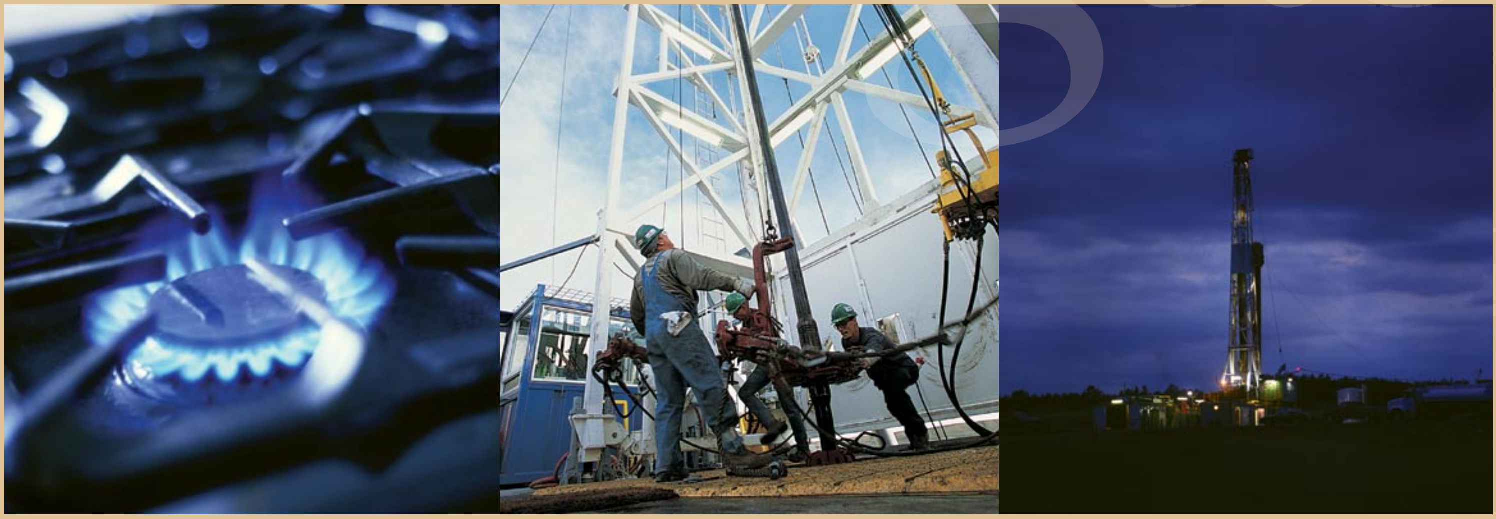
National Energy Board

Office national de l'énergie

Short-term Canadian Natural Gas Deliverability

2006-2008



AN ENERGY MARKET ASSESSMENT OCTOBER 2006

Canada

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Cat. No. NE2-1/2006E
ISBN 0-662-44128-1

This report is published separately in both official languages.

Copies are available on request from:
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For pick-up at the NEB office:
Library
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Printed in Canada

Nº de cat. NE2-1/2006F
ISBN 0-662-72574-3

Ce rapport est publié séparément dans les deux langues officielles.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
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Rez-de-chaussée

Imprimé au Canada

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LIST OF ACRONYMS

B.C.	British Columbia
CBM	Coal Bed Methane
CGPC	Canadian Gas Potential Committee
CNG	compressed natural gas
CSUG	Canadian Society for Unconventional Gas
EMA	Energy Market Assessment
HSC	Horseshoe Canyon
LNG	liquefied natural gas
NEB	National Energy Board
NGLs	natural gas liquids
SOEP	Sable Offshore Energy Project
U.S.	United States
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Bcf	= billion cubic feet
Tcf	= trillion cubic feet
m^3/d	= cubic metres per day
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day

Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas.

The NEB collects and analyses information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. On this note, the Board has received feedback from a wide range of market participants across the country that the NEB has an important role and is in a unique position to provide objective, unbiased information to the public.

This EMA report, titled *Short-term Canadian Natural Gas Deliverability, 2006–2008*, examines the factors that affect gas supply in the short term and presents an outlook for deliverability through to the year 2008. The main objective of this report is to advance the understanding of the short-term gas supply situation by examining recent trends in the production characteristics of the Western Canada Sedimentary Basin (WCSB) and the east coast offshore and applying these trends to provide an outlook for short-term Canadian deliverability. This report is also an update to the Board's October 2005 EMA, titled *Short-term Canadian Natural Gas Deliverability, 2005–2007*.

While preparing this report, the NEB conducted a series of informal meetings and discussions with drilling companies, pipeline companies, natural gas producers and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Questions and comments regarding this EMA can be referred to either:

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Paul Mortensen telephone: 403-299-2712, email: pmortensen@neb-one.gc.ca

Overview

North American natural gas prices reached a peak near the end of 2005 and have softened significantly since. The rise in prices during 2005 reflected high world crude oil prices, a tight balance between natural gas supply and demand, and a major disruption in U.S. gas supply from two major hurricanes in the Gulf of Mexico. The integrated nature of the North American natural gas market meant that hurricane-related price impacts in the U.S. rippled into Canada.

In response to rising prices, western Canada drilling activity broke from typical practice to remain heavily utilized throughout the second half of 2005 and carried on to achieve new highs in early 2006. The sustained pressure on the drilling industry over this period caused industry costs to escalate noticeably. The higher drilling rates also reflect rising costs for key inputs of steel, fuel and labour.

Since late 2005, gas prices have softened due to a storage overhang resulting from a mild 2005-2006 winter. The combination of rising costs and softening prices has impacted margins for Canadian gas producers. Some have reduced drilling growth plans in the more price sensitive regions including some coal bed methane (CBM) and shallow gas in the southeast portion of the WCSB. It appears that an increase in deeper gas drilling on the western side of the basin is being maintained.

The total gas drilling effort for 2006 (conventional gas and coal bed methane), measured in drill days, is expected to be up by roughly three percent over 2005. The increase reflects extremely high activity in the first quarter of 2006 and somewhat slower activity in the second half.

The size of the Canadian drilling rig fleet has expanded significantly and new maximum thresholds for utilization have been achieved. High utilization has resulted in some reduction in efficiency due to shortages in materials and services, and a reduction in the average experience level of the workforce as it has expanded.

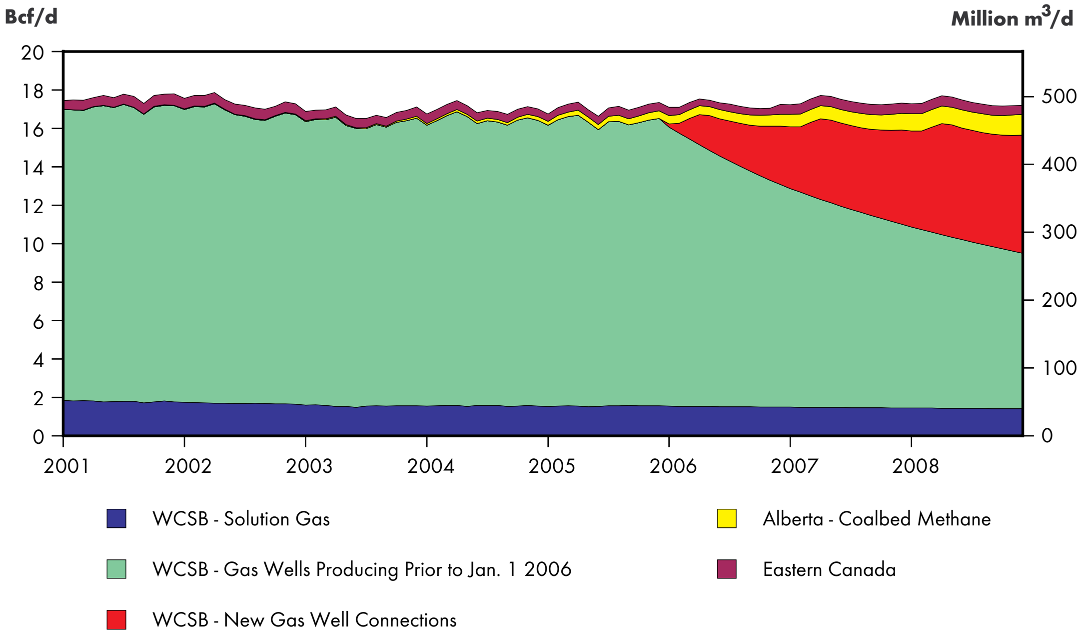
This report provides an assessment of the expected capability of Canadian gas production, or deliverability, through 2008.

The strong natural gas prices have led to record levels of drilling in Canada's natural gas exploration and production industry. The Board anticipates the industry will closely monitor costs and revenues, but in aggregate will continue high levels of drilling to maintain production at around current levels over the next two years.

The Board is projecting a small increase in Canada's total annual average deliverability from 484 million m^3/d (17.1 Bcf/d) in 2005 to 491 million m^3/d (17.3 Bcf/d) in 2008. Annual average deliverability of conventional gas is expected to decline slightly over the projection period, from 475 million m^3/d (16.8 Bcf/d) in 2005 to 464 million m^3/d (16.4 Bcf/d) in 2008. This small decrease is expected to be more than offset by growth in CBM deliverability in western Canada from 8 million m^3/d (0.3 Bcf/d) in 2005 to 27 million m^3/d (1.0 Bcf/d) in 2008.

FIGURE I

Outlook for Canadian Gas Deliverability



Almost 98 percent of Canadian gas is produced from the WCSB with Alberta accounting for roughly 80 percent of the output. British Columbia and Saskatchewan contribute roughly 16 and 4 percent respectively of the total from the WCSB. Despite the projected high levels of drilling, the Board expects that production of conventional natural gas from the WCSB will decrease slightly from 463 million m^3/d (16.3 Bcf/d) in 2006 to 450 million m^3/d (15.9 Bcf/d) in 2008.

CBM deliverability will more than compensate for declines from conventional gas sources over the period. The ongoing large scale development of the Horseshoe Canyon coals in Alberta forms the largest part of the CBM deliverability expectation over the projection period, while a minor but growing share of CBM production is expected to come from Mannville coals where commercial development is beginning to occur.

Atlantic Canada gas developments involve enhancing production from existing fields offshore Nova Scotia and growth in New Brunswick onshore production. Initial indications of renewed interest in the Deep Panuke offshore project are also positive but could not contribute to deliverability within the timeframe of this projection. Deliverability of natural gas from Atlantic Canada is expected to slip to an average 10.0 million m^3/d (0.35 Bcf/d) in 2006, rise as a result of added compression to 14.1 million m^3/d (0.50 Bcf/d) in 2007, before again declining gradually to average 13.4 million m^3/d (0.48 Bcf/d) in 2008.

Despite the contributions from Atlantic Canada and CBM, production of conventional natural gas from the WCSB will remain the mainstay of Canadian gas production for many years. However, the WCSB is a well-explored basin and, on a basin-wide average, production is declining at about 20 percent per year from existing wells. Therefore, new gas wells continue to be essential for maintaining Canadian gas deliverability at the stable levels seen over the past several years. There is an ongoing trend of year-on-year decreases in initial productivity from new gas wells in the WCSB. This means that drilling must increase every year to obtain the levels of deliverability from new wells that is needed to offset the decline in deliverability from existing wells. Drilling activity directed toward conventional gas resources in the WCSB in 2008 is expected to be 8 percent higher, in terms of drill days, than occurred in 2005. This drilling effort is expected to result in 16 700 conventional gas-intent wells in 2006, increasing to 17 500 in 2008.

CBM drilling is expected to increase significantly, but at a more moderate rate than anticipated in the Board's previous outlook. The number of CBM-intent wells drilled annually is expected to rise from an estimated 3 100 in 2006 to 3 900 in 2008.

Despite ongoing volatility, Canadian natural gas prices are expected to generate sufficient cash flow to fund the anticipated activity levels. The ability to sustain adequate drilling activity during periods of price weakness, continue to expand the drilling rig fleet, and slow the escalation of drilling costs will be key challenges for the industry over the projection period.

INTRODUCTION

Canada is an important source of natural gas supply in North America accounting for almost one-quarter of the combined production of Canada and the U.S. in 2005. Because of Canada's substantial role in North American natural gas supply, there is considerable interest in the outlook for Canadian gas deliverability over the next few years. The primary objective of this report is to provide the Board's current outlook for Canadian natural gas deliverability to the end of 2008.

During the period covered by this report, Canadian gas deliverability will primarily be sourced from the WCSB. Deliverability from Atlantic Canada has significant regional importance and minor volumes are available from Ontario and Quebec. This report concentrates on deliverability from the WCSB and Atlantic Canada. As CBM in the WCSB is currently experiencing significant growth and is becoming a noticeable component of deliverability, this report provides a separate analysis of CBM deliverability. This assessment also entails a detailed examination of the Canadian rig fleet for the purpose of estimating future drilling levels on the basis of drilling capacity and utilization.

Chapter 2 provides background on Canadian supply and discusses current and emerging issues. Included is a description of the geographic extent and nature of the supply in each region. Also included is a discussion of recent regional production trends.

Chapter 3 describes the approach used to estimate Canadian gas deliverability. The productive life of each gas well is characterized by production decline, which is the initial production rate that declines as the resources of the well are depleted. The approach includes the analysis of production decline trends by study area to estimate future deliverability from existing wells. The chapter also describes how the production characteristics of the more recently connected wells are used to estimate initial productivity and decline rates for future gas well connections (a well completion with gas and/or oil production is defined as a connection). Also included in this chapter is an analysis of drilling capacity and utilization in the WCSB that is the basis for projecting the number of future gas connections.

Chapter 4 provides the results of the regional deliverability analyses including the estimated production characteristics for currently producing and future gas wells and the number of gas well connections expected over the projection period.

The Board's outlook for Canadian natural gas deliverability is presented in Chapter 5. The observations, issues and conclusions of the assessment are discussed in Chapter 6.

BACKGROUND

The WCSB has traditionally been Canada's main source of gas production and it currently accounts for 98 percent of total Canadian production. Natural gas production from Atlantic Canada started at the end of 1999 and provides most of the remaining gas production in Canada. Figure 2.1 shows the location of these gas producing areas. Descriptions of the significant features of the regions, a summary of recent production and description of current and emerging issues follow.

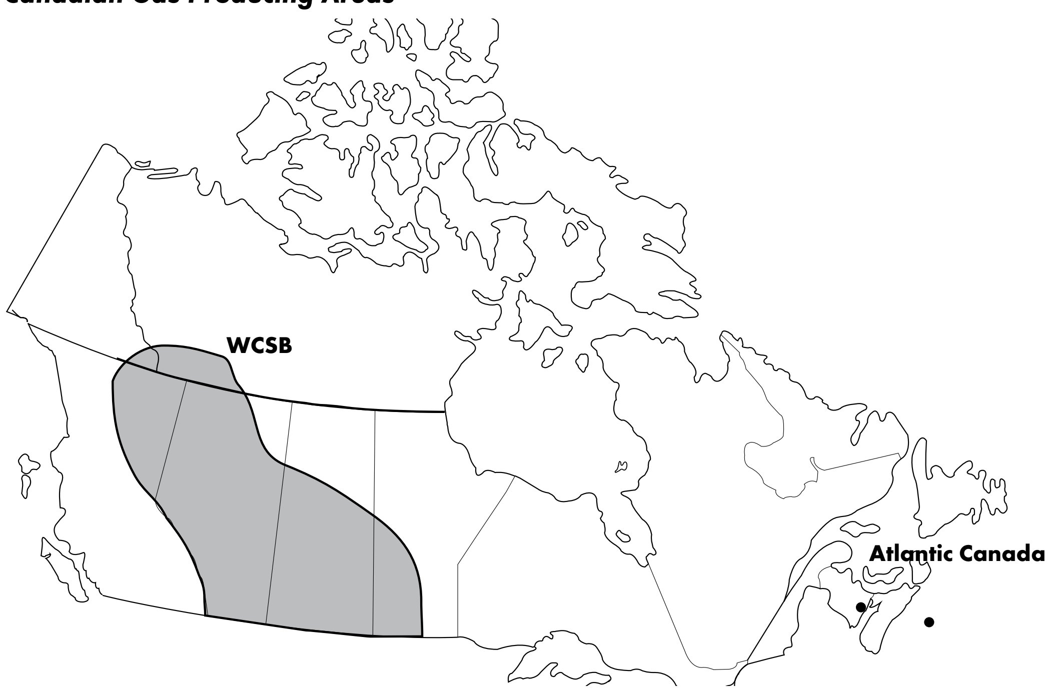
2.1 WCSB – Conventional Gas Supply

The WCSB underlies most of Alberta, significant portions of British Columbia (B.C.) and Saskatchewan, as well as parts of Manitoba and the Yukon and Northwest Territories (Figure 2.1). Alberta accounts for the largest share of production at roughly 80 percent. British Columbia and Saskatchewan provide roughly 16 and 4 percent of the total respectively. The Yukon and Northwest Territories currently contribute less than 1 percent of WCSB production and there is currently no gas production in Manitoba.

