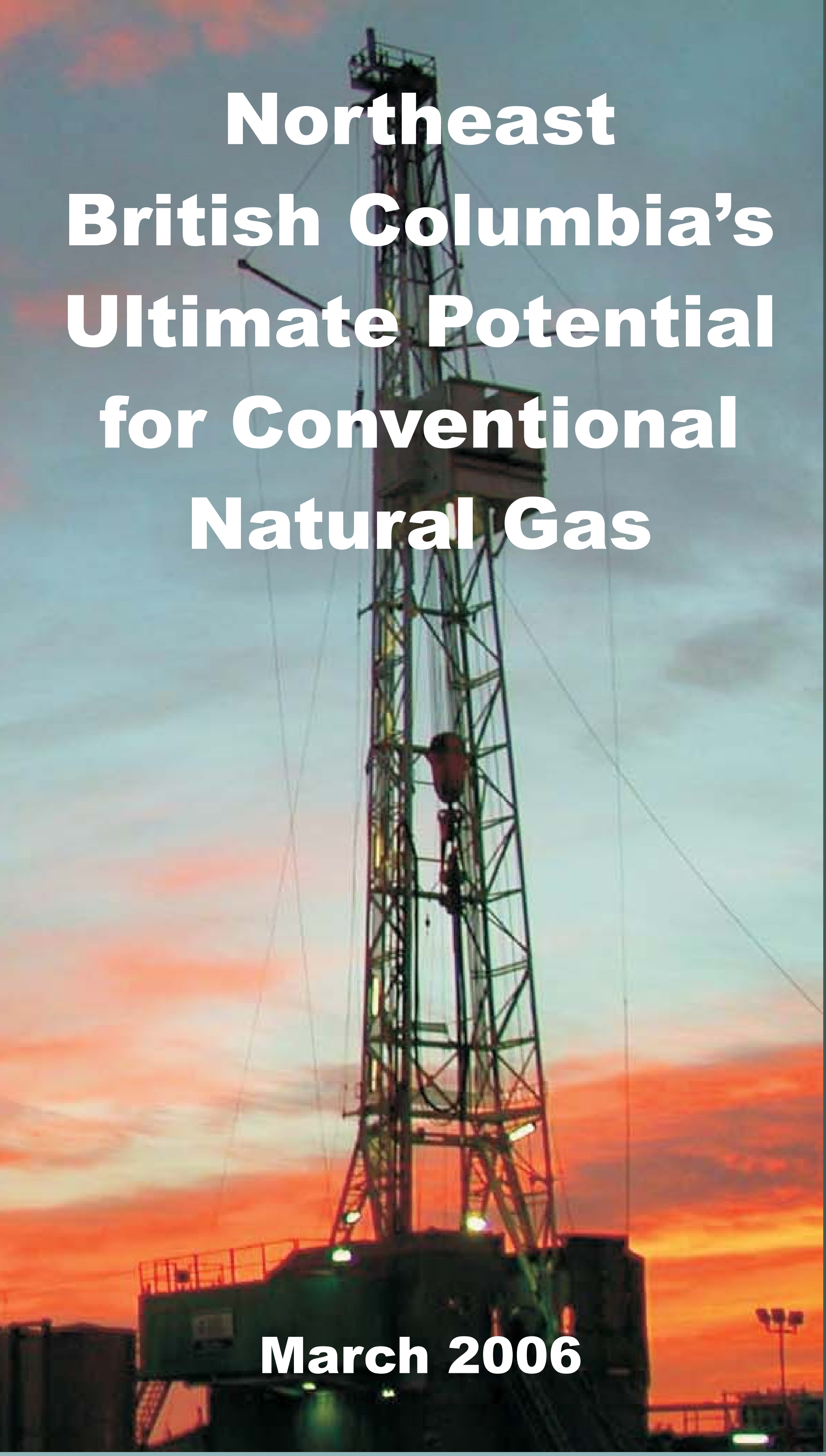

Northeast British Columbia's Ultimate Potential for Conventional Natural Gas

March 2006

Report 2006-A

National Energy Board

BC Ministry of Energy, Mines and Petroleum Resources

Canada

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National Energy Board

Office national de l'énergie

B.C. Ministry of Energy, Mines and Petroleum Resources

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Northeast British Columbia's Ultimate Potential for Conventional **Natural Gas**

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Acronyms

B.C.	British Columbia
CBM	coalbed methane
CBG	coalbed gas
CGPC	Canadian Gas Potential Committee
EMA	Energy Market Assessment
GIP	gas in place
GSC	Geological Survey of Canada
MEMPR	(B.C.) Ministry of Energy, Mines and Petroleum Resources
NEB, the Board	National Energy Board
NGC	natural gas from coal
NGLs	natural gas liquids
OGC	(B.C.) Oil and Gas Commission
psia	pounds per square inch absolute
the agencies	collectively, the NEB and MEMPR
3D	three-dimensional
U.S.	United States of America
WCSB	Western Canada Sedimentary Basin

Units

Bcf	billion cubic feet
Tcf	trillion cubic feet
10^6m^3	million cubic metres
10^9m^3	billion cubic metres
ºC	degrees Celcius
ºF	degrees Fahrenheit
cf/m^3	cubic feet per cubic metre
kPa	kilopascals
m	metres

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The compilation of this report was a collaborative effort amongst several agencies. Key to the play atlas development was the participation of Brad Hayes of Petrel Robertson, who shared his significant knowledge regarding the petroleum geology of northeast British Columbia.

Significant contributions were provided by:

The National Energy Board

- Jim Davidson, Bobbi Feduniak, Orlando Huang, Brent Hogue and Bill Bingham

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FOREWORD

The British Columbia Ministry of Energy, Mines and Petroleum Resources (MEMPR) is the steward of provincially owned oil and gas resources and is mandated to protect the public interest in oil and gas development and ensure that benefits from resource development are maximized for all British Columbians. MEMPR also facilitates investment in the oil and gas sector as well as responsible development of British Columbia's energy and mineral resources to benefit British Columbians. The Ministry vision is a thriving, competitive, safe and environmentally responsible energy and mining sectors significantly benefiting all British Columbians.

The Oil and Gas Division develops and implements policies and programs to maximize the benefits from B.C.'s oil and gas resources, including increasing provincial revenues and private sector business opportunities through innovative oil and gas infrastructure and royalty programs, promoting B.C.'s geological potential and enhancing the competitive business climate for B.C.'s oil and gas service companies.

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 economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs of those pipelines. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's north and certain offshore areas.

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

This EMA, entitled *Northeast British Columbia's Ultimate Potential for Conventional Natural Gas*, is part of a series of EMA reports that provide information on the total gas resources of sedimentary basins in Canada. This series includes the NEB's 2004 *Canada's Conventional Natural Gas Resources: A Status Report*, and the 2005 report on Alberta, *Alberta's Ultimate Potential for Conventional Natural Gas*, completed with the Energy and Utilities Board. This EMA provides information on the undiscovered conventional gas resources remaining in the B.C. portion of the Western Canada Sedimentary Basin and also qualitatively discusses the gas potential that may be present in other areas of B.C. and the potential for additional quantities of unconventional gas that could be present in the province.

During the preparation of this report, the MEMPR and NEB conducted a series of informal meetings and discussions with certain companies exploring in B.C., specifically related to key geological plays. The MEMPR and NEB appreciate the information and comments provided and would like to thank all participants for sharing 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.

EXECUTIVE SUMMARY

The British Columbia Ministry of Energy, Mines and Petroleum Resources (MEMPR) and the National Energy Board (NEB) (the agencies) estimate supply and demand on a provincial and national scale respectively. Ultimate potential of natural gas is recognized as a key component required to project future supply. The NEB's last complete study of the resource potential of B.C. was completed in 1994, based on year-end 1992 data. The NEB also published an update to that report in 2000, based on year-end 1997 data. The current study is based on year-end 2003 data. Between 1992 and 2003, the cumulative number of wells drilled in B.C. almost doubled from 7 582 to 14 568. In 2003, the MEMPR and NEB separately came to the conclusion that due to the increased drilling activity and the discovery of several large pools in plays not previously considered to be present, that there was a need for a new assessment of the B.C. portion of the Western Canada Sedimentary Basin. Part of the reason for the increased drilling activity was due to the provincial government's initiatives facilitating oil and gas development including infrastructure development, targeted royalty programs, regulatory reduction and development of a B.C. based service sector. Collectively, to achieve regulatory efficiency and in line with the cooperation protocol as set out in the MEMPR/NEB Common Reserves Database Agreement, the two agencies decided to collaborate on a joint study. In addition, MEMPR undertook the development of a Play Atlas which describes, in more detail, the geology of the plays considered in this report.

This report, *Northeast British Columbia's Ultimate Potential for Conventional Natural Gas*, presents the results of the joint study. The medium case estimate for northeast B.C.'s ultimate potential of marketable conventional natural gas resources was calculated to be 1 462 10^9m^3 (51.9 Tcf) and henceforth that is the estimate that the agencies will rely on.

The new estimate of ultimate potential is two percent higher than the NEB's previous estimate for the conventional natural gas resources in northeast B.C. The new estimate does show significant increases in some resource categories and plays, and decreases in others. The new estimate is based on increased knowledge obtained from the large number of new wells drilled to enable an enhanced geological assessment.

The agencies also recognize that unconventional resources may become a significant component of the province's future ultimate potential. In addition, other sedimentary basins in the province have potential for both conventional and unconventional gas supplies. In most cases, no marketable volumes of gas have been assigned to individual entities in these areas, but collectively, the NEB has published marketable volumes for the offshore and interior basins.

Cumulative production to the end of 2003 was 484 10^9m^3 (17.2 Tcf), hence the remaining gas available for future demand is 978 10^9m^3 (34.7 Tcf). Annual production from B.C. is now about 26.8 10^9m^3 (950 Bcf). The remaining ultimate potential represents the volume of gas that could be made available in the future for Canadian domestic and export demands. Additional volumes should also be available from both unconventional and conventional supplies from other basins in B.C. Development of those additional resources could supplement long-term supply from northeast B.C. Extraction of gas resources will contribute to a healthy and vibrant oil and gas industry in B.C. for many years to come.

INTRODUCTION

Canada plays an important role in the North American natural gas market. Today, Canada provides about one-quarter of total North American gas production. Canada's ability to remain a key supplier of natural gas will largely depend on the size and quality of its resource base. Within Canada, the province of British Columbia is an important contributor to gas supply, accounting for about 15 percent of the total Canadian production in 2003, second only to Alberta. Annual production from B.C. is now about 26.8 $10^9 m^3$ (950 Bcf). All of the production currently comes from the northeast part of B.C., hence the focus of this study is on that area.

Ultimate potential for natural gas is a key component required to make projections of future supply. It provides base information from which subsequent examinations of the pace of development, deliverability and economics can be conducted. As drilling and technology advance, they bring forth new information on the resource of a basin, which in turn contributes to increased certainty. Increased drilling activity in B.C. and the discovery of several large pools in plays not previously accounted for, warranted the need for a new assessment of B.C.'s ultimate potential.

1.1 Scope

This report focuses primarily on conventional natural gas, i.e., gas from clastic and carbonate reservoirs where recovery is possible with current technology and prices. Most of British Columbia's conventional resources are found in the northeast part of the province which is part of the Western Canada Sedimentary Basin (WCSB). However, there are also conventional resources in other parts of B.C. Sedimentary basins in the interior and offshore of B.C. are thought to contain conventional resources. Due to their very early stage of development, those additional conventional resources are only discussed qualitatively in Appendix 1 of this report. Unconventional gas (gas found in non-typical settings or requiring non-typical extraction techniques[1]) is of increasing interest (see Appendix 1 for a description of unconventional gas). Currently, unconventional gas in B.C. is at an early development stage, so available information is too limited to estimate its ultimate potential.

For the purposes of this report, gas from low permeability reservoirs in certain plays in northeast B.C., that could be considered as unconventional tight gas under some definitions, but which is now being produced, is included as conventional gas.

This report does not specifically address the economics of discovering, developing or producing B.C.'s gas resources. Nor does it deal with the rate of discovery or productive capacity for natural gas. This report and the associated data are meant to form the basis for economic analysis and supply projections by the MEMPR, NEB or others.

1 Includes such resources as coalbed gas (or natural gas from coal), tight gas, shales and gas hydrates.

With the availability of more information because of increased drilling activity, this study is able to provide more detailed information on a geological play basis than previous NEB studies. It also made it possible to apply further rigour in the analysis and provide enhanced results relative to previous studies. In addition, the joint assessment done in this study benefited from the local knowledge of both the MEMPR and Oil and Gas Commission (OGC) geologists.

This study captures the resources of known geological plays, including plays where there are no current discoveries in B.C., but where discoveries have been made in Alberta. The geology is known to cross the provincial boundary and the agencies expect discoveries to be made on the B.C. side in the very near future. The agencies will continue to monitor developments in the size of the resource base for natural gas in British Columbia.

The study also includes conceptual plays, which are geological plays thought to exist but that have not been proven by oil or gas wells capable of production. An example is the Cretaceous Scatter Formation play into northeast B.C. where the presence of the sand is known from drilling that has already been completed, but the presence of hydrocarbons has yet to be confirmed. For this report, the project team identified conceptual plays that it believes could exist in B.C. However, the project team did not assign a volume of undiscovered gas to those plays. That will be done in future reports if, and when, the plays are proven to contain hydrocarbons.

