UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest Corporation) Docket No. RP06-___-000

Prepared Direct Testimony of Walter W. Haessel

Q: Please state your name and business address.

A: My name is Walter W. Haessel and my business address is 4220 Varmoor Road N.W., Calgary Alberta, Canada T3A OB3.

Q: Please state your occupation.

A: I am President of Calgary Energy Consultants Ltd.

Q: Please briefly describe your education, background and training.

A: I obtained a Ph.D. in Economics (with a statistics minor) from Iowa State University. Following my graduate education I taught and conducted research at three universities. I switched in 1979 from teaching to serving as senior economist for the Bank of Montreal, focusing on energy markets. Starting in 1982, I worked with the Canadian Energy Research Institute and its successor, CERI Energy Research Ltd., ultimately serving as a Vice President and Principal, where I provided extensive consulting services, as well as testimony, involving energy matters. I assumed my present position in 1989.

Q: Please summarize your previous testimonial experience.

A: I have appeared as an expert witness in the following venues:

- National Energy Board
- Alberta Energy Utilities Board/Energy Resources Conservation Board
- Ontario Energy Board

- California Energy Commission
- House of Commons Committee on Energy and Natural Resources
- Macdonald Royal Commission on Free Trade

Q: What is the purpose of your testimony in this proceeding?

A: My testimony is directed to the determination of the just and reasonable depreciation rates to be applied to the Gas Transmission Northwest ("GTN") depreciable transmission plant. Particularly, I am presenting an assessment of Canadian gas supplies as it relates to the export markets to the United States.

Q: What Exhibit are you sponsoring in your testimony?

A: I am sponsoring Exhibit No. 20.

ECONOMIC LIFE OF THE GTN SYSTEM

Q: Please summarize your conclusions.

A: The economic life of the GTN system is dependent primarily upon the life of its gas supply and markets.

If the price of gas shipped through GTN loses its competitive viability, serious erosion of the long-term ability to sustain adequate market deliveries will take place. This threat is exacerbated because GTN serves highly competitive "over-piped" markets where customers have multiple gas supply options among pipelines.

Along with the markets, the supply of gas for shipment is crucial to the remaining life of a pipeline system. Approximately 92 percent of the gas currently transported by GTN originates in the Western Canada Sedimentary Basin (WCSB). I analyzed Canadian gas supply as it would affect the GTN system and performed studies concerning the supply life. The results of those studies indicated that a supply life of 20 to 25 years should be used as GTN's economic life.

Q: Aside from the aggregate level of the supply of Canadian gas, are there any considerations that affect GTN's depreciable life?

A: Yes. GTN will have to compete for these gas supplies with other markets. These markets can be broken into two types—markets within the producing areas, and consuming markets served by other pipelines with takeaway capacity from the producing areas that otherwise would provide supplies to GTN. In the case of GTN, the main producing area is the WCSB.

The competing pipeline systems serve markets in Eastern Canada, US Northeast, Midwest, and west coast from Washington to California.

Canadian Gas Resources and Supply

Q: Would you please describe your gas supply studies?

A: I analyzed Canada's gas supply in order to determine the future viability of exports to the United States. The future of these exports directly affects the life of the GTN system, especially those from the WCSB. I analyzed data available on Canada's existing proven reserves of natural gas, the various estimates of potential gas resources, and availability of gas from possible future supply sources.

The supply of gas available to GTN also depends on the competition for these gas supplies from Canadian markets within the producing area as well as competition from pipelines moving gas into other regions of Canada and export markets. The ability of GTN to compete for these supplies will depend on the strength of the intra-WCSB markets as well as the market areas served by other pipelines with take-away capacity relative to the strength of the markets in the GTN delivery area. In other words, if producers can make more money by transporting their gas to Ontario, the Midwest or the Northeast than to Malin, they will desire to use pipelines other than GTN.

Q: Dr. Haessel, would you please discuss Canada's gas supply base?

A: While Canada's total gas resources, including future potential resources, are immense, that does not mean that the resources that are economic to produce are immense. It is critical to understand what portion of the resource base actually can and will be available to support GTN's economic life.

Q: How would we go about determining the gas which is realistically accessible through GTN?

A: First, recognize that potential resources can be categorized as conventional and unconventional.

Conventional natural gas resources occur in normal porous and permeable reservoir rock which can be technically and economically produced using normal production practices. Unconventional gas resources generally require different production techniques and are often more costly to produce, if they indeed are to be produced.

Conventional natural gas resources have been discovered in three main areas:

Western Canada Sedimentary Basin (WCSB)

Northern Frontier Areas

East Coast Frontier Areas

The WCSB has been in production for many years, and the Scotian shelf (East Coast Frontier) started producing in 2000. Unconventional gas in Canada has been identified as:

Coalbed Methane ("CBM")

Tight Gas including Shale gas

Gas Hydrates

Notwithstanding the formal designation of CBM, tight gas and shale gas as separate unconventional sources, as we shall see they are being produced in part in conjunction with WCSB conventional resources.

Conventional Gas Resources

Q: Please discuss Canada's conventional gas resource base.

A: The major gas producing area of Canada is the WCSB. It underlies the Provinces of Alberta, British Columbia, Saskatchewan and the southern tip of the Yukon and Northwest Territories. Virtually all of the marketable natural gas produced in Canada comes from the WCSB. The size, location and depth of reservoirs in the WCSB vary widely. Many of the gas wells also produce valuable liquids, and approximately 40 percent of the reserves are sour (the H_2S must be removed before shipping to market).

According to the National Energy Board (NEB), on a Canada-wide basis, the potential undiscovered resources are larger than the amount already discovered. Unfortunately, most of these undiscovered resources will not be available during the next 30 years.

Q: How can Canada's resource base be categorized into components?

A: Canada's resource base can be divided into three categories: remaining established reserves, discovered (unconnected) resources and undiscovered resources as shown in Schedule No. 1. Remaining established reserves is the proven and economically producible gas discoveries given known technology and realistic price expectations. Discovered resources is gas that has been discovered through exploration drilling, but that is not connected and will not be connected to a transportation system for several years due to adverse locations resulting in poor economics. Both of the foregoing categories are considered discovered resources. Undiscovered resources are estimated gas accumulations that are believed to exist but have not yet been proven by drilling.

Schedule No. 1

Schematic Representation of Ultimate Potential Terminology

<table>
<tr><th colspan="2">Terminology</th><th>Relative Level of Uncertainty</th></tr>
<tr><td rowspan="4">Ultimate Potential</td><td>Undiscovered Resources</td><td>High</td></tr>
<tr><td>Discovered Resources</td><td rowspan="3">Medium
↕
None</td></tr>
<tr><td>Reserves</td></tr>
<tr><td>Cumulative Production</td></tr>
</table>

Source: NEB, “Canada’s Conventional Natural Gas Resources, A Status Report” at p. 7 (2004)

The degree of certainty associated with resource estimates can be pictured as a spectrum with the most-certain-to-flow-to market volumes at one end and the least-certain-to-produce at the other end. Within this spectrum are the various categories of gas accumulations as shown in the above diagram. The highest level of certainty is associated with those volumes that have already been produced (cumulative production). The next highest level of certainty is for accumulations that have been proven through exploration and development drilling with some production history (recoverable or remaining reserves). Estimates of recoverable reserves employ standard methods that are generally reasonably accurate. The next higher level of uncertainty is assigned to resources that have been identified through exploration drilling in remote areas but subject to only limited testing of the productive capability due to lack of economically viable methods of reaching markets. Since the productive capability has not been properly tested, there is a higher level of uncertainty, and these accumulations are often referred to as discovered resources rather than discovered reserves.

Finally, estimation of undiscovered resources has the highest degree of uncertainty. Undiscovered resources are estimated by various volumetric and discovery-process methods. In contrast to the estimates of proven gas reserves, estimates of undiscovered gas resources have a much higher degree of uncertainty.

Q: Could you please quantify Canada's resource base?

A: The most recent comprehensive estimate of Canada's resource base was published in the NEB's report "Canada's Conventional Natural Gas Resources, A Status Report" (2004). On May 10, 2006, the Canadian Gas Potential Committee (CGPC) held a press conference announcing the results of its long anticipated report, Natural Gas Potential in Canada 2005. This four-volume report is still in draft form and is scheduled for publication in mid June, 2006. Draft material was made available for inspection in the CGPC offices. The NEB's 2004 and the CGPC's 2005 estimates of the resource base are summarized and compared to other estimates in Schedule No. 2.

Schedule No. 2

Comparison of Estimates of Ultimate Potential by Area (TCF)

Area	NEB 1994	NEB 1999 Case 1	NEB 1999 Case 2	NEB 2003 Supply Push	NEB 2003 Techo-Vert	NEB 2004	EUB/NEB 2005	NEB/BC 2006	CGPC 1997	CGPC 2001	CGPC 2005
WCSB Conventional											
Alberta	195	270	214	206	217	207	223	223	193	203	218
British Columbia	51	50	37	33	50	51	51	52	38	34	NA
Saskatchewan	8	9	9	9	9	9	9	9	6	9	NA
Southern Territories	1	6	4	2	2	7	7	7	7	2	NA
WCSB Conventional Total	**255**	**335**	**264**	**250**	**278**	**274**	**290**	**291**	**263***	**249**	**279**
Other Conventional											
Ontario/Gulf St. Lawrence	1	2	2	3	3	3	3	3	3	3	3
Mackenzie/Beaufort**	79	75	75	75	75	70	NA	70	59	35	38
Scotian Shelf	18	18	18	23	23	23	NA	23	13	11	5
Other Regions	230	228	228	139	139	131	NA	131	35	43	43
Other Conventional Total	**328**	**323**	**323**	**240**	**240**	**227**	**227**	**227**	**110**	**93**	**89**
Total Conventional	**583**	**658**	**587**	**490**	**518**	**501**	**517**	**517**	**373**	**342**	**368**
WCSB Unconventional	NA	75	75	60	80	NA	NA	NA	NA	NA	11-45
Total Canada	**583**	**733**	**662**	**550**	**598**	**501**	**517**	**517**	**373**	**342**	**378-412**

*Note: The CGPC 1997 WCSB Conventional Total includes 25 TCF of gas in conceptual plays that has not been allocated to individual regions.
** Includes Yukon and NWT outside of WCSB.

Sources:
NEB 1994: Canadian Energy--Supply and Demand 1993 - 2010; Appendix to Technical Report, (Table A6-17).
NEB 1999: Canadian Energy--Supply and Demand to 2025, (Table 5.1, p. 43).
NEB 2003: Canada's Energy Future, Scenarios for Supply and Demand to 2025 (2003, Table A6.1).
NEB 2004: Canada's Conventional Natural Gas Resources, A Status Report, (April 2004, p. 4).
EUB/NEB 2005: Alberta's Ultimate Potential for Conventional Natural Gas (March 2005, p. 13).
NEB/BC 2006: Northeast British Columbia's ultimate Potential for Conventional Natural Gas (March 2006, p. 14)
CGPC 2001: Canadian Gas Potential Committee, Natural Gas Potential in Canada 1997 (Figure 1.2 and 1.3).
CGPC 2001: Canadian Gas Potential Committee, Natural Gas Potential in Canada 2001 (Ch. 1, p. 1 & 10).
CGPC 2005: Canadian Gas Potential Committee, Natural Gas Potential in Canada 2005 (4 Volumes).

Q: Would you please explain the significance of these numbers?

A: The conventional resource potential in the WCSB is the most important component of the ultimate potential numbers since this will form the bulk of the Canadian gas supply for GTN over the next 15 to 20 years. The WCSB conventional gas potential estimates range from a high of 335 TCF (NEB, 1999 Case 1) to a low of 249 TCF (CGPC 2001). The bulk of this difference is accounted for by swings in the estimated Alberta resource base, which ranges from a high of 270 TCF (NEB 1999 Case 1) to a low of 193 TCF (CGPC 1997). I discuss the other resource estimates below.

Q: Since the Alberta ultimate potential number is so important to this proceeding, which estimate do you think is the most reasonable?

A: I use the conventional estimate for Alberta from the 2005 joint study by the EUB and the NEB (*i.e.*, 223 TCF for Alberta), which is only 5 TCF higher than the 218 TCF estimated by the CGPC in its 2005 report. I also note that the 223 TCF for Alberta is the second highest estimate for Alberta, exceeded only by the NEB's 1999 Case 1 estimate of 270 TCF.

Q: What estimate do you use for the WCSB total?

A: I rely on the latest NEB numbers as reported in the 2006 joint report with the BCMENPR. I note that of the 11 different estimates cited in Schedule No. 2, I relied on the second highest estimate for WCSB conventional resources. While this estimate is much higher than many of the other estimates, including the most recent estimate by the CGPC, I have selected it to give the benefit of the doubt to proponents of a larger resource base. This higher resource estimate also makes an allowance for "unconventional" tight and shale gas produced through wells that also produce conventional resources as described below.

Q: What about the conventional ultimate potential outside of the WCSB?

A: I recommend using the CGPC's 2001 estimate of 93 TCF for other conventional, which is virtually identical to the CGPC 2005 estimate of 89 TCF. Both the NEB and CGPC estimates for other potential have been decreasing over time, but the NEB 2004 estimate of 227 TCF is almost 2.5 times as high as the CGPC estimate of 93 TCF. This is a significant difference, and the CGPC addressed this issue in the executive summary to its 2001 report:

> "Comparison between the results of CGPC-2001 and other assessments reveals that it is as much as 300 TCF lower than numbers commonly quoted as the Marketable gas available in Canada. The difference is mainly due to the attribution by other estimators of large gas volumes to high-risk Conceptual Exploration Plays, which in the Committee's view results in a significant overestimation of the amount of gas that may be available in Canada."

Greater detail on the CGPC's concerns is provided in a section entitled "Comparison with Other Assessments" (CGPC 2001, Chapter 2, pages 12-14). The main concern is the large amount of potential resources that are assigned to conceptual plays. A conceptual play is an exploration play that geological analysis suggests may exist but with respect to which no gas has been discovered. According to the CGPC, many conceptual plays fail to materialize as drillable prospects. The CGPC review is particularly critical of the approach used by the NEB and Geological Survey of Canada for failing to properly assess the risk and that this failure leads to a systematic over-assessment of the potential in conceptual plays.

Q: How do gas prices and economics affect estimates of ultimate potential?

A: The EUB discussed the impact of economics (EUB/NEB 2005 update, page 13):

EUB *Report 92-A* suggested that at higher gas prices, the incremental increase in ultimate potential due to increases in gas price is quite small. Given today's relatively high gas prices, it is unlikely that a significant impact on the ultimate potential would occur due to future increases in gas price.

Q: How does economics affect the frontier areas, and have any of the assessments of these areas considered economics?

A: From 1974 until 1993, the Canadian Association of Petroleum Producers (CAPP) and its predecessor agency (Canadian Petroleum Association) carried established gas reserves for the Mackenzie Delta/Beaufort Sea and Arctic Islands. These reserves were initially booked at a time when it was widely believed that gas prices would increase significantly and production/transportation facilities would be developed reasonably quickly. These volumes were subsequently removed from the established reserve category in recognition of the unfavorable economics and the length of time until infrastructure would be developed to move this gas to market.

Q: What conventional resource base do you recommend should be used for this proceeding?

A: I recommend using the NEB 2006 estimate for the WCSB of 291 TCF and combining this with the CGPC 2001 estimate of 93 TCF for resources outside of the WCSB. Of the resources outside the WCSB, only offshore Nova Scotia with 11 TCF, the Mackenzie Delta/Beaufort Sea/Yukon/NWT with 35 TCF, and Ontario with 3 TCF are relevant to this proceeding. The resulting resource base is 340 TCF including the 291 TCF for the WCSB discussed above.

Q: How much of this ultimate potential is left to be found and produced?

A: Cumulative WCSB production to the end of 2005 was 150 TCF. If we use the 291 TCF ultimate potential for the conventional WCSB, the remaining ultimate potential is 141

TCF, and this is a combination of discovered resources that have not been produced and undiscovered potential that remains to be found. I recommend using the CGPC's 2001 estimate of 11 TCF of ultimate potential for the Scotian Shelf even though the CGPC reduced this estimate to only 5 TCF in its 2005 report due to the disappointing production and exploration results in the area. Both the NEB and CGPC estimate the Ontario potential at 3 TCF. Twelve TCF of potential remains for the Scotian Shelf and Ontario since 2 TCF has been produced. This gives a total remaining potential for the producing areas of 153 TCF. Combined with the CGPC frontier potential, the remaining conventional ultimate potential is 230 TCF as shown in Schedule No. 3.