The large regional differences in physical and producing characteristics in the WCSB require that the basin be divided into smaller areas with similar characteristics for production decline analysis. For this

FIGURE 2.1

Canadian Gas Producing Areas



assessment, the WCSB has been split into 14 geographic regions (the "study areas") based on similar producing characteristics, as shown in Figure 2.2.

WCSB historical production of conventional gas by connection year is shown in Figure 2.3. Conventional gas production from the WCSB has been stable for the past three years at around 460 million m^3/d (16.3 Bcf/d) as high levels of drilling activity have been offset by lower initial

FIGURE 2.2

Study Areas in WCSB

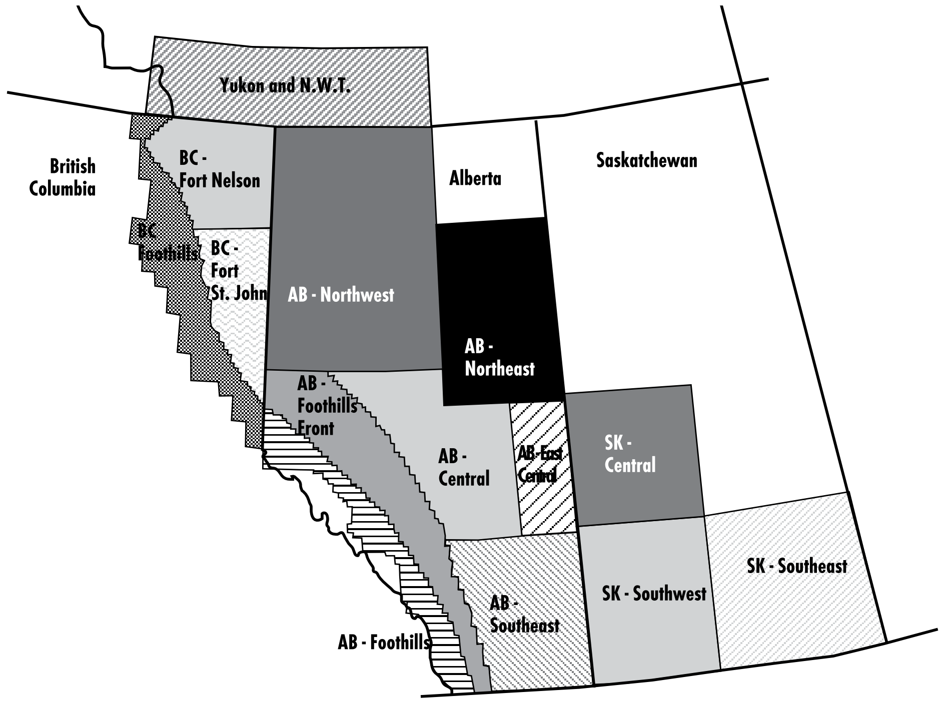
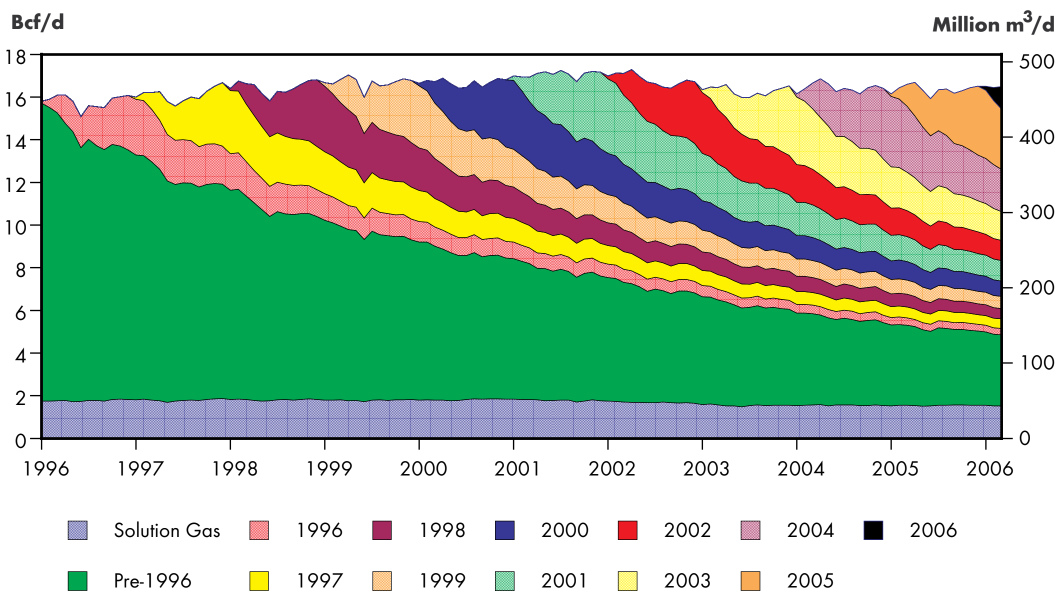


FIGURE 2.3

WCSB Historical Conventional Gas Production by Connection Year



Source: GeoScout Well Production Records with Board Estimate of Shrinkage Applied productivity of new wells and, in some cases, higher decline rates. The vital role of new drilling is also evident, with roughly 50 percent of current production provided by wells that have been on production for five years or less.

Higher prices also support the economics of some new resource types, such as CBM (described in a later section) and lower permeability, or “tighter” gas resources. Tighter gas resources continue to be recorded as conventional gas in this EMA. While tighter gas resources are increasingly a target for development in the WCSB, at present there is no generally agreed upon criteria to identify tight gas. With no such criteria available for identification, no attempt is made to split out tight gas from other conventional gas for separate analysis. Hence, conventional gas in this report includes tight gas.

2.2 WCSB – Coal Bed Methane

Coal bed methane has emerged this decade as a new gas supply source in Canada. CBM is natural gas that is contained in the fracture system and matrix of the coal itself. In-place[1] resources of CBM in Canada are estimated by the Canadian Gas Potential Committee (CGPC) to be approximately 14 trillion m^3 (500 Tcf)[2]. According to the 2005 CGPC Report, about 75 percent of Canada’s total in-place CBM resource is associated with the coals in the Western Plains of Alberta, B.C. and Saskatchewan. Most of the rest is contained in coals of the Rocky Mountain Foothills and Front Ranges in Alberta and B.C.

This report focuses on deliverability expectations of CBM on the Alberta plains where commercial development has been underway since approximately 2002. In-place CBM resources and recoverable resources on the Western Plains of Alberta and Saskatchewan are estimated in the 2005 CGPC Report by geologic formation as shown in Table 2.1.

As evident in Table 2.1, in-place CBM resources are very large, and the recoverable resources are expected to be a small fraction of the in-place resource. Even with this low ratio of recoverable to in-place resources, the recoverable resources still amount to a significant volume in relation to Canada’s total natural gas resources. Industry is actively conducting pilot tests on coals throughout

TABLE 2.1

Summary of CGPC Estimate of CBM Resources on Western Plains of Alberta and Saskatchewan

Geologic Formation	In-Place Resources		Recoverable Resources-Reference Case	
	billion m^3	Tcf	billion m^3	Tcf
Belly River (MacKay, Taber and Lethbridge coal zones)	2 734	96.5	6	0.2
Horseshoe Canyon (Horseshoe Canyon and Carbon-Thompson coal zones)	2 008	70.9	259	9.1
Ardley	1 589	56.1	144	5.1
Mannville	3 479	122.8	224	7.9
Total	**9 810**	**346.3**	**633**	**22.4**

Source: *2005 CGPC Report - Volume 4: U.2 Figure 42 – CBM Resources of the Western Plains*

1 In-place resources are the total volume expected to exist underground. Only a portion of this in-place resource would ever be technically or commercially recoverable

2 Canadian Gas Potential Committee, *Natural Gas Potential in Canada 2005*, May 2006 (“the 2005 CGPC Report”).

the basin, or is in the process of requesting provincial approval to test other coals with potential. Based on this testing, the ratio of recoverable to in-place resources could increase or decrease, perhaps significantly. It should be noted that other estimates of recoverable resources of CBM may differ from the CGPC estimates. For example, the Board estimated that 1.7 to 2.3 trillion m^3 (60 to 80 Tcf) of unconventional gas could be proven as reserves by 2025, with the majority expected to be CBM.[3]

Producing characteristics of the individual coal zones, such as permeability, pressure, depth, net coal thickness, gas content and water content are crucial factors in determining whether or not the resources will be economically recoverable. The producing characteristics vary considerably, geographically within each coal zone and geologically from formation to formation.

The development of technical understanding and experience with particular coals is necessary before a reliable estimate can be made of potential CBM recovery. In Canada, commercial CBM development has occurred largely since 2002, and thus industry knowledge regarding the exploitation of the CBM resource is still being developed and varies considerably geographically and geologically from formation to formation.

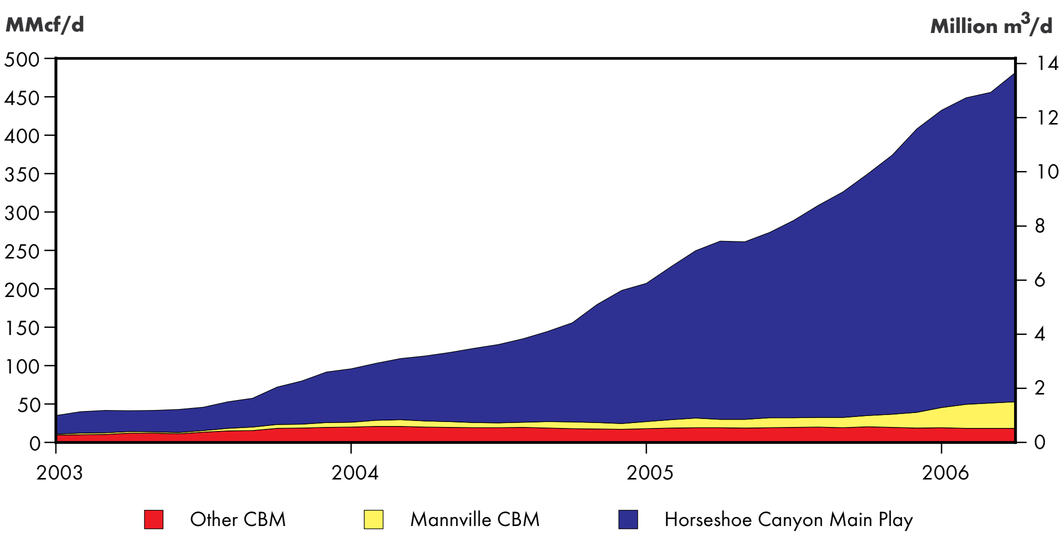
To assess deliverability in this report, CBM resources were categorized into the following three CBM "resource groupings" based on geological formation and geographic location:

- Horseshoe Canyon main play,
- Mannville CBM, and
- Other CBM

Figure 2.4 shows the historical CBM production since January 2003 for these three CBM resource groupings.

FIGURE 2.4

Historical CBM Production by CBM Resource Group



3 National Energy Board, *Canada's Energy Future – Scenarios for Supply and Demand to 2025*, July 2003

Horseshoe Canyon Main Play

In this report, the Horseshoe Canyon main play refers to all CBM connections contained within the Horseshoe Canyon main play area where the producing zone is not the Mannville. The Horseshoe Canyon main play area is as shown on the map included in Appendix C.1.a of this report. This CBM grouping is comprised primarily of CBM connections producing from the Horseshoe Canyon coal zones, but also contains CBM connections that produce from the Belly River coals, commingled Horseshoe Canyon and Belly River coals, and in many instances interbedded sand intervals that are often commingled with the coal zones. The contribution from the sand intervals is considered to be less than 10 percent in most wells. As shown on Figure 2.4, dramatic growth in production has occurred since the start of 2003. This CBM play was responsible for 89 percent of Canadian CBM production in the first four months of 2006.

Mannville CBM

While the CBM in-place resources in the Mannville coals are larger than those of the Horseshoe Canyon, the technical and economic challenges to commercial development are also greater. Mannville coals are generally deeper and have less permeability than the Horseshoe Canyon coals. There also tends to be significant salt water production associated with the Mannville coals, and water handling expenses add to development costs. With the Mannville having these larger challenges to commercial development, large scale development has lagged in comparison to the Horseshoe Canyon main play. In general, the industry is still at an early stage with respect to Mannville CBM, developing the practices and techniques that are needed to exploit this resource.

Significant progress has been made recently with the first large scale commercial development of Mannville CBM in the WCSB being announced for the Corbett area of Alberta in 2005. The Corbett Project area is shown on the map contained in Appendix C.1.b of this report. Horizontal drilling was a key factor in making Mannville CBM commercially viable in the Corbett areas and may result in greatly increased development of Mannville CBM in the coming years.

In this report, the Mannville CBM Group refers to all CBM connections which are either located within the Corbett Project area, or have a producing pool code indicating Mannville production, or have an undefined zone and are located north of Township 59. Figure 2.4 shows the increasing contribution of Mannville CBM production, which has grown from around 340 thousand m^3/d (12 MMcf/d) in mid 2005 to 990 thousand m^3/d (35 MMcf/d) in April of 2006. The Corbett Project is responsible for almost all of this increase.

Other CBM

In this report, the Other CBM Group refers to all CBM connections which are not categorized as Horseshoe Canyon main play or Mannville CBM. The group consists of the miscellaneous CBM resources which thus far have not had notable levels of development, including Ardley coals and the coals of the Belly River and Horseshoe Canyon formations that fall outside the Horseshoe Canyon main play area.

The Other CBM Group has had steady production over the past few years, accounting for about 500 thousand m^3/d (18 MMcf/d) or about four percent of total CBM production over the first four months of 2006.

2.3 Atlantic Canada

Gas production in the region consists of output from the Sable Offshore Energy Project (SOEP) since 1999 and a minor contribution from the onshore McCully field in New Brunswick since 2003. These sources currently account for roughly 9.9 million m^3/d (350 MMcf/d) or about two percent of Canadian natural gas deliverability.

The SOEP has benefited from the addition of three new wells since mid-2005 that are enhancing access to the Venture, South Venture and Alma reservoirs. Pressure declines in some other fields have required that wells be operated in a cycling mode (shut in briefly to rebuild pressure and then restarted) resulting in monthly deliverability from the project varying by almost 25 percent since late 2005. As a result of pressure decline, the North Triumph field has not been producing since November 2005.

To enhance deliverability, the SOEP is in the process of adding compression at the inlet of the pipeline that delivers the gas to shore. The offshore platform and compression unit was installed in mid-2006 and is expected to be hooked up and operational by December. The added compression will allow the existing wells to operate at lower pressures thereby significantly increasing overall project deliverability and potentially enabling the North Triumph field to resume production. Uncertainty exists regarding individual well performance at the new lower pressures, and cycling of some wells may continue.

Interest in the Deep Panuke offshore gas project has resurfaced with an agreement reached in mid-2006 on royalties, employment and industrial benefits, and funding for research and education. Subsequent steps include the filing of a project description and development plan by the end of the year. A final decision to proceed with the potential 28 billion m^3 (1 Tcf) project could come as early as the end of 2007, with initial production, subject to regulatory approval, by 2010.

No gas-related exploration drilling is planned for the Nova Scotia offshore again in 2006. Global competition for offshore drilling equipment, resulting in requirements for longer-term commitments and higher costs, is compounding the difficulty of encouraging additional exploration interest in the area. Existing exploration licences continue to be relinquished and there will be no new call for bids in 2006. Nova Scotia is promoting interest in the region by funding efforts to increase the availability of geology/geophysical data and understanding of the region's prospectivity.

Gas deliverability from the onshore McCully field in New Brunswick has been used for industrial requirements in the immediate area since 2003. Through a 50 km tie-in to the Maritimes and Northeast Pipeline that is to enter service in February 2007, deliverability from the field will be able to increase significantly to represent roughly five percent of Atlantic Canada gas deliverability.

Onshore in Nova Scotia, pilot testing of CBM potential has been initiated in two locations. Extensive coal deposits have been confirmed in the area through previous efforts related to mining. However, testing to assess the technical and economic viability of methane extraction is at too early a stage to make any estimate of potential CBM deliverability within the projection period.