Some portion of the resource may not be accessible from the surface due to physical features such as large lakes, extreme topography, or due to alternative surface uses such as cities or parks. In northeast B.C., most areas can be accessed from outside restricted areas via directional drilling. However, in some cases, access to these vertical or directional drilling locations could be precluded by restrictions on the construction of necessary access roads or by prohibitively costly permitting/mitigation requirements. Since these determinations are quite site-specific, adjustments to the ultimate potential for access restrictions were not considered for the plains regions of northeast B.C. For the foothills, industry was consulted to help develop an estimate of the amount of the non-accessible resources.

1.2 Terminology

For the purpose of this report, the term ultimate potential refers to an estimate of the volume of marketable gas reserves that will be proven to exist in a geological basin or in a specific area after exploration has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential can be expressed as:

Ultimate potential = discovered resources + undiscovered resources

Discovered resources have been confirmed by wells already drilled, while *undiscovered resources* are expected to be discovered by future drilling. Figure 1.1 presents the ultimate potential terminology used in this report. Discovered resources consist of both the volumes of gas already produced (cumulative production) and the known reserves that are still to be produced.

Since estimates of ultimate potential refer to a volume of gas to be discovered in the future, the estimates always have a degree of uncertainty. 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 about them. For the discovered, there is minimal uncertainty. Finally, there is no uncertainty for the volumes already produced.

Additional terminology used in describing discovered resources, or in calculating estimates of the undiscovered resources and ultimate potential are as follows. *Gas in place* is the initial volume of gas

F I G U R E 1 . 1

Terminology for Study of British Columbia's Ultimate Potential for Conventional Natural Gas

Terms			Level of Uncertainty
Ultimate Potential	Discovered	Cumulative Production	none
		Reserves	low
	Undiscovered	Future	high

in the reservoir; *recoverable gas* is the initial volume of gas that can be produced, and marketable gas is the volume that remains after processing. This report uses the gas-in-place (GIP) volumes from the discovered pools as provided in the OGC's annual reserves report[2] to make projections of the undiscovered GIP. The undiscovered GIP is reduced to marketable volumes by applying current recovery factors and surface losses using parameters from existing pools, also published in the annual reserves report. Gas that has been produced and estimates of gas yet to be produced are also shown. *Remaining gas* (ultimate potential minus cumulative production) represents the volume available for future market demands.

1.3 Units of Measure

The data in this report are presented in metric units, followed, where appropriate, by the imperial equivalents in brackets.

Both MEMPR and NEB state natural gas volumes in metric units at the standard conditions of 101.325 kilopascals (kPa) and 15 degrees Celsius (ºC). In imperial units, MEMPR uses standard conditions of 14.65 pounds per square inch absolute (psia) and 60 degrees Fahrenheit (ºF), while the NEB uses 14.73 psia and 60ºF. For the purposes of this report, a conversion factor of 35.49373 cubic feet per cubic metre (cf/m^3) has been used, reflecting the standard conditions used by the MEMPR. Readers requiring an accurate conversion to the NEB standard conditions should use a conversion factor of 35.30096 cf/m^3.

All gas volumes in this report are shown on an "as is" basis, with no adjustment for heating value.

1.4 Effective Date of the Data

Work began on this study in mid-2004 and continued into 2006. Data analysis and updates were done on existing databases throughout that period and new databases specific to the ultimate potential study were developed. The reserves data used is effective to 31 December 2003 and the final ultimate potential estimates are based on that date.

2 Hydrocarbon And By-Product Reserves in British Columbia 2003.

1.5 Updates to this Study

Although this study accounts for drilling to year-end 2003, record drilling levels and increasing attention to exploration and development of new plays such as the Jean Marie and Cadomin require ongoing monitoring of drilling and exploration in the province. The agencies intend to maintain the computer systems, databases, and processes used in this report to update the data on an ongoing basis. Changes may be reported in the annual releases of the OGC's *Hydrocarbon And By-Product Reserves in British Columbia* Reports, or in various NEB publications.

1.6 Uses for the Data in this Study

The agencies expect to make ongoing use of the data and systems of this report, such as the regional analysis of resources near pipelines, gas plants, and populated areas. The addition of gas analysis data allows for the determination of sour gas volumes that may be encountered during future drilling activity and its location relative to, for example, populated areas.

1.7 Play Atlas

MEMPR undertook the development of a Play Atlas which more fully describes the geology of the individual geologic plays. The Play Atlas will also include maps for each formation that show the areal distribution of the play areas. That document which will be published by the MEMPR by the end of April 2006, is meant to be a companion piece to this report, and will also be made available on the MEMPR Web site.

1.8 Reader's Questions and Comments

The reader is encouraged to contact the MEMPR or NEB with questions or comments respecting either this report or the associated data on the MEMPR and NEB Web sites. Please contact:

British Columbia Ministry of Energy, Mines and Petroleum Resources
Oil and Gas Division
PO Box 9326 Stn Prov Govt
Victoria, B.C. V8W 9N3
Web site: www.em.gov.bc.ca/oilandgas

or

National Energy Board
444 – 7th Ave SW
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Attention: Jim Davidson
Phone: (403) 299-3135
E-mail: jdavidson@neb-one.gc.ca

Methodology and Results

2.1 Methodology

The estimate of the ultimate potential of natural gas in northeast B.C. was determined by:

- reviewing pertinent data, statistical analysis, maps and other information
- using the @Risk methodology, described in the NEB report, *Canada's Conventional Natural Gas Resources – A Status Report (2004)*[3]
- using the graphical techniques outlined in the joint Alberta Energy and Utilities Board and NEB report, *Alberta's Ultimate Potential For Conventional Natural Gas*, when sufficient data was available[3]
- relying on the expertise of the project team
- gathering input from industry

The @Risk methodology uses information from the discovered reserves and drilled lands to build statistical distributions within the software. Those distributions are then applied to lands where drilling has not occurred to determine a distribution of volumes of undiscovered resources at different probability values. The project team uses the P90, mean and P10 values for its low, medium and high cases. The software analyses the discovered resources on a GIP basis and determines the undiscovered resources on a GIP basis.

The graphical techniques were compared against the @Risk results. However, because the portion of the WCSB underlying B.C. is smaller in size and less well developed compared with Alberta, a larger percentage of the plays being analysed did not have sufficient information to employ the graphical techniques.

For those plays that did not have enough data to use the @Risk tool or the graphical techniques, the team used their geological expertise to estimate the ultimate potential (e.g., for plays that have either just been confirmed or where exploration is still limited).

The Devonian Jean Marie Formation – Platform Play also required special consideration. The OGC made significant revisions to the estimates of reserves for those pools in 2004. The recognized GIP volume for 2004 was more than double the GIP shown in 2003. As a result, the @Risk methodology, using the 2003 data led to an estimated undiscovered GIP volume that was much too low when compared with the 2004 data. Consequently, the undiscovered GIP had to be estimated by the project team.

3 Available at: http://www.neb-one.gc.ca/energy/energyreports/CanadaConventionalNGResources2004/index_e.htm.

2.2 Industry Input and Peer Review

The agencies met individually, on a confidential and informal basis, with eight companies actively exploring in B.C., especially in the foothills regions. The foothills are geologically complex regions and this, combined with the unreliability of most assessment models to deal with faulted and folded regions, determined the need for a proper check of the results with the experts for those regions. These companies were also consulted to estimate the size of the non-accessible resources in the foothills. The information gained from these meetings is summarized on a collective basis to maintain the confidentiality of the companies. No information from one company was shared with another. Input received from all parties was very beneficial and greatly appreciated.

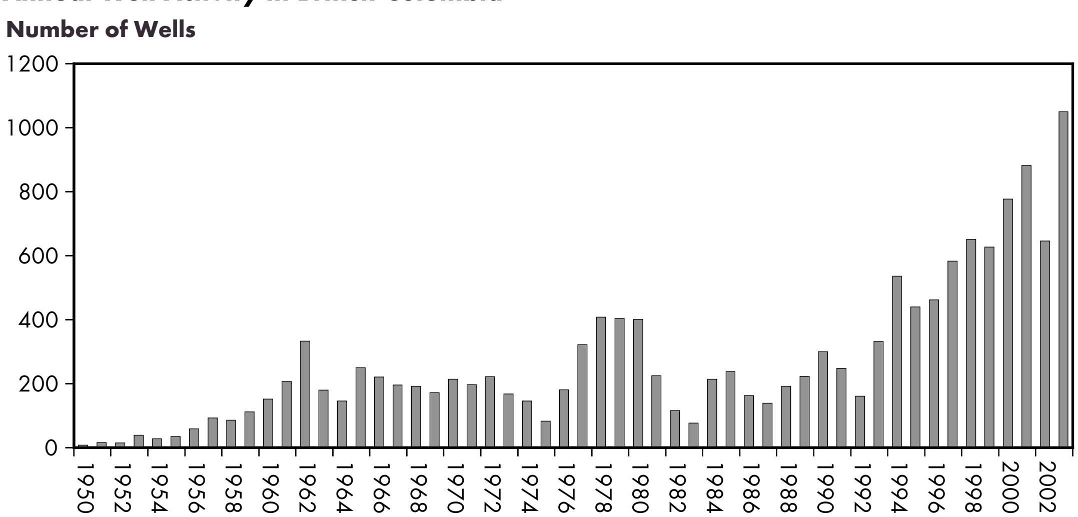
The agencies were also assisted by the expertise of Brad Hayes, a consultant with Petrel Robertson Consulting Limited, of Calgary, Alberta who was contracted by the MEMPR to help to determine appropriate play areas and to review the preliminary results.

2.3 Available Information

Increases in gas prices have resulted in the exploration for and development of low-productivity pools that were previously beyond economic reach. Advances in technology, such as horizontal drilling, underbalanced mud systems, completion techniques, drill bits, and the use of refined seismic technologies including three-dimensional (3D), have also resulted in the discovery and development of many pools. In addition, new development strategies have allowed for the more efficient and economic development of resources that could be considered as unconventional resources. These would include the Jean Marie development by underbalanced horizontal drilling (Bank Edge and Platform plays, map reference for Figure 3.1 is 094J) which started in 1997 and the Deep Basin Cadomin development (093P) which started in 2004. As a result, there has been a rapid increase in the number of wells drilled in northeast B.C. The current study uses data from 14 568 wells drilled by year-end 2003. The NEB 2000 report was based on 9 935 wells drilled by year-end 1997 and its 1994 report was based on 7 582 wells drilled by year-end 1992. The number of wells drilled in B.C. on an annual basis has increased rapidly since 1994, from about 200 wells per year to over 1 000 in 2003 (Figure 2.1).

FIGURE 2.1

Annual Well Activity in British Columbia



2.4 Results

Having regard for the inherent uncertainty in estimating geological prospects and predicting gas potential, the agencies estimated a range for the ultimate potential for marketable conventional natural gas in northeast B.C. That range is 1 150 10^9m^3 (40.8 Tcf) to 1 808 10^9m^3 (64.2 Tcf), as shown in Table 2.1. Note, this estimate includes the gas resources in low permeability plays that have already started to be developed, such as the Devonian Jean Marie Platform and Bank Edge plays and the Cretaceous Cadomin play in the Cutbank region.

Table 2.2 shows a breakdown of ultimate potential (medium case) for natural gas into its categories as of December 2003. Maps showing the distribution of discovered resources, undiscovered resources, ultimate potential and remaining ultimate potential in northeast B.C. are in Appendix 3.

The remaining ultimate potential represents the volume of gas that could be made available in the future to meet Canadian domestic and export demands. The new estimate of remaining ultimate potential for marketable conventional natural gas in northeast B.C. is 978 10^9m^3 (34.7 Tcf). Additional volumes should also be available from both unconventional and conventional supplies from other basins in B.C. Development of those additional resources could supplement long-term supply from northeast B.C. Extraction of gas resources will contribute to a healthy and vibrant oil and gas industry in B.C. for many years to come.

2.4.1 Gas-in-place Results

As explained earlier, in light of the inherent uncertainty in estimating the ultimate GIP, this study includes low, medium and high case estimates. The low case is 2 015 10^9m^3 (71.5 Tcf), reflecting a good deal of certainty that the ultimate potential meets or exceeds that estimate. The medium case is 2 564 10^9m^3 (91.0 Tcf), representing the most realistic estimate. The high case of 3 169 10^9m^3 (112.5 Tcf) recognizes that while resources could be discovered, there is much uncertainty associated with the estimate.

TABLE 2.1

British Columbia's Ultimate Potential for Conventional Natural Gas

Case	Gas In Place		Marketable Gas	
	10^9m^3	Tcf	10^9m^3	Tcf
Low	2 015	71.5	1 150	40.8
Medium	2 564	91.0	1 462	51.9
High	3 169	112.5	1 808	64.2

TABLE 2.2

Categorization of Ultimate Potential – Medium Case

Category	Gas In Place		Marketable Gas	
	10^9m^3	Tcf	10^9m^3	Tcf
Discovered[1]	1 304	46.3	743	26.4
Cumulative Production (to 31 Dec 2003)[1]	849	30.1	484	17.2
Remaining Discovered	455	16.1	259	9.2
Undiscovered[1]	1 260	44.8	719	25.5
Ultimate Potential	2 564	91.0	1 462	51.9
Remaining Ultimate Potential	1 716	60.9	978	34.7

1 MEMPR estimate which includes the produced volumes from newly discovered pools which have yet to be evaluated, discovered and undiscovered volumes adjusted to reflect the additional produced volumes.

