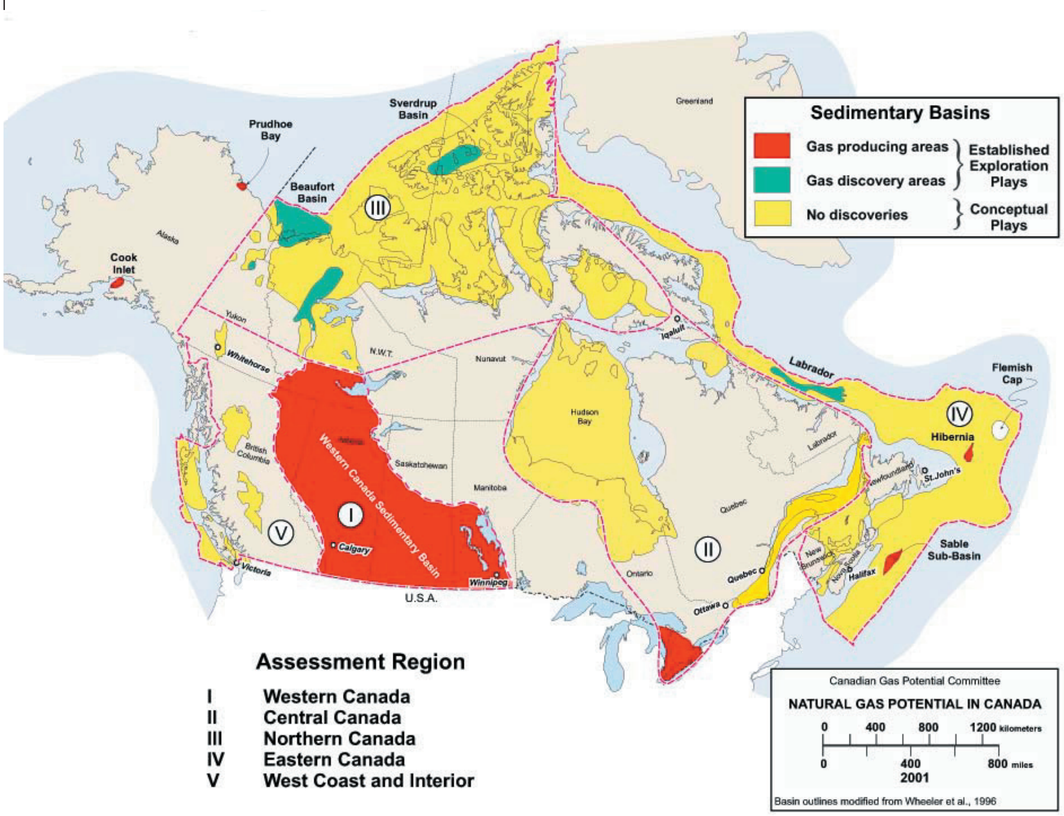
Potential Supply and Costs of Natural Gas in Canada

By Paul Mortensen, Matthew Foss, Brian Bowers and Peter Miles[*]

Canada's annual natural gas production increased almost 20 percent between 1995 and 2001. During that time Canadian gas satisfied continuing growth in domestic markets while increasing exports to the U.S. by almost a third. In 2002, the record of growth came to an end as gas well completions fell by 17 percent and overall production began to drop. Despite higher prices and substantial increases in drilling in 2003, supply growth remains elusive. Does this mean the limit has been reached for conventional gas production from Western Canada, and what does the future hold for alternative sources of Canadian natural gas?

Figure 1
Natual Gas Potential in Canada - 2001
A Report by the Canadian Gas Potential Committee



According to Natural Resources Canada, the Canadian share of the North American market is projected to grow from about 6.2 Tcf in the year 2001 to 8.1 Tcf or greater by 2010[1]. The U.S. Energy Information Administration projects Canadian exports to the U.S. to grow from 3.6 Tcf in 2001 to 4.1 Tcf by 2010 and 5.1 Tcf by 2020[2]. Continued growth in Canadian production would be required to support these projections. But the projections have been made without a detailed assessment of the potential sources and costs of gas in Canada.