Offshore Newfoundland, an extension of the Hibernia project has identified significantly higher oil reserves and solution gas resources than previously indicated. The resulting increase to the duration of oil production (with corresponding re-injection of gas for pressure maintenance) makes it likely that any potential recovery of gas volumes from the project could be delayed from post-2010 to at least post-2015 to 2018. Gas associated with the neighbouring White Rose oil development is not required for oil operations, but instead awaits establishment of a provincial fiscal regime for natural gas and a technically and economically viable means of delivering the gas to markets. Details on provincial gas royalties are expected to be released later in 2006. Commercial projects involving ship-borne compressed natural gas (CNG) are under development in other parts of the world, and are potential considerations for White Rose gas. Post-2012 timing for initial gas production has been suggested.

2.4 LNG

Prospective LNG regasification terminal projects in Atlantic Canada, Quebec and British Columbia are at various stages of development that include planning, obtaining environmental/regulatory approvals, seeking contractual arrangements with suppliers and users, financing and construction. As gas supply for LNG projects is sourced from outside the country, these projects will not be covered in this report of Canadian gas deliverability.

METHODOLOGY

Canadian natural gas deliverability over the projection period will consist of conventional gas supply from the WCSB with contributions from Atlantic Canada and growing CBM production from Alberta. In this EMA, trends in average production characteristics are combined with resource development expectations to determine conventional natural gas deliverability from the WCSB. Due to the limited duration of CBM production history, the Board consulted with industry in addition to the review of historical data to develop the production profile and resource development expectations for CBM. A different approach is used for Atlantic Canada where production history is obtained from a small number of wells from clearly defined fields.

3.1 WCSB – Conventional Gas Supply

The method used in this EMA to determine conventional gas deliverability from the WCSB can be summarized as follows:

Future Deliverability = [Future Deliverability from Existing Gas Connections] +
[Deliverability from Future Gas Connections] +
[Solution Gas Deliverability]

The above formula is applied to each of the study areas identified in Chapter 2 to obtain an estimate of short-term deliverability for the WCSB.

For the purpose of this report, "existing gas connections" means those wells brought on stream before January 1, 2006 and "future gas connections" means those brought on stream after January 1, 2006.

To estimate the **Future Deliverability from Existing Gas Connections** in each study area, gas connections were grouped by connection year and production decline analysis was performed to determine the parameters that define the future deliverability of the group.

To estimate the **Deliverability from Future Gas Connections**, production decline analysis was performed on production data for the "average gas connection" in each study area.[4] The analysis done on the average gas connections is very similar to that performed for existing gas connections, except that the focus is more on defining the production characteristics in the earlier stages of production, rather than emphasizing the most recent production history. The trends seen in the historic data were used to establish parameters that define the deliverability to be expected from future gas connections. The number of gas connections expected in future years is estimated and applied to the expected productivity of the typical gas connection of future years to obtain the Deliverability from Future Gas Connections.

4 In estimating the average gas well connection, the production history data is normalized by using the number of months since the start of production.

Solution Gas Deliverability refers to natural gas produced in conjunction with oil production. Historical natural gas production data was totalled for all oil connections in each study area, and production decline analysis was performed to obtain the parameters that define Solution Gas Deliverability.

In this EMA each connection is categorized as either:

- a gas connection (conventional gas only);
- a CBM connection;
- an oil connection; or
- an oil sands connection.

Connections were categorized as either [gas/CBM] or [oil/oil sands] based on the connection's cumulative production. Other criteria were then used to further identify the CBM and oil sands connections to enable each connection to be classed as one of the four types listed above. Note that in this analysis gas connections are distinct from CBM connections.

The level of certainty and analysis effort associated with the different components of this deliverability projection can be summarized as follows:

Level of Certainty	Analysis Effort Required	Component of Deliverability
Higher	Least	Existing gas connections and solution gas
↓	↑	Existing CBM connections
		Future gas connections
Lower	Most	Future CBM connections

The deliverability projection for existing gas connections and solution gas has the highest level of certainty while requiring the least amount of analysis effort in this assessment because the analysis extrapolates production history for existing wells. A lower degree of certainty is inherent in the deliverability projection for future gas connections because estimates of future drilling activity and performance of future gas connections are required. In view of the importance of future gas connections to deliverability over the projection period, more effort was expended in assessing parameters for future gas connections than what was required to assess existing gas connections.

The level of certainty for the deliverability projections for CBM (both existing CBM connections and future CBM connections) is less than the certainty for the corresponding conventional gas groupings. This is because there is a limited amount of gas production history available for CBM, especially with respect to Mannville CBM.

3.1.1 Existing Conventional Gas Connections

In each study area in Alberta, B.C. and Saskatchewan (except for the southeast area of Saskatchewan where only solution gas is produced) existing gas connections were grouped by connection year and a production decline analysis was performed on each grouping.

For each group of gas connections, the total marketable gas production for each calendar month was calculated and a plot of group production rate versus cumulative production was constructed to determine the following parameters:

- group deliverability as of December, 2005; and
- forward-looking exponential decline rate(s).

The above parameters can be applied to estimate future deliverability for each grouping of existing gas connections. Figure 3.1 shows the plot generated for the Alberta Foothills Front area for the 2001 connection year as an example of the method used to determine performance parameters for the group. In the most recent connection years, the known annual gas well connection schedule and the expected average connection performance parameters were also applied to gain insight into the future deliverability of the group. The exponential decline rate is determined as the slope of the line formed by the production history data on the plot of production rate versus cumulative production. The decline rate determined in this manner is the nominal annual decline rate.

3.1.2 Future Conventional Gas Connections

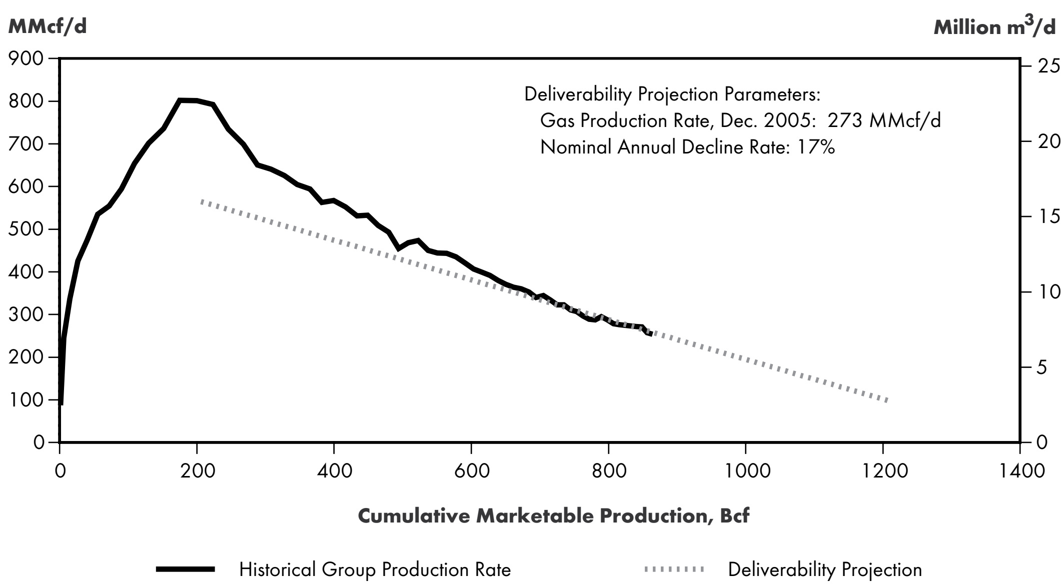
Deliverability from future conventional gas connections is expected to form a large component of gas deliverability over the projection period. To estimate deliverability from this source, it is necessary to estimate the number of future gas connections and the average production characteristics of those future connections. This section describes the assessment of production performance characteristics of the average future gas connection and then describes the methodology used to determine the number of future gas connections.

3.1.2.1 *Performance of Future Gas Connections*

To assess the deliverability from future conventional gas connections in the WCSB, decline analysis was performed on production data representing the "average gas connection" in each study area.

FIGURE 3.1

Example of Group Production Decline Plot (Alberta Foothills Front Area, 2001 Connection Year)



Source: Board Analysis of GeoScout Well Production Data

Production decline analysis suggests that the average gas connection in each study area tends to exhibit a steep decline during initial production, which usually lasts for about 17 months, followed by a period characterized by a significantly lower decline rate. To reflect this behaviour, the production decline analysis provides:

- initial production rate;
- first decline rate;
- months to second decline rate; and
- second decline rate.

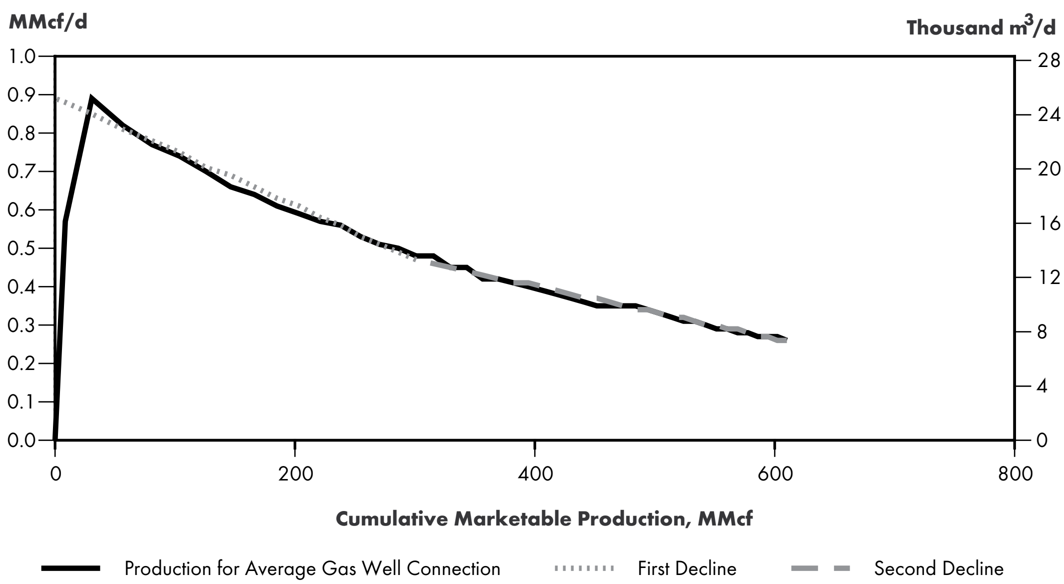
Figure 3.2 provides an example of the type of plot generated when conducting production decline analysis of the average gas connection. Plots of this nature were generated for all study areas and for all connection years between 1996 and 2005. Figure 3.2 shows the analysis for the Alberta Foothills Front area for gas connections brought on stream in 2001.

In all cases, the period of time over which the first and second decline rates apply covers at least the first four or five years of the productive life of the average gas connection. Thus these parameters are all that is required to calculate deliverability over the projection period. However, with a view to establishing performance parameters that would allow calculation of deliverability over a longer period, the Board also determined four additional parameters for each area/connection year grouping. These four additional parameters are third decline rate, months to third decline rate, fourth decline rate and months to fourth decline rate. While these parameters were determined in the course of establishing average connection performance and are provided in this report in Appendix B.2.a, they do not impact the calculation of short term deliverability.

The production decline analysis (as shown in Figure 3.2) results in parameters that define the productivity of average gas connections in past years. The trends evident in well performance in the past years are identified to determine parameters that could be applied to future gas connections. In

FIGURE 3.2

Example of Average Gas Connection Production Decline Plot (Alberta Foothills Front Area, 2001 Connection Year)



Source: Board Analysis of GeoScout Well Production Data

assessing the performance parameters of past years, it can be observed that generally the first decline rate, second decline rate and months to second decline rate were fairly constant in each study area, and thus it is reasonable to apply these historical parameters to future gas connections in each area. However, the initial productivity of the average gas connection generally decreases year after year. These trends are evidenced by examining the performance of the average gas connection over the entire WCSB in recent years (Figure 3.3).

Graphs showing the average gas connection performance for recent years and the projected gas well performance for each study area are contained in Appendix B.4.

To determine the initial productivity of average gas connections in the future, the Board examined the trend in initial productivities over time in each area and projected values for future years that were consistent with the historical trend. Figure 3.4 illustrates the Board's method for selecting initial productivity of gas connections in 2006, 2007 and 2008.

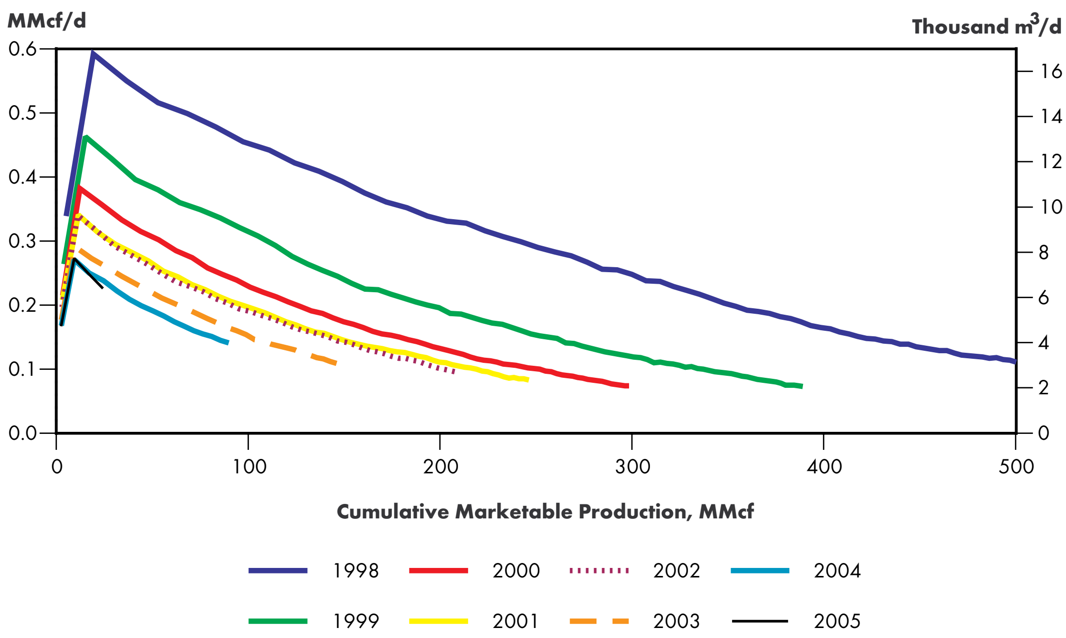
3.1.2.2 Number of Future Gas Connections

The first step in determining the number of future gas connections is to estimate the level of gas well drilling that is expected to occur over the projection period. The number of future gas connections is estimated based on the projected number of gas-intent wells. In this EMA, the number of future gas-intent wells is calculated for each study area using the following equation:

[Average Number of Rigs in WCSB Rig Fleet for year (by rig category) * 365]
* [Study Area Rig Day Allocation Factors (for each rig category)]
* [Rig Utilization Factors (for each rig category and study area)]
* [Target Resource Fractions (for each rig category and study area)]
/ [Drill Days per Well (for each rig category, study area and target resource)]
=> Annual wells drilled (by rig category / study area / target resource)

FIGURE 3.3

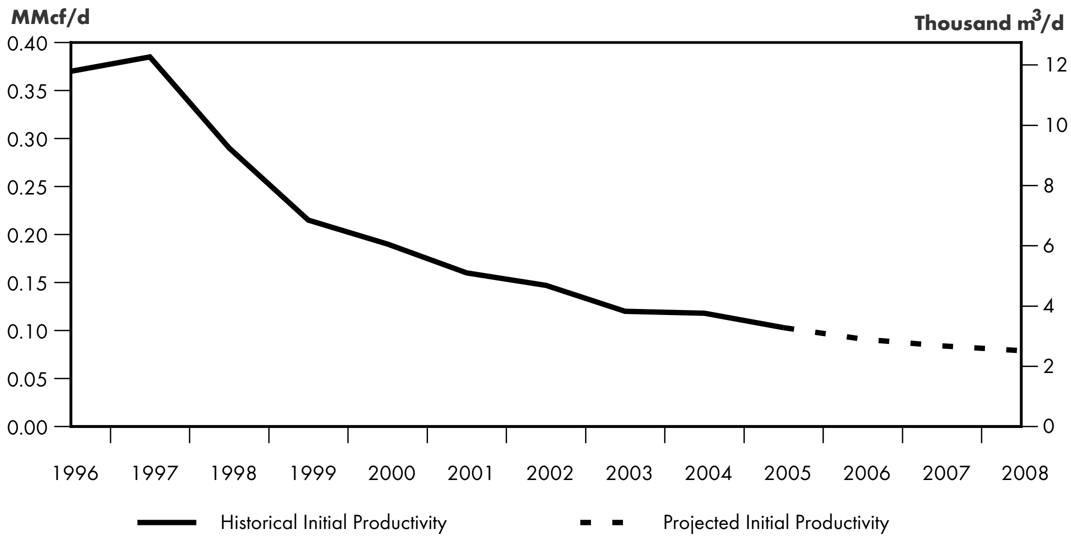
WCSB Average Gas Connection Performance



Source: Board Analysis of GeoScout Well Production Data

FIGURE 3.4

Example of Initial Productivity of Average Gas Connections by Connection Year (Area: Alberta – Southeast)



Source: Board Analysis of GeoScout Well Production Data

The approach outlined above calculates the level of gas-intent drilling activity on the basis of drilling capacity, rig utilization and the fraction of drilling targeted to gas in the WCSB. In the market environment that is likely to prevail throughout the projection period, it is expected that drilling rigs in the WCSB will be used near the maximum level. Thus analysis of drilling capacity over the projection period should provide a reasonable estimate of gas-intent drilling over the projection period.

