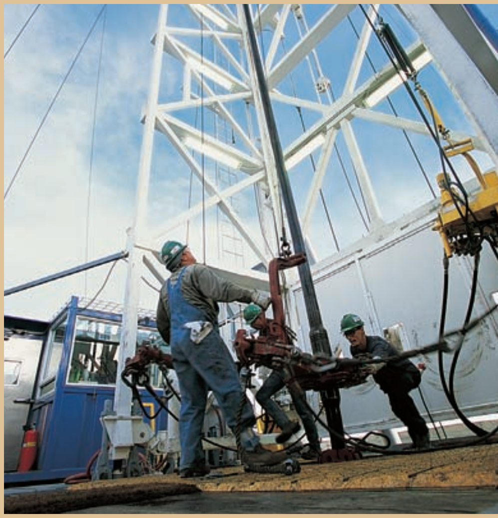
National Energy Board

Office national de l'énergie

Short-term Canadian Natural Gas Deliverability

2007–2009




AN ENERGY MARKET ASSESSMENT OCTOBER 2007

Canada

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FIGURES

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L I S T O F A C R O N Y M S

AB-F	Alberta-Foothills
AB-FF	Alberta-Foothills Front
AB-SE	Alberta-Southeast
AB-EC	Alberta-East Central
AB-C	Alberta-Central
AB-NE	Alberta-Northeast
AB-NW	Alberta-Northwest
BC-FSJ	B.C.-Fort St. John
BC-FtN	B.C.-Fort Nelson
BC-F	B.C.-Foothills
B.C.	British Columbia
BOE	Barrels of Oil Equivalent
CAPEX	Capital Expenditures
CAPP	Canadian Association of Petroleum Producers
CAPP Stats	data obtained from the CAPP Statistical Handbook
CBM	Coalbed Methane
CGPC	Canadian Gas Potential Committee
EMA	Energy Market Assessment
F&D costs	Finding and Developing Costs
HSC	Horseshoe Canyon
LNG	liquefied natural gas
M&NP	Maritimes and Northeast Pipeline
NEB	National Energy Board
NGLs	natural gas liquids
SK-C	Saskatchewan-Central
SK-SE	Saskatchewan-Southeast
SK-SW	Saskatchewan-Southwerst
SOEP	Sable Offshore Energy Project
U.S.	United States
WCSB	Western Canada Sedimentary Basin
YKNT	Yukon and Northwest Territories
$Cdn	dollars Canadian

Units

$10^6m^3/d$	= million cubic metres per day
Bcf	= billion cubic feet
Bcf/d	= billion cubic feet per day
BOE/d	= barrels of oil equivalent per day
GJ	= gigajoule
m^3	= cubic metres
m^3/d	= cubic metres per day
Mcf/d	= thousand cubic feet per day
MMcf	= million cubic feet
MMcf/d	= million cubic feet per day
Tcf	= trillion cubic feet

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 energy efficiency infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyse energy commodities and inform Canadians about trends, events and issues. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it launched an Energy Pricing Information for Canadians section on its website as an additional means to keep Canadians informed on energy market developments.

This EMA report, titled *Short-term Canadian Natural Gas Deliverability, 2007-2009*, examines the factors that affect gas supply in the short term and presents an outlook for deliverability through 2009. The main objective of this report is to advance public understanding of the short-term gas supply situation in Canada. This report is an update to the Board's October 2006 EMA, titled *Short-term Canadian Natural Gas Deliverability, 2006-2008*.

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:

Ken Martin	telephone: 403-299-3107, email: kmartin@neb-one.gc.ca, or
Paul Mortensen	telephone: 403-299-2712, email: pmortensen@neb-one.gc.ca

Executive Summary

Canadian natural gas is an important part of the North American gas market, providing about 25 percent of combined U.S. and Canadian production for the past several years. The value of producers' sales for Canadian marketable natural gas in 2006 was 42 billion $Cdn[1]. This report provides an outlook for Canadian gas deliverability to the end of 2009.

Canadian gas deliverability has been fairly stable since 2000 at about 480 million m^3/d (17 Bcf/d). Approximately 98 percent of the total Canadian volume comes from the Western Canada Sedimentary Basin (WCSB) with most of the rest from Atlantic Canada. Deliverability from Atlantic Canada is expected to average around 12.4 million m^3/d (0.44 Bcf/d) in the short term.

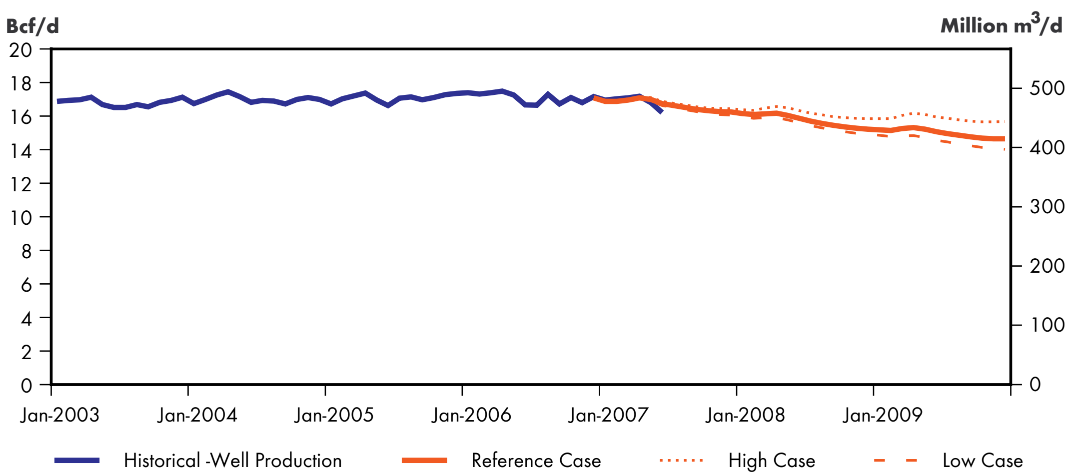
Deliverability expectations for the WCSB in the short term are less certain. Drilling and development activity in the WCSB hinges primarily on the price of natural gas in the North American market. That price is volatile, influenced by uncertainties such as weather-driven market demand, availability of imported liquefied natural gas (LNG), and possible supply disruptions in the Gulf of Mexico.

To reflect the short-term uncertainty of the North American natural gas market, deliverability in this report is projected under three scenarios intended to reflect different levels of drilling investment that may occur: Reference Case, High Case and Low Case.

Deliverability decreases under all three scenarios. Canadian deliverability is projected to fall to between 410 and 449 million m^3/d (14.5 to 15.8 Bcf/d) in 2009 from the 2006 level of 483 million m^3/d (17.1 Bcf/d) (see Figure 1).

FIGURE 1

Outlook for Canadian Gas Deliverability – Reference, High and Low Cases



1 CAPP Statistical Handbook, Table 04-25B.

In the moderate Reference Case scenario, Canadian gas deliverability in 2009 is projected to decrease by almost 59 million m^3/d (2.1 bcf/d) to 424 million m^3/d (15.0 Bcf/d).

For the past several years, new wells drilled in the WCSB have had, on average, comparable decline rates over their lifetimes, but have been less productive at start-up than in the past. Initial productivity of new WCSB gas wells fell sharply in the late 1990s, but those decreases have been more moderate recently. Over their first year and half of production, the annual decline rate of the average gas well is 55 percent. For the two following years, the annual decline rate is a more gradual 30 percent.

With initial well productivity decreasing from year to year, natural gas producers were maintaining overall WCSB deliverability at a stable level by increasing the number of wells drilled annually. Improving technology and relatively high North American natural gas prices encouraged producers to invest, even though costs to develop and produce new gas supplies were also rising.

As market prices for natural gas softened in 2006, the costs of maintaining such high levels of activity could not be sustained. A slowdown in natural gas drilling began in 2006 and has now persisted for over a year. Drilling and service companies have reduced the prices they charge over the past year as a result of lower utilization of drilling rigs and services, but some expenses are more difficult to cut due to the high costs of labour, steel and fuel. Further service cost reductions are becoming more challenging, so price becomes the key factor with the potential to change the economics for development of new gas supplies in the WCSB.

Over the past few years, progressively greater proportions of total gas drilling investments are targeting the western side of the WCSB. The deeper wells on the western side are more expensive to develop and drill but also tend to produce more gas supply than the shallower wells on the eastern side. Many of the natural resources on the western side of the basin are more extensive “resource play” deposits.

Although its level of drilling activity has also slowed over the last year, development of coalbed methane (CBM) resources in Alberta remains a bright spot for Canadian deliverability. With ongoing development of the Horseshoe Canyon coals and the start up of the Mannville CBM development, CBM production is expected to increase to approximately 23 million m^3/d (0.81 Bcf/d) by 2009 in the NEB’s Reference Case projection.

Given Canada’s large natural gas resource base and ongoing innovation and efficiency, Canadian deliverability will continue to constitute a key part of North American gas supplies.

INTRODUCTION

Canada has been one of the mainstays of natural gas supply in North America for many years, currently accounting for almost one-quarter of the combined production of Canada and the U.S. From 2000 through 2006 Canadian gas deliverability has been roughly stable, averaging around 480 million m^3/d (17 Bcf/d). This plateau in production occurred during a period that featured large increases in drilling activity almost every year. The pattern of ever increasing drilling levels was changed by a substantial downturn in WCSB drilling activity that commenced in mid-2006. Lower drilling activity in the WCSB is sure to result in a drop in Canadian gas deliverability. With Canada's substantial role in North American gas production and the uncertainty of drilling levels that will occur to maintain that production, there is considerable interest in the short-term outlook for Canadian gas deliverability. The primary objective of this report is to provide the Board's current outlook for Canadian natural gas deliverability to the end of 2009.

Chapter 2 provides background on the sources of Canadian supply, including a description of the geographic extent and nature of the supply in each region.

