TECHNICAL APPENDIX TO

CANADA'S CONVENTIONAL NATURAL GAS RESOURCES: A STATUS REPORT

An Examination of Alberta's Ultimate Potential
of Conventional Natural Gas

April 2004

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Acronyms

Bcf	billion cubic feet
CAPP	Canadian Association of Petroleum Producers
CGPC	Canadian Gas Potential Committee
EUB	Alberta Energy and Utilities Board
GIP	gas in place
GJ	gigajoule
GSC	Geological Survey of Canada
ha	hectares
MMcf	million cubic feet
NEB	National Energy Board
PETRIMES	Petroleum Resource Information Management and Evaluation System
10^9m^3	billion cubic metres
Tcf	trillion cubic feet
WCSB	Western Canada Sedimentary Basin

CHAPTER ONE

Summary and Conclusions

The Western Canada Sedimentary Basin (WCSB) accounts for almost all gas production in Canada and for about 23 percent of North American natural gas production. In turn, Alberta accounts for about 85 percent of total production in the WCSB. In the last few years, gas production from the WCSB appears to have flattened after many years of growth, leading to increased uncertainty about the ability of industry to increase or maintain production from the basin over the longer term. The purpose of this technical appendix is to provide an assessment of the ultimate potential and remaining resources of conventional natural gas in Alberta. This is an important component in a long-term deliverability outlook.

The ultimate potential of conventional natural gas in Alberta has been examined many times in the past. The EUB[1], in a 1955 study, estimated the marketable ultimate potential of gas to be 1 700 to 2 800 10^9m^3 (60 to 100 Tcf), while in its 1992 study, estimated the marketable ultimate potential to be 5 600 10^9m^3 (200 Tcf). Other studies show a gradually increasing estimate which reflects both the growing knowledge of the geology of the Alberta portion of the WCSB and the impact of developing technologies on estimates of hydrocarbon potential over time. The first study by the Canadian Gas Potential Committee[2] (CGPC) was issued in 1997. The CGPC study estimated the marketable ultimate potential of gas for Alberta to be approximately 5 959 10^9m^3 (210 Tcf). In its 2001 report, the CGPC decreased its estimate for Alberta to 5 760 10^9m^3 (203 Tcf), largely as a result of a change in its treatment of reserves appreciation and a policy decision not to assign potential to conceptual plays.

In its 2004 assessment, the NEB has examined the same data that was available to the CGPC plus two additional years of reserves and drilling information. Further, the NEB had access to the revisions performed by the EUB to its official provincial reserves information. The NEB's methodology uses a combination of geological and statistical analysis applied to the land, drilling and reserves data.

The results of the NEB's assessment of the Alberta ultimate potential of conventional natural gas are shown in Table 1.1.

This estimate of the ultimate potential of Alberta supports the Supply Push scenario as outlined in the Board's most recent Supply and Demand report which is available on the Board's Website at www.neb-one.gc.ca .

[1] The Alberta Energy and Utilities Board (EUB) is the agency responsible for regulation of energy activities in the province of Alberta.

[2] This independent committee consists of volunteers with geoscience knowledge and experience.

Table 1.1 Results of NEB 2004 Alberta assessment

	Gas Volume $10^9 m^3$ (Tcf)		
	Discovered	Undiscovered	Ultimate Potential
Gas In Place	7 126 (252)	2 826 (100)	9 952 (351)
Recoverable	5 002 (177)	1 999 (71)	7 001 (247)
Marketable	4 125 (146)	1 730 (61)	5 855 (207)
Remaining Marketable[1]	1 220 (43)	1 730 (61)	2 950 (104)
[1] Cumulative production to year-end 2000 is removed from the marketable volume.			

CHAPTER TWO

Introduction

At the end of 2000, Alberta's total reserves of natural gas represented over 80 percent of Canada's natural gas reserves and over 83 percent of the natural gas reserves of the WCSB. Following a period of low oil prices during 1997/98, the upstream sector responded by drilling fewer wells. By the end of 2000, marketable gas production from Alberta was flat on a year-over-year basis; the first time there had not been an annual increase. As a result, some concerns were expressed publicly about the future supply left to be found in Alberta. With this backdrop, the NEB decided to assess the remaining potential for conventional gas resources in Alberta.

At the same time, the EUB similarly identified a need to update its last study (1992) of ultimate gas potential in Alberta. Together, the two Boards decided in 2001 to jointly assess the conventional gas resources in the province. Since that time, the two Boards have completed the geological analyses of the study and established the same geological subdivisions and play areas. However, due to a number of factors, the EUB has deferred the completion of the joint project to a later unspecified date. It remains the intention of both Boards to complete the joint assessment, with the goal of publishing a detailed report that describes the results in a manner similar to the EUB's 1992 Report. Notwithstanding the deferral of the joint assessment, the NEB has decided to release its current estimate as an interim view, in light of the current heightened public interest in gas supply. The final results of the joint assessment will be used as the ultimate potential volume input for any long term projections prepared by either Board.

This Technical Appendix provides an overview of the results of the NEB's assessment of the conventional natural gas resources of Alberta. There was no attempt to include unconventional gas resources such as coalbed methane, tight gas or shale gas in this report, as there is currently not enough public information available. However, it is important to note that the distinction between conventional and unconventional resources is constantly changing as a result of changes in technology, or higher commodity prices. Both factors improve the overall economics for industry to exploit lower quality resources and could impact the amount of resources assigned.

Chapter 3 contains a description of previous assessments of the gas resources of Alberta. Chapter 4 contains a description of the methodology used by the Board and provides a description of the results by geological age group, including a comparison with results from other assessments and the reasons for variance between the estimates.

CHAPTER THREE

Previous Assessments

Over the years, several organizations have assessed the ultimate potential of conventional natural gas resources of Alberta, both in detail and from a broader perspective. Some have been studies of the entire WCSB, while others have focused only on Alberta. Three recent detailed assessments were conducted by the EUB in 1992, by the CGPC in 1997 and 2001. The Geological Survey of Canada (GSC) published an overview of its last assessment in 1995. Finally, there have also been two more general assessments performed by Sproule Associates on behalf of TCPL, and Bowers, a petroleum consultant, in 1997 and 2000, respectively. The nature and conclusions of those studies are discussed below.