This EMA incorporates a detailed analysis of the Canadian rig fleet in the assessment of drilling capacity. The weekly Rig Locator report published by Nickle's Energy Group ("the Rig Locator Report") was used as the main source of data in this analysis.

The analysis began by identifying the part of the Canadian rig fleet that can be expected to be drilling in the gas producing areas of the WCSB. This portion of the Canadian rig fleet is referred to as the WCSB rig fleet in this EMA. Appendix A.1 shows the splitting of the Canadian rig fleet into five sub-fleets, which tend to work in specific geographic areas. The WCSB rig fleet comprises the vast majority (about 96 percent) of the Canadian rig fleet.

The WCSB rig fleet was split into three rig categories based on depth capacity of the drill rigs as follows:

Rig Category	Depth Capacity (m)
Shallow	Less than or equal to 1850 m
Medium	Greater than 1850 m and less than or equal to 3050 m
Deep	Greater than 3050 m

The number of rigs in each rig category of the WCSB rig fleet over the projection period was estimated based on information gathered from drilling industry organizations regarding new rig construction and the growth trends in each category over the past five years. Appendix A.2 details the historic and projected rig count for the WCSB rig fleet in each rig category.

With rig count projections for the three rig categories, the rigs were then allocated to the study areas in the WCSB. For each rig category, there are a total number of **rig days** available in each year of the projection period (i.e., the average number of rigs in the year multiplied by 365). The rig days for each rig category were allocated to each study area based on the historical rig location trends observed by the NEB. Some historical trends apply at a more aggregate level. For these particular trends, the historical rig days for each rig category in each study area were grouped into three main geographic areas– North, South and West. These three main geographic areas are defined as follows:

Main Geographic Area	Study Areas Comprising Main Geographic Area
North	AB-Northeast, AB-Northwest, BC-Fort St. John, and BC-Fort Nelson
South	AB-Central, AB-East Central, AB-Southeast, SK-Central, and SK-Southwest
West	AB-Foothills, AB-Foothills Front, and BC-Foothills

Trends by main geographic area can be observed in the charts contained in Appendix A.3.a. These geographic trends were combined with the trends applicable to individual study areas to provide the number of rig days in each year of the projection period for each rig category in each study area (see tables in Appendix A.3.b).

The historic data dealing with the utilization of rigs in each study area was investigated to provide a basis for estimating rig utilization for 2006–2008. Based on the Rig Locator Report, the number of rig days for each rig category in each study area for the past six years was determined. Analysis of well data from GeoScout provided the number of **drill days** associated with the rig categories in each study area. The rig utilization for years 2000 through 2005 was calculated for each rig category in each study area as drill days divided by rig days. Rig utilization levels for 2006–2008 (for each rig category and each study area) were then projected on the basis of the historical data. Appendix A.4 contains tables for each rig category and study area showing the historic and projected rig utilization factors. Application of the rig utilization levels to the corresponding rig day projections results in a projection of drill days for 2006–2008.

A further review of the historic drilling data derived from GeoScout provided insight into the specific resources that were the target of the drilling efforts over 2000–2005. Drilling in the WCSB is generally done for the purpose of exploiting one of the following resources (the "target resources"): conventional gas, CBM, conventional oil or oil sands. The drill days deemed by the NEB to be associated with each target resource was calculated for each rig category and each study area. Based on the historic allocation of drill days to target resources, and based on the Board's view of future exploitation levels of the target resources, allocation factors for each target resource were projected for each rig category in each study area (Appendix A.5). The Board's view of the exploitation levels of the target resources included insights obtained through industry consultations, particularly with respect to drilling targeted to CBM. Through the application of the target resource allocation factors, the number of drill days that might be expected for gas-intent drilling and CBM-intent drilling were calculated for each rig category in each study area. Note that with this assessment of drilling effort, a projection for CBM-intent drilling is produced at the same time as a projection for gas-intent drilling.

To determine the number of gas-intent wells and CBM-intent wells that can be expected over the projection period, the drill days per well were calculated. Drill days per well for 2000–2006 were calculated for each rig category in each study area for each resource target. The drill days for the past six years were used as the basis for projecting drill days per well for 2007 through 2008 (see Appendix A.6 to view details). Dividing drill days by drill days per well yields the number of wells to be drilled.

The gas-intent and CBM-intent drilling levels determined via this process are tabulated in terms of drill days and wells in Appendix A.7. It is useful to view the drilling levels in terms of drill days as this is the more meaningful measure when comparing the drilling efforts in the various study areas.

For CBM-intent wells, a further allocation of drilling effort was required to obtain number of wells for each of the CBM resource groupings used in this report. This allocation is further discussed in paragraph 3.2.2.2 of this report.

The ratio of number of gas connections and number of gas-intent wells drilled was investigated for the past six years for gas and CBM. The ratio for these years was used to project the ratio that was applied to the projection period. Appendix A.8 contains tables detailing the ratio of connections to wells for each study area for conventional gas connections and for each resource grouping for CBM. Using the ratio of connections to wells and the number of wells expected to be drilled, the annual number of gas and CBM connections for the years 2006 through 2008 were calculated.

Finally, the fraction of annual connections that are expected to be made in each month of each year of the projection period is applied to the annual connections to obtain a monthly connection schedule for gas and CBM. Appendix A.9 shows the monthly connection fractions for each study area for conventional gas and for each resource grouping for CBM.

3.1.3 Yukon and Northwest Territories

In the Yukon and Northwest Territories, gas is produced from the Kotaneelee, Cameron Hills and the Liard Plateau gas fields (gas production from Ikhil and Norman Wells is not connected to the pipeline grid and so was not included in this assessment). Due to the small number of producing wells in the territories, a single production decline plot was generated for the aggregate production from Kotaneelee, Cameron Hills and the Liard Plateau to define future deliverability of the existing wells. The level of development anticipated for these producing fields over the projection period is not expected to significantly impact the deliverability from the area. Thus the performance parameters obtained from the production decline analysis were considered to be representative of the total deliverability for the area over the projection period.

3.1.4 Solution Gas

Solution gas currently accounts for about nine percent of total marketable gas deliverability from the WCSB. To estimate future deliverability of solution gas, production decline analysis was performed to obtain the current production rate and the decline rate for solution gas in each study area in Alberta, B.C. and Saskatchewan (with the exception of B.C. Foothills which has no solution gas). As with the deliverability projection for existing gas connections, the deliverability projection for solution gas has a high level of certainty.

3.2 WCSB – Coal Bed Methane (CBM)

To estimate deliverability from CBM wells, the same basic relationship is used as in assessing deliverability from conventional gas supplies (that is, future deliverability = deliverability from existing connections + deliverability from future connections). As discussed in paragraph 2.2 of this report, CBM is split into three resource groupings for the purpose of assessing deliverability: Horseshoe Canyon main play, Mannville CBM, and Other CBM.

3.2.1 Existing CBM Connections

Horseshoe Canyon Main Play and Other CBM

For each of the Horseshoe Canyon main play and Other CBM groupings, connections were grouped into those connections made before 2003, and those made in each of the years 2003, 2004, and 2005. For each grouping of connections, the total marketable gas production in each calendar month was calculated and a plot of group production rate versus cumulative production was made. The deliverability expectation for the group based on the average connection performance parameters and connection schedule was added to the group plot of rate versus cumulative production to give insight into the likely future production profile for the group. From these plots, the deliverability as of December 2005 was determined for each group along with the forward-looking exponential decline rate(s). The parameters for each group were used to project deliverability of existing CBM connections.

Mannville CBM

The Mannville CBM group was divided into the following three sub-groups for the purpose of determining deliverability performance parameters:

- *Horizontal CBM Connections made in 2005 within the Corbett Project Area*—this grouping was created as it accounts for the largest amount of Mannville CBM production from existing connections and is considered to be the most representative of future Mannville CBM developments that are likely to occur over the next few years.
- *Within the Corbett Project Area, All CBM Connections made prior to 2005 and the Vertical CBM Connections made in 2005*—this grouping roughly corresponds to the pilot phase of the Corbett Project. Deliverability is projected to reflect the productivity of these existing connections, but performance of this grouping is not a factor in determining the performance parameters for future Mannville CBM developments.
- *All Mannville CBM Connections made prior to 2006 Outside the Corbett Project Area*—these connections represent the miscellaneous Mannville CBM developments in Alberta that for the most part are experimental or pilot projects. These connections are dispersed over a wide area (see map in Appendix C.1.b), have diverse production characteristics and make up a small portion of the total Mannville CBM production. While experimental and pilot projects involving Mannville CBM are expected to proliferate in the coming years, large scale commercial development of Mannville CBM resources outside of the Corbett Project has not yet occurred and may not occur over the projection period.

For each of the above three groupings of Mannville CBM, the total marketable gas production in each calendar month was calculated and a plot of group production rate versus cumulative production was made. This provides a basis for estimation of group deliverability parameters—these being group deliverability as of December 2005 and forward looking decline rate(s). For the Horizontal CBM Connections made in 2005 Within the Corbett Project Area, the deliverability expectations of the average connection and the 2005 well connection schedule were also applied to give indication of the group deliverability profile.

3.2.2 Future CBM Connections

As with the methodology used to assess deliverability for conventional gas supply, the assessment of deliverability from future CBM connections requires an estimate of the number of CBM connections and the production characteristics of the average CBM connection over the projection period. The deliverability for future CBM connections is projected for each of the three groupings of CBM resources - Horseshoe Canyon main play, Mannville CBM and Other CBM.

3.2.2.1 Average CBM Connection Performance

Horseshoe Canyon Main Play and Other CBM

The Horseshoe Canyon main play has far larger deliverability and drilling activity than the Other CBM group. However, the methodology to assess average connection performance for future wells is the same for the two groupings.

For each of the Horseshoe Canyon main play and Other CBM groupings, the performance of the average connection in years 2003, 2004 and 2005 was analyzed. These connection years represent practically all of the connections for these two CBM groupings. Charts such as the one shown in Figure 3.2 were created for each CBM grouping and connection year. This analysis enabled the estimation of initial productivity and first decline rate of the average CBM connection. The historical data is still insufficient to allow for the reliable determination of the remaining decline parameters (the decline rates that apply over the life of the connection and the months where those decline rates apply). These parameters were still estimated by the NEB based on discussions with CBM producers. For the Horseshoe Canyon main play an ultimate recoverable gas volume of approximately 7.5 – 8.5 million m^3 (270 - 300 MMcf) per well was used to establish the end point for each of the rate versus cumulative production plots in the average connection analysis. Some in the industry consider this estimate to be conservative and that the average recoverable gas from each well could be 14 million m^3 (500 MMcf).

For the Horseshoe Canyon main play, a slight trend towards declining initial productivity of the average connection has occurred over the past three years. The trend is not well established. Nevertheless the initial productivity projected for Horseshoe Canyon main play connections incorporates a slight year on year decrease in initial productivity.

For the Other CBM grouping, the amount of data is far less substantial and no trend was apparent. The greater uncertainty associated with the average connection parameters estimated for the group is recognized and only low levels of drilling activity and deliverability are expected for the Other CBM grouping.

Mannville CBM

The Corbett Project area represents the only large scale Mannville CBM development underway in the WCSB. There are other developments being made on Mannville CBM throughout the WCSB, but the scale and deliverability of these other projects over the projection period is expected to be minor in comparison to the Corbett Project.

Development of Mannville CBM in the Corbett Project area was announced as commercially viable in 2005, largely as a result of the use of horizontal drilling. For the Mannville CBM grouping, the performance of selected horizontal connections made in 2005 in the Corbett Project area were studied to provide a basis for estimation of performance of future Mannville CBM connections.

Unlike the coals of the Horseshoe Canyon main play, the Mannville coals in the Corbett area are saturated with saline water. To enable CBM production, the pressure on the coals must first be reduced by pumping the water out of the formation (this process is called de-watering). As reservoir pressure is reduced, CBM is desorbed from the coals resulting in increasing rates of CBM production during the dewatering phase until a peak production rate is achieved. Typically the well production starts to decline after the peak rate is reached. The production profile for this type of connection is different from the average conventional gas connection or Horseshoe Canyon main play connection, and thus requires a slightly different model to describe performance. The parameters chosen to model performance of average Mannville CBM connection are as follows:

- Peak Rate
- Months to Peak Rate
- First Decline Rate (after Peak Rate is reached)
- Second Decline Rate
- Months to Second Decline Rate (from Initial Production)
- Third Decline Rate
- Months to Third Decline Rate (from Initial Production)

For the purposes of this short-term deliverability assessment, the third decline rate and months to third decline rate do not come into play in determining deliverability. Nevertheless, estimates are made for all these parameters in this assessment and are included in Appendix B.2.b.

The available data allows for a reasonable estimation of peak rate and months to peak rate for horizontal Mannville CBM wells. However the short production history cannot provide reliable estimates of the other parameters. Thus the decline rates that have been estimated at this time for future Mannville CBM have a low level of certainty. Estimates of all the parameters are based on input received from CBM producers and upon the general expectation that CBM wells will decline at lower rates than conventional gas wells and will trend towards very low rates of decline after about five years of production.

3.2.2.2 Allocation of CBM-Intent Drilling to CBM Resource Groupings

The number of future connections relating to each of the three CBM resource groupings is estimated according to the level of drilling projected for each grouping.

The procedure outlined in paragraph 3.1.2.2 of this report provides a projection of CBM-intent drilling for the geographic areas in the WCSB. The great majority of CBM-intent drilling over the next three years is expected to occur in the Southeast and Central areas of Alberta, where the Horseshoe Canyon main play and Corbett Project area are located. Most of the Mannville CBM-intent drilling is expected to occur in the Central area of Alberta.

The number of Mannville CBM wells drilled in 2006 is calculated assuming eight drilling rigs, operating over the entire year at 50 percent utilization, with 10 drill days required to drill each well. For 2007 and 2008, the number of drilling rigs dedicated to Mannville CBM is increased by two rigs in each year. All of this Mannville CBM drilling activity was deemed to occur in the Alberta Central area. CBM-intent wells in the Alberta Central area that were not allocated to the Mannville via this procedure were allocated 99 percent to the Horseshoe Canyon main play and one percent to Other CBM.

For CBM-intent drilling in the Alberta Southeast area, 99 percent of the wells were allocated to the Horseshoe Canyon main play with the remaining one percent allocated to Other CBM.

For all areas other than Southeast Alberta and Central Alberta, the combined amount of CBM-intent drilling is relatively small, amounting to less than three percent of the Alberta CBM-intent drilling total in 2005. All CBM-intent drilling in areas other than the Southeast and Central areas of Alberta was allocated to Other CBM.

The ratio of annual CBM connections to annual CBM wells drilled is estimated by the Board for each grouping. By multiplying the projected number of annual wells drilled by the ratio of annual connections over annual wells drilled, the number of annual CBM connections for the years 2006, 2007 and 2008 is obtained for each CBM grouping.

3.3 Atlantic Canada

For producing wells in the Nova Scotia offshore, an initial 24-month period of relatively constant production followed by an annual exponential decline rate of 30 percent was assumed. This production profile was based on an average of the decline rates in the three original producing fields. No additional infill wells after 2006 are assumed for the producing fields at this time. Offshore compression is expected to be in service by December 2006. The parameters used in the compression analysis were based on discussions with industry representatives.

Onshore production from the McCully field is based on corporate development plans and considers the performance of wells that have been in operation since 2003 serving local industrial demand.

Due to the early stage of testing, reasonable estimates of onshore CBM productivity can not be developed. As a result, no onshore CBM deliverability will be assumed for the projection period.

No deliveries of associated gas from offshore Newfoundland are expected until at least 2012. As a result, no Newfoundland offshore gas deliverability is included during the projection period.

