occurred on short notice, and were not foreseen by us; and existing pipeline capacities were used at higher load factors than we predicted.

For Canadian pipelines serving Canadian markets, the time period between a regulatory application and construction of the capacity is not as long as for export pipelines. Also, Canadian supplies have typically captured essentially all of the Canadian market. For these reasons, we have not attempted to forecast pipeline capacity from Canadian supply regions to Canadian markets. Instead, we have assumed that Canadian gas sales to Canadian markets will be equal to forecast Canadian demand. We use an average of two expert forecasts for our Canadian demand outlook (see page 24 and the Appendix for details).

Table 10: Volume Forecast By Major Export Point & Market Region (Bcf)

	1996	1997	1998	1999	2000	2001	2002
- Huntingdon	368	369	374	380	385	390	395
- Kingsgate	795	809	818	827	836	846	855
Total U.S. West	1,163	1,178	1,192	1,207	1,221	1,236	1,250
- Monchy	548	548	568	687	687	687	695
- Emerson	421	430	421	396	396	396	396
- New Project(s)	0	0	0	61	350	377	381
- Other	63	63	63	63	63	63	63
Total U.S. Midwest	1,032	1,041	1,052	1,207	1,496	1,523	1,535
- Niagara	269	281	278	281	275	284	284
- Iroquois	283	289	289	289	283	283	286
- PNGTS	0	0	8	65	67	68	69
- Sable	0	0	0	22	95	99	102
- Other	90	97	85	84	80	81	82
Total U.S. Northeast	642	668	660	741	800	816	824
Total Exports	2,837	2,887	2,904	3,155	3,518	3,574	3,609
E.Cda	1,203	1,266	1,294	1,327	1,387	1,411	1,433
W.Cda	1,378	1,303	1,349	1,395	1,441	1,477	1,513
Cdn Production	5,401	5,457	5,547	5,877	6,345	6,462	6,555

Capacity Additions

For 1997, 118 MMcf/d of capacity to serve domestic markets is expected to be added by TCPL. Through the forecast period we expect additional construction will allow Canadian demand to be satisfied by Canadian production.

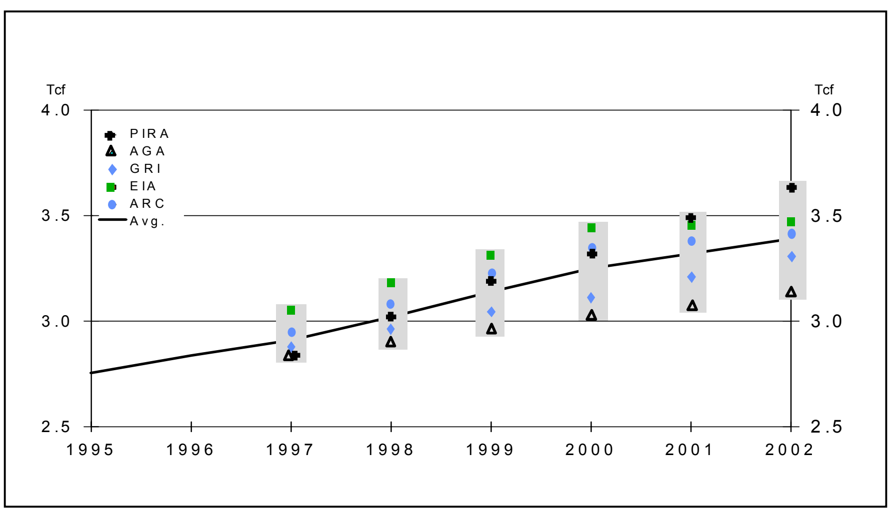
Foothills/Northern Border is preparing to bring on 690 MMcf/d of new capacity in 1998 to serve the U.S. Midwest, while Portland NGTS is expected to add capacity of 210 MMcf/d to the U.S. Northeast by 1999. The sales forecast also anticipates that by 1999 an additional 1,200 MMcf/d of capacity will be serving the U.S. Midwest. At present, TCPL (the NEXUS project) and the Alliance Pipeline group are developing plans to serve this market.

In addition, our sales forecast anticipates that Sable Island gas will reach the U.S. Northeast by 1999.

Our assumptions about export pipeline capacity are shown in Table 9. Together with our assumptions about export load factors, this is used to generate our export forecast, which is shown in Table 10. We expect total natural gas exports to the U.S. to reach 3.6 Tcf by year 2002. Combined with domestic sales volumes, total Canadian production should reach 6.6 Tcf by 2002.

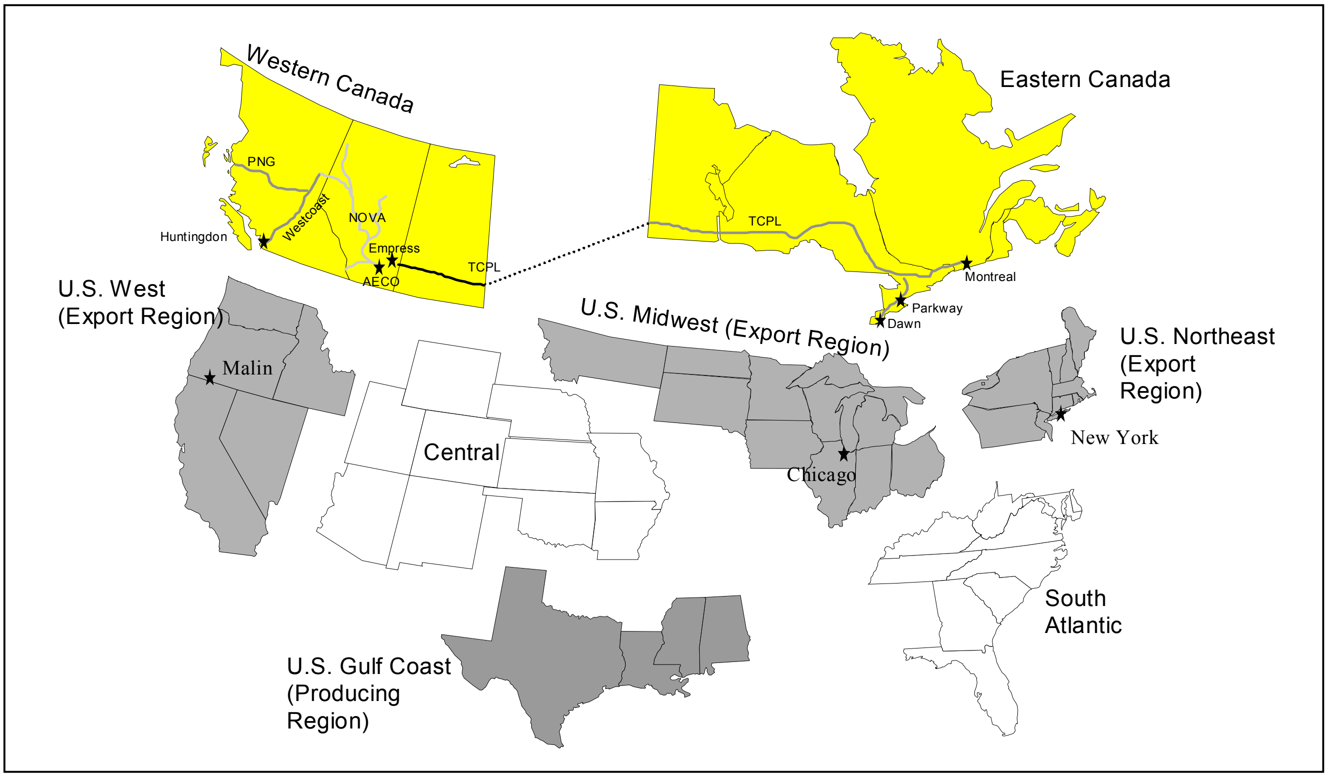
Our forecast of exports is comparable to forecasts made by other organizations. A sampling of such forecasts is shown in Figure 27. The average of the forecasts shown expects 3.4 Tcf of Canadian exports to the U.S. by 2002. Our forecast for exports is at the high end of the range. This is not surprising, given that many of the expert forecasts were prepared some time ago, and may not have considered some of the newer export pipeline expansion proposals.