3.1 Ultimate Potential and Supply of Natural Gas in Alberta, Report 92A, EUB, 1992

This study adopted a mean estimate for marketable ultimate potential of natural gas in Alberta of 5 600 $10^9 m^3$ (200 Tcf). It is worth noting that the estimates were slightly higher in the details of the report. The adopted estimate resulted from a detailed geological analysis of 36 separate stratigraphic intervals, ranging in geological age from the Tertiary Paskapoo sandstones to the Lower Devonian Granite Wash sandstones, covering all zones that had produced gas in Alberta. The data used was approximately 1990 vintage. At the time of that study, the expected remaining marketable resource volume consisted of 1 670 $10^9 m^3$ (59 Tcf) of reserves and 2 161 $10^9 m^3$ (77 Tcf) of undiscovered resources.

Some of the other key conclusions of that study were that:

- 70 percent of the future resource could be economically developed at a gas price of $3.00/GJ, and 87 percent at a gas price of $5.00/GJ;
- production will increase throughout the 1990s and supply from conventional sources will be unable to meet demand by about 2002; and,
- advances in technology will need to continue in order to continue improving the economics of gas exploration and production in Alberta.

3.2 Natural Gas Potential In Canada, A Report by the CGPC, 1997

The 1997 report by the CGPC estimated the marketable ultimate potential of natural gas in Alberta to be 5 959 $10^9 m^3$ (210 Tcf). This resulted from a detailed statistical and geological analysis of the information for discovered pools in the entire WCSB, combined with a subjective estimate for conceptual plays, an assessment of reserves growth in discovered pools over time and extensive consultation with industry. Most geological zones were analyzed using the PETRIMES discovery process model. The study was based on year-end 1993 data. At the time of the study, the expected remaining marketable resource volume consisted of 1 535 $10^9 m^3$ (54 Tcf) of reserves and 2 737 $10^9 m^3$ (97 Tcf) of undiscovered resources.

Some of the key conclusions of that study were:

- the Jurassic to Lower Cretaceous Play Group has the largest undiscovered potential, which will be found in thousands of relatively small gas pools;
- the largest undiscovered pools are predicted to be found in the Upper and Middle Devonian and the Foothills Play Groups; and,
- the maximum number of individual reservoirs and greatest concentration of conventional and unconventional gas endowment is found in the basin depocentre in Northwestern Alberta. Away from the depocentre, the number of potential reservoirs decreases and the concentration of gas resources diminishes sharply.

3.3 Natural Gas Potential In Canada - 2001, A Report by the CGPC, 2001

The CGPC updated its assessment in 2001 and estimated the marketable ultimate potential of natural gas in Alberta to be 5 761 $10^9 m^3$ (203 Tcf), a reduction of three percent from its total 1997 estimate. However, the CGPC converted about one-third of its estimate of undiscovered resources to discovered, reflecting drilling activity during the interim period. The update relied on the same methodologies as the 1997 report but expanded the use of Arps-Roberts[3] to a number of other zones, eliminated the consideration of conceptual plays, and revised its method of estimating reserves growth or reserves appreciation. Peer review was again used. The data used in this report was from year-end 1998. At the time of the study, the expected remaining marketable resource volume for Alberta consisted of 1 240 $10^9 m^3$ (44 Tcf) of reserves and 1 929 $10^9 m^3$ (68 Tcf) of undiscovered resources.

3.4 Other Assessments: GSC, Sproule Associates and Bowers

The GSC has published assessments of the WCSB for both oil and gas, with the most recent being *Oil Resources of the Western Canada Sedimentary Basin* published as an Open File in 1998. Its most recent gas assessment was published as an Overview in the *Oil and Gas Journal* in 1995. It concluded that the undiscovered gas-in-place for the WCSB was 6 575 $10^9 m^3$ (233 Tcf) including new pools in established and conceptual plays, but did not provide a provincial breakdown. The GSC also used a PETRIMES Discovery Process Model.

In 1998, Sproule Associates published an estimate of the total volume of resources for the WCSB of 9 320 $10^9 m^3$ (329 Tcf) of marketable gas, again without a provincial

[3] Arps-Roberts is a discovery process methodology which predicts the number and size of undiscovered pools based on the ratio of the area of the discovered pools compared to the area of the basin and the number of exploratory wells that had been drilled.

breakdown. This was based on an exponential projection of gas-directed drilling; that is, the total metreage of gas wells plus a prorated portion of dry holes drilled in a year.

In 2000, Bowers published an estimate of conventional natural gas in the WCSB of 6 514 $10^9 m^3$ (230 Tcf) of marketable gas. Alberta's share of that was 5 126 $10^9 m^3$ (181 Tcf). The estimates were obtained by plotting the discovery rate per metre of drilling of gas reserves on an annual basis against the cumulative discovered gas in place, which reflects the amount of gas added for every metre of gas-directed drilling.

4.1 Summary of Methodology Used by the NEB, 2003

This study commenced by verifying the stratigraphic intervals and play area boundaries established in the EUB's 92-A Report. Those boundaries were adjusted in conjunction with the geological staff of the EUB according to the improved knowledge of each area since the early 1990s. The adjustments resulted in an expansion to 43 stratigraphic intervals. Each interval can have from one to 12 play areas. A total of 168 play areas were used in this study. Each play area was examined utilizing well penetrations, structure, and hydrocarbon show maps to determine the new play boundaries. Estimates of undrilled lands were based on 64 ha (quarter-section) tracts for most sandstone and pinnacle reef type formations. Full section (259 ha) tract assessments were generally limited to widespread sandstone and platform style carbonate formations.

The determination of undiscovered resource estimates is based on a series of Excel templates using the @Risk simulator as the numerical generator. This probabilistic methodology utilized a range of known reservoir parameters as inputs with most of the input data being represented by probability distributions rather than by single point values. In addition, a distribution of risk was incorporated utilizing known discovery ratios for each play area where sufficient drilling history was available. This process results in a range of estimates of undiscovered conventional resources with various success probabilities assigned. Values for non-associated, associated and solution gas are reported separately.

4.2 Detailed Description of NEB Methodology

1. Using the EUB's 1992A Ultimate Potential Report stratigraphic intervals and play areas as the starting point, proven and potential oil and gas well data were added to the play area maps to update them for drilling that occurred between 1990 and 2000. A large number of play areas were remapped since proven reserves extended beyond the existing play areas and also beyond some of the formational edges as mapped in 1992.

2. The geological review also indicated the need to subdivide some formations that were grouped together in 1992. As a result, the number of stratigraphic intervals increased to 43 from 36. Some of the larger play areas were also subdivided into separate play areas to ease the data requirements or to better fit the increased geological information gained from having more than 80,000 additional wells.