TABLE 2.3

Low, Medium and High Case GIP by Formation and Play Area

		$10^9 m^3$			Tcf		
Formation	**Play area**	**Low case**	**Medium case**	**High case**	**Low case**	**Medium case**	**High case**
Glacial Sand	Glacial Sand	1.012	1.416	1.995	0.036	0.050	0.071
Belly River	Deep Basin	1.296	1.813	2.554	0.046	0.064	0.091
Chinook	Deep Basin	0.972	1.360	1.916	0.035	0.048	0.068
Cardium	Deep Basin	2.511	3.513	4.949	0.089	0.125	0.176
Cardium	Regional Aquifer	0.071	0.100	0.141	0.003	0.004	0.005
Doe Creek	Deep Basin	1.525	2.133	3.005	0.054	0.076	0.107
Dunvegan	Deep Basin	2.592	3.626	5.108	0.092	0.129	0.181
Dunvegan	Fort St. John	1.215	1.700	2.395	0.043	0.060	0.085
Sikanni - Goodrich	Sikanni	1.012	1.416	1.995	0.036	0.050	0.071
Paddy	Deep Basin	4.215	13.625	35.301	0.150	0.484	1.253
Paddy	Northern Barrier	6.074	8.498	11.971	0.216	0.302	0.425
Cadotte	Deep Basin	6.935	9.313	18.147	0.246	0.331	0.644
Cadotte	Regional Aquifer	2.646	7.947	29.961	0.094	0.282	1.063
Cadotte	South Foothills	3.130	4.379	6.168	0.111	0.155	0.219
Spirit River-Notikewin-Falher	Deep Basin-South Foothills	11.497	16.868	46.771	0.408	0.599	1.660
Spirit River	Northern Shoreface	10.090	24.287	46.317	0.358	0.862	1.644
Bluesky	Deep Basin	1.786	4.507	8.396	0.063	0.160	0.298
Bluesky	Peace River Shoreface	0.459	60.701	137.965	0.016	2.155	4.897
Bluesky	Altares-Aitken Valley	4.038	11.753	49.008	0.143	0.417	1.739
Bluesky	Keg River Shoreface	1.376	3.322	6.939	0.049	0.118	0.246
Gething	Fluvial-Alluvial Plain	16.841	54.968	122.945	0.598	1.951	4.364
Cadomin	Deep Basin	80.686	254.572	448.021	2.864	9.036	15.902
Cadomin	Spirit River Valley	4.480	11.639	39.395	0.159	0.413	1.398
Chinkeh	Liard Basin	24.296	33.993	47.883	0.862	1.207	1.700
Nikanassin	South Foothills	4.823	12.206	40.688	0.171	0.433	1.444
Nikanassin	North Foothills	4.362	6.103	8.597	0.155	0.217	0.305
Nikanassin	Deep Basin	0.830	1.161	1.635	0.029	0.041	0.058
Nikanassin	Buick Creek	60.186	66.835	329.922	2.136	2.372	11.710
Pardonnet-Baldonnel	South Foothills	127.449	171.070	318.896	4.524	6.072	11.319
Pardonnet-Baldonnel	North Foothills	10.162	27.784	242.198	0.361	0.986	8.597
Pardonnet-Baldonnel	Fort St. John 1	82.740	107.328	280.008	2.937	3.809	9.939
Pardonnet-Baldonnel	Fort St. John 2	35.337	46.846	72.764	1.254	1.663	2.583
Upper Charlie Lake	North Foothills	4.915	6.877	24.743	0.174	0.244	0.878
Lower Charlie Lake	North Foothills	1.417	1.983	2.793	0.050	0.070	0.099
Lower Charlie Lake	South Foothills	1.012	1.416	1.995	0.036	0.050	0.071
Combined Charlie Lake	Fort St. John	34.751	51.107	131.987	1.233	1.814	4.685
Halfway	North Foothills	7.065	30.991	132.352	0.251	1.100	4.698
Halfway	South Foothills	10.123	14.164	19.952	0.359	0.503	0.708
Halfway	Fort St. John 1	41.256	54.217	111.463	1.464	1.924	3.956
Halfway	Fort St. John 2	90.127	114.396	249.679	3.199	4.060	8.862
Doig-Lower Halfway	Fort St. John-Deep Basin	12.238	19.667	48.201	0.434	0.698	1.711

TABLE 2.3 (CONTINUED)

Low, Medium and High Case GIP by Formation and Play Area

		10^9m^3			Tcf		
Formation	**Play area**	**Low case**	**Medium case**	**High case**	**Low case**	**Medium case**	**High case**
Montney	Subcrop	39.900	62.788	95.564	1.416	2.229	3.392
Montney	Distal Shoreface-Turbities	13.750	53.440	119.343	0.488	1.897	4.236
Belloy	North Foothills	10.123	14.164	19.952	0.359	0.503	0.708
Belloy-Debolt	South Foothills	45.229	141.456	623.759	1.605	5.021	22.140
Belloy	Fort St. John	41.502	55.856	87.432	1.473	1.983	3.103
Kiskatinaw	Peace River Embayment	11.446	21.416	64.618	0.406	0.760	2.294
Mattson	Liard Basin	4.037	15.218	45.873	0.143	0.540	1.628
Debolt	North Foothills	34.012	57.037	136.046	1.207	2.024	4.829
Debolt	Cretaceous Subcrop	4.836	11.662	19.070	0.172	0.414	0.677
Debolt	Regional Platform	12.956	23.108	45.835	0.460	0.820	1.627
Shunda-Pekisko-Banff	Cretaceous Subcrop	0.548	2.890	18.909	0.019	0.103	0.671
Shunda-Pekisko-Banff	Regional Platform	1.044	1.461	2.058	0.037	0.052	0.073
Shunda-Pekisko-Banff	Liard Basin	1.044	1.461	2.058	0.037	0.052	0.073
Wabamun	Fort St. John-Deep Basin	11.375	20.216	63.706	0.404	0.718	2.261
Kakisa	Platform	0.986	1.278	2.469	0.035	0.045	0.088
Jean Marie	Platform	74.861	200.225	362.170	2.657	7.107	12.855
Jean Marie	Bank Edge	48.529	86.153	249.750	1.722	3.058	8.865
Slave Point	Reef Margin	154.314	171.641	329.415	5.477	6.092	11.692
Slave Point	Platform	32.418	58.744	183.414	1.151	2.085	6.510
Slave Point	Ladyfern	28.806	53.247	146.682	1.022	1.890	5.206
Keg River	Reef Margin	163.010	190.751	332.671	5.786	6.770	11.808
Keg River	Lower Platform	2.592	6.088	16.203	0.092	0.216	0.575
Nahanni	Fort Nelson-Liard	30.370	42.492	59.855	1.078	1.508	2.124

Table 2.3 shows the low, medium and high case estimates for each play area.

2.4.2 Marketable Gas Results

Conversion of GIP estimates to marketable gas requires the application of a recovery factor to obtain producible reserves and a surface loss factor to yield marketable gas. The recovery factor recognizes that for practical and economic reasons, only a portion of the GIP can be produced. Surface loss accounts for field plant extraction of natural gas co-products and impurities from the raw gas, the flaring of test gas and solution gas (where solution gas is not conserved), and lease fuel. In northeast B.C., recovery factors average 69.5 percent and surface losses average 17.9 percent.

The recovery and surface loss factors for future gas discoveries are generally assumed to be the same in each play as that for gas discovered to date. Table 2.1 shows the low, medium and high case results for marketable volumes as well. Table 2.4 shows the medium case results for each play area. The total shown is the ultimate potential for conventional natural gas in northeast B.C.

T A B L E 2 . 4

Marketable Gas Estimates by Formation and Play Area

Formation	Play area	10^9m^3			Tcf		
		GIP	Producible	Marketable	GIP	Producible	Marketable
Glacial Sand	Glacial Sand	1.416	0.708	0.665	0.050	0.025	0.024
Belly River	Deep Basin	1.813	1.378	1.199	0.064	0.049	0.043
Chinook	Deep Basin	1.360	1.061	0.870	0.048	0.038	0.031
Cardium	Deep Basin	3.513	1.440	1.282	0.125	0.051	0.046
Cardium	Regional Aquifer	0.100	0.072	0.060	0.004	0.003	0.002
Doe Creek	Deep Basin	2.133	1.903	1.690	0.076	0.068	0.060
Dunvegan	Deep Basin	3.626	3.191	2.234	0.129	0.113	0.079
Dunvegan	Fort St. John	1.700	1.190	1.130	0.060	0.042	0.040
Sikanni - Goodrich	Sikanni	1.416	1.133	1.020	0.050	0.040	0.036
Paddy	Deep Basin	13.625	10.510	9.871	0.484	0.373	0.350
Paddy	Northern Barrier	8.498	5.252	5.151	0.302	0.186	0.183
Cadotte	Deep Basin	9.313	7.852	7.335	0.331	0.279	0.260
Cadotte	Regional Aquifer	7.947	6.302	5.935	0.282	0.224	0.211
Cadotte	South Foothills	4.379	3.404	3.065	0.155	0.121	0.109
Spirit River-Notikewin-Falher	Deep Basin-South Foothills	16.868	13.422	12.434	0.599	0.476	0.441
Spirit River	Northern Shoreface	24.287	20.514	15.531	0.862	0.728	0.551
Bluesky	Deep Basin	4.507	2.671	2.450	0.160	0.095	0.087
Bluesky	Peace River Shoreface	60.701	49.951	40.366	2.155	1.773	1.433
Bluesky	Altares-Aitken Valley	11.753	8.693	7.565	0.417	0.309	0.269
Bluesky	Keg River Shoreface	3.322	2.141	1.811	0.118	0.076	0.064
Gething	Fluvial-Alluvial Plain	54.968	42.360	34.429	1.951	1.504	1.222
Cadomin-Chinkeh	Deep Basin	254.572	127.825	115.045	9.036	4.537	4.083
Cadomin-Chinkeh	Spirit River Valley	11.639	8.228	6.879	0.413	0.292	0.244
Chinkeh	Liard Basin	33.993	25.494	22.772	1.207	0.905	0.808
Nikanassin	South Foothills	12.206	9.067	7.828	0.433	0.322	0.278
Nikanassin	North Foothills	6.103	3.418	3.008	0.217	0.121	0.107
Nikanassin	Deep Basin	1.161	0.890	0.778	0.041	0.032	0.028
Nikanassin	Buick Creek	66.835	56.861	46.197	2.372	2.018	1.640
Pardonnet-Baldonnel	South Foothills	171.070	137.545	100.183	6.072	4.882	3.556
Pardonnet-Baldonnel	North Foothills	27.784	20.048	18.147	0.986	0.712	0.644
Pardonnet-Baldonnel	Fort St. John 1	107.328	85.204	68.023	3.809	3.024	2.414
Pardonnet-Baldonnel	Fort St. John 2	46.846	36.273	30.229	1.663	1.287	1.073
Upper Charlie Lake	North Foothills	6.877	6.074	5.017	0.244	0.216	0.178
Lower Charlie Lake	North Foothills	1.983	1.318	1.152	0.070	0.047	0.041
Lower Charlie Lake	South Foothills	1.416	0.822	0.723	0.050	0.029	0.026
Combined Charlie Lake	Fort St. John	51.107	36.543	27.317	1.814	1.297	0.970
Halfway	North Foothills	30.991	27.041	23.071	1.100	0.960	0.819
Halfway	South Foothills	14.164	6.087	5.111	0.503	0.216	0.181
Halfway	Fort St. John 1	54.217	39.721	32.184	1.924	1.410	1.142
Halfway	Fort St. John 2	114.396	85.303	67.165	4.060	3.028	2.384

TABLE 2.4 (CONTINUED)

Marketable Gas Estimates by Formation and Play Area

Formation	Play area	10^9m^3			Tcf		
		GIP	Producible	Marketable	GIP	Producible	Marketable
Doig-Lower Halfway	Fort St. John-Deep Basin	19.667	12.667	9.566	0.698	0.450	0.340
Montney	Subcrop	62.788	49.090	42.984	2.229	1.742	1.526
Montney	Distal Shoreface-Turbities	53.440	20.007	18.621	1.897	0.710	0.661
Belloy	North Foothills	14.164	12.748	11.580	0.503	0.452	0.411
Belloy-Debolt	South Foothills	141.456	113.093	83.805	5.021	4.014	2.975
Belloy	Fort St. John	55.856	46.516	39.983	1.983	1.651	1.419
Kiskatinaw	Peace River Embayment	21.416	12.785	10.634	0.760	0.454	0.377
Mattson	Liard Basin	15.218	12.538	10.896	0.540	0.445	0.387
Debolt	North Foothills	57.037	32.521	30.765	2.024	1.154	1.092
Debolt	Cretaceous Subcrop	11.662	9.577	8.062	0.414	0.340	0.286
Debolt	Regional Platform	23.108	10.106	8.800	0.820	0.359	0.312
Shunda-Pekisko-Banff	Cretaceous Subcrop	2.890	2.020	1.719	0.103	0.072	0.061
Shunda-Pekisko-Banff	Regional Platform	1.461	1.133	0.997	0.052	0.040	0.035
Shunda-Pekisko-Banff	Liard Basin	1.461	1.011	0.870	0.052	0.036	0.031
Wabamun	Fort St. John-Deep Basin	20.216	18.100	16.639	0.718	0.642	0.591
Kakisa	Platform	1.278	1.139	1.015	0.045	0.040	0.036
Jean Marie	Platform	200.225	130.076	116.262	7.107	4.617	4.127
Jean Marie	Bank Edge	86.153	76.714	67.465	3.058	2.723	2.395
Slave Point	Reef Margin	171.641	83.692	66.759	6.092	2.971	2.370
Slave Point	Platform	58.744	29.901	23.049	2.085	1.061	0.818
Slave Point	Ladyfern	53.247	45.723	37.475	1.890	1.623	1.330
Keg River	Reef Margin	190.751	149.424	107.913	6.770	5.304	3.830
Keg River	Lower Platform	6.088	2.636	2.127	0.216	0.094	0.076
Nahanni	Fort Nelson-Liard	42.492	9.102	7.404	1.508	0.323	0.263

2.5 Comparison With Previous Studies

Estimates of ultimate potential for natural gas in B.C. have been made periodically in the past. The last detailed NEB report to examine the undiscovered resources portion of the ultimate potential, *Natural Gas Resource Assessment Northeast British Columbia* was based on year-end 1992 data and published in 1994. The last NEB report on resources in northeast B.C., *Northeast British Columbia Natural Gas Resource Assessment 1992-1997*, published in 2000, was based on year-end 1997 data. It only examined changes in the discovered resources between 1992 and 1997, while maintaining ultimate potential estimates from the 1994 report.