3.4 Other Canadian Production

Deliverability from the WCSB and Atlantic Canada discussed in the preceding sections of this chapter account for 99.8 percent of total Canadian production. The final component of Canadian production is the minor amount of gas production that occurs in Ontario and Quebec. Deliverability from these sources over the projection period is assumed to correspond to the production level seen in recent years.

3.5 Canadian Deliverability and Canadian Demand

To better understand the role of natural gas deliverability in relation to the Canadian natural gas market, it is useful to compare the Board's outlook for deliverability with current and anticipated Canadian natural gas demand.

Canadian natural gas deliverability is defined as the amount of gas available after field processing. As a result, all estimated gas use prior to the outlet from field processing plants has already been deducted from the deliverability estimate, and likewise is not included in the demand estimate. Gas consumed at the Goldboro processing facility in Nova Scotia is included in this category of field processing and has therefore already been deducted from Atlantic Canada deliverability.

Current and projected Canadian gas demand is divided geographically at the Saskatchewan-Manitoba border into western and eastern Canada demand. Western Canada demand includes gas volumes withdrawn during the recovery of natural gas liquids at straddle plants. Approximately 85 to 90 percent of the gas volumes leaving Alberta are processed through the straddle plants, where much of the ethane and most of the propane and heavier components are extracted. The straddle plants lower the heat content of the marketable gas leaving Alberta. Marketable gas in Alberta prior to straddle plant processing has an average heat content of approximately 39.4 MJ/m^3. After straddle plant extraction, the average heat content of the marketable gas exported from Alberta is approximately 37.9 MJ/m^3.

Western and eastern Canada gas demand includes gas required for pipeline fuel in the respective areas. The Board's projection of western and eastern Canada gas demand is based on historical trends and expected major increments of industrial demand (including oil sands projects) and power generation projects. The demand projection is based on the assumption of average weather conditions. Considerable variability in actual gas demand is possible due to the impact of weather variation on Canada's large space heating markets.

DELIVERABILITY PARAMETERS – RESULTS

4.1 WCSB – Conventional Gas Supply

As discussed in Chapter 3, conventional gas supply in the WCSB is comprised of three components—Existing Gas Connections, Future Gas Connections and Solution Gas. The parameters relating to each of these components are discussed below.

4.1.1 Decline in Production from Existing Gas Connections and Solution Gas

Production decline analysis was performed for each study area and connection year for existing gas connections and for each study area for solution gas. As of the end of 2005, there were approximately 115 000 existing conventional gas connections producing in the WCSB. From this analysis it was possible to determine the deliverability as of year-end 2005 and determine applicable production decline rates from which future deliverability of existing gas connections and solution gas could be calculated. A table containing all production decline parameters for existing gas connections and solution gas is included as Appendix B.1. Deliverability can be projected from these parameters to be 468 million m^3/d (16.5 Bcf/d) at the end of 2005, 370 million m^3/d (13.1 Bcf/d) at the end of 2006, 312 million m^3/d (11.0 Bcf/d) at the end of 2007, and 269 million m^3/d (9.5 Bcf/d) by the end of 2008.

4.1.2 Future Gas Connections

The production decline analysis discussed in Section 4.1.1 concludes that, because of the historically consistent production decline in existing gas well connections and solution gas, approximately 97 million m^3/d (3.4 Bcf/d) of deliverability will have to be replaced annually from new gas wells to maintain production from the WCSB.

4.1.2.1 Performance Parameters for Future Average Gas Connections

The level of deliverability to be expected from future gas connections is a key factor in assessing future deliverability. The production decline analysis described in Chapter 3 provided the basis for establishing performance parameters for future gas connections.

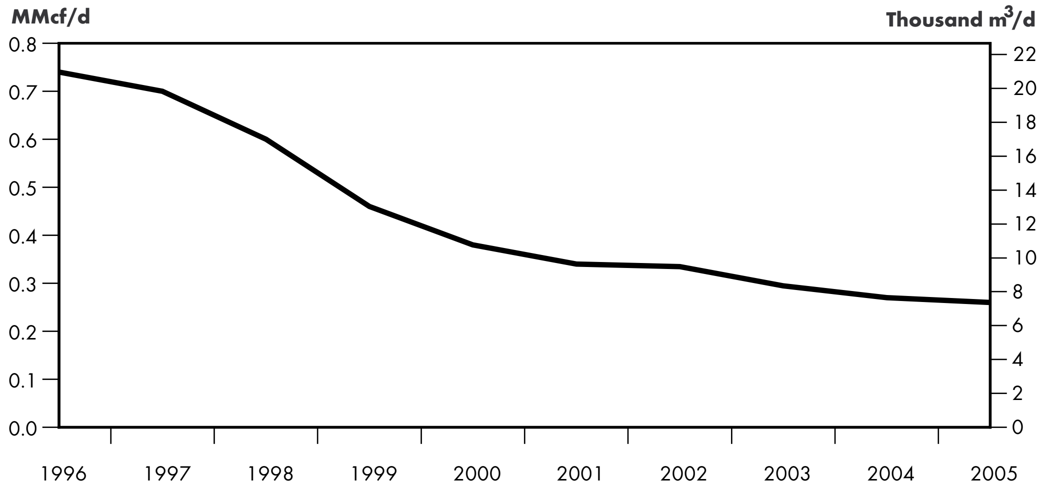
In general, the first and second decline rate and the number of months to the second decline rate observed in each geographic area have been fairly constant in recent connection years. Consequently, these average gas well performance parameters were applied to future connection years (see Appendix B.2.a). An exception to this trend is in the Fort St. John and Fort Nelson areas in northeast B.C., where significantly steeper initial decline rates have occurred since 2003 compared to previous years. This is attributed to the large-scale development of tighter gas plays in those areas over the past two years. Tighter gas resources are usually characterized by steep initial decline rates, followed by a progressive flattening out to very low rates of decline.

For the initial productivity of gas connections, the trend varies considerably from area to area (see Appendix B.3). In general, the initial productivity of gas connections continues to decrease from year to year, with smaller decreases apparent in recent years. Figure 4.1 shows the overall trend in initial gas well productivity over time for the entire WCSB.

Specific performance parameters established for future gas connections in each study area for 2006-2008 are shown in Table 4.1.

FIGURE 4.1

WCSB Initial Productivity of Average Gas Well Connections by Connection Year



Source: Board Analysis of GeoScout Well Production Data

TABLE 4.1

Production Characteristics for Average Gas Connections by Area in 2006, 2007 and 2008

Area	First Decline Rate (fraction)	Months to 2nd Decline Rate	Second Decline Rate (fraction)	Initial Productivity					
				2006		2007		2008	
				$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d
Alberta - Foothills	0.380	17	0.180	39.01	1.377	35.38	1.249	32.24	1.138
Alberta - Foothills Front	0.510	17	0.270	15.01	0.530	14.16	0.500	13.60	0.480
Alberta - Southeast	0.620	17	0.270	2.58	0.091	2.38	0.084	2.24	0.079
Alberta - East Central	0.620	18	0.290	3.34	0.118	3.00	0.106	2.72	0.096
Alberta - Central	0.620	18	0.330	6.09	0.215	5.44	0.192	4.87	0.172
Alberta - Northeast	0.310	30	0.180	5.67	0.200	5.38	0.190	5.13	0.181
Alberta - Northwest	0.580	22	0.290	11.30	0.399	10.45	0.369	9.66	0.341
B.C. - Fort St. John	0.720	15	0.300	19.09	0.674	18.19	0.642	17.34	0.612
B.C. - Fort Nelson	0.710	13	0.350	26.29	0.928	24.59	0.868	22.97	0.811
B.C. - Foothills	0.300	24	0.140	74.82	2.641	71.76	2.533	68.24	2.409
Saskatchewan - Central	0.600	24	0.300	4.73	0.167	4.33	0.153	3.99	0.141
Saskatchewan - Southwest	0.520	17	0.250	2.27	0.080	2.15	0.076	2.04	0.072

4.1.2.2 *Number of Future Gas Connections*

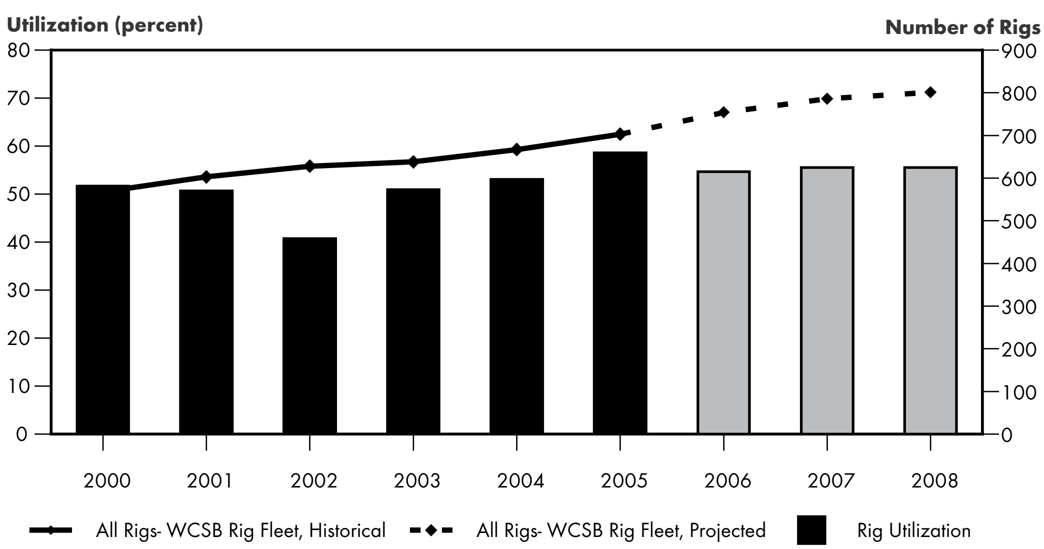
In this report, the number of future gas connections was determined as a function of gas-intent drilling. Gas-intent drilling was determined through the assessment of drilling capability in the WCSB. As discussed in Chapter 3, gas-intent drilling in the WCSB will be undertaken by that portion of Canadian rigs that comprise the WCSB rig fleet (Appendix A.1).

Based on historical trends and consultations with industry, the Board made projections of WCSB rig fleet growth for each rig category – shallow, medium and deep (see Appendix A.2). Strong natural gas prices and high levels of development in the deeper western side of the WCSB are expected to enable growth in the medium and deep portions of the WCSB rig fleet over the projection period. The size of the shallow rig fleet has increased significantly in 2004 – 2005, but softening gas prices in 2006 has caused utilization rates to slip. The Board is projecting that the size of the shallow rig fleet will stabilize at around 250 rigs by 2007. The allocation of the WCSB rig fleet to the various study areas and the rig utilization levels expected over the projection period are described in detail in Appendices A.3 and A.4 respectively.

The growth of the WCSB rig fleet (including all rig categories) and the projected overall rig utilization levels are shown in Figure 4.2. The very strong natural gas prices in 2005 drove rig utilization levels in that year to close to 59 percent. This was significantly higher than the 52 to 53 percent utilization that the Board had previously considered to be the practical operating maximum of the WCSB rig fleet. While factors such as spring break up, rig moving, contrary weather and rig servicing continue to impose real limits on rig utilization levels, the drilling activity seen in 2005 set a new standard for the maximum practical operating capacity of the WCSB rig fleet. The high utilization in 2005 also contributed to significant escalation of drilling costs. To moderate future cost escalation and to account for possible temporary periods of price weakness, the Board estimates the overall rig utilization level for the years 2006 – 2008 to be around the 55 percent level as shown in Figure 4.2. This estimate reflects the drilling industry operating at close to maximum capacity.

FIGURE 4.2

WCSB Rig Fleet Growth and Utilization



Source: NEB analysis of Nickle's *Rig Locator Report* and GeoScout Well Data

Significant expansion of the Canadian drilling fleet (by roughly 35 rigs or five percent during 2005 and another 50 rigs through mid-2006) facilitated increases in drilling. There appears to be the potential for another 50 rigs to be added to the Canadian fleet in 2007. To retain access to particular rigs in a highly competitive market, rigs were often contracted on an annual basis and this further encouraged high levels of utilization. As a result, the number of gas-directed drill days increased by 14 percent in 2004 and grew by a further 16 percent during 2005.

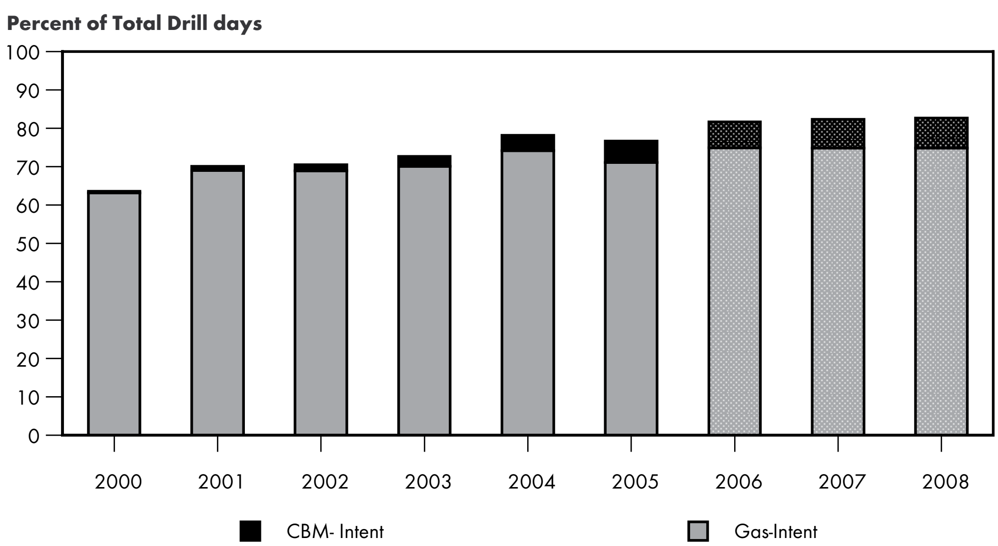
The increasing size of the WCSB rig fleet and the consistently high rig utilization levels projected in this EMA result in a progressively higher number of drill days that can be expected in each year of the projection period. The allocation of these drill days to target resources for each rig category in each study area is described in Appendix A.5. Figure 4.3 summarizes this allocation of drill effort in terms of percentage of total drill days allocated to gas and CBM. The chart shows the increasing focus of the drill effort on gas relative to oil and the emergence of CBM as a significant drilling target over the past five years. Figure 4.3 also shows increasing levels of CBM-intent drilling and the continued large share of gas-intent drilling projected for 2006 - 2008.

Applying the drill days per gas well (see Appendix A.6) to the gas-intent drill days provides a projection of the number of gas-intent wells for each resource in each study area. Tables summarizing the gas-intent drilling effort both in terms of drill days and wells are contained in Appendix A.7. Figure 4.4 provides the historic and projected drilling effort of the WCSB rig fleet for gas and CBM in terms of drill days and wells. The chart shows that approximately 16 700 conventional gas-intent wells will be drilled in the WCSB in 2006, rising to approximately 17 500 in each of 2007 and 2008. A progressively larger share of gas-intent wells is projected to occur in the western side of the WCSB where the basin is much deeper and drill days per well much greater. This greater focus of drilling on the western side of the basin is the reason why the number of gas-intent wells does not increase in proportion with the increasing gas-intent drill days over the projection period.