Figure 27: Canadian Gas Export Forecasts



This page intentionally left blank

Appendix A:
Regional Market Analysis



This year, we evaluated six regional natural gas markets: the three U.S. export markets (West, Midwest, Northeast) which we traditionally analyze, as well as Western and Eastern Canada, and the U.S. Gulf Coast.

The decision to include Canadian gas markets in this publication results from the merging of our *Canadian Natural Gas Overview* (which dealt with domestic markets) and *Canadian Gas Export* (which dealt with export markets) publications.

Inclusion of the Gulf Coast recognizes that this is the largest single regional gas market in North America (total consumption of 5,560 Bcf in 1996 -- 25% of U.S. demand), and the market which determines gas prices for the U.S. Midwest and Northeast markets.

A two-page review and outlook for supply, demand, and other statistics is provided for each regional market.

Canadian Gas Statistics

Canadian gas market statistics are not exactly comparable to those we show for the three U.S. export markets. In Canada, producer consumption is excluded in supply or demand statistics. Pipeline quality gas supply and demand is net of upstream producer use, and is termed “marketable gas”. The approximate U.S. equivalent, “dry gas”, includes such producer consumption.

Statistics Canada, the source of Canadian gas demand data, includes gas used in electric generation in the industrial sector. The “system losses” sector identified in the following snapshots includes the utility’s own use, pipeline transportation losses (including fuel), unaccounted for gas, etc.

1996 Review

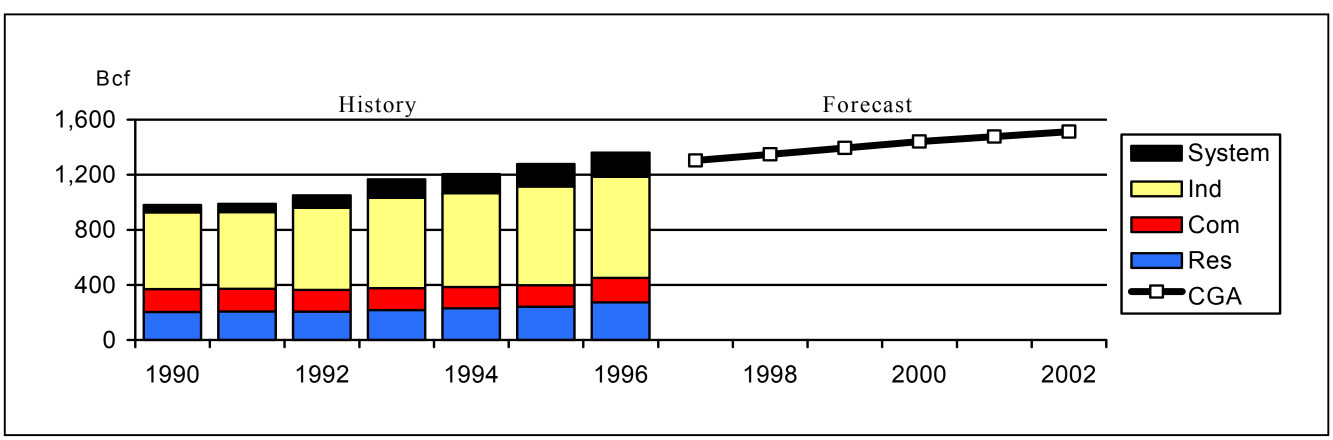
Natural gas sales in Western Canada were very strong in 1996, increasing 8% as shown in the table above. Alberta accounted for 61% of demand, British Columbia 21%, and Saskatchewan 18%. Western Canada is the largest market for Canadian gas sales. Due to higher volumes and prices, revenues from sales to this market increased 30% for 1996.

The residential and commercial sectors accounted for most (65%) of the demand increase. Residential and commercial demand increased in all three provinces. The high (13%) rate of growth was due to very cold weather in 1996 and, to a lesser extent, growth in the customer base due to population growth.

The most important sector for gas demand is the industrial sector, as shown in Figure A-1 below. Industrial demand growth was lower (2.2%), and differed considerably from one province to the other. Alberta recorded the highest rate of industrial gas demand growth, with an increase of 6.6%, while industrial gas demand remained stable in Saskatchewan and fell by 10% in British Columbia.

Strong Alberta industrial gas demand growth reflects stronger economic growth (3.2%), in Alberta, as well as a different industrial mix. Alberta is dominated by petrochemicals and refining, while British Columbia is dominated by pulp and paper. The sharp decline in industrial

Figure A-1: Western Canada Gas Consumption



sales in British Columbia reflects limited use by BC Hydro of its Burrard gas-fired electric plant, given the significant improvement in water conditions on the West Coast in 1996. British Columbia industrial sales were also driven down by temporary shutdowns in the pulp and paper industry, due to a significant decline in pulp and paper prices in 1996.

Western Canadian Gas Prices

Average prices paid by Western Canadian customers for natural gas are not easily calculated, as many sales are confidential and not captured in statistics released by regulatory agencies.