As described in previous NEB reports, estimates of ultimate potential generally tend to increase over time. This is usually the result of increased information available as development of a basin or area matures. The data available shows a slight increase over time for ultimate potential estimates of marketable conventional natural gas in northeast B.C. As shown in Figure 2.2, the MEMPR/NEB's new estimate of B.C.'s ultimate potential has increased from 1 436 10^9m^3(50.6 Tcf) in 1992 to the current 1 462 10^9m^3 (51.9 Tcf). Future studies will continue to monitor the trend in ultimate potential.

Studies of ultimate potential for conventional natural gas have been undertaken by others as well. Notably, the Canadian Gas Potential Committee (CGPC)[4] conducts studies for all of Canada and released reports in 1997 and in 2001, titled *Natural Gas Potential in Canada*. The CGPC is expected to publish an updated report in 2006. Table 2.5 shows a comparison of the estimates for conventional gas in northeast B.C. only.

2.6 Canadian Resources

The NEB, as part of its mandate, maintains estimates of ultimate potential for all regions of Canada. Its current estimates of Canadian resources were provided in its 2004 Report *Canada's Conventional Natural Gas Resources: A Status Report*. Table 2.6 shows the new estimate of B.C.'s ultimate potential for natural gas in perspective with the rest of Canada in both metric and imperial units. Data in Table 2.6 is current to year-end 2004.

FIGURE 2.2

Changes in Estimates of Ultimate Potential for Conventional Marketable Gas in British Columbia

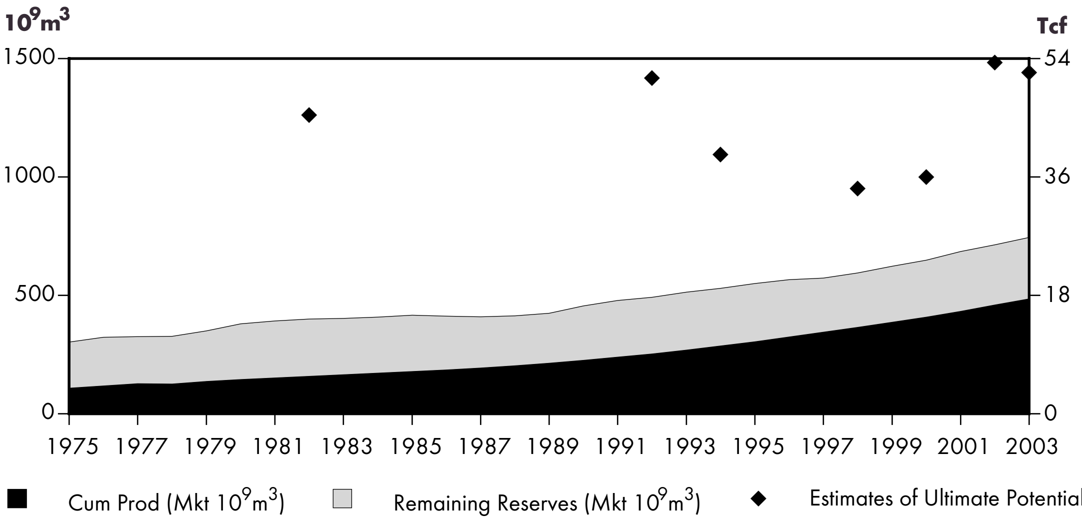


TABLE 2.5

Comparison of Ultimate Potential Estimates for Conventional Natural Gas in British Columbia

Source	Reference Date	Ultimate Potential (10^9m^3)	Ultimate Potential (Tcf)
BCMEMPR/NEB 2006	2003	1 462.3	51.9
Drummond 2002	2001	1 512.7	53.4
Bowers 2000	2000	1 020.0	36.2
CGPC 2001	1998	969.0	34.3
CGPC 1997*	1994	1 117.5	39.7
NEB 1994	1992	1 436.2	50.6
GSC 1982	1981	1 286.1	45.4

* - approximate volume only, for provincial breakdown

4 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.

TABLE 2.6A

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

	Discovered Resources	Undiscovered Resources	Ultimate Potential[1]	Remaining Ultimate Potential[2]
Western Canada Sedimentary Basin				
Alberta	4 542	1 734	6 276	2 856
British Columbia	784	678	1 462	952
Saskatchewan	213	42	255	102
Southern Territories	27	169	196	181
Total	**5 566**	**2 623**	**8 189**	**4 091**
East Coast (Offshore)				
Labrador	130	660	790	790
East Newfoundland Basin	0	352	352	352
Grand Banks	110	375	485	485
Southern Grand Banks	0	86	86	86
Laurentian Sub-Basin	0	170	170	170
Nova Scotia	147	505	652	629
George's Bank	0	60	60	60
Total	**387**	**2 208**	**2 595**	**2 572**
West Coast				
Offshore	0	255	255	255
Intermontane	0	230	230	230
Total	**0**	**485**	**485**	**485**
Northern Canada				
Northwest Territories - Colville Hills	17	117	134	134
Mackenzie-Beaufort	254	1 460	1 714	1 714
Yukon - Eagle Plains	2	28	30	30
Yukon - Others	1	114	115	115
Arctic Islands	331	793	1 124	1 124
Eastern Arctic	0	140	140	140
Hudson Bay	0	28	28	28
Total	**605**	**2 680**	**3 285**	**3 285**
Ontario	**44**	**23**	**67**	**33**
Gulf of St. Lawrence (Maritimes Basin)	**2**	**38**	**40**	**40**
TOTAL CANADA[1]	**6 604**	**8 057**	**14 661**	**10 506**

1 - numbers may not add due to rounding

2 - as of 31 December 2004, latest date for complete production information

TABLE 2.6B

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

	Discovered Resources	Undiscovered Resources	Ultimate Potential[1]	Remaining Ultimate Potential[2]
Western Canada Sedimentary Basin				
Alberta[3]	161	61	223	101
British Columbia[3]	28	24	52	34
Saskatchewan	8	1	9	4
Southern Territories	1	6	7	6
Total	**198**	**92**	**291**	**145**
East Coast (Offshore)				
Labrador	5	23	28	28
East Newfoundland Basin	0	12	12	12
Grand Banks	4	13	17	17
Southern Grand Banks	0	3	3	3
Laurentian Sub-Basin	0	6	6	6
Nova Scotia	5	18	23	22
George's Bank	0	2	2	2
Total	**14**	**77**	**91**	**90**
West Coast				
Offshore	0	9	9	9
Intermontane	0	8	8	8
Total	0	17	17	17
Northern Canada				
Northwest Territories - Colville Hills	1	4	5	5
Mackenzie-Beaufort	9	52	61	61
Yukon - Eagle Plains	0	1	1	1
Yukon - Others	0	3	3	3
Arctic Islands	12	28	40	40
Eastern Arctic	0	5	5	5
Hudson Bay	0	1	1	1
Total	**22**	**94**	**116**	**116**
Ontario	**1**	**1**	**2**	**1**
Gulf of St. Lawrence (Maritimes Basin)	**0**	**1**	**1**	**1**
TOTAL CANADA[1]	**235**	**282**	**517**	**370**

1 - numbers may not add due to rounding

2 - as of 31 December 2004, latest date for complete production information

3 - Converted to imperial using 35.49373 cf/m3, refer to Section 1.3

OBSERVATIONS

3.1 General

The new estimate of ultimate potential for conventional natural gas in northeast B.C. is 1 462.3 10^9m^3 (51.9 Tcf), an increase of two percent from the last NEB estimate. While the new estimate is similar to the previous estimate, the distribution of the ultimate potential in both a vertical sense (geological) and horizontal sense (geographical) has changed. These changes have occurred as a result of where discoveries have been made (formation and location) since 1992 and the current geological understanding of this portion of the WCSB. In a general sense, there has been an increased recognition of the undiscovered potential of the shallower Cretaceous intervals, new intervals recognized due to discoveries made, and a reduction in the undiscovered potential attributed to the foothills areas.

Geological plays in B.C. tend to be less developed than similar plays in Alberta. Only two plays, the Nikanassin Buick Creek and the Belloy Ft. St. John, have had more than 50 percent of the available land in the play areas drilled to date. Both of these plays have relatively small play areas and were developed over a long period of time following relatively early discoveries. The very shallow Cretaceous plays have technically been penetrated to a fairly high degree, but the vast majority of those wells were targeting deeper horizons and by-passed shallower Cretaceous zones during drilling. Today these zones, with the higher gas prices, are recognized as having potential which is being successfully exploited through adaptive drilling practices which avoid formation damage. The agencies believe that there will be additional discoveries made in these zones in the near future.

Over the past six years, industry has successfully developed deeper new plays in many portions of northeast B.C., including discovery of the Ladyfern Field (094H) in the Devonian Slave Point Formation. As well, with the increased drilling activity many smaller new pools have been located and placed on production. Between year-end 1997 and year-end 2003, the volume of discovered GIP increased from 562.8 to 709.9 10^9m^3 (20.0 to 25.2 Tcf), an overall increase of 25 percent. In total, an average of 24.6 10^9m^3 (0.87 Tcf)/year of GIP has been added from new discoveries and/or revisions to the GIP of older pools during that time. Thirty-eight percent of that increase occurred in Devonian formations, 37 percent from Triassic formations and 18 percent from the shallower Cretaceous formations. Devonian increases occurred as a result of the Ladyfern Slave Point discovery and from increases in the Jean Marie plays. Triassic increases occurred as a result of development of the Pardonnet/Baldonnel play, Halfway/Doig plays and Montney plays such as the Ring-Border Field (094H). Cretaceous increases occurred as a result of development of many smaller pools.

The Devonian Jean Marie Formation play areas have experienced a significant increase in drilling and in reserves in the past few years. The Platform play which has been produced since the 1970s continues to have its pools extended laterally. These reservoirs consist of relatively tight fractured carbonates which do not appear to have a down-dip water leg. Horizontal drilling and larger, more efficient fracturing programs, spurred by higher gas prices and royalty changes, have allowed industry to aggressively pursue development on a larger scale. New seismic techniques and better geologic interpretations have resulted in the Bank Edge play being recognized and developed in the last five years. Industry is also becoming more efficient in development, by utilizing more planning, and using year-round drilling to reduce costs in these plays. From an analysis standpoint, the reserves data at year-end 2003 were insufficient to make a proper @Risk analysis for the Bank Edge Play. As well, significant revisions occurred in the reserves information for the Platform play in 2004, which hindered the @Risk analysis. The recognized gas-in-place volume for that play more than doubled in 2004. As a result, the agencies were guided by information obtained through consultation with industry to estimate the undiscovered gas resources for these plays.

The Cadomin Deep Basin play area development started in 2004. Resource play development strategies learned during the development of the Jean Marie play, are now being applied to the tight sands in the Cadomin Formation. Since this development took place after the 2003 reserves data were finalized, the agencies again were guided by information from industry consultations to estimate the undiscovered resources in this play area.

3.2 Regional

Figure 3.1 is a map of northeast B.C. showing the geographical regions used by the provincial government. Those areas are somewhat different from the areas identified in the last NEB assessment, with the major difference being the boundary between the Fort St. John and Northern Foothills region in map areas 94-B-16 and 94-G-1. The former boundary was located further to the east which put a significant volume of discovered resources in the Fort St. John region instead of the Northern Foothills region. As a result, it is difficult to compare between 1992 and 2006 results on a regional basis. Table 3.1 shows the discovered, undiscovered and ultimate potential estimates for both gas in place and marketable volumes for each of the geographical regions. The Liard Basin and Liard Fold Belt regions are combined for this report.

