National Energy Board

Office national de l'énergie

Canada's Conventional **Natural Gas** Resources

A **S**tatus **R**eport

gas gas gas gas

An **ENERGY MARKET ASSESSMENT** • April 2004

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ACRONYMS

B.C.	British Columbia
BCMEM	British Columbia Ministry of Energy and Mines
CGPC	Canadian Gas Potential Committee
CNOPB	Canada-Newfoundland Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
EMA	Energy Market Assessment
EUB	Alberta Energy and Utilities Board
GIP	gas in place
GSC	Geological Survey of Canada
NEB, the Board	National Energy Board
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

UNITS

Bcf	= billion cubic feet
Tcf	= trillion cubic feet

FOREWORD

As part of its mandate, under the NEB Act, the National Energy Board (NEB or the Board) continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and natural gas liquids) and the demand for Canadian energy commodities in both domestic and export markets. The Board publishes reports on energy, known as Energy Market Assessments (EMAs), which examine various facets of the Canadian energy market. These reports include both long-term assessments of Canada's supply and demand and specific reports on current and near-term energy market issues.

In addition to its mandate to monitor energy markets in Canada, the Board has a specific monitoring role pursuant to its regulatory responsibilities. The Board is required to monitor Canadian energy markets to ensure that markets are operating such that Canadian energy requirements are being met at fair market prices.

This EMA report examines the geological potential for conventional natural gas resources and presents an estimate of those resources for the country. The main objective of this report is to provide the current status of the NEB estimates and to provide the groundwork for future work through partnerships with other provincial, territorial or federal agencies.

Summary and Conclusions

In its most recent Canadian Energy Supply and Demand report, titled *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (Energy Future)[1], the Board identified the size of the natural gas resource base as a key uncertainty in projecting future natural gas supply. Further, during the public consultations leading up to that report, the Board received suggestions to update its estimates of ultimate potential of conventional natural gas. Considering the importance of ultimate potential in determining Canada's future natural gas availability, the Board is embarking on a program to reassess its estimates.

The primary purpose of this report is to provide the current status of the Board's estimates of conventional natural gas resources in Canada. As well, this report will serve as a starting point for a series of assessments of the ultimate potential of conventional natural gas. The first such assessment is already underway. In partnership with the Alberta Energy and Utilities Board (EUB), the size of Alberta's conventional natural gas resource base is being examined. A second assessment is being considered by the British Columbia Ministry of Energy and Mines (BCMEM) and the Board to examine the ultimate potential for conventional natural gas in British Columbia (B.C.).

The Board has also completed an internal assessment of the ultimate potential of conventional natural gas in Alberta to further verify its findings contained in the Energy Future report and to identify areas for further examination in the joint assessment with the EUB. As such, the Board considers its internal assessment to be an interim estimate until the results of the joint assessment are released in late 2004 or early 2005.

The Board's internal assessment (2004 assessment) has resulted in an estimate of 5 855 10^9m^3 (207 Tcf) for the ultimate potential of conventional natural gas in Alberta. This estimate is slightly higher than the estimate provided by the Canadian Gas Potential Committee (CGPC) in 2001 and is higher than the EUB's last assessment from 1992.

The results of the Board's assessment of Alberta indicate that in spite of the very high drilling activity levels and the exploration success over the 10-year period from 1990 to 2000, the total resource base did not increase substantially. Rather, resources have been converted from the undiscovered category to discovered and produced. The Board's methodology captures the ultimate potential of established plays in Alberta. Should new plays be developed in the future, the resources in those plays would be added to the results of the 2004 assessment.

The Board also notes that the majority of the undiscovered resources in Alberta will be found in the shallower Cretaceous zones, not in the deeper Devonian zones. In addition, the Board examined the impact of restricted access to drilling, such as under cities, national parks and large lakes. The Board

1 The Board published *Canada's Energy Future: Scenarios for Supply and Demand to 2025* in 2003. This report describes two scenarios for the future and the reader is referred to that document for a full explanation of those scenarios. The report is available from the NEB Website at www.neb-one.gc.ca.

found that this restriction does not have a significant impact, as only 71 10^9m^3 (2.5 Tcf), or four percent, of the undiscovered resources are not accessible. However, the impacted volume could increase by another 41 10^9m^3 (1.5 Tcf) if undiscovered sweet gas in the areas around the cities is not developed shortly.

In addition to its recent assessment covering Alberta, the Board also made revisions to its estimate for the Mackenzie Delta-Beaufort Sea region and the East Newfoundland Basin. The remainder of the frontier area estimates are unchanged.

The Board's current estimate for ultimate potential of conventional natural gas in Canada stands at 14 214 10^9m^3 (501 Tcf). This estimate includes the recent internal assessment for Alberta and the revisions to some frontier estimates. Further updates will be provided upon completion of joint assessments with the EUB and the BCMEM-NEB assessment, if it proceeds. As well, the Board will be exploring opportunities to update estimates of ultimate potential of natural gas in other regions in order to better define this key uncertainty regarding future natural gas supplies in Canada. Figure 1.1 shows the distribution of the resources by basin, while Tables 1.1A and 1.1B shows the estimates for each basin in both metric and imperial units.

FIGURE 1.1

Distribution of Canada's Ultimate Potential of Conventional Natural Gas Resources by Region

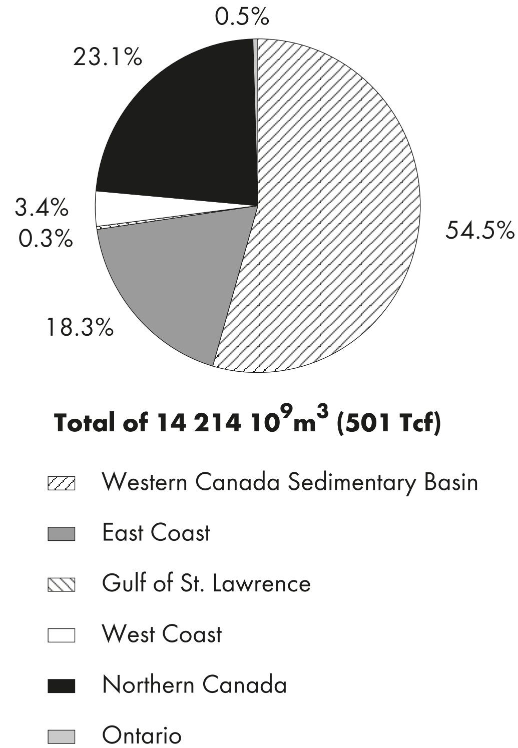


TABLE 1.1A

Current NEB Estimates of Ultimate Potential for Conventional Marketable Natural Gas in Canada (10^9m^3)

	Discovered Resources	Undiscovered Resources	Ultimate Potential[1]
Western Canada Sedimentary Basin			
Alberta	4 125	1 730	5 855
British Columbia	663	773	1 436
Saskatchewan	213	42	255
Southern Territories	27	169	196
Total	**5 028**	**2 714**	**7 742**
East Coast (Offshore)			
Labrador	130	660	790
East Newfoundland Basin	0	352	352
Grand Banks	110	375	485
Southern Grand Banks	0	86	86
Laurentian Sub-Basin	0	170	170
Nova Scotia	147	505	652
George's Bank	0	60	60
Total	**387**	**2 208**	**2 595**
West Coast			
Offshore	0	255	255
Intermontane	0	230	230
Total	**0**	**485**	**485**
Northern Canada			
Northwest Territories - Colville Hills	17	117	134
Mackenzie-Beaufort	254	1 460	1 714
Yukon - Eagle Plains	2	28	30
Yukon - Others	1	114	115
Arctic Islands	331	793	1 124
Eastern Arctic	0	140	140
Hudson Bay	0	28	28
Total	**605**	**2 680**	**3 285**
Ontario	**44**	**23**	**67**
Gulf of St. Lawrence (Maritimes Basin)	**2**	**38**	**40**
TOTAL CANADA[1]	**6 066**	**8 148**	**14 214**

1. Numbers may not add due to rounding.

TABLE 1.1B

Current NEB Estimates of Ultimate Potential for Conventional Marketable Natural Gas in Canada (Tcf)