Chapter 3 provides discussion regarding recent production and development trends and includes a discussion of costs associated with development and production of new gas supplies in the WCSB.

Chapter 4 contains a discussion of the three scenarios under which Canadian deliverability was assessed. North American gas market conditions can cause high volatility of the gas price, which in turn can cause large swings in drilling investment in the WCSB. Three scenarios have been created to reflect this uncertainty—Reference Case, High Case and Low Case. The rationale surrounding the three scenarios is explored in this chapter.

Chapter 5 briefly describes the methodology used to estimate Canadian gas deliverability and points to the detailed discussion on the methodology and parameters impacting deliverability that are available in Appendices B and C.

The Board's outlook for Canadian natural gas deliverability is presented in Chapter 6. The conclusions of the assessment are discussed in Chapter 7.

BACKGROUND

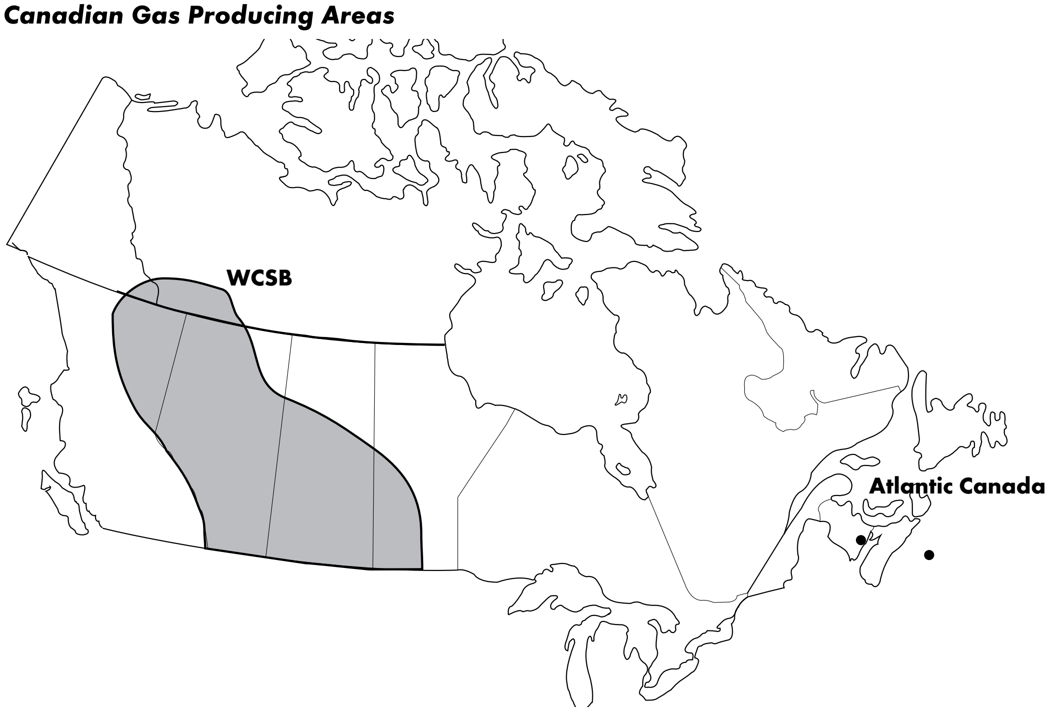
The WCSB has traditionally been Canada's main source of gas production and currently accounts for 98 percent of total Canadian production. Natural gas production from Atlantic Canada started at the end of 1999 and provides most of the remaining gas production in Canada[2]. Figure 2.1 shows the location of these gas producing areas. A discussion of the production sources and major developments for each region is included in this chapter. With respect to the WCSB, a review of prices and historical costs is also included.

2.1 Western Canada Sedimentary Basin

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 gas production from the Basin 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.

FIGURE 2.1

Canadian Gas Producing Areas



2 In addition to the WCSB and Atlantic Canada, a small amount of gas production also occurs in Central Canada and in more northerly areas of the Northwest Territories.

In this analysis, gas production in the WCSB is broadly split into conventional and unconventional categories. In this report, unconventional gas refers solely to coalbed methane (CBM) and conventional gas refers to all other gas production.

WCSB Conventional Resources

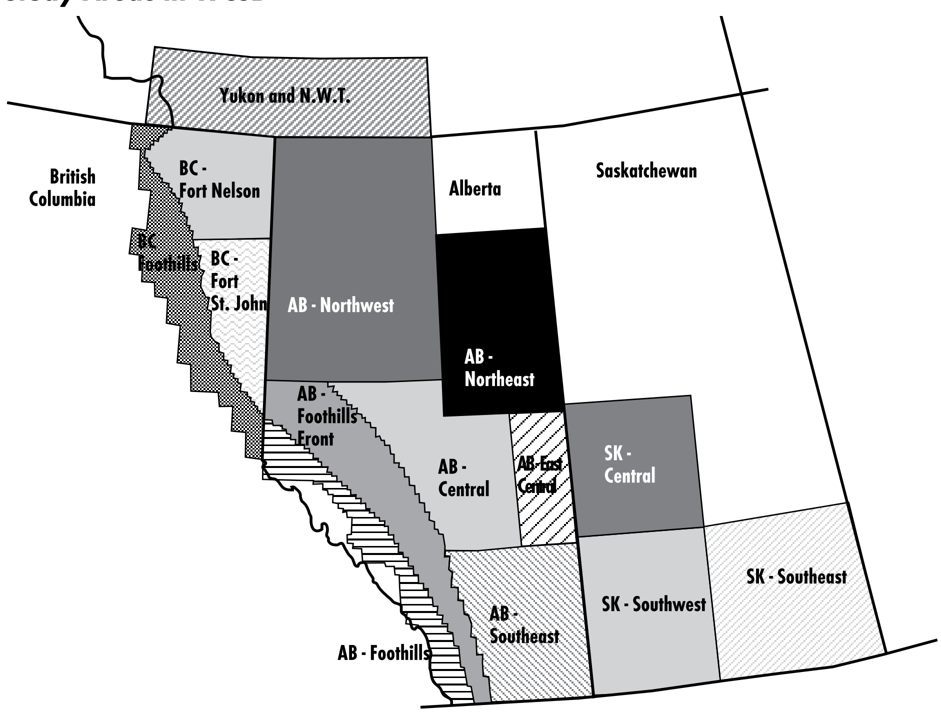
Conventional gas production is the mainstay of gas deliverability in the WCSB, accounting for about 96 percent of total gas production from the basin.

A significant amount of WCSB conventional gas production is produced from low permeability reservoirs that might more properly be categorized separately as "tight gas". Some estimates have tight gas comprising approximately 30 per cent of total production in the WCSB in recent years and, as the basin matures, lower permeability formations are increasingly a target for development. At present, tight gas in Canada is not defined, nor is it distinguished from conventional gas. With no standard criteria available for identification of tight gas wells, no attempt is made in this report to split out tight gas from other conventional gas for separate analysis.

There are large regional differences in physical and producing characteristics in the WCSB and as such the basin is divided into smaller areas with similar characteristics for production decline analysis. For this assessment, the WCSB has been split into 14 geographic regions (the "study areas") as shown in Figure 2.2. These study areas are subject to deliverability assessment for conventional resources. Within each study area, conventional gas connections are grouped by connection year for the assessment of producing characteristics and deliverability.

FIGURE 2.2

Study Areas in WCSB



WCSB Unconventional Resources – CBM

The WCSB has very large in-place resources of CBM, located primarily in the plains of Alberta. CBM was not the target of development in the WCSB until the start of the current decade, when higher gas prices and successful CBM development in the U.S. encouraged efforts to exploit these resources in Canada. With the recent development efforts, CBM production in Canada has increased from approximately 1.4 million m^3/d (50 MMcf/d) in mid-2003 to over 17 million m^3/d (600 MMcf/d) by the end of 2006.

CBM resources in the plains of Alberta exist in four geological formations – Belly River, Horseshoe Canyon, Ardley and Mannville. The physical and gas producing characteristics of coals vary widely geographically and geologically from formation to formation. The differences are most significant from formation to formation and so, for the purposes of deliverability assessment, geologic formation is the most useful criteria for categorization of CBM. In this report, CBM in Alberta is categorized into the following three groupings:

Horseshoe Canyon main play – wells identified as CBM producers within the Horseshoe Canyon main play area and not producing from the Mannville Formation. Figure 2.3 shows the Horseshoe Canyon main play area, which has been the focus of most CBM development in Alberta to date. The Horseshoe Canyon main play accounts for the vast majority of CBM wells and about 85 percent of all CBM deliverability as of year end 2006.

Mannville CBM – wells identified as CBM producers producing from the Mannville Formation. Since 2005, Mannville CBM has also been a focus of increasing levels of development as industry attempts to expand from an initial commercial project to other locations and continues to enhance technologies and practices that may enable more of its large potential to be realized.

Other CBM – wells identified as CBM producers and not already established as Horseshoe Canyon main play or Mannville CBM. This grouping consists of mostly of wells on the periphery of the Horseshoe Canyon main play area and experimental efforts of CBM development in Ardley coals.

In development of Horseshoe Canyon CBM, coal intervals are often commingled with conventional sand intervals. This report categorizes these types of wells as CBM, so it should be recognized that the CBM deliverability estimates presented in this report include some contribution from the commingled conventional sands. The commingling of coal intervals with conventional sands at similar depth in the Horseshoe Canyon main play area has a beneficial effect on resource development, as the economics for the commingled group of zones are better than if the zones had to be segregated.

2.2 Atlantic Canada

Gas production from Atlantic Canada consists mainly of output from the Sable Offshore Energy Project (SOEP). Since 1999, the SOEP has produced marketable gas volumes in the range of 8.5 to 14.2 million m^3/d (300 to 500 MMcf/d), with production in the spring of 2007 averaging 12.5 million m^3/d (440 MMcf/d).