Schedule No. 3

Remaining Conventional Ultimate Resource Potential (TCF)

Region	Ultimate Resource Potential	Cumulative Prod. to Dec. 31, 2005	Remaining Potential
WCSB Conventional	**291**	**150**	**141**
Alberta	223	124	99
British Columbia	52	20	32
Saskatchewan	9	6	3
Southern Territories	7	1	6
Other Producing	**14**	**2**	**12**
Ontario	3	1	2
Scotian Shelf	11	1	10
Frontier	**79**	**0**	**79**
Mackenzie/Beaufort	35	0	35
Other Frontier	44	0	44
Total	**384**	**152**	**232**

Unconventional Gas Potential

Q: What resource estimates are available for unconventional gas in Canada?

A: Most of the estimates of unconventional gas resources focus on gas in place. A number of estimates indicate large in-place resources. Proponents of significant recovery factors to calculate marketable gas engage in a guessing game since the unconventional gas industry is in its infancy and the production history is minimal.

Q: Please elaborate on coalbed methane.

A: Several agencies and organizations have published estimates of CBM in the WCSB, the only region where CBM is relevant for this proceeding. The NEB provided a summary of estimates of CBM potential shown in Schedule No. 4. I have added the 2005 CGPC estimate to this table.

Schedule No. 4

Estimates of Coalbed Methane for the WCSB

Agency/organization	Year	Gas in place TCF	Marketable gas TCF
Alberta EUB	1992	250+	
TCPL/Sproule	1998	214	
National Petroleum Council	1992		129
CGPC	1997	304-543	135-261
NEB	1997		75
CGPC*	2005	528	11-45

* The CGPC 2005 estimate of gas in place is for all known coal deposists in Canada but the estimated marketable gas is for the WCSB only

Source: NEB, Canadian Energy Supply and Demand to 2025 (1999, p. 42).
NEB, Canadian Energy Supply and Demand to 2025 (1999, p. 42).
CGPC 2005: Natural Gas Potential in Canada 2005 (4 Volumes).

In its 2003 report, "Canada's Energy Future: Scenarios for Supply and Demand", the NEB adopted two ultimate potential estimates of 60 and 80 TCF. The NEB states,

> Very little development of unconventional natural gas has occurred to date; consequently, the uncertainty associated with estimates of unconventional natural gas resources is very high. (p. 64)

These estimates are nothing more than best guesses which are included since analysts assume that there will be production from this source. An important question, regardless of the resource estimate, is how quickly these resources can be turned into gas supply. I will return to this question after I discuss the supply potential for conventional gas from the WCSB.

Canadian Gas Supplies

Q: How do you propose to discuss the gas supply potential for Canada?

A: I do this in two stages. First, I review the NEB's two most recent Canadian gas supply forecasts and show that these forecasts are being reduced over time. Then, I present a forecast of the conventional WCSB supply potential reflecting recent drilling results and well performance trends. This will be supplemented by forecasts of CBM production from the WCSB, possible gas from LNG imports and production from the Mackenzie Delta. The impact of Alaskan gas production flowing through the WCSB is also explored. Finally, I will analyze the gas supply potential in Eastern Canada.

Q: What has happened to the NEB's production outlook?

A: I compare the forecasts in the NEB long term supply/demand reports published in 1999 and 2003. The NEB produced two forecasts for both reports. Case 1 from the 1999 study shows production increasing throughout the forecast period to reach 26 BCF/d in 2025. The 1999 Case 2 production peaks in 2015 at 22 BCF/d and then remains relatively flat for the remainder of the period.

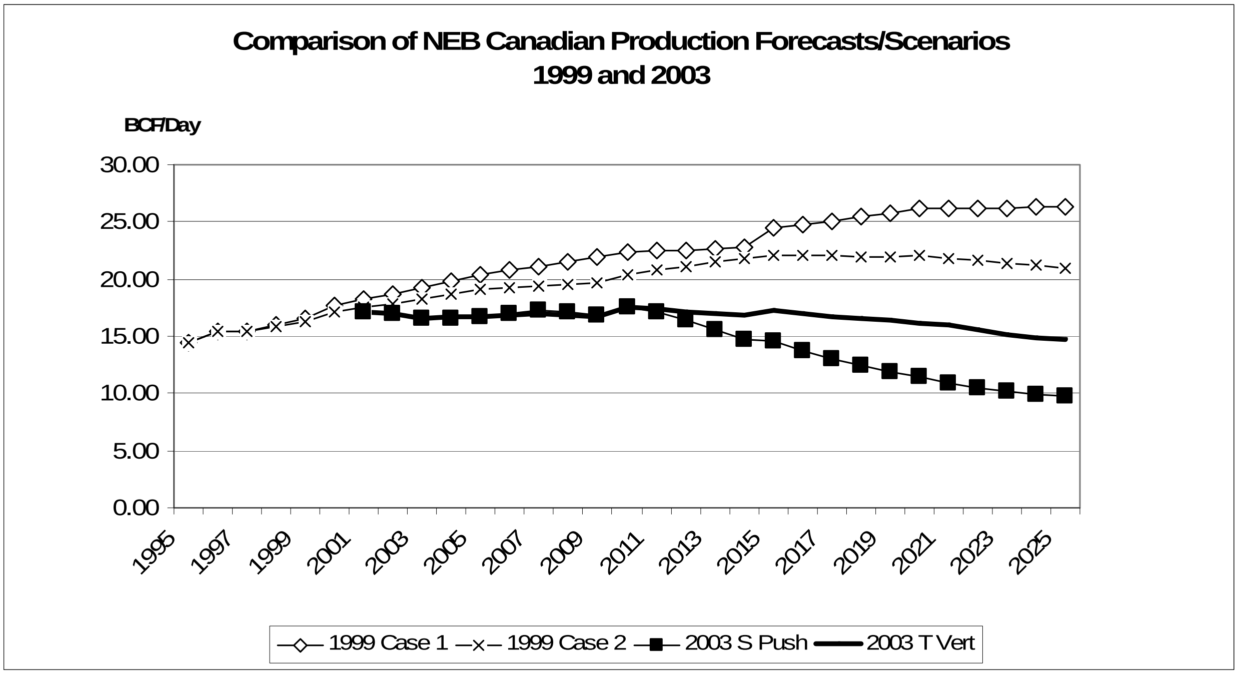
The NEB adopted a scenario-based approach in which two energy futures were explored for its 2003 study — a Supply Push scenario and a Techno-Vert scenario. The two scenarios are described as follows (NEB, 2003, p.3):

> "The ***Supply Push*** scenario represents a world in which technology advances gradually and Canadians take limited action with respect to the environment. The main theme of this scenario is security of continental energy supply and the push to develop known conventional sources of energy.
>
> The ***Techno-Vert*** scenario represents a world in which technology advances rapidly and Canadians take broad action with respect to the environment and the accompanying preference for environmentally-friendly products and cleaner-burning fuels."

The NEB's deliverability forecasts have decreased significantly between the 1999 and 2003 reports as shown in Schedule No. 5. The 2003 forecasts for the Supply Push and Techno-Vert scenarios are virtually identical until they begin to diverge in 2011. In the Supply Push scenario, production peaks at 17.1 BCF/d in 2010 when Mackenzie

Delta gas is assumed to begin flowing, and then declines throughout the remaining forecast period. The Techno-Vert scenario also peaks in 2010 and then remains relatively flat until 2015 before declining. These peaks in the 2003 forecasts are 35% and 23% lower than the 1999 Case 1 and Case 2 peaks respectively.

Schedule No. 5



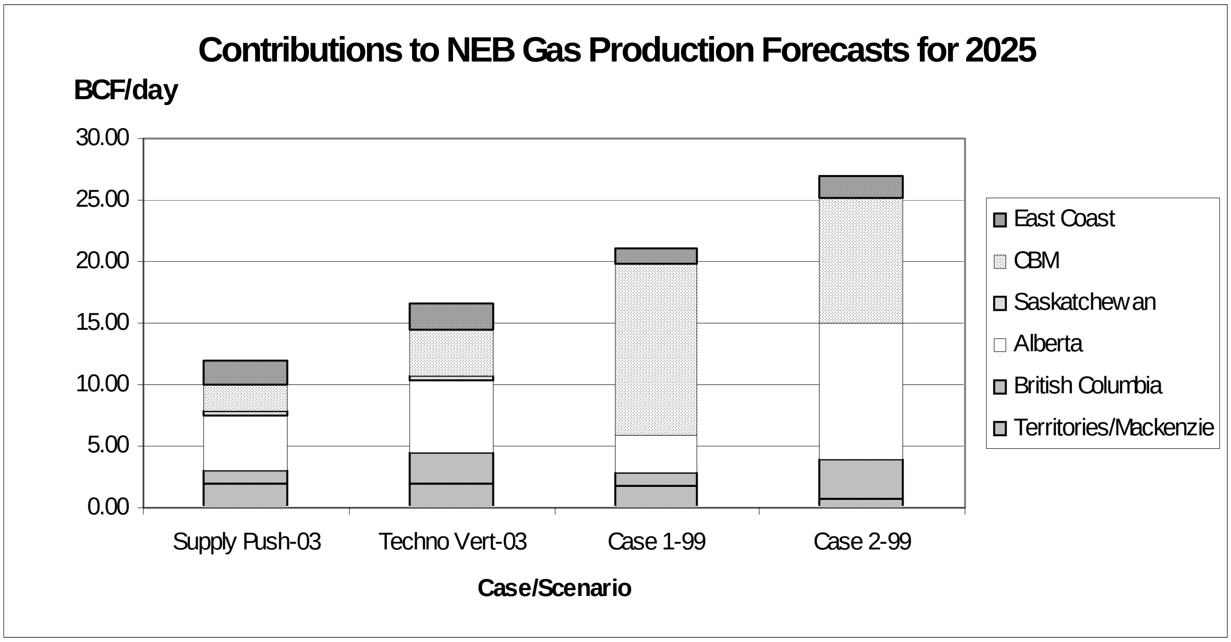
Q: Is this the latest gas supply forecast provided by the NEB?

A: No. The NEB's latest forecast was reported in its Energy Market Assessment, "Short Term Natural Gas Deliverability, 2005-2007" (October 2005). The forecasts in this report differed by 1% or less from the forecasts in the 2003 report for each of the three years.

Q: What accounts for the major difference between the 1999 and 2003 forecasts?

A: The 2003 scenarios have much lower volumes of CBM production in 2025 as shown in Schedule No. 6. The other major swing in the forecasts is the major decline in production expected from WCSB conventional reservoirs, especially in Alberta.

Schedule No. 6



Q: Please describe how you assess the gas supplies available to GTN.

A: GTN can only access Canadian gas supplies through the WCSB. This gas must either be produced in the WCSB or supplement WCSB production. I analyze the conventional gas production potential of the WCSB and compare this to the latest NEB forecasts. Then I examine the CBM drilling and production information available for the WCSB to date, examine the available economic information, and propose a CBM production scenario over the period to 2035.

The information on WCSB supplies is supplemented with a discussion of the volumes of gas that might flow into the WCSB from the Mackenzie Delta and Alaska as well as west coast LNG potential to determine the total gas supplies that could be available to the WCSB pipeline nexus. As I show below, total available WCSB supply cannot satisfy all intra-WCSB gas requirements and fill the total takeaway demand for gas by pipelines moving gas out of the WCSB, including GTN. Particularly, the data below demonstrate that the total available supply, compared to total intra-WCSB requirements and takeaway capacities, will produce a significant shortfall long before the end of the period under review.

Q: Are there any other considerations that come into play in determining the economic life of GTN?

A: Yes. The demand by other pipelines that compete with GTN for gas supplies from the WCSB will be affected by gas supplies that enter the marketplace they serve. For example, the demand for WCSB gas by the TCPL/Iroquois system may be affected by gas supplies available from the east coast. Either a rapid expansion of Atlantic Canada gas production or LNG capacity would trigger an expansion of the Maritimes & Northeast pipeline and could potentially back gas out of the TCPL system and make more gas available for GTN. A continued downward spiral of Sable Island gas would have the opposite effect. These secondary impacts will be discussed after the net supply available from the WCSB is analyzed.

WCSB Conventional Gas Production

Q: Please provide an overview of how you analyzed WCSB gas supplies.

A: A number of studies have identified characteristics of new gas discoveries, and my analyses make extensive use of this information to reflect performance of new wells. Over 65% of the gas wells drilled in the WCSB were drilled between 1990 and 2004. Trends in the initial productivity of gas wells connected over this period were analyzed and applied to calculate future production.

Q: Please explain your analysis in simple terms.

A: The production forecast consists of two components—those wells producing at the beginning of the forecast period (end of 2005) and new wells added in subsequent years.

The performance of new wells is determined by three parameters. First, the initial productivity (production in the first year of a well's producing life) for new gas wells is based on an analysis of the historical trends from 1990 through 2004. The forecasted decline in initial productivity is derived from the observable trends in historical data, and these trends are used to forecast the initial performance of wells connected in future years.

Second, the productivity in the second and subsequent years of a well's producing life is derived from the actual production performance over time of wells connected in recent years. The productivity performances observed for wells connected in recent years were analyzed to determine the productivity performance of wells over their productive life after the first year.

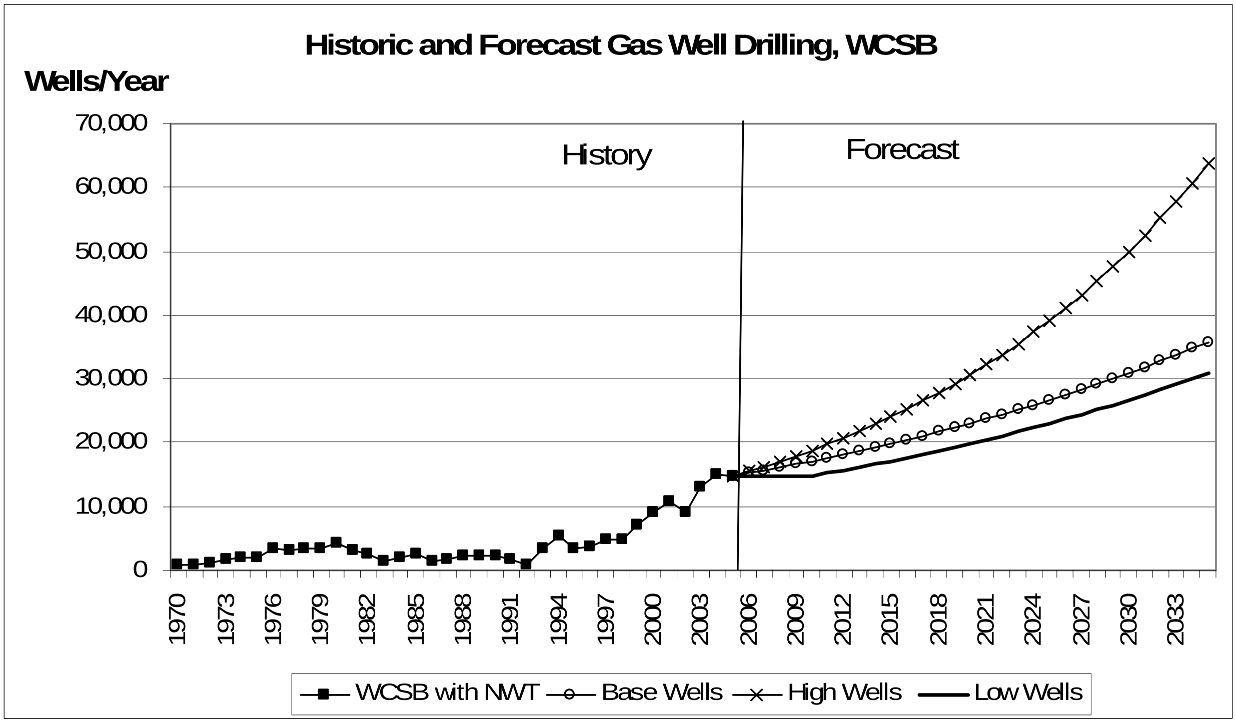
Third, wells connected in any particular year are assumed to remain on production until the productivity level declines to an economic limit.

The production from new wells is added to the production from existing wells producing at the end of 2005. WCSB production from the existing wells starts from 16.5 BCF/day for 2005. This base is adjusted using annual decline rates derived from production profile data for existing wells in the NEB 2003 report on energy scenarios.

Q: What are the conclusions of your analysis?