The number of future gas-intent wells is converted into future gas connections by applying a factor based on the historical relationship between the two parameters. Appendix A.8 provides a summary of the historical and projected ratio of connections to wells in each geographic area for conventional

FIGURE 4.3

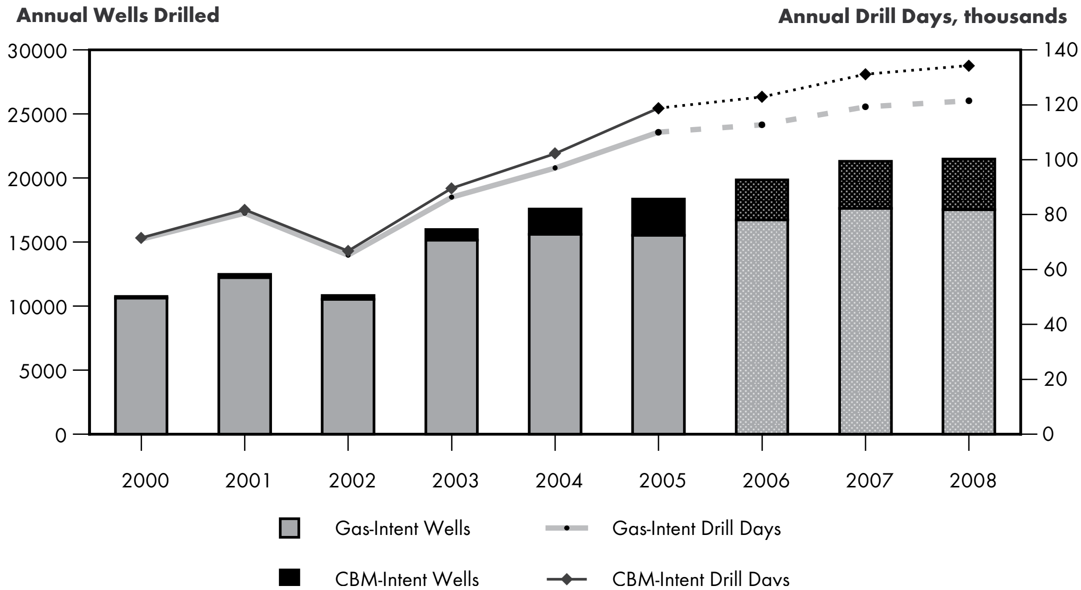
Portion of WCSB Rig Fleet Drill Days Directed to Gas and CBM



Source: : NEB analysis of GeoScout Well Data

FIGURE 4.4

WCSB Rig Fleet Annual Drill Days and Wells – Gas-Intent and CBM-Intent



Source: : NEB analysis of GeoScout Well Data

TABLE 4.2

Projected Gas and CBM Connections by Area or CBM Grouping

Area/CBM Grouping	Year		
	2006	**2007**	**2008**
Conventional Gas Connections			
Alberta - Foothills	111	118	123
Alberta - Foothills Front	2 359	2 501	2 595
Alberta - Southeast	6 711	7 034	6 843
Alberta - East Central	1 041	1 130	1 129
Alberta - Central	1 564	1 651	1 596
Alberta - Northeast	518	545	545
Alberta - Northwest	1 252	1 304	1 311
B.C. - Fort St. John	815	846	858
B.C. - Fort Nelson	266	272	278
B.C. - Foothills	39	42	43
Saskatchewan - Central	350	368	367
Saskatchewan - Southwest	1 804	1 890	1 889
Subtotal – Conventional Gas Connections	**16 833**	**17 700**	**17 576**
CBM Connections			
Alberta CBM - Horseshoe Canyon Main Play	2 904	3 394	3 626
Alberta CBM - Mannville	131	164	197
Alberta CBM - Other	44	50	52
Subtotal – CBM Connections	**3 080**	**3 608**	**3 875**
Total – Conventional Gas plus CBM Connections	**19 864**	**21 412**	**21 452**

gas and for each resource grouping for CBM. Based on these factors, the Board's projection of gas and CBM connections by area is shown in Table 4.2. The Board projects that there will be 16 800 conventional gas connections in the WCSB in 2006, rising to 17 700 in 2007 and slipping slightly to just under 17 600 in 2008.

The number of annual gas connections is expected to increase in practically all of the study areas over the projection period. The largest increases are expected to occur on the western side of the basin, particularly the Alberta Foothills Front area. The higher level of initial productivity of gas connections in the western portions of the basin, and the increasing levels of activity anticipated for those areas are key to maintaining overall deliverability from the WCSB.

4.2 WCSB – Coal Bed Methane

4.2.1 Existing CBM Connections

Coal bed methane deliverability as of the end of 2005 was about 11.6 million m^3/d (0.41 Bcf/d). Based on the performance parameters estimated for CBM connections (see Appendix B.1), deliverability of these existing CBM connections is expected to be 10.4 million m^3/d (0.37 Bcf/d) by the end of 2006, 8.9 million m^3/d (0.32 Bcf/d) by the end of 2007, and 7.7 million m^3/d (0.27 Bcf/d) by the end of 2008.

4.2.2 Future CBM Connections

The NEB's estimate of the number of future CBM connections was obtained by the same process used to determine the projected future conventional gas connections. To review the factors leading to estimation of the number of CBM connections, see Appendices A.2 to A.8. Total CBM-intent wells were allocated to each of the three CBM resource groupings as per the procedure described in Section 3.2 of this report. CBM-intent wells (shown stacked on top of gas-intent wells in Figure 4.4) are expected to amount to approximately 3 100 wells in 2 006, 3 700 in 2007, and 3 900 in 2008. Most of these CBM-intent wells are associated with development of the Horseshoe Canyon main play in the Calgary–Edmonton corridor (see Appendix C.1a for map). A relatively small, but growing number of the CBM-intent wells are attributable to Mannville CBM development, primarily in the Corbett Project area. Only a small portion of the CBM-intent wells are attributable to Other CBM resources. The total numbers of CBM connections resulting from this drilling effort were projected to be approximately 3 100 in 2006, 3 600 in 2007 and 3 900 in 2008.

For the Horseshoe Canyon main play, the high levels of development since 2003 have established a reasonable amount of initial production data, providing a good basis for establishing the initial performance parameters of the average connection. The initial productivity of the average connection for this resource is estimated at 2.3 thousand m^3/d (0.08 MMcf/d) in 2006, and slightly less in each of the subsequent years. Appendix C.2.a provides charts showing the average connection performance for the Horseshoe Canyon main play for 2003, 2004 and 2005 and the performance expected for 2006, 2007 and 2008 connections. As the connections for this resource have exhibited fairly flat production for the initial months of production, the decline rates assigned are five percent for the first 16 months of production followed by 15 percent for the following 44 months. After the first five years of production a decline rate of 10 percent is estimated.

The average connection for Mannville CBM is estimated to have peak productivity of 11 thousand m^3/d (0.40 MMcf/d) that is reached in the fourth month of production. In the first, second and third months of production, the average connection productivity is estimated to be zero percent, 40 percent and 80 percent respectively of peak productivity. In the fourth production month peak productivity is reached, after which a first decline rate of 25 percent is applied until the 24th month of production. A second decline rate of 15 percent is estimated for production months 25 through 60, followed by a third decline rate of 10 percent for the remaining life of the connection. Appendix C.2.b provides a chart illustrating average performance and expectations of Mannville CBM wells. Given the small number of producing connections and the short production history, there is a high degree of uncertainty associated with the parameters chosen for Mannville CBM. Nevertheless, the Board believes these parameters are reasonable estimates of resource performance at this early stage of development.

The Other CBM resource grouping is not expected to provide a significant contribution to deliverability over the projection period. Appendix C.2.c provides a chart of historical and projected average connection performance for this grouping based on the limited development seen thus far.

The average connection performance parameters used in this assessment for all three CBM resource groupings (Horseshoe Canyon main play, Mannville CBM and Other CBM) can be viewed in Appendix B.3.b.

4.3 Atlantic Canada

Nova Scotia offshore deliverability was sourced from five fields in 2005. One field (North Triumph) was shut in during 2006 due to insufficient wellhead pressure to access the gathering system. Total marketable gas deliverability at the end of 2005 was about 11.4 million m^3/d (400 MMcf/d).

The addition of offshore compression at SOEP at the end of 2006 is expected to initially boost deliverability by roughly 33 percent. With the added compression providing the energy to move the gas to shore, the field gathering system should operate at lower pressure and enable the North Triumph field to resume operations.

In the onshore McCully field, approximately 10 wells are expected to be drilled and connected annually assuming the services of one rig. On this basis, production is expected to stabilize in late 2008 (with new connections offsetting declines) at roughly 1.1 million m^3/d (40 MMcf/d).

Deliverability Outlook

The outlook for Canadian gas deliverability is shown in Table 5.1 by study area. The table shows annual average production for 2005 and expected annual average deliverability for 2006, 2007 and 2008 for each component. Canadian annual average deliverability is expected to increase slightly from 484 million m^3/d (17.1 Bcf/d) in 2005 to 491 million m^3/d (17.3 Bcf/d) in 2008.

TABLE 5.1

Canadian Gas Deliverability Outlook by Area

Area	Average Annual Production							
	Historical		Projection					
	2005		2006		2007		2008	
	10^6m^3/d	MMcf/d	10^6m^3/d	MMcf/d	10^6m^3/d	MMcf/d	10^6m^3/d	MMcf/d
Alberta - Foothills	21.47	758	22.01	777	22.28	786	22.41	791
Alberta - Foothills Front	127.42	4 498	131.53	4 643	133.10	4 699	133.88	4 726
Alberta - Southeast	76.90	2 714	74.50	2 630	72.53	2 560	70.35	2 483
Alberta - East Central	17.19	607	16.57	585	16.02	566	15.49	547
Alberta - Central	48.54	1 713	46.88	1 655	44.23	1 561	41.77	1 475
Alberta - Northeast	23.80	840	21.33	753	20.20	713	19.11	675
Alberta - Northwest	51.74	1 826	51.77	1 827	49.99	1 765	48.22	1 702
B.C. - Fort St. John	37.58	1 327	40.47	1 429	40.98	1 447	41.35	1 460
B.C. - Fort Nelson	24.28	857	23.49	829	22.65	800	21.98	776
B.C. - Foothills	12.95	457	12.82	453	13.31	470	13.73	485
Saskatchewan - Central	5.21	184	5.29	187	5.34	189	5.27	186
Saskatchewan - Southwest	14.20	501	14.45	510	14.70	519	14.81	523
Saskatchewan - Southeast	0.76	27	0.85	30	0.84	30	0.83	29
Yukon and Northwest Territories	1.17	41	0.73	26	0.59	21	0.49	17
Total WCSB Conventional Gas	**463.22**	**16 352**	**462.67**	**16 332**	**456.77**	**16 124**	**449.70**	**15 874**
Alberta CBM - HSC Main Play	7.44	263	12.31	435	17.68	624	23.02	813
Alberta CBM - Mannvile	0.37	13	1.35	48	2.55	90	3.89	137
Alberta CBM - Other	0.54	19	0.50	18	0.47	17	0.46	16
Total Alberta CBM	**8.35**	**295**	**14.17**	**500**	**20.70**	**731**	**27.37**	**966**
Total WCSB - All Gas	**471.57**	**16 646**	**476.84**	**16 832**	**477.47**	**16 855**	**477.07**	**16 841**
Atlantic Canada	11.10	392	10.02	354	14.14	499	13.44	475
Other (Ontario and Quebec)	0.93	33	0.93	33	0.93	33	0.93	33
Total Canada	**483.60**	**17 071**	**487.79**	**17 219**	**492.54**	**17 387**	**491.45**	**17 348**

5.1 WCSB - Conventional Gas

The average annual deliverability of conventional gas from the WCSB is expected to decrease slightly over the projection period from 463 million m^3/d (16.4 Bcf/d) in 2005 to 450 million m^3/d (15.9 Bcf/d) in 2008. Deliverability of conventional gas from the largest producing province, Alberta, is expected to decline over the projection period from approximately 367 million m^3/d (13.0 Bcf/d) in 2005 to 351 million m^3/d (12.4 Bcf/d) in 2008. Decreases in conventional gas production are expected to occur in all areas of Alberta except for the Foothills Front and Foothills areas. The key growth area in Alberta is the Foothills Front where significantly increased levels of drilling activity applied to a large resource base results in upward trending total production for the area. The Southeast area of Alberta has been a key area of conventional gas production, with year on year increases recorded for many of the past several years. However, decreasing production is now expected from the Alberta Southeast as declining well productivity and low prospectivity finally begin to impact production levels.

Deliverability is expected to remain stable in B.C. at approximately 77 million m^3/d (2.71 Bcf/d) over the projection period.

Total deliverability from Saskatchewan is projected to remain stable over the projection period at 21 million m^3/d (0.73 Bcf/d).

5.2 WCSB - Coal Bed Methane

CBM production in Alberta has grown remarkably over the past few years and is expected to have an even larger role in the Canadian gas supply over the projection period. Average CBM deliverability for 2008 is expected to be 27 million m^3/d (1.0 Bcf/d), which is about triple the average 2005 production level. As shown in Figure 5.1, most of that growth in CBM deliverability is expected to come from the Horseshoe Canyon main play, with Mannville CBM also making a significant and growing contribution over the projection period. Deliverability from Other CBM resources are expected to continue to be minor over the projection period.

FIGURE 5.1

CBM Drilling and Deliverability

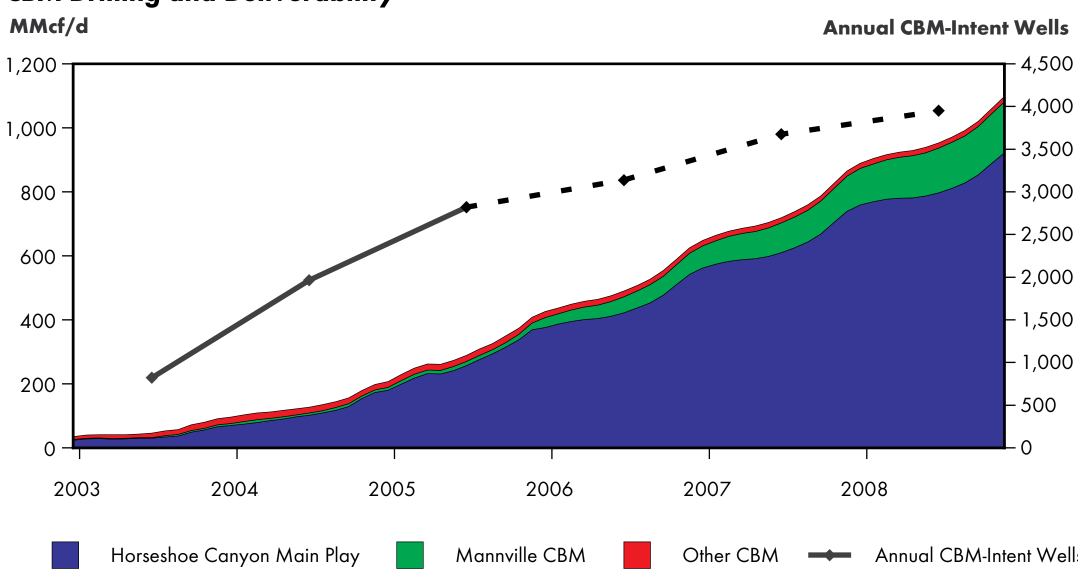


Figure 5.2 also shows the rising development activity associated with CBM. The annual number of CBM-intent wells is expected to increase from approximately 2 800 in 2005 to 3 900 in 2008. By 2008, CBM is expected to account for roughly five percent of overall Canadian deliverability.

5.3 Atlantic Canada

As illustrated in Figure 5.2, the estimate of deliverability from the SOEP through October 2006 incorporates ongoing natural declines in the four fields currently on production. Deliverability by field may be more variable than indicated due to the possible ongoing need to cycle individual wells. The addition of offshore compression late in 2006 is expected to increase deliverability from the original fields to average 13.4 million m^3/d (470 MMcf/d) in 2007. Due to uncertainty regarding the performance of individual wells at lower pressures, no attempt has been made to allocate the compression increase to separate fields. However, it is expected that the North Triumph field can resume deliverability as a result of the added compression.

In the onshore McCully field, deliverability into the Maritimes and Northeast Pipeline is expected to begin at 0.71 million m^3/d (25 MMcf/d) in early 2007 and increase gradually to 1.1 million m^3/d (40 MMcf/d) by late 2008 as more wells are drilled and connected. Assuming the full time utilization of one drilling rig, McCully deliverability is expected to stabilize in late 2008 at 1.1 million m^3/d (40 MMcf/d).