The discovered resources, using either GIP or marketable volumes, have increased by 25 percent over the past six years. Looking at the foothills regions, the discovered in place volumes are similar to those volumes reported in 1997. In contrast, the plains regions have seen the discovered volumes increase by 30 percent. There have been large new discoveries at Ladyfern (Fort St. John), Ring-

TABLE 3.1

Geographical Distribution of Resources in Northeast British Columbia

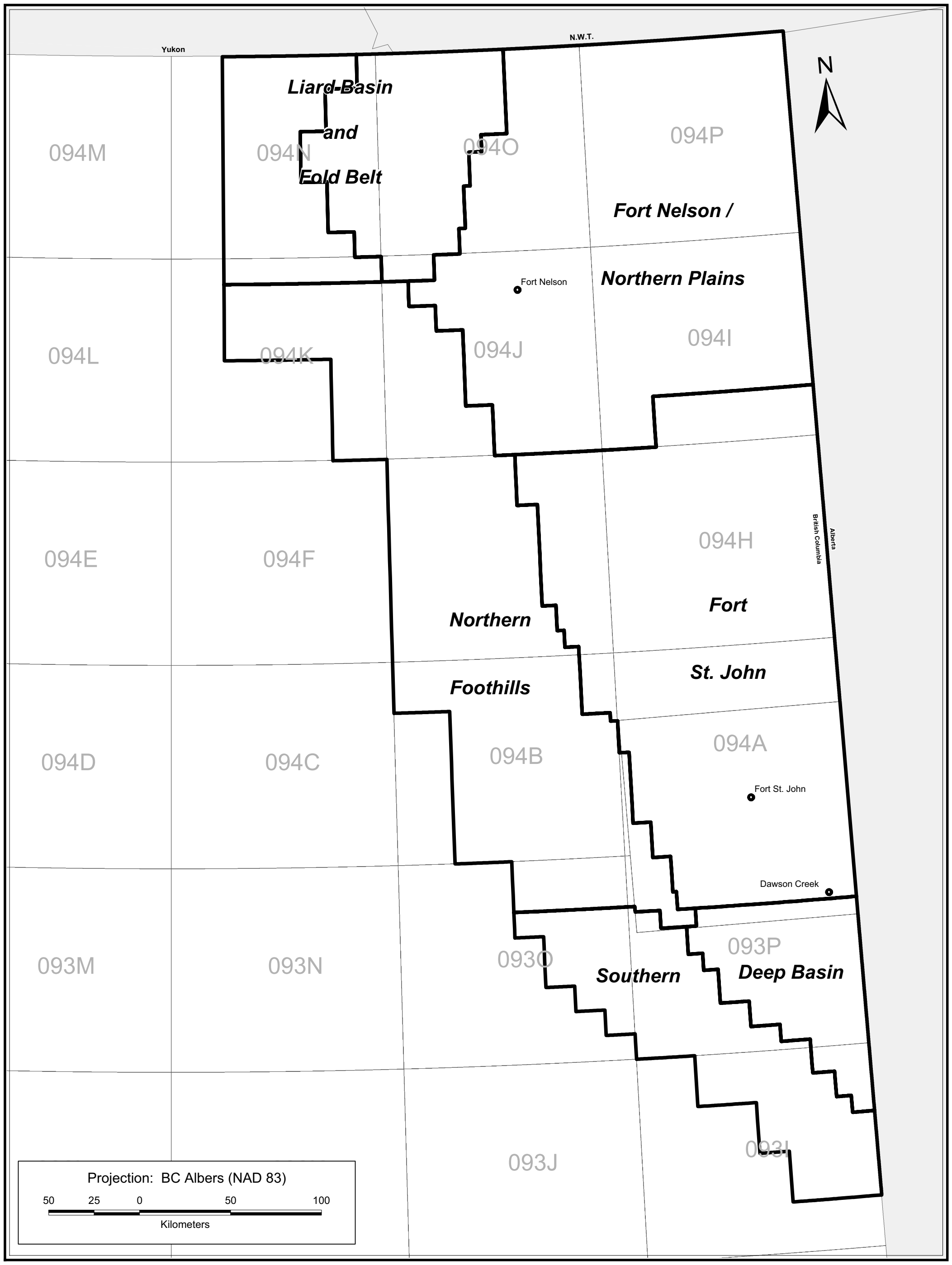
Region	Discovered				Undiscovered				Remaining Ultimate Potential[2]	
	Gas In Place		Marketable		Gas In Place		Marketable		Marketable	
	10^9m^3	Bcf	10^9m^3	Bcf	10^9m^3	Bcf	10^9m^3	Bcf	10^9m^3	Bcf
Deep Basin[1]	28 685	1 018	19 556	694	313 098	11 113	157 337	5 584	164 111	5 825
Fort St. John[1]	560 752	19 903	352 639	12 516	361 834	12 843	211 522	7 508	349 864	12 418
Fort Nelson[1]	395 273	14 029	206 871	7 343	261 301	9 275	148 551	5 273	201 098	7 138
Liard	22 197	788	14 430	512	69 807	2 478	26 767	950	32 904	1 168
South Foothills	142 572	5 060	82 621	2 933	230 851	8 194	131 606	4 671	174 808	6 205
North Foothills	58 882	2 090	33 647	1 194	118 983	4 223	76 640	2 720	87 941	3 121
Total	1 208 361	42 889	709 764	25 192	1 355 874	48 125	752 423	26 706	1 010 726	35 874

1 regions collectively considered as the plains area

2 as per OGC annual reserves report

FIGURE 3.1

Geographical Regions of Northeast British Columbia



Border (Fort St. John), Greater Sierra (Fort Nelson) and in the Helmet area (Fort Nelson) since 1997. In the Liard Basin, the discovered volume has increased as a result of the Maxhamish Lake Field (094O).

The undiscovered potential for northeast B.C. has been reduced by 14 percent since 1997 as new discoveries and positive revisions to the reserves of discovered pools used up some of the 1997 undiscovered potential. The undiscovered potential in the foothills regions have been reduced through better geological knowledge and incorporation of industry knowledge through the consultation process of this report. The undiscovered potential for the Liard Basin has been reduced from the 1997 results as there have been no large discoveries made there since the Maxhamish Lake Field and any deep wells drilled since 1997 have been unsuccessful. Finally, the undiscovered potential for the plains regions have increased since 1997 in spite of the many large discoveries made. Recognition of new zones, continuation of zones with discoveries on the Alberta side of the border into the B.C. side, and increased geological knowledge from the many new wells drilled have all contributed to the increase.

For ultimate potential, there has been a slight increase for northeast B.C. (two percent). For the foothills regions, the ultimate potential has been reduced overall (no change in discovered, reduced undiscovered). For the Liard region, the ultimate potential has also been reduced (discovered up, undiscovered down significantly). The plains regions have seen the ultimate potential increase (discovered up, and undiscovered up).

All regions of northeast B.C. contain sufficient volumes of undiscovered resources to support increased drilling levels for a number of years.

3.3 Sour Gas

The discovered marketable resource from the year-end 2003 data is comprised of 420.5 10^9m^3 (15 Tcf) of sour gas and 289.4 10^9m^3 (10.3 Tcf) of sweet gas, based on OGC information. The agencies analysis of the undiscovered marketable gas indicates that it will be comprised of 505.3 10^9m^3 (17.9 Tcf) of sweet gas and 247.1 10^9m^3 (8.8 Tcf) of sour gas. Approximately 60 percent of the discovered gas was sour gas, but only 32 percent of the undiscovered resources are expected to be sour since the majority of undiscovered resources will be found in sweet gas plays. Hydrogen sulphide content ranges from 0.1 to 39 percent with an average of 3.7 percent.

3.4 Foothills

Companies that were consulted in this process provided information (on the various plays that are recognized as having potential in either the southern or northern foothills) that contributed to a better understanding of the resource potential in those regions. While there was never complete agreement from different companies on any particular zone, the agencies determined which formations required either increases or decreases to the preliminary estimates of undiscovered resources.

In addition, the companies were asked about issues that impact activity in these complex areas. The following are some of the issues that illustrate the complexities and that may require government resolution:

- Drilling in the foothills is an expensive and time-consuming proposition. Wells can take longer to get regulatory approval to proceed (in comparison with wells drilled on the plains) and, with the warmer winters recently, there are concerns that wells may not be completed in a single season. As in other areas of northeast B.C., there is recognition of the greater need for environmental studies and discussion with the First Nations than in the past. The foothills tend to provide larger targets than corresponding pools in the plains regions which provides the incentive for companies to explore. Companies suggest that the land tenure system should take into account the delays for regulatory approval, environmental studies and access negotiations.
- The companies indicated that the economics of drilling in these regions are still only marginal in spite of the high gas prices experienced recently. Further, activity is restricted

to companies with sufficient financial resources to work in these regions. Since those companies also tend to have international opportunities, prospects in the B.C. foothills may have to compete for limited exploration dollars.

- From a producer's perspective, a significant issue affecting activity is access to sour gas plants. Existing plants are often operating at or near capacity and available plant capacity for third parties can be a limiting factor. Some operators suggested a new plant in the area or improved access to sour gas plants elsewhere through pipelines from the area would be desirable. However, the financial risk associated with building a plant prior to drilling, or drilling without capacity to produce is very high. This is a similar situation as seen in the Alberta foothills.
- Companies also identified a need for improved coordination in activity notification between the various government bodies and users of surface land, including coal mining, forestry and petroleum companies.

3.5 Access Restrictions

The use of the @Risk model allows for an approximate determination of undiscovered resources that may be precluded from development by surface access restrictions. This is also referred to as sterilization of the resource. Due to the absence of national parks, large urban areas and large lakes in northeast B.C., there does not appear to be any significant resource volumes that, in theory, can not be accessed through directional drilling technology. Industry consultations did not give a clear indication that there were any resources that have been sterilized for all practical purposes due to surface restrictions. Practically; however, incremental costs associated with directional drilling can have a significant impact on competitiveness. Two of the eight companies suggested that there could be sterilized resources in the foothills, with one company suggesting as much as 42 $10^9 m^3$ (1.5 Tcf) is impacted.

CONCLUSIONS

1. The revised estimate of ultimate potential for conventional gas in the B.C. portion of WCSB is 1 462.3 (51.9 Tcf), a slight increase from the 1992 NEB estimate.
2. Northeast B.C. is not as mature as the Alberta portions of the basin, with only two plays currently having more than 50 percent of their land drilled to date.
3. The Devonian Jean Marie Platform has seen continual expansion of the pools over larger areas, including a significant expansion in 2004. As a result, use of the 2003 data led to poor @Risk results which were too low in comparison to the 2004 data. The agencies assigned a large GIP estimate with a reduced recovery factor.
4. Discovered resources have increased by 25 percent since 1997. Large discoveries made since 1997, such as the Maxhamish Lake, Ladyfern and Greater Sierra Fields have revised the distribution of undiscovered potential in the geological section.
5. Undiscovered potential has been increased in the shallower Cretaceous horizons compared with 1997. The potential in these zones was not recognized in past assessments.
6. Approximately 60 percent of discovered resources contain sour gas; however, it is expected that only 32 percent of the undiscovered resources will be sour, since the large sour gas plays are already well developed.
7. Foothills areas have seen little growth in discovered resources since 1997 and as a result the undiscovered potential attributed to them has decreased. This was confirmed through industry consultation.
8. The Liard area has seen an increase in the discovered resources, but the undiscovered resources have decreased due to poor results from deeper tests.
9. Limits to surface access may have some impact on the exploration for undiscovered resources.
10. There are additional conventional and unconventional gas resources available for development in the interior of B.C. and in offshore basins (see Appendix 1).
11. Total undiscovered potential has been reduced by 14 percent since 1997 as a number of pools have been discovered and downward revisions of resources for some plays have been made on the basis of drilling results and pool performance. However, the remaining undiscovered resources will support high drilling levels for many years.
12. Northeast British Columbia holds about one-quarter of the ultimate remaining conventional natural gas resources in the WCSB.

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Unconventional Gas, Southeast British Columbia, Interior Basins and Offshore Basins

Gas from low permeability reservoirs, that could be considered as unconventional under some definitions, but which is currently being developed, is included in the assessment of conventional ultimate potential in this report. Other unconventional resources such as coalbed gas, tight gas that is not currently being developed, and shale gas are described qualitatively below, with no new estimates of marketable resources. Figure A1.1 shows the location of basins with coalbed gas resources in British Columbia. Table A1.1 shows the gas-in-place estimates for unconventional resources for British Columbia.