For discussion purposes, what is shown in Table A-1 is the netback from a spot month sale at AECO C in Alberta.

To calculate plant gate producer netbacks from AECO prices, the applicable pipeline transportation rates were deducted, assuming 100% load factors. Revenues were then calculated based on these netbacks.

Outlook

Figure A-1 also shows the outlook for Western Canadian gas demand from the Canadian Gas Association (CGA). For the 1997-2002 period, the CGA forecast implies an average annual growth rate of 1.6%, compared to a historical annual average growth rate of 6.9% over the past five years. Western Canadian sales are expected to increase by a total of 135 Bcf over this period. Western Canadian supply is expected to capture all of this growth. (Note: CGA's forecast assumed 1,255 Bcf of Western Canadian gas demand in 1996 [actual demand was 1,378 Bcf]. Based on the lower 1996 number, the 1996-2002 annual growth rate would have been 3.2%)

CGA forecasts an annual average growth rate for the industrial sector of 4.3%. Most of this growth will occur in Alberta.

The growth of industrial sales in Alberta will result from major new in-situ and mining oilsands plants; new power generation; and petrochemicals expansions.

Petrochemical (ethylene, polyethylene) expansions are expected for Alberta plants at Fort Saskatchewan, Joffre, Prentiss, and Edmonton.

The driving force for the British Columbia industrial sector will be power generation, as major cogeneration projects are planned over the forecast period. These projects account for most of the incremental industrial gas demand expected in British Columbia over the 1996 to 2002 period.

In Saskatchewan, industrial demand growth of approximately 20 Bcf is anticipated. Most of the increase is expected from the expansion of enhanced oil recovery. New sales are also expected to satisfy additional power requirements to meet higher peak load demands in the province.

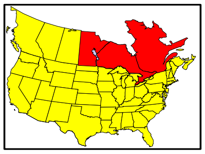
New demand in the Western Canadian residential and commercial sectors is expected to occur mainly in British Columbia, with an annual growth rate of 2.0 to 2.5% over the period. This is due to population migration and continued customer additions on Vancouver Island. In Alberta and Saskatchewan, residential demand is expected to increase marginally over the period, due to efficiency improvements offsetting growth in number of customers.

Due to the expected "reconnecting" of Western Canadian gas markets with U.S. markets (due to pipeline capacity expansions), prices for gas in Western Canada are expected to increase substantially over the outlook period. As shown in our section on prices (page 28), average annual Western Canadian gas prices are expected to rise to CDN$2.12/MMBtu by 2002.

The price rise (if it occurs) and volume increase will drive plant gate revenues to producers much higher as well.

Table A-2: Eastern Canada

A Statistical Snapshot



Manitoba
Ontario
Quebec

	1996	1995	% Change
Canadian Sales to Eastern Canada (Bcf)	1,203	1,196	0.5
LDC WACOG @ Empress ($US/MMBtu)	$1.18	$1.27	-7.3
AECO C Spot Price ($US/MMBtu)	$1.02	$0.84	22.0
Average Plant Gate Netback ($US/MMBtu)	$1.08	$1.18	-8.5
Revenue @ Plantgate (Million$Cdn)	$1,994	$2,120	-6.0
Gas Consumption in Eastern Canada (Bcf)	1,246	1,220	2.1
Residential	345	318	8.2
Commercial	265	252	5.2
Industrial	576	561	2.6
System losses, etc.	60.6	88.5	-31.5
Market share of Canadian gas in region, %	96.6	98.1	-1.6

1996 Review

Sales of Canadian gas to Eastern Canadian markets were flat as compared to 1995, despite a 2% increase (26 Bcf) in Eastern Canadian gas demand. Most of the additional demand was satisfied via higher imports of gas from the U.S.

Ontario accounted for 74% of demand, Quebec 18%, and Manitoba 8%. Eastern Canada is the second largest market for Canadian gas, and has grown steadily since 1990, as shown in Figure A-2. The industrial sector is about the same size as the residential and commercial sectors combined.

Western Canadian producers capture almost all of this market. There is a small amount of Ontario production (roughly 16 Bcf/year) and imports from

In 1996, the residential and commercial sectors accounted for most (73%) of the demand increase.

Eastern Canadian Gas Prices

We do not have the same detail on domestic gas sales as we have on export sales. The prices paid for Canadian gas by the Eastern Canadian market are also difficult to quantify due to complex buying practices in the Eastern Canadian market.

Firstly, there is no significant Eastern Canadian spot gas market *per se*, where sizeable gas volumes are traded. Parkway and Dawn, the largest Eastern Canadian spot gas markets, commonly trade less than 100 MMcf/d between them.

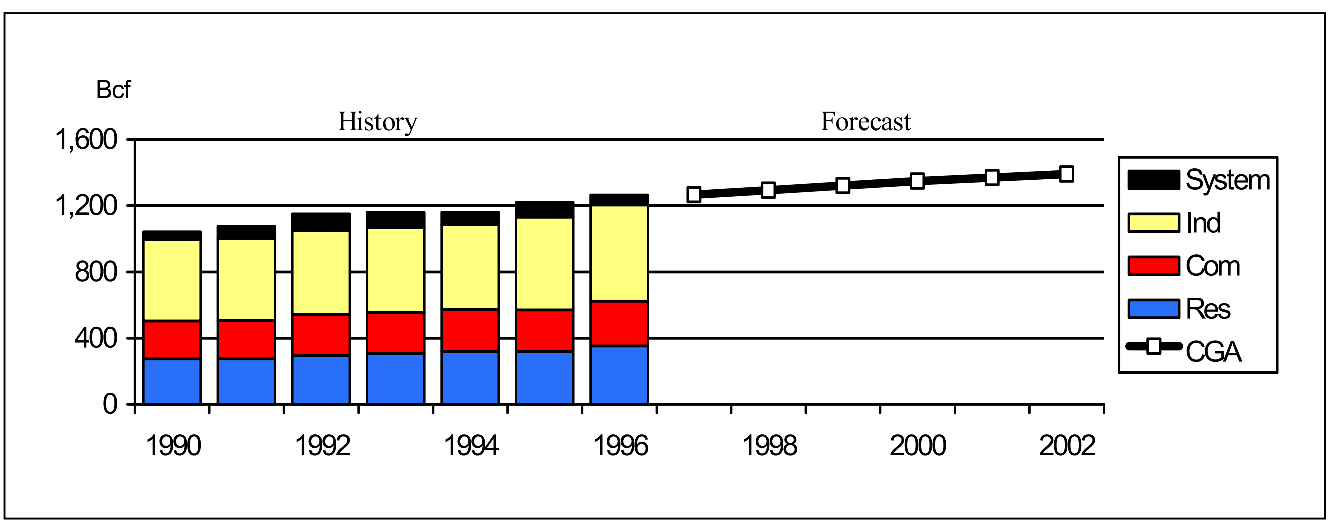
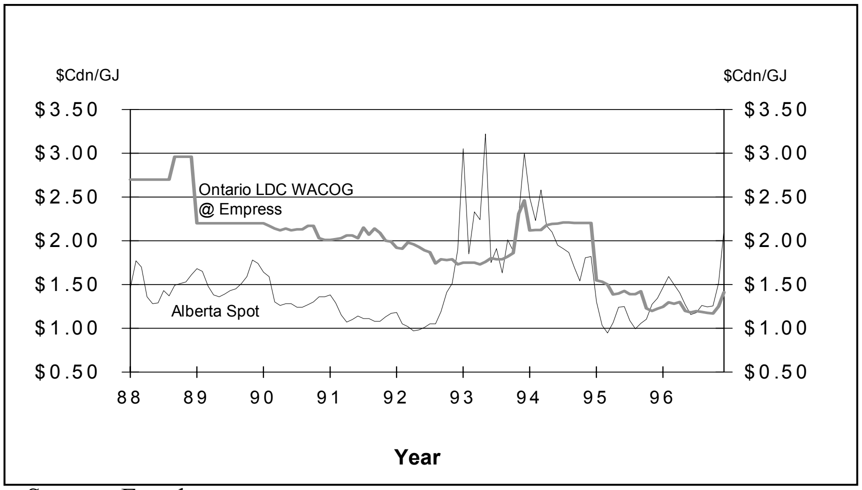


