Alberta's Ultimate Potential for Conventional Natural Gas

March 2005

Alberta Energy and Utilities Board
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Foreword

The Alberta Energy and Utilities Board (EUB) is an independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development, and delivery of Alberta's energy resources and utilities services take place in a manner that is fair, responsible, and in the public interest.

The EUB regulates the safe, responsible, and efficient development of Alberta's energy resources—oil, natural gas, oil sands, coal, and electrical energy—and the pipelines and transmission lines to move the resources to market. On the utilities side, it regulates rates and terms of service of investor-owned natural gas, electric, and water utility services, as well as the major intra-Alberta gas transmission system, to ensure that customers receive safe and reliable service at just and reasonable rates.

The National Energy Board (NEB) is an independent, quasi-judicial agency of the Government of Canada. Its purpose is to promote safety, 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.

As part of its mandate under the *National Energy Board Act*, the NEB continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas, and their by-products) and the demand for Canadian energy commodities in both domestic and export markets. The NEB publishes reports on energy, known as Energy Market Assessments, which examine various facets of Canada's supply and demand and specific reports on current and near-term energy market issues. The NEB also has a specific monitoring role pursuant to its regulatory responsibilities whereby it monitors Canadian energy markets to ensure that they are operating such that Canadian energy requirements are being met at fair market prices.

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. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Independently, the EUB and NEB recognized the need for a re-examination of the conventional natural gas resources in Alberta. In order to make best use of limited staff availability and to demonstrate regulatory efficiency, the two Boards formed a partnership for this study. This study examines the geological potential for conventional natural gas resources and provides an estimate of those resources for Alberta. The main objective of this report is to provide the estimate and the methodology used to determine that estimate. The estimate, subject to future joint revisions, will be used by the EUB and NEB in their future projections of natural gas supply.

Executive Summary

The Alberta Energy and Utilities Board (EUB) and the National Energy Board (NEB) (the Boards) estimate supply and demand on a provincial and national scale respectively. Ultimate potential of conventional natural gas is a key component required to make projections of future supply. Since the EUB's last detailed study of the ultimate potential for gas in Alberta was done in 1992, the number of wells drilled has doubled. Similarly, almost 25 per cent more wells have been drilled in Alberta since the last NEB study, released in 2004, which was based on data from year-end 2000. In 2001, the Boards separately came to the conclusion that an updated ultimate potential estimate was required. Collectively, to show regulatory efficiency and in line with the cooperation as set out in the EUB/NEB *Common Reserves Database Agreement*, the two Boards decided to collaborate on a joint study.

This report, *Alberta's Ultimate Potential for Conventional Natural Gas*, presents the results of the joint study and includes details on the methodology. The Boards have adopted 6276 billion cubic metres (10^9 m^3) (223 trillion cubic feet [Tcf]) as their estimate of ultimate potential for marketable conventional natural gas. Note that this estimate does not include unconventional gas, such as coalbed methane (CBM). The new estimate for conventional natural gas will be used by both Boards in future supply projections.

The new estimate is 12 per cent higher than the last EUB estimate and is 7 per cent higher than the last NEB estimate. The primary reason for the increased ultimate potential is a better understanding of the geology of the province gained as a result of the increased drilling since 1992. As a result, Alberta will continue to be the main supply region for Canadian gas demands.

Having regard for the inherent uncertainty in estimating geological prospects and predicting gas potential, the project team estimated a range for the ultimate potential for marketable conventional natural gas in Alberta to be 5765 10^9 m^3 (205 Tcf) to 7134 10^9 m^3 (253 Tcf), as shown in Table A.

Table A. Alberta's ultimate potential for marketable conventional natural gas

	Gas in place		Marketable gas	
Case	10^9 m^3	Tcf	10^9 m^3	Tcf
Low	9731	345	5765	205
Medium	10583	376	6276	223
High	12012	426	7134	253

Table B shows a breakdown of ultimate potential for natural gas into its components as of early December 2004 (production to end of October 2004).

Table B. Categorization of ultimate potential—medium case

	Gas in place		Marketable gas	
Category	10^9 m^3	Tcf	10^9 m^3	Tcf
Discovered	7744	275	4542	161
Cumulative production	5863	208	3438	122
Remaining discovered	1882	67	1104	39
Undiscovered	2838	101	1734	62
Ultimate potential	10583	376	6276	223
Remaining ultimate potential	4720	168	2838	101

The remaining ultimate potential estimate represents the volume of gas that will be available in the future to meet Canadian domestic and export demands. The new estimate of remaining ultimate potential for conventional natural gas in Alberta is 2838 10^9 m^3 (101 Tcf).

Although increased from earlier estimates, Alberta's remaining ultimate potential of marketable conventional natural gas will require supplements from unconventional gas supplies in order to continue to meet Canadian domestic and export demands. Extraction of both types of gas resources will contribute to a healthy and vibrant oil and gas industry in Alberta for many years to come.

1 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 depend on the size and quality of its resource base. Within Canada, the province of Alberta is the major contributor to gas supply, accounting for almost 80 per cent of the total Canadian production.

1.1 History

Recently, there have been record levels of drilling in Alberta, reserves growth has been unable to match production, and Alberta appears to have reached, or at least is very near, its peak capacity. Consequently, there is significant interest in Alberta's ultimate potential for marketable conventional natural gas.

Beginning in the 1950s, the Alberta Energy and Utilities Board (EUB) and the National Energy Board (NEB) (the Boards) have made periodic estimates of the ultimate potential for natural gas in Alberta. The EUB's last detailed study used data available to mid-1991, and these data were presented in EUB *Report 92-A: Ultimate Potential and Supply of Natural Gas in Alberta*. The NEB's most recent study took advantage of the data for wells drilled to year-end 2000. The NEB report *Conventional Natural Gas Resources—A Status Report,* released in April 2004, dealt with all of Canada. The NEB's assessment of Alberta's resources detailed in that report was intended as an interim estimate to be superseded by the results of this joint assessment.

Estimates of ultimate potential tend to increase over time. This is usually the result of increased information available as development of a basin or area matures. Estimates reflect the judgement of the estimators. As shown in Figure 1.1, estimates for Alberta's ultimate potential have increased from 2254 billion cubic metres ($10^9\ m^3$) (80 trillion cubic feet [Tcf]) in 1955 to the current 6276 $10^9\ m^3$ (223 Tcf). Future studies will continue to monitor the trend in ultimate potential.

Ultimate potential studies have been undertaken by others as well. Notably, the Canadian Gas Potential Committee (CGPC) conducts studies for all of Canada and released reports in 1997 and 2001, the most recent entitled *Natural Gas Potential in Canada 2001*. Table 1.1 shows a comparison of the estimates noted with the medium case value from this study.

Table 1.1. Comparison of ultimate potential marketable natural gas estimates for Alberta

Source	Date of data	Ultimate potential ($10^9\ m^3$)	Ultimate potential (Tcf)
EUB/NEB 2005	2004	6276	223
NEB 2004	2000	5855	207
CGPC 2001	1998	5761	203
EUB 1992	1991	5600[1]	200[2]

[1] 37.4 megajoules per cubic metre basis.
[2] 1000 British Thermal Units per cubic foot basis.

The current study uses data from 320 000 wells drilled by December 2004. The NEB 2004 report was based on data from 250 000 wells drilled in Alberta by year-end 2000. The 2001 CGPC report used data from the 230 000 wells that had been drilled by its reference date of year-end 1998. The EUB's 1992 report was based on data from 160 000 wells that had been drilled in Alberta by mid-1991.