5.4 Total Canada

Figure 5.3 portrays the outlook for total Canadian gas deliverability and the major segments of gas supply over the projection period (Note: Figure 5.3 is also shown in the Overview section of this EMA). Total Canadian production is expected to increase slightly over the projection period. This increase is due to the increasingly significant production of CBM added to the relatively stable levels of conventional gas production expected in the WCSB. The annual bump in deliverability occurring in the first few months of each year of the projection period is caused by the seasonal connection

FIGURE 5.2

Atlantic Canada Deliverability Outlook

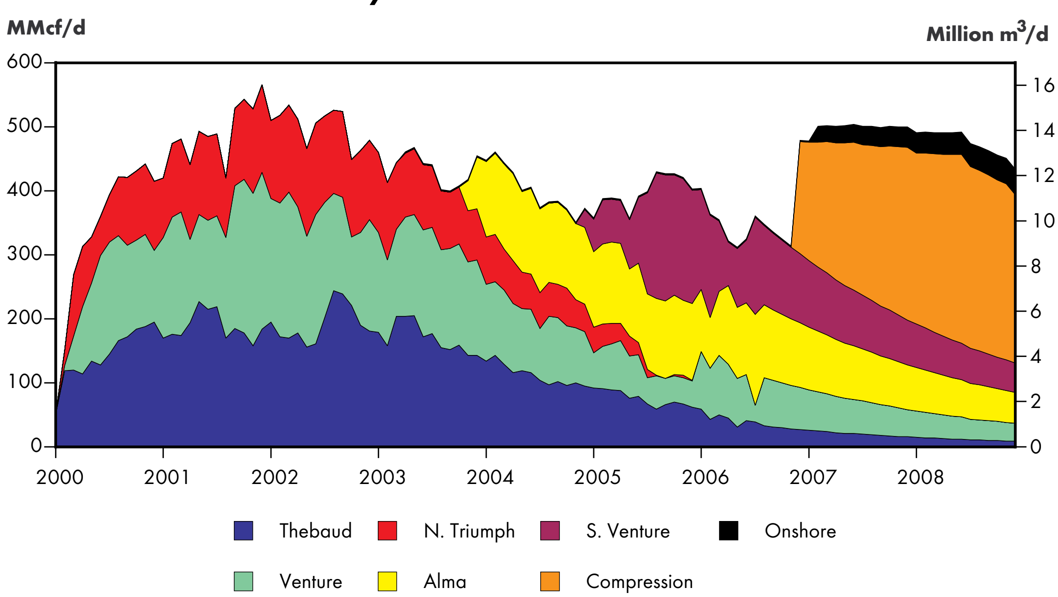
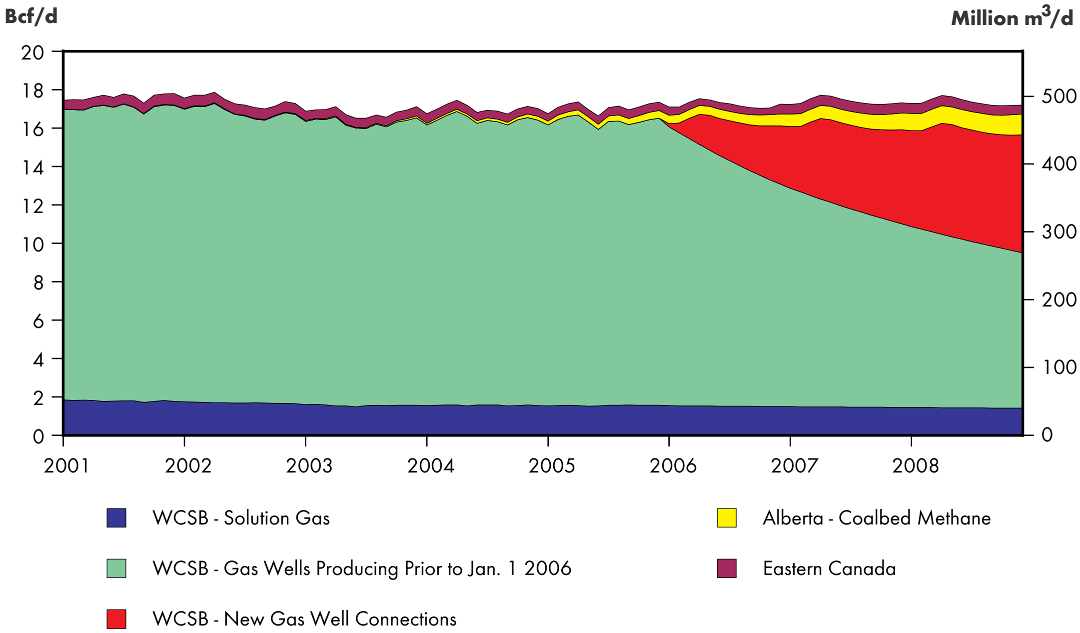


FIGURE 5.3

Outlook for Canadian Gas Deliverability



patterns that prevail in the WCSB. Eastern Canada deliverability is predominantly from offshore Nova Scotia, but also includes deliverability from New Brunswick, Ontario and Quebec.

5.5 Key Differences from Previous Projection

Relative to the Board's October 2005 deliverability projection, this outlook is roughly 2.8 million m^3/d (100 MMcf/d) higher over the 2005 to 2006 period. Key regional differences are as follows:

Gas wells drilled in the Foothills and Foothills Front areas of the basin were higher in 2005 than anticipated in the Board's previous EMA (2 500 in 2005 compared to previous expectation of 2 200) resulting in higher deliverability than expected.

The industry drilled just over 2 800 CBM wells in 2005 and is expected to drill another 3 100 in 2006 and increase gradually to 3 900 in 2008. This rate of growth is considerably slower than was anticipated in the previous EMA when 5 400 CBM wells per year were projected by 2007.

CBM drilling in the central region is occurring about as was expected in the previous EMA. However, the level of CBM activity in the southeast part of the basin is much lower than previously anticipated and suggests that economic development of the Horseshoe Canyon play is not extending to the southeast as much as expected.

The industry drilled far fewer conventional shallow gas wells in southeast Alberta in 2005 than expected in the Board's previous EMA. Due to wet weather, flooding and inefficiencies associated with less-experienced drilling crews and delays in obtaining services and materials, only 5 700 gas wells were drilled in southeast Alberta in 2005. This was well below the Board's previous expectation of 6 900 wells for the year.

Relative to the Board's previous outlook, gas drilling in the Fort St. John area was much stronger in 2005 than expected (900 wells vs. an expected 700) and could result in roughly 2.8 million m^3/d (100 MMcf/d) higher deliverability in 2006.

Gas drilling in the Fort Nelson area is not expected to increase over the projection period whereas the Board's previous expectation was for a roughly 25 percent rise in gas drilling.

5.6 Canadian Deliverability and Demand

The Board's outlooks for gas deliverability and Canadian gas demand over the projection period are included in Table 5.2 to provide market context for the relative changes in gas deliverability.

The biggest driver of change in Canadian gas demand over the period from 2006 to 2008 is expected to be increasing fuel requirements for oil sands projects in Alberta. The impact of potential coal to gas substitution in the Ontario power market appears to be delayed beyond the 2008 period. Considerable variability in gas demand estimates is possible due to the impact of weather variations on Canada's large space heating markets. A portion of Canadian gas demand may also be served by imports of gas from the U.S.

Canadian annual gas demand is expected to rise by just under 34 million m^3/d (1.2 Bcf/d) between 2005 and 2008. Almost 28 million m^3/d (1.0 Bcf/d) or 85 percent of the demand growth is expected to occur in western Canada over this period. Gas deliverability is projected to increase by under 8.5 million m^3/d (0.3 Bcf/d) over the same period.

TABLE 5.2

Average Annual Canadian Deliverability and Demand

	2005		2006		2007		2008	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
Canadian Deliverability	483.6	17.07	487.8	17.22	492.5	17.39	491.4	17.35
Western Canada Demand	125.2	4.42	138.9	4.90	145.2	5.12	153.2	5.41
Eastern Canada Demand	102.0	3.60	102.0	3.60	104.3	3.68	106.9	3.78

OBSERVATIONS, ISSUES AND CONCLUSIONS

6.1 Observations

Observations on key developments impacting current and projected deliverability are provided below.

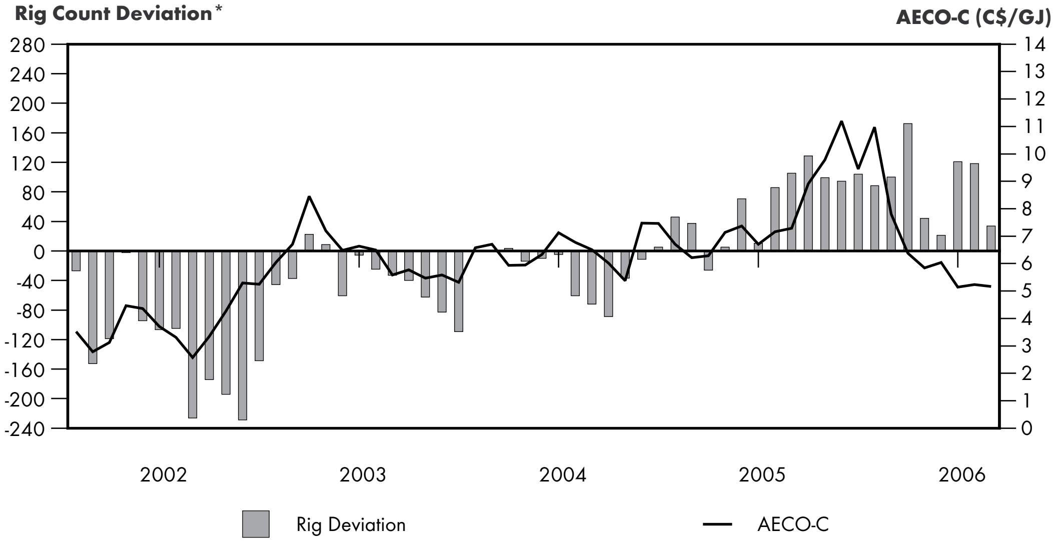
- Production declines on existing wells remain the same
  - The effective decline rate for production from existing wells is expected to remain at around 20 percent per year. This means that in each year new connections need to replace about a fifth of the previous year's output to keep overall production constant.
- Initial productivity of new wells continues to decline
  - The trend of lower initial productivity in new WCSB gas wells is continuing. Consequently, to offset production declines from producing wells, the number of new gas connections must rise each year to maintain production levels.
- High gas prices in 2005 led to very strong drilling activity and cost escalation
  - Concerns about a tight supply/demand balance and upward price pressure associated with high oil prices were compounded in the late summer of 2005 by significant supply disruptions from two major hurricanes in the Gulf of Mexico. An early blast of cold winter weather further magnified concerns and caused gas prices to soar over $15/MMBtu by December.
  - In response to high gas prices, the second half of 2005 saw utilization of the Canadian drilling fleet far above typical seasonal levels. The strength in rig utilization in the second half was also related to recovering from unplanned downtime due to a particularly wet June and flooding in southern portions of the WCSB. Due to this high utilization, the number of gas-directed drill days increased by 16 percent during 2005.
  - Strong gas-related drilling activity was reinforced by increased oil drilling in western Canada in response to high oil prices. The combined pressure on the drilling industry, coupled with rising input costs for labour, steel and fuel, caused drilling costs to rise at an annual rate reported by various industry sources to be in the vicinity of 15 percent.
  - The acceleration in drilling activity also began leading to delays in the delivery of critical services like well testing and materials such as casing and cement. The reduced efficiency was most noticeable in the southeast part of the basin where the average time required to drill a well increased by over 30 percent. The greater time expended per well served to offset some of the positive impacts associated with the addition of rigs to the fleet and high utilization.

- Momentum of expanded drilling programs carried forward into 2006
  - An average of almost 700 rigs were active in the WCSB in the first quarter of 2006, or roughly 100 more than in the same quarter of 2005. Weather conditions were also such that the onset of the spring break-up was delayed and the 2005/2006 winter drilling season extended by about three weeks.
  - Drilling activity by deep rigs was particularly strong in the first half of 2006 at roughly 40 percent higher than in the same period of 2005.
- The 2005/2006 winter turned mild resulting in a storage overhang and falling prices
  - The weather turned extremely mild in early 2006 and provided a North American winter that was ten percent warmer than average and the third warmest in the last 55 years. This reduced gas demand for space heating and resulted in a significant storage overhang by the end of the 2005/2006 winter. Due to the abundance of gas in storage, gas prices dropped from their December peak by more than 50 percent.
- WCSB drilling activity begins to slow in response to gas prices
  - Shrinking margins between softening gas prices and rising drilling costs caused gas producers to moderate increases in gas-directed drilling activity in the second half of 2006. Some drilling activity has also been redirected to oil prospects to capitalize on more favourable economics.
  - Drilling activity in the WCSB has typically been fairly responsive to changes in producer cash flow as indicated in Figure 6.1 (with cash flow reflected here by changes in AECO-C gas prices). Wells with short production lives have economics that are highly dependent on near-term prices and are typically the first to be impacted by declining margins. This would suggest that shallow gas drilling in southeast Alberta and southwest Saskatchewan will be the most affected in the second half of 2006.
  - There is some risk of further temporary decreases in North American drilling during September and October 2006 should gas storage become full well in advance of the November start of the withdrawal season, and should no significant alternative markets emerge to accept the excess gas. These conditions could lead to a further short-lived price drop and even result in production shut-ins that could impede the cash flow needed to maintain high levels of drilling.
- Drilling activity and gas wells
  - The total number of gas wells drilled during 2006 is expected to be roughly eight percent (1 520 wells) higher than in 2005. The increase is attributed to expansion of the rig fleet and its high utilization in the first half of the year. The expected number of gas-related drill days (including CBM) in 2006 is expected to be 3.5 percent higher than in 2005.
  - The June update to the annual drilling forecast by the Canadian Association of Oil Well Drilling Contractors (CAODC) indicates a similar eight percent increase in total wells drilled in 2006[5]. The CAODC's estimate of total gas plus oil drill days anticipates a 1.3 percent increase during 2006.
  - The July update to the drilling forecast by the Petroleum Services Association of Canada (PSAC) is considerably more negative regarding 2006 with the expectation

5 2006 CAODC Forecast – June 14 Update, from www.caodc.ca/forecasts.htm

FIGURE 6.1

Responsiveness of WCSB Rig Count to Gas Price



* Deviation in active rigs in a month relative to the 2003 – 2005 average for that month

of a 7.5 percent drop in total wells drilled[6]. Given the strength of drilling in the first half of the year, this outlook would suggest a major cutback in shallow gas and CBM drilling in the second half of 2006.

- CBM drilling continues to grow, but more slowly than previously expected. The industry drilled just over 2 800 CBM wells in 2005 and is expected to drill another 3 100 in 2006 and increase gradually to 3 900 in 2008. This rate of growth is considerably slower than was anticipated in the previous EMA when 5 400 CBM wells per year were projected by 2007.
- Shallow gas drilling lagged expectations in 2005. However, growth of the shallow rig fleet and associated service sector is expected to enable 6 400 gas wells to be drilled in southeast Alberta in 2006 and another 6 700 wells in 2007. A modest pull back to 6 500 new gas wells is expected for 2008 as the area begins to become more prospect limited.
- B.C. activity is shifting from Fort Nelson to Fort St. John. Gas drilling in the Fort St. John area was much stronger in 2005 than expected (900 wells vs. an expected 700). Current expectations are that gas drilling will grow gradually from this level to reach 975 in 2008. The higher activity could cause deliverability to rise by about 2.8 million m^3/d (100 MMcf/d) in 2006 and then stabilize at roughly 41 million m^3/d (1 450 MMcf/d). Gas drilling in the Fort Nelson area is not expected to increase over the projection period.

- Price weakness expected to be temporary
    - The softening of North American gas prices is expected to be a temporary condition in the market, since storage can only be refilled to its capacity (roughly the same level as last year) and the storage overhang is thereby erased by the start of the heating season in early November. At that point (assuming a return to relatively normal winter weather) the generally tight balance between supply and demand that has

6 PSAC News Release, "Q2 Gas Prices Indicate Decrease for Drilling Activity, says PSAC", July 27, 2006, from www.psac.ca/media_centre/pdf/20060727.pdf

prevailed in recent years is likely to reassert itself. NYMEX gas futures prices for the 2006/2007 winter months reflect this expectation by indicating an upward trend.

    - Rising prices would be likely to strengthen interest in gas and initiate the next cycle of increases in drilling activity/drilling costs and production volumes. With stronger prices, gas-intent drilling is expected to rise by seven percent in 2007 and maintain a minor one percent increase in 2008.

- Total Canadian gas deliverability is expected to grow by just one percent annually until 2008

    - Canadian gas deliverability is expected to be essentially stable over the period with slight gains in 2006 and 2007 and a minor loss in 2008.

    - CBM deliverability is expected to grow steadily over the period with an increase of just over 5.7 million m^3/d (200 MMcf/d) each year. Although below the expectations of 7.0 to 8.5 million m^3/d (250 to 300 MMcf/d) annual growth in the Board's previous outlook, increases in CBM deliverability are still able to largely offset declines in conventional gas deliverability. The low decline characteristics of CBM wells are expected to have a slight stabilizing effect on basin deliverability over the long term.

    - The deeper western side of the basin provides the most support to conventional gas production. Deliverability from the Foothills and Foothills Front is expected to rise by 4.2 million m^3/d (150 MMcf/d) (three percent) in 2006 and another 2.8 million m^3/d (100 MMcf/d) over the next two years. The combination of high gas price, improving technology and the ever increasing knowledge of the basin potential and resource exploitation practices, is resulting in the development of deeper and tighter conventional gas resources on the western side of the basin. While these tighter gas resources usually have steep initial decline rates, the subsequent progression to very low rates of decline over a very long productive life is expected to have a stabilizing effect on overall basin deliverability over the long term.