	Discovered Resources	Undiscovered Resources	Ultimate Potential[1]
Western Canada Sedimentary Basin			
Alberta	146	61	207
British Columbia	23	27	51
Saskatchewan	8	1	9
Southern Territories	1	6	7
Total	**178**	**96**	**274**
East Coast (Offshore)			
Labrador	5	23	28
East Newfoundland Basin	0	12	12
Grand Banks	4	13	17
Southern Grand Banks	0	3	3
Laurentian Sub-Basin	0	6	6
Nova Scotia	5	18	23
George's Bank	0	2	2
Total	**14**	**77**	**91**
West Coast			
Offshore	0	9	9
Intermontane	0	8	8
Total	**0**	**17**	**17**
Northern Canada			
Northwest Territories - Colville Hills	1	4	5
Mackenzie-Beaufort	9	52	61
Yukon - Eagle Plains	0	1	1
Yukon - Others	0	3	3
Arctic Islands	12	28	40
Eastern Arctic	0	5	5
Hudson Bay	0	1	1
Total	**22**	**94**	**116**
Ontario	**1**	**1**	**2**
Gulf of St. Lawrence (Maritimes Basin)	**0**	**1**	**1**
TOTAL CANADA[1]	**215**	**286**	**501**

1. Numbers may not add due to rounding.

Introduction

In its Energy Future report, the NEB provided estimates of the ultimate potential of conventional natural gas resources for sedimentary basins in Canada. In that report, the Board utilized two different estimates of the resource base for the Western Canada Sedimentary Basin (WCSB). The first resource base was that published by the CGPC in 2001. The second and higher resource base utilized the NEB's own assessment for the B.C. portion of the basin and included additional resources in the Alberta portion of the basin. In both scenarios, the Board relied on one set of estimates, based on work done by the Geological Survey of Canada (GSC), for the basins outside of the WCSB.

During the Board's consultation process for the Energy Future report, several parties suggested that the Board should update its estimates of ultimate potential. As a result, the NEB plans to examine the ultimate potential of gas resources in Canada over the next number of years. To the extent possible, these studies are planned to be done through partnerships with provincial, territorial or other federal agencies.

The first study will be an examination of the Alberta portion of the WCSB, to be completed with the EUB. That work has been underway for about two years, and is expected to be completed and released as a joint report in late 2004 or early in 2005. In this EMA, the NEB utilizes its own interim assessment for Alberta. The second study could be an assessment of the B.C. portion of the WCSB, to be done in conjunction with the BCMEM. Decisions on the reassessment of other areas of Canada will be made at a future date.

The primary purpose of this EMA is to provide the current status of estimates of ultimate potential of conventional natural gas in Canada; secondly, this EMA will serve as the starting point for the reassessments indicated above. This EMA provides the NEB's current estimates of ultimate potential of conventional natural gas for each area, observations of current drilling activity in each area and, finally, discusses possible impacts of that activity on the ultimate potential of conventional natural gas in that area. Since this EMA discusses the current NEB estimates, there is only one estimate provided for the WCSB, not two, as were provided for the two different scenarios considered in the Energy Future report. Further, this estimate is almost exclusively the NEB's own assessment. This EMA does not address additional resources that could be found in unconventional sources of gas such as coalbed methane, tight gas sands, gas hydrates, or shale gas.

BACKGROUND

3.1 Terminology

The term *ultimate potential* refers to an estimate of the volume of resources that will be proven to exist in a geological basin, or in a specific area, after exploration has ceased. At any point in time, ultimate potential is the sum of resources that have been *discovered* and resources that are still *undiscovered*. Discovered resources have been confirmed by wells already drilled, while undiscovered resources are expected to be found by future drilling. The ratio between discovered and undiscovered resources provides a measure of the basin or area's maturity. More mature areas have a smaller portion of undiscovered resources compared with discovered while less mature areas have a smaller portion of discovered resources compared with undiscovered.

Discovered resources include currently economic volumes (called reserves), currently non-economic volumes and volumes already produced (called cumulative production). Reserves, by definition, refer to the volume that remains to be produced at a given point in time. The term *remaining resources* is used to describe the volume that could be produced in the future and includes the reserves, non-economic volumes and undiscovered resources.

Many estimates of ultimate potential are a calculation of the volume of gas in the ground, expressed as *gas in place* (GIP). Some estimators report the volume that can be produced, expressed as *recoverable gas*. Further, some estimators report the *marketable gas* volume or the volumes that remain after processing. In this report, only marketable volumes are given.

Since estimates of ultimate potential refer to a volume of gas to be discovered in the future, the estimates always have some degree of uncertainty associated with them. The amount of uncertainty varies for each component of the estimate. *Undiscovered resources* have the highest amount of uncertainty, since there is no specific information known about them. The level of uncertainty for *discovered resources* is medium, for reserves, it is minimal, and finally, there is no uncertainty for the volume of cumulative production.

The uncertainty around the undiscovered resources portion also varies according to the maturity of the area being examined. In mature areas where abundant information is available, estimators can usually establish the undiscovered portion with more accuracy. However, in less mature areas the uncertainty is much higher and the range of estimates tends to be larger. Some estimators only provide their best estimate, or mean value, whereas others provide a full range of estimates. In this report, the NEB provides the mean values of its estimates. Figure 3.1 is a schematic representation of the terminology used in discussing ultimate potential.

FIGURE 3.1

Schematic Representation of Ultimate Potential Terminology

Terminology		**Relative Level of Uncertainty**
Ultimate Potential	**Undiscovered Resources**	**High**
	Discovered Resources	**Medium**
	Reserves	
	Cumulative Production	**None**

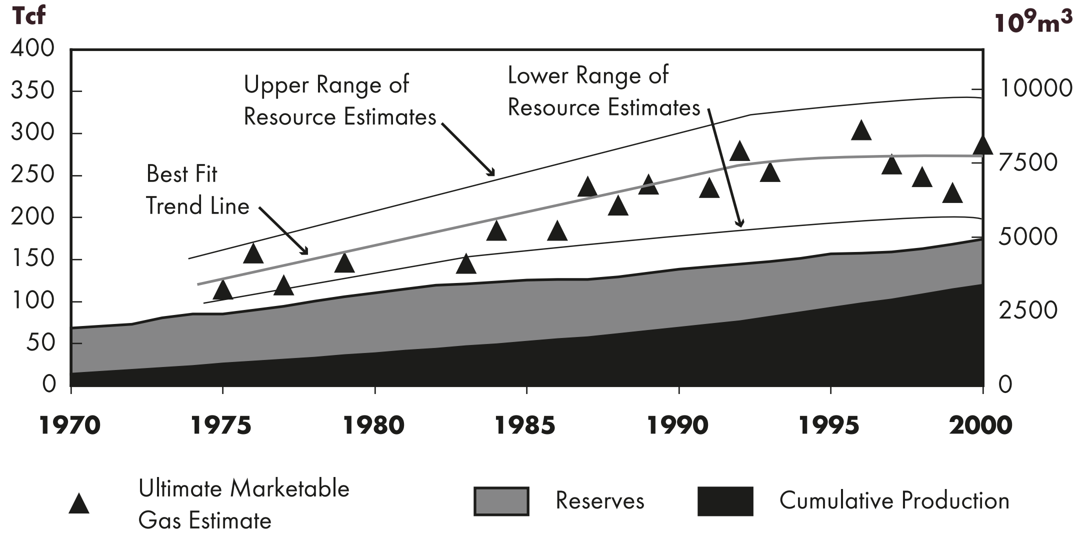
3.2 Evolution of Estimates

Estimates of ultimate potential of conventional natural gas and the range of those estimates change over time as more becomes known about the geology of the basin and as technology develops. For example, improved seismic processing has allowed industry to better locate reef edges – the Ladyfern discovery in B.C. added a very large pool to a play that had previously been estimated to have a much smaller undiscovered resource. Over time, the rate of growth of the estimates is expected to flatten as the size of the discovered resources approaches the ultimate potential of the basin.

Figure 3.2 shows the changes in estimates for the WCSB over the past 30 years. This figure also compares estimates of ultimate potential with the cumulative production and reserves. A close examination of the latest data suggests that the rate of growth has slowed. This emerging trend may be a signal that the WCSB is becoming mature. If so, while there may yet be new geological plays discovered, the size of the overall resource base is expected to remain near current estimates.