3. For each play area, a total of 168 play and sub-play areas, the geoScout[4] system was used to get an initial dataset of wells. That initial dataset was screened for wells that

[4] A bundled data and software analysis and decision support tool developed by geoLOGIC Systems Ltd. of Calgary.

penetrated the horizon below the zone of interest, except for those horizons with only one target interval within the zone of interest. For example, all wells with a Glauconitic top noted were considered to have tested the Glauconitic zone, even if the underlying zone top was not noted. The dataset of remaining wells was restricted to those wells completed prior to Dec. 31, 2000 for determination of drilled versus undrilled land in the play area.

4. Base maps covering prime geological features, production, regional structure, and drill stem test maps were created in the geoScout system for the zone of interest. Primary geological features were added to the maps, such as reef outlines, erosional edges, and the edge of the disturbed belt to further define the play area. In addition, major cities, assigned city buffer zones, large lakes and parks were outlined. The reviewer, based on the geological data, noted any portions of the play area that were deemed to have no potential for discoveries.

5. The maps were used to determine the total number of sections or quarter-sections contained in the play area. In addition, the number of sections or quarter-sections deemed to have no undiscovered resources and those considered to be non-accessible because they were located under a city, large lake, or national park, and finally those that were considered to be under a city buffer zone were determined.

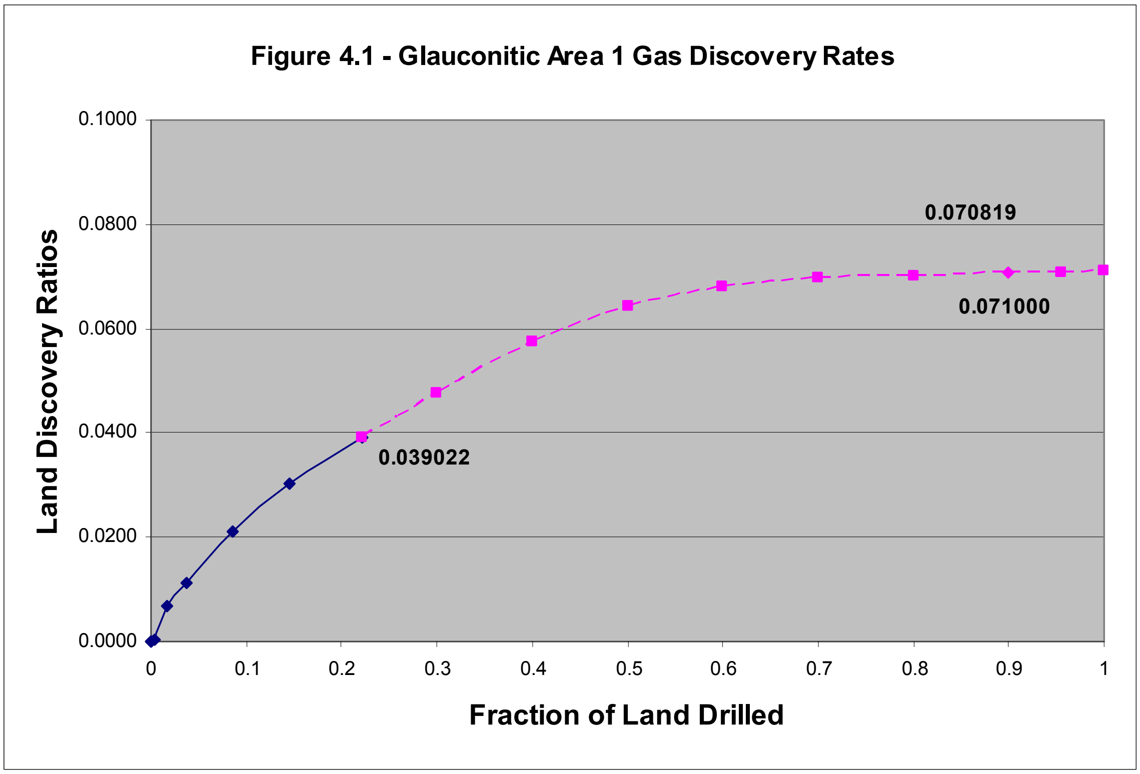
6. The well data was sorted to remove duplicate wells (those wells which were drilled in the same section or quarter-section as an older well), and also sorted by decade of completion. Sections (259 ha) were used when the zone of interest consisted of a large regional carbonate banks or regional sheet sand distributions. Quarter-sections (64 ha) were used for zones with discrete sand deposits or small pinnacle reefs such that average pool sizes were much less than a section in size. Since larger gas pools are not usually drilled to the quarter-section spacing level, the amount of drilled lands compared with proven lands from the reserves database can be somewhat understated. That understatement was determined to be quite small in comparison with the total amount of undrilled land.

7. The EUB's reserves data for year-end 2000 was used to assign the proven reserves for each play area. Commingled pools were subdivided and volumes were assigned to each component pool so that the component pools could be moved to their respective play area. For example, a commingled Cretaceous and Devonian pool was split to give the Devonian component to its Devonian play area and the Cretaceous component went to its Cretaceous play area. For some commingled pools, the EUB database may not provide the initial reserves for all of the component pools. As a result, it was often necessary to determine the volume of component pools by using the volumetric parameters provided in the EUB database and prorating the outcomes to match the commingled total.

8. The pools were then sorted into non-associated, associated and solution gas pools and oil pools for each play area. Oil pool data was matched to the associated and solution pools in the database. For oil pools with no solution gas pools, the NEB calculated a solution gas volume based on initial reservoir temperature and pressure conditions and calculated the remaining solution gas volume from the remaining oil volume.