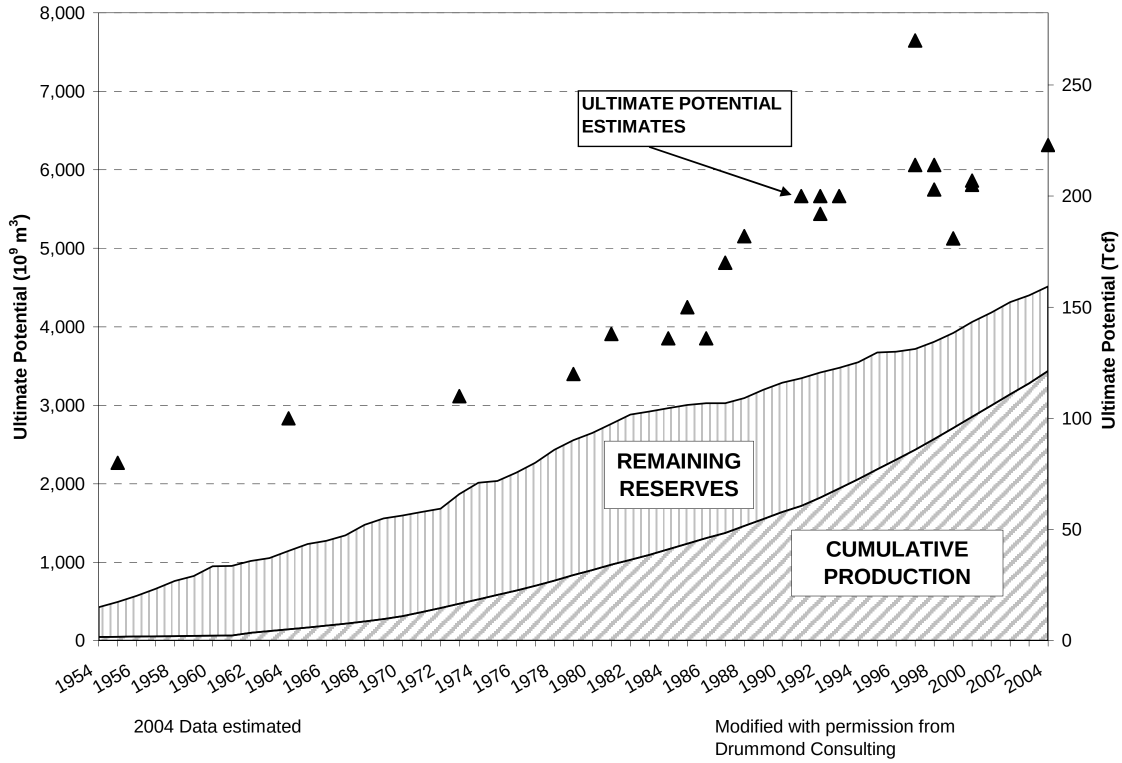

Figure 1.1. Historical estimates of Alberta's ultimate potential for conventional natural gas

In addition to new well information available since the previous studies, circumstances have changed significantly in recent years. Increases in gas prices have resulted in the exploration for and development of many new low-productivity pools that were previously beyond economic reach. The Boards recognize that a large number of wells have been drilled in development areas to maintain contract rates and were not for exploratory purposes. Advances in technology, such as horizontal drilling, 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 new pools.

The Boards concluded that a new study of ultimate potential was required. In line with their partnership on natural gas and crude oil reserves and to improve regulatory efficiency, the Boards decided to collaborate on a joint study of the conventional natural gas resources of Alberta. Consequently, a project team of staff from the Boards was created (see Acknowledgements).

1.2 Scope and Format of This Report

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. 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 drilled, while undiscovered resources are expected to be discovered by future drilling.

The terminology used in discussing ultimate potential in this study is presented in Figure 1.2.

<table>
<tr><th colspan="4">Terms</th><th>Level of Uncertainty</th></tr>
<tr><td rowspan="4">Ultimate Potential</td><td rowspan="2">Undiscovered</td><td colspan="2">Future</td><td rowspan="2">High
↑
Medium</td></tr>
<tr><td colspan="2">Unbooked/Unconfirmed/Bypassed</td></tr>
<tr><td rowspan="2">Discovered</td><td rowspan="2">Booked</td><td>Reserves</td><td>Low</td></tr>
<tr><td>Cumulative Production</td><td>None</td></tr>
</table>

Figure 1.2. Terminology for study of Alberta’s ultimate potential for conventional natural gas

Gas in place is the volume of gas in the reservoir, *recoverable gas* is the volume that can be produced, and *marketable gas* is the volume that remains after processing. Although this report focuses on gas in place (GIP), it also includes estimates of recoverable and marketable gas using parameters from existing pools. 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 to meet future market demands.

This report deals only with conventional natural gas, that is, gas from clastic and carbonate reservoirs where recovery is possible with technological improvements and prices that can be reasonably anticipated. Coalbed methane (CBM), shale gas, and other forms of unconventional gas are not considered. As discussed in Section 5.1, the main source of unconventional gas in Alberta is CBM.

In recognition of the inherent uncertainty in making estimates of ultimate potential for gas, this report presents low, medium, and high case estimates. The low case reflects a high degree of certainty, while the high case recognizes that the resources could be discovered but that there is much uncertainty associated with the estimate. The medium case is assumed to be the most realistic estimate.

This report does not specifically deal with the economics of discovering, developing, or producing Alberta’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 intended to form the basis for economic analysis and supply projections by the EUB, NEB, or others.

The appendix presents the details of the methodology applied in estimating the ultimate GIP. Section 3 discusses the conversion of the ultimate GIP estimates to producible, initial marketable, and remaining marketable gas volumes.

1.3 Units of Measure

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

Both the EUB and NEB state natural gas volumes in metric units at the standard conditions of 101.325 kilopascals (kPa) and 15 degrees Celsius (°C). In imperial units, the EUB uses standard conditions of 14.65 pounds per square inch absolute (psia) and 60 degrees Fahrenheit (°F), while the NEB uses 14.73 psia and 60°F. For 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 EUB. 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-2001 and continued to the end of 2004. Data analysis and updates were done on existing EUB databases throughout that period and new databases specific to the ultimate potential study were developed. All data retrievals were refreshed on December 7, 2004, and the final ultimate potential estimates were based on these data. This means that wells drilled and evaluated and internal reserve changes made prior to December 7, 2004, are incorporated in this study.

1.5 Industry Input and Peer Review

The project team did not request formal input from industry in the form of a public hearing or proceeding for this study. However, informal discussions were held with various operators active in the foothills area in order to gain further insight into this geologically complex area. In addition, a limited peer review was conducted with staff from the CGPC and the Earth Science Sector of Natural Resources Canada. Input received from all parties was very beneficial and greatly appreciated.

1.6 Supplemental Information

In addition to this report, a considerable amount of supplemental information is available. Figure 1.3 shows the format and the media on which each part is available. The report is available in English and French at no charge. The report and maps are available on the EUB and NEB Web sites. A CD containing the report, maps, and supplemental information is available at the EUB at no charge. A second CD containing the ultimate potential database, as well as the report, maps, and supplemental information, is available at the EUB at a cost.

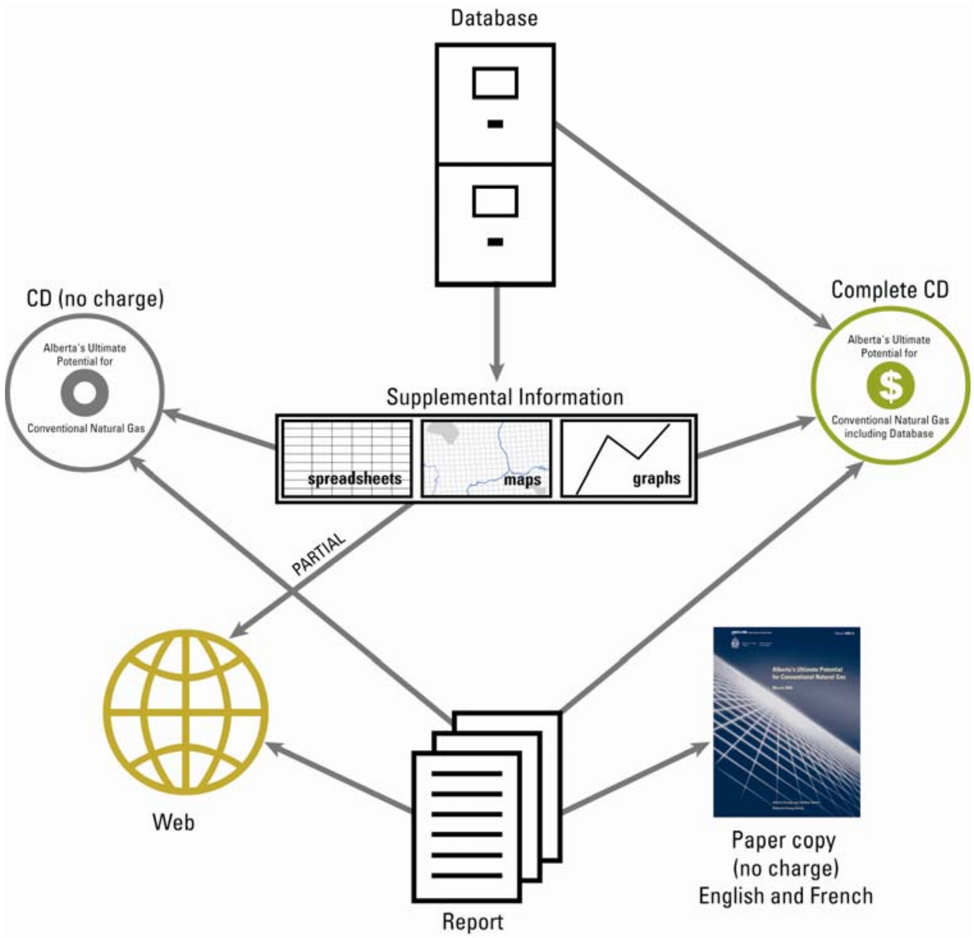

Figure 1.3. *Alberta's Ultimate Potential for Conventional Natural Gas*—information availability