FIGURE 3.2

Changes in Estimates of Marketable Gas Ultimate Potential for WCSB



Regional Overview

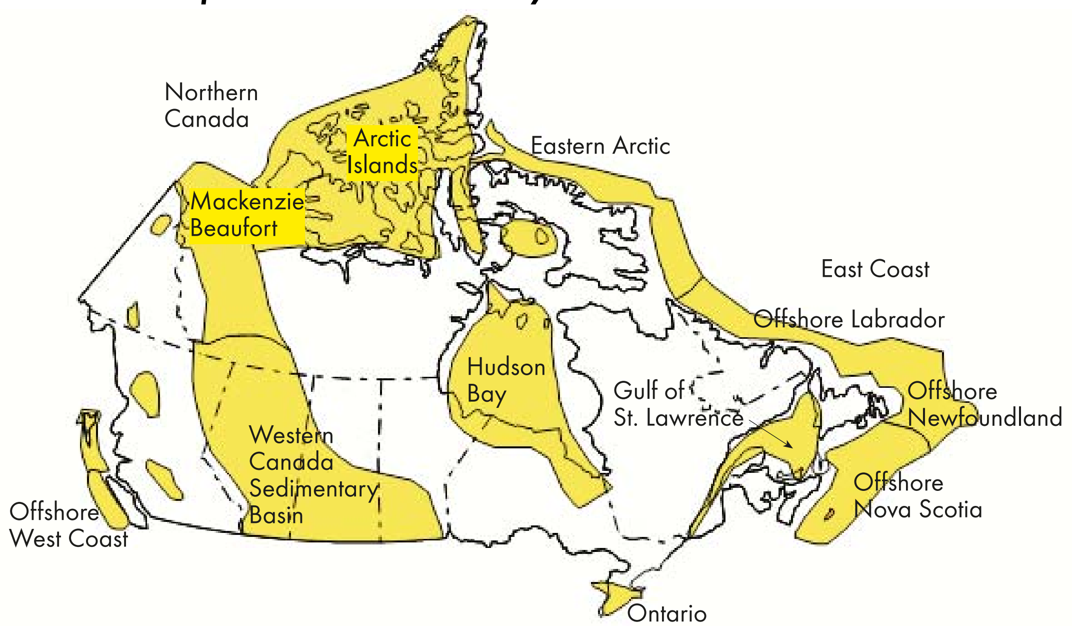
This chapter discusses each sedimentary basin in Canada where there are estimates of ultimate potential of conventional natural gas available, provides the NEB estimates, discusses recent upstream activity taking place and makes some general observations on how that activity may impact the estimates of ultimate potential in the future. When applicable, there is also an indication given as to the status of any updates for the estimate of ultimate potential of conventional natural gas, either by a government body, the NEB (in partnership with the provincial or territorial regulatory agency), or by another source. Note that this EMA only discusses estimates of ultimate potential of conventional gas, which for the remainder of the report will be referred to as ultimate potential. There is no assessment of any unconventional gas types in this report. Figure 4.1 shows the locations of the sedimentary basins in Canada.

4.1 Western Canada Sedimentary Basin

The WCSB covers most of Alberta, about one-third of Saskatchewan, and smaller portions of British Columbia, Yukon, the Northwest Territories and Manitoba. The WCSB is the major hydrocarbon basin in Canada and one of the most important in North America in terms of gas production. It accounts for more than 90 percent of the gas production in Canada and for about 23 percent of

FIGURE 4.1

Generalized Map of Canadian Sedimentary Basins



North American natural gas production annually. In the last few years, gas production from the WCSB appears to have flattened after many years of growth, leading to increased uncertainty about the ability of industry to increase or maintain current production levels from the basin over the longer term.

The ultimate potential of the WCSB has been assessed many times in the past, as shown in Chapter Three. The most recent estimates have been conducted by Sproule Associates, on behalf of TransCanada Pipelines, Bowers (an independent petroleum consultant), the CGPC, and the GSC. Table 4.1 shows the dates and sizes of recent estimates of ultimate potential of the WCSB, to allow for comparison between estimates.

4.1.1 Alberta

In Alberta, oil and gas are found in rocks of many different age groups and sediment types, ranging from small continental-type sand deposits through widespread marine sheet sands to the deeper and older reefs and broad carbonate banks. The WCSB is centered over Alberta, with most of the deepest parts of the basin in western Alberta. Alberta can be sub-divided into regions with similar geographic and geological characteristics. Broadly, there are plains-type regions, which tend to be shallower and less structurally complex and the foothills-type regions, which tend to be deeper and more structurally complex. Recent estimates of marketable ultimate potential in Alberta range from 5 600 10^9m^3 (200 Tcf) as estimated by the EUB in 1992 to 5 761 10^9m^3 (203 Tcf) as estimated by the CGPC[2] in 2001. The NEB and EUB are currently conducting a joint assessment of the Alberta portion of the WCSB and expect to complete and publish their estimate late in 2004 or early in 2005.

TABLE 4.1A

Comparison of Recent Estimates of Ultimate Potential of the WCSB, in Total and for Individual Provinces (10^9m^3)

Marketable Gas					
Evaluator and Date	**British Columbia**	**Alberta**	**Saskatchewan**	**NWT/YT**	**WCSB Total**
GSC 1995[1]					7 903
CGPC 1997[2]	1 045	5 949	252	74	7 450
Sproule 1998					9 320
Bowers 2000	1 020	5 127	255	113	6 515
CGPC 2001	969	5 761	258	62	7 054
CERI 2002	1 465	6 238	241	201	8 144
NEB - total[3]	**1 436**	**5 855**	**211 (228)[4]**	**193**	**7 712**

1. based on discovered GIP of 6 374 at year-end 1990 and undiscovered of 6 575, converted to marketable gas by NEB
2. approximate values only, for provincial breakdown
3. compilation of NEB ultimate potential estimates from 1996 to 2004
4. estimate was for non-associated gas only (total with discovered solution and associated gas)

2 The CGPC uses the term Nominal Marketable Gas when it provides a marketable gas estimate. The nominal portion of the term is used to indicate that the estimate does not take into account restricted access issues, economics of developing all pools, not all pools will be found, undiscovered pools may not have the same characteristics as discovered pools and that production and transportation may not be available for the development of all pools. In this report, the CGPC estimates will be called marketable gas.

In the interim, the NEB undertook its own assessment to further verify some of its assumptions in its 2003 Energy Future report. A description of the methodology used, and a discussion of the NEB results can be found in the technical appendices to this EMA, available on the NEB website (www.neb-one.gc.ca).

In its 2004 assessment, the NEB used a different statistical approach than that employed by the CGPC. The NEB methodology uses a combination of geological and statistical analysis applied to the land, drilling and reserves data. The CGPC used a Petroleum Resources Information Management and Evaluation System analysis on reserves data. Year-end 2000 data was the most up-to-date available when the study began and forms the basis for the 2004 assessment. Subsequently, there has been an additional three years of very high drilling activity in the WCSB and Alberta. The results of that additional drilling information have not been included in the NEB assessment. However, that activity will be examined in the context of the joint assessment. The results of the NEB's assessment of the Alberta ultimate potential are shown in Table 4.2.

Additional Observations

In spite of significant drilling activity over the 10 years between 1990 and 2000 (the dates of data used to generate both the EUB's and NEB's estimates), there has been only a marginal increase in the estimate of ultimate potential of the province. The larger impact of that drilling has been a change in the ratio of undiscovered to discovered gas. For example, in 1992, the proportion of undiscovered was 39 percent, while in the 2004 assessment it is 30 percent, indicative of a maturing basin with limited opportunity for significant additional growth in the ultimate potential. In examining access issues, the NEB determined that 71 10^9m^3 (2.5 Tcf) of remaining marketable gas resources should be considered as non-accessible[3], leaving 2 579 10^9m^3 (91 Tcf) at year-end 2002, to satisfy Canadian domestic and export demand currently met from Alberta.

TABLE 4.1B

Comparison of Recent Estimates of Ultimate Potential of the WCSB, in Total and for Individual Provinces (Tcf)

	Marketable Gas				
Evaluator and Date	**British Columbia**	**Alberta**	**Saskatchewan**	**NWT/YT**	**WCSB Total**
GSC 1995 [1]					279
CGPC 1997 [2]	36.9	210	8.9	2.6	263
Sproule 1998					329
Bowers 2000	36	181	9	4	230
CGPC 2001	34.2	203.4	9.1	2.2	249
CERI 2002	51.7	220.2	8.5	7.1	287.5
NEB - total[3]	**50.7**	**207**	**7.4 (8)[4]**	**6.8**	**273**

1. based on discovered GIP of 225 at year-end 1990 and undiscovered of 257.2, converted to marketable gas by NEB
2. approximate values only, for provincial breakdown
3. compilation of NEB ultimate potential estimates from 1996 to 2004
4. estimate was for non-associated gas only (total with discovered solution and associated gas)

3 Land that industry cannot drill on for environmental and other reasons. See Section 4.6 of Technical Appendix.

TABLE 4.2

Results of NEB 2004 Alberta Assessment

	Gas Volume 10^9m^3 (Tcf)		
	Discovered	**Undiscovered**	**Ultimate Potential**
Gas In Place	7 126 (252)	2 826 (100)	9 952 (351)
Recoverable	5 002 (177)	1 999 (71)	7 001 (247)
Marketable	4 125 (146)	1 730 (61)	5 855 (207)
Remaining Marketable[1]	920 (32)	1 730 (61)	2 650 (94)

1. Cumulative production to year-end 2002 is removed from the marketable volume.

The 2004 assessment only considered conventional natural gas resources in Alberta and did not consider additional volumes that may be available from different types of unconventional sources in Alberta. These unconventional sources include coalbed methane, shale gas, and gas resources contained in tight sands which do not have currently recognized resources. Timing and the amount of gas production from those sources remains unclear, although it should be noted that commercial production of coalbed methane has recently started in Alberta.