A1.1 Coalbed Gas (CBG)

Coalbed gas, also known as coalbed methane (CBM) or natural gas in coal (NGC), is gas found in coal seams, either in the open fracture pore-space of the coal, or adsorbed within the matrix of the coal. The majority of the gas is adsorbed in the coal matrix and in order to get that gas to be desorbed,

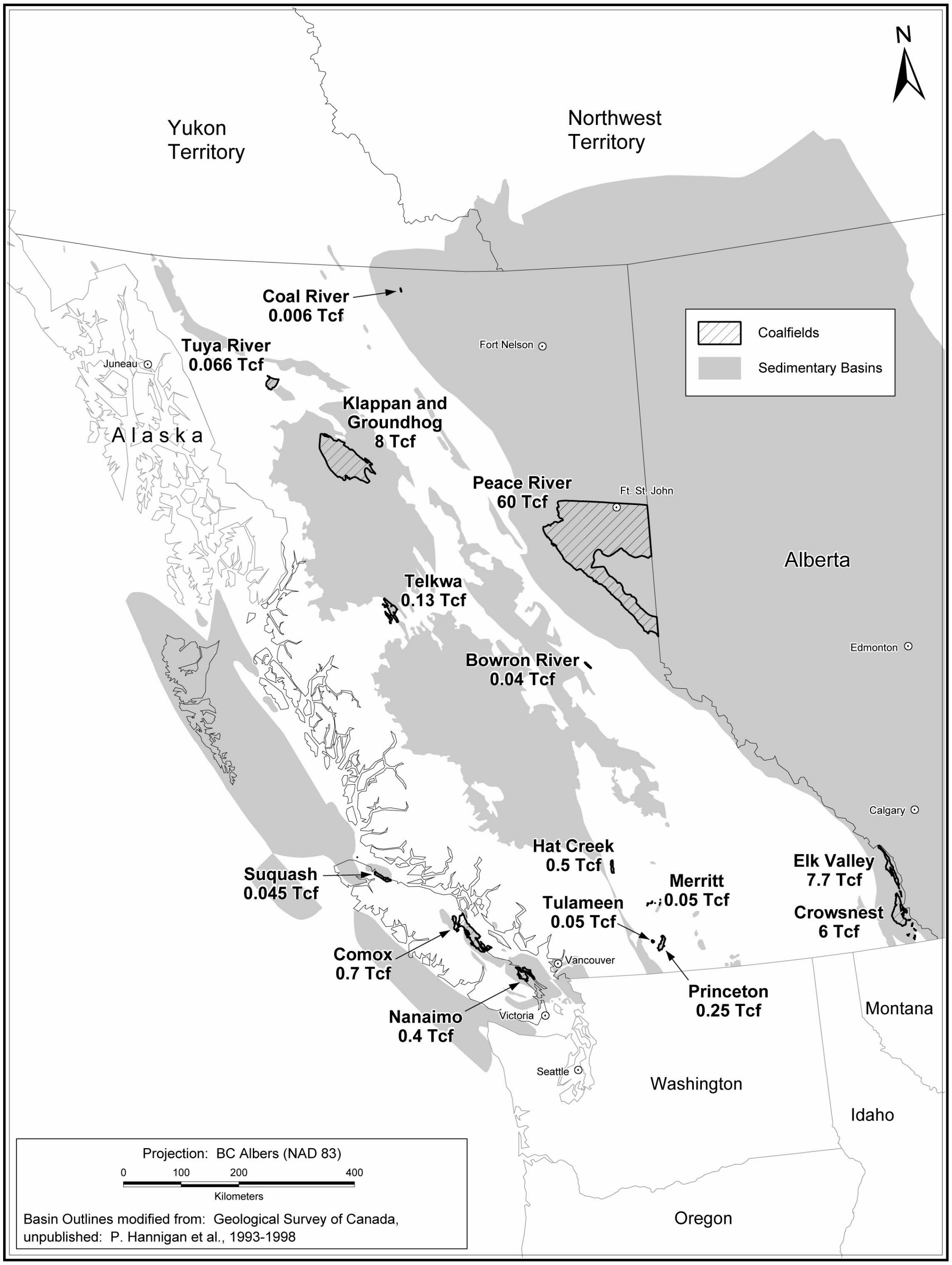
TABLE A1.1

Gas-in-place Estimates of Unconventional Resources in British Columbia

Unconventional Gas Type	Basin	Estimate of GIP	
		10^9m^3	Bcf
Coalbed Gas	Crowsnest	169	6 000
	Elk Valley	216.9	7 700
	Princeton	7	250
	Tulameen	1.4	50
	Merritt	1.4	50
	Hat Creek	14.1	500
	Nanaimo	11.3	400
	Comox	19.7	700
	Suquash	1.3	45
	Bowron River	1.1	40
	Telkwa	3.7	130
	Klappen-Groundhog	225.4	8 000
	Tuya River	1.9	66
	Coal River	0.2	6
	Peace River	1 690.4	60 000
Tight Gas	WCSB	8 500	300 000
Shale Gas	WCSB	7 082	250 000
Gas Hydrates	Offshore B.C.	3 200-24 000	113 000-847 000

FIGURE A1.1

Map of Basins with Coalbed Gas Potential in British Columbia



the pressure must be reduced. In the U.S., pressure reduction has been achieved by producing the water associated with coal seams which releases the gas that is co-produced with the water. Over time, the amount of water produced declines and the amount of gas increases. In Canada, CBG has been commercially produced both from the shallow Cretaceous Horseshoe Canyon Formation and from the deeper Lower Cretaceous Mannville Formation in Alberta. The Horseshoe Canyon Formation is a dry coal with little to no water production associated with the gas production. The Mannville coals are produced with saline water, and this water is then disposed into other formations.

In northeast British Columbia, the Mannville coals are present and have been tested near Tumbler Ridge and Hudson's Hope. Elsewhere in B.C., the Lower Cretaceous to Jurassic-aged Kootenay coal is being evaluated in the Elk Valley near Sparwood. In the Princeton area and on Vancouver Island, CBG evaluation programs are underway or being planned. The MEMPR has previously published reports on the CBG potential in the province. These reports provide basic information on coal age, thickness, and preliminary gas contents, and provide estimates of the GIP. Readers are referred to the MEMPR Web site[5] for a list of those reports. Figure A1.1 shows where the coal deposits are found in the province and gives the GIP of each deposit.

The amount of CBG that could be recovered in the future is still unknown due to the early stage of evaluation. In this report, the agencies have not assigned any marketable gas volumes to CBG.

A1.2 Tight Gas

Low permeability or "tight gas" represents the major amount of what could be defined as unconventional gas currently under development in B.C. Stricter Canadian definitions of tight gas are in the process of being developed by the Canadian Society for Unconventional Gas. Future reports by the MEMPR or NEB may use those definitions.

In the U.S., tight gas is defined for tax purposes as production from formations with less than 0.1 milli-Darcies of permeability. Generally, these formations require fracturing of the reservoir rock using large volumes of fluid such as nitrogen under high pressures and the injection of materials (proppants), usually silica sand grains or ceramic beads, to hold the fractures open after the induced pressures are released. In addition, these formations may require the drilling of horizontal wells or multiple vertical wells to efficiently and economically produce these gas resources.

It has been estimated that as much as 30 percent of Canada's conventional gas would fit into the U.S. definition, and studies are underway to more accurately determine that ratio. Northeast British Columbia plays that will likely be considered as tight gas formations in the future include the Devonian Jean Marie plays, some of the Cretaceous Cadomin plays, and some of the Cretaceous sand plays in the Deep Basin region. In this study, producing plays, such as the examples given, have been included as conventional gas. However, the agencies believe that the conventional GIP attributed to these formations understates additional volumes that could be recognized as tight gas. In other B.C. basins, it is too early to tell what kind of volumes could be recovered from tight gas formations.

A1.3 Shale Gas

As the name implies, these gas resources are contained in formations that are composed of shale, a very fine grained mixture of organic and inorganic material. Gas in these formations can be present within the microscopic pore spaces or adsorbed onto the fine organic material within the matrix. Pressure reduction allows the gas to desorb and flow to the well bore. In reality, these shales should be considered to cover a wide range of rock types ranging from pure shale to shaley sands or silts. In the past, these formations were considered to be a source rock, that is, the source of the petroleum products that migrated to conventional sand and carbonate formations from which they were produced. The quality of a source rock is dependent on the amount of organic material it contains

5 www.em.gov.bc.ca/subwebs/coalbedgas/Regions/

and on the degree that it has been heated to (via depth and pressure) over time, to convert the organic material to hydrocarbons.

In the U.S., it has now been found that under certain conditions these formations can be productive reservoirs that will generally produce at relatively low rates but for a longer term than conventional reservoirs. The amount of natural fracturing within the formation, and the amounts of organic material and coarser material it contains combine to determine the quality of the zone as a reservoir. These formations may need multiple wells per section, the use of horizontal well bores and additional hydraulic fracturing to achieve economic flow rates.

At present, there are no large scale production programs from shale horizons in Canada, although there are occasional wells in Alberta that do produce gas or oil from highly fractured shales. In northeast B.C., there has been some testing of shale reservoirs, but there is no public information to draw upon. In February 2005, MEMPR released a study of the Devonian Gas shales of northeast B.C. (Exshaw, Besa River, Muskwa, and Ft. Simpson Formations). Other intervals of interest are Cretaceous shales (Wilrich, Moosebar and Buckinghorse Formations), Jurassic shales (Fernie and Nordegg Formations), and the Triassic (Pardonnet, Doig Phosphates and Montney Formations).

A1.4 Gas Hydrates

Gas hydrates consist of methane molecules trapped within a cage-like structure of ice. In Canada, hydrates have been found in marine areas as ice on or under the ocean bottom or in perma-frost conditions in the north. The offshore portion of British Columbia has Type B gas hydrates, those that have lower saturations, may be continuous, occupy the sediment/rock pore spaces and commonly contain biogenic hydrocarbons. Samples of these hydrates have been recovered from the Tofino Basin. GIP estimates are very large but technologies have yet to be developed to commercially recover gas hydrates. Due to the uncertainties associated with gas hydrates, no estimate of marketable gas is included.

A1.5 Southeast British Columbia

A1.5.1 Resource Assessment

The southeast part of British Columbia has had a long history of petroleum exploration, with the first wells drilled in the early 1900s. Although commercially unsuccessful, subsequent exploration in the 1980s discovered large accumulations of carbon dioxide rich natural gas within thrust faulted rocks of the Rocky Mountains. However, the area remains relatively unexplored. Since 1950, only 20 wells have been drilled in this area, which comprises over 6 000 km^2, and significant potential remains.

MEMPR has conducted two geological studies of the Fernie and Flathead areas and both are available from the MEMPR Web site. These studies identified major play trends and the petroleum resource potential of the area (see Table A1.2).

The most prospective targets for significant methane rich natural gas discoveries lie within strata below the Lewis Thrust Fault in southeast British Columbia (Waterton Paleozoic Play). The Geological Survey of Canada (GSC) has an ultimate resource estimate of 27 Tcf in place within southern B.C., southwestern Alberta and northwestern Montana. Of this, over eight Tcf has been found predominantly in bordering regions in southwestern Alberta. While southeast B.C. has potential for large gas accumulations within this play type, a significant carbon dioxide component is anticipated.

Another play with significant oil and gas potential occurs within the Tertiary Kishenehn Basin southeast of Fernie. Eight wells, some with recorded hydrocarbon shows, have been drilled in the Kishenehn Basin. Of these, five predate the 1950s and none test the thicker parts of the basin.

A1.6 Interior Basins

A1.6.1 Geological Framework

The Interior Basins of British Columbia are part of the Cordilleran Intermontane Basins.

In this report, the Interior Basins, which historically have been considered as containing hydrocarbon potential, have been subdivided into seven categories: 1) Nechako Basin; 2) Quesnel Trough; 3) Rocky Mountain Trench; 4) Tyaughton-Methow Basin; 5) Bowser Basin; 6) Sustut Basin and 7) Whitehorse Trough (see Figure A1.2).

A1.6.2 Resource Assessment

The GSC and MEMPR produced a series of reports[6] which provide the details of the geological make-up of these basins, as well as the probabilistic resource assessments for the various Interior

TABLE A1.2

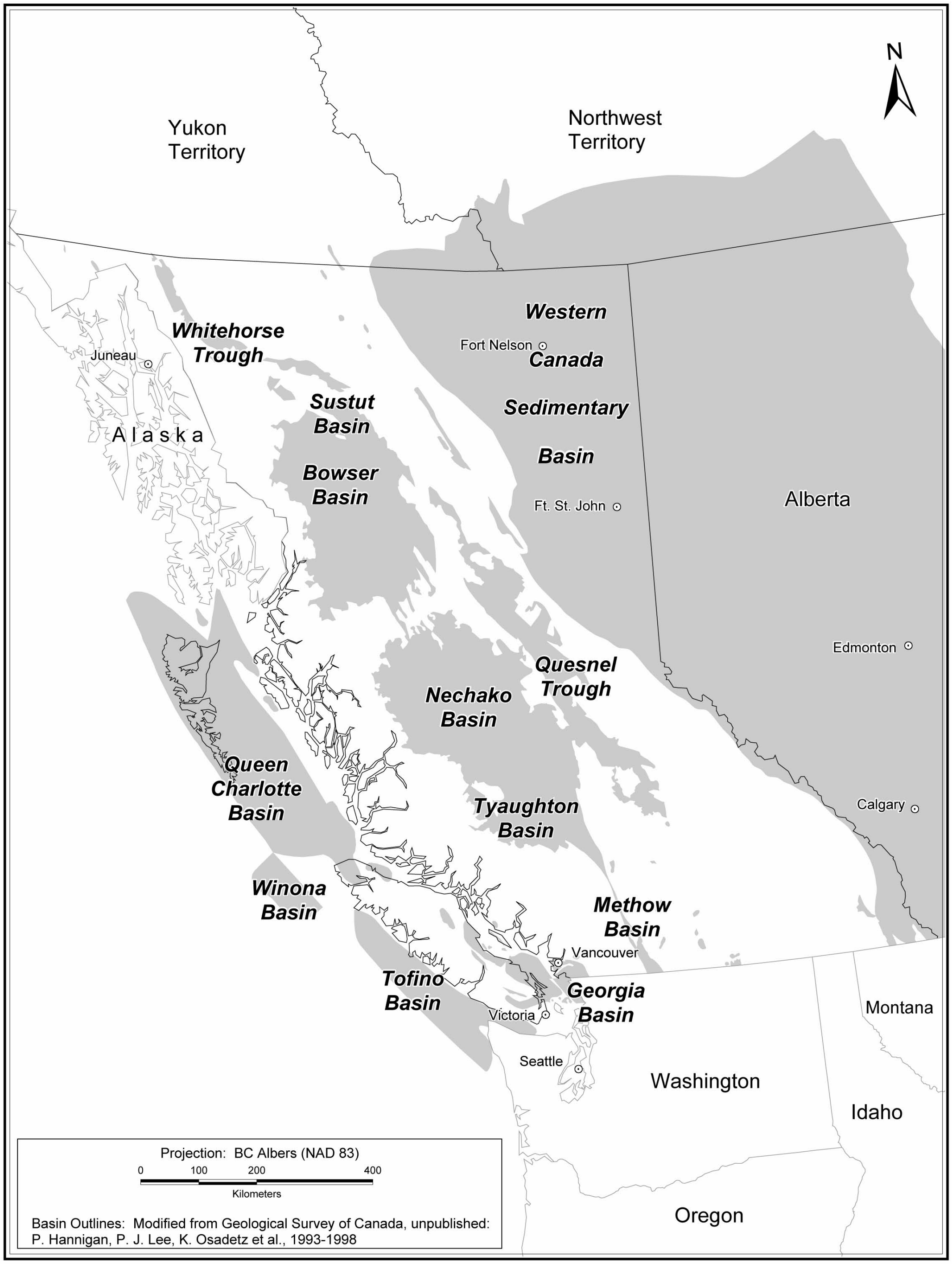
Oil and Gas-in-place Estimates for Interior Basins and Southeast British Columbia