Figure A-3: Ontario LDC WACOG v. Alberta Spot Price



Source: Enerdata

Most gas sold to Eastern Canadian customers is sold at Empress, Alberta, on the Alberta/ Saskatchewan border, (see map at front of Appendix), and then moved by the customer to Eastern Canada on TCPL.

Buy/Sells

Most Eastern Canadian gas purchases go through Eastern Canadian Local Distribution Companies (LDCs). In a "buy/sell" transaction, the first purchase of gas is a "direct purchase" between an end-user/buyer and (usually) an Alberta seller. This gas is then resold to the Eastern Canadian LDC *in Alberta*, and moved to Eastern Canada and resold again by the LDC, in what is called the "buy/sell". In this way, the LDC remains responsible for pipeline capacity from western to eastern Canada.

LDC WACOG

The price paid by the LDCs for buy/sell gas is not equal to the price originally paid to the producer. Rather, the price paid by the LDCs is based on the Weighted Average Cost Of Gas (WACOG), which is the average price for all gas purchased by the LDC.

Besides "buy/sell" purchases, LDCs purchase so-called "system gas" from producers. System gas is bought by the LDC, and resold to end-users in the LDCs franchise area. These system contracts had in the past typically been long term (longer than one-month) contracts, with either one-year fixed or indexed pricing. Prices paid under these contracts were considerably higher than Alberta spot month prices, as shown in Figure A-3. These contract prices pulled LDC WACOGs considerably above Alberta spot prices.

Gas users could buy gas at a low Alberta price, resell it to Eastern Canadian LDCs at a higher WACOG price, and then buy gas from the LDC at their burner tip for the WACOG price. Through this mechanism, some Eastern Canadian gas buyers effectively paid lower prices for natural gas, applying profits made on buy/sells to gas costs paid to the LDC.

This situation changed in 1993, when monthly Alberta spot prices skyrocketed, surpassing LDC WACOGs, which were still dominated by one-year fixed pricing. Then in 1995, Eastern Canadian LDCs began to purchase system gas at prices indexed to Alberta spot prices. Due to these changes, LDC WACOGs began to track Alberta spot prices.

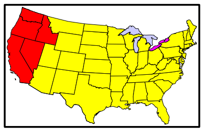
In Table A-2, we have used WACOG prices, weighted by each LDC's sales volumes, to calculate revenues from gas sold to the Eastern Canadian market. This may overestimate the revenues actually received by producers. Another approach would be to use the AECO price as an estimate of the price actually received by producers.

Outlook

CGA forecasts that natural gas demand in eastern Canada will grow at an average growth rate of 1.9% over the 1997-2002 period, for an estimated total volume of 145 Bcf (see Figure A-2). Most growth (91 Bcf) will be in the industrial sector. Additional supplies will mainly be from Western Canada.

Table A-3: U.S. West

A Statistical Snapshot



California
Idaho
Nevada
Oregon
Washington

	1996	1995	% Change
Canadian Exports to the West (Bcf)	1,164	1,096	6.2
Average International Border Price ($US/MMBtu)	$1.28	$1.03	23.6
Average Plant Gate Price ($US/MMBtu)	$1.07	$0.72	50.2
International Border Revenue (Million$Cdn)	2,024	1,549	30.7
Gas Consumption in the West (Bcf)	2,284	2,357	-3.1
Residential	608	592	2.7
Commercial	338	373	-9.3
Industrial	952	931	2.2
Electric Utility	386	460	-16.2
Market share of Canadian gas in region, %	50.9	46.5	9.5
Malin Spot Month Price ($US/MMBtu)	$1.54	$1.13	36.9
AECO-C to Malin differential ($US/MMBtu)	$0.52	$0.29	79.3
AECO-C to Malin pipeline toll ($US/MMBtu)	$0.56	$0.55	1.8
Capacity To Region in Period (Bcf/yr)	1,439	1,439	0.0
Average LF on capacity to region, %	80.9	76.2	6.2