With the majority of the undiscovered resources expected to be found in numerous small pools contained in Cretaceous zones, it will be necessary for industry to drill an increasing number of wells to maintain production, or to lessen the decline of overall deliverability from Alberta sources. Since it is expected that wells will find continually smaller pools, exploitation of these smaller pools may result in a trend towards higher supply costs in the future. However, these costs may be offset to some extent by new technology. Drilling and completion costs have been kept relatively low by technological improvements made in many areas between 1990 and 2000. Technology gains of the past have allowed for the development of many new pools that would not have been economic previously. However, with the increased activity over the past year, there are signs that overall costs may be increasing.

The Board's methodology captures the resources found and expected to be found in plays that have been established to date. Should new plays develop in the future, the resources in those new plays would be added to the ultimate potential estimate provided in the 2004 assessment.

4.1.2 British Columbia

Northeastern British Columbia contains the northwestern part of the WCSB and has both oil and gas discovered in many of the same sediment types as Alberta. There are two distinct settings of geography and geology; one is the shallower, less structurally complex plains region and, the other is in the structurally complex and deeper foothills region. The NEB's 2000 estimate of ultimate potential in British Columbia is 1 436 10^9m^3 (51 Tcf). The NEB and BCMEM are considering a joint assessment of the B.C. portion of the WCSB with a target to complete and publish their estimate in 2005. As of year-end 2002, 435 10^9m^3 (15 Tcf) of gas has been produced from B.C., leaving reserves and undiscovered resources of 1 001 10^9m^3 (35 Tcf).

Over the past few years, there has been a large increase in the number of wells drilled annually in British Columbia. The B.C. portion of the WCSB is considered to be somewhat less developed than the Alberta portion; hence, there may be opportunities to find larger pools both in the plains region and in the foothills. For example, the recent Ladyfern discovery in a Slave Point reef was estimated to contain as much as 28 10^9m^3 (1 Tcf) and that discovery was made after the NEB assessment was completed. Industry has also reported the discovery of gas in Mississippian and Devonian aged rocks in areas where previous assessments did not project significant volumes of undiscovered resources. These developments could have a significant impact on the total ultimate potential of B.C.

4.1.3 Saskatchewan

Saskatchewan covers most of the eastern part of the WCSB and oil and gas discoveries are mainly found in sandstone deposits. In southeastern Saskatchewan, there is a second basin called the Williston Basin (still considered to be part of the WCSB, Figure 4.1) where oil is found in tidal carbonate deposits, small carbonate reefs, and small sand deposits. The CGPC estimated the ultimate potential in Saskatchewan to be 257 10^9m^3 (9 Tcf) in 2001 and the NEB currently utilizes this estimate. The NEB, in 1998, estimated 211 10^9m^3 (7 Tcf) for non-associated gas only; adding discovered solution and associated volumes would add an additional 16.9 10^9m^3 (0.6 Tcf) to the NEB total. While there are no current plans for a new assessment of Saskatchewan gas resources by the NEB, new activity and new discoveries could indicate a need for an updated assessment. As of year-end 2002, 221 10^9m^3 (7.8 Tcf) of the marketable ultimate potential had been discovered, of which 144 10^9m^3 (5 Tcf) of gas has been produced, leaving reserves and undiscovered resources of 113 10^9m^3 (4 Tcf).

Drilling activity has increased in recent years, with the majority still directed toward oil development. The recent discovery of shallow gas in the Shackleton area, east of the existing Hatton Field complex, has added new reserves and extended the area of the Milk River gas zone. As in Alberta, the gas resources in that zone and the Medicine Hat zone have been underestimated in the past.

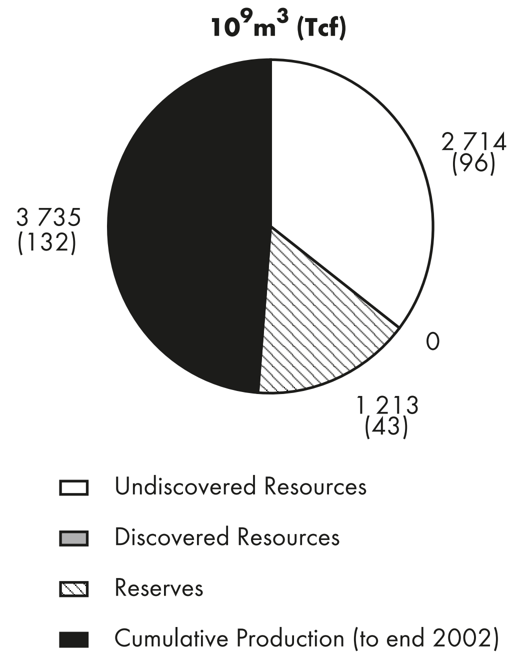
4.1.4 Manitoba

Manitoba contains the northeastern part of the Williston Basin and contains oil in tidal carbonate complexes. At this time, there are no recognized gas pools in Manitoba, although solution gas has been flared from its oil pools. There has been some speculation that the Cretaceous sediments could hold potential for undiscovered gas resources as evidenced by shallow gas wells that have been drilled to supply local farm needs.

However, the total volume of that undiscovered gas is likely to be small, less than 28 10^9m^3 (1 Tcf). Figure 4.2 shows categories of the WCSB resources.

FIGURE 4.2

Categories of WCSB Resources

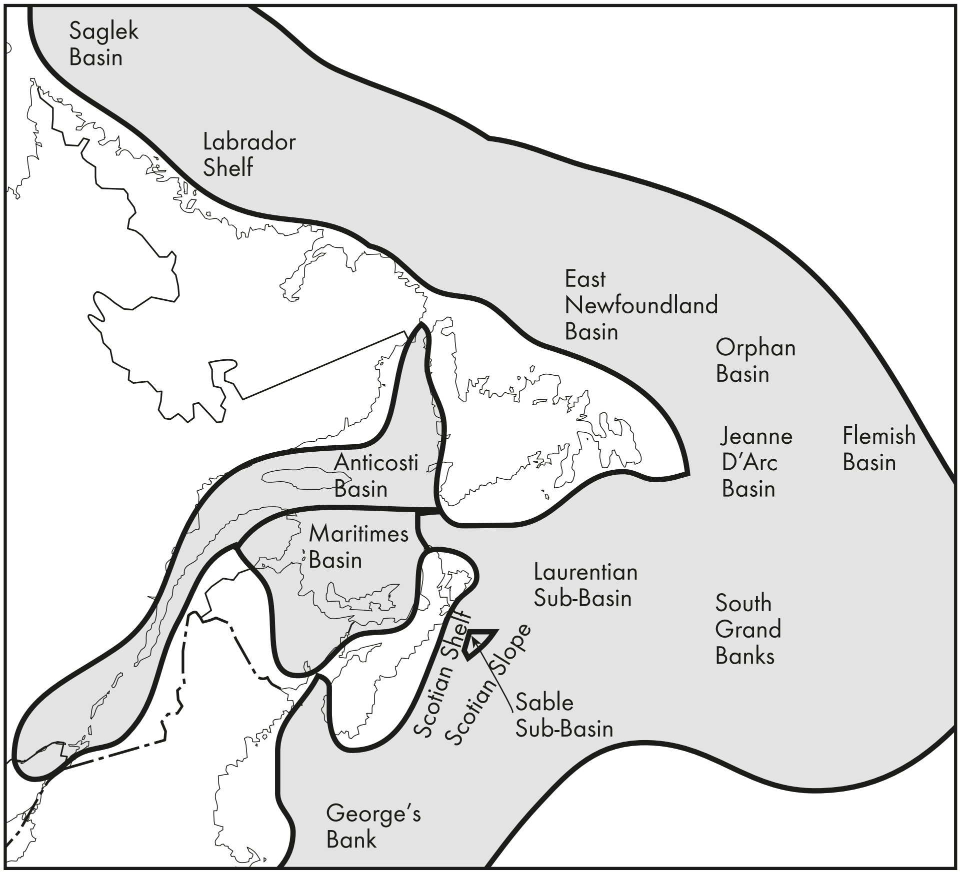


4.2 East Coast

There are three major offshore regions in eastern Canada that have significant natural gas discoveries and have potential for more discoveries: offshore Labrador, offshore Newfoundland (Grand Banks), and offshore Nova Scotia. Some of the major regions have minor areas which are also discussed. Figure 4.3 shows a regional map of the East Coast areas, while Figure 4.4 shows the categories of the resources.