9. The reserves information for each play area was then sorted into decades.

10. Success rates were based on the land data and determined for each mature play by reviewing the number of successful sections (or quarter-sections) versus total sections (or quarter-sections). The success rates were determined for both the total play life (from date of first discovery to Dec. 31, 2000) and for each decade in that play life. These success rates were based on all wells penetrating the zone (excluding duplicate wells removed in step 6), not just wells that specifically targeted that zone. There is usually one decade, generally close to when the play was initially discovered, when high success rates were found, but these high rates declined quickly to long-term lower values. These success rates were plotted on a cumulative basis against the land fraction of the play over



1. In this example, the solid portion of the line shows the cumulative drilling success ratio for all the wells penetrating the Glauconitic zone within the Glauconitic play area 1 (covers southern Alberta from Edmonton south in W4 lands, and south of T43 in W5 lands), compared with the fraction of total quarter-sections drilled in the same play area. Here, the cumulative success rate is 3.9 percent as the first 23 percent of the quarter-sections have been drilled. The dashed portion of the curve represents our projection of what will happen in the future for this play area, as the remaining quarter-sections are drilled. In this example, our projection is quite aggressive as the next 25 percent of the land is drilled. At some point when the last 50 percent of the land is being drilled it may become impractical to drill all of the remaining land, as the resource added becomes very small. Here, we would expect that the cumulative success would grow to a maximum of 7.1 percent. However, since there are city and park lands deemed to be non-accessible in this play area, the ultimate accessible success rate used is only 7.08 percent. The difference between the ultimate success and the current success (7.08-3.9=3.18 percent) is used as the mean input in the @Risk model to project the volume of undiscovered resources.

time. The projection of that curve, based on the geological knowledge and the judgment of the evaluator, gives the overall success rate at a time where all available land would be drilled. In cases where no clear trend could be established, emphasis was put on the recent activity, combined with geological knowledge of the play to estimate a future trend. The difference between the cumulative success rate at the end of 2000 and when all the land is drilled provides the median future success value that was put into the model.

11. The drilling, land and reserves information was combined to estimate the undiscovered resources. The input was based on a series of Excel templates using the @Risk simulator as a numerical generator. This probabilistic methodology uses a probability distributed range of GIP/ha, recovery factor and surface loss as inputs. This process results in a range of estimates of undiscovered conventional resources with a probability distribution. Outputs for non-associated, associated and solution gas are calculated. The @Risk simulator uses distributions that are anchored to the data such that the distribution type that provides the “best fit” is the chosen distribution type. Most distributions were skewed and some had to be truncated.

12. For play areas where insufficient drilling history and/or reserves data exists, an examination of the play area’s geology and adjacent areas’ reserves information was incorporated into a subjective assignment of the areas hydrocarbon potential.

13. For the 12 foothills plays, subjective adjustments were made to the EUB’s 92A estimates, based on the results of industry consultation.

14. The mean volume of resource estimates for each play area were summed to determine the province’s ultimate potential, by adding the total discovered and the total undiscovered estimates.

15. For the Milk River and Medicine Hat Formations only, a different methodology was used since previous estimating techniques have consistently underestimated gas volumes for these formations. The NEB’s assessment consists of three components. The first component was the reserves estimate determined from production decline analysis by the EUB and published in its year-end 2000 database. Since year-end 2000, the EUB has reverted to a volumetric determination as the production decline results were not reliable. The second component was determined by assuming that undrilled quarter-sections within the total area covered by the defined pools at year-end 2000 were not contributing to the EUB’s production decline estimate. Well spacing indicates drainage areas are quite restricted in these formations. The NEB determined the number of undrilled quarter-sections within the defined pool areas and assigned the average volumetric GIP from those defined pools to the undrilled quarter-sections and considered these to be undiscovered resources. The third component consisted of the difference between the production decline-based estimate plus the undrilled quarter-section estimate and the total reserves estimate determined by volumetric means. That difference was counted as undiscovered resources but with only a 35 percent recovery factor assigned. The NEB

believes that the difference represents a conventional gas resource contained in a "tighter" gas reservoir environment that can be recovered, if producing wells are allowed to flow for a long enough period of time.

In the fringe areas surrounding the EUB's defined pools, existing wells have reported perforations, but few have tests with gas shows. The NEB applied a ratio of the net pay to perforated interval from wells in the adjacent proven pool areas to the reported perforation intervals for wells in the fringe areas. Utilizing year-end 2002 data, it was confirmed that the perforated zones in non-producing fringe wells were being put on production in 2001 and 2002. The fringe areas were graded into high, medium and low volumes areas based on the proximity to proven pools and proximity to wells put on production in 2001 and 2002. These were assigned average GIP volumes from adjacent proven pools and then subjectively risked (0.85, 0.50, 0.30).

16. The NEB consulted with the United States Geological Survey on the methodology it used to generate its estimates of undiscovered resources. The NEB also did a peer review with selected agencies in Calgary on both the methodology and the results. The agencies consisted of the EUB, the GSC, the Canadian Association of Petroleum Producers (CAPP), and two local consultants experienced in resources assessment techniques and Alberta geology. Information from the consultations was used to make adjustments to the NEB estimates.

17. The Board's methodology captures the resources associated with plays that are already established in the province. Should new plays be discovered and developed, the resources of those new plays would be additive to the Board's estimate of ultimate potential for the province.

4.3 Results

The results of this study are shown in Tables 4.1 A and 4.1 B. Those tables provide the ultimate potential and the undiscovered resources, based on the NEB study, and provide comparative estimates from the EUB and the latest CGPC studies. Although the estimates are similar at the mean volume, each estimate can have a range of values. Based on the results, the NEB concludes that the ultimate potential has not changed significantly between 1992 and 2000; however, a large part of the earlier undiscovered estimate is now contained in the discovered estimates as a result of successful drilling between 1990 and 2000.

In this study, the @Risk methodology was not used for every play area, but the undiscovered resources determined using the @Risk model amounts to almost two-thirds of the total undiscovered resources. The assigned undiscovered resources portion, for those plays with insufficient data, amounts to two percent of the total undiscovered resources. The undiscovered resources determined for the Milk River and Medicine Hat zones amount to nine percent of the total undiscovered resources. Finally, the assigned

Table 4.1A Comparison of Estimates of Marketable Ultimate Potential					
Source	NEB (2003)	EUB (1992)	CGPC (2001)	Difference in Ultimate Potential	
Data Date	2000	1990	1998	NEB-CGPC	NEB-EUB
	10^9m^3 (Tcf)				
Ultimate Potential	5 855 (207)	5 600 (200)	5 761 (203)	255 (9)	94 (3)

Table 4.1B Comparison of Estimates of Marketable Undiscovered Resources					
Source	NEB (2003)	EUB (1992)	CGPC (2001)	Difference in Undiscovered Resources	
Data Date	2000	1990 [1]	1998 [1]	NEB-CGPC	NEB-EUB
	10^9m^3 (Tcf)				
Undiscovered Resources	1 730 (61)	1 488 (53)	1 654 (58)	242 (9)	76 (3)
[1] Undiscovered resource estimates adjusted to 2000, using published EUB discovered data.					

undiscovered resources for the foothills play areas amounts to about one-quarter of the total undiscovered resources.