The McCully field in New Brunswick became a significant component of deliverability from Atlantic Canada in 2007. Several new wells and a tie-in line to the Maritimes and Northeast Pipeline (M&NP) system resulted in an increase from approximately 0.06 million m^3/d (2 MMcf/d) in the first half of 2007 to deliverability in the range of 0.85 million m^3/d (30 MMcf/d) in July and August of 2007.

The SOEP and McCully Field represent the gas deliverability that is expected from Atlantic Canada over the projection period. There are several other possible developments in the region that could represent future gas deliverability following the projection period.

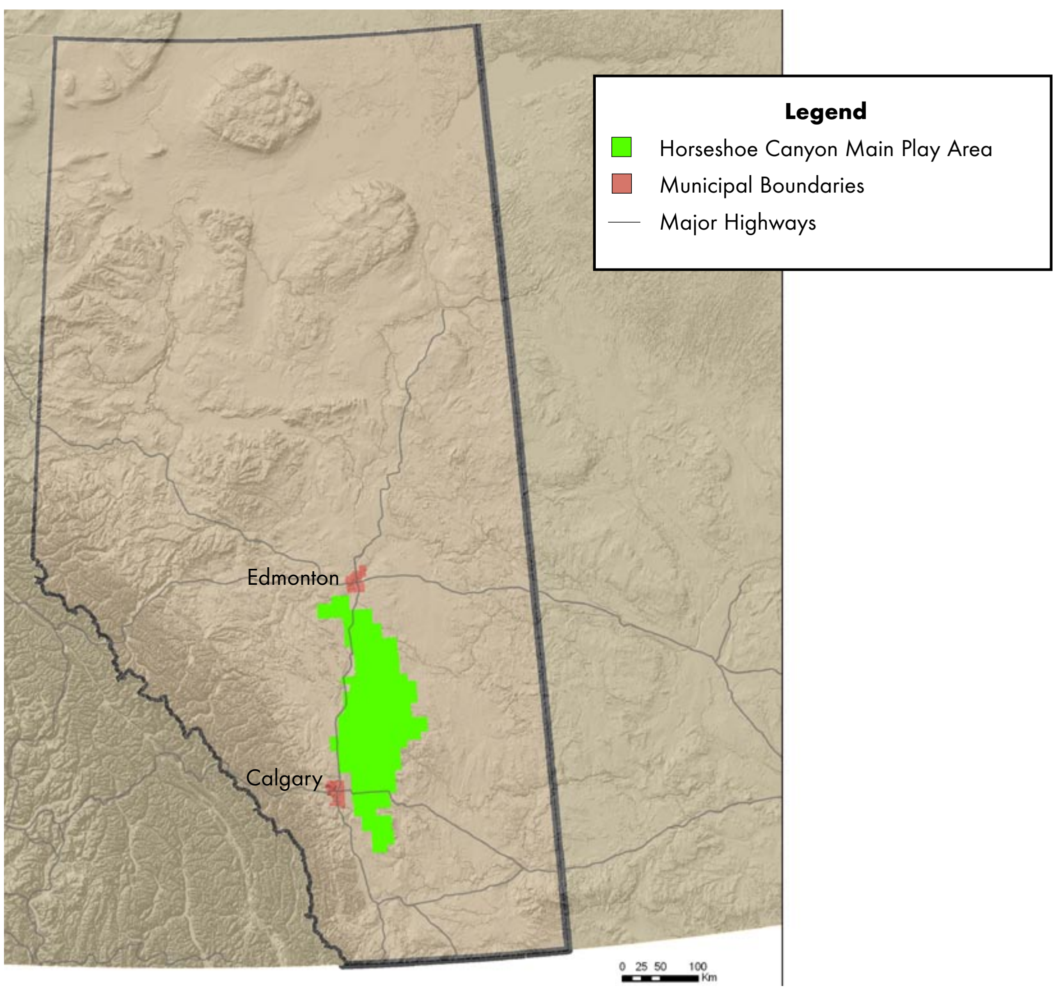
The most significant projects for potential future deliverability in Atlantic Canada are Deep Panuke offshore of Nova Scotia and solution gas in the White Rose Field offshore of Newfoundland and Labrador. The gas resources associated with both projects are large, with roughly 17 billion m^3 (600 Bcf) in Deep Panuke and 57 billion m^3 (2,000 Bcf) in White Rose. Possible timing for first production might be as early as 2010 for Deep Panuke and between 2015 and 2020 for White Rose. Other onshore projects such as CBM in the Stellarton and Cumberland Basins of Nova Scotia and conventional gas in Quebec are also being considered.

2.3 Liquified Natural Gas

Prospective liquidied natural gas (LNG) regasification terminal projects in Atlantic Canada, Quebec and British Columbia are at various stages of consideration or development. Since gas supply for LNG projects is sourced from outside the country, these projects will not be covered in this report of Canadian natural gas deliverability.

FIGURE 2.3

Coalbed Methane – Horseshoe Canyon Main Play Area



Recent Trends

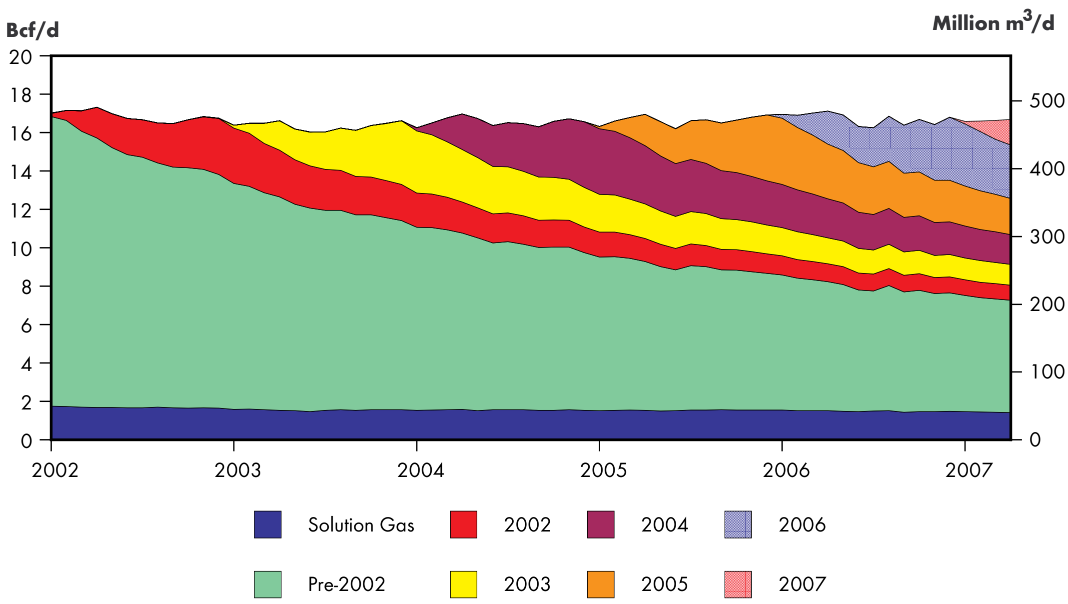
3.1 WCSB Historical Production and Development

Total WCSB historical gas production (all conventional and CBM) by connection year is shown in Figure 3.1. Gas production from the WCSB has been stable for the past several years at about 470 million m^3/d (16.6 Bcf/d) as high levels of drilling activity have been offset by lower initial productivity of new wells and, in some cases, higher decline rates. The importance of ongoing gas drilling activity to total production is evident with approximately half of all production at the end of 2006 coming from gas wells that came on stream over the previous four or five years. Ongoing gas drilling activity is crucial to maintaining WCSB deliverability at the level that has been sustained over the past several years.

Throughout the period of stable production over the past several years, gas-intent drilling activity has generally trended higher each year. Figure 3.2 shows the amount of gas-intent drilling (including CBM) that has occurred in each year since 1996 and the average annual total deliverability in the WCSB over that period. In most years from 2000 through 2005, gas drilling activity was limited by the capacity of the expanding Canadian rig fleet. During this period, increasing annual drilling activity only resulted in maintaining WCSB deliverability.

FIGURE 3.1

WCSB Total Historical Gas Production by Connection Year

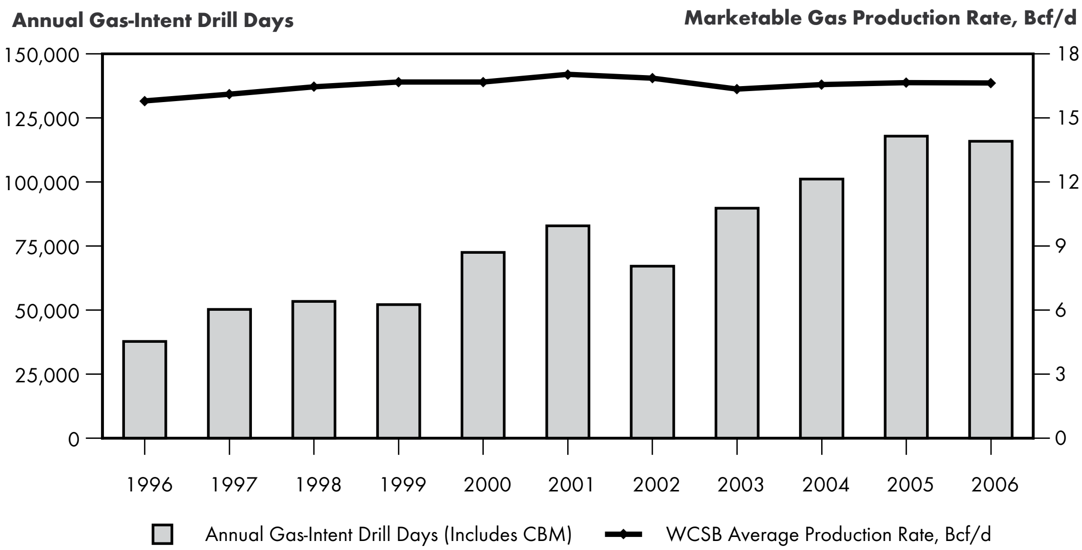


Source: NEB Analysis of GeoScout Well Data

In mid-2006 a downturn in drilling activity commenced in the WCSB. This downturn is evident in Figure 3.3, which shows cumulative annual active rig weeks in the WCSB for each of the past several years. Drilling activity in 2006 was on track to be substantially higher than 2005, until approximately mid-year, after which the pace of drilling activity slowed markedly and 2006 total year active rig weeks ended up slightly lower than the 2005 level. The downturn in drilling activity has continued into 2007, and thus far there are no indications of recovery to the previous trend of drilling at near maximum capacity. The reasons for the downturn in drilling activity are economic and will be explored further in Section 3.2.