F I G U R E 4 . 3

East Coast Regional Map



4.2.1 Labrador

The Labrador Shelf is located offshore of Labrador and for this report includes the Saglek Basin portion of the Eastern Arctic, which extends northward from Labrador to offshore Baffin Island (Figure 4.3). To date, marketable gas resources of 130 $10^9 m^3$ (4.6 Tcf) have been discovered in six significant discovery areas. These discoveries were made between 1973 and 1980 and are all remote from any transportation options for the gas. There has been no activity for the past decade, with the exception of speculative seismic programs (done by seismic companies for sale to industry).

4.2.2 Grand Banks

The Jeanne d'Arc Basin located on the Grand Banks of Newfoundland has discovered marketable gas resources of 110 $10^9 m^3$ (3.9 Tcf) (Figure 4.3). However, the majority of discoveries in this basin have been oil and the majority of discovered gas is associated and solution gas. Two of the larger accumulations, Hibernia and Terra Nova, are now producing oil. A third oil accumulation, White Rose, is nearing its production start-up date. The associated and solution gas in these fields will be required to maintain the reservoir pressure in the fields in order to maximize oil recovery. As a result, this gas will not be available for production for most of the next decade.

The NEB utilizes 1 275 $10^9 m^3$ (45 Tcf) for the Grand Banks and Labrador regions combined, based on estimates provided by the GSC and Canada Newfoundland Offshore Petroleum Board (CNOPB).

The CNOPB is generating a new estimate for the Flemish Pass area, and this is expected to be released in 2004.

4.2.3 East Newfoundland Basin

The East Newfoundland Basin is located between the Grand Banks and the Labrador Shelf, and has seen only limited activity in the past (Figure 4.3). The NEB estimated the marketable gas resources to be 352 10^9m^3 (12 Tcf), based on estimates provided by the GSC in 1983. In a recent land sale, large blocks of land in the Orphan area were released and it is expected that exploration will commence in 2004 with seismic. Drilling of new geological structures may still be some time in the future. No activity is expected in the western portion of this basin in the near future.

4.2.4 Southern Grand Banks

In the Southern Grand Banks, there are a number of small sub-basins that have been explored in the past without finding commercial volumes of oil or gas (Figure 4.3). The NEB estimated the marketable ultimate potential to be 86 10^9m^3 (3 Tcf), based on estimates provided by the GSC in 1983. Activity has been limited in these basins for some time; however, Husky has proposed drilling a well in 2004.

4.2.5 Laurentian Sub-Basin

This area lies to the east of Cape Breton Island, between the Nova Scotia offshore sub-basins and the Southern Grand Banks offshore sub-basins (Figure 4.3). The NEB estimates the marketable ultimate potential for this area to be 170 10^9m^3 (6 Tcf), based on a 1992 GSC estimate. Upstream industry activity has been slowed pending resolution of the border issue between Newfoundland and Nova Scotia. This matter was recently settled in the courts, but negotiations between the federal and provincial governments and industry over pre-existing permits is still required. There was one unsuccessful well drilled recently in the French waters south of the islands of St. Pierre and Miquelon.

4.2.6 Nova Scotia Offshore

Out of the three East Coast regions, offshore Nova Scotia is the only area to have commercial natural gas production (Figure 4.3). The still relatively unexplored Scotian Shelf and Slope are viewed to have potential for new discoveries. The results from drilling programs taking place in the upcoming years will be critical in indicating the potential level of production from the basin.

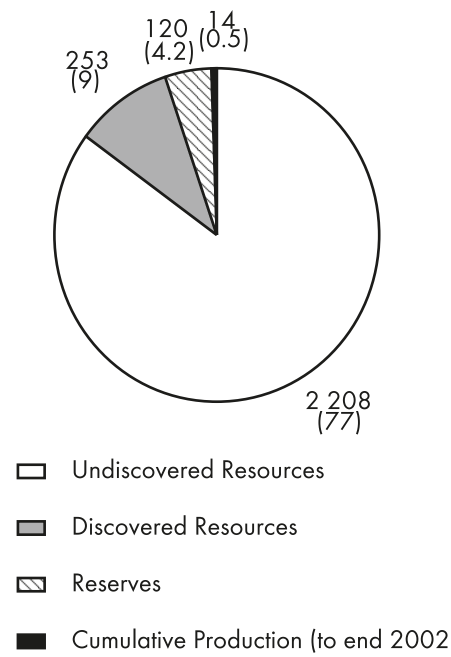
Scotian Shelf/Scotian Slope:

The estimates of discovered marketable gas resources range from 102 to 147 10^9m^3 (3.6 to 5.2 Tcf) in the Sable sub-basin. The NEB recognizes that the lack of recent exploration success in the shallow water plays warrants the use of a reduced estimate of ultimate

FIGURE 4.4

Categories of East Coast Resources

10^9m^3 (Tcf)



potential. As such, the current NEB ultimate potential estimate consists of 248 10^9m^3 (8.8 Tcf) of marketable gas in the shallow water and 404 10^9m^3 (14 Tcf) for the deep water plays, for a total of 652 10^9m^3 (23 Tcf). The NEB estimate is based on estimates provided by the GSC and the Canada Nova Scotia Offshore Petroleum Board (CNSOPB). At year-end 2002, 13.7 10^9m^3 (0.5 Tcf) of marketable gas had been produced from the Sable project.

Activity in the Sable Sub-Basin on the Scotian Shelf is being conducted by EnCana and Canadian Superior. Canadian Superior is pursuing two shallow water prospects, the Marquis and Mariner wells, just northwest and northeast of Sable Island. In January 2004, Mariner was showing significant gas during drilling. The Mariner block has a resource potential of 34 10^9m^3 (1.2 Tcf) of natural gas. EnCana is drilling a deep water prospect at Weymouth.

Deep Panuke:

The Deep Panuke gas field is located on the Scotian shelf, 45 kilometers southwest of the Sable Offshore Energy Project and 175 kilometers southeast of Goldboro, Nova Scotia. EnCana discovered this gas field in the late 1990s and estimates the discovered resources to be 28 10^9m^3 (1 Tcf). Encana estimates the undiscovered resources to be in the range of 85 to 255 10^9m^3 (3 to 9 Tcf) for the entire Baccaro Reef play. Two other reportedly successful wells have now been drilled and these could boost confidence in the economic potential of the Deep Panuke discovery. The first was the Margaree well drilled in July 2003. The second well is MarCoh, which was spudded in August 2003 but is currently suspended.

4.2.7 George's Bank

The George's Bank is located south of Nova Scotia, with a divided jurisdiction between Canada and the United States (Figure 4.3). This area is under a moratorium on activity, which was recently extended to 2012. The NEB estimates the Canadian portion to have a marketable ultimate potential of 60 10^9m^3 (2 Tcf), based on estimates provided by the GSC in 1983.

4.3 West Coast

4.3.1 Offshore

There are five basins located offshore of British Columbia: the Georgia, Queen Charlotte, Hecate, Winona, and Tofino Basins, and these are shown in Figure 4.5. These basins have been lightly explored in the past without finding commercial volumes of oil or gas. In its Energy Future report, the NEB assigned the marketable ultimate potential as 255 10^9m^3 (9 Tcf), based on estimates provided by the CGPC in 2001.

There were 28 wells drilled into the Hecate, Queen Charlotte and Tofino Basins between 1913 and 1984. These wells confirmed the presence of reservoir rocks, source rock material and potential seals in the basins. Seismic data confirms the presence of potential trapping configurations. One hundred and twenty-two onshore wells have been drilled into the various sub-basins of the Georgia Basin (located between Comox on Vancouver Island and Bellingham, Washington) in Canada and the United States, many of which encountered shows of both oil and gas in rocks of Tertiary to Cretaceous age.