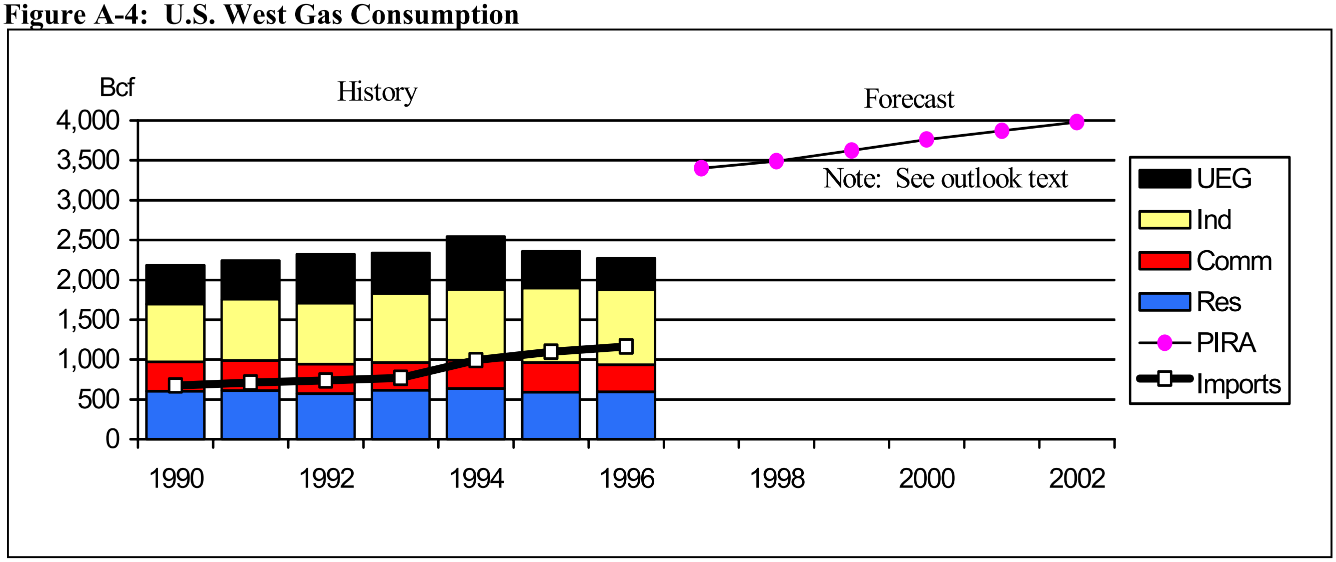
1996 Review

Western U.S. gas demand fell by 73 Bcf, or 3%, during 1996. The bulk of the demand decrease occurred in the UEG and commercial sectors. The decline in the UEG sector can be attributed to higher gas prices during 1996, and better availability of hydropower. Industrial and residential demand both rose (2%, 3%, respectively).

There were no pipeline capacity expansions from Canada to the Western region during 1996. Canadian gas sales to the region increased 68 Bcf, or 6%. This increase was due to a significant improvement in flows through the Huntingdon export point. Huntingdon exports increased 16% over the year. The load factor of Huntingdon export capacity improved from 61% to 71%. As discussed previously, low load factors through Huntingdon are due to user-dedicated lines and other factors. There is now little scope for increasing exports across Huntingdon without adding capacity.

Market share of Canadian gas in the region increased from 47% to 51%, as Canadian gas backed out San Juan supplies, which now have

Figure A-4: U.S. West Gas Consumption



eastward sales options in addition to California.
Prices for Canadian gas delivered to the region are the poorest of the export regions. This is the result of pricing in the U.S. West being determined by its marginal supplier, the U.S. Rockies. Prices in the Rockies have been low, due to the low cost nature of this basin, and pipeline limitations trapping gas and lowering prices.

Revenues from Canadian gas sold to the U.S. West increased 31% during 1996, due to higher prices and higher load factors on pipeline capacity (leading to a lower average transportation cost). Plant gate netbacks averaged US$1.07/MMBtu (up 50%) due mainly to higher prices.

While netbacks improved in the last months of the year, this region remains the poorest market for Canadian sales in terms of per MMBtu profitability.

Outlook

As shown in Figure A-4, PIRA's forecast for Western gas demand shows 3.9% average annual growth (PIRA's West area includes some Mountain states not in our U.S. West area - for this reason, volumes are higher). Using PIRA's 3.9% growth rate on our West region leads to total demand growth of 530 Bcf over the 1996-2002 period. We have assumed U.S. West demand growth will be somewhat lower, at 286 Bcf.

Current Canadian export capacity to the West is fairly full, running at an 81% load factor in 1996. Very large increases in exports to the Western U.S. are now not possible until pipeline capacity is expanded. However through gradual improvements in load factors on existing capacity, increased exports of 87 Bcf are expected over the period.

At present, there are no export capacity expansions from Canada to the U.S. West applied for. However, some pipelines have been assessing market interest in such expansions.

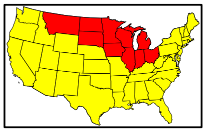
With considerable market growth expected in this region to the year 2002, the question is whether Canadian pipeline capacity will be expanded to capture this growth, or whether growth will be satisfied via increased deliveries from the San Juan and perhaps Gulf Coast basins. These basins have excess pipeline capacity to California.

Prices and revenues from sales to this region are expected to continue to improve. Prices in the U.S. Rockies (which drive U.S. West prices) have recently reconnected with Gulf Coast prices, rising considerably. Continued pipeline expansion out of the U.S. Rockies supply region is expected to keep price differentials between the U.S. east and west smaller than they had been in recent years.

In counterpoint, U.S. Rockies and Western Canadian production appears likely to continue to grow. Pipeline capacity out of these regions could periodically be less than exportable production. This could result in periodic supply surpluses in the U.S. Rockies and Western Canada, and periodically low prices in Western North America compared to the east and south.

Table A-4: U.S. Midwest

A Statistical Snapshot



Illinois
Iowa
Indiana
Michigan
Minnesota
Montana
North Dakota
Ohio
South Dakota
Wisconsin

	1996	1995	% Change
Canadian Exports to the Midwest (Bcf)	1,031	1,006	2.5
Average International Border Price ($US/MMBtu)	$2.05	$1.45	41.7
Average Plant Gate Price ($US/MMBtu)	$1.77	$1.13	56.7
International Border Revenue (Million$Cdn)	2,882	2,002	44.0
Gas Consumption in the Midwest (Bcf)	4,709	4,480	5.1
Residential	1,913	1,790	6.9
Commercial	981	917	7.0
Industrial	1,732	1,659	4.4
Electric Utility	83	113	-26.8
Market share of Canadian gas in region, %	21.9	22.5	-2.5
Representative Local Spot Month Price (Chicago)	$2.77	$1.69	63.9
AECO-C to Chicago differential	$1.75	$0.85	105.6
AECO-C to Chicago pipeline toll	$0.92	$0.88	4.5
Capacity To Region in Period	1,047	1,047	0.0
Average LF on capacity to region, %	98.5	96.1	2.5