A geologic assessment of Canada's natural gas resources was published in September 2001 when the Canadian Gas Potential Committee (CGPC) released its second assessment of Canadian natural gas potential[3]. The CGPC assessment provides estimates for the total volume of potentially recoverable gas, by geological play, for all of Canada's sedimentary basins. It concludes that there is approximately 590 Tcf of discovered and undiscovered natural gas in place in Canada.

The CGPC work is a geologic assessment and, though critical, is only part of the analysis needed to understand the prospects for Canada's gas supply. The other part relates to the costs of finding, developing and producing the gas - 'supply costs'. Without this latter analysis, the likely size of Canada's prospective gas production cannot be determined.

The Canadian Energy Research Institute (CERI) recently released a report[4] containing an assessment of the costs and related potential supply of natural gas in Canada. The study represents the most comprehensive public analysis ever undertaken into the potential and costs of Canadian natural gas supply. For the first time, a detailed pool-based analysis of the Western Canada Sedimentary Basin is supplemented by analysis of Canadian coalbed methane, and of frontier regions in the North and off the East and West Coasts. The report estimates the size of the economically recoverable natural gas resource base and provides a 20-year projection for Canadian gas production.

This article reports the study's principal findings beginning with a summary of the geological estimates that underlie the analysis.

The Canadian natural gas resource base consists of resources in the currently producing supply regions – Western Canada and offshore Nova Scotia – and in the frontier regions that are currently unconnected to the pipeline infrastructure of North America. The major frontier regions are the Mackenzie Valley and Delta (onshore and offshore), the Arctic islands, offshore Newfoundland and Labrador, offshore Brit-

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ish Columbia (BC) and the unconnected geological basins of offshore Nova Scotia (Figure 1).

Currently, an estimated 304 Tcf of gas in place has been discovered in the Western Canada Sedimentary Basin (WCSB), of which about 181 Tcf are expected to be recovered as marketable gas. To the end of 2001, about 127 Tcf has been produced and about 54 Tcf remains to be produced. In the frontier regions and central Canada, about 63 Tcf of gas in place has already been discovered, of which about 42 Tcf are expected to be marketable. Apart from a small amount of production in Ontario and from the Sable project off Nova Scotia (about 1 Tcf in total), there has been no production to date from frontier resources.

For the whole of Canada, 367 Tcf (304+63) of gas in place has been discovered to date, of which 223 Tcf (181+42) are expected to be marketable. Subtracting the 127 Tcf of production to date leaves remaining discovered marketable resources of about 96 Tcf for the whole of Canada.

The size of Canada's natural gas resource base is uncertain, notwithstanding the large number of discoveries and the significant analysis performed to date. In this study uncertainty about the geology is taken into account through the use of two scenarios – the "CGPC" and "Alternate" cases respectively. The CGPC estimates that conventional gas, originally in place totals 593 Tcf. Of this, 367 Tcf has already been discovered and 226 Tcf remains to be discovered. Gas originally in place in the WCSB, amounts to 423 Tcf of which 304 Tcf has already been discovered and 119 Tcf remains to be discovered. Gas originally in place in the Canadian frontiers and eastern Canada, amounts to 170 Tcf of which 63 Tcf has already been discovered and 107 Tcf remains to be discovered (Table 1).

Table 1

Distribution of Discovered and Undiscovered Conventional Gas Resources In Canada – Year End 2001

(original gas in place in Bcf)

Assessment Region	CGPC Estimates DISC.	CGPC Estimates UNDISC.	CGPC Estimates TOTAL	Alternate Estimates DISC.	Alternate Estimates UNDISC.	Alternate Estimates TOTAL
Total WCSB And Yukon	304060	118985	423045	304060	173442	477502
Total Central Canada	1959	3060	5019	1959	3126	5085
Total Northern Canada	34343	50553	84896	34343	172287	206630
Total Eastern Canada	26602	39174	65776	26602	147435	174037
Total West Coast And Interior	0	13724	13724	0	30803	30803
All Canada	366964	225496	592460	366964	527093	894057

SOURCES: (1) Natural Gas Potential in Canada - 2001, A Report by the Canadian Gas Potential Committee, 2001; and (2) Canada's Ultimate Natural Gas Potential – Defining a Credible Upper Board, Drummond Consulting, March 2002.

Because the CGPC resource estimate excludes volumes for a number of areas thought to have reasonable prospects for natural gas discoveries, CERI commissioned a study to define an alternate, more comprehensive, estimate of Canada's natural gas resources. The study uses estimates of the Geological Survey of Canada and others, that include assessments of gas in place for conceptual plays, to provide an alternate – more complete – estimate of total resources.