The NEB has estimated the ultimate marketable gas potential for the province of Alberta to be 5 855 10^9m^3 (207 Tcf), comprised of 4 125 10^9m^3 (146 Tcf) of discovered gas and 1 730 10^9m^3 (61 Tcf) of undiscovered gas. The 1 730 10^9m^3 (61 Tcf) of undiscovered gas is the mean value with a probability of 39 per cent. The range of possible outcomes for the undiscovered component varies from 1 064 10^9m^3 (38 Tcf) at 90 percent confidence to 2 670 10^9m^3 (94 Tcf) at a 10 per cent confidence.

There were 81,617 new oil and gas wells drilled in Alberta over the decade from 1990 to 2000 and 20,571 wells drilled in 1999 and 2000 alone. These additional wells contributed greatly to the understanding of the geology and gas resources of the Alberta portion of the WCSB. A key point to note is that in spite of the number of wells drilled, and gas reserves found between 1990 and 2000, there has not been an appreciable increase in the total resource base. This implies that future drilling in Alberta will continue to shift undiscovered resources to discovered, without a significant appreciation of the total resource base.

In total, 777 10^9m^3 (27 Tcf) of the EUB's identified undiscovered potential in 1992 has been discovered by year-end 2000, based on the net increase in the discovered volumes at year-end 1990 and 2000. Similarly, some of the undiscovered gas potential identified in the CGPC report was found in the two years between its data cut-off and the NEB data cut-off. There were approximately 254 10^9m^3 (9 Tcf) of net reserves additions over 1999 and 2000.

The discovered marketable resource from the year-end 2000 data is comprised of 2 724 10^9m^3 (96 Tcf) of sweet gas and 1 340 10^9m^3 (47 Tcf) of sour gas, based on EUB information. The NEB's analysis of the undiscovered marketable gas indicates that it will be comprised of 1 310 10^9m^3 (46 Tcf) of sweet gas and 420 10^9m^3 (15 Tcf) of sour gas. Approximately 33 percent of the discovered gas was sour at year-end 2000, but only 28 percent of the undiscovered resources are expected to be sour since the majority of undiscovered resources will be in the Cretaceous formations that generally contain sweet gas.

Directly comparing the NEB and EUB total resources, there is a four percent difference overall. That small difference in the total resources is more significant when comparing undiscovered volumes. The EUB undiscovered volume after correcting to year-end 2000 is about 15 percent smaller than the NEB's undiscovered volume.

Directly comparing the NEB and CGPC 2001 results, there is less than one percent difference overall. Again, considering only the undiscovered volumes, after adjusting the CGPC to year-end 2000, the CGPC estimate is four percent smaller than the NEB's estimate. The CGPC's undiscovered volume includes the addition of reserves appreciation (308 10^9m^3 (10.9 Tcf)); the NEB estimate does not include a separate appreciation or growth factor. The NEB believes that it captures any appreciation volumes in its methodology.

4.4 Age Group Comparison, NEB versus EUB and CGPC

The maturity indicator shown in Table 4.2 is the portion of an age group's undiscovered resources compared with the total resources of that same age group. The lower the number, the more mature that age group is in terms of development. The discovery rate is determined by subtracting the total 1990 discovered marketable volume from the 2000 discovered marketable volume, as published by the EUB, for each age group and dividing the difference by ten for an annual rate. The remaining exploration life is determined by dividing the marketable undiscovered volume by the discovery rate. The remaining exploration life is an approximate estimate of the time it will take industry to find the remaining potential based on activity level from 1990 to 2000. A higher success rate, similar to what industry has been finding in the past few years, would reduce the remaining exploration life shown. Note, industry found 250 10^9m^3 (8.8 Tcf) in 2001 and 2002, a rate 60 percent higher than the period 1990-2000.

A summary of the discovered and undiscovered resource estimates, for the NEB's analysis by play area, is available in Appendix 2, while a description of the geology for each play area analyzed is available in Appendix 3. The NEB's play endowment graphs are available in Appendix 4. The Board's @Risk output tables for each play area are in Appendix 5. The NEB play area maps are available in Appendix 6.

Table 4.2 NEB Estimate of Remaining Marketable Undiscovered Resources, Maturity Indicator and Remaining Exploration Life					
	Undiscovered Resources	Share of Total Undiscovered Resources	Maturity Indicator	10 Year Discovery Rate	Remaining Exploration Life (at end of 2000)
	10^9m^3	%	%	10^9m^3/year	Years
Age Group					
Upper Cretaceous	328	19	35	16.4	20
Lower Cretaceous	809	47	32	42.3	19
Jurassic	35	2	23	1.6	22
Triassic	84	5	38	6.1	14
Permo-Penn	25	1	36	0.1	NA
Mississippian	222	13	23	9.4	24
Devonian	227	13	23	10.1	22
Provincial Total	1730		29	77.6	22

NA – not applicable

4.4.1 Cretaceous Formations

The Cretaceous formations have seen the largest changes over the decade from 1990 to 2000. The EUB's 1992 estimate of undiscovered resources for Cretaceous zones was discovered, yet more pools continue to be found. The new pools are relatively small and are often found in the same section as pools discovered earlier but can be in a slightly different layer of sand. This is true across the plains portion of the basin and especially in Eastern Alberta. The Mannville Above Glauconitic interval can have multiple layers of sand, as many as seven, with each layer capable of containing an oil and gas pool.

The Upper Cretaceous contains 19 percent of the total marketable undiscovered resources while the Lower Cretaceous contains 47 percent. In comparison, the EUB had attributed 21 percent in the Upper and 26 percent in the Lower. A similar comparison with the CGPC results is not possible as this information was not published.

For the Upper Cretaceous formations, the NEB's estimate of marketable discovered reserves in this study increased from 448 10^9m^3 (16 Tcf), as determined by the EUB in 1992, to 611 10^9m^3 (22 Tcf). This increase would have been higher except for the results of a number of internal studies within the EUB over the 1990s. For most zones, the EUB has relied more on production decline and material balance techniques as opposed to strictly volumetric calculations. The revisions to larger pools based on production performance resulted in net decreases for those pools between 1990 and 2000. The use of smaller area assignments for single well pools and the removal of long-term single well unconnected gas pools also resulted in a net decrease to the discovered reserves. In spite of the increased discovered resources, the undiscovered portion has increased, from 314 10^9m^3 (11 Tcf) as determined by the EUB in 1992, to 328 10^9m^3 (12 Tcf). As a result, the remaining resource is now 577 10^9m^3 (20 Tcf), consisting of this undiscovered volume and 249 10^9m^3 (9 Tcf) of reserves.

