ANNUAL INFORMATION FORM
For the Year Ended December 31, 2004

March 30, 2005

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INTRODUCTORY INFORMATION

In this annual information form, unless otherwise specified or the context otherwise requires, reference to "Paramount" or to the "Company" includes reference to subsidiaries of and partnership interests held by Paramount Resources Ltd. and its subsidiaries.

Unless otherwise indicated, all financial information included in this annual information form is determined using Canadian generally accepted accounting principles ("Canadian GAAP"), which differs from generally accepted accounting principles in the United States ("U.S. GAAP"). The notes to Paramount's audited consolidated financial statements contain a discussion of the principal differences between Paramount's financial results calculated under Canadian GAAP and under U.S. GAAP.

This annual information form contains disclosure expressed as "Boe", "MBoe", "Boe/d", "MMcfe", MMcfe/d" and "Bcfe". All oil and natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars and all references to "dollars" or "$" are to Canadian dollars and all references to "U.S. $" are to United States dollars.

NOTE REGARDING FORWARD LOOKING STATEMENTS

This annual information form contains forward-looking statements. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: capital expenditures, business strategy and objectives, reserve estimates, net revenue, production levels, exploration plans, development plans, acquisition and disposition plans and the timing thereof, and the Trust Spinout (as defined herein) and the completion, timing and effect on Paramount thereof.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other things contemplated by the forward-looking statements will not occur. Although Paramount believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this annual information form include, but are not limited to: volatility of oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in Paramount's operations, risks inherent in Paramount's current and anticipated marketing method for its production, including credit risk, imprecision of reserves estimates and estimates or recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves, Paramount's ability to replace and expand its oil and natural gas reserves, Paramount's ability to generate sufficient cash flow form operations to meet its current and future obligations, Paramount's ability to access external sources of debt and equity capital, general economic and business conditions, Paramount's ability to enter into or renew leases, Paramount's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, Paramount's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations or the interpretation of such regulations, risks associated with existing and potential future lawsuits and regulatory actions against Paramount, difficulty in obtaining necessary regulatory approvals and such other risks and uncertainties described from time to time in Paramount's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimates, and can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. The forward-looking statements contained in this annual information form are made as of the date hereof and Paramount undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this annual information form are expressly qualified by this cautionary statement.

CORPORATE STRUCTURE

Paramount was incorporated under the laws of the Province of Alberta on February 14, 1978. Paramount amalgamated with Paramount Acquisition Ltd. on January 1, 1992 and amended its articles on May 16, 1997 to split its common shares on a three for one basis.

Paramount's common shares are listed on the Toronto Stock Exchange and Paramount is currently part of the S&P/TSX Composite Index (Oil & Gas Producers sub index).

The head and principal office of the Company is located at Suite 4700, 888 – 3rd Street S.W., Calgary, Alberta T2P 5C5.

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation or formation of Paramount's principal subsidiaries and partnerships. The following table does not include all subsidiaries and partnerships of Paramount. The subsidiaries and partnerships listed in the following table held, in aggregate, greater than 95 percent of Paramount's consolidated assets as at December 31, 2004 which accounted for greater than 95 percent of Paramount's consolidated revenues for the year ended December 31, 2004.

Subsidiaries and Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation or Formation
Summit Resources Limited	100	Alberta
Paramount Resources (general partnership)	100	Alberta
Summit Operating Partnership (general partnership)	100	Alberta
1136980 Alberta Ltd.	100	Alberta

Note:

(1) Includes indirect ownership.

GENERAL DEVELOPMENT OF THE BUSINESS

Paramount is an independent Canadian energy company involved in the exploration, development, production, processing, transportation and marketing of natural gas and its byproducts and crude oil. The Company commenced operations as a public company on December 18, 1978, with an initial public offering that raised $4.7 million and a share exchange with a private company, Paramount Oil & Gas Ltd., for certain crude oil and natural gas assets with a book value of $341,000.

Set forth below is a brief description of the events that have influenced the general development of Paramount's business over the past three fiscal years.

2002

In July 2002, Paramount completed the acquisition of Summit Resources Limited for total consideration of $332.1 million, consisting of $249.6 million in cash and the assumption of $82.5 million of net debt. The acquisition increased the Company's proved and probable natural gas reserves at January 1, 2003 by approximately 91 Bcf and proved and probable oil and natural gas liquids reserves by approximately 12 MMBbl. The Company's production was initially increased by approximately 50 MMcf/d of natural gas and 5,000 Bbl/d of oil and natural gas liquids as a result of the acquisition.

During 2002, Paramount received $46.4 million in the form of reduced royalties as compensation from the Government of Alberta relating to the shut-in of approximately 22 MMcf/d (net) of gas over bitumen production at the Surmont area in May 2000. Paramount retains legal ownership of the mineral rights and their associated gas reserves, subject to an 11 percent gross overriding royalty held by the Crown.

2003

During the first quarter of 2003, Paramount completed the disposition of its Northeast Alberta natural gas assets, which had average natural gas production during 2002 of 97 MMcf/d, to Paramount Energy Trust ("PET"). PET was formed by Paramount for the purpose of completing the disposition of such assets to PET for cash and units of PET and the subsequent dividend of such units by Paramount to its shareholders and the rights offering by PET to its unitholders to subscribe for additional units of PET (collectively, the "PET Transaction").

The PET Transaction was completed through the following transactions:

- On February 3, 2003, Paramount transferred to PET assets in the Legend area of Northeast Alberta for net proceeds of $28 million and 9,907,767 units of PET.

- On February 3, 2003, Paramount declared a dividend-in-kind, payable to shareholders of record at the close of business on February 11, 2003, of the 9,907,767 units of PET received from the asset disposition.

- On March 11, 2003, in conjunction with the closing of the rights offering by PET to its unitholders to acquire additional units of PET, Paramount disposed of additional assets in Northeast Alberta to PET for net proceeds of $167 million, after adjustments.

On October 1, 2003, the Company sold its Sturgeon Lake properties in the Grande Prairie area, including the associated oil batteries and gas plant, to an unrelated third party for proceeds of $54 million.

On October 27, 2003, the Company completed a public offering in the United States of U.S. $175 million of 7⅞ percent senior notes due 2010 (the "2010 Notes").

During 2003, the Company also successfully completed a disposition program consisting of minor, non-core producing and non-producing properties for total consideration of $71.2 million.

2004

On June 29, 2004, the Company completed a public offering in the United States of U.S. $125 million of 8⅞ percent senior notes due 2014 (the "2014 Notes").

On June 30, 2004, Paramount completed the acquisition of oil and natural gas assets in the Kaybob area in central Alberta and in the Fort Liard area in the Northwest Territories and northeast British Columbia for $185.1 million, after adjustments. Paramount's business acquisition report dated September 10, 2004 in respect of such acquisition is incorporated by reference herein.

On August 16, 2004, Paramount completed the acquisition of assets in the Marten Creek area in Grande Prairie for $86.9 million, after adjustments. The assets acquired were producing approximately 14 MMcf/d of natural gas or 2,300 Boe/d at the date of acquisition. The reserves attributable to the properties as of July 1, 2004 consisted of proved reserves of approximately 17.4 Bcf of natural gas or 2.9 million Boe and proved plus probable reserves of approximately 22.2 Bcf of natural gas or 3.7 million Boe.

On October 15, 2004, Paramount completed the private placement of 2,000,000 common shares issued on a "flow-through" basis at $29.50 per share for gross proceeds of $59 million. On October 25, 2004, Paramount completed the issuance of 2,500,000 common shares at $23.00 per share for gross proceeds of $57.5 million.

On December 6, 2004, Paramount completed the acquisition of certain natural gas and crude oil properties in the Fort Liard Area of the Northwest Territories and Northeast British Columbia for consideration of approximately $50 million, subject to adjustments. Paramount also acquired 45,133 net acres of land in the acquisition. As at December 6, 2004, the acquired assets were producing approximately 14 MMcfe/d.

At a meeting of Paramount's board held on December 13, 2004, after considering the recommendation of management and after receiving legal and financial advice from Paramount's advisors, Paramount's board approved a proposed reorganization of Paramount (the "Trust Spinout") which would result in Paramount's shareholders and Paramount receiving units of a new energy trust which would indirectly own existing assets of Paramount in the Kaybob and Marten Creek areas of Alberta.

On December 15, 2004, Paramount initiated an offer to exchange the 2010 Notes and 2014 Notes outstanding following the redemption (described below) for an equal principal amount of new notes and cash and solicited consents from the holders of such notes to certain amendments to the indentures governing such notes (the "Notes Offer").

On December 30, 2004, Paramount redeemed approximately U.S. $41.7 million aggregate principal amount of its 2010 Notes and approximately U.S. $43.8 million aggregate principal amount of its 2014 Notes. The redemption price was U.S. $1,078.75 per U.S. $1,000 principal amount of the 2010 Notes and U.S. $1,088.75 per U.S. $1,000 principal amount of the 2014 Notes.