A: Three scenarios for the number of wells are shown in Schedule No. 7. The number of wells in the base case is increased at 3% per year from the 2005 level. The 36,000 wells drilled in 2035 are more than double the 15,000 successful gas wells completed in each of 2004 and 2005. Almost 724,000 gas wells are included in the base case drilling scenario from 2006 to 2035, over 4.5 times as many as have been drilled to the end of 2005. In the high wells scenario, the number of wells is assumed to increase by 5% per year from the 2005 level to end the period at 64,000 per year. In this case, over 1 million additional gas wells would be drilled by 2035, over 6.5 times the number drilled to the end of 2005.

Schedule No. 7



Q: Will it be possible to drill this many wells?

A: That is a good question and I think the answer is no. Gas prices in 2005 were at an all-time high, and drilling rigs were in high demand. However, preliminary estimates suggest that 275 fewer gas wells were completed in 2005 than in 2004. The decline in gas well completions occurred in an environment of record gas prices. Gas prices have fallen since the end of 2005, and this has triggered several announcements of cuts in exploration budgets. It is highly likely that fewer gas wells will be drilled in 2006 than in 2004 or 2005. The Canadian Association of Oilwell Drilling Contractors data support this contention and indicate that fewer gas wells were completed in the first four months of 2006 than in either 2004 or 2005.

Since this aggressive drilling schedule is unlikely to be met, I included a lower wells scenario where the number of gas wells completed is held constant at the 2005 level through 2010. The number of wells is assumed to increase by 3% per year from that point forward.

The drilling sector is straining to meet demand at the present time. The rig fleet has expanded significantly in the last few years. However, there is a lot more to drilling and completing a well than just getting a drilling rig onsite to drill the hole. The drilling rig must be supported by a host of other services such as mud supply, testing, logging, cementing and casing the well. Many of these tasks require specialized knowledge. Unfortunately, the supply of qualified workers has not expanded along with the rig fleet. It is highly unlikely the number of gas wells included in the high case can be drilled along with the inevitable dry holes, service wells and oil wells, and the number in the base case is also uncertain.

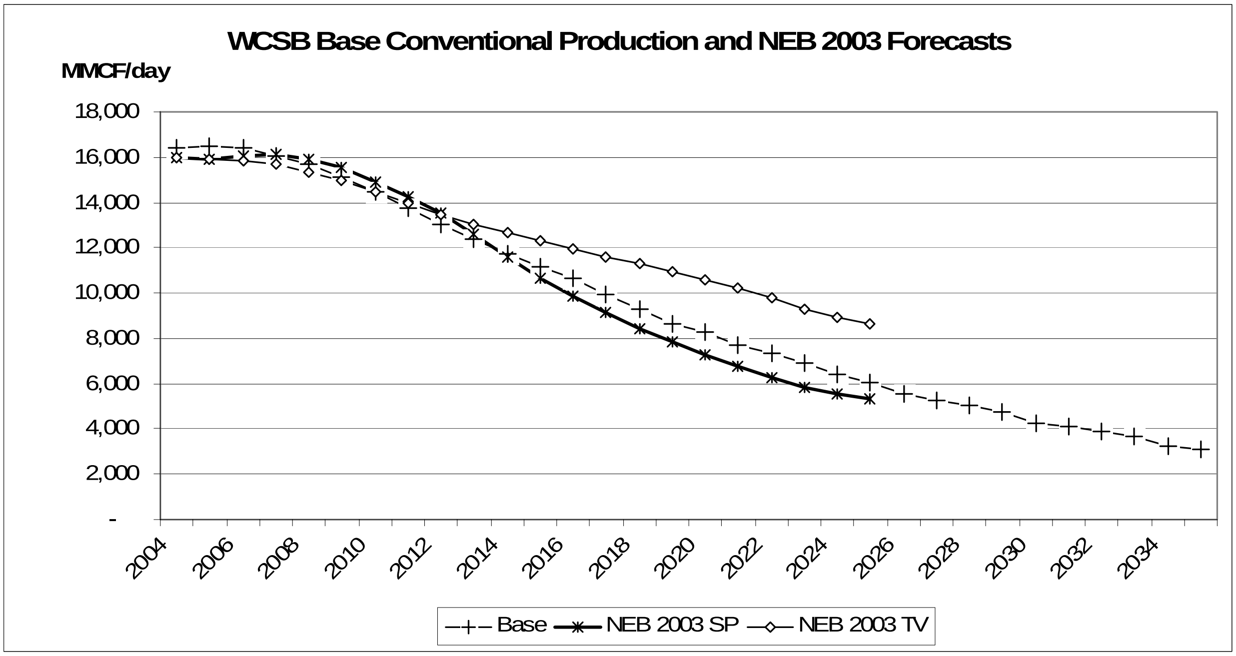
Q: If there is a shortage of workers, why doesn’t the wage rise so that workers will switch jobs from other sectors or migrate from other regions of Canada?

A: Traditionally, farm laborers were one of the major sources of oilfield workers, but this source has disappeared with the consolidation of the farming sector. Furthermore, the boom in Alberta construction is creating intense competition since the construction industry requires many of the same skills as the oilfield services industry. The problem is exacerbated by the boom in the oilsands industry where projects worth tens of billions of dollars are under construction and labor shortages are also a critical factor. The problem in the future will be compounded by the anticipated construction of the Mackenzie Valley gas pipeline scheduled to come on-stream early in the next decade, and British Columbia is just gearing up to build facilities for the 2010 Olympics anticipated to cost hundreds of millions of dollars. Hence the problem is likely to get worse over the next few years. Workers from other parts of Canada often find the wages and working conditions in the oilsands areas and construction industry are more attractive than the “migrant” types of jobs available in the oilfield services industry. Moreover, oilfield services employment is seasonal with peaks in the winter. This requires working outdoors, often in adverse climate which is a deterrent to recruiting oilfield workers.

Q: If we assume all these wells can be drilled, what are your conclusions about conventional WCSB gas supplies?

A: My base forecast is slightly above the NEB Supply Push and Techno-Vert forecasts for 2006. Then my forecast drops below the Supply Push forecast and is between the two NEB scenarios until 2011, is below both forecasts from 2011 through 2013, and then remains between the two NEB scenarios for remainder of the forecast period. These results are shown in Schedule No. 8.

Schedule No. 8



Q: Did you do any sensitivity analysis on your production forecast?

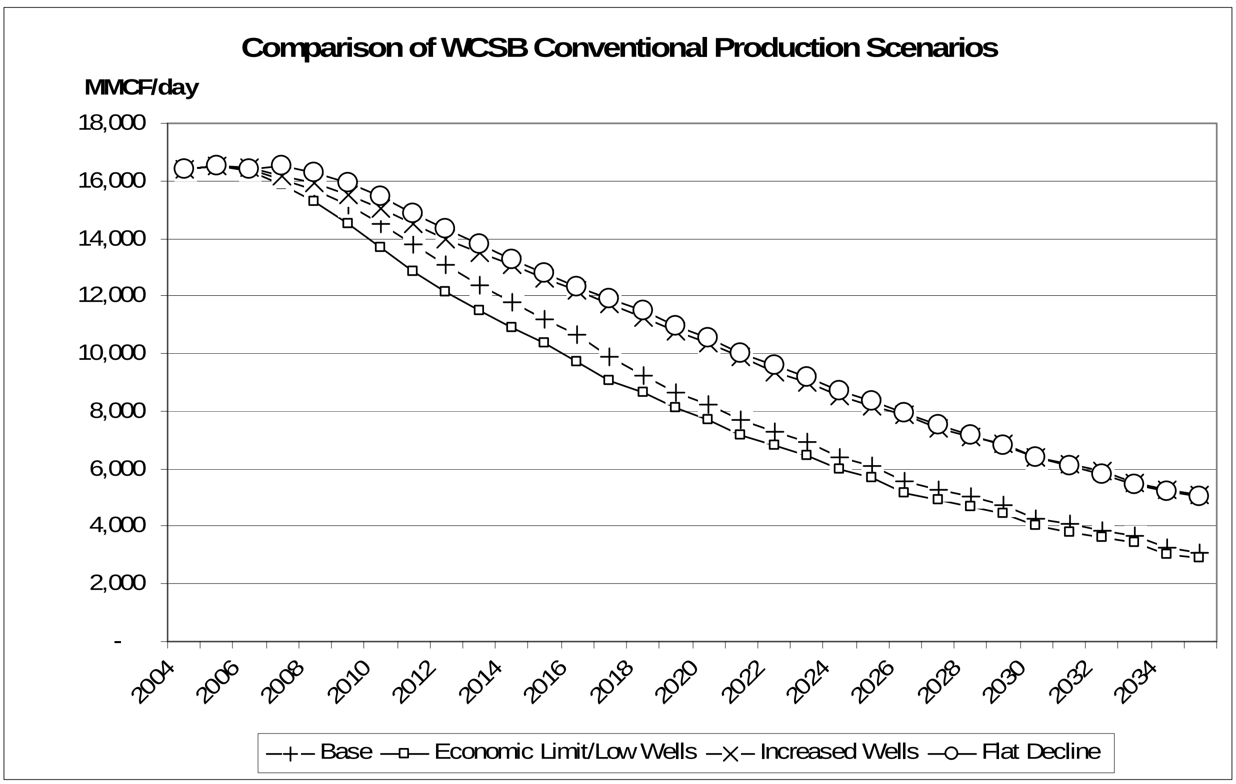
A: Yes. The base forecast in Schedule No. 8 incorporates a well drilling scenario which increases the number of wells drilled by 3% per year beginning in 2006. It also uses well performance parameters derived from the trend in values over the period from 1990 though 2004. The two critical parameters are the initial production rate of the new wells connected in each year, and the rate at which the production of individual wells connected in specific years declines over time. These parameters are varied with the year in which the wells are connected based on an analysis of historical trends. In the base case, the economic limit is set at a very low 5 MCF/day/well.

Three scenarios were analyzed to determine the sensitivity of the results to the numbers of wells, the rate of decline, and the economic limit. In the first scenario, the number of wells drilled was increased by 5% per year beginning in 2006. In the second scenario, the decline rate for wells connected in all years was held constant at the level calculated for wells connected in 2004. The final sensitivity imposes an economic limit of

10 MCF/day/well and the number of wells drilled is held constant at the 2005 level until 2010 and then increased 3% per annum beginning in 2011.

The results of these scenarios are shown in Schedule No. 9 relative to the base case. It is apparent from this schedule that increasing the number of wells or holding the decline rate constant does provide a boost to the production profile and these two scenarios are almost identical. Production in the final year of the forecast is almost 2 BCF/day higher in the flat decline and higher wells cases than the base case. Imposing an economic limit of 10 MCF/day/well and combining this with the slower well drilling scenario, the final-year production is 0.2 BCF/day lower than the base case. However, the base case was over 1 BCF/day higher than the low case in 2016.

Schedule No. 9



Q: How reasonable are these production scenarios?

A: In my opinion, only the base and the economic limit/low well cases are realistic and can be realized over the next 30 years. The base case is very aggressive and will be a challenge since completing the specified number of gas wells will be difficult. Schedule No. 10 shows the production profiles for the four scenarios along with the production profiles from the NEB's 1999 and 2003 reports. The bottom of the schedule includes the total reserves that will have to be discovered and produced over the analysis period and compares this to the WCSB remaining conventional ultimate potential of 141 TCF at the beginning of 2006.

The base scenario uses well performance parameters derived from recent historical data showing the initial well productivity is lower for wells connected in more recent years. Also, wells connected in later years have higher annual decline rates than wells connected in earlier years. If these trends are continued into the future, the number of completed gas wells will have to increase at about 3% per year to find about 78% of the remaining ultimate potential estimated to exist at the end of 2004. These discoveries are needed to satisfy production and provide the necessary reserves to support the production in the last year. If an economic limit of 10 MCF/day/well is imposed along with the slower drilling schedule, about 74% of the potential would have to be found by 2035.

Schedule No. 10

WCSB Conventional Gas Production Forecasts and Remaining Undiscovered Potential

(MMCF/DAY)

Year	Base	Economic Limit/Low Wells	Flat Decline	Increased Wells	NEB 2003 SP	NEB 2003 TV	NEB 1999 Case 1	NEB 1999 Case 2
2004	16,404	16,404	16,404	16,404	15,987	15,987	19,211	18,027
2005	16,520	16,520	16,520	16,520	15,944	15,944	19,726	18,384
2006	16,428	16,366	16,428	16,469	16,041	15,851	20,022	18,438
2007	16,049	15,848	16,507	16,185	16,120	15,677	20,318	18,493
2008	15,675	15,266	16,312	15,913	15,927	15,323	20,614	18,548
2009	15,150	14,521	15,928	15,516	15,543	14,943	20,910	18,603
2010	14,496	13,680	15,426	15,029	14,897	14,451	21,205	18,658
2011	13,782	12,851	14,864	14,503	14,280	13,977	21,288	18,186
2012	13,058	12,116	14,312	13,996	13,513	13,483	21,370	17,715
2013	12,381	11,466	13,790	13,519	12,608	13,035	21,452	17,244
2014	11,759	10,877	13,291	13,060	11,620	12,690	21,534	16,773
2015	11,178	10,334	12,810	12,613	10,669	12,317	21,616	16,301
2016	10,632	9,709	12,345	12,175	9,894	11,924	21,293	15,008
2017	9,905	9,077	11,896	11,747	9,149	11,572	20,970	13,715
2018	9,257	8,624	11,461	11,265	8,402	11,288	20,647	12,422
2019	8,662	8,089	10,983	10,752	7,819	10,925	20,323	11,129
2020	8,245	7,689	10,528	10,335	7,307	10,562	20,000	9,836
2021	7,692	7,173	10,026	9,859	6,736	10,259	19,008	8,751
2022	7,312	6,807	9,601	9,376	6,244	9,780	18,016	7,666
2023	6,943	6,455	9,186	8,999	5,855	9,297	17,025	6,581
2024	6,413	5,964	8,708	8,522	5,559	8,949	16,033	5,496
2025	6,083	5,655	8,320	8,179	5,329	8,623	15,041	4,411
2026	5,550	5,173	7,948	7,851				
2027	5,271	4,914	7,499	7,403				
2028	5,010	4,672	7,160	7,114				
2029	4,764	4,443	6,834	6,840				
2030	4,284	4,011	6,410	6,410				
2031	4,076	3,817	6,114	6,165				
2032	3,878	3,633	5,832	5,931				
2033	3,690	3,458	5,437	5,493				
2034	3,239	3,038	5,185	5,287				
2035	3,104	2,894	5,028	5,089				
Total (TCF)	108.4	102.8	127.4	125.8	89.6	101.1	159.7	113.3
2035 production (TCF)	1.13	1.06	1.84	1.86	1.95	3.15	5.49	1.61
2035 reserves @ R/P=5	5.66	5.28	9.18	9.29	9.73	15.74	27.45	8.05
Total discovered	114.03	108.05	136.59	135.04	99.31	116.79	187.18	121.34
Undiscovered Potential	32.97	37.95	9.41	10.96	46.69	29.21	(41.18)	24.66

Q: Please tell us about the other two scenarios. Are these plausible?

A: No, I don't think they are plausible since these two cases essentially run out of resources. The high drilling scenario is essentially out of the question since 126 TCF will be produced by 2035, and another 9 TCF of discovered reserves will be required to support the final-year production rate of 1.86 TCF assuming an R/P ratio of 5. The total resource requirement of 135.4 TCF would only leave 11 TCF of remaining undiscovered ultimate potential at the end of 2035, just 8% of the amount at the beginning of the analysis period. The flat decline analysis is even more questionable for the same reasons.

The NEB 1999 Case 1 scenario is an illustration of the implications of maintaining a production rate that is not sustainable because the 160 TCF produced by 2025 exceeds the entire resource base as shown in Schedule No. 10.

In summary, the WCSB remaining conventional resource base is inadequate to maintain production at recent levels. Indeed, WCSB conventional production peaked either in 2001 (CAPP) or in 2002 (Statistics Canada). Hence I discuss other sources of supply that will need to be brought on stream to maintain production at recent levels.

WCSB CBM Potential

Q: Please tell us about the CBM potential of the WCSB.

A: CBM can potentially make a significant contribution to WCSB gas supplies. The in-place gas resources are huge; the challenge is to establish production processes that are both economic and environmentally acceptable. These constraints need to be recognized when evaluating possible sources of CBM.

Schedule No. 11 provides a summary of the main potential in Alberta. The in-place resources reported in this schedule are substantial. However, aside from the Horseshoe Canyon ("HSC") formation, so little is known about the production potential that there are only guesses about the amount of this resource that will be producible in a way that is both commercially profitable and environmentally acceptable.