Contributing to the increased estimate of ultimate potential were new formations added and expanded play areas for the Badheart, Colorado and Lower Colorado Formations. In addition, there was growth in the reserves of the key shallow gas formations in southeastern Alberta. For the Medicine Hat and Milk River Formations, the core areas of the established multi-field pools were considered by the NEB to have a 100 percent chance of success based on historical drilling experience. In addition, the EUB has moved from a production decline type of analysis for these pools to a volumetric determination, since the year-end 2000 database was published. As a result, the difference between the production decline and volumetric estimates was also assigned as undiscovered potential. The NEB believes that, in these formations, there has been a significant contribution to the long term gas production from the tighter sands formerly unrecognized as net pay, and interbedded with the conventional sand portions. The Medicine Hat and Milk River are two formations where these tighter gas sands are contributing to the production, but are generally not recognized due to their low reservoir quality; this has contributed to a significant under-booking of resources in the past. Consequently, by considering the contribution from this gas, the NEB's determinations of remaining resources, for these Upper Cretaceous formations, are substantially higher than those of the EUB and CGPC.

For the Lower Cretaceous formations, the NEB's marketable discovered reserves increased from 1 248 10^9m^3 (44 Tcf), as determined by the EUB in 1992, to 1 712 10^9m^3 (60 Tcf), and again, could have been higher except for the same reasons noted in the discussion of the Upper Cretaceous formations. The undiscovered portion has only decreased from 811 10^9m^3 (29 Tcf) to 809 10^9m^3 (29 Tcf), in spite of the large increase in the discovered portion. The remaining resource is now 1 295 10^9m^3 (46 Tcf), made up of the undiscovered volume and 486 10^9m^3 (17 Tcf) of reserves. The CGPC, in its 2001 study, assessed the Lower Cretaceous as still having an undiscovered volume of 991 10^9m^3 (35 Tcf).

The discoveries made between 1990 and 2000 are mainly located in the plains regions from southeastern Alberta to northwestern Alberta at relatively shallow depths, generally less than 2000 m and in relatively small pools. In making its assessment, the NEB, jointly with the EUB, made a thorough effort to assign discovered pools to the correct geological formation. For pools named Upper Mannville, Mannville, and Blairmore, available formation tops were used to assign the pools to the individual sandstone formations. As a result, these pools were assigned to formations ranging from Colony to Cadomin. This will account for some of the difference between the NEB discovered volumes and the discovered volumes assigned by the EUB and CGPC when comparing results of specific geological formations.

These formations are penetrated by all wells that target deeper and older age groups and thus, have the highest number of well penetrations. Given the multiple pay zones that can be penetrated, it is difficult to recognize significant upside to these estimates. However, recognition of significant volumes of previously by-passed pay in zones, such as the Belly River, indicate that there is still room for additional upside to the NEB estimates for these zones. For example, there were 32 $10^9 m^3$ (1.1 Tcf) of reserves added to the estimate for the Belly River zone in the 1990s.

4.4.2 Jurassic

The Jurassic formations have a relatively restricted distribution in the province, confined to western Alberta adjacent to the foothills, minor portions in the foothills and a strip across the southern part of the province. The Jurassic formations contain only two percent of the NEB total undiscovered resources, and five percent of the EUB's total undiscovered resources. The CGPC reduced the undiscovered resources for these formations by about 40 percent from the EUB's estimate in its latest report, and the NEB assessment further reduces the undiscovered resources. Recent drilling has not found significant volumes of Jurassic resources, and as a result, the age group does not warrant a higher undiscovered estimate. The formations are well drilled and detailed geological mapping indicates only limited areas of potential remain. The remaining marketable gas as estimated by the NEB is 70 $10^9 m^3$ (2.5 Tcf), made up of 35 $10^9 m^3$ (1.2 Tcf) of undiscovered resources and 35 $10^9 m^3$ (1.2 Tcf) of reserves.

4.4.3 Triassic

The Triassic plays occupy a relatively small area of northwestern Alberta and the majority of the discoveries found in plains region are pools related to tidal and shoreface deposits. There have been a few Triassic-aged discoveries made in the foothills and the NEB has assigned all of these to its estimate of discovered resources in the Montney Formation. However, there are other zones that are now developing into plays in the northern foothills, specifically the Charlie Lake and Spray River Formations. The Triassic formations contain five percent of the NEB and EUB total undiscovered resources. The NEB currently estimates that the remaining marketable gas is 156 $10^9 m^3$ (5.5 Tcf), made up of 84 $10^9 m^3$ (3 Tcf) of undiscovered resources and 72 $10^9 m^3$ (2.5 Tcf) of reserves.

About 40 percent of the undiscovered resources assigned by the EUB in 1992 have been discovered by year-end 2000 but, again, due to the limited play area, discovery of new resources is unlikely to continue at that pace. The NEB and CGPC assessments have decreased the overall estimate of the Triassic Formations compared with the EUB. The NEB has assigned some undiscovered resources to these formations in conceptual plays in the region between the foothills and the main areas of play development. In that region, these formations are quite deep and there is some risk that the reservoir temperature may be too high to preserve gas. In addition, the reservoir quality declines towards the southwest which makes the region even riskier. The NEB assigned a higher level of risk in that region.

4.4.4 Permian-Pennsylvanian (Permo-Penn)

The Permo-Penn formations of the Belloy and Kiskatinaw/Taylor Flats/Golata are found in the plains of northwestern Alberta, although there is a developing play for the Belloy in the northern foothills of Alberta. The NEB recognizes that the Kiskatinaw and Golata more properly belong to the Mississippian section but, for the purposes of this study, groups them with the Permo-Penn section since the geology and trapping mechanisms are similar. The volume of discovered gas has almost doubled between 1990 and 2000 as industry has developed a better understanding of the geology in this area. Table 4.2 incorrectly estimates the 10 year discovery rate due to the differences in the handling of the Kiskatinaw and Golata Formations. Almost all of the undiscovered potential assigned by the EUB in 1992 was discovered by year-end 2000. However, given the limited play areas, there is little probability for increases to continue at the same pace.

The Permo-Penn formations contain two percent of the total undiscovered resources estimated by the NEB. The NEB estimates that the remaining marketable gas is 39 $10^9 m^3$ (1.4 Tcf), made up of 25 $10^9 m^3$ (0.9 Tcf) of undiscovered resources and 14 $10^9 m^3$ (0.5 Tcf) of reserves.