FIGURE 3.2

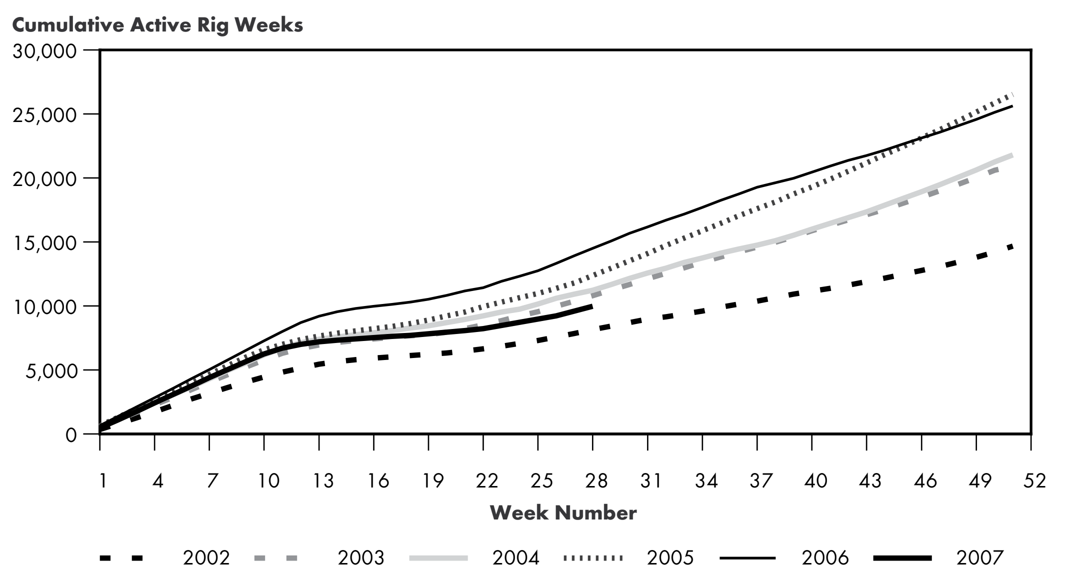
WCSB Historical Annual Average Gas Production and Annual Gas-Intent Drill Days



Source: Board Analysis of GeoScout Well Data

FIGURE 3.3

WCSB Cumulative Annual Active Rig Weeks, 2002 through 2007



Source: Nickle's Rig Locator Report

3.2 WCSB Costs to Develop New Gas Supplies

The relationship between development costs and natural gas price has had a strong influence on drilling activity in the WCSB. New gas supplies resulting from future gas drilling activity will be an extremely important factor in sustaining WCSB deliverability.

A review of the economic factors influencing development of new gas supplies is useful to understand gas drilling activity levels in the WCSB. Capital expenditures are incurred in drilling each well and if the well is successful further capital costs are incurred to complete the well and connect it to processing facilities and the pipeline grid. Once the well comes on stream the revenue generation commences. After reaching its initial production rate the production rate of the well naturally declines. Throughout production, there are further costs incurred, mainly operating costs and royalties, until eventually the economic limit of operations is reached and the well is abandoned. For economic success, the revenue generated over the productive life must payout all of the costs incurred for the well and provide the producer with a return on investment.

Full-cycle costs represent the total costs associated with a well. Through consultations, various producers indicated that current full-cycle costs in the WCSB are in the range of 8 $Cdn per GJ. The main components of the full cycle costs are:

- finding and development ("F&D") costs;
- operating costs; and
- royalties.

The Board has made an independent estimate of these three major categories of cost for development of new gas supplies for each year since 1996. The costs can be compared to price to provide insight into the economic environment for development of new gas supplies. The methodologies used in deriving historical estimates for each of the three major costs are discussed in Appendix A.1.

F&D costs are a measure of capital costs incurred per amount of gas developed, and there are two separate underlying factors involved. The first underlying factor is the finding rate, which is the amount of gas developed for a given amount of development effort (GJ/drill day). Finding rate is a function of geological potential and exploitation efficiency, and there is a well established trend of decreasing finding rate year on year in the WCSB. In all likelihood the finding rate in future years will be somewhat lower than it is currently, which will drive F&D costs higher.

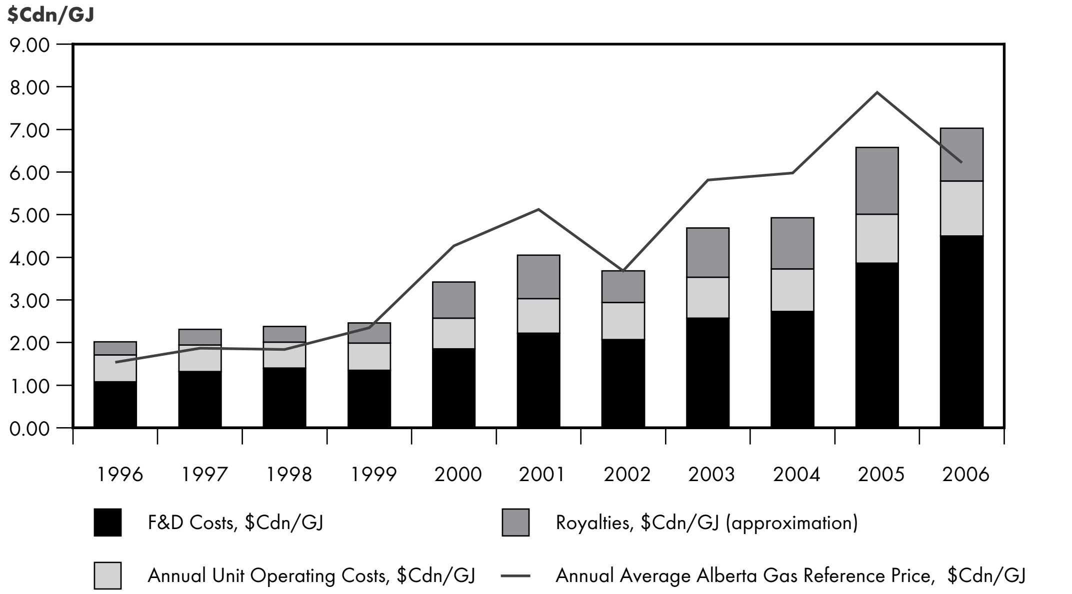
The second underlying factor relevant to F&D costs is the cost incurred for a given amount of development effort. These costs are set in the market place of supply and demand for upstream services and thus there is some elasticity in this factor. However, there are real constraints to this elasticity due to continuing high costs for key service sector inputs such as labour, steel and fuel.

Figure 3.4 shows a comparison for the years 1996 through 2005 between the major costs determined for the WCSB and the average annual Alberta Gas Reference Price. It must be noted that all of the cost values shown in Figure 3.4 are Board estimates as determined using the methodologies described in Appendix A.1. In spite of the approximate nature of the values presented, a review of this information provides useful insight into the drilling trends over the past several years, and the drivers for drilling activity in future years.

The annual F&D costs, operating costs and royalties represent the expenditures involved in providing marketable production. Marketable production is measured as the gas volumes available at the outlet of field plants delivering into major pipeline systems. In addition to the three major costs of F&D,

FIGURE 3.4

WCSB Approximate Major Costs and Price, 1996-2006



Source: NEB Analysis of CAPP Statistics; NEB estimates of Gas Recovery by Connection Year; Alberta Monthly Reference Price Calculations.

operating and royalties, producers require a return on investment. The Alberta Gas Reference Price is intended to be representative of the average market price for gas sales in Alberta at the plant gate and are used here as an indicator of average market price for production in the WCSB. The historical relationship between the major costs and the gas price gives strong indication of the economic environment for development of new gas supplies in recent years.

Just as there is a wide range of gas prospects in Western Canada, there is a wide range in the length of time that wells produce and in their cost. Similarly, prices can vary over the life of a well and by the choice to lock in future prices in advance through hedging or accepting the variability of daily spot markets. As a result of this variability in costs, prices and expectations, some drilling remains profitable even when average costs exceed average prices.

For all years from 2000 through 2005, except for 2002, the average price significantly exceeded the average of the sum of major costs. Also, in each of those years, drilling activity was very strong, with the rig fleet in the WCSB operating at close to maximum capacity. In 2002, when the price dipped down to approximately equal to the sum of the costs, drilling activity also declined markedly (see Figure 3.2).

Drilling activity was very strong in 2006 until approximately mid-year, driven by high prices in the winter of 2005/2006. In the spring of 2006, a sustained period of lower prices commenced, altering the relationship between major costs and price such that a widespread drop in drilling activity occurred in the WCSB. On average, the price in 2006 was approximately 6.20 $Cdn/GJ, which was again below the estimated average costs for that year.

3.3 Other Trends and Events Pertinent to Gas Development

Cost escalation and reduced drilling efficiency were symptoms of overheated economic conditions in the western Canada oil and natural gas drilling sector in 2006. As cost inflation caused companies to exhaust their drilling budgets early, drilling activity in the second half of the year fell further behind the frantic pace of 2005 and even below 2004 levels. Gas storage filled ahead of schedule and helped to send natural gas prices in Western Canada, at the end of September 2006, to their lowest level since 2002.