In 1972, the Canadian federal government declared an indefinite moratorium on offshore oil and gas activities due to environmental concerns. This was extended after the Exxon Valdez oil spill in 1989.

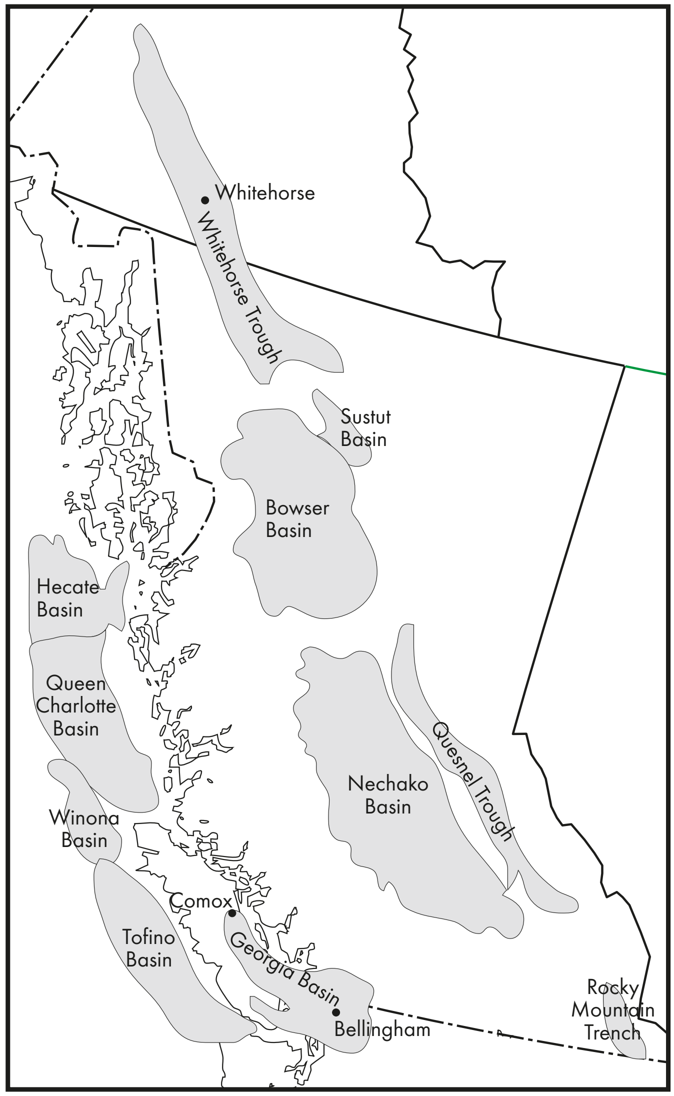
In 2003, the Minister of Natural Resources Canada announced that Canada will proceed with a review of the federal moratorium for the Queen Charlotte Area.

4.3.2 B.C. Intermontane Basins

There is a series of sedimentary basins in the central part of B.C., stretching from the Rocky Mountain Trench in southeastern B.C., through the Quesnel Trough and Nechako Basins, the Bowser/Sustut Basins and finally the Whitehorse Trough in northwestern B.C. and the Yukon Territory (Figure 4.5). The GSC conducted informal assessments of these basins for the B.C. Government in 1992, 1993 and 1994. A new assessment is in progress for the Bowser Basin. The current NEB marketable ultimate potential estimate for these basins, including the B.C. portion of the Whitehorse Trough, is 230 10^9m^3 (8 Tcf).

FIGURE 4.5

West Coast Regional Map



There were two wells drilled in the Bowser/Sustut Basins, in 1969 and 1973. One well had a gas show in a fractured shale zone. There have been 12 wells drilled in the Nechako Basin/Quesnel Trough between 1930 and the early 1980s. A total of 100 oil and gas shows were documented in the Cretaceous sections of these wells. Approximately 25 wells have been drilled in the Rocky Mountain Trench, mainly on the U.S. side of the international border, with a total of six gas shows reported. No wells have been drilled in the Whitehorse Trough. Figure 4.6 shows the categories of resources on the West Coast.

4.4 Northern Canada

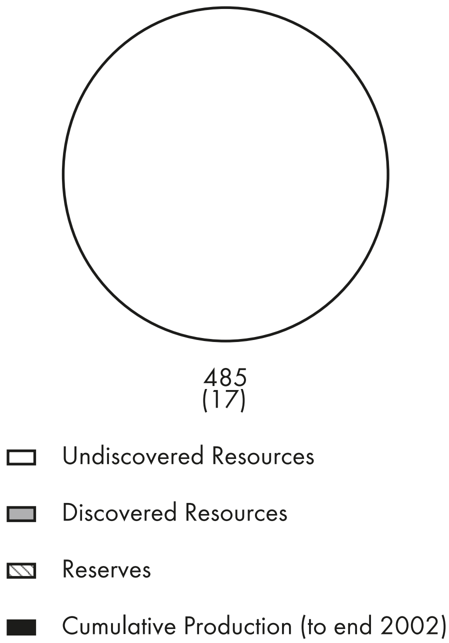
4.4.1 Northwest Territories

In the southern region of the Northwest Territories, gas plays exist just north of the 60th parallel in the northern limit of the WCSB. The Liard Plateau and the Great Bear Plain contain Devonian to Cretaceous age sediments having gas potential. All of the northern Canada basins are shown on Figure 4.7. Marketable ultimate potential for the WCSB extension is estimated by the NEB to be 132 10^9m^3 (4.7 Tcf) with only 1.8 10^9m^3 (70 Bcf) discovered to date. Gas is being produced in the Fort

FIGURE 4.6

Categories of West Coast Resources

10^9m^3 (Tcf)



Liard area and by year-end 2002, 9 10^9m^3 (0.3 Tcf) of marketable gas had been produced. Current activity is in two areas: Cameron Hills and Liard. In Cameron Hills, four wells have been approved for drilling this winter and in Liard, three wells have been approved for drilling.

Further north, in the Coleville Hills, a Cambrian sandstone play has been identified. The CGPC estimated 17 10^9m^3 (619 Bcf) of marketable discovered resources and 117 10^9m^3 (4.1 Tcf) of marketable undiscovered resources for this area. Seven wells have been approved for drilling and two others approved for work-over, in the winter of 2003-2004.

In addition, there is a series of carbonate plays along the Mackenzie River Valley, highlighted by the oil discovery at Norman Wells made in the 1920s. To date, no additional discoveries have been made. It is expected that industry will become more active in the valley as the planning and regulatory process for a Mackenzie Valley pipeline project continues.

4.4.2 Mackenzie Delta – Beaufort Sea

The Mackenzie Delta and Beaufort Sea region has a marketable ultimate potential of 1 714 10^9m^3 (61 Tcf), based on a GSC estimate from 1988 (Figure 4.7). Of this total, the NEB estimates the marketable discovered resources in the Mackenzie Delta to be 140 10^9m^3 (4.9 Tcf), with an additional 114 10^9m^3 (4.1 Tcf) discovered in the Beaufort Sea.

Gas production is currently limited to the Ikhil Field, which supplies gas to Inuvik, some 50 kilometres away. There has been a limited amount of drilling activity over the past year with some indications of gas success. Two wells are approved for drilling this winter on the Delta.

4.4.3 Yukon

The Yukon includes eight gas potential areas. Only the Liard Plateau, in the south, currently produces commercial volumes of gas (Figure 4.7). Marketable discovered gas resources in Liard (part of the WCSB extension), are estimated by the NEB to be 5.2 10^9m^3 (148 Bcf) with undiscovered resources of 56 10^9m^3 (2.0 Tcf). At year-end 2002, 4 10^9m^3 (0.2 Tcf) of marketable gas has been produced. Evaluation of recent drilling activity is expected to result in some revision to these estimates.