1.7 Reader Questions and Comments

The reader is encouraged to contact the EUB or NEB with questions and comments respecting either this report or the associated data included on the compact discs and EUB/NEB Web sites. Please contact

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2 Methodology

The project team first assembled all pertinent data, statistical analysis, maps, and other information in an easily accessible and understandable format. The project team then used their expertise and judgement to make geological assessments and determinations to arrive at the estimates of ultimate potential. As mentioned earlier, a peer review process was also undertaken to incorporate the knowledge and expertise of others.

The depositional/erosional edges of major stratigraphic units used in EUB *Report 92-A* formed the basis for a geological model of Alberta. These edges were reviewed and refined from new drilling data. Play area boundaries from EUB *Report 92-A* were modified to reflect new discoveries and geological interpretations. Throughout the study, the project team relied heavily on existing EUB/NEB databases containing well, geological, and reserves data.

Additionally, the project team made extensive use of Geographic Information System (GIS) software, which has significantly enhanced and simplified the analysis of the several large datasets used in this study. GIS enabled the team to do detailed analysis and create informative maps, many of which are contained in the report's supplemental information.

The appendix presents the details of the methodology.

3 Gas in Place

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 9731 10^9 m^3 (345 Tcf), reflecting a good deal of certainty that the ultimate GIP meets or exceeds that estimate. The medium case is 10 583 10^9 m^3 (376 Tcf), representing the most realistic estimate. The high case of 12 012 10^9 m^3 (426 Tcf) recognizes that while the resources could be discovered, there is much uncertainty associated with the estimate.

Table 3.1 shows the low, medium, and high case estimates for each of the 42 stratigraphic intervals (numbered as Strat ID).

3.1 Comparison with Previous Studies

Table 3.2 compares results of this study with those of *Report 92-A* and the NEB's April 2004 report. The table gives the growth in both booked GIP and ultimate GIP. As shown in the percentage change column, the majority of reserves growth has been in the shallow Cretaceous zones, with only limited growth and in some instances a reduction in the estimate of booked GIP and ultimate GIP for the deeper Devonian zones. This observation may be more a reflection of the drilling over the past years, concentrating on the shallow, more accessible targets. Also, during the years between studies, a number of the deeper zones, especially in the foothills region, have not proven to be as large or as productive as previously expected. Many pools in the foothills have been restudied with performance data and a large volume of GIP has been deleted from the EUB/NEB database.

There has been more than a 43 per cent increase in booked GIP since *Report 92-A*. This increase has resulted in less than a 10 per cent increase in the estimate of ultimate GIP. *Report 92-A* adopted 9600 10^9 m^3 (340 Tcf) as the ultimate GIP for Alberta. The April 2004 NEB report estimated 9952 10^9 m^3 (351 Tcf), and this study estimates 10 583 10^9 m^3 (376 Tcf).

Table 3.1. Low, medium, and high case GIP

		10^9 m^3			Tcf		
Strat ID	Stratigraphic interval	Low case	Medium case	High case	Low case	Medium case	High case
1	Paskapoo & Edmonton	34.77	39.80	49.59	1.23	1.41	1.76
2	Belly River	314.34	327.73	361.15	11.16	11.63	12.82
3	Chinook	7.85	8.33	8.80	0.28	0.30	0.31
4	Milk River	292.25	296.01	300.44	10.37	10.51	10.66
5	Medicine Hat	358.30	361.98	365.66	12.72	12.85	12.98
6	Colorado	17.15	18.24	19.34	0.61	0.65	0.69
7	Lower Colorado & Badheart	3.36	3.89	4.75	0.12	0.14	0.17
8	Cardium	640.76	684.35	727.94	22.74	24.29	25.84
9	Doe Creek	16.61	17.79	18.98	0.59	0.63	0.67
10	Dunvegan	102.55	110.43	123.73	3.64	3.92	4.39
11	Second White Specks	177.17	185.23	193.30	6.29	6.57	6.86
12	Fish Scales	11.67	14.83	17.99	0.41	0.53	0.64
13	Viking	678.76	718.88	790.23	24.09	25.52	28.05
14	Basal Colorado	48.66	50.39	53.05	1.73	1.79	1.88
15	Mannville Above Glauconitic	1028.41	1108.86	1198.47	36.50	39.36	42.54
16	Glauconitic	969.37	1044.13	1150.76	34.41	37.06	40.84
17	Ostracod	78.54	86.27	94.01	2.79	3.06	3.34
18	Ellerslie	779.31	874.40	1005.91	27.66	31.04	35.70
19	Cadomin	118.74	134.13	153.10	4.21	4.76	5.43
20	Nikanassin	12.20	15.04	18.57	0.43	0.53	0.66
21	Rock Creek & Sawtooth	132.42	150.21	177.83	4.70	5.33	6.31
22	Nordegg	119.52	130.53	143.15	4.24	4.63	5.08
23	Baldonnel	13.25	14.57	15.90	0.47	0.52	0.56
24	Charlie Lake	44.83	52.32	69.68	1.59	1.86	2.47
25	Boundary	7.44	7.59	7.78	0.26	0.27	0.28
26	Halfway	84.63	88.93	99.21	3.00	3.16	3.52
27	Doig	32.14	35.20	38.27	1.14	1.25	1.36
28	Montney	155.37	181.47	229.09	5.51	6.44	8.13
29	Belloy	17.11	21.59	26.06	0.61	0.77	0.93
30	Kiskatinaw & Taylor Flat	67.36	76.13	92.70	2.39	2.70	3.29
31	Turner Valley	1139.80	1234.33	1516.15	40.46	43.81	53.81
32	Shunda	66.60	77.59	85.40	2.36	2.75	3.03
33	Pekisko	162.70	182.51	225.16	5.77	6.48	7.99
34	Banff	50.06	62.96	91.82	1.78	2.23	3.26
35	Bakken	7.43	8.26	9.76	0.26	0.29	0.35
36	Wabamun Crossfield	405.08	497.08	633.80	14.38	17.64	22.50
37	Winterburn Nisku	225.94	257.77	317.02	8.02	9.15	11.25
38	Leduc & Grosmont	632.51	679.63	743.33	22.45	24.12	26.38
39	Swan Hills & Slave Point	535.93	568.66	651.90	19.02	20.18	23.14
40	Gilwood & Granite Wash	34.86	39.55	46.86	1.24	1.40	1.66
41	Sulphur Point	22.22	26.61	36.32	0.79	0.94	1.29
42	Zama & Keg River	82.76	88.28	98.80	2.94	3.13	3.51
	Totals[1]	9730.73	10582.48	12011.76	345.36	375.60	426.33

[1] Discrepancies are due to rounding.