THE TRUST SPINOUT

GENERAL

The Trust Spinout is to be accomplished through a series of transactions, including an arrangement under the *Business Corporations Act* (Alberta) (the "Arrangement"). The Trust Spinout, if completed, will result in Paramount's shareholders receiving one common share and one unit of Trilogy Energy Trust (the "Trust") for each common share held. The Trust will indirectly own existing assets of Paramount in the Kaybob and Marten Creek areas of Alberta (the "Spinout Assets") which have current production of approximately 25,000 Boe/d. The balance of Paramount’s assets, consisting of its predominantly growth-oriented assets, will remain with Paramount.

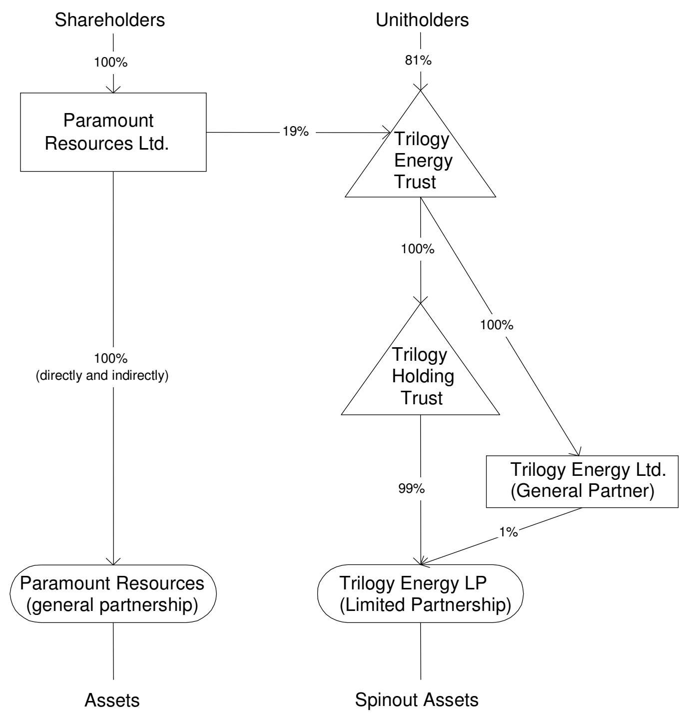
The Spinout Assets are primarily low-risk, high working interest, lower decline properties that are geographically concentrated with many infill drilling opportunities and good access to infrastructure and processing facilities. Paddock Lindstrom & Associates Ltd. ("Paddock Lindstrom"), independent petroleum engineers, have assigned in its report (the "Paddock Lindstrom Report") dated January 28, 2005 44,722 MBoe (268.3 Bcfe) of proved reserves and 64,254 MBoe (385.5 Bcfe) of proved plus probable reserves to the Spinout Assets, before deduction of royalties, as of December 31, 2004.

Paramount obtained the consent of the holders of the 2010 Notes and 2014 Notes to the Trust Spinout through the completion of the Notes Offer, as amended, on February 7, 2005. Paramount issued U.S. $213,593,000 principal amount of 8½ percent senior notes due 2013 ("2013 Notes") and paid aggregate cash consideration of approximately U.S. $36.2 million in exchange for approximately 99.31 percent of the outstanding 2010 Notes and 100 percent of the outstanding 2014 Notes under the offer. Paramount's shareholders and optionholders approved the Arrangement at a special meeting of such securityholders held on March 28, 2005 and the Court of Queen's Bench of Alberta approved the Arrangement on March 29, 2005. The Trust Spinout is expected to be completed on April 1, 2005.

Upon completion of the Trust Spinout, Paramount's shareholders will own all of the issued and outstanding common shares of Paramount and 81 percent of the issued and outstanding units of the Trust, with the remaining 19 percent of the issued and outstanding units being held by Paramount.

STRUCTURE FOLLOWING THE TRUST SPINOUT

The following diagram illustrates the organizational structure of Paramount and the Trust following the completion of the Trust Spinout.



NARRATIVE DESCRIPTION OF THE BUSINESS

OVERVIEW

The description of Paramount's business, major properties and reserves and other information respecting Paramount and its operations contained in this "Narrative Description of the Business" section of this annual information form do not give effect to the Trust Spinout, although the Spinout Assets are described under "Narrative Description of the Business - Major Properties". For a description of the effect of the Trust Spinout on Paramount, see "Appendix C - Effect of the Trust Spinout on Paramount". For a description of the reserves as of December 31, 2004 and other oil and gas information attributable to Paramount's assets other than the Spinout Assets (the "Retained Assets"), see "Appendix A - Reserves and Other Oil and Gas Information for the Retained Assets". For a description of the reserves attributable to the Spinout Assets as of December 31, 2004, see "Appendix B - Reserves Information for the Spinout Assets".

Paramount's principal properties are located primarily in Alberta, the Northwest Territories, British Columbia and Saskatchewan in Canada. Paramount also has properties offshore on the East Coast in Canada, and in Montana, North Dakota and California in the United States. In 2004, approximately 80 percent of the Company's production was natural gas.

The Company's ongoing exploration, development and production activities are designed to establish new reserves of oil and natural gas and increase the productive capacity of existing fields. In order to optimize its net capacity and control costs, the Company increases ownership and throughput in existing plants as economic opportunities arise and occasionally disposes of lower working interest properties. Paramount strives to maintain a balanced portfolio of opportunities, increasing its working interest in low to medium risk projects and entering into joint venture arrangements on select high risk/high return exploration prospects.

Paramount also participates in the petroleum and natural gas industry through the focused acquisition of petroleum and natural gas assets within established core areas. This acquisition strategy focuses on long-term value including assets which will increase Paramount's current working interest.

At December 31, 2004, approximately 77 percent of Paramount's proved and probable natural gas reserves and approximately 75 percent of its crude oil and natural gas liquids reserves were located in Alberta, with the balance in Paramount's other operating areas. In 2004, Paramount operated approximately 90 percent of its net producing natural gas wells and approximately 89 percent of its net producing crude oil and natural gas liquids wells.

Paramount has established areas of production in Kaybob, Grande Prairie, Northwest Alberta, Liard, Northwest Territories, Northeast British Columbia, Southern Alberta, Southeast Saskatchewan, Montana and North Dakota. Paramount continues to explore actively for petroleum and natural gas reserves within and beyond these areas. The Company has also established opportunities for heavy oil exploration and development in Northeast Alberta.

MAJOR PROPERTIES

The following is a summary of Paramount's major producing properties at December 31, 2004. Paramount's exploration efforts are primarily concentrated in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana and North Dakota. The Company is focused on the five core operating areas described below.

Paramount retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of Paramount's natural gas and crude oil reserves as at December 31, 2004. Paddock Lindstrom evaluated the natural gas and crude oil reserves as at December 31, 2004 attributable to the Spinout Assets and reported on them in the Paddock Lindstrom Report, and McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated the natural gas and crude oil reserves as at December 31, 2004 attributable to the Retained Assets and reported on them in its report dated February 1, 2005 (the "McDaniel Report"). All reserves information contained in the descriptions of Paramount's five core operating areas described below are as of December 31, 2004 and derived from the Paddock Lindstrom Report and the McDaniel Report. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. References to reserves in the following property descriptions are based on forecast prices and costs contained in the McDaniel Report and Paddock Lindstrom Report.

Kaybob

Kaybob, located in central Alberta, is Paramount's largest producing core area, accounting for approximately 56 percent of Paramount's production for the year ended December 31, 2004. Production in the area for that period averaged 120.9 MMcfe/d or 20.2 Mboe/d, comprised of 96.4 MMcf/d of natural gas and 4,091 Bbl/d of crude oil and natural gas liquids. Paramount's Kaybob area contains 265.3 Bcfe of proved reserves that are 77 percent natural gas weighted and 114.1 Bcfe of probable reserves that are 80 percent natural gas weighted.

Paramount operates three natural gas plants in this core area. These plants process approximately 70 percent of the natural gas produced from the Kaybob area. The Company also operates three oil batteries at North Kaybob and West Kaybob. Third-party facilities process the majority of non-controlled gas from this core area. On a Boe basis, the Company controls approximately 70 percent of the total production from this area.

The Spinout Assets include all of the oil and gas properties in Paramount's Kaybob core area, other than certain oil and gas properties in West Kaybob with production as of December 31, 2004 of less than 2,000 Boe/d. These properties contain 250.3 Bcfe of proved reserves that are 77 percent natural gas weighted and 360.1 Bcfe of probable reserves that are 78 percent natural gas weighted. The Spinout Assets also include 373,362 (333,203 net) undeveloped acres of land in this area and Paramount's interest in all of the operated natural gas plants and oil batteries in this area.

Grande Prairie

The primary properties in this core area include Marten Creek, Mirage, Saddle Hills, Sunset and Valhalla. The Grande Prairie core area accounted for approximately 14 percent of Paramount's production for the year ended December 31, 2004. Production in this area averaged 30.3 MMcfe/d or 5.1 Mboe/d in 2004, comprised of 26.8 MMcf/d of natural gas and 585 Bbl/d of crude oil and natural gas liquids. Grande Prairie is weighted to natural gas with 36.9 Bcfe of proved reserves that are 93 percent natural gas and 13.9 Bcfe of probable reserves that are 94 percent natural gas.

Paramount controls two gas facilities at Goose River and Marten Creek, and two oil batteries at Mirage and Valhalla. Approximately 28 percent of the area's total production is processed through these Company operated facilities.