Drilling budgets for 2007 were being set at roughly the same time that natural gas prices were bottoming out in September-October 2006. Negative sentiment regarding natural gas prices coincided with an estimated 5 billion $Cdn increase in 2007 capital spending requirements for oil sands projects in Alberta and better economics for conventional and heavy oil drilling. With no expected rise in total upstream capital spending in 2007, it appears that the entire increase in oil and oil sands related expenditures could come from gas drilling budgets. This could result in approximately a 8 billion $Cdn or 35 percent reduction in gas-related drilling expenditures in 2007.

Coupled with reduced gas drilling activity, growth in the Western Canada drilling rig and service fleets in 2007 is also contributing to lower utilization. While some of the newly constructed rigs have been shifted to projects in the U.S., the total Canadian drilling rig fleet has grown from 844 to 885 in the first half of 2007. Rig Utilization over the first half of 2007 has fallen to 40 percent, compared to 65 percent over the same period in 2006. Lower utilization has resulted in new rigs displacing older less-efficient units, less work by inexperienced rig crews, and the ability for services to keep up with drilling operations to reduce delays. These factors are expected to contribute to improved drilling efficiency (metres drilled per day) in 2007.

Although background cost inflation from oil sands-related activity in Alberta and worldwide economic growth continue to put pressure on input costs such as labour, steel, fuel and services, lower utilization has resulted in operators reducing drilling day rates. Through lower drilling costs and improved drilling efficiency, some producers have begun reporting reductions in well costs of 10 to 30 percent from 2006 levels. Some of this reduction has been eroded by the appreciation of the Canadian dollar with respect to U.S. export revenues.

The WCSB remains positive with respect to natural gas prospectivity, with an estimated remaining recoverable resource base of 2,600 billion m^3 (92 Tcf) from conventional gas alone at the end of 2004. Significant volumes of unconventional gas (CBM, tight gas and shale gas) are likely to be added to the recoverable resource base as producers continue to develop the understanding and techniques to unlock these resources. However, recent supply cost studies and general industry sentiment suggests that, even with recent cost reductions, natural gas prices in Western Canada may need to exceed 7 $Cdn/GJ and perhaps even 8 $Cdn/GJ before margins would be sufficient for drilling to recover toward the roughly 18,000 gas-intent wells drilled per year in 2004 and 2005.

After many years with an increasing focus on shallow gas and CBM, the industry in western Canada has significantly reduced its shallow gas activity and has been drilling more deeper targets on the west side of the basin. The average depth per gas well in the WCSB in 2006 was approximately 1,080 metres, compared to around 960 metres in 2003.

Investment in upstream natural gas development may be negatively impacted by fiscal uncertainty regarding a change to tax policy for energy trusts and a royalty review in Alberta. Some energy trusts have reported that uncertainty over how they will revert to taxable status by 2011 has made it more difficult to raise capital and thereby continue to purchase producing properties. The uncertainty in the trust sector may also be impacting the junior oil and gas sector (less than 10,000 BOE/d), as the strategy of many of the junior companies was to grow to a certain size and then sell producing assets to the trusts.

A decision by the Alberta Energy and Utilities Board to authorize commingling of production from multiple CBM zones in the Horseshoe Canyon rather than require project-specific approvals was initially viewed as likely to lead to significantly increased CBM development in Alberta. However, the low productivity and lengthy production lives of Horseshoe Canyon CBM wells, relative to the escalation in capital costs to drill, complete and connect the large number required, and to drill and monitor test wells, has led to a significant reduction in CBM activity.

Some companies are beginning to examine shale gas potential in areas of Alberta and northeast B.C. based on the success of shale gas development in the U.S. such as the Barnett Shale in east Texas. Interest is at a very early stage in Western Canada and wells being drilled are typically under experimental status with no information publicly released.

On the east coast, Sable gas production has increased and a dormant field brought back into production through the addition of offshore compression. Production has also increased from the onshore McCully field in New Brunswick. All other offshore activity has been oil related. The contribution to Canada's gas production from Nova Scotia and New Brunswick is expected to rise to an average of 12.5 million m^3/d (0.44 Bcf/d) in 2007 with added compression.

The amount of working gas storage capacity has increased by roughly 12 percent to 127 million m^3 (4.5 Tcf) while gas demand has been relatively flat. After relatively benign winter weather, this has resulted in a rather stubborn storage overhang following the heating season that has tended to weigh down gas prices over the late summer and fall. Consistently experiencing an excess of gas in storage at the end of winter could eventually reduce the winter/summer price spread.

Imports of LNG into the U.S. increased significantly in 2007 as new LNG production facilities began operating and less LNG was needed in Europe after a mild winter left Europe with excess gas in storage. Increased LNG into North America has accelerated the refilling of storage and is a contributing factor to downward pressure on prices.

Scenarios Overview

Most Canadian gas production is sourced from the WCSB, where gas drilling activity plays a large role in determining future deliverability. A significant downturn in Western Canada natural gas drilling activity occurred around mid-2006 as producers reduced investment due to less favourable economics. In this report three scenarios are explored reflecting the uncertainty in the level of drilling activity that will occur over the projection period.

Economics drives drilling investment. The key factors influencing the economics for gas drilling activity in the WCSB are price, costs and finding rate. The historical relationship of these factors was discussed in Chapter 3. The current environment of price, costs and finding rate does not favour high levels of development.

Average costs for upstream services in 2007 have come down from the levels of 2006 in the face of lower levels of industry activity. Further cost reductions are affected by continuing high costs of inputs such as labour, steel and fuel. Finding rate in the WCSB is mostly a function of geological potential and has followed a clear trend for many years; therefore, finding rate is a relatively inflexible factor in the economic equation. Price has high potential for variability. It is expected that price variability will be the key factor that will influence the economics and therefore impact drilling activity levels in the WCSB.

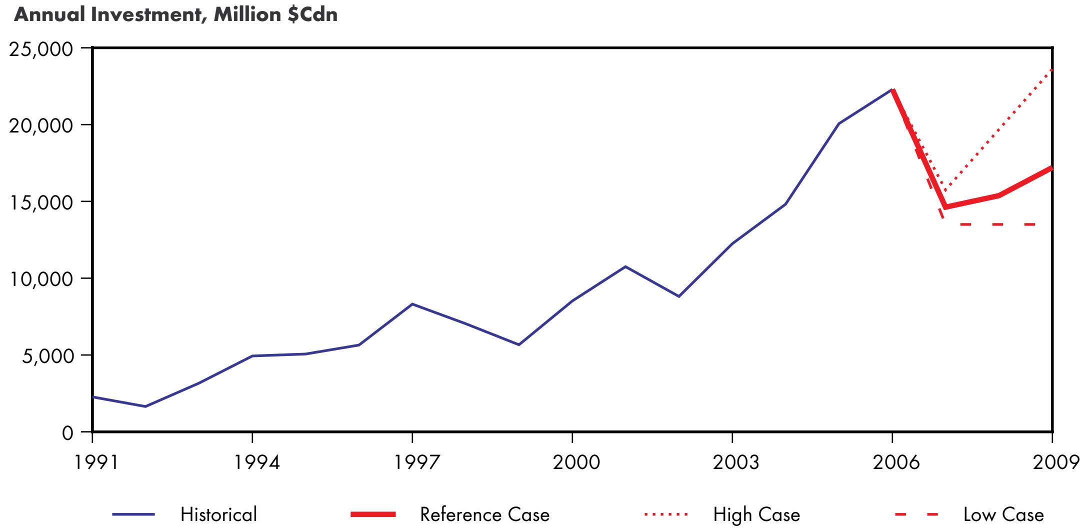
Natural gas price is set in the context of the North American gas market. Many of the factors influencing the North American gas market are associated with weather and so are quite volatile and unpredictable. Hurricanes in the Gulf of Mexico can cause large disruptions in gas supply from that region. The weather in North America has a large impact on gas demand in both winter and summer. Gas demand in Europe, again often a function of weather, can cause large swings in the volume of LNG available for import into North America. With these volatile factors influencing the North American gas market, price is volatile and can be difficult to predict.

Due to the market uncertainties, three scenarios of Canadian gas deliverability have been created – **Reference Case**, **High Case** and **Low Case**. Each scenario is associated with a market environment that results in an assumed level of drilling investment and average drilling costs. The drilling investment levels and drilling costs levels were chosen on the basis of consultations with industry, and on the impact of market conditions that exist in each scenario, and in light of historical trends.

The WCSB total drilling investment used in each scenario is shown in Figure 4.1. In the **Reference Case**, WCSB drilling investment decreases by approximately 35 percent in 2007 from the 2006 level of 22.3 billion $Cdn. This scenario assumes that market conditions will cause a slight upward movement of annual average gas price from 2007 to 2008, resulting in a 5 percent increase in drilling investment in 2008 from 2007. In 2009, market conditions are assumed to drive a stronger upward movement in annual average price resulting in a further 12 percent increase in drilling investment from 2008 to 2009.

FIGURE 4.1

Drilling Investment Levels for Alberta, B.C. and Saskatchewan for Projection Scenarios



Source: CAPP Statistics for historical drilling investment levels

In the **High Case**, drilling investment decreases by approximately 30 percent in 2007 from the 2006 level of 22.3 billion $Cdn. However, 2008 drilling investment rises markedly by 25 percent from the 2007 level and another 20 percent in 2009. Possible drivers for this scenario include lower imports of LNG into North America, potential supply disruptions due to hurricanes in the Gulf of Mexico, and strong market demand.

In the **Low Case**, drilling investment decreases by approximately 40 percent in 2007 and stays at that level in 2008 and 2009. Possible market conditions for this scenario include strongly increasing imports of LNG into North America, growing domestic supply in the U.S. without major disruptions, and weaker market demand.