Table 3.2. GIP in current study compared with previous EUB and NEB studies (10^9 m^3)

Strat ID	Stratigraphic interval	EUB Report 92-A Discovered	EUB Report 92-A Ultimate	NEB – 2004 Discovered	NEB – 2004 Ultimate	EUB/NEB 2005 Discovered	EUB/NEB 2005 Ultimate	% change from Report 92-A to EUB/NEB 2005 Discovered	% change from Report 92-A to EUB/NEB 2005 Ultimate
1	Paskapoo & Edmonton	1.73	5.83	5.46	15.39	19.44	39.79	1023.7%	582.7%
2	Belly River	96.53	160.99	184.43	366.81	232.32	327.73	140.7%	103.6%
3	Chinook	0.96	5.77	5.58	8.27	6.92	8.33	620.8%	44.4%
4	Milk River	166.31	224.29	226.01	391.82	286.30	296.01	72.1%	32.0%
5	Medicine Hat	194.55	253.45	215.49	324.35	341.47	361.98	75.5%	42.8%
6	Colorado[1]	NA	NA	8.52	9.99	15.44	18.24	NA	NA
7	Lower Colorado & Badheart[1]	NA	NA	1.67	3.17	2.51	3.89	NA	NA
8	Cardium	257.30	510.65	480.09	558.96	544.34	684.35	111.6%	34.0%
9	Doe Creek	8.07	15.32	12.65	15.25	14.69	17.79	82.0%	16.1%
10	Dunvegan	18.09	50.98	36.49	56.04	57.95	110.43	220.3%	116.6%
11	Second White Specks	66.38	121.17	85.82	92.17	134.31	185.23	102.3%	52.9%
12	Fish Scales	0.83	2.11	1.98	4.15	5.47	14.83	559.0%	602.8%
13	Viking	433.37	647.36	469.60	583.91	526.89	718.88	21.6%	11.0%
14	Basal Colorado	40.59	65.66	42.49	51.58	43.09	50.39	6.2%	-23.3%
15	Mannville Above Glauconitic	419.57	667.91	656.97	971.96	758.77	1108.86	80.8%	66.0%
16	Glauconitic	437.86	790.54	737.79	1094.97	743.37	1044.13	69.8%	32.1%
17	Ostracod	29.33	72.96	43.77	71.61	51.00	86.27	73.9%	18.2%
18	Ellerslie	449.30	853.37	667.51	1014.78	576.99	874.40	28.4%	2.5%
19	Cadomin	42.66	150.94	46.25	84.82	67.66	134.13	58.6%	-11.1%
20	Nikanassin	12.75	61.20	9.82	16.82	8.56	15.04	-32.9%	-75.4%
21	Rock Creek & Sawtooth[2]	43.05	130.72	61.61	81.73	80.77	150.21	87.6%	14.9%
22	Nordegg	66.08	134.41	108.85	135.11	96.49	130.53	46.0%	-2.9%
23	Baldonnel[3]	NA	NA	6.92	9.35	9.92	14.57	NA	NA
24	Charlie Lake[3]	8.42	40.04	26.62	59.18	27.22	52.32	223.3%	30.7%
25	Boundary	2.67	7.50	7.42	7.88	7.24	7.59	171.2%	1.2%
26	Halfway	38.62	100.42	58.36	78.07	64.00	88.93	65.7%	-11.4%
27	Doig[4]	26.69	55.55	29.42	40.40	28.74	35.20	7.7%	-36.6%

(continued)

Table 3.2. GIP in current study compared with previous EUB and NEB studies (10^9 m^3) (concluded)

Strat ID	Stratigraphic interval	EUB Report 92-A Discovered	EUB Report 92-A Ultimate	NEB – 2004 Discovered	NEB – 2004 Ultimate	EUB/NEB 2005 Discovered	EUB/NEB 2005 Ultimate	% change from Report 92-A to EUB/NEB 2005 Discovered	% change from Report 92-A to EUB/NEB 2005 Ultimate
28	Montney[4]	30.84	84.22	93.88	157.94	106.29	181.47	244.6%	115.5%
29	Belloy	19.78	34.28	9.55	22.59	8.39	21.59	-14.2%	-37.0%
30	Kiskatinaw & Taylor Flat	22.22	50.94	51.40	73.39	50.40	76.13	126.8%	49.5%
31	Turner Valley	892.76	1304.32	911.83	1217.76	978.04	1234.33	9.6%	-5.4%
32	Shunda	33.86	62.65	56.60	63.60	49.46	77.59	46.1%	23.8%
33	Pekisko	124.62	208.78	145.96	176.48	133.60	182.51	7.2%	-12.6%
34	Banff	18.25	57.06	34.18	47.58	32.87	62.96	80.1%	10.3%
35	Bakken	4.65	11.93	1.89	3.10	5.57	8.26	19.8%	-30.8%
36	Wabamun Crossfield	234.03	527.70	255.40	403.53	277.35	497.08	18.5%	-5.8%
37	Winterburn Nisku	131.87	369.45	171.27	228.38	175.40	257.77	33.0%	-30.2%
38	Leduc & Grosmont	542.54	768.62	561.68	618.97	566.33	679.63	4.4%	-11.6%
39	Swan Hills & Slave Point	410.16	851.00	476.70	641.46	485.65	568.66	18.4%	-33.2%
40	Gilwood & Granite Wash	26.17	57.05	30.56	38.28	29.66	39.55	13.3%	-30.7%
41	Sulphur Point	14.21	33.01	12.90	18.36	16.43	26.61	15.6%	-19.4%
42	Zama & Keg River	51.87	74.93	74.25	92.08	76.79	88.28	48.0%	17.8%
	Totals[6]	5419.54	9625.08	7125.61	9952.04	7744.10	10582.48	43.2%	9.9%

[1] Zone not included within *Report 92-A*.

[2] The NEB 2004 report split the Rock Creek Sawtooth into three zones: Sawtooth, Swift, and Rock Creek.

[3] *Report 92-A* combined the Baldonnel with the Charlie Lake.

[4] *Report 92-A* combined the Doig with the Montney.

[5] The NEB 2004 report split the Jean Marie from the Nisku.

[6] Discrepancies are due to rounding.

4 Marketable Gas

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 coproducts and impurities from the raw gas, the flaring of test gas and solution gas (where solution gas is not gathered), and lease fuel.

The recovery and surface loss factors for future gas discoveries are assumed to be the same in each play as that for gas discovered to date. The GIP, producible gas, and marketable gas for each stratigraphic interval are shown for the medium case in Table 4.1.

Table 4.1. Marketable gas

		10^9 m^3			Tcf		
Strat ID	Stratigraphic interval	GIP	Producible	Marketable	GIP	Producible	Marketable
1	Paskapoo & Edmonton	39.80	24.40	23.17	1.41	0.87	0.82
2	Belly River	327.73	205.95	192.34	11.63	7.31	6.83
3	Chinook	8.33	6.52	5.53	0.30	0.23	0.20
4	Milk River	296.01	188.07	178.71	10.51	6.68	6.34
5	Medicine Hat	361.98	232.27	224.63	12.85	8.24	7.97
6	Colorado	18.24	11.61	10.99	0.65	0.41	0.39
7	Lower Colorado & Badheart	3.89	2.56	2.44	0.14	0.09	0.09
8	Cardium	684.35	227.28	179.21	24.29	8.07	6.36
9	Doe Creek	17.79	13.06	11.66	0.63	0.46	0.41
10	Dunvegan	110.43	86.07	78.05	3.92	3.05	2.77
11	Second White Specks	185.23	121.50	114.36	6.57	4.31	4.06
12	Fish Scales	14.83	10.04	9.38	0.53	0.36	0.33
13	Viking	718.88	534.97	496.78	25.52	18.99	17.63
14	Basal Colorado	50.39	43.22	41.10	1.79	1.53	1.46
15	Mannville Above Glauconitic	1108.86	797.01	741.61	39.36	28.29	26.32
16	Glauconitic	1044.13	763.67	695.15	37.06	27.11	24.67
17	Ostracod	86.27	63.64	55.33	3.06	2.26	1.96
18	Ellerslie	874.40	630.54	566.08	31.04	22.38	20.09
19	Cadomin	134.13	84.73	76.64	4.76	3.01	2.72
20	Nikanassin	15.04	10.61	9.66	0.53	0.38	0.34
21	Rock Creek & Sawtooth	150.21	105.69	92.74	5.33	3.75	3.29
22	Nordegg	130.53	96.11	83.46	4.63	3.41	2.96
23	Baldonnel	14.57	11.01	9.90	0.52	0.39	0.35
24	Charlie Lake	52.32	38.32	32.76	1.86	1.36	1.16
25	Boundary	7.59	3.55	2.57	0.27	0.13	0.09
26	Halfway	88.93	64.69	55.37	3.16	2.30	1.97
27	Doig	35.20	26.16	22.37	1.25	0.93	0.79
28	Montney	181.47	125.94	110.18	6.44	4.47	3.91

(continued)

Table 4.1. Marketable gas (concluded)

		10^9 m^3			Tcf		
Strat ID	Stratigraphic interval	GIP	Producible	Marketable	GIP	Producible	Marketable
29	Belloy	21.59	16.10	13.89	0.77	0.57	0.49
30	Kiskatinaw & Taylor Flat	76.13	62.21	58.23	2.70	2.21	2.07
31	Turner Valley	1234.33	992.33	766.82	43.81	35.22	27.22
32	Shunda	77.59	60.06	54.19	2.75	2.13	1.92
33	Pekisko	182.51	145.74	127.22	6.48	5.17	4.52
34	Banff	62.96	47.49	41.24	2.23	1.69	1.46
35	Bakken	8.26	6.31	5.93	0.29	0.22	0.21
36	Wabamun Crossfield	497.08	384.72	265.18	17.64	13.66	9.41
37	Winterburn Nisku	257.77	173.62	129.47	9.15	6.16	4.60
38	Leduc & Grosmont	679.63	485.37	359.40	24.12	17.23	12.76
39	Swan Hills & Slave Point	568.66	394.68	262.71	20.18	14.01	9.32
40	Gilwood & Granite Wash	39.55	22.85	16.68	1.40	0.81	0.59
41	Sulphur Point	26.61	19.49	16.65	0.94	0.69	0.59
42	Zama & Keg River	88.28	53.80	36.14	3.13	1.91	1.28
	Totals[1]	10582.48	7393.96	6276.05	375.60	262.45	222.72

[1] Discrepancies are due to rounding.