4.4.5 Mississippian

The Mississippian age group saw an increase in discovered marketable reserves of 94 $10^9 m^3$ (3.3 Tcf) from 1990 to 2000. About half of the discovered resources are located in the plains region of Alberta, in pools found along the subcrop edge of the individual formations. The other half of the discovered volumes are found in structural plays in the foothills. The majority of new discoveries found between 1990 and 2000 were made in the smaller plains type pools. However, horizontal drilling in the foothills areas have allowed for development of pools found in the past that did not economically produce gas from vertical wells. Much of the remaining undiscovered resource is in the foothills within the Turner Valley and Debolt formations. However, issues related to access may not allow for the development of all the foothills potential. NEB and CGPC estimates are very similar for this age group.

The Mississippian formations contain 13 percent of the NEB's and 14 percent of the EUB's total undiscovered resources. A comparison with the CGPC is not possible. The NEB currently estimates that the remaining marketable gas is 359 $10^9 m^3$ (12.6 Tcf), made up of 222 $10^9 m^3$ (7.8 Tcf) of undiscovered resources and 137 $10^9 m^3$ (4.8 Tcf) of reserves. The NEB and CGPC estimates of undiscovered potential are essentially the same when only comparing the plains potential - all of their differences are due to estimates of foothills potential.

4.4.6 Devonian

The Devonian group of formations had a total increase in marketable discovered resources of 198 10^9m^3 (6.9 Tcf) over the decade from 1990 to 2000, via new discoveries and net positive increases in pools reserves through revisions by the EUB. The majority of the plays in this age group are relatively mature as they have been targeted since the late 1940s. As well, most of the reserves are found in relatively large carbonate banks and reef trends which can be seen identified with 2D seismic. Recent exploration is focused on pools where the reef trends are hidden by other factors and in areas in the deepest parts of the basin. Much of the remaining undrilled land for these plays, are in the shale-filled areas which have little chance of containing conventional gas resources. Past assessments appear to have overstated the undiscovered resources in Devonian formations. The CGPC, in its 2001 Report, indicated a 10 percent decrease for its total Devonian resources from its 1997 Report. The NEB's current assessment is also less optimistic for the Devonian formations as its estimate is a further decrease of 6 percent from the CGPC. The Devonian pools are the oldest and deepest pools in the province and contain a higher portion of sour gas. As a result of increased drilling depths, and the increased costs to process the sour gas, economics dictate that the average size of developed pools is larger than the average Cretaceous pool. Nonetheless, it is important to note that the Devonian may still contain some very large gas pools as evidenced by the recent discovery at Ladyfern in British Columbia.

The Devonian formations contain about 13 percent of the NEB's estimates of total undiscovered resources compared with 30 percent of the EUB's estimate in 1992, reflecting the past overstatement of the Devonian resources. The NEB estimates that the remaining marketable gas is 379 10^9m^3 (13.4 Tcf), made up of 227 10^9m^3 (8 Tcf) of undiscovered resources and 152 10^9m^3 (5.4 Tcf) of reserves.

4.5 Remaining Resources

To compare different assessments of ultimate potential, it is necessary to examine the initial GIP volumes. However, for the purpose of projecting production into the future, it is more important to be aware of the volume that remains, either to be found in new undiscovered pools or remaining in the already discovered pools. The remaining resources are the only gas that will be available for future domestic and export demand at the point of the study.

It is readily apparent from Table 4.3 that the volumes of remaining reserves and undiscovered resources are similar for all studies.

Table 4.3 Alberta Ultimate Potential Estimates - Remaining Resources			
	Marketable - $10^9 m^3$ (Tcf)		
Report	Ultimate Potential	Produced[1]	Remaining Resources
EUB, 1992	5 600 (200)	2 853 (101)	2 747 (99)
CGPC, 2001	5 761 (203)	2 853 (101)	2 908 (102)
NEB, 2003	5 855 (207)	2 916 (103)[2]	2 939 (104)
1 Alberta's cumulative production to year-end 2000, as reported in EUB Report SS2001-98. 2 EUB estimate plus NEB's produced (flared) calculated solution gas.			

Comparing discovered marketable resources from the year-end 2000 EUB database (4 064 $10^9 m^3$ (143 Tcf)) with the same estimate from 1990, (3 287 $10^9 m^3$ (116 Tcf)), it can be determined that industry found 777 $10^9 m^3$ (27.4 Tcf) of net reserves additions - an average of about 78 $10^9 m^3$ (2.8 Tcf) per year. However, these additions are equivalent to only 70 percent of the average annual production for the same decade, consequently, Alberta's remaining reserves have been in a decline for the past few years.

4.6 Accessibility

An issue that has received a growing amount of attention in the United States, particularly for portions of the offshore coastal areas, in Alaska, and in the Rocky Mountain Basins, is the amount of land that is restricted, or closed, to exploration by industry. The volume of undiscovered resources in those areas can be very large. The CGPC has noted that areas in Alberta are subject to access restrictions as well. The CGPC uses the term "nominal marketable gas" for its undiscovered resources to reflect that not all of that volume will be available for development due to these restrictions or because of economics; however, the CGPC does not try to estimate the portion of gas not available.

The NEB has examined the issue related to land access and has done an assessment of how much of its estimated undiscovered resource could be in those areas, and therefore, is unavailable. Generally, such lands include the areas under cities or towns, or under large lakes where wells drilled from shore cannot reach selected reservoirs, under national parks, or under areas designated by governments as being sensitive for environmental or archeological reasons. That portion of the undiscovered resource is lost for future production purposes and cannot be relied upon to meet future demands for gas.

In this study, the NEB has estimated the size of those unavailable resources to be minimal, only 71 $10^9 m^3$ (2.5 Tcf). This estimate was made by considering the areas located under the current city boundaries of Lethbridge, Medicine Hat, Calgary, Red Deer, Edmonton, and Grande Prairie to be non-accessible from this point forward. The NEB also added a buffer region of approximately 10 kilometres (six miles) around those identified cites as being non-accessible today for any zones that would contain sour gas. Further, the areas under Elk Island, Banff, Waterton, and Jasper National Parks were considered to be non-accessible from this point forward. A large portion of the foothills belt is considered to be non-accessible to industry now, except where there are existing roads and old well sites available. Finally, the areas located more than five kilometers (three miles) from the shores of Lesser Slave Lake were considered to be non-accessible.

The NEB projected that the buffer areas around the current cities would also become non-accessible for sweet gas development in the near future. An additional 41 $10^9 m^3$ (1.5 Tcf) of undiscovered resource is at risk of becoming unavailable.