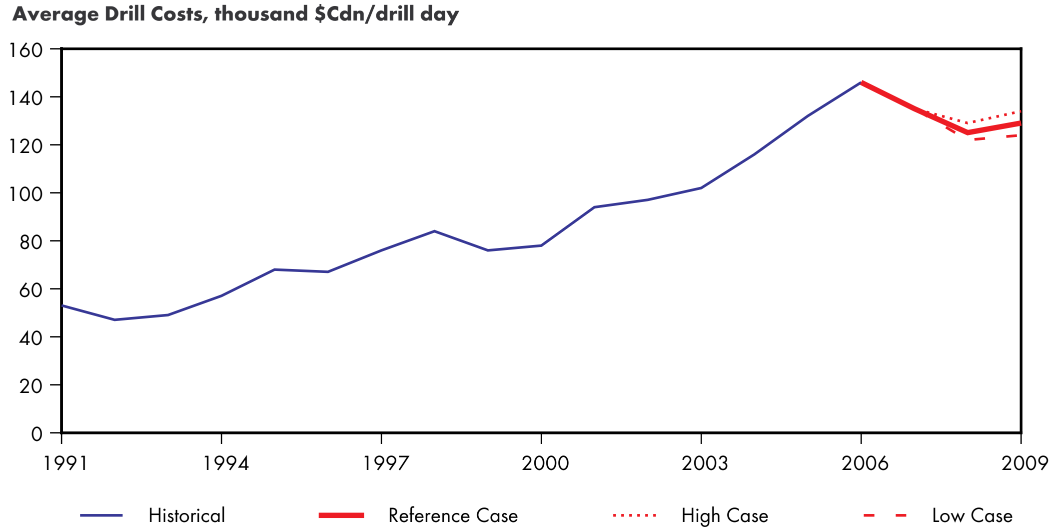
Drilling costs are also varied slightly between the scenarios reflecting higher or lower demand for upstream services. In all three cases, average costs per drill day are assumed to drop by approximately 7 percent from 2006 to 2007. In the **Reference Case**, costs per drill day drop again by 7.5 percent from 2007 to 2008 and then increase by three percent for 2009. In the **High Case**, costs per drill day drop 5 percent from 2007 to 2008 and then increase by 4 percent for 2009. In the **Low Case**, costs per drill day drop 10 percent from 2007 to 2008 and then increase by 2 percent for 2009.

The varying levels of drilling investment and costs per drill day results in different WCSB gas drilling projections for each scenario. The procedure used to determine the gas drilling levels based on drilling investment and costs per drill day is described in detail in Appendix B. Different levels of gas drilling activity result in differing deliverability projections.

The total gas-intent drilling projections associated with each scenario is summarized in Table 4.1. More detailed information regarding these projections is available in Appendix C. Even in the High Case, gas drilling activity does not reach the 18,000 gas-intent well level that occurred in 2005.

FIGURE 4.2

WCSB Average Drilling Costs per Drill Day for Projection Scenarios



Source: For Drilling Costs – CAPP Statistics for 2006 and earlier; For Drill Days – NEB analysis of GeoScout well data for 2006 and earlier.

TABLE 4.1

WCSB Drilling and Connection Projections for The Three Scenarios

	Annual Number of Gas-Intent wells (Including CBM)			Annual Number of Gas Connections (Including CBM)		
	Low Case	Reference Case	High Case	Low Case	Reference Case	High Case
2007	10,734	**11,620**	12,514	10,974	**11,879**	12,793
2008	11,293	**12,490**	15,591	11,489	**12,706**	15,861
2009	10,925	**13,401**	17,469	11,069	**13,578**	17,710

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 report, trends in well production characteristics and resource development expectations are assessed to determine parameters that define future natural gas deliverability from the WCSB. A different approach is used for Atlantic Canada where production is sourced from a very small number of wells.

Rather than presenting these technical procedures and detailed results in the body of this report, this information is made available in the following Appendices:

Appendix B. Methodology Applied and Resulting Parameters

1. Methodology (Detailed Description)
2. Deliverability Parameters – Results
3. Group Performance Parameters for Existing Connections
4. Historical and Projected Average Connection Parameters

Appendix C. Drilling Projection Details

1. Factors for Allocation of Gas-Intent Drill Days to Resource Groupings
2. Detailed Drilling and Connection Projections for Scenarios

The parameters obtained from the analysis performed for this report were fed into a model to produce the deliverability projections. As discussed in Chapter 4, market conditions create considerable uncertainty in the drilling activity that will occur in the WCSB, so deliverability projections were made for three different scenarios of gas drilling activity. These projections are presented in Chapter 6.

DELIVERABILITY OUTLOOK

Three scenarios of deliverability projections were analysed in this report: Reference Case, High Case and Low Case. The scenarios reflect different levels of gas drilling activity that may occur in the WCSB over the projection period. The Board's deliverability outlook by area/resource for the Reference Case is shown in Table 6.1. Similar tables for the High Case and Low Case scenarios are available in Appendix D.

Table 6.1 shows annual average production for 2006 and expected annual average deliverability for 2007, 2008 and 2009 for each grouping. Canadian annual average deliverability is expected to decrease from 483 million m^3/d (17.1 Bcf/d) in 2006 to 424 million m^3/d (15.0 Bcf/d) in 2009.

TABLE 6.1

Canadian Gas Deliverability Outlook by Area/Resource – Reference Case

Area/Resource	Historical		Projection					
	2006		2007		2008		2009	
	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	22.37	790	22.65	800	22.41	791	22.20	784
Alberta – Foothills Front	131.20	4,631	130.45	4,605	125.54	4,431	122.25	4,315
Alberta – Southeast	74.75	2,639	71.23	2,514	66.45	2,346	61.78	2,181
Alberta – East Central	16.28	575	14.75	521	13.17	465	11.77	415
Alberta – Central	48.14	1,699	44.65	1,576	40.19	1,419	36.52	1,289
Alberta – Northeast	21.11	745	18.54	655	16.35	577	14.45	510
Alberta – Northwest	48.81	1,723	46.10	1,627	41.71	1,472	38.55	1,361
B.C. – Fort St. John	40.12	1,416	39.73	1,402	37.74	1,332	36.42	1,285
B.C. – Fort Nelson	21.92	774	20.10	709	17.91	632	16.51	583
B.C. – Foothills	12.15	429	12.66	447	12.23	432	11.93	421
Saskatchewan – Central	4.95	175	4.43	157	4.06	143	3.70	131
Saskatchewan – Southwest	14.63	516	13.23	467	12.24	432	11.22	396
Saskatchewan – Southeast	0.92	33	1.01	36	1.00	35	0.99	35
Yukon and Northwest Territories	0.77	27	0.67	24	0.61	21	0.55	19
Total WCSB Conventional	**458.13**	**16,172**	**440.20**	**15,539**	**411.61**	**14,530**	**388.86**	**13,727**
Alberta CBM – HSC Main Play	12.62	445	15.54	548	16.79	593	17.75	627
Alberta CBM – Mannvile	1.30	46	2.26	80	3.22	114	4.43	157
Alberta CBM – Other	0.58	21	0.65	23	0.63	22	0.65	23
Total Alberta CBM	**14.50**	**512**	**18.45**	**651**	**20.64**	**729**	**22.83**	**806**
Total WCSB	**472.63**	**16,684**	**458.65**	**16,190**	**432.25**	**15,258**	**411.69**	**14,533**
Atlantic Canada	9.98	352	12.41	438	13.08	462	11.72	414
Other Canada	0.70	25	0.67	24	0.65	23	0.63	22
Total Canada	**483.31**	**17,061**	**471.73**	**16,652**	**445.98**	**15,743**	**424.04**	**14,969**

More detailed discussion of the WCSB deliverability projection under the Reference Case and the deliverability Projections for Atlantic Canada and Total Canada (Reference Case) is provided in the following sections. The total Canada deliverability projections for all three scenarios are summarized in Section 6.5.

6.1 WCSB – Reference Case

Sections 6.1.2 and 6.1.2 deal with the Reference Case deliverability projections for conventional gas and CBM in the WCSB. With the decline projected for conventional deliverability and the growth expected for CBM deliverability, total WCSB deliverability in the Reference Case is projected to decrease from 473 million m^3/d (16.7 Bcf/d) in 2006 to 412 million m^3/d (14.5 Bcf/d) in 2009.

6.1.1 Conventional Gas

In the Reference Case, average annual deliverability of conventional gas from the WCSB is expected to decrease over the projection period from 458 million m^3/d (16.2 Bcf/d) in 2006 to 389 million m^3/d (13.7 Bcf/d) in 2009. Deliverability of conventional gas from the largest producing province, Alberta, is expected to decline over the projection period from approximately 363 million m^3/d (12.8 Bcf/d) in 2006 to 308 million m^3/d (10.9 Bcf/d) in 2009. Decreases in conventional gas production are expected to occur in all areas of Alberta. The deliverability decreases expected in the Foothills Front and Foothills areas of Alberta are much smaller than those projected for other areas of Alberta, reflecting an increasing proportion of future drilling investment expected to be directed to those areas. Deliverability from B.C. is expected to decrease in the Reference Case, from approximately 74 million m^3/d (2.6 Bcf/d) in 2006 to 65 million m^3/d (2.3 Bcf/d) in 2009. Total deliverability from Saskatchewan is expected to decrease in the Reference Case, from approximately 21 million m^3/d (0.72 Bcf/d) in 2006 to 16 million m^3/d (0.56 Bcf/d) in 2009.