The Spinout Assets in the Grande Prairie area include all of the oil and gas properties in the Marten Creek area which produced approximately 17 MMcf/d of natural gas as of December 31, 2004. These properties contain 18.0 Bcfe of proved reserves that are 100 percent natural gas weighted and 25.5 Bcfe of probable reserves that are 100 percent natural gas weighted. The Spinout Assets also include 117,120 (115,200 net) undeveloped acres of land in this area.

Northwest Alberta/Cameron Hills, NWT

The Northwest Alberta/Cameron Hills, NWT core area, located in the extreme northwest corner of Alberta and in the Northwest Territories, Canada, accounted for approximately 12 percent of Paramount's production for the year ended December 31, 2004. Production in the area for that period averaged 25.0 MMcfe/d or 4.2 Mboe/d in 2004, comprised of 20.2 MMcf/d of natural gas and 797 Bbl/d of crude oil and natural gas liquids. Paramount's Northwest Alberta area contains 55.8 Bcfe of proved reserves that are approximately 83 percent natural gas weighted and 15.3 Bcfe of probable reserves that are approximately 63 percent natural gas weighted.

The Company controls one sour gas plant at Bistcho Lake, which also processes gas from Cameron Hills in the Northwest Territories, and one sweet gas plant at East Negus, near Rainbow Lake in northern Alberta. Paramount also controls an oil battery at Cameron Hills in the Northwest Territories. Natural gas at the Haro property is produced from a nearly 50 percent-owned third-party operated gas plant. This controlled gas production accounts for approximately 84 percent of the total production from this core area.

Liard, NWT/Northeast British Columbia

The Liard, NWT/Northeast British Columbia core area, located in northern British Columbia and southwestern Northwest Territories, accounted for approximately 7 percent of Paramount's production for the year ended December 31, 2004. Production averaged 16.3 MMcfe/d or 2.7 Mboe/d in 2004, comprised of 16.2 MMcf/d of natural gas and 12 Bbl/d of crude oil and natural gas liquids. This area contains 38.8 Bcfe of proved reserves that are approximately 100 percent natural gas weighted and 55.9 Bcfe of probable reserves that are approximately 100 percent natural gas weighted.

Paramount operates three gas plants in northeast British Columbia, at Tattoo, Maxhamish and West Liard, and produces natural gas from a third-party operated facility in Clarke Lake, British Columbia. The Company controlled 68 percent of its production from this core area in 2004.

Southern

The Southern core area accounted for approximately 10 percent of Paramount's production for the year ended December 31, 2004. Contained in this core area are properties located in southern Alberta and southeast Saskatchewan in Canada and Montana and North Dakota in the United States. Production in the area for that period averaged 21.6 MMcfe/d or 3.6 Mboe/d, comprised of 10.8 MMcf/d of natural gas and 1,798 Bbl/d of crude oil and natural gas liquids. This area contains 38.6 Bcfe of proved reserves that are approximately 58 percent natural gas weighted and 11.9 Bcfe of probable reserves that are approximately 71 percent natural gas weighted.

The Company controls six gas plants in the Southern core area, one at Sylvan Lake, three at the Chain properties, one at Long Coulee and one at Enchant, all of which are located in Alberta. Approximately 70 percent of the natural gas produced in the Southern area comes from these operated plants. Crude oil is produced from eight Company-operated oil batteries, five in Alberta, one in Montana and two in North Dakota. Approximately 76 percent of the total oil production came from Company-operated batteries. On a Boe basis, the Company controls 74 percent of the total production in this core area.

RESERVES AND OTHER OIL AND GAS INFORMATION

Paramount retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of Paramount's natural gas and crude oil reserves as at December 31, 2004. Paddock Lindstrom evaluated the natural gas and crude oil reserves as at December 31, 2004 attributable to the Spinout Assets and reported on them in the Paddock Lindstrom Report, and McDaniel evaluated the natural gas and crude oil reserves as at December 31, 2004 attributable to the Retained Assets and reported on them in the McDaniel Report. The reserves information provided below combines the applicable information from the Paddock Lindstrom Report and the McDaniel Report. The evaluations by Paddock Lindstrom and McDaniel were prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil & Gas Activities ("NI 51-101").

The following tables set forth information relating to Paramount's working interest share of reserves, net reserves after royalties, and present worth values as at December 31, 2004. The reserves are reported using constant price and costs as well as forecast prices and costs. Columns may not add in the following tables due to rounding.

All evaluations of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of Paramount's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein.

Paramount's Audit Committee, comprised of independent board members, reviews the qualifications and appointment of the independent qualified reserves evaluators. The Audit Committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluation by the independent qualified reserves evaluators.

Reserves Information

Reserves Data - Constant Price and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using constant price and costs.

	Natural Gas		Light and Medium Crude Oil		Natural Gas Liquids		Total	
Reserves Category	**Gross** (Bcf))	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Canada								
Proved							-	-
Developed Producing	254.5	204.8	5,615	4,826	5,552	3,700	53,592	42,664
Developed Non-Producing	52.4	44.2	667	594	501	366	9,898	8,321
Undeveloped	39.9	33.9	308	308	289	220	7,251	6,179
Total Proved	346.9	282.9	6,590	5,728	6,342	4,286	70,741	57,164
Probable	221.3	177.9	2,910	2,548	2,087	1,438	41,887	33,643
Total Proved Plus Probable Canada	568.2	460.8	9,500	8,276	8,430	5,724	112,628	90,807
United States								
Proved								
Developed Producing	0.4	0.3	2,104	1,619	-	-	2,165	1,667
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	0.4	0.3	2,104	1,619	-	-	2,165	1,667
Probable	-	-	431	322	-	-	437	327
Total Proved Plus Probable US	0.4	0.3	2,534	1,941	-	-	2,602	1,994
Total Company							-	-
Total Proved	347.2	283.2	8,693	7,347	6,342	4,286	72,906	58,831
Total Probable	221.4	178.0	3,341	2,870	2,087	1,438	42,324	33,970
Total Reserves	**568.6**	**461.2**	**12,034**	**10,217**	**8,430**	**5,724**	**115,230**	**92,801**

Net Present Value of Future Net Revenue – Constant Price and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the constant price and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $ Millions									
	Before Income Taxes Discounted at					**After Income Taxes Discounted at**				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Canada										
Proved										
Developed Producing	1,355.2	1,128.9	976.9	866.9	783.2	1,150.3	964.4	840.6	751.2	683.0
Developed Non-Producing	223.4	179.6	151.0	130.7	115.5	160.2	128.0	107.7	93.6	83.3
Undeveloped	149.1	96.3	67.9	50.9	39.8	108.2	68.6	47.7	35.4	27.4
Total Proved	1,727.7	1,404.8	1,195.8	1,048.5	938.5	1,418.7	1,161.0	996.0	880.2	793.8
Probable	1,025.8	725.4	548.4	433.2	353.2	712.9	512.9	393.3	314.4	259.0
Canada	2,753.5	2,130.2	1,744.3	1,481.7	1,291.7	2,131.6	1,673.9	1,389.4	1,194.6	1,052.8
United States										
Proved										
Developed Producing	36.0	29.2	24.5	21.1	18.6	36.0	29.1	24.4	21.1	18.6
Developed Non-Producing	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	35.7	28.9	24.2	20.9	18.4	35.7	28.9	24.2	20.8	18.4
Probable	8.3	5.0	3.3	2.3	1.7	8.2	5.0	3.3	2.3	1.7
Total Proved Plus Probable US	43.9	33.9	27.5	23.1	20.0	43.9	33.9	27.5	23.1	20.0
Total Company										
Total Proved	1,763.4	1,433.7	1,220.0	1,069.3	956.9	1,454.4	1,189.9	1,020.2	901.0	812.2
Total Probable	1,034.0	730.4	551.7	435.5	354.9	721.1	517.9	396.6	316.7	260.7
Total Reserves	**2,797.4**	**2,164.1**	**1,771.7**	**1,504.8**	**1,311.8**	**2,175.5**	**1,707.8**	**1,416.8**	**1,217.7**	**1,072.9**

Future Net Revenue – Constant Price and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using constant price and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties**[1]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	2,987.8	594.8	528.3	59.0	42.2	1,763.4	309.0	1,454.4
Proved Plus Probable	4,693.5	917.0	799.6	135.3	44.3	2,797.4	621.9	2,175.5

[1] Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, Saskatchewan Capital Surcharge, net profit interest payments and are net of the Alberta Royalty Tax Credit and other income.

Future Net Revenue by Production Group - Constant Price and Costs

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using constant price and costs, discounted at 10 percent.

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%) ($ millions)
Proved	Associated and non-associated gas	1,017.7
	Light and medium crude oil	195.7
	Alberta Royalty tax credit and other income	6.6
Total Proved		**1,220.0**
Proved Plus Probable	Associated and non-associated gas	1,508.4
	Light and medium crude oil	255.0
	Alberta Royalty tax credit and other income	8.3
Total Proved Plus Probable		**1,771.7**

Reserves Data – Forecast Prices and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using forecast prices and costs.