For the Alternate case, the estimated total conventional gas, originally in place in Canada, amounts to 894 Tcf, with 527 Tcf remaining to be discovered. Gas originally in place in the WCSB, amounts to 478 Tcf, and 174 Tcf remains to be discovered. Gas originally in place in the Canadian frontiers and eastern Canada amounts to 416 Tcf, and 353 Tcf remain to be discovered (Table 1).

Unconventional sources of natural gas include coalbed methane (CBM), gas hydrates, tight gas and shale gas. All of these are known to have very large volumes of gas in place. However, little is known about the amount that may be available for commercial production in Canada.

In Canada commercial production of CBM is just commencing. There is currently no identified production from tight reservoirs or shale formations, although some production from these sources occurs along with production from conventional gas reservoirs. With respect to gas hydrates, the technology to extract the methane gas from the hydrates does not currently exist.

A key feature of the analysis is adjustment of the resource estimates to reflect access restrictions. Off-limits to drilling are areas such as national parks, municipalities and large lakes. Other environmentally sensitive areas may not preclude drilling but instead introduce additional costs and delays to satisfy more stringent conditions. The issue is especially critical in the Foothills of Western Canada where some of the highest potential for new gas finds is in areas with moderate to high degrees of access restrictions. Access restrictions were found to remove roughly 7 percent of the remaining resource base in Western Canada and 12 percent in the North.

CERI undertook detailed pool by pool supply cost analysis of the majority of the remaining gas in Western Canada and all of the gas in the frontiers. Producing pools were analyzed to determine the extent of additional development and gas recovery that could be achieved at higher price levels. Analysis of unconnected pools provided the cost points where this additional gas could begin production. Supply costs for undiscovered gas incorporate the full costs of exploration in addition to pool development. Separate techniques were used for onshore, offshore and coalbed methane resources to capture the unique attributes of each. The results of the analysis provide the volume of gas available at one dollar supply cost increments up to \$10/Mcf[5] for all regions and all categories of gas in Canada.

The supply cost analysis provides the material to construct some illustrative profiles of what the evolution of Canadian production and related supply costs might look like over the next two decades.

For the WCSB, annual productive capacity will be related to the pace of drilling. Three time profiles for drilling activity illustrate a plausible range as a basis for assessing the possible evolution of productive capacity:

- a low case, depicted by a constant rate of drilling at 8000 gas wells per year;
- a high case in which drilling occurs at a rate of 15000 gas wells per year; and
- a middle scenario in which drilling increases from 8000 wells per year in 2002 to 15000 wells in 2008 and 2009 and then declines to about 10,000 wells per year in 2025.

As a point of reference, approximately 9000 gas wells were drilled in Western Canada in 2002.

For the two higher drilling scenarios in the CGPC case, WCSB productive capacity remains at or above 2002 levels until about 2010 and subsequently declines steadily. For the low drilling case, productive capacity begins a steady decline in 2005. In the Alternate case, WCSB production increases in the near term in both high and middle scenarios and remains above present levels until about 2015.

For the unconnected frontier regions, potential future supplies are illustrated by two scenarios–"constrained" and "unconstrained".

The unconstrained case (Figure 2) is intended to characterize the potential productive capacity of the available resources without regard to timing. Annual volumes are estimated on the assumption that each field is produced over a twenty-year period. No assessment is made as to the time by which the gas could be connected to markets.