5 Other Issues

5.1 Unconventional Gas

Unconventional gas resources have not been studied for this report. Very recently, unconventional gas, in particular CBM, has been confirmed as commercially producible and has undergone a substantial increase in drilling activity. Although the amount of data available and the understanding of Alberta's CBM resources have certainly grown a good deal in the last several years, it remains very difficult to arrive at an estimate of ultimate potential for CBM.

The EUB's Alberta Geological Survey (AGS) does provide an initial look at the ultimate GIP of gas contained within the coals of Alberta in its 2003 report *EUB/Alberta Geological Survey Earth Science Report ESR 2003-03: Production Potential of Coalbed Methane Resources in Alberta*, by A. Beaton. The AGS study resulted in an ultimate GIP estimate for CBM of greater than 14.2 trillion m^3 (500 Tcf). As the understanding of CBM improves and more information becomes available, CBM will become part of future studies.

5.2 Restricted Access

As indicated earlier, the use of GIS software allows for an estimate of the future potential within any section in Alberta. The project team determined that there is 54.4 10^9 m^3 (2 Tcf) of marketable gas under the current boundaries of major cities, lakes, protected areas, and federal and provincial parks. No sour gas buffer zone around cities was used, as in the NEB 2004 report. These estimates are based on current technology. Future advances in technology or changes in surface access restrictions would result in revisions to these estimates.

5.3 Canadian Resources

As previously noted, Alberta is the major contributor to the Canadian gas supply, accounting for almost 80 per cent of the total. The NEB, as part of its mandate, maintains estimates of ultimate potential for all regions of Canada. Its current estimates were provided in the 2004 report. Table 5.1 shows the new estimate of Alberta's ultimate potential for natural gas in perspective with the rest of Canada.

Table 5.1. Current NEB estimates of ultimate potential for conventional marketable natural gas in Canada—10^9 m^3 (Tcf)

	Discovered		Undiscovered		Ultimate potential[1]	
Western Canada Sedimentary Basin						
Alberta	4542	(161)	1734	(62)	6276	(223)
British Columbia	691	(24)	745	(27)	1436	(51)
Saskatchewan	242	(9)	13	(0)	255	(9)
Southern territories	29	(1)	167	(6)	196	(7)
Subtotal	5504	(195)	2659	(95)	8163	(290)
East coast (offshore)	387	(14)	2208	(77)	2595	(91)
West coast	0	(0)	485	(17)	485	(17)
Northern Canada	605	(22)	2680	(94)	3285	(116)
Ontario	45	(1)	22	(1)	67	(2)
Gulf of St. Lawrence (Maritimes Basin)	2	(0)	38	(1)	40	(1)
Total Canada[1]	6543	(231)	8092	(286)	14635	(517)

[1] Discrepancies are due to rounding.

5.4 Updates to This Study

Although this study accounts for almost all drilling to date, record drilling levels and increasing attention to exploration and development of shallow Cretaceous pools require ongoing monitoring of drilling and exploration in the province. The Boards intend to maintain the several complex computer systems, databases, and processes developed for this study and to update the data on an ongoing basis. Any updates of the ultimate potential estimates will be reported in the EUB's annual *Statistical Series 98: Alberta's Reserves and Supply/Demand Outlook* or in various NEB publications.

5.5 Uses for the Data in This Study

The Boards expect to make ongoing use of the data and systems generated in this study, such as in the regional analysis of resources near pipelines, gas plants, and populated areas. The addition of gas analysis data will allow for the determination of sour gas volumes that may be encountered during future drilling activity and its locations relative to, for example, populated areas. Others are encouraged to use the data to improve their knowledge and understanding of the gas resources in Alberta.

6 Observations

6.1 General

Estimates of Alberta's ultimate potential for conventional marketable natural gas continue to grow, increasing from 5600 10^9 m^3 (200 Tcf), as estimated in *Report 92-A*, to 5855 10^9 m^3 (207 Tcf), as estimated by the NEB in 2004, and to 6276 10^9 m^3 (223 Tcf) in this study. This new estimate is 12 per cent higher than that in *Report 92-A* and 7 per cent higher than the 2004 NEB estimate. This follows the general trend of increasing estimates of ultimate potential over time as a basin matures, as discussed in the 2004 NEB report. The increase is attributed to a better understanding of the geology of the basin and increases in technology that allow industry to locate and develop pools in challenging areas.

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. The level of uncertainty of unbooked, unconfirmed, and bypassed resources is medium, for booked reserves it is minimal, and finally, there is no uncertainty for cumulative production.

The new study only captures the resources of known geological plays. Should conceptual plays be discovered in the future, the resources for those plays would be added to the current estimate. The Boards will continue to monitor development in the size of the resource base for natural gas in Alberta.

Since 1991 (*Report 92-A*), discovered resources in Alberta have increased for all geological periods, as shown in Figure 6.1. Although most of the additions to discovered resources can be attributed to discovery of small pools and the expansion of large shallow pools, the recent discovery at Tay River confirms that large pools can still be found in Alberta. As the NEB noted in its 2004 report, over the period 1991 to 2000, the majority of discovered resource increases have been in the shallower zones.

Although the discovered resources for all geological periods have increased, the ultimate GIP for the Jurassic, Mississippian, and especially the Devonian period has decreased (see Figure 6.1). Estimates of the GIP in many discovered pools in these periods were decreased based on poor pool performance. Additionally, declining historical success rates caused the project team to often use even lower estimates of future success.

The Boards note that the majority of growth in the discovered and undiscovered resources has occurred in the Cretaceous periods. Higher gas prices in recent years have made these zones more economic than in the past, and industry has aggressively pursued development. This development has been in new pools, additions to existing pools, and the discovery of pools in areas and formations not previously considered to have potential. Several of the Cretaceous play areas have been substantially expanded from *Report 92-A* to account for recent discoveries. Growth in these shallower zones has been offset by decreases or minimal growth in the deeper Devonian period. However, these deeper plays still have significant undiscovered resources and the potential to find very large pools.