1996 Review

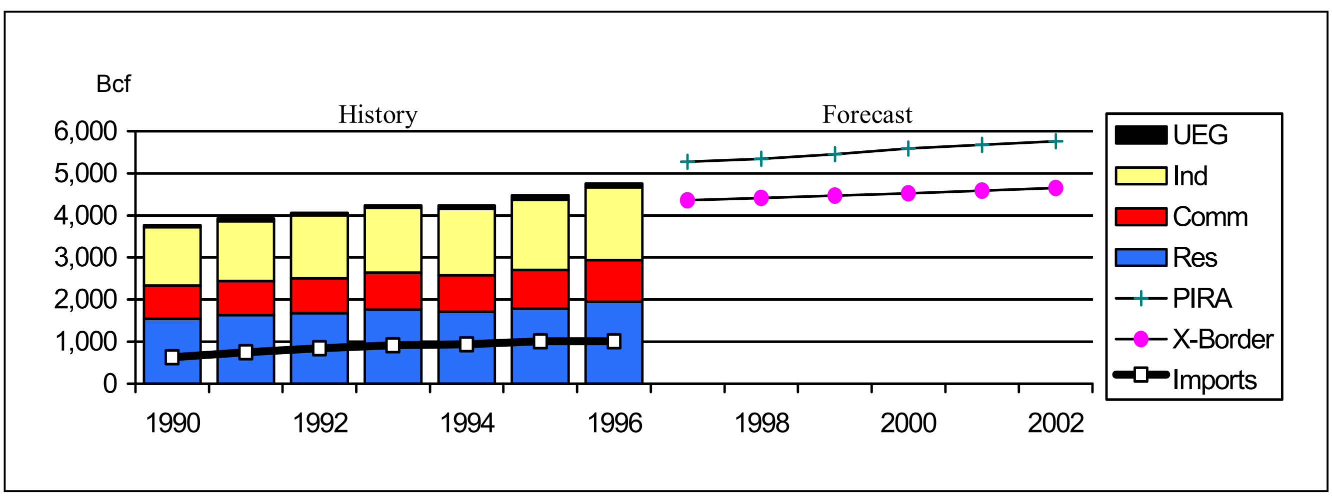
U.S. Midwest gas demand increased by 229 Bcf, or 5%, during 1996. The bulk of the demand increase occurred in the residential and commercial sectors and was mainly due to colder weather. However, industrial demand also rose 4%, reflecting strong economic growth. With higher gas prices during 1996, demand in the price-sensitive UEG sector fell 27%. Gas demand by sector and Canadian exports are shown in Figure A-5.

Canadian gas sales to the region increased only 25 Bcf, or 2.5%. This was due to minor improvements in load factors through the Emerson export point. Significantly higher exports are not possible until pipeline capacity is expanded. There were no pipeline capacity expansions from Canada to the Midwest region during 1996.

Market share of Canadian gas in the region slipped slightly, from 23% to 22%, as demand growth was satisfied by U.S. sources.

Prices for Canadian gas delivered to the region vary, depending on whether sellers or buyers hold pipeline capacity to the market, and whether the gas is sold at the Midwest end of the pipeline (yielding a high seller netback), or in Alberta (yielding a lower seller netback). The average international border price for Canadian gas sold to the region

Figure A-5: U.S. Midwest Gas Consumption



Sources: EIA, PIRA, Crossborder. Note: Midwest definition differs between organizations.

increased 42% during 1996. This mainly reflected higher Midwest spot prices (spot prices rose 64%). Due to higher realized prices, revenues for gas sales to the region increased 44%, to reach CDN$2.9 billion. Plant gate netbacks averaged US$1.77/MMBtu (up 57%) due mainly to higher prices.

High netbacks and the large price differential between the Midwest and Alberta (much larger than the cost of pipelining gas from Alberta to the Midwest) made the Midwest market very attractive in 1996.

Outlook

As shown in Figure A-5, both PIRA and Crossborder expect natural gas demand in the U.S. Midwest to continue to be reasonably strong. Growth is expected to average 1.7% to 2.7%. We are assuming Midwest demand will reach 5,255 Bcf by 2002 (i.e., 1.8% annual growth).

Over the past five years, Midwest gas demand has actually grown an average of 3.7%, for total growth of 779 Bcf. The residential sector accounted for 38% of the increase, commercial 21%, industrial 38%, and UEG 2.8%.

Canadian gas exports to the Midwest have grown from 749 Bcf in 1991 to 1,031 Bcf in 1996, for a total increase of 282 Bcf. Canadian gas exports have thus captured 36% of Midwest gas demand growth over the past five years.

Canadian gas exports to the region are "baseload" supplies, and export pipeline capacity has generally run essentially full over the past five years. The U.S. Gulf Coast is the marginal supplier to the region. Thus, Gulf Coast prices determine Midwest prices, with Midwest prices consistently being equal to Gulf prices plus an amount for Gulf to Midwest pipeline transportation.

Several very large export pipeline expansions to the Midwest are under way. The first is the Foothills/Northern Border expansion. This expansion has been approved by U.S. and Canadian regulators, and is expected to add 690 MMcf/d of capacity from Alberta to the Midwest by November, 1998.

Given the past experience with high load factors on Northern Border, we expect the expansion will also run at high load factors. The higher export volumes will be absorbed into the Midwest via lower flows from the Midwest's marginal supplier, the Gulf Coast.

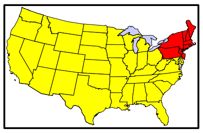
Beyond 1998, there are two other proposed large pipeline expansions from Canada to the Midwest -- TCPL's Nexus project and associated projects (new Voyageur line and Great Lakes expansion), and the Alliance Pipeline. Neither have been approved yet by regulators, and one or both may proceed. Alliance has applied to FERC for the U.S. portion of the line, and to the NEB (preliminary) for the Canadian portion.

Our general practice has been to book additional forecast export pipeline capacity when an application to regulators has been made.

For this report, we are assuming 690 MMcf of capacity will be added to the Midwest in 1998 (Northern Border), and 1,200 MMcf/d in 2000. We draw no conclusions about which pipeline projects will proceed, but have selected this capacity number as probable. These assumptions, and our assumption of high load factors, drive our Midwest export forecast of 1,535 Bcf by 2002.

Prices and revenues from Canadian gas sales to the Midwest are expected to remain attractive over the period. Additional U.S. Rockies or Western Canadian supplies flowing into the Midwest are not expected to completely back out Gulf Coast gas. Thus, the Gulf is likely to remain the marginal supplier to the Midwest. Gulf prices will continue to determine Midwest prices. As the Gulf is a high cost supplier, this will keep prices in the Midwest relatively attractive.