Schedule No. 11

Characteristics of Coalbed Methane Resources in Alberta

Formation	Coal Seam	Gas in Place (TCF)	Net Coal Thickness	BCF/Sec.	Comments
Scollard	Ardley	53	5-20	2-10	Limited permeability but seems to be variable; two small areas with favorable potential focus of exploration
Horseshoe Canyon	Carbon Thompson	14	2-5	0.5-1.5	Discontinuous, thin, little interest
Horseshoe Canyon	Daly-Weaver	14			Discontinuous, variable thickness, little interest
Horseshoe Canyon	Drumheller	38	2-18	2-6	Main CBM target to date, Large area with > 4m thickness and some over 10 m thick; discontinuous, under-pressured, moderate permeability; low water
Belly River Group	Lethbridge	18	2-4	0.5-1.25	Shallow, low pressure, thin, discontinuous, a few areas of interest with 3-4 m thickness but less than 0.75 BCF/sec; limited potential
Belly River Group	Taber	20	2-4	0.5-1.25	Thin, shallow, limited area with >2m thickness
Belly River Group	MacKay	28	2-4	< 0.5	Discontinuous, small areas with > 3m thickness but < 0.75 BCF/section
Mannville Group	Mannville	320-400	4-12		Several large areas with > 4m thickness and > 8 m common, areas shallower then 1,500 m attractive targets; areas with 4 m at least 5 BCF/section and areas with 8 m up to 10 BCF/sec. Little public data but seems to have low permeability but variable over small distances in same seam; may have potential in pockets with higher permeability; produces lots of saline water.

Source: A. Beaton, Production potential of coalbed methane resources in Alberta; Alberta Energy and Utilities Board, EUB/AGS Earth Sciences Report 2003-03.

Q: How has CBM drilling and production evolved in Canada?

A: Exploration for and development of CBM in Canada is in its infancy relative to the United States where the CBM industry has been very active for over two decades. Exploration for CBM began in 1977 in the foothills of southwestern Alberta. This was followed by several other futile attempts to establish commercial CBM production over the next 20 years when approximately 140 CBM wells were evaluated.

The first commercial CBM success in Canada was announced in 2002 in Southern Alberta in the Horseshoe Canyon formation. Since that time, many wells have been drilled into the HSC. AJM Petroleum Consultants estimated that 2,065 wells were producing from HSC coal seams on March 31, 2005, with total production of 180 MMCF/d for an average of 87 MCF/day/well. During December 2005, some 318 MMCF of gas was produced by 3,337 wells producing from all CBM formations for an average of 95 MCF/day/well. This compares with average production of 167 MCF/day/well for conventional WCSB production. The HSC wells produce very little if any water which makes them somewhat unique as CBM wells and helps keep the operating costs down.

The median HSC well depth is relatively shallow and wells can be drilled very quickly. Initial productivity ranges from 20 to 500 MCF/day/well. Wellhead pressures tend to be low and adding compression is very important. These are not great wells, and the fact that they are located in areas with existing infrastructure with excess capacity assists with the economics.

The CBM in the Mannville formation is also attracting a lot of attention. The Mannville has different characteristics than HSC, some of which are beneficial and some of which are detrimental. For instance, the formation is deeper (more expensive to drill), saline water is produced that must be re-injected, and permeability tends to be low.

The Mannville coals tend to be quite deep and have low permeability, and the permeability varies both laterally and stratigraphically over small distances. Since permeability is inversely related to depth, the CGPC did not include any resources below a depth of 1200 metres (3,940 feet) in its 2001 assessment. Much of the Mannville coal is deeper than this cutoff and reaches depths of 4,000 metres (13,100 feet) in the western part of the basin.

Scores of wells have been drilled into Mannville coals. In June 2005, several pilots reportedly were operating 56 wells producing about 2 MMCF/d (equivalent to 36 MCF/day/well) and about 5,000 barrels of water per day. Trident Exploration operates the oldest pilot project in the Mannville (since 2000), and in July 2005 Trident announced that the project will be expanded to a commercial scale. This declaration of commerciality will no doubt encourage further attempts to locate additional areas where developers hope the combination of parameters will result in a profitable operation.

Unfortunately, insufficient public information is available on Trident's pilot project to prepare a forecast of production potential.

It remains to be seen how quickly or successfully the industry can develop techniques to exploit this resource. As of May, 2006, I am unaware of any announcements of commercial CBM projects in the Mannville other than the Trident project.

Q: How did you analyze CBM production?

A: I concentrated on potential CBM production from the HSC formation since this is the only formation that has any useful commercial CBM information in the public domain. I make some remarks about CBM in the Mannville formation after I discuss the HSC analysis and results.

The HSC analysis is based on information in a presentation by Dave Russum ("Current Status of CBM in Western Canada", The Canadian Institute 4th Annual Coalbed Methane Symposium, June 13-14, 2005). Russum stated that the average HSC well is expected to produce approximately 300 MMCF and that about 48,000 wells will be required to drain the fairway. This implies 14 TCF of recoverable gas.

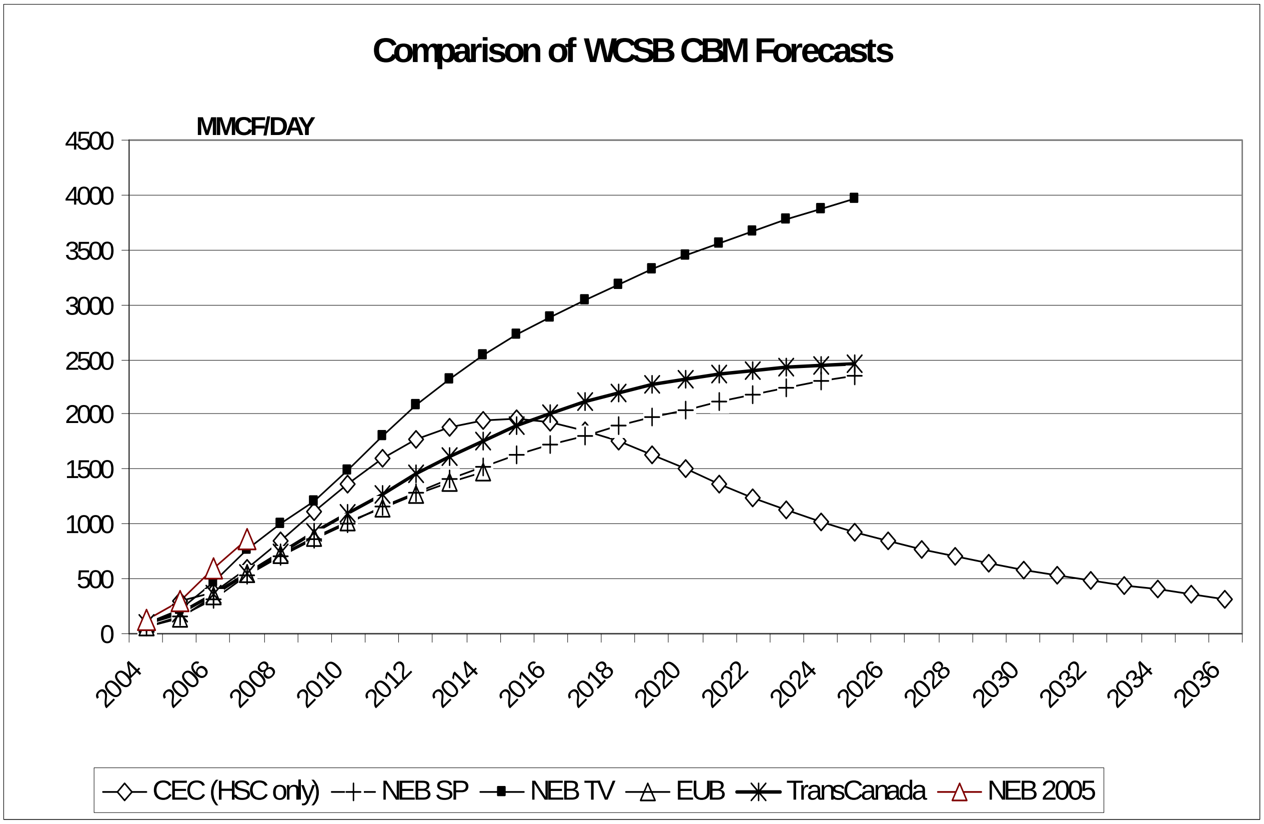
The number of HSC wells is projected to increase fairly rapidly from the 890 and 1907 drilled in 2004 and 2005 respectively to reach a peak of 3,800 wells per year by 2010 followed by a gradual decline as the fairway is drilled up. The 48,000 wells are all assumed to be drilled by the end of the forecast period.

Q: How does your CBM production forecast compare with those of the NEB and others in the public domain?

A: My HSC production forecast is shown in Schedule No. 12 along with five other CBM forecasts. My forecast is between the NEB Supply Push and Techno-Vert forecasts until my forecast levels off and drops below the Supply Push scenario in 2018 after the rate of drilling declines as the HSC fairway is drilled up. The NEB's CBM deliverability forecast in its October 2005 report is very similar to the Techno-Vert forecast.

It is interesting to note that the EUB forecast is also essentially identical to the NEB Supply Push CBM forecast to 2014 when the EUB forecast ends. Similarly, a forecast by TransCanada is very close to the NEB Supply Push scenario for the first few years. Between 2010 and 2018, the TransCanada forecast increases more rapidly than the Supply Push, but the difference between the two scenarios shrinks after 2018 when the TransCanada forecast begins to level off.

Schedule No. 12



Q: **What about CBM from Mannville and other coal seams or formations?**

A: As I indicated above, large volumes of gas in place have been identified for the Mannville formation. To date, only one commercial project has been announced for Mannville CBM, and very little information is publicly available for this project. Thus, I think forecasts of large volumes of gas from the Mannville are premature until commercially profitable and environmentally acceptable production processes can be established for the Mannville. There are some CBM basins in the US which also have large volumes of gas in place but for which no efficient production process has yet been established. For example, the U.S. Geological Survey has estimated that the Greater Green River basin in Colorado and Wyoming contains 314 TCF of CBM in place.

However, only one TCF is considered to be technically recoverable (U.S. Department of Energy, "Rocky Mountain States Natural Gas Resource Potential and Prerequisites to Expanded Production" (undated, p.2)). Having a large resource base in place does not provide any guarantee that this resource can be economically produced in a reasonable time frame.

Q: Do you expect a rapid development of CBM in Canada?

A: There has certainly been a major emphasis placed on CBM development over the last few years. Each coal deposit is unique, and evidence is mounting that there is a great deal of variability within particular formations. This will continue to create a challenge for producers and makes forecasting CBM supplies with confidence impossible since no reliable information is available about the performance characteristics of these wells. There will probably be production from formations other then HSC, but this is unlikely to be a smooth or easy process.

There is growing opposition from landowners concerned about the environmental problems associated with CBM development based on some of the difficulties documented in the United States. Also, there are legal issues associated with the ownership of CBM for any coals that are owned freehold, which accounts for about 20% of all mineral resources in Alberta. At least two cases are currently before the courts and will no doubt cause concerns for companies considering the leasing of CBM rights on freehold lands.

Q: So how do you deal with CBM?

A: I adopt the Supply Push scenario as my low CBM case since it is virtually identical to the EUB forecast and is similar to the TransCanada forecast. I use the NEB Techno-Vert

CBM scenario as a high case sensitivity and an average of the Supply Push and Techno-Vert scenarios is used as a base case. The TransCanada, NEB and EUB forecasts are for all coal seams/formations, not just the HSC.

Q: How do these production profiles reconcile with the recently released CGPC report on ultimate potential for CBM?

A: The CPGC estimated the ultimate potential for marketable CBM in the WCSB to be between 11 and 45 TCF. In the high case, 1.9 TCF would be produced in the last year of the forecast (2035), and 38 TCF of CBM would be produced by 2035. Another 10 TCF would have to be discovered to support the production of 1.9 TCF in the last year of (R/P = 5). Hence the high case implies 48 TCF of reserves would have to be found which exceeds the upper end of the CGPC range. The high case is inconsistent with the CGPC estimate of ultimate potential marketable CBM.

Q: What is the energy content of the CBM?

A: Even though the characteristics of the reservoirs vary significantly among the various formations the quality of the gas is remarkably consistent with an energy content of about 1000 Btu/cubic foot.

Other Unconventional Gas

Q: What about other unconventional gas such as tight gas?

A: Unlike in the United States, there is no generally accepted definition of tight gas in Canada, and tight gas production is not recorded separately. Many of the pools that have been brought on production in recent years have lower productivity in part because the permeability is low, and this is a major factor contributing to the rapid decrease in initial productivity of conventional wells. The Canadian gas industry has been drilling and producing “tight” gas for many years, and the proportion of production that comes from tight sands will increase over time. This is particularly true in the shallower parts of the basin such as southeastern Alberta and southern Saskatchewan.

Q: Is this also true for the deep basin tight gas?

A: Yes. Tight gas was discovered in the deep basin in the 1970s and has been produced since that time. Deep basin tight gas resources are included in the EUB/NEB resource potential estimate to the extent that there is production from these reservoirs, and the same is true of the latest NEB/BCMEMPR evaluation of gas resources in British Columbia. Any reservoir type—including tight reservoir types that are producing—will be included in the resource base estimates. If there is no recorded production from particular types of tight reservoirs, the resources associated with these non-producing reservoir types will not be included in the resource assessment. No production for a known reservoir type presumably means production is not technically feasible or is not economic. These excluded reservoir types must await new technology before being included in the ultimate potential estimates.

Q: Does this imply that tight gas is included in the conventional resource estimate?

A: Yes. The methodologies used by the EUB/NEB and NEB/BCMEMPR in their joint resource assessments for Alberta and British Columbia include estimates for any type of reservoir producing gas. This includes the low permeability reservoirs in southeastern and southern Alberta as well as the resources associated with any deep basin gas and the tight sands of the Jean Marie play in British Columbia. Including a separate estimate for tight gas would amount to double counting. As noted above, I have utilized a number at the high end of the range as my estimate of WCSB resources.

Q. What about shale gas?

A. Very little information is available on the production potential of shale gas in the WCSB. The complex intermingling of shale and sand in southern Alberta makes it difficult to separate gas that is produced from shale versus the intermingled sands. This is particularly true of the Medicine Hat, Milk River and Second White Specks formations. Many TCF of gas have been produced from these intermingled sands and shales, and it is generally accepted that some of the gas has originated from the shale. How much of this gas originates from the shale is unknown but more will be produced in the normal course of draining these reservoirs. The EUB/NEB methodology for estimating resource potential will include resources for any similar intermingled shale/sand formations. The BCMEMPR has investigated the characteristics (thickness, aerial extent and total organic carbon) of shale rock in British Columbia but did not estimate gas-in-place volumes.

Q. What about gas hydrates?

A: All estimates of the resource in place for gas hydrates are very large. However, until research demonstrates this resource can be economically exploited, gas hydrates will remain a scientific curiosity with tantalizing potential. There is no evidence that hydrates will make a contribution to North American gas supplies during the foreseeable future.

Frontier Gas

Q: Are there other sources of gas that might be available to supplement WCSB production?

A: Yes. There has been a lot of discussion about the construction of two pipelines from the Arctic. The Mackenzie Valley pipeline proposes to bring gas from fields in the Mackenzie Delta to interconnect with the TransCanada Alberta System in northwestern

Alberta. The other proposal is the Alaska gas pipeline which could bring gas from Alaska into the WCSB pipeline nexus.

Q: Please tell us about the Mackenzie Delta pipeline.

A: This pipeline was first considered in the 1970s but was delayed for two reasons—it was uneconomic, and it encountered problems with aboriginal land claims. Currently, a pipeline is being considered with an initial capacity of 1.2 BCF/day. Start-up has been delayed until 2011 and further delays are possible. Capacity could increase to 1.9 BCF/day in 2016.

Q: Is this pipeline a done deal?

A: Not at all. After 35 years, this proposal is again floundering on land claims and aboriginal issues. Imperial/Exxon-Mobil, the lead proponent among the gas producers, called a halt to all development work pending progress on these issues. Work was at a standstill for several months, but the process was restarted in the fall of 2005, and regulatory proceedings began in January, 2006. A decision is not expected for about 18 months (mid 2007) with a decision on construction not expected until late 2007. Project start-up is not expected until 2011.

Q: What about the Alaska gas pipeline?