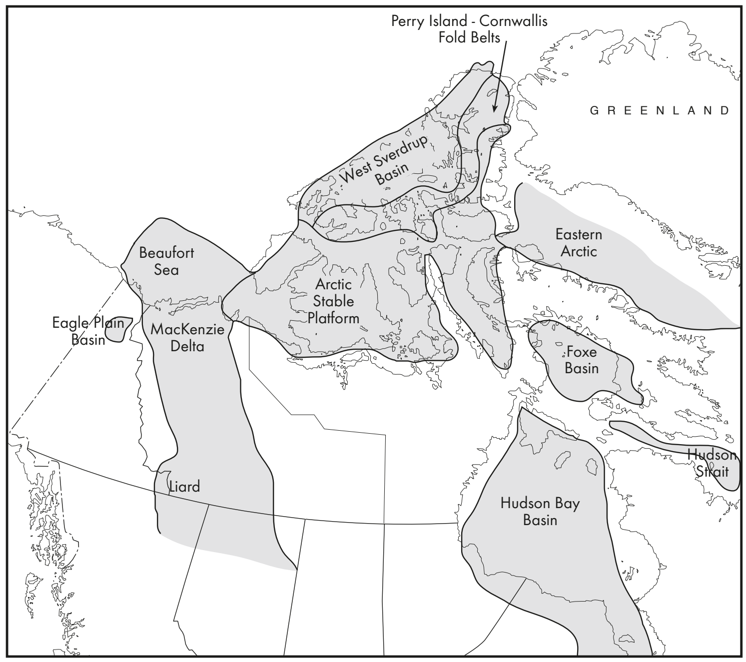
The other six basins and one coastal area in the Yukon have a combined estimate of 2.5 10^9m^3 (72 Bcf) of marketable discovered resources and 142 10^9m^3 (5 Tcf) of marketable undiscovered resources, based on a series of assessments done by the GSC and NEB for the Yukon Government in 2000 and 2001. The Eagle Plains Basin is the largest of these, with an estimated 1.8 10^9m^3 (51 Bcf) of marketable discovered gas and 28 10^9m^3 (1 Tcf) of marketable undiscovered gas. There is no drilling occurring at this time but the Yukon government is encouraging activity.

4.4.4 Arctic Islands

The Arctic Islands region contains three structural components: the West Sverdrup Basin, the Parry Island-Cornwallis Fold Belts, and the Stable Platform region (Figure 4.7). The West Sverdrup Basin has a marketable discovered gas resource of 331 10^9m^3 (12 Tcf), and a marketable undiscovered gas resource of 433 10^9m^3 (15 Tcf) as estimated by the NEB, based on estimates provided by the GSC in 2000. The NEB evaluation of the Fold Belts has marketable ultimate potential of 172 10^9m^3 (6 Tcf) while the Stable Platform has 188 10^9m^3 (7 Tcf), based on estimates provided by the GSC in 1983. The total NEB estimate for the region is 1 124 10^9m^3 (40 Tcf).

FIGURE 4.7

Northern Canada Regional Map



4.4.5 Eastern Arctic

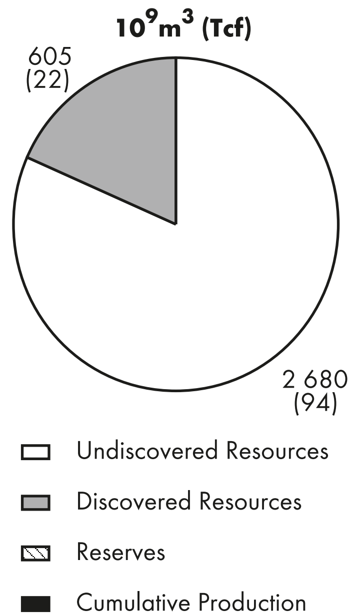
The Eastern Arctic region is found offshore of Baffin Island and includes Lancaster Sound and the Canadian portions of Baffin Bay and Davis Strait (Figure 4.7). The NEB estimate of marketable ultimate potential is 140 10^9m^3 (5 Tcf), based on estimates provided by the GSC in 1983. The only current activity for these areas is some exploration on the Greenland portion of Baffin Bay and Davis Strait. Successful exploration and development in that area could renew the interest of Canadian industry.

4.4.6 Hudson Bay

The Hudson Bay Basin contains carbonate rocks of Paleozoic age and underlies or is adjacent to Hudson Bay, Hudson Strait and Baffin Island in Manitoba, Ontario, and Nunavut (Figure 4.1). There have been nine wells drilled in total in these areas. No commercial volumes of oil or gas have been found, and there is no activity taking place at this time. The NEB currently uses a marketable ultimate potential estimate of 28 10^9m^3 (1 Tcf), based on estimates provided by the GSC in 1983. Figure 4.8 shows the categories of Northern Canada resources.

FIGURE 4.8

Categories of Northern Canada Resources



4.5 Ontario

Canada's first oil discovery was made in southern Ontario, between Lake Huron and Lake Ontario, at Oil Springs in 1858 (Figure 4.1). The sedimentary rocks in this basin range in age from Cambrian to Devonian and extend southward into the Michigan Basin in the U.S. In southern Ontario, discoveries tend to be relatively small and are found in both sandstone and carbonate reservoirs. There have been a few estimates of ultimate potential made since the early 1980s, with the most recent being that by the CGPC in 2001. The NEB estimates the marketable undiscovered gas resources to be 23 10^9m^3 (0.8 Tcf) based on estimates provided by the GSC in 1983. The Canadian Association of Petroleum Producers estimates that 33 10^9m^3 (1.2 Tcf) of gas had been produced by year- end 2000. Figure 4.9 shows the categories of southern Ontario resources.

Exploration activity continues in southern Ontario at a relatively slow pace with only 80 wells drilled in 2003. Talisman is the most active large company and has been drilling wells under Lake Erie using barges. Given the size of the basin in southern Ontario and the long history of development, it is unlikely that there will be any significant increase to the ultimate potential in this basin. Small pool development in this basin is enhanced by very low transportation costs due to its very close proximity to major market centres in southern Ontario and the U.S.

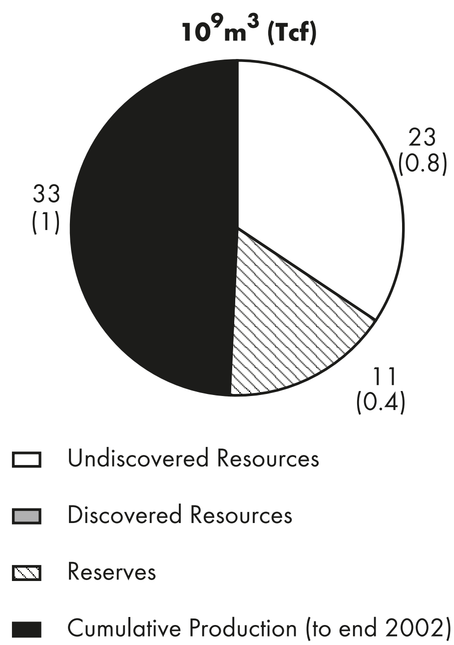
4.6 Gulf of St. Lawrence

4.6.1 Anticosti Basin

This linear trend of sedimentary rocks is the Canadian extension of the Appalachian geology and consists mainly of rocks ranging in age from Ordovician to Devonian (Figure 4.1). Shallow Quaternary sand deposits from the last glaciation phase in the area also contain localized gas deposits. The southwestern part of this trend, near Montreal, contains one area for exploration in structurally controlled settings. In the Anticosti Basin, mainly under the Gulf of St. Lawrence, the same targets exist, again in structurally controlled settings. The CGPC estimates the recoverable discovered gas resources for all of these plays to be 1.6 10^9m^3 (45 Bcf) but does not estimate undiscovered volumes due to a lack of data.

FIGURE 4.9

Categories of Ontario Resources



A limited number of wells have been drilled in these plays, although drilling in Newfoundland goes back for more than 130 years. The drilling history has been largely unsuccessful in all of these plays, with only two commercial gas fields found in Québec in 1955 and 1976. Corridor Resources has conducted some recent drilling on Anticosti Island but did not find commercial quantities of gas or oil.

4.6.2 Southern Portion

The southern portion of the Gulf is occupied by the sedimentary rocks of the Magdalen or Maritimes Basins (Figure 4.1). The basin is mainly located under the waters of the Gulf, but does extend onshore in

New Brunswick, Prince Edward Island, Newfoundland and Nova Scotia. Sediments in this area are mainly of Mississippian age with some local Devonian aged rocks that are primarily sandstones, siltstone and shales of continental origin. There is a thick sequence of limestones and evaporates in the lower portion of the basin. The NEB estimates the marketable ultimate potential to be 38 10^9m^3 (1.3 Tcf), based on estimates provided by the GSC in 1983, for the entire Gulf of St. Lawrence region.