Table A-5: U.S. Northeast



Connecticut
Maine
Masachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Rhode Island
Vermont

A Statistical Snapshot

	1996	1995	% Change
Canadian Exports to the Northeast (Bcf)	642	648	-0.9
Average International Border Price ($US/MMBtu)	$2.89	$2.28	26.7
Average Plant Gate Price ($US/MMBtu)	$1.96	$1.36	44.5
International Border Revenue (Million$Cdn)	2,533	2,028	24.9
Gas Consumption in the Northeast (Bcf)	2,780	2,994	-7.1
Residential	987	1,005	-1.8
Commercial	655	658	-0.4
Industrial	882	922	-4.4
Electric Utility	256	408	-37.2
Market share of Canadian gas in region, %	23.1	21.6	6.7
New York Spot Month Price ($US/MMBtu)	$3.28	$2.05	60.5
AECO-C to New York differential	$2.26	$1.21	87.6
AECO-C to New York pipeline toll	$1.40	$1.34	4.5
Capacity To Region in Period	685	671	2.1
Average LF on capacity to region, %	93.7	96.6	-2.9

1996 Review

After five straight years of solid growth, Northeast gas demand declined by 214 Bcf, or 7%, during 1996. The bulk of the demand decrease occurred in the UEG sector, which dropped a whopping 152 Bcf, or 37%. Industrial gas demand also fell hard (40 Bcf or 4%), while residential and commercial demand fell marginally.

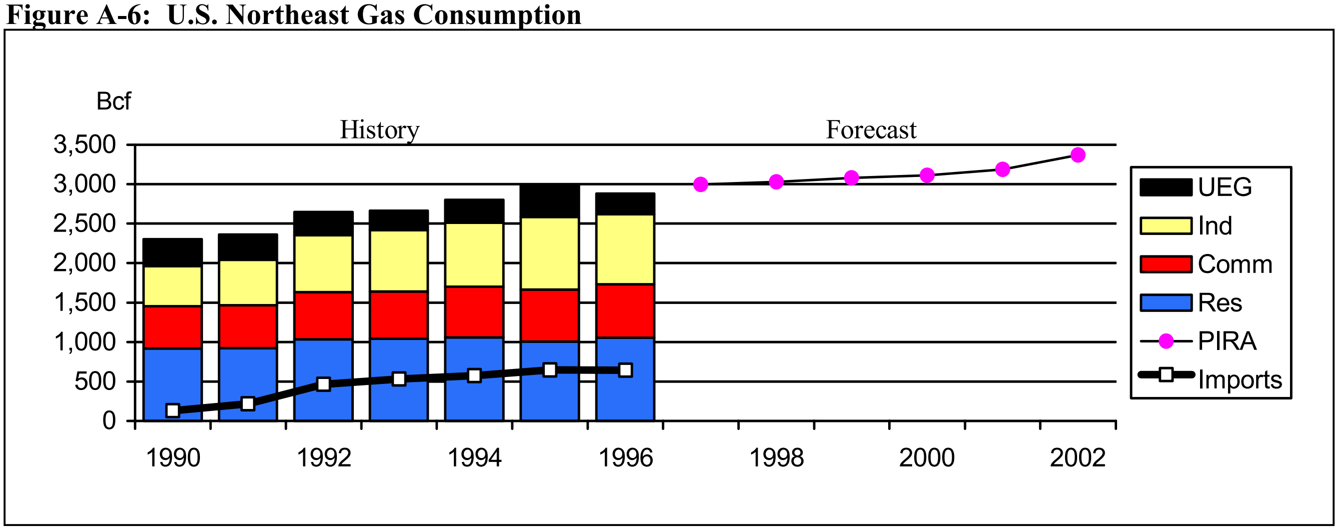
Canadian gas sales to the region fell slightly, by 6 Bcf or 1%. There was a small Canada-to-Northeast pipeline capacity expansion at the Iroquois export point (41 MMcf/d) during 1996.

Market share of Canadian gas in the region improved from 22% to 23%, as U.S. suppliers absorbed the brunt of lower demand.

The average international border price for Canadian gas sold to the region increased 27%. Due to higher realized prices, revenues for gas sales to the region increased 25%, to reach Cdn$2,533 million. Plant gate netbacks averaged US$1.96/MMBtu (up 45%) due mainly to higher prices.

High netbacks and the large price differential between the Northeast and Alberta (much larger than the cost of moving gas from Alberta to the Northeast) made the Northeast the most attractive

Figure A-6: U.S. Northeast Gas Consumption



Sources: EIA, PIRA

market for Canadian gas sellers in 1996.

Outlook

As shown in Figure A-6, PIRA expects Northeast gas demand to increase by an average 3% per year. Our outlook assumes growth of 2.7% per year, for total demand growth of 489 Bcf to 2002.

With existing Canada-to-Northeast capacity being effectively full, pipeline expansions will be required if Canadian gas is to capture any of this market growth.

Several pipeline projects are now being proposed to allow Canadian gas to capture some of this market growth. These include the Portland Natural Gas Transportation System (PNGTS) project which would increase potential exports to the New England region by approximately 200 MMcf/d by 1999, and the TCPL Nexus expansion and the related Millennium Pipeline, which propose to bring 650 MMcf/d to the Northeast from Canada. The proposed 900 MMcf/d Independence pipeline linking the U.S. Midwest and Northeast could also facilitate increased Canadian exports to the Northeast, depending on capacity additions from Canada to the Midwest.

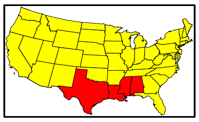
A new supply basin is expected to begin supplying gas to the Northeast during the forecast period. We expect the Sable offshore area to begin producing up to 480 MMcf/d in late 1999. This greenfield project and the associated pipeline are currently in the process of obtaining necessary regulatory approvals, both in Canada and in the U.S.

For forecasting purposes, only the projects which have submitted applications to regulators are included in our capacity forecasts. Our outlook assumes new capacity of 800 MMcf/d will be added over the period. Given our assumption of high load factors on this capacity, we are forecasting 824 Bcf of Canadian sales to the Northeast market by 2002.

The outlook for prices and revenues for Canadian gas sold to the Northeast market remains strong. At present, this market provides the best prices and netbacks to Canadian producers. The bulk of Northeast gas supplies come from the Gulf Coast and Midcontinent. These high cost supply regions are the marginal suppliers to the Northeast, and so Northeast prices are likely to remain linked to Gulf prices.