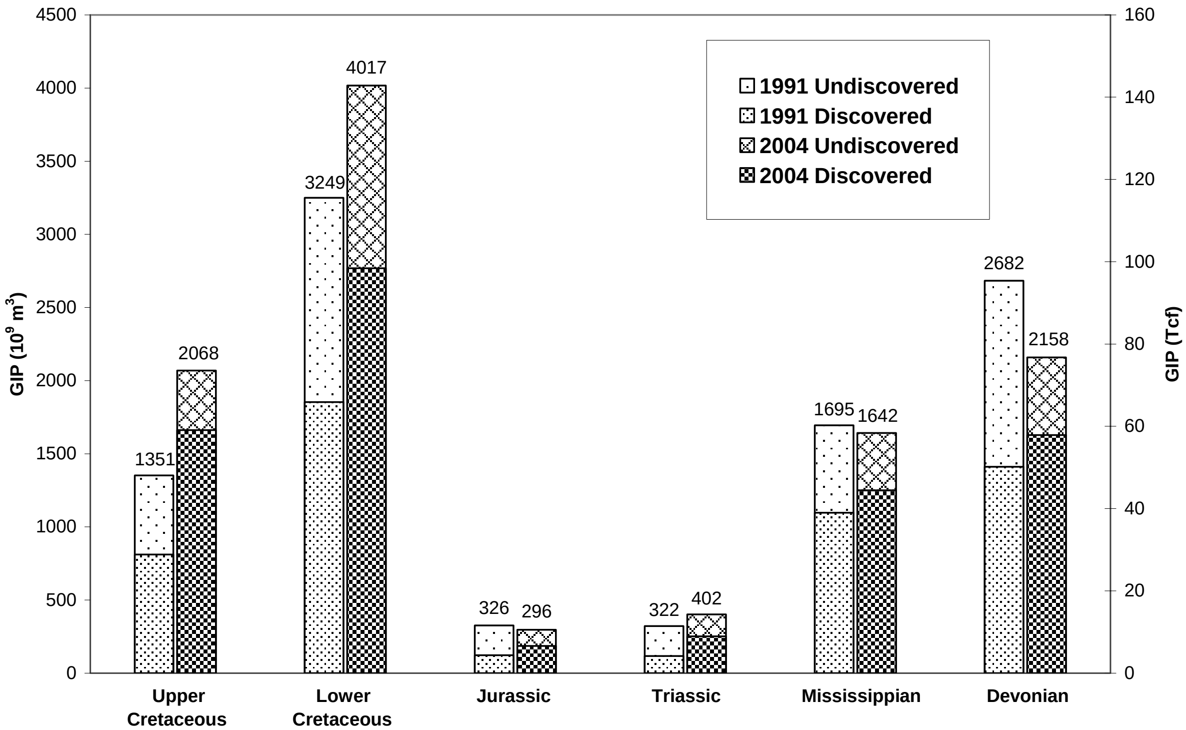

Figure 6.1. Gas in place by geological period

Alberta's initial reserves, as booked by the EUB/NEB, have increased by an average of 105 10^9 m^3 (3.8 Tcf) per year over the past four years. If these increases continue at the same rate, it would take about 16 years to find all of the undiscovered resources of conventional natural gas estimated in this study. The project team anticipates that annual additions will decline in future years and thus it will take longer to find all of the undiscovered resources. Alberta's annual production is in the order of 136 10^9 m^3 (4.8 Tcf), a volume that exceeds annual additions. Consequently, Alberta's remaining reserves will continue to decline.

In *Report 92-A*, about 39 per cent of the 5600 10^9 m^3 (200 Tcf) was undiscovered. In this study, only 28 per cent of the 6276 10^9 m^3 (223 Tcf) is undiscovered. Additionally, in *Report 92-A*, cumulative production represented 32 per cent of the total resources, while at year-end 2004 it represented 52 per cent of the total resources.

6.2 Foothills

The foothills region continues to be relatively unexplored when compared to the majority of the province; however, the Boards still consider the foothills to have considerable undiscovered resources. In this study, the ultimate potential in the foothills is estimated to be 1005.8 10^9 m^3 (36 Tcf), with 34 per cent still undiscovered. The undiscovered portion in the foothills amounts to about 20 per cent of the total undiscovered resources in the province. In *Report 92-A*, there were 1076.5 10^9 m^3 (38 Tcf) of total resources for the foothills, with 45 per cent undiscovered. The undiscovered portion in the foothills amounted to more than 22 per cent of the total undiscovered resources at that time.

Foothills plays have been added in several formations that were previously not considered to have potential, and some formations have been reduced. Discovered resources in the foothills have not increased substantially, in part due to reductions as a result of pool performance studies.

The geological complexity of the foothills makes it difficult to accurately estimate undiscovered resources. As a result, the project team relied upon industry consultation to assist in a better assessment of the region.

7 Conclusions

In order to reflect the uncertainty of estimating undiscovered resources, the project team has developed a range of ultimate potential estimates for Alberta. On a marketable gas basis, the range is 5765 10^9 m^3 (205 Tcf) to 7134 10^9 m^3 (253 Tcf), and the medium estimate is 6276 10^9 m^3 (223 Tcf).

The Boards reviewed the findings and estimates in this report and adopted an ultimate potential for marketable conventional natural gas of 6276 10^9 m^3 (223 Tcf) to be used in future supply projections.

The remaining ultimate potential estimate represents the volume of gas that will be available in the future to meet Canadian domestic and export demands. The new estimate of remaining ultimate potential for conventional natural gas in Alberta is 2838 10^9 m^3 (101 Tcf).

The increased ultimate potential is due to a better understanding of the geology of the province. Recognition of gas potential in new stratigraphic intervals and expansion of several play areas, especially in the Cretaceous, have contributed to this increase.

Although a significant amount of conventional natural gas remains to be discovered in Alberta, high levels of industry activity will be required to meet the growing demand for natural gas throughout North America. Additionally, new supplies from unconventional sources will be required to supplement the conventional gas supply from Alberta and the rest of Canada. This supply will ensure a healthy oil and gas industry in Alberta for many years.

Appendix Methodology

A1 Introduction—Assumptions

The major assumptions upon which this study is based are as follows:

- **Conceptual plays:** All future gas, as estimated in this report, will be discovered in currently known stratigraphic intervals and depositional environments. Although conceptual plays can exist, the likelihood that they would be significant relative to the total Alberta ultimate potential is assumed to be very low, but would be added to the estimate from this study.

- **Median GIP per section:** The GIP per section of future discoveries in each play area is generally equal to the median GIP per section of the discoveries to date. This issue was discussed in some detail in EUB *Report 92-A*. That report stated, “As the play area matures and pool size continues to decrease, the rate of change becomes minimal such that, even if a large number of additional pools is anticipated, the change in median GIP/sec will be insignificant.” The median GIP was used in almost all cases.

- **Success rate:** Success rate (successful tracts divided by drilled tracts) can vary from year to year but generally declines over the life of a play area. The project team assigned a success rate for all future discoveries in a play area representing an estimate of the average for the future life of that play area.

- **Economics:** No detailed economic analysis was undertaken for this report. EUB *Report 92-A* suggested that at higher gas prices, the incremental increase in ultimate potential due to increases in gas price is quite small. Given today’s relatively high gas prices, it is unlikely that a significant impact on the ultimate potential would occur due to future increases in gas price.

- **Technology:** Advances in technology can increase the ultimate potential, but no detailed analysis has been conducted as part of this study. Reasonably anticipated improvements in technology are assumed to be encompassed in the range of estimates of ultimate potential.

A2 Data

The data used in this study included

- **basic well:** location, finished drilling date, depth, status, and deepest stratigraphic interval penetrated;
- **formation tops:** stratigraphic zone and depth;
- **zone evaluation:** zone, pay type, and depth;
- **reserves:** zone, reservoir area and thickness, reserve type, oil in place, GIP, producible gas, initial marketable gas, remaining marketable gas, and gas analyses;
- **test:** absolute open flow potential and drillstem test;
- **production:** monthly and cumulative production; and
- **stratigraphic interval:** zones, depths, and map of aerial extent.

A3 Stratigraphic Intervals

The project team reviewed all hydrocarbon-bearing zones recognized as being capable of contributing to Alberta's ultimate potential for gas. EUB *Report 92-A* recognized 36 stratigraphic intervals. The project team reviewed these stratigraphic intervals, split some intervals into more than one, and added new intervals. There were 148 zones identified in this study, which were grouped into 42 stratigraphically equivalent intervals (numbered as Strat ID), as shown in the table on the next page.

Grouping of stratigraphic intervals has been done on the basis of lithology and geological time. There are some variations and exceptions:

- In a few cases, even though two or more zones may not strictly be geological equivalents, they are geographically separated and have been grouped for convenience. An example is the inclusion of the Quaternary with the Paskapoo & Edmonton interval.
- Some zones, such as the Gilwood and Granite Wash, which have been continuously deposited over a long period of time, are separated by other stratigraphic intervals in most areas of Alberta. However, in some areas it is difficult to differentiate between the two zones and, consequently, the zones have been combined into a single stratigraphic interval.
- In other instances, such as the Mannville Group above the Glauconitic, a large number of zones representing a complex distribution of individual sands have been combined into one stratigraphic interval.

GIS layers were created for each of the 42 stratigraphic intervals showing the depositional or erosional edges. GIS layers were also created to show the foothills and front range edges. These layers were overlain with the well information—formation tops and pay data. The accuracy of the boundary data and the well data was assessed and corrections and adjustments were made as necessary.

The revised layers formed the geological basis for all subsequent work. Maps showing these layers for each of the 42 stratigraphic intervals are included in the supplemental information to this report.