	Natural Gas		**Light and Medium Crude Oil**		**Natural Gas Liquids**		**Total**	
Reserves Category	**Gross** (Bcf)	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Canada								
Proved								
Developed Producing	254.5	205.9	5,615	4,858	5,552	3,771	53,592	42,941
Developed Non-Producing	52.4	44.3	667	596	501	369	9,898	8,349
Undeveloped	39.9	34.1	308	308	289	224	7,251	6,219
Total Proved	346.9	284.3	6,590	5,762	6,342	4,364	70,741	57,509
Probable	221.3	179.1	2,901	2,560	2,087	1,471	41,882	33,874
Total Proved Plus Probable Canada	568.2	463.4	9,492	8,322	8,430	5,835	112,622	91,383
United States								
Proved								
Developed Producing	0.4	0.3	2,108	1,623	-	-	2,169	1,671
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	0.4	0.3	2,108	1,623	-	-	2,169	1,671
Probable	-	-	431	322	-	-	437	327
Total Proved Plus Probable US	0.4	0.3	2,539	1,945	-	-	2,606	1,998
Total Company								
Total Proved	347.2	284.6	8,698	7,385	6,342	4,364	72,910	59,180
Total Probable	221.4	179.1	3,332	2,882	2,087	1,471	42,319	34,201
Total Reserves	**568.6**	**463.7**	**12,031**	**10,267**	**8,430**	**5,835**	**115,230**	**93,381**

Net Present Value of Future Net Revenue – Forecast Prices and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the forecast prices and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $ Millions									
	Before Income Taxes Discounted at					After Income Taxes Discounted at				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Canada										
Proved										
Developed Producing	1,266.6	1,063.9	929.5	832.3	757.9	1,089.2	918.1	806.1	725.5	664.0
Developed Non-Producing	205.7	166.1	140.8	122.9	109.5	148.6	119.0	100.7	88.2	79.0
Undeveloped	142.8	91.2	64.0	48.0	37.6	103.3	65.0	45.0	33.3	25.8
Total Proved	1,615.2	1,321.2	1,134.3	1,003.2	905.1	1,341.2	1,102.1	951.8	847.0	768.9
Probable	950.6	663.5	500.7	396.3	324.2	658.5	467.9	358.1	286.7	236.9
Total Proved Plus Probable Canada	2,565.8	1,984.7	1,635.0	1,399.4	1,229.3	1,999.7	1,570.0	1,309.9	1,133.7	1,005.8
United States										
Proved										
Developed Producing	29.8	25.3	21.9	19.4	17.4	29.8	25.3	21.9	19.4	17.4
Developed Non-Producing	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	29.5	25.0	21.6	19.1	17.2	29.5	24.9	21.6	19.1	17.2
Probable	6.0	3.9	2.7	1.9	1.4	6.0	3.9	2.7	1.9	1.4
US	35.5	28.8	24.3	21.0	18.6	35.5	28.8	24.3	21.0	18.6
Total Company										
Total Proved	1,644.7	1,346.2	1,156.0	1,022.3	922.3	1,370.6	1,127.0	973.4	866.1	786.1
Total Probable	956.6	667.4	503.4	398.2	325.6	664.5	471.8	360.7	288.6	238.3
Total Reserves	**2,601.3**	**2,013.6**	**1,659.3**	**1,420.5**	**1,247.9**	**2,035.1**	**1,598.8**	**1,334.2**	**1,154.8**	**1,024.4**

Future Net Revenue by Production Group - Forecast Prices and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using forecast prices and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties**[(1)]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	2915.8	556.2	601.6	61.4	52.0	1644.7	274.0	1370.6
Proved Plus Probable	4596.1	857.6	939.7	139.4	58.2	2601.3	566.1	2035.1

[(1)] Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, Saskatchewan Capital Surcharge, net profit interest payments and are net of the Alberta Royalty Tax Credit.

Future Net Revenue by Production Group - Forecast Prices and Costs

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using forecast prices and costs, discounted at 10 percent.

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%) ($ millions)
Proved	Associated and non-associated gas	982.6
	Light and medium crude oil	167.0
	Alberta Royalty tax credit and other income	6.3
Total Proved		1,156.0
Proved Plus Probable	Associated and non-associated gas	1,436.7
	Light and medium crude oil	214.5
	Alberta Royalty tax credit and other income	8.1
Total Proved Plus Probable		**1,659.3**

The following definitions and assumptions form the basis of classification for reserves presented in the McDaniel Report and the Paddock Lindstrom Report:

a) **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Developed Reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

b) **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

c) **Gross Reserves** are defined as the reserves owned before deduction of any royalties.

d) **Net Reserves** are defined as the gross reserves of the properties in which an interest is held, less all royalties and interests owned by others.

Summary of Pricing and Inflation Rate Assumptions

Summaries of the pricing and inflation rate assumptions used in the evaluations of McDaniel and Paddock Lindstrom in their reports are contained in Appendix A and B hereto, respectively.

Reserves Reconciliation

Summary of Gross Reserves as at December 31, 2004 using Forecast Prices and Costs

		Production Group
	Natural Gas	**Crude Oil & Natural Gas Liquids**
Reserve Category	(Bcf)	(MBbl)
Proved	347.2	15,041
Probable	221.4	5,420
Total Gross Reserves	**568.6**	**20,460**

Reconciliation of Gross Reserves, by Principal Product Type using Forecast Prices and Costs

The following table sets forth the reconciliation of Paramount's gross reserves for the year ended December 31, 2004 using forecast prices and costs. Gross reserves include working interest reserves before royalties.

	Natural Gas			**Light and Medium Crude Oil & Natural Gas Liquids**		
		(Bcf)			(MBbl)	
	Proved	**Probable**	**Total**	**Proved**	**Probable**	**Total**
January 1, 2004	241.7	87.7	329.4	10,617	1,896	12,513
Extensions and discoveries	83.3	64.9	148.2	1,624	1,532	3,156
Improved recovery	-	-	-	-	-	-
Technical Revisions	22.6	17.2	39.8	1,066	662	1,727
Acquisitions	63.1	51.6	114.8	5,426	1,505	6,931
Dispositions	(0.2)	-	(0.2)	(1,021)	(176)	(1,196)
Economic Factors	-	-	-	-	-	-
Production	(63.4)	-	(63.4)	(2,671)	-	(2,671)
December 31, 2004	**347.2**	**221.4**	**568.6**	**15,041**	**5,420**	**20,460**

Summary of Net Reserves as at December 31, 2004 using Forecast Prices and Costs

		Production Group
	Natural Gas	**Crude Oil & Natural Gas Liquids**
Reserve Category	(Bcf)	(MBbl)
Proved	284.6	11,749
Probable	179.1	4,353
Total Net Reserves	**463.7**	**16,102**

Reconciliation of Net Reserves, by Principal Product Type using Forecast Prices and Costs

The following table sets forth the reconciliation of Paramount's net reserves for the year ended December 31, 2004 using forecast prices and costs. Net reserves include working interest reserves after royalties.

	Natural Gas (Bcf)			**Light and Medium Crude Oil & Natural Gas Liquids** (MBbl)		
	Proved	**Probable**	**Total**	**Proved**	**Probable**	**Total**
January 1, 2004	196.8	65.9	262.7	8,702	1,632	10,334
Extensions and discoveries	65.3	50.3	115.6	1,297	1,256	2,553
Improved recovery	-	-	-	-	-	-
Technical Revisions	20.8	15.6	36.4	912	491	1,403
Acquisitions	53.0	47.3	100.3	3,956	1,126	5,081
Dispositions	(0.1)	-	(0.1)	(960)	(151)	(1,111)
Economic Factors	-	-	-	-	-	-
Production	(51.2)	-	(51.2)	(2,158)	-	(2,158)
December 31, 2004	**284.6**	**179.1**	**463.7**	**11,749**	**4,353**	**16,102**

Reconciliation of Changes in Future Net Revenue

The following table sets forth the Company's reconciliation of after-tax future net revenue attributable to net proved reserves from January 1, 2004 to December 31, 2004 using constant price and costs, discounted at 10 percent.

Period/Factor		($ millions)
Present value of future net revenue at January 1, 2004	$	631.5
Sale of production, net of production costs and royalties		(234.9)
Net change in prices, production costs, and royalties related to future production		135.7
Revisions of estimates in development costs incurred		(43.6)
Changes in estimated future development costs		(79.2)
Extensions, improved recoveries and discoveries		274.0
Acquisitions of reserves		281.7
Dispositions of reserves		(18.7)
Net change resulting from revisions in quantity estimates		85.4
Accretion of discount		74.7
Net change in income taxes		(86.3)
Present value of future net revenue at December 31, 2004	**$**	**1,020.2**

Additional Information Relating to Reserves

Undeveloped Reserves

The following table summarizes the Company's gross proved undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	**2004**	**2003**	**2002**	**2001**	**2000**
Natural Gas (Bcf)	39.9	18.6	26.7	24.7	5.3
Light and medium crude oil (MBbl)	308	437	845	328	-
Natural Gas Liquids (MBbl)	289	111	165	-	-

These reserves are classified as proved undeveloped if they are expected to be recovered from new wells on previously undrilled acreage with untested reservoir characteristics, or they are reserves from existing wells that require major capital expenditures to bring them on production.