Basin	Play	Gas		Oil	
		10^9m^3	Bcf	10^6m^3	Million Barrels
Nechako	Tertiary Structural	14.2	500	21.7	136
	Upper Cretaceous Structural	0.6	23	2.0	13
	Skeena Structural	247.0	8 767	774.0	4 870.6
Quesnel	Tertiary Structural	8.4	296	12.1	76
Rocky Mountain Trench	Sifton Structural	0.1	5	0.0	0
Tyaughton-Methow	Skeena Structural (BC portion)	0.0	1	0.0	1
Bowser	Skeena Structural	71.9	2 540	201.0	1 264
	Bowser Lake	57.8	2 000	0.0	0
Sustut	Upper Cretaceous	52.7	1 860	184.0	1 158
Whitehorse Trough	Takwahoni (BC portion)	21.8	770	0.0	0
	Inklin Structural (BC portion)	15.7	557	0.0	0
	Stuhini/Lewis River (BC portion)	15.3	540	0.0	0
Southeast B.C.	Waterton Colorado	0.6	21	0.0	0
	Kishenehn	1.5	53	10.3	65
	Waterton Paleozoic	5.8	205	0.0	0
	MacDonald Paleozoic	0.4	14	0.0	0
	Waterton Mannville	0.9	32	3.5	22
	Fernie/Elk Valley Mesozoic	0.2	7	0.0	0
	Fernie/Elk Valley Paleozoic	2.0	71	0.0	0
	Rocky Mtn Trench	0.2	7	0.0	0

6 Oil and Gas Resource Potential of the Nechako-Chilcotin Area of British Columbia, Oil and Gas Resource Potential of the Bowser-Whitehorse Area of British Columbia, and Petroleum Exploration Potential of the Nechako Basin

F I G U R E   A 1 . 2

Map of Interior and Offshore Basins in British Columbia



Basins based on geological parameters and risk factors. The parameters and risk factors that were incorporated into the models were based on the knowledge base at the time and where information was lacking, assumptions were made. Since these reports were written, new geological information has been, or is currently being gathered by the MEMPR or the GSC in some areas (Whitehorse Trough, Bowser and Sustut Basins, Nechako area) that will be incorporated into revised resource assessments that should more accurately reflect the hydrocarbon potential of these basins.

Only a limited amount of drilling has taken place in these basins to date. However, extensive field work has been conducted recently. That field work has identified several play types, the inference of possible source rocks, reservoir rocks, and geological trapping mechanisms that could be present in the subsurface. The agencies will continue to monitor developments in these basins and will report on those developments as required.

Table A1.2 summarizes the total mean in-place oil and gas resource estimates for each play type within Interior Basins in British Columbia. The Tertiary plays have been broken out, although they were originally assigned to the various basins. Although several play types, such as the Relay Mountain Group of the Tyaughton-Methow Basin and the Ashcroft Formation of the Quesnel Trough, could conceptually contain hydrocarbons, these were deemed too risky and no estimate was generated. The reader is referred to these publications for a detailed description of play parameters and risk factors. Collectively, the NEB currently assigns 230 $10^9 m^3$ (8 Tcf) of marketable gas resources to these basins at this time.

A1.7 Offshore Basins

A1.7.1 Geological Framework[7]

In this report, the Offshore Basins which historically have been considered as containing hydrocarbon potential have been subdivided into three regions: 1) Queen Charlotte and Hecate Basins; 2) Georgia Basin and 3) Tofino and Winona Basins. Petroleum exploration took place up to 1972 when the federal government imposed a moratorium in response to environmental concerns. Starting in the late 1990s, the provincial and federal governments initiated studies of both the technology and environment to determine if the offshore could be re-opened to petroleum exploration in the future. No decision has been made at this time. Gas-in-place estimates are reported for each of the offshore basins, based on work done by the GSC. Table A1.3 shows the gas-in-place estimates for the offshore basins. Collectively, the NEB currently assigns 255 $10^9 m^3$ (9 Tcf) of marketable gas resources to these basins.

A1.7.2 Queen Charlotte and Hecate Basins

These basins have been penetrated by nine onshore wells drilled from the Queen Charlotte Islands and eight offshore wells prior to 1972, with the first well drilled in 1913. In addition, there are several thousand kilometres of marine seismic and gravity surveys over the basins. There have been numerous gas and oil seeps observed on the Queen Charlotte Islands and wells encountered significant shows of both oil and gas. Drilling did not find any commercial volumes of hydrocarbons.

A1.7.3 Georgia Basin

The Georgia Basin underlies the Strait of Georgia, parts of Vancouver Island, the Fraser River Delta and part of northwestern Washington State and consists of a series of four sub-basins. The Georgia Basin has been penetrated by 125 wells drilled onshore, mostly in Washington, with the first well drilled in 1901. No offshore wells have been drilled. There have been aeromagnetic surveys, and both onshore and marine seismic surveys done. There has been gas production reported from glacial sediments in Washington and other wells have reported gas shows. Coalbeds were the original source rock for most of the gas shows, but at least some thermogenic gas has been reported.

7 *Petroleum Resource Potential of Sedimentary Basins On The Pacific Margin of Canada*, 1998

TABLE A1.3

Oil and Gas-in-place Estimates for Offshore British Columbia Basins

Basin	Play	Gas		Oil	
		10^9m^3	Bcf	10^9m^3	Million Barrels
Queen Charlotte/Hecate	Pliocene	321.8	11 706	398.0	2 503
	Miocene	285.7	10 141	574.0	3 610
	Cretaceous	75.4	2 676	392.0	2 465
Georgia	Pleistocene	0.2	7	0.0	0
	Tertiary	59.3	2 105	0.0	0
	Cretaceous	118.5	4 206	0.0	0
Tofino/Winona	Tertiary	266.0	9 441	0.0	0

A1.7.4 Tofino and Winona Basins

The Tofino Basin lies offshore of the west coast of Vancouver Island. There are numerous aeromagnetic surveys and seismic surveys, that were conducted from the 1960s to the 1980s, available for research. Four onshore and six offshore wells have been drilled without success. Onshore gas seeps have been reported along with thermogenic gas shows recorded in at least two wells. Gas hydrates have been recovered from the ocean bottom in this area, with the latest testing done by the Integrated Ocean Drilling Program in 2005.

ASSESSMENT METHODOLOGIES USED FOR NORTHEAST BRITISH COLUMBIA

This appendix reviews how the methodologies are applied to each of the play areas, with reference to the accompanying Play Atlas to be published by MEMPR by the end of March 2006 (Table A2.1).

TABLE A2.1

Methodology Used for Assessing Geologic Plays in the Northeast British Columbia Conventional Gas Assessment

Geological Age	Play Area	Methodology Used	Reason(s)
Tertiary	Glacial Sand	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Belly River-Deep Basin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Chinook-Deep Basin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Cardium-Deep Basin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Cardium-Regional Aquifer	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Doe Creek-Deep Basin	Assignment	Insufficient reserve data in B.C., discoveries made
Upper Cretaceous	Dunvegan-Deep Basin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Dunvegan-Fort St. John	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Upper Cretaceous	Dunvegan-Liard Basin	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Upper Cretaceous	Sikanni-Liard	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Upper Cretaceous	Sikanni-Fort St. John	Assignment	Insufficient data in B.C., based on geological knowledge
Lower Cretaceous	Scatter-Liard	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Lower Cretaceous	Paddy-Deep Basin	@Risk Model	Sufficient data
Lower Cretaceous	Paddy-Northern Barrier	Assignment	Insufficient reserve data in B.C., discoveries made
Lower Cretaceous	Paddy-Northeast Deep Basin	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Lower Cretaceous	Cadotte-South Deep Basin	@Risk Model	Sufficient data

TABLE A2.1 (CONTINUED)

Methodology Used for Assessing Geologic Plays in the Northeast British Columbia Conventional Gas Assessment

Geological Age	Play Area	Methodology Used	Reason(s)
Lower Cretaceous	Cadotte-Regional Aquifer	@Risk Model	Sufficient data
Lower Cretaceous	Cadotte-South Foothills	@Risk Model	Sufficient data
Lower Cretaceous	Spirit River-Deep Basin/South Foothills	@Risk Model	Sufficient data
Lower Cretaceous	Spirit River-Northern Shoreface	@Risk Model	Sufficient data
Lower Cretaceous	Bluesky-Deep Basin	@Risk Model	Sufficient data
Lower Cretaceous	Bluesky-Peace River Shoreface	@Risk Model	Sufficient data
Lower Cretaceous	Bluesky-Altares-Aitken Valley	@Risk Model	Sufficient data
Lower Cretaceous	Bluesky-Keg River Shoreface	@Risk Model	Sufficient data
Lower Cretaceous	Gething-Fluvial/Alluvial Plain	@Risk Model	Sufficient data
Lower Cretaceous	Gething-Northern Isolated Valley Fills	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Lower Cretaceous	Cadomin-Deep Basin	Assignment	Assignment based on industry consultation
Lower Cretaceous	Cadomin-Spirit River Valley	@Risk Model	Sufficient data
Lower Cretaceous	Chinkeh-Liard	Assignment	Insufficient reserve data in B.C., discoveries made
Lower Cretaceous	Nikanassin-South Foothills	@Risk Model	Sufficient data
Lower Cretaceous	Nikanassin-North Foothills	Assignment	Assignment made after industry consultation, proportional to South Foothills
Lower Cretaceous	Nikanassin-Deep Basin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Lower Cretaceous	Nikanassin-Buick Creek	@Risk Model	Sufficient data
Triassic	Pardonnet Baldonnel-South Foothills	@Risk Model	Sufficient data
Triassic	Pardonnet Baldonnel-North Foothills	@Risk Model	Sufficient data
Triassic	Pardonnet Baldonnel-Deep Basin	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Triassic	Pardonnet Baldonnel-Fort St. John 1	@Risk Model	Sufficient data
Triassic	Pardonnet Baldonnel-Fort St. John 2	@Risk Model	Sufficient data
Triassic	Upper Charlie Lake-North Foothills	@Risk Model	Sufficient data
Triassic	Lower Charlie Lake-North Foothills	Assignment	Assignment based on industry consultation

TABLE A2.1 (CONTINUED)

Methodology Used for Assessing Geologic Plays in the Northeast British Columbia Conventional Gas Assessment

Geological Age	Play Area	Methodology Used	Reason(s)
Triassic	Lower Charlie Lake-South Foothills	Assignment	Assignment based on industry consultation
Triassic	Upper & Lower Charlie Lake-Fort St. John/Deep Basin	@Risk Model	Sufficient data
Triassic	Halfway-North Foothills	@Risk Model	Sufficient data
Triassic	Halfway-South Foothills	Assignment	Assignment based on industry consultation
Triassic	Halfway-Fort St. John 1	@Risk Model	Sufficient data
Triassic	Halfway-Fort St. John 2	@Risk Model	Sufficient data
Triassic	Doig/Lower Halfway-Fort St. John/Deep Basin	@Risk Model	Sufficient data
Triassic	Montney-Subcrop	@Risk Model	Sufficient data
Triassic	Montney-Distal Shoreface/ Turbidites	@Risk Model	Sufficient data
Triassic	Montney-Foothills	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Triassic	Montney-Liard	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Permo-Penn	Belloy-North Foothills	Assignment	Assignment based on industry consultation
Permo-Penn	Belloy-Fort St. John	@Risk Model	Sufficient data
Permo-Penn	Belloy/Debolt-South Foothills	@Risk Model	Sufficient data
Permo-Penn	Belloy-Deep Basin	Conceptual	Assignment based on industry consultation
Permo-Penn	Belloy-Liard	Conceptual	Assignment based on industry consultation
Mississippian	Kiskatinaw-Fort St. John	@Risk Model	Sufficient data
Mississippian	Mattson-Liard	@Risk Model	Sufficient data
Mississippian	Debolt-Cretaceous Subcrop	@Risk Model	Sufficient data
Mississippian	Debolt-Regional Platform	@Risk Model	Sufficient data
Mississippian	Debolt-North Foothills	@Risk Model	Sufficient data
Mississippian	Shunda/Pekisko/Banff-Cretaceous Subcrop	@Risk Model	Sufficient data
Mississippian	Shunda/Pekisko/Banff-Regional Platform	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Mississippian	Shunda/Pekisko/Banff-Distal Ramp Margin	Assignment	Insufficient data in B.C., based on geological knowledge and Alberta results
Devonian	Wabamun-Fort St. John/Deep Basin	@Risk Model	Sufficient data
Devonian	Wabamun-Northern Platform	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Wabamun-South Foothills	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Kakisa-Platform	@Risk Model	Sufficient data, area restricted to near discoveries
Devonian	Jean Marie-Platform	Assignment	Large change in 2004 versus 2003 reserves data, used very large GIP, but reduced recovery factor
Devonian	Jean Marie-Bank Edge	Assignment	Assignment based on industry consultation
Devonian	Jean Marie-South	Conceptual	Zone present, but not proven by the drilling of oil or gas wells