A4 Play Areas

Each stratigraphic interval has been subdivided into play areas where the geology is similar. The formation depths, fluid type (oil, gas, bitumen), GIP per section, success rate, and other parameters are reasonably consistent within these play areas. This consistency provides for the statistical and geological analysis of the drilled wells and discovered resources in the play area and the subsequent extrapolation of that information to the undrilled regions of the play area.

The play areas created in EUB *Report 92-A* were used as the starting point for this study, but they have undergone extensive revision based on new well information. As was done with the depositional and erosional edges, the project team used GIS software to assess the information and ensure the accuracy of the well data and play area boundaries.

Appendix Table. Stratigraphic intervals

Strat ID	Stratigraphic interval	Zones (group, formation, member)
1	Paskapoo & Edmonton	Quaternary, Paskapoo, Edmonton, Horseshoe Canyon
2	Belly River	Wapiti, Bearpaw, Belly River, Brazeau, Oldman, Foremost, Ribstone Creek, Victoria, Brosseau
3	Chinook	Chinook
4	Milk River	Milk River
5	Medicine Hat	Medicine Hat
6	Colorado	Colorado
7	Lower Colorado & Badheart	First White Specks, Badheart, Lower Colorado
8	Cardium	Cardium
9	Doe Creek	Doe Creek
10	Dunvegan	Dunvegan
11	Second White Specks	Second White Specks
12	Fish Scales	Fish Scale, Barons, Base Fish Scales
13	Viking	Bow Island, Viking, Provost, Hamilton Lake, Peace River, Paddy, Cadotte
14	Basal Colorado	Basal Colorado
15	Mannville Above Glauconitic	Viking-Blairmore, Mountain Park, Blairmore, Mannville, Upper Mannville, Colony, Grand Rapids, Spirit River, Notikewin, McLaren, Waseca, Falher, Sparky, Wainwright, Clearwater, General Petroleum, Rex, Lloydminster
16	Glauconitic	Home, Glauconitic, Cummings, Cummings-Dina, Bluesky, Bluesky-Gething, Wabiskaw, Moulton
17	Ostracod	Ostracod
18	Ellerslie	Wabiskaw-McMurray, Lower Blairmore, Lower Mannville, Basal Mannville, Dina, Gething, McMurray, Sunburst, Sunburst-Swift, Basal Quartz, Ellerslie, Cutbank, Taber, Detrital
19	Cadomin	Dalhousie, Cadomin
20	Nikanassin	Kootenay, Nikanassin, Morrissey
21	Rock Creek & Sawtooth	Swift, Sawtooth, Rock Creek
22	Nordegg	Nordegg, Nordegg-Banff, Jurassic, Jurassic Detrital
23	Baldonnel	Baldonnel
24	Charlie Lake	Charlie Lake
25	Boundary	Boundary
26	Halfway	Halfway
27	Doig	Doig
28	Montney	Bluesky-Montney, Spray River, Montney, Bluesky-Gething-Montney, Bluesky-Triassic
29	Belloy	Belloy
30	Kiskatinaw & Taylor Flat	Taylor Flat, Kiskatinaw
31	Turner Valley	Bluesky-Debolt, Rundle, Debolt, Mount Head, Livingstone, Turner Valley, Elkton, Elkton-Shunda
32	Shunda	Shunda
33	Pekisko	Shunda-Pekisko, Pekisko
34	Banff	Banff
35	Bakken	Bakken
36	Wabamun Crossfield	Palliser, Wabamun, Big Valley, Crossfield
37	Winterburn Nisku	Winterburn, Graminia, Blueridge, Arcs, Nisku, Jean Marie, Camrose Tongue
38	Leduc & Grosmont	Woodbend, Ireton, Grosmont, Peechee, Leduc, Cairn, Cooking Lake
39	Swan Hills & Slave Point	Beaverhill Lake, Swan Hills, Slave Point, Slave Point-Granite Wash
40	Gilwood & Granite Wash	Gilwood, Granite Wash
41	Sulphur Point	Sulphur Point
42	Zama & Keg River	Muskeg, Zama, Zama-Keg River, Keg River, Winnipegosis

Each stratigraphic interval has at least one and up to nine play areas. The play areas are given an identifier number called a "Play ID". In all but two stratigraphic intervals, there is one play area, in some cases a very large one, that is considered to have no geological potential for discovery of gas. These barren play areas are always given a Play ID of 10.

A5 Play Area Tracts

Each play area has been further subdivided into single section (1.6 kilometre by 1.6 kilometre) tracts, based on the Dominion Land Survey System. Thus, a play area tract is a 3D cell that is 256 hectares (ha) in area and one stratigraphic interval in thickness. Of course, the thickness will vary a great deal, depending on the number and thicknesses of the zones in the stratigraphic interval. "Play area tracts" are referred to in this appendix and the supplemental information as tracts.

The project team developed computer programs that create a spatially enabled (GIS) database of all tracts in Alberta. This database forms the basis for virtually all of the analysis. Each tract is represented by one database record, which contains GIP, drilled date, and tract status.

The tract status is key to the estimation of ultimate potential and may be one of the following:

- booked,
- unbooked,
- unconfirmed,
- bypassed,
- drilled,
- no potential, or
- future.

As there may be more than one well or zone in a tract, the status of the tract is assigned in a hierarchical fashion in the order shown above. That is, if one or more wells or zones have "booked" GIP, the tract status is set as "booked" and the other wells or zones in that tract are ignored. If there is no booked GIP, but one or more of the wells or zones has "unbooked" GIP, the tract status is set to "unbooked," and so on through the list.

All tracts in the barren play areas (Play ID = 10) are assumed to have no potential and the tract status is set to "drilled" or "no potential" to indicate whether or not a well has penetrated the stratigraphic interval in that section.

The following subsections provide a more detailed discussion and explanation of the tract statuses.

A5.1 Booked Tract

A booked tract is one for which the EUB/NEB reserves database recognizes GIP. All GIP contained in the tract is summed and entered on the tract record in the database. That is, where more than one zone contains GIP or where there is more than one pool in the same zone in a section, the GIP is summed for the tract.

In some instances, a tract may be undrilled but is contained within a pool boundary. Such tracts are assigned the appropriate GIP and given a status of booked.

A5.2 Unbooked Tract

A tract that has no booked GIP but has significant undefined production is assigned a tract status of “unbooked”. Undefined production is considered significant only if the well is not abandoned or it has produced more than 500 thousand m^3. The GIP assigned is the median GIP for the play area. Undefined production exists due to the time span between the start of production and the booking of the reserves.

A5.3 Unconfirmed Tract

A tract that has no booked or unbooked GIP but has a geological evaluation that indicates “potential” pay is assigned a status of “unconfirmed”. Potential pay is assigned to a zone if the well logs indicate there may be pay but insufficient evidence is available from flow tests in order to establish with certainty that the zone is capable of production.

As is done for unbooked tracts, the GIP assigned to unconfirmed tracts is the median GIP for the play area. However, in recognition that not all of these unconfirmed tracts will prove to be capable of production, a probability of success is assigned to unconfirmed tracts on a play area basis. In most cases, it is 15, 30, and 45 per cent in the low, medium, and high cases respectively. The percentages have been adjusted in some areas where the data quality of the logs, experience of the project team, or recent production data suggests that the tract is more or less likely to be capable of production.

A5.4 Bypassed Tract

A tract that has no booked, unbooked, or unconfirmed GIP but has a flow test (drillstem or absolute open flow potential test) to support that it may be capable of production is assigned a status of “bypassed”. The term bypassed is used because the zone may be capable of production but has been ignored, at least for the time being. The rate of a flow test had to be at least 400 m^3/day (14 mcf/day) before bypassed pay was assigned.

The GIP assigned to bypassed tracts is the median GIP for the play area, and as with unconfirmed tracts, a probability of success is assigned to bypassed tracts. In most cases, 5, 10, and 15 per cent are used in the low, medium, and high cases respectively, but adjustments are made where experience or recent production data suggest that the tract is more or less likely to be capable of production.

A5.5 Drilled Tract

A tract is given a “drilled” status if there is evidence that a well has penetrated the tract (for example, a formation top is recorded) and there is specific evidence that the well is not capable of production (for example, an evaluation indicates the zone[s] is wet, tight, eroded, not deposited) or at least there is no evidence that the tract may be capable of production. A drilled tract is assumed to be unsuccessful.