FIGURE 6.1

WCSB Conventional Deliverability – Reference Case

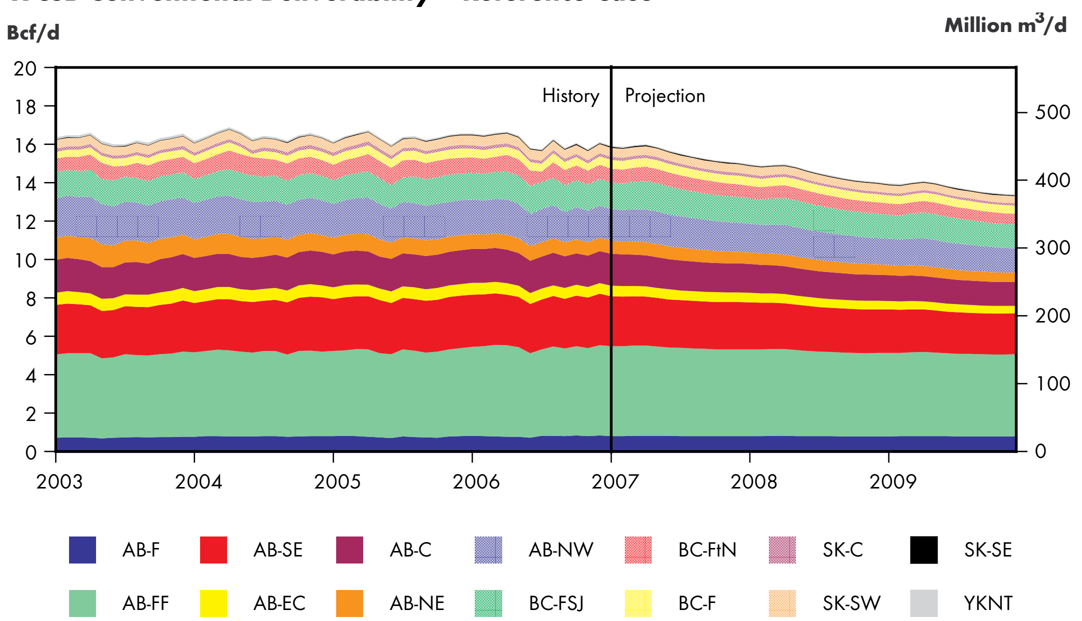


FIGURE 6.2

CBM Deliverability by Formation– Reference Case

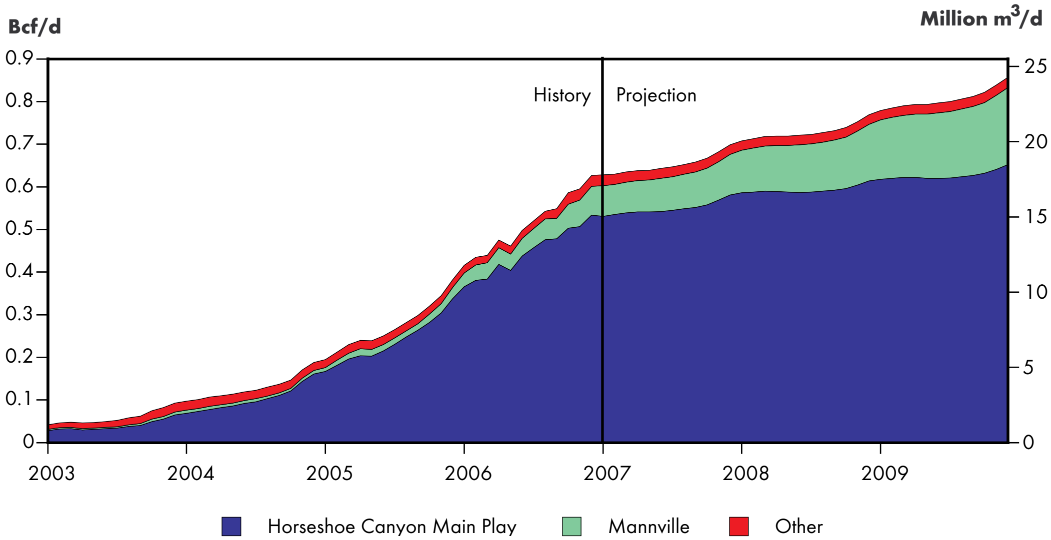


Figure 6.1 shows the Reference Case deliverability projection for conventional gas in the WCSB broken down by area. The general decrease projected for conventional gas deliverability in the WCSB after many years of almost stable production is apparent on this chart. The stable production levels were the result of ever increasing drilling levels that largely offset the declining initial productivity of new gas wells in the WCSB. The projected reduction in gas drilling levels through 2009 combine with the downward trend in initial well productivity to drive the projection of conventional gas deliverability into decline.

6.1.2 WCSB – Coal Bed Methane

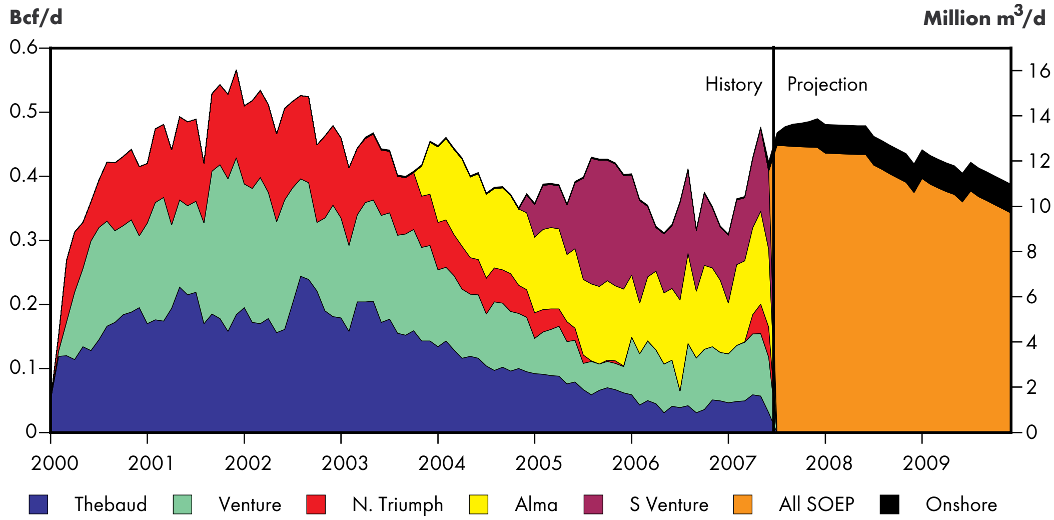
Coalbed methane production in the WCSB has grown markedly since 2003. However, CBM is still a small fraction of total WCSB gas supply, amounting to 14.5 million m^3/d (0.51 Bcf/d) or 3 percent of total WCSB production in 2006. Figure 6.2 shows the historical and projected deliverability of CBM in the Reference Case split by resource grouping. In the Reference Case, total CBM deliverability is expected to increase to 23 million m^3/d (0.81 Bcf/d) or 5.5 percent of total WCSB deliverability by 2009.

Figure 6.2 clearly shows CBM deliverability growing at a slower pace than what occurred from 2003 to 2006. CBM development faces similar economic challenges as conventional gas in the current market environment, and the current widespread downturn in drilling activity in the WCSB has impacted practically all areas of drilling activity, including CBM.

Slower growth in deliverability projected for the Horseshoe Canyon main play reflects both lower drilling activity over the projection period and expected decline in production from existing wells. Mannville CBM production only started to become noticeable in 2005 and is projected to continue to grow rapidly in these initial phases of development, with deliverability roughly tripling between 2006 and 2009. Deliverability growth in Mannville CBM is expected to come mainly from commercial development in the Corbett Area, with increasing contributions from other areas as industry pursues other projects targeting this resource. Deliverability from the Other CBM resources is expected to remain at a steady low level for the projection period.

FIGURE 6.3

Atlantic Canada Deliverability Outlook



6.2 Atlantic Canada

As illustrated in Figure 6.3, the estimate of deliverability from Atlantic Canada includes the compression addition at the SOEP and onshore production from the McCully field in New Brunswick. The compression addition allowed deliverability from the North Triumph field to resume. Due to uncertainty regarding the performance of individual wells at lower pressures, no attempt was made to allocate the compression increase to separate fields. SOEP deliverability is expected to average 11.9 million m^3/d (420 MMcf/d) in 2007 and gradually decline to average 10.5 million m^3/d (370 MMcf/d) in 2009.

At the end of June 2007, McCully production began to flow through a 50 km tie-in to the M&NP. Deliverability from the field is expected to gradually ramp up to 1.3 million m^3/d (45 MMcf/d) by November and remain relatively constant at that level over the projection period.

6.3 Total Canada

Figure 6.4 portrays the Reference Case outlook for total Canadian gas deliverability split into major segments of gas supply over the projection period. Total Canadian production is expected to decrease, as lower gas drilling activity expected over the projection period will result in fewer new gas wells. Different market conditions that may occur cause uncertainty in the projection shown, as lower or higher drilling levels would significantly impact the deliverability expected from new gas connections. Charts showing the deliverability projections for the High Case and Low Case scenarios are available in Appendix D.