Figure A-6: U.S. Gulf Coast

A Statistical Snapshot



Texas
Louisiana
Mississippi
Alabama

	1996	1995	% Change
Gulf Coast Production	642	648	-0.9
Internal Gulf Coast Consumption (Bcf)	$2.89	$2.28	26.7
Net Exportable Production (Bcf)	$1.96	$1.36	44.5
Gas Consumption in the Gulf (Bcf)	2,533	2,028	24.9
Residential	987	1,005	-1.8
Commercial	655	658	-0.4
Industrial	882	922	-4.4
Electric Utility	256	408	-37.2
Market share of Canadian gas in region, %	0.0	0.0	0.0
Representative Local Spot Price (NYMEX)	$3.28	$2.05	60.5
NYMEX - AECO C differential	$2.26	$1.21	87.6

1996 Review

Gulf gas demand increased by 118 Bcf, or 2% in 1996. Gulf Coast demand has grown steadily since 1990. As is evident in Figure A-7, the industrial and UEG sectors account for the lion's share of demand.

The bulk of the 1996 demand increase occurred in the industrial sector. Refining and petrochemicals are important industrial segments in the Gulf, and with high oil and petrochemicals prices, gas demand was driven up.

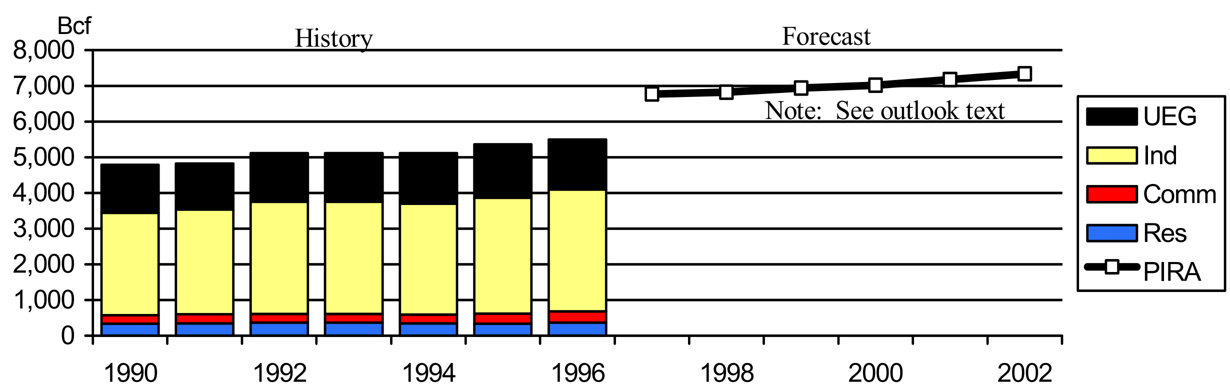
With higher gas prices during 1996, demand in the price-sensitive UEG sector fell 7%, or 103 Bcf. Residential and commercial loads increased by a large percentage (10%), but represent small volumes.

Gulf Coast production rose 406 Bcf during 1996. As production increased more than demand, gas flows out f the region increased 288 Bcf over last year.

Gas flows into the region also increased during 1996. This occurred mainly as more of the capacity of the Transwestern and El Paso pipelines from the eastward flows, and more San Juan production in the Gulf Coast market itself, or moved north to markets in the U.S. Midwest. During most months, there is spare capacity on Gulf Coast to Midwest natural gas pipelines.

There are no physical deliveries of Canadian gas to the Gulf region, nor any knows gas sales to the

Figure A-7: U.S. Gulf Coast Consumption



Sources: EIA, PIRA

region. Some contractual sales of Canadian gas to Gulf markets may be occurring via swaps or backhauls.

Outlook

PIRA's forecast region shown in Figure A-7 includes four states not included in our Gulf Coast region. PIRA forecasts growth in this larger region at 2% per year. Using this 2% rate on our smaller Gulf Coast region yields a forecast of 6,170 Bcf of demand in 2002.

Over the past five years, annual Gulf Coast gas demand has grown 2% per year, for a total increase of 599 Bcf. The industrial sector accounted for 77% of the increase. Over the same period, annual Gulf Coast gas production has grown by 757 Bcf. Gulf Coast production growth has only slightly exceeded demand growth, leading to a moderate increase (+158 Bcf) in gas flowing out of the Gulf.

This has been an important factor in higher Canadian gas exports to the U.S. Canadian gas has been able to capture market growth in the U.S. Midwest and Northeast, while outflows from the Gulf stagnated. For the U.S. West export region, Canadian gas and U.S. Rockies gas have completely displaced Gulf Coast supplies over the past five years. The Gulf Coast had been the marginal gas supplier to the Western U.S., but the marginal supplier now is the U.S. Rockies. The net result of this has been lower prices in the U.S. West export region.

However, the Gulf Coast remains an important gas supplier to the Midwest. By our calculations, the Gulf Coast currently sends over 1,000 Bcf per year (or 2.7 Bcf per day) of pipeline capacity from other supply regions is built to the U.S. Midwest, the Gulf should continue to be the marginal supplier to the Midwest. Thus, there is little likelihood that Midwest gas prices will become disconnected from Gulf Coast gas prices over the outlook period. For similar reasons, the Gulf is expected to continue to drive U.S. Northeast gas pricing.

The Gulf Coast As Competitor

In past years, the Gulf Coast and Midcontinent have been the marginal, high coast suppliers to several U.S. markets accessible to Canadian and U.S. Rockies producers ("Western" producers). Western producers have successfully penetrated markets, increasing market share at the expense of the Gulf.

Many analysts are now forecasting that the dynamics of Gulf Coast gas supply have changed. With the Gulf appearing to particularly benefit from new technologies (3-D and 4-D seismic, tension leg platforms, subsea completions, etc.), these analysts see the Gulf supplying more and more natural gas to U.S. markets into the future.

This has important ramifications for Canadian exporters, pipelines, and markets. As the high cost supplier to North America, the Gulf Coast has the most influence on North American gas prices. If the Gulf has changed, then there will be a downward influence on overall prices.

The future of the Gulf also has very important implications for pipeline projects proposing to connect Canadian or U.S. Rockies supplies to U.S. markets. If the Gulf is rejuvenating and new pipeline capacity in the West is built, a price war could result in the U.S. Northeast and Midwest markets. In this scenario, the Gulf would provide increasing supplies at very low prices. Load factors on pipeline capacity from the West would suffer, and shippers would incur unabsorbed demand charges.

However, little evidence for this view exists in current trends. The Gulf Coast remains the high cost and marginal supplier in most gas markets. Gas price differentials are also instructive in this regard. In recent history, Canadian and U.S. Rockies basin prices plus regulated tolls to various markets produce a delivered price of gas which is lower than the delivered price of gas which is lower than the delivered price of Gulf Coast gas in those markets. As a result, west-to-east pipelines have been operating at high load factors, while Gulf Coast to market pipelines have been operating at lower load factors.

Pipelines and their prospective shippers will decide which view is correct, and whether new pipelines are constructed.