Past exploration activity established one oil and gas pool at Stony Creek in New Brunswick which produced both gas and oil for markets in Moncton up to the 1940s. Corridor Resources made a discovery of gas at the McCully Field in New Brunswick, near Moncton, in the 1990s. Corridor Resources estimates that this discovery could contain as much as 28 10^9m^3 (1 Tcf) of marketable gas, and it is now supplying gas to a local potash mill while continuing with its plans to develop the field. Additionally, in 1974, there was a gas discovery offshore Prince Edward Island but it is too small to justify production at this stage. An onshore oil discovery was made near Port Au Port, Newfoundland in the 1990s. Canadian Imperial Ventures is continuing to assess the development of that discovery today. There have also been gas discoveries reported on the Gaspé Peninsula in Québec with at least one being produced for local use. Nova Scotia expects to have four wells drilled onshore in the next year. Offshore activity in the Gulf continues to be affected by regulatory issues and interprovincial border questions. Corridor Resources and Hunt Resources received approval to proceed with some new seismic offshore Cape Breton Island, after a regulatory process in which environmental concerns were prominent. Corridor Resources completed its program in December 2003. Figure 4.10 shows the categories of the Gulf of St. Lawrence resources.

Table 4.3 shows the more recent estimates of ultimate potential available for basins in Canada, other than the WCSB, in both metric and imperial units.

FIGURE 4.10

Categories of Gulf of St. Lawrence Resources

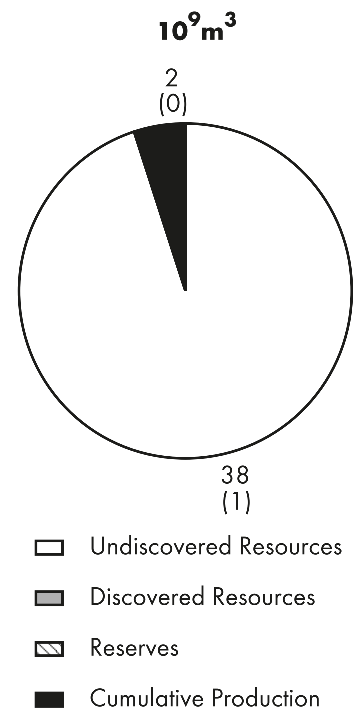


TABLE 4.3A

Current NEB Estimates of Ultimate Potential for Conventional Marketable Natural Gas for Canadian Basins Excluding the WCSB ($10^9 m^3$)[1]

	Evaluator and Date[1]										
Basin or Area	**GSC 1983**	**GSC 1988**	**GSC 1992**	**GSC 1998**	**GSC 2000**	**CGPC 1997**	**CGPC 2001**	**Yukon 2000**	**CNOPB 2001**	**CNSOPB 2002**	**CERI 2002**
East Coast											
Newfoundland											
Labrador	781						265				866
Grand Banks	329						239		486		501
East Newfoundland Basin	352										234
South Grand Banks	86										22
Nova Scotia											
Scotian Shelf	589	487				362	310				528
George's Bank	143										53
Laurentian Sub-Basin			238								208
Deep Water										397-1105	272
West Coast											
Offshore	257			1167			369				513
Intermontane					22						61
Northern Canada											
Mackenzie Corridor						83	134				134
Mackenzie-Beaufort	2021	1713				1584	844				1505
Yukon						13	13	105			75
Arctic Islands[2]	2040				1616	732	728				2481
Eastern Arctic	257										198
Hudson Bay	86										19
Ontario	57					65	65				85
Gulf of St. Lawrence	38										69

1. all estimates in marketable, converted by NEB
2. only the West Sverdrup portion was revised

TABLE 4.3B

Current NEB Estimates of Ultimate Potential for Conventional Marketable Natural Gas for Canadian Basins Excluding the WCSB (Tcf)[1]

	Evaluator and Date[1]										
Basin or Area	**GSC 1983**	**GSC 1988**	**GSC 1992**	**GSC 1998**	**GSC 2000**	**CGPC 1997**	**CGPC 2001**	**Yukon 2000**	**CNOPB 2001**	**CNSOPB 2002**	**CERI 2002**
East Coast											
Newfoundland											
Labrador	28						9				31
Grand Banks	12						8		17		18
East Newfoundland Basin	12										8
South Grand Banks	3										1
Nova Scotia											
Scotian Shelf	21	17				13	11				19
George's Bank	5										2
Laurentian Sub-Basin			8								7
Deep Water										14-39	10
West Coast											
Offshore	9			41			13				18
Intermontane					22						2
Northern Canada											
Mackenzie Corridor						3	5				5
Mackenzie-Beaufort	71	61				56	30				53
Yukon						1	1	4			3
Arctic Islands[2]	72				57	26	26				88
Eastern Arctic	9										7
Hudson Bay	3										1
Ontario	2					2	2				3
Gulf of St. Lawrence	1										2

1. all estimates in marketable, converted by NEB
2. only the West Sverdrup portion was revised

GLOSSARY

Associated gas	Natural gas that overlies and is in contact with crude oil in the reservoir, at original reservoir pressure and temperature conditions.
Clastic deposits	A group of sedimentary rocks that form as a result of the erosion of older rocks, generally consisting of sandstone, conglomerate, silt and shale.
Coalbed methane	A unconventional form of natural gas that is trapped within the matrix of coal seams, also called natural gas from coal.
Conceptual plays	These are geological plays that are thought to exist or have been shown to exist, but have not been proven by the drilling of oil or gas wells that are capable of production.
Conventional Gas	This is natural gas that is found in the pore space of a reservoir and is produced through a wellbore with known technology and where the drive for production is provided by expansion of the gas or by pressure from an underlying aquifer.
Discovered volume	The quantity of gas and related substances that are estimated, at a particular time, to be initially contained in known accumulations that have been penetrated by a well bore.
Gas in place	This is the total quantity of gas that is estimated to be contained in any given pool or reservoir and includes both the portion that can be recovered and the portion that will remain in the reservoir.
Geological basins	A segment of the earth's crust which has been downwarped, usually for a considerable time, but with intermittent risings and sinkings. The sediments in such basins increase in thickness toward the centre of the basin.
Geological play	A geological configuration, within a defined area, which combines source rock, reservoir rock, trap, migration and preservation in such a way that the critical factors that control the occurrence of oil and gas are essentially similar.

Non-associated gas	Natural gas found in a reservoir in which no crude oil is present at reservoir conditions.
Play area	The geographical area that contains a defined geological configuration within a stratigraphic interval. That geological configuration now contains or is expected to contain producible gas or oil, if the economic conditions are right.
Recovery Factor	A factor applied to the gas in place (or oil in place) in a reservoir in order to obtain the volume of gas that can be physically recovered at the surface.
Reserves	The estimated remaining quantity of oil or natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and, specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.
Reserves appreciation	The concept whereby an increase in initial reserves from discovered petroleum reservoirs is inferred from historical experience that additions to reserves continue to accrue over time. These increases can result from the extension of known reservoirs in known fields, or from revision to estimates of the portion of the volume in place that may ultimately be recovered.
Resources	As used in this report, resources refers to the total volume of oil or natural gas that is thought to be found in an area, or to that portion of the total resources that is not penetrated by a wellbore to date, or the volume that could be found as a result of appreciation.
Shale Gas	A form of unconventional gas where the gas molecules are mainly trapped on the organic material in a host rock of fine-grained shale.
Solution gas	Natural gas that is dissolved in crude oil in the reservoir at original reservoir temperature and pressure conditions and is normally produced with the crude oil.
Spudded	A well that has started drilling.
Stratigraphic intervals	A grouping of all the productive geological formations into layers of sedimentary rocks of approximately the same geological age. For example, the Swan Hills and Slave Point Formations are geologically different, but they are approximately of the same geological age and are grouped for the purposes of this study.

Surface loss factor
: A factor applied to the gas recovered from a reservoir in order to determine the volume of gas actually available to be delivered to the market. It is generally used to account for impurities in the gas and the volume of gas used to fuel the equipment that allows for the production at a particular location.

Tight gas
: A form of non-conventional natural gas that is held in the pore space of a rock that has a lower permeability or ability to flow than usual for the type of rock that it is.

Ultimate potential
: A term used to refer to an estimate of the marketable resources that will be developed in an area by the time that exploratory and development activity has ceased, having regard for the geological prospects of an area, known technology and economics. It includes cumulative production, remaining reserves, and future additions to reserves through extension and revision to existing pools and the discovery of new pools. For most of this report it is used as a short form of "ultimate potential of conventional natural gas".

Unconventional gas
: Natural gas that is contained in a reservoir rock that requires additional stimulus to allow gas flow. It may be that the gas is held by the matrix material such as coal, ice, or shale; or where the reservoir has an unusually low amount of porosity and permeability.

Undiscovered volume
: The portion of the ultimate potential that has yet to be penetrated by a wellbore or that has yet to be proven by changes in a discovered pool's reserves through extension or revision.

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