Figure 2
Potential Productive Capacity of Unconnected Frontier Resources

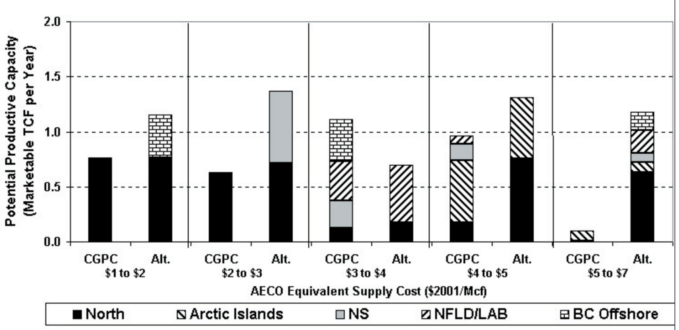
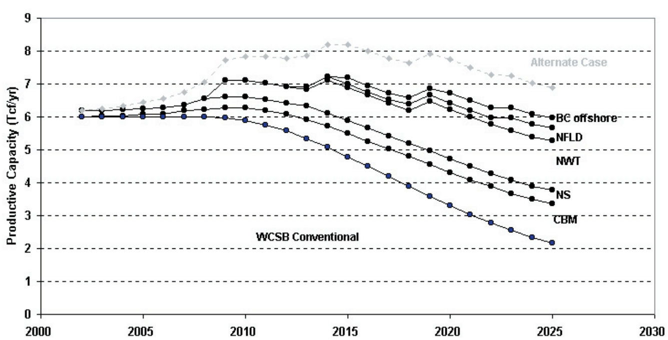


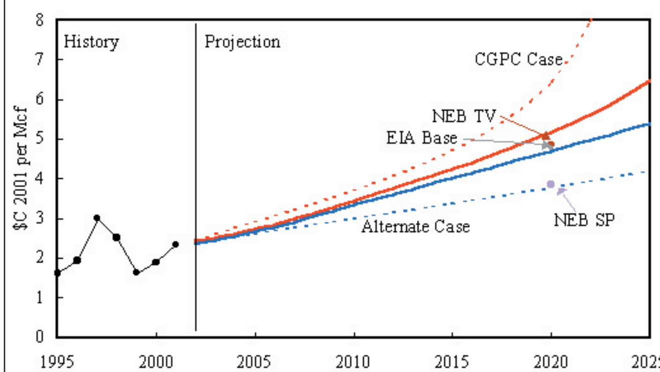
Figure 3
Gas Productive Capacity
CGPC Case (Tcf/year))



Prospective frontier volumes are substantial; the amounts potentially producible for up to $4/Mcf (2001 Canadian dollars) are estimated to total between 2.6 and 3.2 Tcf/year in the CGPC and Alternate cases respectively, close to half of Canada's production in 2002.

Much of the production potential at relatively low costs is in the North along the Mackenzie Valley and in shallow waters of the Beaufort Sea. But the analysis also suggests that there is reasonably low cost potential production offshore British Columbia, Nova Scotia, and Newfoundland. Realization of much of this potential is, however, contingent on the construction of lengthy pipelines and related infrastructure. These facilities, involving large capital expenditures and long lead times, are inherently risky.

Figure 4
Average Marginal Supply Costs at AECO



SOURCES: (1) Canadian Energy Research Institute (2003); (2) NEB: National Energy Board, Canada's Energy Future- Scenarios for Supply and Demand to 2025 (draft for public consultation), - TV = Techno-Vert, SP=Supply Push Scenario; and (3) EIA Base: Reference case from Energy Information Administration, Annual Energy Outlook, 2003.

For the constrained case (Figure 3) judgments are made, based on available information about the likely timing of production startup for frontier basins. Such timing must take into account a number of factors including time taken to negotiate with stakeholders, to obtain regulatory approvals and to undertake construction.

The constrained case yields a time profile in which, for the CGPC case—relatively low geological potential total Canadian production (assuming the middle drilling scenario for the WCSB) increases to some 7 Tcf/year by 2010 from its 2002 level of about 6 Tcf. Production is maintained at about 7 Tcf/year until 2015, following which it declines at a modest rate to about 6 Tcf in 2025. In the Alternate case, productive capacity remains well above 2003 levels throughout the projection horizon, so that it is still about 7 Tcf/year in 2025.

These projections indicate that, so long as supplies of gas from unconventional sources, such as CBM, and from new basins can be brought on stream in a timely manner, natural gas production in Canada can be sustained at levels higher than now exist through at least 2025. Indeed, if the geological estimates of the Alternate case are correct, production could be as high as 8 Tcf per year over much of the projection horizon.

The analysis concludes, however, that such levels of production are likely to come at ever-increasing supply costs (Figure 4). Compared to its level of some $2.50/Mcf in 2002, the supply costs of Canadian gas – in 2001 Canadian dollars – are likely to be at least $4.00 by 2020. Supply costs associated with the mid-point of the supply projections are about $5.00/Mcf by 2020. This cost range appears to be generally consistent with price projections from other agencies.[6]

This, in turn, implies that the North American gas price would have to continue to trend upwards from its annual average in 2002. However, it also raises questions as to whether the prices observed in the early months of 2003 (which have ranged from $5.42/Mcf to $13.64/Mcf – Canadian dollars – at AECO, the principal hub for the Western Canada basin) are likely to be sustainable in the long run.