One other issue related to accessibility is the ongoing regulatory challenge between the owners of the bitumen rights in northeastern Alberta and the owners of gas rights in the same area. The EUB has determined that the bitumen resources have priority and this has put current and future gas production in the area at risk. The current EUB estimate of the impacted discovered resource is 8.2 $10^9 m^3$ (0.3 Tcf), approximate 0.7 percent of the provinces' remaining gas reserves. At this time, some of the production has been halted, but may eventually be available in the future. For this study, the NEB considers these resources to be available.

4.7 Additional Comments on the Foothills Region

The foothills region of Alberta has a number of special concerns related to its development. There are only a limited number of companies that have the financial ability and knowledge to operate in that high cost area. These companies tend to have an international portfolio of prospects so that limited available capital will be directed to the best economic prospects, having some regard for the political stability and certainty of the regulatory systems in the other locations. As well, the limited number of companies implies that there may be less opportunity for innovation due to reduced competition, compared with the plains area where several hundred companies pursue each play. The number of available rigs capable of drilling in the foothills in Alberta is sufficient for the number of companies actively drilling. The high costs of drilling in the foothills is due to technical challenges, related to higher reservoir pressures, deeper well depths, longer drilling times, often higher sour gas component of the targets, the long lead times and extensive consultations required to get landowner, land user and First Nations consent to drill. These factors, when combined with often short drilling windows in select areas, can result in wells needing two drilling seasons to complete. Industry has also pointed out the need for additional pipeline infrastructure in areas of the foothills in order to interconnect different gas plants. That would allow more gas to move to plants with spare capacity. In addition, there may be a need for more sharing of sour gas plant capacity at a reasonable cost between companies operating sour gas plants and other companies that want to drill in the same area. Industry would also like more clarity on the regulations over access to drilling prospects in the foothills and more regulatory stability.

@ Risk	A computer program from Pallisade Corporation that adds risk analysis and modeling capabilities to Excel spreadsheets.
Associated gas	Natural gas that overlies and is in contact with crude oil in the reservoir, at original reservoir temperature and pressure conditions.
Clastic deposits	A group of sedimentary rocks that form as a result of the erosion of older rocks, generally consisting of sandstone, conglomerate, silt and shale.
Coalbed methane	A unconventional form of natural gas that is trapped within the matrix of coal seams, also called natural gas from coal.
Conceptual plays	These are geological plays that are thought to exist or have been shown to exist, but have not been proven by the drilling of oil or gas wells that are capable of production.
Conventional Gas	This is natural gas that is found in the pore space of a reservoir and is produced through a wellbore with known technology and where the drive for production is provided by expansion of the gas or by pressure from an underlying aquifer.
Depocentre	This generally refers to the area with the maximum thickness of sedimentary fill and the deepest part of the basin.
Discovered volume	The quantity of gas and related substances that are estimated, at a particular time, to be initially contained in known accumulations that have been penetrated by a well bore.
Fluid types	These are the fluids that a reservoir may contain, either separately or in some combinations, such as crude oil, natural gas, or water.

Gas in place	This is the total quantity of gas that is estimated to be contained in any given pool or reservoir and includes both the portion that can be recovered and the portion that will remain in the reservoir.
Geological basins	A segment of the earth's crust which has been downwarped, usually for a considerable time, but with intermittent rising and falling. The sediments in such basins increase in thickness toward the centre of the basin.
Geological play	A geological configuration, within a defined area, which combines source rock, reservoir rock, trap, migration and preservation in such a way that the critical factors that control the occurrence of oil and gas are essentially similar.
Net Reserves	Net reserves are new finds plus any positive revisions to existing pools, less negative pool revisions.
Non-associated gas	Natural gas found in a reservoir in which no crude oil is present at reservoir temperature and pressure conditions.
Play area	The geographical area that contains a defined geological configuration within a stratigraphic interval. That geological configuration now contains or is expected to contain producible gas or oil, if the economic conditions are right.
Recovery Factor	A factor applied to the gas in place (or oil in place) in a reservoir in order to obtain the volume of gas that can be physically recovered at the surface.
Reserves	The estimated remaining quantity of oil or natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and, specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.
Reserves appreciation	The concept whereby an increase in initial reserves from discovered petroleum reservoirs is inferred from historical experience that additions to reserves continue to accrue over time. These increases can result from the extension of known reservoirs in known fields, or from revision to estimates of the portion of the volume in place that may ultimately be recovered.

Resources	As used in this report, resources refers to the total volume of oil or natural gas that is thought to be found in an area, or to that portion of the total resources that is not penetrated by a wellbore to date, or the volume that could be found as a result of appreciation.
Shale Gas	A form of unconventional gas where the gas molecules are mainly trapped on the organic material in a host rock of fine-grained shale.
Solution gas	Natural gas that is dissolved in crude oil in the reservoir at original reservoir temperature and pressure conditions and is normally produced with the crude oil.
Stratigraphic intervals	A grouping of all the productive geological formations into layers of sedimentary rocks of approximately the same geological age. For example, the Swan Hills Formation and Slave Point Formations are geologically different, but they are of the same approximately geological age and are grouped for the purposes of this study.
Success rate	The ratio of successful versus unsuccessful section, quarter-section, or wells, as designated by the user, for a particular stratigraphic interval within a specific play area, whereby a successful section, quarter-section, or well encounters producible natural gas or crude oil.
Surface loss factor	A factor applied to the gas recovered from a reservoir in order to determine the volume of gas actually available to be delivered to the market. It is generally used to account for impurities in the gas and the volume of gas used to fuel the equipment that allows for the production at a particular location.
Tight gas	A form of non-conventional natural gas that is held in the pore space of a rock that has a lower permeability or ability to flow than usual for the type of rock that it is.

Ultimate potential	A term used to refer to an estimate of the marketable resources that will be developed in an area by the time that exploratory and development activity has ceased, having regard for the geological prospects of an area, known technology and economics. It includes cumulative production, remaining reserves, and future additions to reserves through extension and revision to existing pools and the discovery of new pools. For most of this report it is used as a short form of "ultimate potential of conventional natural gas".
Unconventional gas	Natural gas that is contained in a reservoir rock that requires additional stimulus to allow gas flow. It may be that the gas is held by the matrix material such as coal, ice, or shale; or where the reservoir has an unusually low amount of porosity and permeability.
Undiscovered volume	The portion of the ultimate potential that has yet to be penetrated by a wellbore or that has yet to be proven by changes in a discovered pool's reserves through extension or revision.