A: Again, this pipeline has been under consideration for over 30 years and did not proceed in the 1970s due to economics. There are still serious questions being raised about the economic viability of this proposal. Some progress is being made. The U.S. Energy Bill included provisions for Alaska gas, and the project proponents (BP, Exxon Mobil and Conoco-Phillips) have completed a feasibility study. Producers are hoping for some form of financial backstop or guarantee from the U.S. government and fiscal terms are still being negotiated with the State of Alaska. The project will not proceed until an acceptable agreement is in place. It is expected that 10 years will be required between the decision to proceed and the first transmission of gas.

The Alaska gas pipeline is a much larger and more expensive project than the Mackenzie Valley proposal (US $20 to $25 billion versus US $6 billion) and will require a larger pipeline. The three major operators in Prudhoe Bay completed a detailed study of gas production options in 2002 and investigated a pipeline carrying 4.5 BCF/day, but fuel requirements and liquids recovery would reduce deliveries to only 4.0 BCF/day of marketable gas. The National Petroleum Council (NPC) identified 35 TCF of discovered resource that could be accessed, and this would be enough to keep the pipeline operating at capacity for only 20 years. The producers indicated that the capacity of the pipeline could be increased by 1 BCF/day by adding compression. The NPC in its 2003 study considered two start-up times—2013 and 2018.

I have included gas flows from Alaska starting in 2017 at a rate of 4.5 BCF/day of deliveries with an expansion to 5.4 BCF/day in 2022. This is more volume than included in the producers' study. If these volumes were maintained for a 30-year life span, a total of 57 TCF of gas would be moved to market and would be 22 TCF more than the current discovered resources—a very aggressive assumption on gas discoveries and production.

Q: What is the current status of this project?

A: Various participants are bargaining and posturing over critical issues that must be resolved before that pipeline can be considered a realistic source of gas. The process is also being clouded by a dispute between TransCanada PipeLines and Enbridge for the rights to build the Canadian portion of the line. In 1978, the Canadian government passed the Northern Pipeline Act which gave the rights to build the Canadian portion of the Alaska Natural Gas Transportation System (ANGTS) to Foothills Pipelines. Foothills is now owned by TransCanada which claims it has the exclusive right to build the Canadian portion of the line. Enbridge is challenging this right claiming that the Act is outdated and that the right is not exclusive. This dispute may have to be solved in court and could cause the pipeline to be delayed.

Q: Are there any other outstanding issues?

A: Yes. The proposed pipeline route crosses the traditional territories of many aboriginal groups. The traditional territories overlap in many instances, and there are issues of who to negotiate with since it is often not clear who has the authority to negotiate. Resolving these issues may cause delays.

Q: Are there any alternatives to shipping Alaska gas by pipeline through Canada to the lower 48 states?

A: Yes, there are two. First, it would be possible to build a pipeline across Alaska following the route of the Alaska oil pipeline, with the gas then liquefied and shipped to US or other markets as LNG. Authorization for such a project has been granted by FERC. The gas could be transported to Mexico to be regasified and then piped back to the US. The trans-Alaska pipeline would be much shorter than an overland route to the lower 48, and the total transport costs are claimed by its sponsors to be less. Sponsors also claim the shorter pipeline would cause less environmental disruption. Alternatively, the liquefied volumes could be shipped to Asian markets if the economics were attractive enough. This option has received recent support as an alternative to the “through Canada” route. However, the project proponents discount this option since building an 800-mile pipeline to reach tidewater would put Alaskan LNG at a serious competitive disadvantage to those supplies that are close to tidewater.

Second, the gas could be converted to liquids using the gas-to-liquids technology and then piped across Alaska to be transported by tanker to markets in the Pacific or elsewhere.

Q: Are there any other alternatives that might prevent Alaskan gas from reaching GTN?

A: Yes. Enbridge has publicized a "bullet line" from Alberta to Chicago for Alaskan volumes, thus depriving GTN of such volumes. Alliance (partly owned by Enbridge) claims that it can expand relatively inexpensively by adding compression and could be part of this "bullet" option.

Q: Is it possible that only one of the lines from the Arctic might proceed?

A: This is a definite possibility. There is concern among the proponents of the Mackenzie Valley pipeline that if the project is delayed to the point where the construction of the Alaskan line is imminent, the Mackenzie line would experience a setback.

Q Given the uncertainty of these two alternatives, what do you recommend as a frontier gas supply scenario for this proceeding?

A: I recommend including the gas from the Mackenzie Delta as the current proposal stands with flows starting in 2011, but keeping in mind that this project may be delayed. It is even possible that the project will be put on hold indefinitely if it is delayed enough that the Alaska proposal proceeds at approximately the same time. Although progress has been made in recent months, there are still some serious issues to be resolved with aboriginal groups.

Although there is a great deal of uncertainty associated with the Alaska pipeline project, I recommend that this should be included in the analysis since there is likely to be a serious shortage of gas by the time the project is ready to start flowing gas. There is a distinct possibility that the startup date will be delayed by several years beyond the 2017 proposed startup. In the high WCSB gas supply scenario, the flows of Alaska gas are delayed until 2022.

Western Canadian LNG

Q: Please discuss the proposed LNG projects on the west coast of Canada.

A: Kitimat LNG is proposing to build a terminal with a send-out capacity of 610 MMCF/day at Kitimat. Westpac Terminals is proposing a competitive project at Ridley Island, just 60 kilometres north of Kitimat, with an initial send-out capacity of 150 MMCF/day and potential to expand to 300 MMCF/day.

Q: What do you recommend should be included for gas supply?

A: In my view, only one of the two will proceed but there is also a good chance that neither project will proceed. If only one proceeds, Kitimat has the better chance. Kitimat plans to market 110 MMCF/day to local industries and build a pipeline to access the Duke Energy (Westcoast) transmission system. I recommend that 350 MMCF/day be added to WCSB gas supplies beginning in 2009 (610 MMCF/day at 75% capacity less 110 MMCF/day).

Q: What is the next step in the analysis?

A: The next step involves an analysis of the demand for gas primarily within the WCSB and an analysis of demand for gas in central Canada that has traditionally been supplied from WCSB sources. These total gas requirements will then be compared to the above total available supply to determine the volumes available for export.

Canadian Natural Gas Demand Forecasts

Q: What Canadian gas demand is relevant to this proceeding?

A: Gas originating from or flowing into the WCSB will be the main source of gas available to GTN over the relevant period. GTN must compete with other demands for gas, including demand within the WCSB and competing pipelines with takeaway capacity. The WCSB demand is represented by demand in British Columbia, Alberta, Saskatchewan, Manitoba and the Territories. Manitoba does not produce gas, but is included as part of the demand because Manitoba is totally dependent on WCSB supply. Gas demand in Ontario and Quebec (central Canada) are next in the hierarchy of Canadian demand since these provinces traditionally relied almost exclusively on WCSB supplies. The completion of the Vector pipeline in December 2000 greatly expanded Ontario's and Quebec's ability to access gas supplies from the U.S. However, the majority of the gas flowing into Ontario and Quebec still originates in the WCSB.

Q: What about Atlantic Canada?

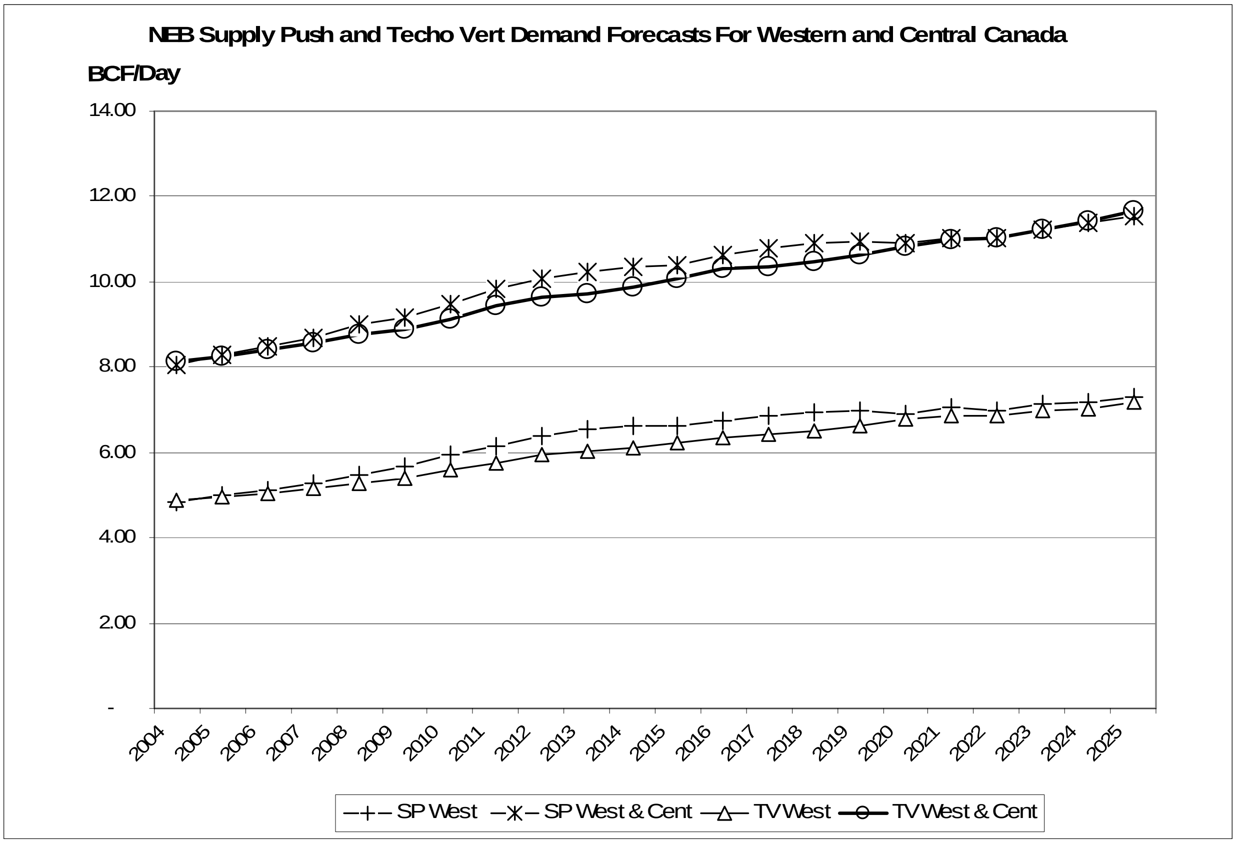
A: Currently there are no pipeline connections between the WCSB and Atlantic Canada. Thus, the supply and demand for gas in Atlantic Canada is of interest to this proceeding only because large increases in supplies (production or LNG) in Atlantic Canada could result in competition for gas markets in the US northeast, which could make more WCSB gas available to other markets by displacement. Alternatively, the development of sufficient gas production or LNG capacity in the Atlantic Provinces might result in the integration of the Atlantic gas market with the rest of Canada by the construction of a pipeline interconnect.

Q: What is expected to happen to natural gas demand in the WCSB and central Canada?

A: Natural gas demand is expected to continue to expand. The NEB provides two forecasts of gas demand in its 2003 report to the year 2025. The Supply Push and Techno-Vert gas demand forecasts for the WCSB and the WCSB plus Central Canada are shown in Schedule No. 13.

The WCSB Supply Push demand forecast is higher than the Techno-Vert forecast throughout the time period, with the biggest difference occurring from 2010 through 2018, after which the differential narrows. The WCSB plus central demand also exceeds the Techno-Vert demand until 2022, and the Techno-Vert demand exceeds the Supply Push for the remainder of the period. The cross-over occurs because the WCSB Supply Push demand growth slows beginning in 2018 while the Techno-Vert central demand begins growing more rapidly.

Schedule No. 13



Q: Did you make any adjustments to these demand forecasts?

A: Yes, I made two types of adjustments. First, I benchmarked the NEB forecasts against history. The NEB's forecast was published in 2003 and at the time of preparation, the latest available demand data were for 2000. Demand data are now available from Statistics Canada and various provincial agencies through 2004. After a number of discussions with NEB personnel as well as employees of statistical and regulatory agencies and industry participants, I assembled a set of historical demand data which I compared to the NEB's forecasts for each province. The results are shown in Schedule No. 14 for both the Supply Push and Techno-Vert cases. My numbers are largely based on Statistics Canada data, but several adjustments were made to the NEB procedures to account for differences in the NEB's objectives and the requirements of this study. For example, the NEB gas demand excludes shrinkage at reprocessing plants in Alberta and natural gas used to make refined petroleum products since these volumes are transformed to other energy forms (natural gas liquids and refined petroleum products). However, the transformed gas volumes are not available as potential gas exports and are gas demands for the purposes of my analysis..

The results of my comparisons indicate that the NEB's forecasts for British Columbia, Quebec and Manitoba were too high but the demands for the other provinces were too low for the period from 2001 through 2004. For example, the NEB Supply Push forecast for British Columbia was, on average, 35.1 TBtu higher than the actual demand, and the Alberta forecast was 85.2 TBtu below the actual demands for this period.

Schedule No. 14

Comparison of NEB Gas Demand Forecast by Province/Region to Statistics Canada Actual Data, 2000-2004

		BC & Territories T Btu	Alberta T Btu	Saskatch-ewan T Btu	Manitoba T Btu	Ontario T Btu	Quebec T Btu	Atlantic Canada T Btu	Canada T Btu	WCSB BCF/d	Canada BCF/d	Other CDA BCF/d
NEB Supply Push Forecast												
NEB	2000	342.75	975.03	211.43	93.32	1038.14	231.93	0.00	2892.61	4.45	7.92	3.48
NEB	2001	331.09	1028.58	198.41	97.01	971.44	230.91	18.86	2876.31	4.53	7.88	3.35
NEB	2002	327.25	991.69	196.37	97.18	953.16	226.32	19.38	2811.34	4.42	7.70	3.28
NEB	2003	338.21	1049.85	197.82	97.95	953.14	227.41	20.43	2884.81	4.61	7.90	3.29
NEB	2004	342.43	1125.88	197.89	98.87	950.86	227.79	21.92	2965.62	4.84	8.12	3.29
Actuals												
CEC (see below)	2001	343.98	1077.04	191.80	84.11	968.68	194.02	6.22	2865.86	4.65	7.85	3.20
CEC	2002	297.17	1095.32	199.25	94.58	1023.16	217.06	38.78	2965.32	4.62	8.12	3.50
CEC	2003	274.43	1160.14	212.99	88.54	1056.67	209.89	25.78	3028.43	4.76	8.30	3.54
CEC	2004	283.16	1204.13	205.83	88.61	1013.18	213.04	27.55	3035.49	4.88	8.32	3.43
Ave Difference CEC-NEB		-35.06	85.15	4.85	-8.79	58.27	-19.61	4.44	89.26	0.13	0.24	0.12
NEB Techno Vert Forecast												
NEB	2001	335.13	1035.62	200.77	96.41	977.63	230.52	19.39	2895.47	4.57	7.93	3.36
NEB	2002	332.37	1004.50	198.66	96.62	961.92	228.10	20.09	2842.27	4.47	7.79	3.32
NEB	2003	338.12	1065.87	200.35	97.00	961.22	230.94	21.38	2914.88	4.66	7.99	3.32
NEB	2004	340.90	1139.37	200.17	97.39	956.65	232.80	23.15	2990.44	4.87	8.19	3.32
Actuals												
CEC	2001	343.98	1077.04	191.80	84.11	968.68	194.02	6.22	2865.86	4.65	7.85	3.20
CEC	2002	297.17	1095.32	199.25	94.58	1023.16	217.06	38.78	2965.32	4.62	8.12	3.50
CEC	2003	274.43	1160.14	212.99	88.54	1056.67	209.89	25.78	3028.43	4.76	8.30	3.54
CEC	2004	283.16	1204.13	205.83	88.61	1013.18	213.04	27.55	3035.49	4.88	8.32	3.43
Ave Difference CEC-NEB		-36.95	72.81	2.48	-7.89	51.07	-22.09	3.58	63.01	0.08	0.17	0.09

Sources:
NEB, "Canada's Energy Future: Scenarios for Supply and Demand to 2025", (2003, Appendix A.3)
Actuals are based on an analysis of data from Statistics Canada, Alberta Energy Utilities Board, Provincial Agencies, and discussions with Statistics Canada, NEB and AEUB staff as well as participants in the industry.
Data downloaded from Statistics Canada's CANSIM Energy databases
http://cansim2.statcan.ca/cgi-win/cnsmcgi.exe#Here
EUB ST98-2005 Appendix

Q: Please explain the conclusions of this analysis.