6.4 Scenario Deliverability Summary

Deliverability projections were made in this report under three scenarios, reflecting the uncertainty surrounding gas drilling activity in the WCSB. Table 6.2 summarizes the total Canadian annual average deliverability under each scenario. Figure 6.5 shows the deliverability for the three scenarios and the historical production. Canadian deliverability is projected to decrease in all three scenarios. In the Reference Case, average annual deliverability is expected to drop between 2006 and 2009 by 59

FIGURE 6.4

Outlook for Canadian Gas Deliverability – Reference Case

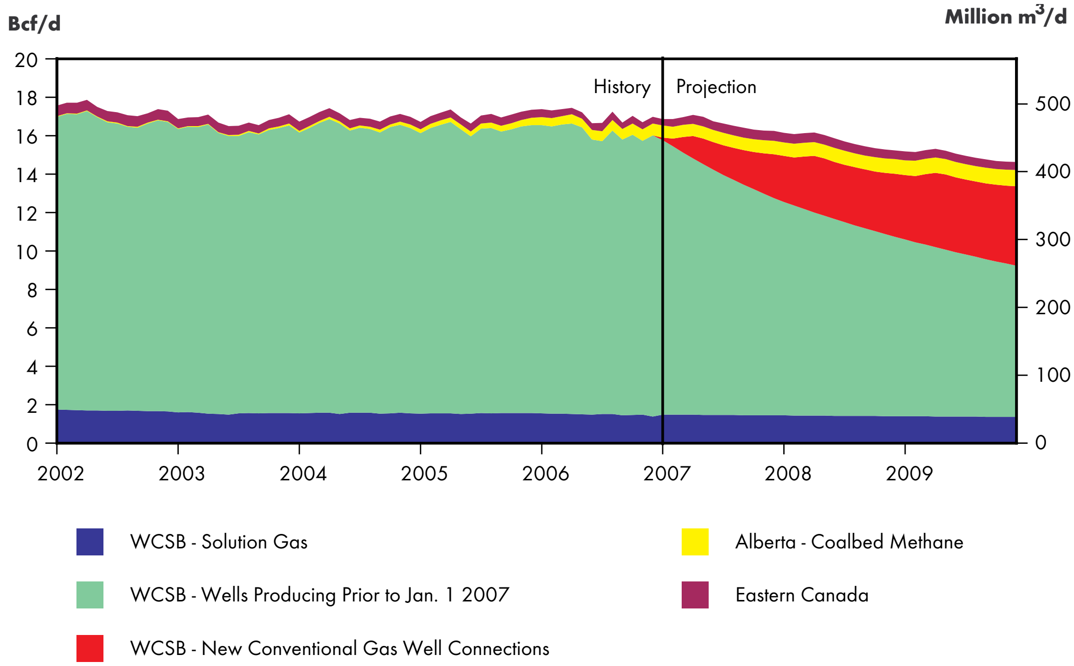


TABLE 6.2

Deliverability Summary for Scenarios

	Historical Production		Deliverability Projections					
			Low Case		Reference Case		High Case	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
2006	483.3	17.06	-	-	-	-	-	-
2007	-	-	468.6	16.54	471.7	16.65	474.9	16.76
2008	-	-	438.5	15.48	446.0	15.74	458.7	16.19
2009	-	-	410.1	14.48	424.0	14.97	448.8	15.84

million m³/d (2.1 Bcf/d). This drop is expected to be 35 million m³/d (1.2 Bcf/d) in the High Case and 73 million m³/d (2.6 Bcf/d) in the Low Case.

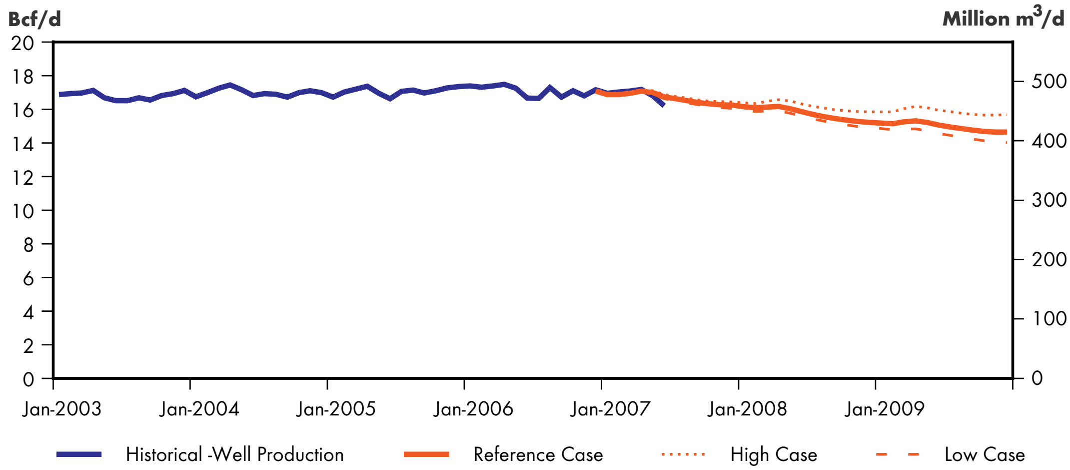
6.5 Key Differences from Previous Projection

Lower gas drilling activity – In the previous report (the 2006 report) drilling activity was established by applying high utilization factors to the available rig fleet. With unfavourable economics for development of new gas supplies in 2007 (as discussed in Chapter 3), drilling activity has been reduced and rig utilization levels are far below the levels anticipated in the 2006 report. In this report, drilling activity is projected on the basis of investment. With expected lower drilling investment levels projected for the coming years, substantially lower gas drilling projections would be expected.

Three scenarios to reflect uncertainty in gas drilling – The 2006 report provided a single projection reflecting the Board's best estimate of future deliverability. A single best estimate deliverability projection is important, but in reality there is a high degree of uncertainty surrounding gas drilling activity (discussed in detail in Chapter 4), and future gas drilling activity is critical in determining

FIGURE 6.5

Outlook for Canadian Gas Deliverability – Scenario Comparisons



future deliverability. In this report, three scenarios of deliverability are provided, with the Reference Case being the most likely scenario in the Board's view.

Decreases in Canadian deliverability – The 2006 report projected that Canadian deliverability would remain roughly flat around 490 million m^3/d (17.3 Bcf/d) for the years 2006 through 2008. In this report, significantly reduced drilling activity is projected for the WCSB, resulting in declining Canadian deliverability in all three scenarios.

6.6 Canadian Deliverability and Canadian Demand

The Board's outlooks for gas deliverability and Canadian gas demand over the projection period are included in Table 6.3 to provide market context for the relative changes in gas deliverability.

Total Canadian annual gas demand is expected to grow from 228 million m^3/d (8.0 Bcf/d) in 2006 to 252 million m^3/d (8.9 Bcf/d) in 2009, with most of the demand increase coming from increased usage for oil sands development in Western Canada. In the Reference Case scenario, gas deliverability is projected to decrease by 59 million m^3/d (2.1 Bcf/d) over the same period.

TABLE 6.3

Average Annual Canadian Deliverability and Demand

	2006		2007		2008		2009	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
Canadian deliverability, Reference Case	483.3	17.06	471.7	16.65	446.0	15.74	424.0	14.97
Western Canada demand	130.2	4.59	132.9	4.69	140.6	4.96	148.2	5.23
Eastern Canada demand	97.8	3.45	99.3	3.51	101.0	3.57	104.1	3.68

CONCLUSIONS

- Western Canada will remain the source for approximately 98 percent of Canadian gas production.
- Atlantic Canada accounts for most of the remaining 2 percent of Canadian gas production, with deliverability expected to rise in the near term before beginning a gradual decline.
- An increasing share of gas drilling activity in Western Canada is being drawn to the deeper western side of the basin.
- Gas drilling activity in Western Canada has fallen dramatically since mid-2006 as gas prices failed to keep pace with rising costs.
- Natural gas finding and development costs, operating costs and royalties had been rising since 2002 in conjunction with increasing activity and higher gas prices.
- In addition to the rising costs for services such as drilling, completing and connecting wells to pipeline systems, costs have also risen due to a decreasing finding rate. The decreasing finding rate is a reflection of the lower initial productivity of new gas wells that decline at roughly the same rates as wells drilled in earlier years.
- With lower utilization, the costs of services have come down in 2007 from the high levels in 2006. Based on industry consultations, the Board estimates that 2007 annual average service sector costs could be 7.5 percent lower than in 2006. A further reduction of service costs is anticipated for 2008 if rig utilization remains low.
- The extent of further cost reductions may be limited as the cost of key inputs (steel, labour and fuel), is likely to remain high.
- With further cost reductions limited and the trend of annual decreases in the finding rate, an increase in gas prices would be needed for a return to stronger gas drilling levels in Western Canada.
- Natural gas prices are established in the North American market and are dependent on such factors as U.S. domestic production, weather driven demand, the amount of gas in storage, and imports of LNG. The variability of these factors makes North American gas prices difficult to predict, and often quite volatile.
- Three scenarios were developed to account for a reasonable range of investment and drilling activity that may occur in Western Canada over the projection period.
- The Board presents the Reference Case as the most likely scenario, based on industry consultations and current market trends.
- Canadian gas deliverability is projected to decline in all three scenarios. In the Reference Case, Canadian gas deliverability is expected to decrease from an annual average of 483 million m^3/d (17.1 Bcf/d) in 2006 to 424 million m^3/d (15.0 Bcf/d) in 2009.
- Canadian gas deliverability in 2009 might range from 410 million m^3/d (14.5 Bcf/d) to 449 million m^3/d (15.8 Bcf/d) at alternative levels of drilling in Western Canada.

GLOSSARY

average connection	An average connection applies to gas connections (either conventional or CBM) and represents the average producing characteristics of all connections 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-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.
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 3 050 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, 2007.
finding rate	The amount of energy developed per effort or investment—for example, GJ per drill day.
future connections	Connections on production after January 1, 2007.
gas connection	A connection for which natural gas production has been reported, and where that production is deemed to be gas (either conventional or CBM). 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 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 greater than 2 Bcf per section as presented in "U2 Figure 27 – Gas Concentration (Bcf/Section) within the Horseshoe Canyon Coal Zone" from the *Natural Gas Potential in Canada 2005- Volume 4*, published by the Canadian Gas Potential Committee, and where formation depth is less than 1,000 m. The Main Horseshoe Canyon main play area is illustrated in Figure 2.3 of this report.
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 1 850 m and less than or equal to 3 050 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 2007 to December 31 2009
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.
shallow rig(s)	Drilling rigs with a depth capacity less than or equal to 1 850 m.
solution gas	Natural gas that is produced from an oil well connection.
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 report.

Available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityCanada2007_2009_e.htm

A. Discussion of Major Costs Associated with Developing New Gas Supplies in the WCSB

B. Methodology Applied and Resulting Parameters

1. METHODOLOGY (DETAILED DESCRIPTION)
2. DELIVERABILITY PARAMETERS – RESULTS
3. Group Performance Parameters for Existing Connections
4. Historical and Projected Average Connection Parameters

C. Drilling Projection Details

1. Factors for Allocation of Gas-Intent Drill Days to Resource Groupings
2. Detailed Drilling and Connection Projections for Scenarios

D. Deliverability Details for High and Low Case Scenarios

1. HIGH CASE SCENARIO
2. LOW CASE SCENARIO