The following table summarizes the Company's gross probable undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	**2004**	**2003**	**2002**	**2001**	**2000**
Natural Gas (Bcf)	81.0	19.6	49.1	33.1	39.0
Light and medium crude oil (MBbl)	621	109	688	633	-
Natural Gas Liquids (MBbl)	484	47	101	5	5

These reserves are classified as probable undeveloped when analysis of drilling, geological, geophysical and engineering data does not demonstrate them to be proved under current technology and existing economic conditions; however, this analysis does suggest that there is a likelihood of their existence and future recovery.

Future Development Costs

The following table describes the estimated future development costs deducted in the estimation of future net revenue. The costs are per reserve category and quoted for no discount and a discount rate of ten percent.

Reserve Category	**2005E**		**2006E**		**2007E**		**2008E**		**2009E**	
($millions)	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**
Proved:										
Constant Price Case	43.5	41.5	9.4	8.1	-	-	0.1	0.1	0.1	-
Forecast Price Case	44.0	42.0	9.6	8.3	-	-	0.1	0.1	0.1	-
Proved & Probable:										
Constant Price Case	102.5	97.7	17.7	15.3	0.6	0.5	7.5	5.4	0.1	0.1
Forecast Price Case	103.3	98.5	18.1	15.7	0.6	0.5	8.2	5.8	0.1	0.1

Paramount expects that funding for future development costs will come from the Company's cash flow, a properly managed debt funding program and, in some cases, equity issues.

Other Oil and Gas Information

Oil and Gas Properties and Wells

As at December 31, 2004, Paramount had an interest in 2,277 gross (1,330.1 net) producing and non-producing oil and natural gas wells as follows:

	Producing		Non-producing[1]	
As at December 31, 2004	**Gross[2]**	**Net[3]**	**Gross**	**Net**
Crude oil wells				
Alberta	253	146.4	109	58.6
British Columbia	-	-	3	1.8
Saskatchewan	4	1.0	1	0.3
Northwest Territories	4	3.6	12	10.0
Montana	22	18.5	3	2.3
North Dakota	38	20.6	9	5.1
Subtotal	321	190.1	137	78.1
Natural gas wells				
Alberta	1,074	644.8	596	354.2
British Columbia	22	10.2	32	19.3
Saskatchewan	2	0.3	4	4.0
Northwest Territories	15	9.6	34	16.7
Montana	21	1.6	16	0.8
California	-	-	3	0.4
Subtotal	1,134	666.5	685	395.4
Total	**1,455**	**856.6**	**822**	**473.5**

(1) "Non-producing" wells are wells which Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.
(2) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be convertible to a working interest.
(3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth Paramount's land position at December 31, 2004 and 2003. The Company's holdings total 6,633,604 gross (4,081,699 net) acres. Approximately 83 percent of the Company's gross land holdings are considered undeveloped and approximately 40 percent of the undeveloped land is located in Alberta.

	2004		2003	
(thousands of acres)	**Gross[1]**	**Net[2]**	**Gross**	**Net**
Undeveloped Land				
Alberta	2,190	1,649	1,752	1,314
British Columbia	348	258	263	183
Saskatchewan	17	13	29	24
Northwest Territories	1,235	661	948	412
Montana, North Dakota	102	39	100	35
Other	1,644	822	1,664	832
Subtotal	5,536	3,442	4,756	2,800
Acreage Assigned Reserves				
Alberta	942	561	850	529
British Columbia	46	18	37	10
Saskatchewan	4	3	6	3
Northwest Territories	76	43	59	29
Montana, North Dakota	29	15	29	15
Subtotal	1,098	640	981	586
Total Acres	**6,634**	**4,082**	**5,737**	**3,386**

[(1)] "Gross" acres means the total acreage in which Paramount has a working interest, or a royalty interest that may be converted to a working interest.
[(2)] "Net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

As of December 31, 2004, the Company had 2,619,796 (1,395,733 net) acres of undeveloped lands that were due to expire in 2005. Of this total, 31,581 (22,179 net) acres of undeveloped lands due to expire in 2004 have had dry and abandoned wells drilled on them. The other 2,588,215 (1,373,554 net) acres have not been tested as of December 31, 2004.

In the Colville Lake exploration area, Paramount had, at December 31, 2004, 578,966 net acres of undeveloped land that are subject to four separate four-year work commitments totaling $21.7 million. These commitments are already partially fulfilled, and Paramount expects to meet or exceed these commitments within the allotted time period through its ongoing capital expenditure program. In the unlikely case that the commitments are not fulfilled, Paramount would only be obligated to pay the deposit amount of 25 percent of the commitment, or $5.4 million.

Forward Contracts

The Company's future commitments as at December 31, 2004 to sell natural gas and oil and natural gas liquids are set forth at note 11 of the Company's audited consolidated financial statements as at and for the year ended December 31, 2004 included in the Company's annual report, which information is incorporated by reference herein.

In March, 2005, Paramount acquired an indirect 25 percent ownership interest in a gas marketing limited partnership. In conjunction with the acquisition of the ownership interest, Paramount agreed to make available for delivery an average of 150 million GJ/d of natural gas over a five year term, to be marketed on Paramount's behalf by the gas marketing limited partnership. Paramount expects to receive prices at or above market for such natural gas.

Abandonment & Reclamation Costs

As at December 31, 2004, the Company had 1,389.2 net wells capable of production for which it expected to incur abandonment and reclamation costs.

The Company's estimates of abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines, undiscounted and discounted at 10 percent, are $136.2 million and $79.2 million, respectively. The future net revenue disclosed in this annual information form does not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The McDaniel Report deducted $21.7 million (undiscounted) and $9.0 million (10 percent discount) for abandonment and reclamation costs for wells only and the Paddock Lindstrom Report deducted $22.6 million (undiscounted) and $9.4 million (10 percent discounted) for abandonment and reclamation costs for wells only in estimating the future net revenue disclosed in this annual information form.

The Company does not expect to pay any material amounts with respect to abandonment and reclamation costs in the next three financial years.

Tax Horizon

Based on the current tax regime, and the Company's available tax pools and anticipated level of operations, Paramount is not expected to be cash taxable in 2005, and does not expect to become cash taxable in the near future.

Costs Incurred

The following table summarizes, for the periods indicated, the costs incurred by Paramount for property acquisitions and exploration and development costs.

Cost Type ($ millions)	**2004**	**Q4**	**Q3**	**Q2**	**Q1**
Acquisitions (corporate and property)					
Proved properties	302.6	49.3	86.9	166.4	-
Unproved properties	57.9	10.7	9.4	31.1	6.7
Exploration	62.7	21.4	8.0	10.9	22.4
Development (including facilities)	215.7	70.7	34.4	25.6	85.0
Total	**638.9**	**152.1**	**138.7**	**234.0**	**114.1**

Exploration and Development Activities

The following table summarizes the results of Paramount's drilling activity for each of the last two fiscal years. The working interest in certain of these wells may change after payout.

	2004		**2003**	
	Gross[(1)]	**Net[(2)]**	**Gross**	**Net**
Development Wells[(3)]				
Gas	164	102.8	135	90.0
Oil	11	8.6	13	10.4
Standing/service	-	-	–	–
Dry	9	4.9	7	3.5
Oilsands evaluation	17	17.0	–	–
Subtotal	201	133.3	155	103.9
Exploratory Wells[(4)]				
Gas	65	42.8	45	30.7
Oil	1	0.9	5	2.1
Standing/service	-	-	–	–
Dry	4	3.3	6	2.2
Subtotal	70	47.0	56	35.0
Total Wells	**271**	**180.3**	**211**	**139.9**
Success Rate	**95%**	**75%**	**94%**	**96%**

(1) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be converted to a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.
(3) "Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.
(4) "Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool that is partly discovered.

The total capital budget for 2005 is estimated at $340 million. Much of the activity in 2005 will occur in the Kaybob and Grande Prairie producing core areas with plans to complete the downspacing drilling programs initiated in the second half of 2004. Exploration activity continues in all of the core areas as well as the Colville Lake property in the Northwest Territories.

The following table describes the estimated 2005 capital budget per core area:

Area		**2005E** ($ millions)
Kaybob	$	130
Grande Prairie	$	65
Northwest Alberta/Cameron Hills, NWT	$	20
Liard, NWT/Northeast British Columbia	$	60
Southern	$	50
Heavy oil	$	15
Total	**$**	**340**

(1) McDaniel and Paddock Lindstrom have collectively estimated Paramount's capital expenditures to be $62.4 in their evaluations.

Production Estimates

The following table summarizes the total estimated production for 2005 using constant price and costs.

	Estimated Production – Constant Prices and Costs	
	Proved	**Proved Plus Probable**
Canada		
Natural gas (MMcf)	71,791	81,821
Light and medium crude oil (MBbls)	1,567	1,800
Natural gas liquids (MBbls)	1,109	1,212
Total Canada (MBoe)	**14,641**	**16,649**
USA		
Natural gas (MMcf)	84	86
Light and medium crude oil (MBbls)	282	284
Natural gas liquids (MBbls)	-	-
Total USA (MBoe)	**296**	**298**
Total Production (MBoe)	**14,937**	**16,947**

The following table summarizes the total estimated production for 2005 using forecast prices and costs.