A: Over the 2001 through 2004 period, total gas consumption in Canada was about 89 TBtu (3%) higher than forecasted in the Supply Push case and 63 TBtu (2%) higher than forecasted in the Techno-Vert case. While the total demand for Canada is reasonably close, there is considerable variation among the provinces. The largest percentage error occurred in British Columbia where actual demand was about 12% lower than forecasted demand. However, the biggest absolute error occurred in Alberta where actual consumption was about 85 TBtu or 7 percent higher than forecasted in the Supply Push case. There are two reasons for this. First, the NEB forecast excluded a number of items that I have included. The excluded items are natural gas used by refineries as part of refining process, shrinkage at reprocessing plants, and natural gas used for transportation other than pipeline fuel. The gas consumed as reprocessing shrinkage and transformation to refined products were deliberately (and correctly) excluded by the NEB because this gas is transformed into other fuels (refined products and natural gas liquids) and accounted for as NGL and RPP consumption. However, the natural gas used in these processes is not available to be transported to export markets as natural gas and must be included as a demand in my analysis. Natural gas used as transportation fuel was missed due to an oversight. It should be noted that natural gas for transportation fuels was overlooked in all provinces and the use of natural gas in refineries also applies to Saskatchewan and Ontario.

Q: What did you do with these results?

A: I used the average differences between the forecasted and the actual demands to adjust the NEB's forecasts for the period from 2005 through 2025 for each province. I did this by adding or subtracting the average difference from the annual forecasts. For example, the British Columbia Supply Push demand forecast was reduced by 35.06 TBtu for each of the years from 2005 through 2025. Similarly, the Alberta Supply Push forecast was increased by 85.15 TBtu in each of those years. The other provinces were similarly adjusted.

Q: Did you make any other adjustments to the demand forecasts?

A: Yes, I made a further adjustment to the forecast for 2005 to get the WCSB production minus WCSB and central consumption to equal net exports in 2005. At the time of the analysis (March 2006), preliminary estimates of WCSB gas production and gas exports and imports were available, but natural demand forecasts do not typically become available for several more months. Hence, I multiplied the 2005 demand forecasts by an adjustment factor to get the net surplus to equal exports. These adjustment factors were 0.94 and 0.95 for the Supply Push and Techno-Vert forecasts respectively.

Q: How will Canada's ratification of the Kyoto accord affect gas demands in Canada?

A: The Kyoto accord requires Canada to significantly reduce greenhouse gas emissions by 2012. Much of the discussion in Canada has centered on reducing carbon dioxide emissions from combustion of fossil fuels. Policies to achieve this reduction are still being developed. However, natural gas emits less CO_2 per unit of heat produced than either coal or fuel oil, and there is an incentive to switch from these other fuels to gas. For example, in a June 15, 2005 news release, the Government of Ontario announced that it would replace all its coal-fired electric generating facilities with alternative generating sources by 2009. This will take 7,578 megawatts of coal-fired capacity out of production, and natural gas fired generation is expected to play a key role in replacing this capacity.

Q: What impact is that expected to have on the Ontario electricity market?

A: At the beginning of 2005, Ontario had 7,543 MW of coal-fired generation in service, and this accounted for 25% of the province's generation capacity. Retiring this capacity over such a short time will create many serious problems due to the important role of coal in the Ontario electricity market. Coal-fired generation provides base-load electricity and also provides important load-tracking and peaking services that many of the other generation forms cannot provide. The government is placing a heavy emphasis on conservation, demand management and renewable power. Unfortunately, these options are not well suited to tracking load or providing peaking services. Nuclear is expected to contribute to base load, but nuclear is not well suited to track load or provide peaking services.

Q: How will that affect Ontario gas demands?

A: The Ontario Government asked the Ontario Power Authority ("OPA") to prepare an integrated power system plan to phase out the coal-fired generation. The OPA explored five different scenarios representing different views on how the world might unfold and prepared two different portfolios for each of these scenarios. These 10 portfolios were then combined to develop a composite portfolio that is expected to be robust under a wide variety of outcomes. I have examined each of the portfolios and used information from the OPA's report to adjust the NEB's natural gas demand forecasts to account for the retirement of gas-fired electricity. The resulting incremental demand takes account of nuclear capacity that is expected to enter the market as well as various forms of renewable energy, conservation and demand management that the OPA identified as probable sources of electricity. The incremental gas-fired generating capacity was taken from Table 2.8.2 of the OPA report, "Supply Mix Advice",(Dec. 9, 2005, p. 258) http://www.powerauthority.on.ca/Storage/18/1352_Part_2-8_Porfolios.pdf. This information was combined with information from the NEB 2003 report, "Canada's Energy Future: Scenarios for Supply and Demand to 2025". The resulting analysis is shown in Schedule No. 15. The incremental gas volumes from the last two columns of Schedule No. 15 were added to the NEB's Ontario gas demand estimates.

Schedule No. 15

Analysis of Incremental Gas Requirements to Retire Ontario Coal-Fired Electric Generation

	Incremental Capacity MW	Capacity MW	Assumed Utilization Rate %	Electricity Generated TWh	SP Heat Rate PJ/TWh	TV Heat Rate PJ/TWh	Gas Required SP Heate Rate PJ	Gas Required TV Heate Rate PJ	NEB SP Gas Requirement PJ	NEB TV Gas Requirement PJ	SP Incremental Requirement PJ	TV Incremental Requirement PJ
2005		4,976	25	11	8.3	8.3	90.6	90.71	50.41	56.86	40.17	33.85
2006	117	5,093	26	12	8.3	8.3	96.4	96.25	47.92	46.70	48.47	49.55
2007	155	5,248	27	12	8.0	8.3	99.0	102.74	50.84	43.77	48.18	58.97
2008	3,720	8,968	22	17	8.0	7.7	138.9	132.93	58.01	54.40	80.85	78.53
2009	794	9,762	22	19	7.8	7.7	146.9	144.56	64.27	54.71	82.59	89.85
2010	1,040	10,802	22	21	7.9	7.3	164.2	152.61	72.74	64.93	91.46	87.68
2011	200	11,002	22	21	7.8	7.4	165.6	156.99	87.25	71.74	78.31	85.25
2012	40	11,042	22	21	7.8	7.2	166.9	152.27	91.01	80.59	75.86	71.68
2013	40	11,082	22	21	7.5	6.8	160.4	146.17	77.63	64.89	82.81	81.28
2014	60	11,142	22	21	7.5	6.7	161.8	142.94	79.87	72.74	81.91	70.20
2015		11,142	22	21	7.6	6.6	162.6	141.99	83.82	67.41	78.83	74.58
2016	250	11,392	22	22	7.7	6.7	169.5	146.17	99.14	73.37	70.35	72.80
2017	330	11,722	22	23	7.9	6.6	179.4	149.97	127.57	70.90	51.80	79.07
2018	250	11,972	22	23	8.0	6.7	184.6	153.51	136.65	74.07	47.91	79.44
2019	350	12,322	22	24	8.0	6.6	190.1	157.57	138.61	71.57	51.52	86.00
2020		12,322	22	24	7.9	6.6	186.9	157.34	119.66	67.59	67.22	89.75
2021		12,322	22	24	7.7	6.6	183.0	157.27	100.29	67.56	82.75	89.71
2022		12,322	22	24	7.8	6.6	185.0	157.22	110.07	70.24	74.93	86.98
2023		12,322	22	24	7.9	6.6	187.0	157.27	121.26	73.09	65.78	84.18
2024	140	12,462	22	24	8.0	6.7	191.2	159.73	133.26	81.75	57.95	77.98
2025		12,462	22	24	8.0	6.7	191.9	161.09	137.97	90.15	53.91	70.94

Source:
Ontario Power Authority, "Supply Mix Advice", (December 9, 2005, pp. 6 and 258)
http://powerauthority.on.ca/Storage/18/1338_Part_1-1_Supply_Mix_Summary.pdf

NEB, "Canada's Energy future: Senarios for Supply and Demand to 2025", (2003, Appendix Tables A3.4. A3.14, A4.1.6, A4.2.6, and A4.3.6).
http://www.neb-one.gc.ca/energy/SupplyDemand/2003/SupplyDemandAppendices2003_e.pdf

Q: Did you make any other adjustments to demands in Central Canada?

A: Yes, I made an adjustment for imports. The volume of gas imported into Canada has increased substantially since the completion of the Vector pipeline in 2000 and the expansion of some other interconnections. This imported volume offsets gas demand from the WCSB. I have incorporated gas imports into the analysis by subtracting an import volume that amounts to 31% of the NEB forecasted demand for Ontario and Quebec. The 31% was determined as the gross volumes of gas imported as a percent of Ontario and Quebec adjusted demand for the period 2003 through 2005. Future imported volumes are calculated as 31% of the NEB's forecasted Ontario and Quebec gas demand adjusted for the differences between the NEB forecasts and the actual volumes for the 2001 through 2004 period but excluding the adjustment for Ontario coal-fired generation retirements. The imported volumes are supplemented beginning in 2009 with LNG imports from the projects proposed for Quebec.

Q: Please tell us about the LNG imports.

A: Two projects have been proposed to import LNG into Quebec. These projects are discussed in my testimony on page 57. I believe one of these projects will proceed and add 375 MMCF/day to gas supplies in central Canada. I have reduced the central Canada demand by 100 MMCF/day in 2009 and then 375 MMCF/day for the remainder of the forecast period.

Q: What is your forecast for gas demand in the WCSB and Central Canada?

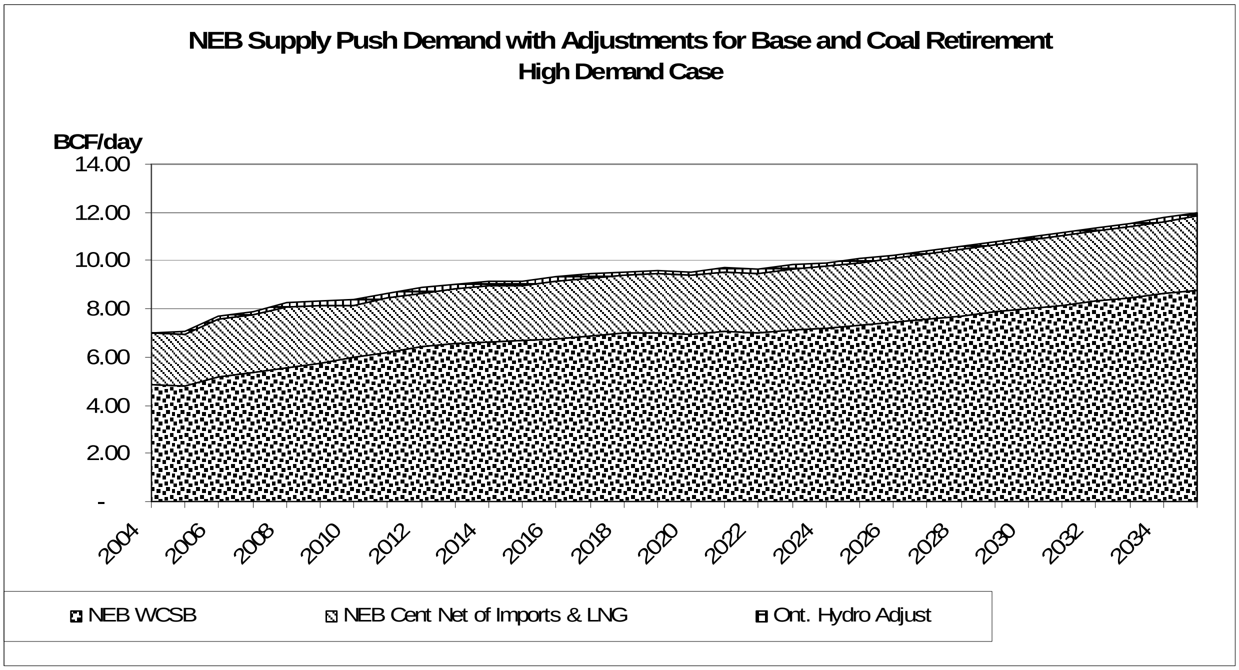
A: I have extended the NEB Supply Push and Techno-Vert forecasts from 2025 to 2035 by increasing requirements in each province at an annual rate that is the average of the annual growth rates for the forecast period from 2004 through 2025, where the annual growth rates are calculated on the volumes adjusted for the base but not including the adjustments for Ontario coal retirements or imports. I then aggregate the provincial demands to WCSB (Alberta, British Columbia, Saskatchewan and Manitoba) and central (Ontario and Quebec) subtotals.

The central forecast was adjusted for the incremental gas required to phase out coal-fired generation as set out in Schedule 15.

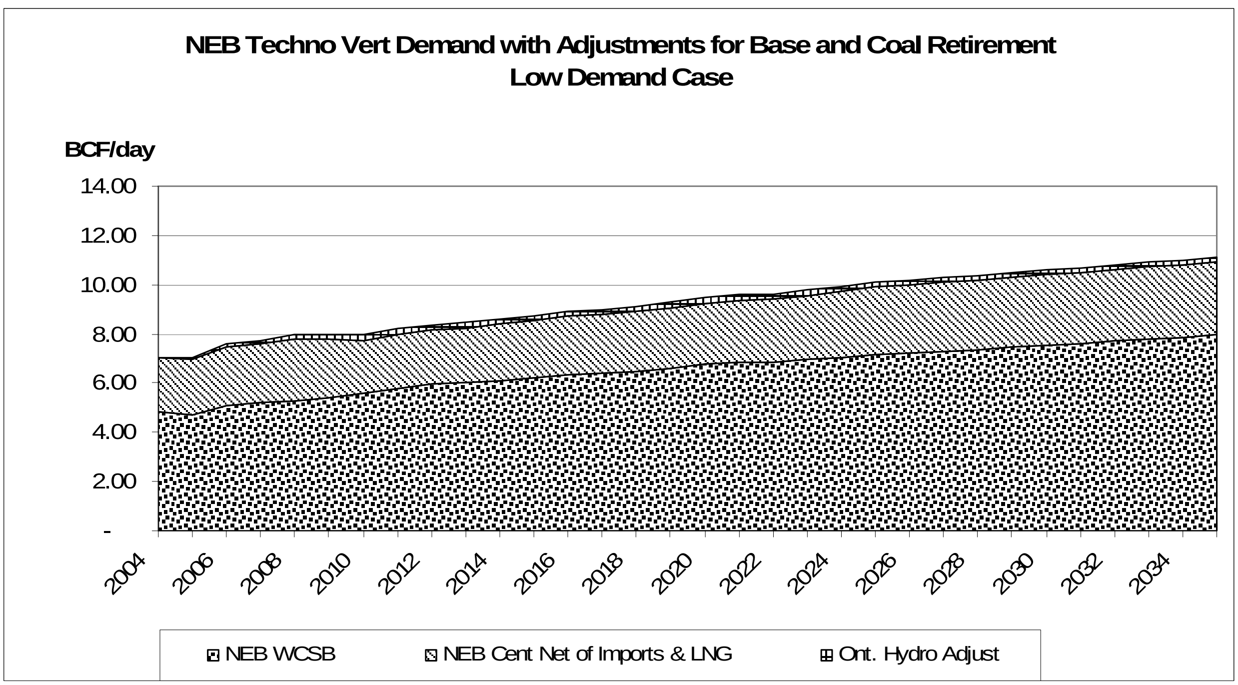
Q: What is the resulting demand when you put all this together?

A: The gross demand forecasts are shown in Schedules No. 16 and No. 17. These gross demands will be reduced by the amount of imports, primarily into central Canada. Demand in the NEB Techno-Vert scenario is lower than the Supply Push scenario because the NEB assumed higher efficiency gains in the former case. The Techno-Vert scenario has been combined with smaller adjustments for Ontario coal fired generation retirement (the NEB forecast included relatively less coal-fired generation in the Techno-Vert scenario) and results in the “low” demand forecast. The modified Supply Push demand scenario is the “high” demand forecast. In 2035, the Supply Push forecast is 0.87 BCF/day higher than the Techno-Vert forecast. An average of the high and low forecasts is used as the base case demand.