TABLE A2.1 (CONTINUED)

Methodology Used for Assessing Geologic Plays in the Northeast British Columbia Conventional Gas Assessment

Geological Age	Play Area	Methodology Used	Reason(s)
Devonian	Leduc-Peace River Arch	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Slave Point-Reef Margin	@Risk Model	Sufficient data
Devonian	Slave Point-Ladyfern	@Risk Model	Sufficient data
Devonian	Slave Point-Platform	@Risk Model	Sufficient data
Devonian	Slave Point-North Foothills	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Keg River-Reef Margin	@Risk Model	Sufficient data
Devonian	Keg River-Lower Platform	@Risk Model	Sufficient data
Devonian	Keg River-Transition to Muskeg Evaporites	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Keg River-North Foothills	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Chinchaga/Nahanni-Bank Edge	Assignment	Insufficient reserve data in B.C., discoveries made
Devonian	Chinchaga/Nahanni-Carbonate Platform	Conceptual	Zone present, but not proven by the drilling of oil or gas wells
Devonian	Granite Wash-Peace River Arch	Conceptual	Zone present, but not proven by the drilling of oil or gas wells

APPENDIX THREE

Maps Showing the Resource Distribution in Northeast British Columbia

FIGURE A3.1

Discovered Conventional Natural Gas Resources

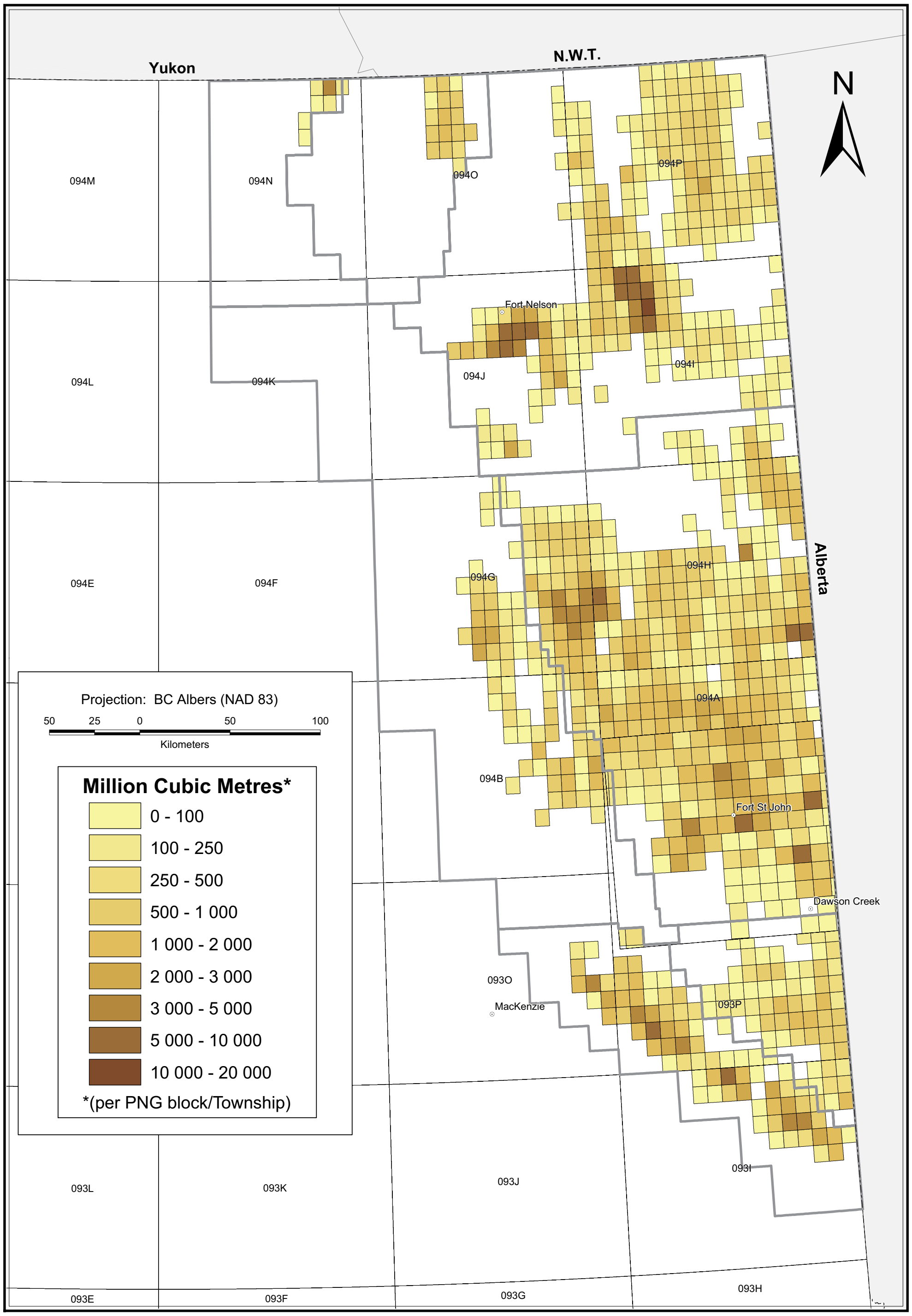


FIGURE A3.2

Undiscovered Conventional Natural Gas Resources

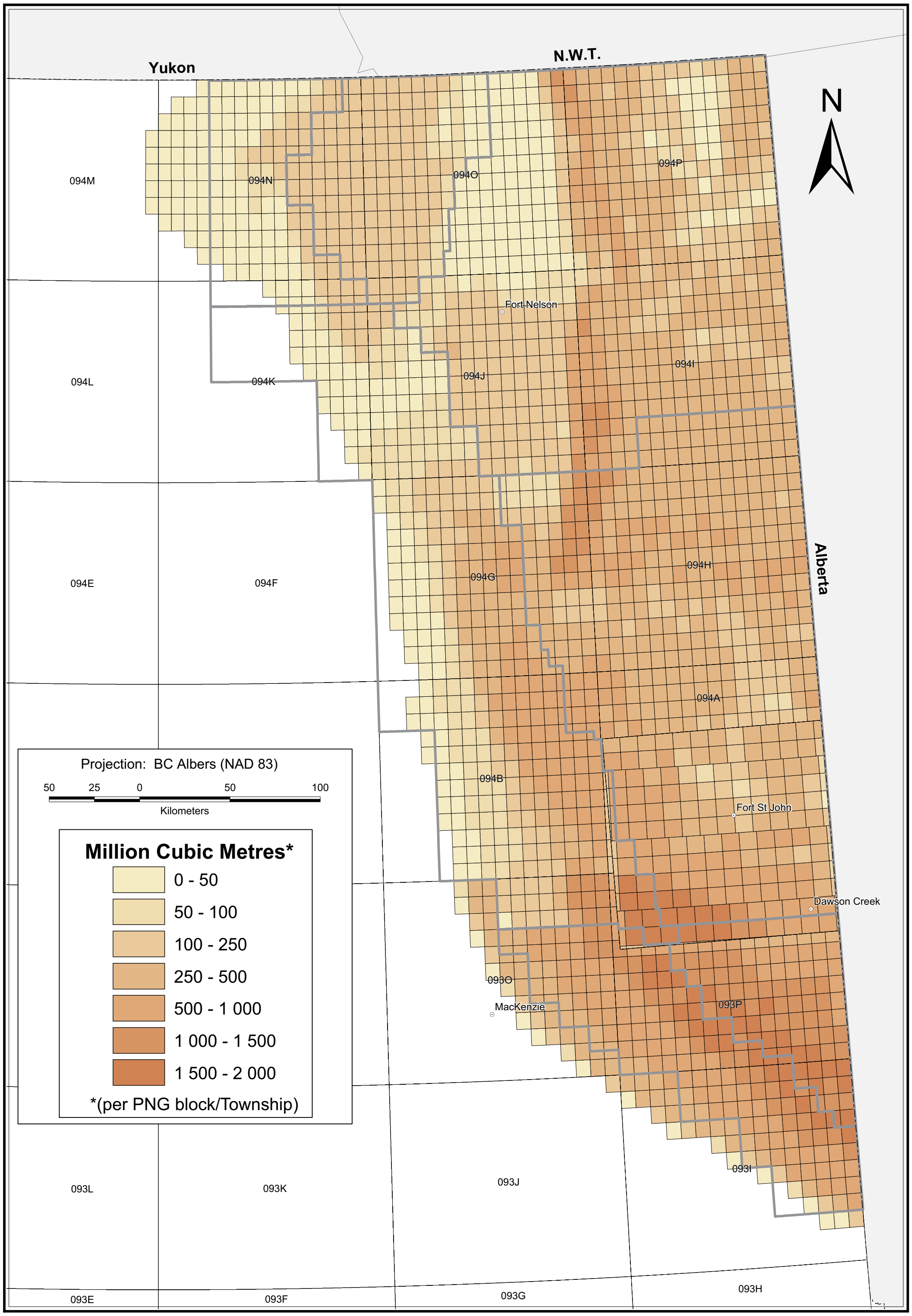
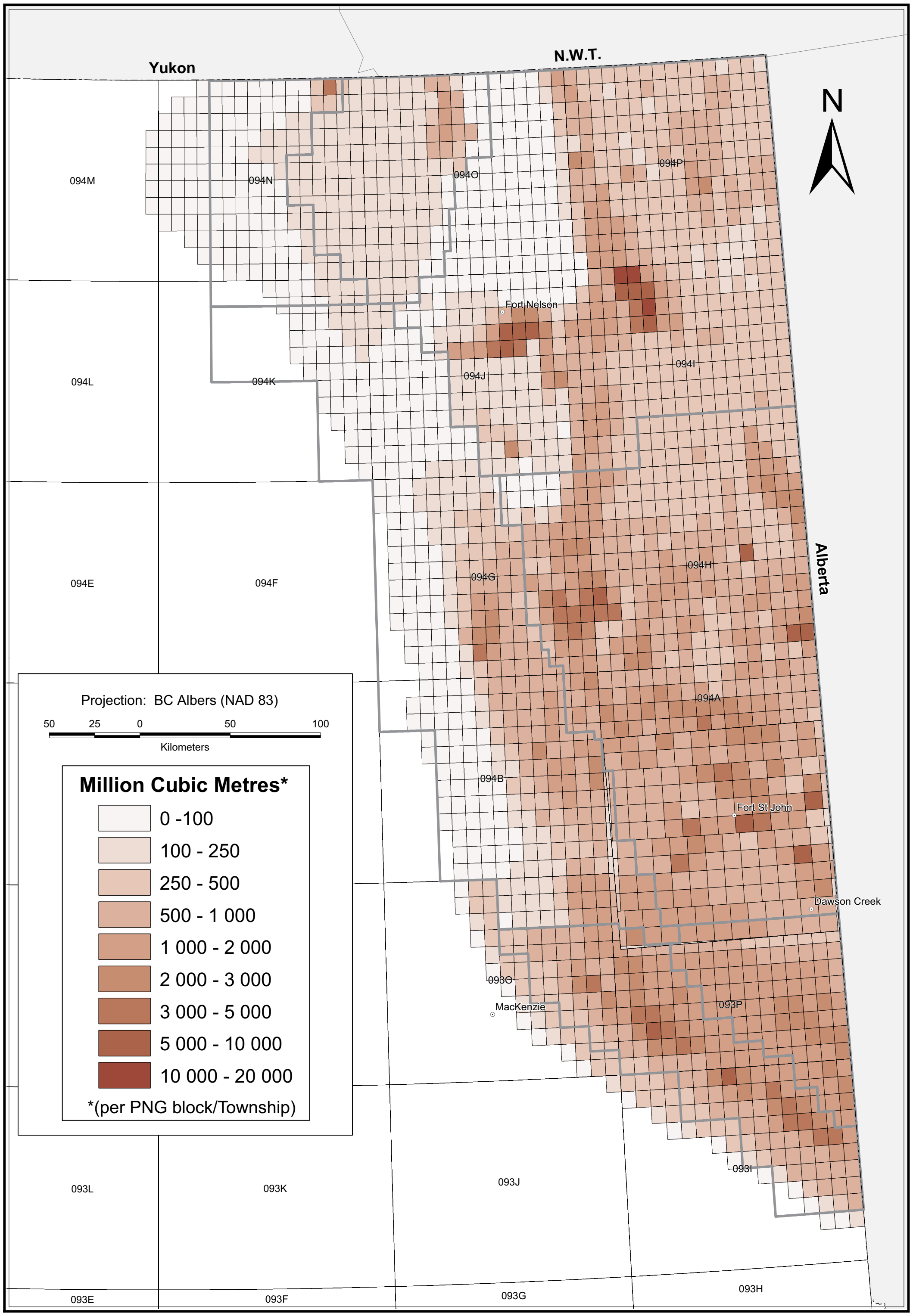


FIGURE A3.3

Ultimate Potential for Conventional Natural Gas



F I G U R E   A 3 . 4

Remaining Ultimate Potential for Conventional Natural Gas