	Estimated Production – Forecast Prices and Costs	
	Proved	**Proved Plus Probable**
Canada		
Natural gas (MMcf)	71,791	81,821
Light and medium crude oil (MBbls)	1,567	1,800
Natural gas liquids (MBbls)	1,109	1,212
Total Canada (Mboe)	**14,641**	**16,649**
USA		
Natural gas (MMcf)	84	86
Light and medium crude oil (MBbls)	282	284
Natural gas liquids (MBbls)	-	-
Total USA (MBoe)	296	298
Total Production (MBoe)	**14,937**	**16,947**

Production History

The following tables summarize daily sales volume results for Paramount on a quarterly and annual basis for 2004 and 2003 respectively.

	2004	**Q4**	**Q3**	**Q2**	**Q1**
SALES - Canada					
Produced gas (MMcf/d)	172.9	197.6	195.6	156.9	140.5
Light and medium crude oil (Bbls/d)	3,803	4,549	4,561	3,593	2,491
Natural gas liquids (Bbls/d)	2,644	3,373	3,061	1,754	2,374
SALES - United States					
Produced gas (MMcf/d)	0.3	0.3	0.2	0.4	0.5
Light and medium crude oil (Bbls/d)	830	978	782	765	793
Natural gas liquids (Bbls/d)	21	2	42	22	17
SALES – Total					
Produced gas (MMcf/d)	173.2	197.9	195.8	157.3	141.0
Light and medium crude oil (Bbls/d)	4,633	5,527	5,343	4,358	3,284
Natural gas liquids (Bbls/d)	2,665	3,375	3,103	1,776	2,391

	2003	**Q4**	**Q3**	**Q2**	**Q1**
SALES - Canada					
Produced gas (MMcf/d)	152.1	140.5	135.1	141.2	192.4
Light and medium crude oil (Bbls/d)	4,040	3,267	4,067	4,342	4,498
Natural gas liquids (Bbls/d)	2,080	1,772	2,316	2,009	2,218
SALES - United States					
Produced gas (MMcf/d)	0.7	0.4	0.7	0.8	0.8
Light and medium crude oil (Bbls/d)	1,024	838	1,036	1,075	1,149
Natural gas liquids (Bbls/d)	25	-	42	39	27
SALES – Total					
Produced gas (MMcf/d)	152.8	140.9	135.8	142.0	193.2
Light and medium crude oil (Bbls/d)	5,064	4,105	5,103	5,417	5,647
Natural gas liquids (Bbls/d)	2,105	1,772	2,358	2,048	2,245

(1) NI 51-101 came into effect on September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. As such, for the fourth quarter of 2003 and subsequent periods natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

The following tables summarize the average netbacks on a quarterly and annual basis for 2004 and 2003 respectively.

	Net Product Price Results – 2004				
	2004	**Q4**	**Q3**	**Q2**	**Q1**
Produced gas ($/Mcf)					
Price, before transportation	7.18	7.38	6.77	7.52	7.08
Transportation	(0.46)	(0.41)	(0.41)	(0.51)	(0.54)
Royalties	(1.29)	(1.27)	(1.26)	(1.33)	(1.33)
Operating costs(2)	(1.13)	(1.23)	(1.16)	(1.03)	(1.08)
Netback excluding realized financial instruments	4.30	4.47	3.94	4.65	4.13
Realized financial instruments	0.14	0.57	(0.13)	(0.31)	0.42
Netback including realized financial instruments	4.44	5.04	3.81	4.34	4.55
Total conventional oil ($/Bbl)					
Price, before transportation	49.91	52.62	52.15	47.78	44.39
Transportation	(1.19)	(1.15)	(1.12)	(1.13)	(1.43)
Royalties	(8.21)	(8.38)	(10.13)	(6.79)	(6.64)
Operating costs(2)	(9.56)	(10.29)	(8.66)	(9.20)	(10.26)
Netback excluding realized financial instruments	30.95	32.80	32.24	30.66	26.06
Realized financial instruments	(4.20)	(5.70)	(0.27)	(5.46)	(6.42)
Netback including realized financial instruments	26.75	27.10	31.97	25.20	19.64
Natural gas liquids ($/Bbl)					
Price, before transportation	43.47	41.25	48.93	42.24	40.38
Transportation	-	-	-	-	-
Royalties	(9.44)	(9.55)	(9.82)	(9.52)	(8.73)
Operating costs(2)	(7.96)	(10.83)	(6.96)	(5.54)	(6.97)
Netback	**26.07**	**20.87**	**32.15**	**27.18**	**24.68**

	Net Product Price Results – 2003				
	2003	**Q4**	**Q3**	**Q2**	**Q1**
Produced gas ($/Mcf)					
Price, before transportation	6.55	5.69	6.29	6.44	7.44
Transportation	(0.56)	(0.55)	(0.55)	(0.54)	(0.59)
Royalties	(1.13)	(0.55)	(1.30)	(1.14)	(1.43)
Operating costs(2)	(1.03)	(1.26)	(1.19)	(0.95)	(0.80)
Netback excluding realized financial instruments	3.83	3.33	3.25	3.81	4.62
Realized financial instruments	(0.83)	0.25	(0.72)	(1.09)	(1.52)
Netback including realized financial instruments	3.00	3.58	2.53	2.72	3.10
Total conventional oil ($/Bbl)					
Price, before transportation	40.27	36.59	38.84	39.27	45.28
Transportation	(1.08)	(1.40)	(1.01)	(0.97)	(1.00)
Royalties	(7.30)	(6.44)	(6.64)	(7.09)	(8.77)
Operating costs(2)	(9.79)	(10.81)	(11.07)	(9.88)	(7.76)
Netback excluding realized financial instruments	22.10	17.94	20.12	21.33	27.75
Realized financial instruments	(3.92)	(4.47)	(3.32)	(2.30)	(5.64)
Netback including realized financial instruments	18.18	13.47	16.80	19.03	22.11
Natural gas liquids ($/Bbl)					
Price, before transportation	36.06	37.94	33.55	33.35	39.73
Transportation	-	-	-	-	-
Royalties	(7.92)	(7.13)	(6.97)	(7.78)	(9.71)
Operating costs(2)	(7.43)	(11.45)	(7.70)	(6.30)	(4.94)
Netback	**20.71**	**19.36**	**18.88**	**19.27**	**25.08**

(1) NI 51-101 came into effect on September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. As such for the fourth quarter of 2003 and subsequent periods natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

(2) Operating costs include all costs related to the operation of wells, facilities and gathering systems. Processing revenue has been deducted from these costs.

The following table summarizes production volumes from Paramount's major producing properties for 2004 and 2003.

Production Volume	**2004**	**2003**
Natural gas (MMcf)		
Kaybob	35,281	29,024
Grande Prairie	9,855	4,522
Northwest Alberta/Cameron Hills, NWT	7,397	8,140
Liard, NWT/Northeast British Columbia	5,926	4,235
Southern	3,947	3,483
Northeast Alberta	598	5,914
Non-core	356	443
Total	**63,360**	**55,761**
Light and medium crude oil (MBbl)		
Kaybob	707	354
Grande Prairie	128	531
Northwest Alberta/Cameron Hills, NWT	275	133
Liard, NWT/Northeast British Columbia	-	-
Southern	580	825
Non-core	6	5
Total	**1,696**	**1,848**
Natural gas liquids (MBbl)		
Kaybob	790	540
Grande Prairie	86	114
Northwest Alberta/Cameron Hills, NWT	16	30
Liard, NWT/Northeast British Columbia	4	3
Southern	78	72
Non-core	1	9
Total	**975**	**768**

SELECTED CONSOLIDATED FINANCIAL AND OPERATIONAL INFORMATION

Year Ended December 31 *($ thousands, except per share amounts)* [(1)]	**2004**	**2003**	**2002**
Revenues, net of transportation and including realized gain (loss) on financial instruments	$ 549,899	$ 379,835	$ 473,942
Expenses			
Royalties, net of ARTC	105,046	82,512	74,444
Operating	95,767	81,193	86,067
Interest[(2)]	24,122	19,053	23,943
General and administrative [(3)]	25,247	19,051	15,870
Lease rentals	3,546	3,574	4,552
Bad debt expense	(5,523)	5,977	–
Current income taxes and other	6,795	2,689	9,150
Cash flow from continued operations	294,899	165,786	259,916
Cash flow from discontionued operations	667	1,490	-
Cash flow from operations	295,566	167,276	259,916
Per share – basic	4.95	2.78	4.37
Per share – diluted	4.84	2.77	4.36
Depreciation and depletion	191,578	165,098	169,433
Dry hole costs	24,676	36,600	120,058
Net earnings	41,174	1,151	10,307
Per share – basic	0.69	0.02	0.17
Per share – diluted	0.67	0.02	0.17
Balance Sheet Information			
Capital expenditures - net[(4)(5)]	579,014	(144,978)	494,535
Proceeds from property sales[(5)]	61,806	371,601	5,042
Working capital/(deficiency), excluding bank and shareholder loans	7,954	(10,593)	(15,973)
Total assets	1,542,786	1,177,130	1,526,786
Total debt	459,141	287,237	539,270
Shareholders' equity	625,039	496,033	546,105
Share information			
Weighted average number of common shares outstanding *(thousands)*	59,755	60,098	59,458
Market price			
High	$ 27.90	$ 16.95	$ 17.60
Low	$ 10.41	$ 8.51	$ 13.00

Notes:

[(1)] All per share amounts are calculated using the weighted average number of shares outstanding, except dividends paid per share which are based upon actual shares outstanding at time of dividend declaration.