Schedule No. 16



Schedule No. 17

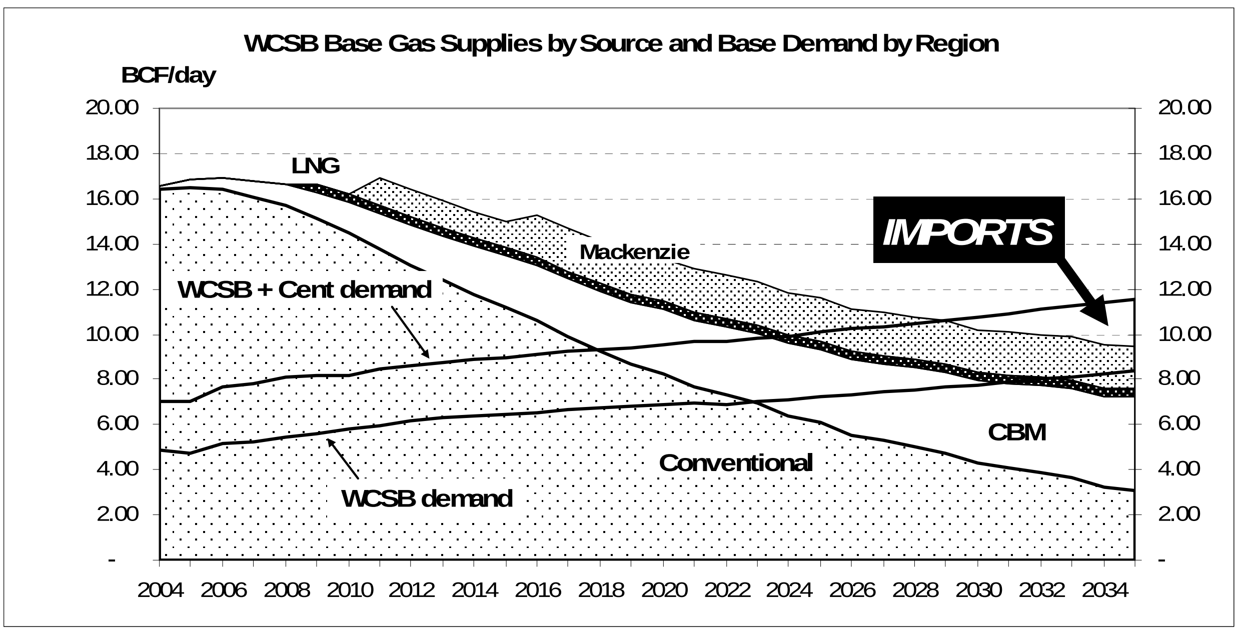


WCSB Gas Available for Export

Q: How does your demand forecast compare with your supply outlook?

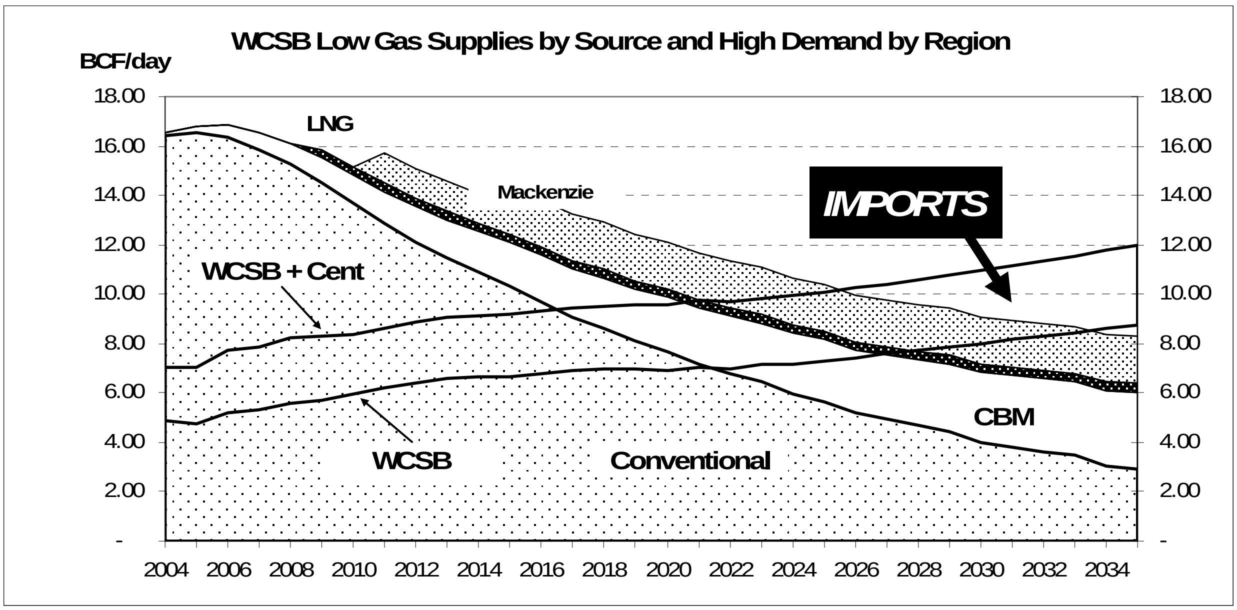
A: Schedule No. 18 shows the base case demand for gas in western and central Canada. This demand is compared to the base case supply available from conventional production, CBM, LNG imports and Mackenzie Delta gas. Production from conventional sources declines but total supply increases due to supplemental volumes from CBM and LNG imports and Mackenzie Delta gas. The total gas supply remains above the 2005 level in 2006, then drops below this level until Delta gas starts flowing in 2011 when it reaches the 2005 level for one year. WCSB and Central demand for WCSB gas also increases but production is always surplus to WCSB requirements. However, imports would have to increase beyond the level incorporated into the forecast to satisfy requirements in central Canada after 2029.

Schedule No. 18



Schedule No. 19 shows the equivalent information with a less ambitious supply forecast using the conventional production forecast with the higher economic cutoff and fewer wells. This is combined with the Supply Push (low) forecast for CBM production and the high demand case is used. In this scenario, WCSB gas supplies essentially remain flat in 2006 and then begin a decline that is arrested for one year when Mackenzie delta gas begins to flow in 2011, and there is no surplus available for exports after 2025. By 2034, gas supplies would not be adequate to meet WCSB requirements and a small shortfall occurs.

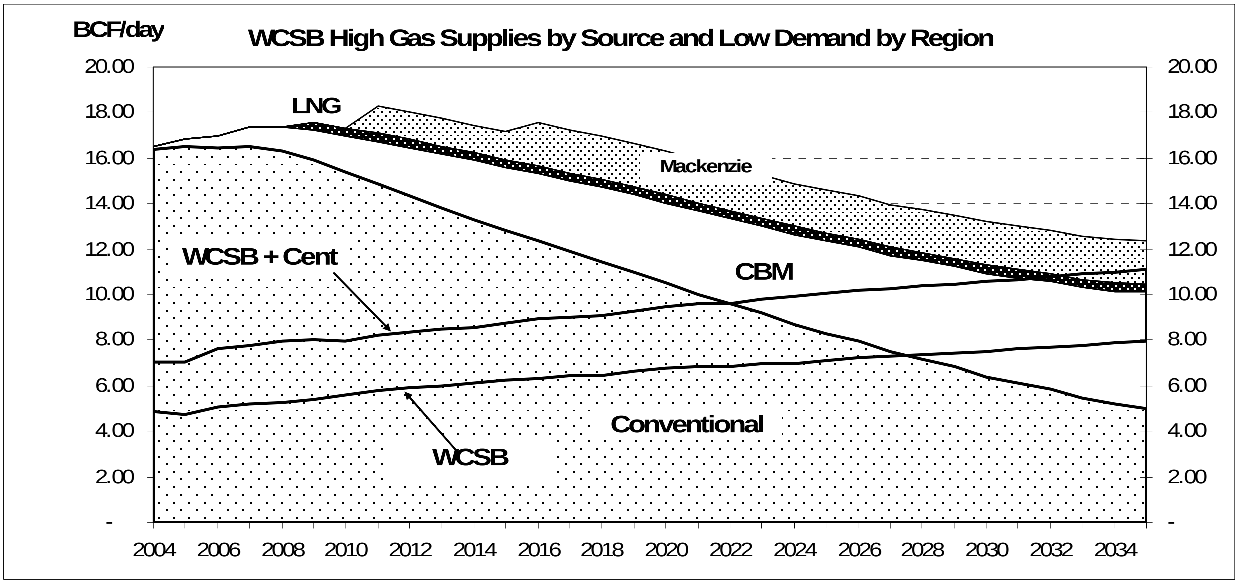
Schedule No. 19



Q: Dr. Haessel, you have discussed two cases for net available supply—a base case and pessimistic low supply-high demand case. Do you also have an optimistic, high supply-low demand combination?

A: Yes. Schedule No. 20 combines the high supply case with the low demand forecast. This is an extremely aggressive production scenario for both conventional and CBM production. Total gas available in the WCSB will be above the 2005 level in every year until 2018. The high production scenario uses 94% of the conventional resource base by 2035 and is unlikely to be achieved. Since this optimistic supply is combined with a low demand forecast, surplus gas is available for exports throughout the entire period even without Alaska gas.

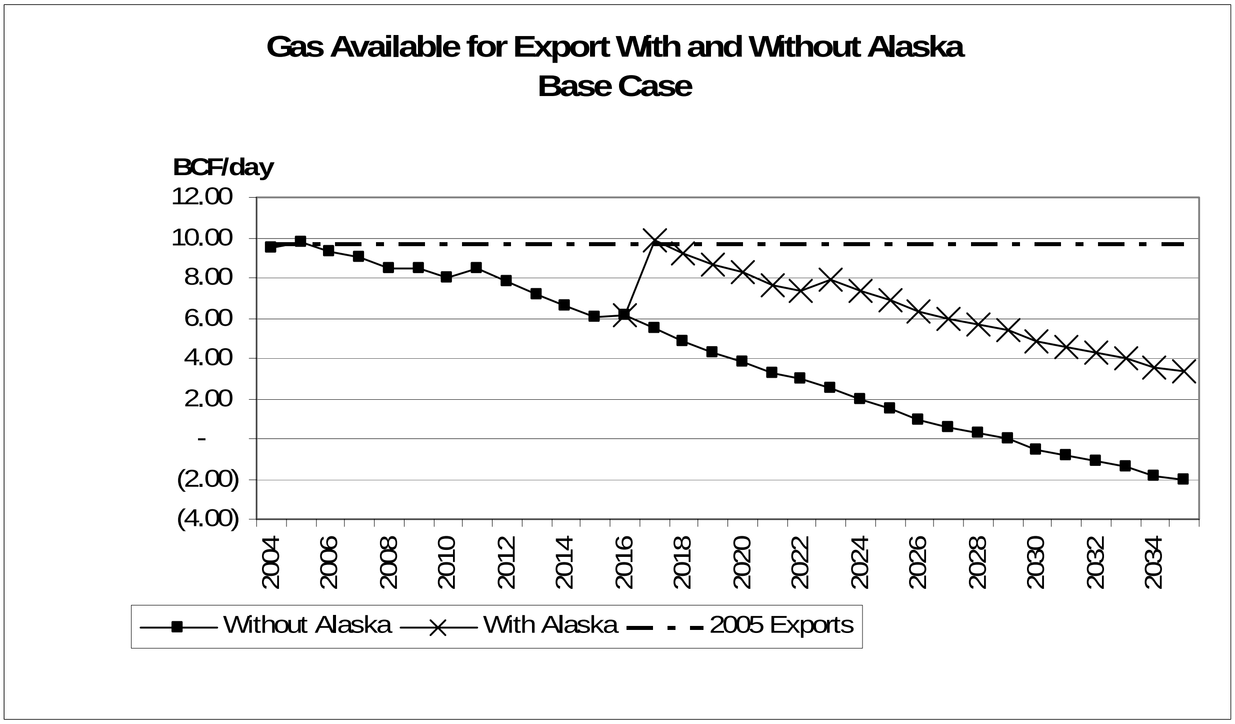
Schedule No. 20



Q: Dr. Haessel, what happens to the export potential if you add the volumes from Alaska to the supply base?

A: Schedule No. 21 shows the impact of Alaskan volumes on the net amount available for export using the base case gas supply-demand scenario. The schedule also shows the net amount of gas (9.7 BCF/day) that was exported from the WCSB in 2005. Under this scenario, the volume available for export declines continuously until a small increase occurs when Mackenzie Delta gas begins to flow in 2011. The decline resumes in 2012 and continues until Alaska gas starts flowing in 2017. The available exportable surplus drops to 6 BCF/day in 2015; less than two-thirds of the 2005 volume. Exports would jump to 2005 levels in 2017 when Alaskan gas starts flowing. By the end of the forecast period, 3.3 BCF/day would be available for export; only 1/3 of the 2005 export levels.

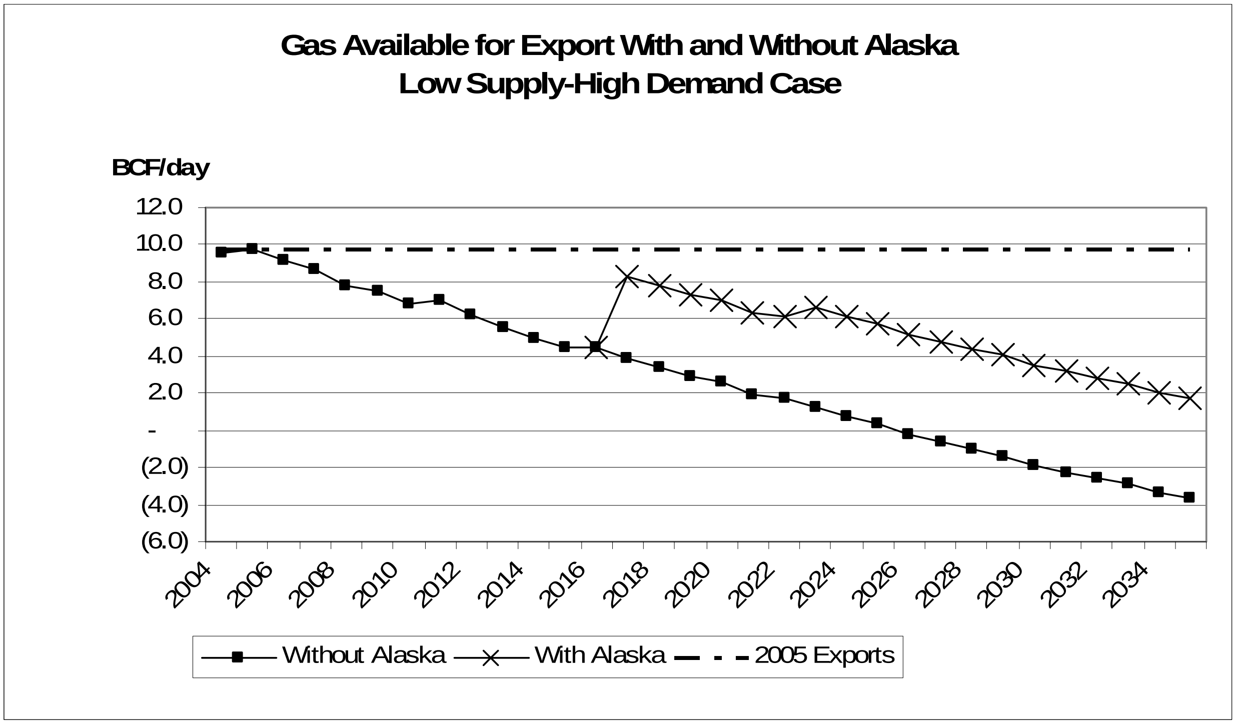
Schedule No. 21



Q: Please discuss the low gas supply case with Alaskan production.

A: This scenario is illustrated in Schedule No. 22. The amount available for export drops below the 2005 volume throughout the forecast period. Only 4.5 BCF/day would be available for export in 2016 before Alaskan volumes begin to flow; less than half of the 2005 volumes exported. Without Alaskan volumes, no gas would be available for export after 2025. With Alaskan gas, sufficient supply is available to allow exports throughout the period but only 1.7 BCF/day would be available in 2035.