Unfortunately, the EUB databases do not specifically indicate the deepest stratigraphic interval that a well has penetrated. For wells for which formation tops or pay data exist, the tops of penetrated stratigraphic intervals are known. These data were used to create a GIS layer showing all known tops and subsequently another layer was created showing the measured or interpolated top for every tract in Alberta. This final layer was used to estimate the deepest stratigraphic interval that each well had penetrated.

A5.6 No Potential Tract

Most stratigraphic intervals have areas that are not considered to have any future potential based on geological interpretation, lack of trapping mechanism, or lack of reservoir lithology. All tracts in these barren play areas (Play ID = 10) are assigned a status of "no potential".

For each stratigraphic interval, any area beyond the depositional or erosional edges will, of course, have no potential. No tracts are created for such areas and no specific reference to them is in the database.

A5.7 Future Tract

All remaining tracts are given a status of "future". That is, a well may be drilled in the future and there is at least some potential that the tract could be capable of gas production. It is within these tracts that the undiscovered portion of Alberta's ultimate potential for natural gas lies.

A5.8 Tracts and GIP

The GIP assigned to future tracts is estimated based on information from the booked, unbooked, unconfirmed, and bypassed tracts. Ultimate GIP is the sum of the GIP in all tracts. For the purpose of this study, discovered GIP consists only of the booked GIP, while undiscovered GIP is the sum of future, unbooked, unconfirmed, and bypassed GIP.

A6 Maps, Summaries, Graphs, and Statistical Analyses

The project team has created several maps, summaries, graphs, and statistical analyses based on the data assembled in this study. The following is a brief overview of the content and purpose of each.

A6.1 Main Spreadsheet

This spreadsheet forms the central working document for the project team's estimation of ultimate potential. It contains basic information for the low, medium, and high case for each play area, including

- number of drilled, future, and total tracts,
- booked, unbooked, unconfirmed, and bypassed GIP,
- probability of success for unconfirmed and bypassed tracts,
- median GIP,
- estimate of future average success rate,
- undiscovered GIP (sum of future, unbooked, unconfirmed, and bypassed),
- GIP not yet discovered,
- ultimate GIP, and
- ultimate potential.

The spreadsheet contains formulas for calculating new estimates of ultimate GIP by adjusting the probability of success, median GIP, and success rate for the play area. These adjustments were made as the team reviewed the information described in the following subsections.

A6.2 Maps

GIS software was used to create computer maps of each stratigraphic interval and play area. Various layers could easily be added to or removed from the map in order to display the information that the project team needed to see as they reviewed each play area. GIS allows the user to zoom in or out to show detail or broad perspective, as required.

The layers that could be displayed on the maps included depositional and erosional edges, major structural features, miscellaneous geological features, play areas, formation tops, and pay, reserves, basic well, and base map (township, section, cities, etc.) data.

These maps provided an excellent visual perspective of each play area. The GIS was one of the most important tools in the project team’s analysis of the data and estimation of ultimate potential.

A6.3 Cumulative GIP versus Tracts

A plot of cumulative GIP versus drilled tracts was created for each play area. If discoveries in a play area are totally random—that is, the likelihood of success drilling the first tract is the same as when drilling the last tract—this plot will be a straight line. Extrapolating this straight line to the total number of tracts in the play area will yield the ultimate GIP for the play area.

In play areas that are not primary targets, discoveries are virtually random and this plot generally works well. However, if the play area is made up of target zones and especially if extensive use of seismic data has occurred, early drilling generally is more successful and finds the larger pools first. In such cases, this plot tends to flatten out over time and is of less use, although it will tend to indicate an upper limit for the play area.

In all cases, this plot is only reliable if a reasonably high percentage of the play area has been drilled, in the order of 50 per cent. Where less than 30 to 40 per cent has been drilled, the plot is of limited use.

A6.4 Log Cum GIP/Tract versus Log Cum Tracts

A plot of the logarithm of cumulative GIP per drilled tract versus the logarithm of cumulative tracts (Log Cum GIP/Tract versus Log Cum Tracts) was created for each play area. This plot appears to work reasonably well for target zones where the best pools are found early and the drilling success rate and size of pools decline over the history of the play area. The plot tends toward a straight line as a reasonably large percentage of the play area is drilled, and this line can be extrapolated to the total number of tracts in the play to show the ultimate GIP.

As with the previous plot of cumulative GIP versus drilled tracts, if less than 30 to 40 per cent has been drilled, the plot is of limited use. This plot and the cumulative GIP versus tracts plot were reviewed concurrently. Based on the project team’s knowledge of historical exploration (targeted zones, use of seismic data, etc.), the results from one or the other of these plots were often taken as a good indication of the ultimate GIP. Where insufficient drilling had taken place in a play area, both plots were of limited use.

A6.5 GIP versus Time

A plot of cumulative GIP versus time was created for each play area. This plot was reviewed to give the project team a historical perspective of growth in discovered GIP in the play area.

This plot was also useful as a further check of how reasonable an ultimate GIP estimate might be, having regard for historical growth rates.

A6.6 Drilling Success Rate versus Time

A plot of drilling success rate versus time was created for each play area. Drilling success rate was calculated on a “per tract” basis rather than, as is generally done, on a “per well” basis. A drilled tract is considered to be successful if it is assigned booked, unbooked, unconfirmed, or bypassed status. Success rate is the number of successful tracts divided by drilled tracts and is calculated on an annual and cumulative basis. Also shown on the plot are summary statistics, including the number of successful, unsuccessful, future, and total tracts in the play area, as well as the percentage of tracts remaining to be drilled and the cumulative success rate to the present time.

This plot and the summary data gave the project team a good overview of the history of the play area and the extent to which it had been explored. The future success rate for the play area was always based on and checked against these historical data to ensure reasonableness.

A6.7 GIP per Tract versus Tract Count

A plot of GIP per tract versus tract count was created for each of the nonassociated, associated, and solution resource types in each play area. A plot combining all three resource types was also created. The amount and variance in the data provided an indication of the reliability of the median GIP values used for the play area.

A6.8 GIP per Tract versus Time

A plot of GIP per tract versus time was created for each play area. This plot was used to check data validity and to assess the reliability of the median GIP.

A7 Evaluation Process

The well and reserves data, as well as the depositional/erosional edges and play area boundaries, were checked and refined. Concurrently, maps, summaries, graphs, and statistical analysis software were developed. The process of estimating ultimate GIP was iterative in that after each pass through the process, data were corrected, play area boundaries modified, and all data, maps, and graphs refreshed.

The final evaluation to estimate ultimate GIP for each play area involved most, and in some cases all, of the following steps, generally in the order shown:

- Review the maps to gain an overall perspective of the play area, its location, size, depth, maturity, oil versus gas mix, and proximity to infrastructure.
- Review the historical success rates to assess the trend of success rate and to understand any anomalies.
- Review the cumulative GIP versus tracts and Log Cum GIP/Tract versus Log Cum Tracts to assess the utility and reliability of these graphs.
- Review the critical ultimate GIP calculation parameters, proven reserves, probability of success for unconfirmed and bypassed tracts, median GIP, and success rate.
- Adjust the success rate in the Main spreadsheet to provide an initial estimate of ultimate GIP.

- Check the reasonableness of the estimate using the “GIP versus Time” graph.
- Review any of the other data and graphs that may have been deemed to be informative.
- Iterate through any or all of the above steps to reach consensus on the best estimate of ultimate GIP for the low, medium, and high cases.

This process relied very heavily on the expertise and experience of the team members. Discussion focused on geological parameters, use of seismic data, success rate, and other relevant information. In some cases, where the play area was well understood and very mature, consensus was easy to reach and the range between the low and high case estimates was small. In other cases, where there were very few data, a good deal of discussion was required and further investigation was often undertaken before the final estimates were agreed upon. For such play areas, there was generally a larger range between the low and high estimates to reflect the uncertainty in the estimates.

As a final step, a number of external peer reviews were conducted, especially for those play areas where a good deal of uncertainty remained or if the project team was aware of an individual or group that had studied the area in detail. For instance, a number of companies actively exploring in the foothills areas were able to provide very useful information, as many of these play areas had seen little recent activity and not much public data was available. A number of play areas were also reviewed with staff from the Earth Science Sector of Natural Resources Canada and from the CGPC. These two organizations spend a great deal of time and effort in studying the geology and ultimate potential for Canada. Their assistance and input was extremely valuable and very much appreciated.