[(2)] Net of non-cash interest expense.

[(3)] Net of non-cash general and administrative expenses.

[(4)] Excludes capital expenditures of discontinued operations and other minor accounting adjustments.

[(5)] 2003 disposition proceeds include the $51 million related to PET units.

GENERAL

Competitive Conditions

The petroleum and natural gas industry is highly competitive. Paramount competes with numerous other participants in the search for and acquisition of crude oil and natural gas properties and in the marketing of these commodities. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and reserves. Paramount's competitive position depends upon its geological, geophysical and engineering expertise and its financial resources. In addition, successful reserve replacement in the future will depend not only on the further development of present properties, but also on the ability to select and acquire suitable prospects for exploratory drilling and development.

Paramount has firm service for most of its natural gas production as opposed to interruptible allocations on pipeline systems. The Company closely monitors the daily production from all of its plants to ensure that contractual obligations will be met. Balancing contractual commitments, natural gas sales are directed to those markets where the Company believes prices will be best.

Employees

At December 31, 2004 Paramount had 163 full-time head office employees and 104 full-time employees at field locations. The Company's compensation of full time employees includes a combination of salary, benefits and participation in either a stock option plan or a Company-assisted share purchase savings plan. Shares under the savings plan are purchased in the marketplace by the plan trustee.

Environmental Protection

The oil and natural gas industry is governed by environmental requirements under both Canadian and United States federal, provincial, state and municipal laws, regulations and guidelines, which restrict and/or prohibit the release or emission of pollutants and regulate the storage, handling, transportation and disposal of various substances produced or utilized in association with oil and gas industry operations.

Paramount has in place an Environmental, Health and Safety Committee comprised of three directors of the Company. The tenet of the Company's Environmental Policy is as follows: *Paramount is committed to protecting the environment, to maintaining public health and safe workplaces, and to compliance with all applicable laws, regulations and standards. Paramount will do all that it reasonably can to ensure that sound environmental, health and safety practices are followed in all of its operations and activities.*

The Environmental, Health and Safety Committee is guided by a specific set of principles to ensure that this policy is supported. These principles apply to all employees of Paramount and are designed to make certain that all applicable environmental laws, regulations and standards are complied with. The Company monitors all activities and makes reasonable efforts to ensure that companies who provide services to Paramount will operate in a manner consistent with its environmental policy.

DIRECTORS AND OFFICERS

The following information is provided for each director and executive officer of Paramount as at the date of the annual information form:

DIRECTORS

Names and Municipality of Residence	Director Since	Principal Occupation
Clayton H. Riddell[(1)] Calgary, Alberta, Canada	1978	Chief Executive Officer Paramount Resources Ltd.
James H.T. Riddell[(2)] Calgary, Alberta, Canada	2000	President and Chief Operating Officer Paramount Resources Ltd.
John C. Gorman[(3)(4)] Calgary, Alberta, Canada	2002	Retired

Names and Municipality of Residence	Director Since	Principal Occupation
Dirk Jungé, C.F.A.[4] Bryn Athyn, Pennsylvania, United States	2000	Chairman, Pitcairn Trust Company (a trust company)
David M. Knott Mill Neck , New York, United States	1998	General Partner Knott Partners, L.P. (an investment management firm)
Wallace B. MacInnes, Q.C.[1][3][4][5] Calgary, Alberta, Canada	1978	Retired
Violet S.A. Riddell Calgary, Alberta, Canada	1978	Business Executive
Susan L. Riddell Rose Calgary, Alberta, Canada	2000	President and Chief Operating Officer Paramount Energy Trust (a public energy trust)
John B. Roy[1][3][4][5] Calgary, Alberta, Canada	1981	Independent Businessman
Alistair S. Thomson[3][4] Calgary, Alberta, Canada	1992	President, Touch Thomson & Yeoman Investment Consultants Ltd. (an investment consulting firm)
Bernhard M. Wylie[5] Calgary, Alberta, Canada	1978	Business Executive

Notes:
(1) Member of the Compensation Committee of Paramount's board.
(2) Mr. Riddell has been the President and Chief Operating Officer of Paramount since June 2002. Prior thereto, Mr. Riddell held various positions with Paramount. Mr. Riddell was a director of Jurassic Oil and Gas Ltd. ("Jurassic"), a private oil and gas company, within one year prior to such company becoming bankrupt. Jurassic's bankruptcy was subsequently annulled.
(3) Member of the Audit Committee of Paramount's board.
(4) Member of the Corporate Governance Committee of Paramount's board.
(5) Member of the Environmental, Health and Safety Committee of Paramount's board.

EXECUTIVE OFFICERS

Names and Municipality of Residence	Office
Clayton H. Riddell Calgary, Alberta, Canada	Chief Executive Officer
James H.T. Riddell Calgary, Alberta, Canada	President and Chief Operating Officer
Bernard K. Lee Calgary, Alberta, Canada	Chief Financial Officer
Charles E. Morin Calgary, Alberta, Canada	Corporate Secretary

As at December 31, 2004, the directors and officers of the Company as a group beneficially owned or controlled, directly or indirectly, 33,182,651 common shares, representing approximately 52.5 percent of the 63,185,600 common shares outstanding at such date.

Certain directors and officers of Paramount are also directors and/or officers and/or significant shareholders of other companies engaged in the oil and gas business generally and which, in certain cases, own interests in oil and gas properties in which Paramount holds, or may in the future hold, an interest. As a result, situations may arise where such individuals have a conflict of interest. Such conflicts of interest will be resolved in accordance with Paramount's governing corporate statute, the *Business Corporations Act* (Alberta), and Paramount's internal policies respecting conflicts of interest. The *Business Corporations Act* (Alberta) requires that a director or officer of a corporation who is party to a material contract or proposed material contract with the corporation, or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the corporation, disclose in writing to the corporation or request to have entered into the minutes of meetings of directors the nature and extent of the director's or officer's interest; and, if a director, that he or she not vote on any resolution to approve the contract, except in certain circumstances. The *Business Corporations Act* (Alberta) also requires that a corporation's directors and officers act honestly and in good faith with a view to the best interest of the corporation. Paramount's internal policies respecting conflicts of interest require that directors and officers of Paramount avoid putting themselves in a conflict of interest position and, if such a position arises, that disclosure of such position be made so that Paramount can approve or disapprove such position, with disapproved conflict of interest positions requiring immediate cessation by the director or officer.

AUDIT COMMITTEE INFORMATION

The full text of the audit committee's charter is included in Appendix F of this annual information form.

Composition of the Audit Committee

The audit committee consists of 4 members, all of which are independent and financially literate. The relevant education and experience of each audit committee member is outlined below:

J.B. Roy

Mr. Roy has been a director of the Company since 1981. He is an independent businessman. Prior to December 1, 2003, he was Vice-President and Director, Investment Banking of Jennings Capital Inc. From 1970 to 1996, he held various positions at Greenshields Incorporated and its successor, Richardson Greenshields of Canada Ltd. Mr. Roy graduated from Queen's University with a Bachelor of Science degree in Mechanical Engineering and received a Diploma in Management from McGill University. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

W. B. MacInnes

Mr. MacInnes has been a director of the Corporation since 1978. From 2001 to 2004 he was counsel to Gowling Lafleur Henderson LLP. Prior thereto he was a partner with, and counsel to, Ballem MacInnes LLP. Mr. MacInnes graduated from the University of Manitoba with an honours Bachelor of Laws degree and is a member of the Canadian Bar Association.

J. C. Gorman

Mr. Gorman has been a director of the Company since 2002. He is currently a business consultant prior to which he was employed with ECT Canada from 1996 to 2000, retiring as Chairman of the Board. Previously he was a corporate banker with Bank of Montreal from 1972 to 1996, retiring as Senior Vice President, Natural Resources Group. Mr. Gorman obtained a Bachelor of Arts degree from the University of Ottawa and a Master of Business Administration degree from the University of Western Ontario.

A. S. Thomson

Mr. Thomson has been a director of the Company since 1992. He is the President of Touche Thomson & Yeoman Investment Consultants Ltd. Mr. Thomson graduated from the University of St. Andrews with a Master of Arts (Honours) degree in Political Economy and Geography. He is a former President of both the Alberta Society of Financial Analysts and the Economics Society of Alberta.