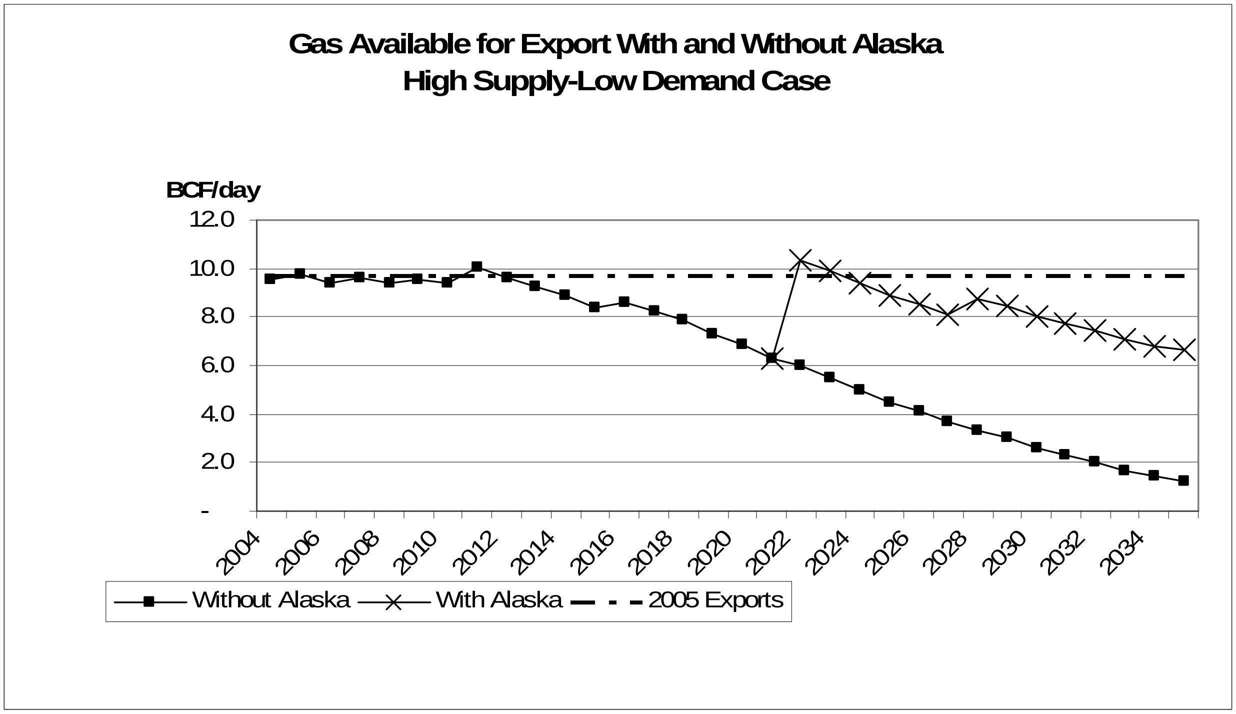
Schedule No. 22



Q: How much gas is available for export in the high supply-low demand case?

A: In this extremely optimistic production/demand combination, exports remain essentially flat at the 2005 level until an increase occurs in 2011 when Mackenzie Delta gas begins to flow. At that point the surplus begins to decline until Alaskan gas arrives as shown in Schedule No. 23. In this scenario, since the WCSB volumes are so strong relative to the demand levels, the flows of Alaska gas volumes are delayed until 2022. The volume available for export in 2022—the year Alaska gas is expected to flow—is about 2/3 of the 2005 level. After Alaska gas starts flowing in 2022, exports exceed the 2005 level for two years and almost 7 BCF/day would still be available for export at the end of the analysis period.

Schedule No. 23



Liquefied Natural Gas in Central Canada

Q: Since there may be a shortage of natural gas, is there any consideration of importing LNG other than the two west coast projects that you have discussed?

A: Yes, five other Canadian proposals have been put forward. These can be divided into two types—those projects that could impact the amount of gas available to GTN through direct displacement through the existing pipeline systems and those that might have an impact through indirect displacement. As discussed above, two projects are being promoted in Quebec which, if built, would reduce the traditional demand for WCSB gas in central Canada. The other three projects are proposed for the Maritime Provinces and would only impact the gas available to GTN by indirect displacement through pipelines serving the northeastern US or the construction of pipelines to connect the Maritimes to Quebec.

Q: Please discuss the two Quebec proposals.

A: Both of these projects are being sited on the St. Lawrence River, and both are anticipating flows commencing in late 2009. The Rabaska project is a proposed import terminal at Ville Guay/Beaumont area of Quebec being promoted by Enbridge, Gaz Metro and Gaz de France. The send-out capacity of 500 MMCF/day is intended to serve the Quebec and eastern Ontario markets with any excess flowing into the northeastern US. TransCanada, in partnership with PetroCanada, proposes to build an import facility at Gros Cacouna Quebec with a send-out capacity of 500 MMCF/day with any excess destined for the US.

It is highly unlikely that both will be built, and from a gas supply perspective it does not matter which proceeds. Both have a send out capacity of 500 MMCF/day and would provide an average of 375 MMCF/day of gas supplies to the Quebec and Ontario markets at a 75% operating capacity. The projection for central Canada demand for gas from the WCSB has been reduced by 100 MMCF/day in 2009 and 375 MMCF/day in 2010 and thereafter to reflect this additional gas supply.

Analysis of Atlantic Canada

Q: What about the three Atlantic Canada LNG projects?

A: Two of these projects are primarily import for re-export while the other proposal is in conjunction with a petrochemical complex with no surplus gas supplies planned at this stage.

Anadarko’s Bear Head project at Canso Strait in Nova Scotia received all approvals, and construction has started. The plant has a planned send-out capacity of 1 BCF/day, and Anadarko has reserved space for 793 MMCF/day on the Maritimes and

Northeast Pipeline ("M&NP") commencing in 2008. Anadarko announced a delay in March 2006 indicating that it has been unable to secure gas supplies. However, Anadarko is optimistic it can still secure gas supplies and is marketing its project as having all approvals and is the most advanced project on the east coast of North America.

Irving Oil plans to develop a project at its Canaport deep water port in Saint John, New Brunswick with a 1 BCF/day send-out capacity. Irving is partnering with Repsol YPF. Irving will market the gas in Atlantic Canada and Repsol will provide the LNG for the facility and market the gas in the rest of Canada and the USA. Canaport has reserved capacity of 732 MMCF/day of capacity on the M&NP commencing in 2008. All approvals have been received, and gas is expected to reach markets in 2008. Since Anadarko has been delayed, the Canaport project is the probably the most advanced on the east coast. However, Repsol recently announced a 25% write-down of its gas reserves, and this may cause the project to be delayed.

Keltic Petrochemicals Inc. is proposing to build a CDN $4 billion petrochemical/LNG/cogeneration facility at Goldsboro, Nova Scotia with a send-out capacity of 500 MMCF/day. At this time it appears that Keltic plans to use the entire LNG supply for its own use so will not have any net impact on gas supplies. The LNG component of the project was sold to European interests in March 2006 while Keltic retains its interest in the petrochemical complex.

Q: Please summarize what this means for Atlantic gas supplies.

A. The Irving Canaport project has a good chance of coming on stream in late 2008, and the Anadarko Bear Head project is likely to be delayed to at least 2010,if it is completed at all. Each of these plants has a potential send-out capacity of 1 BCF per day which would provide a total of about 1.5 BCF/day of base load supplies if the plants operate at 75% capacity. Between the two projects, 1,525 MMCF/day of capacity has been reserved on the M&NP, almost equal to the 1.5 BCF/day of anticipated operating capacity. Anadarko may choose to delay its commitment to capacity. The Keltic project would have very little if any gas surplus to its own requirements if it proceeds as planned.

Q: What impact are the Atlantic LNG projects likely to have on gas supplies available to GTN?

A. The potential impact has to be measured against the size of the market demand and any other supplies that might be available to compete for those markets. The capacity reserved on the M&NP will transport the gas to markets in the Maritime Provinces and the northeastern US. The Atlantic Canada market is quite small at this time with the NEB forecasting consumption of only about 100 MMCF/day in 2005, but this is expected to expand to between 260 and 300 MMCF/day in 2025.

The market will also be impacted by any changes in gas production in Atlantic Canada. The NEB forecasted that Sable Offshore Energy Project (“SOEP”) production would be 550 MMCF/day from 2002 until 2007 and then decline steadily to only 200 MMCF/day in 2016. However, SOEP production peaked at 504 MMCF/d in 2002, dropped steadily to only 392 MMCF/day in 2005.

The NEB forecasted additional production to come on stream in 2008—400 MMCF/day from Panuke in the both the Techno-Vert and Supply Push cases, and an additional 200 MMCF/day from Newfoundland in the Supply Push case. In the Techno-Vert case, the Newfoundland production is delayed until 2015 which highlights the uncertainty associated with these numbers.

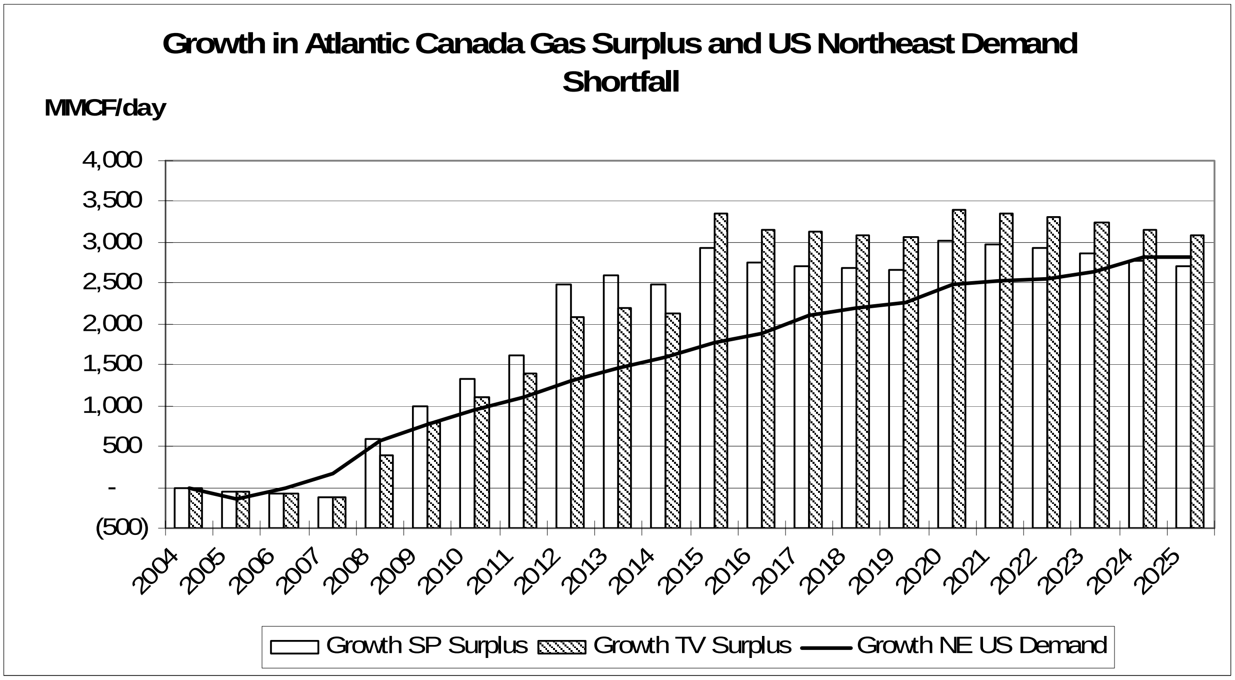
The Deep Panuke production was expected at an earlier date. Just like SOEP, Deep Panuke has been a serious disappointment for its sponsors. A prior planned expansion of the M&NP was canceled because Deep Panuke's originally projected production failed to materialize, in turn reflecting overly optimistic projections regarding the underlying resources. Further doubt about the veracity of this additional indigenous supply is evidenced by the fact that some contracted capacity on M&NP has been released. Some of this released capacity results from the additional declines that are expected at the SOEP and some is from other capacity holders. Even so, a further expansion of pipeline takeaway capacity may be required if this extra production comes on stream in 2008 at the same time that LNG starts to flow.

The disappointing results for SOEP and Deep Panuke resulted in the CGPC reducing the estimated ultimate marketable gas potential for the Scotian Shelf to only 5 TCF in its 2005 report compared with 11 TCF in its 2001 report.

Q: Can this extra production be absorbed in the market area served by the M&NP?

A. That will depend on the growth of the market in the US northeast relative to the gas supplies available. Schedule No. 24 shows the growth in the Atlantic Canada net gas surplus for the NEB Supply Push and Techno-Vert demand and production forecasts. LNG volumes are included starting in 2008 and ramp up to 1.5 BCF/day by 2013 to allow some delay for the Anadarko project. The schedule also shows the growth in natural gas demand in the New England and Middle Atlantic census divisions from the 2005 Energy Information Administration long-term forecast.

Schedule No. 24



It is clear that the growth in demand is adequate to absorb the Atlantic Canada incremental supply over the 20 year forecast horizon, but a surplus exceeding 1.0 BCF/day may exist in some years.

Q: Can this additional capacity be absorbed into the market?

A. Probably. The EIA 2005 long-term outlook forecasted natural gas demand in the New England and Middle Atlantic census districts would expand by over 1.6 BCF/day between 2004 and 2014. During that same time period, lower 48 gas consumption is forecasted to increase by 15.6 BCF/day, while Lower 48 gas production is forecasted to increase by only 4.7 BCF/day, resulting in an incremental supply shortfall of 10.9 BCF/day. Since the Northeast consumes about 16% of the lower 48 gas volumes, this translates into a pro rata shortfall of 1.7 BCF/day for this region (16% of 10.9 BCF/day). This should provide enough room to absorb the extra volumes from Atlantic Canada.

Q: Is there any other supply source that might fill some of this shortfall?

A. Yes. Ten LNG projects have been proposed for the U.S. northeast coast. These projects are summarized in Schedule No. 25 and have a combined nameplate capacity of 7.35 BCF/day. Only one project with a base-load capacity of 0.4 BCF/day has been approved, and one has been rejected by FERC but is under appeal. Another project has received FERC approval but is having problems with local authorities, and six have not yet formally begun the regulatory process. The majority of these projects are unlikely to proceed. For instance, three proposed projects are located in close proximity to each other in Washington County, Maine. Not all three will be built, and it is likely that that none will be built since the LNG tankers would have to pass through the narrow Head Harbor Passage in Canada where safety concerns have been raised.

If 25% of the proposed US northeast capacity comes on stream over the period to 2015 and operates at 75% of nameplate capacity, approximately 1.4 BCF/day would be added to base-load capacity.

Schedule No. 25

Northeast US LNG Proposals

			Capacity (BCF/day)		
Status	Proponent	Location	Baseload	Peak	Startup
Approved	Hess LNG	Fall River MA	0.4	0.80	2009
Approved by FERC but local problems	BP	Logan Township NJ	1.2	1.40	2008
Rejection by FERC is being appealed	Keyspan & BP	Providence RI		0.50	
Prefiled with FERC	TransCanada & Shell	Long Island Sound, NY		1.00	2010
Announced, no application yet	Somerset LNG	Somerset MA		0.65	
Announced, no application yet	PGW (Freedom Energy Center)	Philadelphia PA		0.60	2007
Announced, no application yet	Tractebel (Neptune LNG)	22 mi offshore Boston MA		0.40	2009
Announced, no application yet	Downeast LNG	South Mill Cove, Maine		0.50	
Announced, no application yet	Quoddy Bay	Split Rock, Maine		0.50	
Announced, no application yet	BP Consulting	Calais, Maine		1.00	
		Total		7.35	

Source: Gas Daily

Q: Can this extra capacity also be absorbed without backing Canadian gas out of the northeastern United States?

A. I think so. The Supply Push and Techno-Vert Atlantic Canada surplus in Schedule No. 24 averages about 2.6 BCF/day from 2013 to 2015. For the same period, the U.S. Northeast supply shortfall is 1.6 BCF/day, which leaves a surplus of 1.0 BCF/day to be absorbed. The regional pro rata shortfall of Lower 48 production relative to consumption for that time period is 1.7 BCF/day. That shortfall will absorb the 1.0 BCF/day of Atlantic surplus and still leave a shortfall of 0.7 BCF/day which can absorb half of the extra 1.4 BCF/day of LNG supply that might come on stream in the Northeast.

The 0.7 BCF/day of unabsorbed surplus will occur only if all of the supplies come on stream as discussed. This requires the two Canadian LNG projects proceed on schedule, the additional Atlantic Canada production materializes, and 1.4 BCF/day of LNG capacity comes on stream along the U.S. east coast situated to supply the New England and Middle Atlantic census areas. Not all of these are likely to materialize. Previous projections of Atlantic Canada production have been far more optimistic than reality and actual supplies are likely to fall short of expectations again.

In the event that all these do happen, the surplus would have to be prorated among the various supply sources. This could result in a small amount of WCSB supply being backed out of the U.S. Northeast. However, this does not materially affect my conclusions regarding the WCSB given the expected supply shortfalls in western Canada.

Q. Does this conclude your prepared direct testimony?

A. Yes.