Finally, it is important to emphasize that this analysis relates to the long-term potential for Canadian natural gas. The actual path of development of that potential takes time and is influenced by a number of factors, including producers' price expectations and the availability of capital and other resources. The production profile that actually emerges will be much less smooth than that portrayed above.

Footnotes

[1] *Canadian Natural Gas Outlook, 2001 Market Review and Outlook*, Natural Resources Canada, Natural Gas Division, Ottawa, Ontario, June 2002.

[2] *Annual Energy Outlook 2003 With Projections to 2025*, DOE/EAI 0383 (2003), Energy Information Administration, Washington, DC, January 2003.

[3] *Natural Gas Potential in Canada - 2001*, A Report by the Canadian Gas Potential Committee, 2001.

[4] Paul Mortensen, Matthew Foss, Brian Bowers and Peter Miles, *Potential Supply and Costs of Natural Gas in Canada*, CERI Study 107, Canadian Energy Research Institute, Calgary, Alberta, June 2003.

[5] All costs and prices are expressed in 2001 Canadian dollars. The exchange rate at the time of writing was approximately $1 Canadian = $0.74 U.S.

[6] The fact that the price projections are similar to CERI cost estimates does not imply similar consistency of EIA and NEB supply projections with those of this analysis. The price/cost comparison is made simply to illustrate that the broad cost/price trends are similar.

Hong Kong Energy Studies Centre Holds International Conference on Energy Market Reform

The Hong Kong Energy Studies Centre, together with the Department of Geography of Hong Kong Baptist University held an international conference on "Energy Market Reform: Issues and Problems," (Second Asian Energy Conference) on August 25-26, 2003 at the University. Scholars and experts from 15 countries presented 27 papers, 17 of which dealt with energy market reform; practically all focusing on reform of the electricity market. Approximately 100 people attended the conference. Attendees included the paper presenters, senior executives and other personnel of local energy firms –power companies, towngas company and oil firms–government officials, academics, consultants and individuals.

At present, the power industry in Hong Kong, consisting of two investor-owned, vertically integrated utilities, is governed by a Scheme of Control, a rate of return type of regulatory framework. The Scheme will expire in 2008, and the Hong Kong SAR government is in the process of working out a new market structure, with the possibility of opening up the market. Consequently, relevant government officials, senior executives of local energy firms, politicians, environmental groups, consultants and academics are all intensely interested in the topic. They would like to know how energy market reform is working or not working in the other countries, and what lessons Hong Kong could learn from foreign experiences.

Stemming from this, the papers on energy market reform were organized along country lines, with 8 papers dealing with reform in Asian countries, including China, Hong Kong, Taiwan, Japan, Thailand, Singapore and India (2 papers). Seven papers covered western countries, including the EU, Sweden, Canada, the U.S. (2 papers) and Australia, and one dealt with Israel. While all focusing on electricity market reform, some of the papers discussed broad issues such as the steps taken to introduce reform and the problems encountered, while others dealt with more specific issues relating to reform. Both types of papers were useful and informative. Certainly the Hong Kong audience learned a great deal about foreign experiences in reform, as reflected in the conversation with local participants during and after the conference.

The other 10 papers covered a variety of themes, including the application of renewable energy in Hong Kong and China, the relationship between fuel quality on the one hand and taxation and the economy on the other, and papers on Chinese energy. Overall, the quality of most of the papers was quite good.

Following the practice of the First Asian Energy Conference held in August 2001 at the University, "Asian Energy in the New Century: Issues and Policies," the Hong Kong Energy Studies Centre has made arrangements with *Energy Policy* to publish a special issue containing selected papers from the conference. An international editorial committee consisting of Dr. Larry Chow, Director of the Centre and serving as chairman, Dr. Hiroshi Asano, Prof. Fred Banks, Prof. Leslie Dienes, Prof. David Green and Dr. C.K Woo, was formed to select the papers. The committee met on August 27, 2003 to make the selection, based upon a ranking of the papers according to their quality and suitability for

(continued on page 26)