    - Deliverability from the shallower eastern side of basin is expected to slide by about 4.2 million m^3/d (150 MMcf/d) each year in the outlook.

    - Conventional gas deliverability in the intermediate central and northwest parts of the basin is expected to be flat in 2006, and then fall back by about 4.2 million m^3/d (150 MMcf/d) per year.

    - The contribution from Atlantic Canada is expected to continue to trend down until late in 2006 and then rise to average 14 million m^3/d (500 MMcf/d) in 2007 through added offshore compression and new onshore deliverability.

6.2 Issues

A number of key issues are expected to influence Canadian gas deliverability over the projection period.

- Impacts of rising gas drilling activity

  A major rise in gas-related drilling activity during the second half of 2005 and first half of 2006 resulted in significant cost escalation and some loss of efficiency due to shortages of experienced personnel and delays in obtaining critical services and materials.

Cost escalation consists of discretionary and non-discretionary increases. Discretionary increases in the form of raising rates to achieve higher margins can be expected during periods when demand for rigs and services outstrips their supply. The drilling industry has responded to this condition by aggressively adding to the size of the rig fleet. As has occurred in previous periods, this is likely to result in some over-building of capacity that will eventually reduce or eliminate the opportunity for discretionary rate increases. There may already be some evidence that the recent and planned expansion of the shallow component of the rig fleet may be exceeding current requirements.

Non-discretionary cost increases refer to higher input costs for the drilling industry such as higher costs for labour, steel and fuel. Beyond making technology improvements to reduce input requirements, the drilling industry has little ability to mitigate these cost increases since they are largely driven by external factors.

An increase in drill days per well without a corresponding increase in well depth is evidence of reduced efficiency at high utilization levels. It is unknown what proportion of this reduced efficiency may be attributable to indirect factors such as shortages of materials, services and experienced personnel, and how much may be attributable to direct factors of operating rigs longer and harder such as equipment failures due to postponed maintenance or worker fatigue. The former could be considered "growing pains" that will eventually be resolved as support services catch up to requirements. The latter are more systemic and would tend to be resolved once sufficient capacity is available to return utilization closer to former levels.

- Resolution of storage overhang

  A key issue may be the extent that prices soften in the latter stages of 2006 should North American gas storage fill in advance of the start of the heating season. Should this cause gas prices to fall precipitously and/or require significant shut-ins of North American gas production, the corresponding impact on industry cash flow could lead to a temporary reduction in gas drilling activity. A similar situation could potentially result from another extremely mild winter. These conditions are by no means certain to occur, as a number of factors could potentially reduce the current storage surplus. Such factors could include a repeat of supply disruptions associated with hurricanes, and/or early or intense cold to increase demand.

- Investments in natural gas deliverability relative to other opportunities

  The Canadian upstream industry has a choice between reinvesting in gas deliverability and investing elsewhere (e.g., oil reinvestment, foreign investment, trust distributions, share buybacks). Experience to this point indicates that the industry is redirecting some of the investment possibly available for gas development into higher-return conventional oil projects, to cover cost overruns in oil sands projects, and to reduce pressure on the drilling industry in an attempt to moderate cost escalation. The relative spread between oil and natural gas prices is a key factor regarding the investment mix.

- Composition of the Canadian drilling fleet

  The Canadian drilling industry is continuing to increase the size of the rig fleet. Recent additions indicate a stronger emphasis on deep rigs relative to medium rigs. Deep rigs are considered to be more versatile for Canadian conditions in that they are able to drill opportunities in the deeper western side of the basin, horizontal wells to access Mannville CBM, and horizontal drilling of heavy oil prospects. A strong emphasis on additions of shallow rigs and coiled-tubing units to meet opportunities in Horseshoe Canyon CBM and shallow gas may have temporarily exceeded requirements due to the recent slowing of the growth in drilling activity in these areas.

- Labour shortages

  The Canadian drilling industry faces an ongoing challenge of staffing the growing rig fleet. The future levels of drilling anticipated for the WCSB will require a well-trained and skilled workforce to conduct work in a safe, efficient and environmentally sound manner. The drilling industry's ability to further increase the size of the rig fleet and high utilization levels will depend largely on the industry's management of this challenge.

- Development of unconventional resources

  Sustainability of current deliverability and potential incremental growth may be largely dependent on success in overcoming technical and economic challenges associated with developing Canada's large in-place endowment of unconventional resources such as CBM, tight gas and gas shales. Commercial development of Horseshoe Canyon CBM is now well established. Commercial development of the larger Mannville CBM resource is at an early stage with initial progress in terms of adoption of horizontal well technology but with no clear indication of the effectiveness of particular horizontal drilling patterns or configurations. The variability of the CBM resource between areas is a key issue that will impact the applicability of certain techniques and their commercial viability. Tight gas and gas shales with low permeability may require considerable access by horizontal wells to yield commercial volumes of their large in-place resource. The challenge of escalating costs may need to be managed before sufficient drilling could be achieved.

- Atlantic Canada onshore deliverability

  Expansion of onshore drilling capacity in Atlantic Canada will be required to increase the pace of onshore development. Availability of additional drilling rigs would enable more rapid development of discovered resources. Incentives to construct additional onshore rigs within Atlantic Canada are a component of the benefits agreement for the proposed Deep Panuke development. The ability to successfully compete with other regions to retain these rigs within the region will be a key factor in the pace of onshore development of conventional gas and potentially CBM.

- Atlantic Canada offshore deliverability

  Progress toward developing the Deep Panuke project may be key to encouraging additional exploration activity off the east coast. Provincial efforts to improve access to data and understanding of reservoir systems in the offshore could potentially help to reinvigorate interest in the offshore.

6.3 Conclusions

The Board expects annual average deliverability of conventional gas to decline slightly over the projection period, from 463 million m^3/d (16.4 Bcf/d) in 2005 to 450 million m^3/d (15.9 Bcf/d) in 2008. This small decrease is expected to be more than offset by growth in CBM deliverability from 8 million m^3/d (0.3 Bcf/d) in 2005 to 27 million m^3/d (1.0 Bcf/d) in 2008.

Volatile market prices and industry cost escalation are likely to be key considerations, particularly in the nearer term. Any significant price softening in the last third of 2006 is likely to be temporary, but could have lingering implications should drilling be substantially reduced.

The industry faces significant challenges in reducing costs. Some industry cost escalation is non-discretionary and reflects upward cost pressure on key inputs such as steel and fuel. This component of cost escalation is generally due to factors beyond the industry's control and is likely to persist. Other components of cost escalation over which the industry may have greater influence include the ongoing expansion of the drilling fleet to lower the pressure on utilization. Key challenges include greater labour recruitment and training, recovering prior efficiency gains, and expanding and improving supply chains for materials and services.

The deliverability outlook reflects the industry operating at high, but below maximum levels. The second half of 2005 and first half of 2006 established a new threshold for maximum utilization of the drilling fleet in western Canada. Substantial growth of the rig fleet is occurring. The ability to adequately crew the additional rigs and provide corresponding materials and services to maintain operating efficiency will be key challenges to overcome. Maintaining good stakeholder relations and environmental practices with a larger fleet and high utilization will be key determinants. If satisfactorily achieved, the ability to significantly increase gas well drilling bodes well for maintaining deliverability.

Initial productivity of new wells continues to decline and will require an increasing number of the new wells each year just to hold deliverability constant. The decline in well productivity reflects the maturing of the WCSB. Although significant amounts of gas remain, it is available in smaller increments and will require increasing levels of activity and effort for each added unit of deliverability.

CBM deliverability will more than compensate for declines from conventional gas sources over the period. Although impacted by drilling cost escalation, scale up of Horseshoe Canyon development is expected to continue. Technical progress with Mannville CBM has been achieved through horizontal drilling and will provide a minor but growing contribution to deliverability over the period.

Atlantic Canada deliverability is increasing from both onshore and offshore sources. Addition of offshore compression is underway at the Sable project and New Brunswick onshore production is being connected into the transmission system. The Sable compression addition should help to reduce recent production volatility associated with the cycling of wells. The possible resurrection of the Deep Panuke project is a potential future source of deliverability.

GLOSSARY

average connection	An average connection may apply to gas connections or CBM connections and represents the average producing characteristics of ALL connections (either gas or CBM) for a geographic area and connection year. Production data for the average connection for any grouping (geographic area/connection year) is calculated as: [total production for all connections in grouping, summed by normalized production month]/ [the total number of connections in the grouping].
Canadian rig fleet	Drilling rigs that are listed in the Nickle's Energy Group weekly Rig Locator report.
CBM	Coalbed Methane
CBM connection	A connection for which natural gas production has been reported, and where that production is deemed to be CBM.
CBM Resource Groups	The three groupings of CBM resources made for the purpose of assessing Canadian CBM deliverability. The CBM Resource Groups are described in detail in Chapter 2 of this report.
CBM-intent drilling	Applies to drilling, drill days or wells deemed by the NEB to be undertaken for the purpose of exploiting CBM resources.
connection	A completion in a geological horizon (or horizons) within a well for which oil and/or natural gas production is reported.
connection year	The year associated with the "On Production Date" for a connection.
conventional gas	Refers to natural gas from all sources other than CBM.
Corbett Project Area	A block of 24 townships approximately centered on township 62-5W5 as per presentation titled "The Corbett CBM Field: An Emerging Giant Gas Field" in the 2005 Annual CSUG Conference, November 2005. The Corbett Project area is illustrated in Appendix C.1.b.
decline rate	A term used to describe the decrease in production rate over time as a resource is depleted. There are various ways of expressing decline rates, and in this report **exponential decline** is the type used to define well production decline characteristics. With exponential decline, a straight line is exhibited when production rate is plotted against cumulative production, and the slope of the line defines the **nominal** decline rate (in this report it is expressed as fraction per

	year). Another way of expressing Decline Rate is in terms of effective decline rate, which is the decrease in production divided by the initial production rate. The effective decline rate can be converted into nominal terms using the equation: nominal decline rate = -ln(1 – effective decline rate)
deep rig(s)	Drilling rigs with a depth capacity greater than 3050 m.
deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
depth capacity	the depth capacity (meters) for each drill rig as listed on the weekly Rig Locator Report published by Nickle's Energy Group
drill day(s)	The number of days that a rig is engaged drilling a well, calculated as Drilling Completion Date minus the Spud Date plus 1.
existing connections	Connections on production prior to January 1, 2006.
future connections	Connections on production after January 1, 2006.
gas connection	A connection for which natural gas production has been reported, and where that production is deemed to be conventional gas. If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
gas well	A well bore with one or more geological horizons capable of producing natural gas.
gas-intent drilling	applies to drilling, drill days or wells deemed by the NEB to be undertaken for the purpose of exploiting conventional gas resources, excluding solution gas.
Horseshoe Canyon Main Play Area	A collection of townships in Central Alberta intended to approximately reflect the areas of the Horseshoe Canyon Coal zone where gas concentration > 2 Bcf per section as presented in "U2 Figure 27 - Gas Concentration (Bcf/Section) within the Horseshoe Canyon Coal Zone" from report Natural Gas Potential in Canada 2005- Volume 4, published by the Canadian Gas Potential Committee. The Main Horseshoe Canyon Play Area is illustrated in Appendix C.1.a.
In place resources	Resources that are estimated to exist in the original position or place
In-Basin Usage	In reference to the WCSB, In-Basin Usage means withdrawals from the stream of marketable gas in Alberta, B.C. and Saskatchewan.
marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
medium rig(s)	Drilling rigs with a depth capacity greater than 1850 m and less then or equal to 3050 m.

normalized production month	For any gas well connection and for any production month, the normalized production month is the number of months since the first month of production for the gas well connection.
oil connection	A connection for which oil production has been reported, and where that production is deemed NOT to be associated with oil sands. If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
oil sands connection	A connection for which oil production has been reported, and where that production is deemed to be associated with oil sands.
projection period	January 1 2006 to December 31 2008
rig categories	The groupings of Shallow, Medium and Deep drill rigs in the WCSB Rig Fleet, based on depth capacity.
rig day(s)	Each day of the year for each drilling rig represents a rig day. The annual allocation of the rigs in the WCSB rig fleet to the various study areas results in an aggregate number of annual rig days for each area.
rig utilization	In this EMA, rig utilization applies to drill rigs comprising the WCSB rig fleet and is calculated as Drill Days / Rig Days. Rig Utilization is determined separately for each rig category and study area in the WCSB as detailed in Appendix A.4.
shallow rig(s)	Drilling rigs with a depth capacity less than or equal to 1850 m.
solution gas	Natural gas that is produced from an oil well connection.
spud date	For each well, the date where drilling commences.
straddle plant(s)	These are gas processing plants in Alberta that process marketable gas flowing through major pipelines, extracting natural gas liquids resulting in gas for export from Alberta that has lower heat content than the marketable gas flowing in the major pipelines within Alberta.
study area(s)	The areas of the WCSB defined in Figure 2.2 of this EMA.
target resource(s)	Conventional oil, conventional gas, CBM, or oil sands. In this EMA, the drilling of each well is deemed to be for the purpose of exploiting one of the target resources.
WCSB rig fleet	Drilling rigs comprising the Canadian Rig Fleet that have been determined by the NEB to work predominantly in Alberta, B.C., and western Saskatchewan. This excludes those drilling rigs of the Canadian Rig Fleet that are determined by the NEB to work predominantly in Eastern Saskatchewan, Eastern Canada (Offshore and Onshore) and Northern Canada (see Appendix A.1 for further details).

Available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityCanada2006_2008_e.htm

A. Analysis Regarding Determination of Number of Future Gas Connections

1. Components of Canadian Rig Fleet
   Weekly location of rigs comprising each of the following rig groupings:
   a) WCSB rigs
   b) eastern Saskatchewan rigs
   c) northern Canada rigs
   d) east coast offshore rigs
   e) eastern Canada onshore rigs

2. WCSB Rig Fleet
   Charts of historical and projected rig fleet growth by rig category for:
   a) shallow rigs
   b) medium rigs
   c) deep rigs
   d) All rigs

3. WCSB Rig Fleet
   Allocation of rig days to study areas:
   a) Historical weekly rig count split by main geographic area (North, South and West):
      i. shallow rigs
      ii. medium rigs
      iii. deep rigs
   b) Tables of historical and projected annual rig day allocations to study areas:
      i. shallow rigs
      ii. medium rigs
      iii. deep rigs

4. Tables of Historical and Projected Rig Utilization:
   a) shallow rigs
   b) medium rigs
   c) deep rigs

5. Tables of Historical and Projected Resource Targets for Drilling:
   a) shallow rigs
   b) medium rigs
   c) deep rigs

6. Drill Days per Well for each Resource Target in each Study Area:
   a) shallow rigs
   b) medium rigs
   c) deep rigs

7. Historical and Projected Drilling Levels for each Study Area for Gas-Intent and CBM-Intent Wells:
   a) Table of drill days
   b) Table of wells

8. Ratio of Annual Connections to Annual Wells Drilled:
   a) Gas-Intent Wells by Study Area
   b) CBM-Intent Wells by CBM Resource Grouping

9. Fraction of Annual Gas Connections for each Month in Year by Study Area:
   a) Conventional Gas Tables:

      Charts for each study area

   b) CBM Tables:

      Charts for AB-Southeast and AB-Central study areas applicable to Horseshoe Canyon Main Play

B. Analysis Regarding Production Performance

1. Group Performance Parameters for Existing Connections in the WCSB:
   a) Conventional Gas- by Study Area and Connection Year for non-Solution Gas, and by Study Area for Solution Gas.
   b) CBM –by CBM Resource Grouping and Connection Year

2. Historic and Projected Performance Parameters for Average Connections by Connection Year and Study Area

   a) Conventional Gas Connections by Connection Year and Study Area

   b) CBM Connections by Connection Year and CBM Resource Grouping

3. Trend of Initial Productivity of Average Gas Connection by Study Area

   - Appendices B.3.a thru B.3.l are charts showing initial productivity trend over time for conventional gas connections in each Study Area

4. Performance Charts (Rate versus Cumulative Production) for Historical and Projected Average Gas Connections for each Study Area

   - Appendices B.4.a thru B.4.l - charts showing average conventional gas connection production profiles for different connection years for each Study Area

C. Analysis Regarding Coal Bed Methane (CBM)

1. Maps Relating to CBM Resource Groupings:

   a) Horseshoe Canyon Main Play Area and Development

   b) Mannville CBM Resources and Development

   c) Other CBM Development

2. CBM Average Connection Performance Charts- Historical and Projected:

   a) Horseshoe Canyon Main Play

   b) Mannville CBM

   c) Other CBM