Pre-Approval Policies and Procedures

The Company's audit committee has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by Ernst & Young LLP:

> *The audit committee has delegated authority to the Chairman of the audit committee to pre-approve the provision of non-prohibited audit and non-audit services by Ernst & Young LLP not otherwise pre-approved by the full audit committee, including the fees and terms of the proposed services ("Delegated Authority"). All pre-approvals granted pursuant to Delegated Authority must be presented by the Chairman to the full audit committee at its next meeting. All proposed services and the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the audit committee or pursuant to Delegated Authority.*

Of the fees reported below under the heading "External Auditor Service Fees", none of the fees billed by Ernst & Young LLP were approved by the audit committee pursuant to an available *de minimis* exception.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by Ernst & Young LLP during fiscal 2004 and 2003:

($ thousands)	2004	2003
Audit fees	688	387
Audit - related fees	20	8
Tax fees	43	48
All other fees		23
Total	**$751**	**$466**

Audit Fees. Audit fees consist of fees for the audit of the registrant's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the registrant's financial statements and are not reported as Audit Fees. During fiscal 2004 and 2003, the services provided in this category included research of accounting and audit-related issues, review of reserves and other disclosures and the completion of audits required by contracts to which the registrant is a party.

Tax Fees. Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2004 and 2003, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns and other filings, and research and advice on certain tax matters.

All Other Fees. During fiscal 2003, the services provided in this category included assistance with motor-fuel tax rebate claims.

DESCRIPTION OF SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. As of December 31, 2004, there were 63,185,600 common shares issued and outstanding and no preferred shares outstanding.

Common Shares

The holders of the common shares are entitled to receive dividends if, as and when declared by the board of directors of the Company. The holders of the common shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per common shares held at all such meetings. In the event of the liquidation, dissolution or winding up of the Company or other distribution of assets of the Company among its shareholders for the purpose of winding up its affairs, the holders of the common shares will be entitled to participate ratably in any distribution of the assets of the Company.

Preferred Shares

Preferred shares are non-voting and may be issued in one or more series. The board of directors may determine the designation, rights, privileges, restrictions and conditions attached to each series of preferred shares before the issue of such series.

CREDIT RATINGS

The 2010 Notes and 2013 Notes have been assigned a rating of "B3" by Moody's Investor Services, Inc. Standard & Poor's Corporation has placed Paramount's long-term senior unsecured debt rating of "B" on CreditWatch with negative implications pending completion of the Trust Spinout. A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, debt securities rated "B" generally lack the characteristics of the desirable investment. Assurance of interest and principal payments or of maintenance of other terms of the contract over any long period of time may be small. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt securities rated "B" are more vulnerable to nonpayment than obligations rated "BB", but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (–) sign to show relative standing within the major rating categories.

MARKET FOR SECURITIES

The common shares of Paramount are listed on the Toronto Stock Exchange under the trading symbol "POU".

The following table outlines the share price trading range and volume of shares traded by month in 2004.

2004	Price Range ($) High	Low	Trading Volume
January	11.36	10.41	2,604,285
February	12.45	10.70	2,569,047
March	13.30	12.25	1,456,883
April	13.02	11.60	2,801,221
May	14.99	11.91	2,854,315
June	14.75	13.50	1,883,033
July	16.75	14.30	2,240,266
August	18.47	16.53	4,578,331
September	23.90	17.80	4,240,910
October	24.59	22.26	2,698,236
November	26.39	22.30	3,185,629
December	27.90	24.31	7,376,969

DIVIDENDS

Paramount has not paid a cash dividend in the last three fiscal years. Future payments will be dependent upon the financial requirements of the Company to reinvest earnings, the financial condition of the Company and other factors which the Board of Directors of the Company may consider appropriate.

On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 units of PET. Paramount received these units, in addition to $28 million in net proceeds, as consideration for the transfer of certain assets in the Legend area of Alberta to PET. The units were deemed to have a total value of $51 million. See "General Development of the Business".

LEGAL PROCEEDINGS

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in Paramount's favour, the Company does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Company may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity.

RISK FACTORS

Below are certain risk factors related to Paramount which you should carefully consider.

Oil and natural gas prices are volatile and low prices will adversely affect Paramount's business.

Fluctuations in the prices of oil and natural gas will affect many aspects of Paramount's business, including:

- Paramount's revenues, cash flows and earnings;
- Paramount's ability to attract capital to finance its operations;
- Paramount's cost of capital;
- the amount Paramount is allowed to borrow under its senior credit facility; and
- the value of Paramount's oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil and natural gas prices have fluctuated widely during recent years and are likely to continue to be volatile in the future. Oil and natural gas prices may fluctuate in response to a variety of factors beyond Paramount's control, including:

- global energy policy, including the ability of the Organization of Petroleum Exporting Countries to set and maintain production levels and prices for oil;
- political conditions, including hostilities in the Middle East;
- global and domestic economic conditions;
- weather conditions;
- the supply and price of imported oil and liquefied natural gas;
- the production and storage levels of North American natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity of reserves to, and capacity of, transportation facilities;
- the effect of world-wide energy conservation measures; and
- government regulations.

Paramount's operations are highly focused on natural gas. In recent years, oil and natural gas prices have been generally high on a historical basis. Any material decline in natural gas prices could result in a significant reduction of Paramount's production revenue and overall value. Any material decline in oil prices could also result in a reduction of Paramount's production revenue and overall value.

The economics of producing from some oil and natural gas wells could change as a result of lower prices. As a result, Paramount could elect not to produce from certain wells. Any material decline in oil and/or natural gas prices could also result in a reduction in Paramount's oil and natural gas acquisition and development activities.

Any substantial and extended weakness in the price of oil or natural gas would have an adverse effect, possibly significant, on Paramount's operating results and Paramount's borrowing capacity because borrowings under Paramount's senior credit facility are limited by a borrowing base amount that is established periodically by the lenders. This borrowing base amount is the lenders' estimate of the present value of the future net cash flow from Paramount's oil and natural gas properties.

Paramount's actual reserves could be lower than estimates.

Estimates of oil and natural gas reserves involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. The probability of the existence and recoverability of reserves is less than 100 percent and actual recoveries of proved reserves usually differ from estimates.

Estimates of oil and natural gas reserves also require numerous assumptions relating to operating conditions and economic factors, including, among others:

- the price at which recovered oil and natural gas can be sold;
- the costs associated with recovering oil and natural gas;
- the prevailing environmental conditions associated with drilling and production sites;
- the availability of enhanced recovery techniques;
- the ability to transport oil and natural gas to markets; and
- governmental and other regulatory factors, such as taxes and environmental laws.

A change in one or more of these factors could result in known quantities of oil and natural gas previously estimated as proved reserves becoming unrecoverable. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production of that oil or natural gas commercially impracticable. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also reduce the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and future net cash flows expected from them are prepared by different independent engineers, or by the same engineers at different times, and may vary substantially.

Furthermore, in accordance with Canadian GAAP and U.S. GAAP, Paramount could be required to write down the carrying value of its oil and natural gas properties if oil and natural gas prices become depressed for even a short period of time, or if there are substantial downward revisions to Paramount's quantities of proved reserves. A write down would result in a charge to earnings and a reduction of shareholders' equity.

If Paramount is unsuccessful in acquiring and developing oil and natural gas properties, it will be prevented from increasing its reserves and its business will be adversely affected because it will eventually deplete its reserves.

Paramount's future success depends upon its ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable. Without successful exploration, exploitation or acquisition activities, Paramount's reserves, revenues and cash flow may decline. Paramount cannot assure you that it will be able to find and develop or acquire additional reserves at an acceptable cost. The successful acquisition and development of oil and natural gas properties requires an assessment of:

- recoverable reserves;
- future oil and natural gas prices and operating costs;
- potential environmental and other liabilities; and
- productivity of new wells drilled.

These assessments are inexact and, if Paramount makes them inaccurately, it may not recover the purchase price of a property from the sale of production from the property or might not recognize an acceptable return from properties it acquires. In addition, the costs of exploitation and development could materially exceed Paramount's initial estimates.

Paramount will not be able to develop its reserves or make acquisitions if it is unable to generate sufficient cash flow or raise capital. If Paramount is unable to increase its reserves, its business will be adversely affected because it will eventually deplete its reserves.

Paramount will be required to make substantial capital expenditures to develop its existing reserves, to discover new oil and natural gas reserves and to make acquisitions. Paramount will be unable to accomplish these tasks if it is unable to generate sufficient cash flow or raise needed capital in the future. If Paramount is unable to increase its reserves, its business will be adversely affected because Paramount will eventually deplete its reserves. Paramount also makes offers to acquire oil and natural gas properties in the ordinary course of its business. If these offers are accepted, Paramount's capital needs may increase substantially.

Paramount's future exploration, exploitation and development projects are subject to change.

Whether Paramount ultimately undertakes an exploration, exploitation or development project will depend upon the following factors among others:

- the availability and cost of capital;
- the receipt of additional seismic data or the reprocessing of existing data;
- the current and projected oil or natural gas prices;
- the cost and availability of drilling rigs, other equipment supplies and personnel necessary to conduct operations;
- the success or failure of activities in similar areas;
- changes in the estimates of the costs to complete a project;
- Paramount's ability to attract other industry partners to acquire a portion of the working interest so as to reduce Paramount's costs and risk exposure; and
- the decisions of Paramount's joint working interest owners.

Paramount will continue to gather data about Paramount's projects and it is possible that additional information will cause Paramount to alter its schedule or determine that a project should not be pursued at all. You should understand that Paramount's plans regarding its projects might change.

Drilling activities are subject to many risks and any interruption or lack of success in Paramount's drilling activities will adversely affect Paramount's business.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered and that Paramount will not recover all or any portion of its investment. The cost of drilling, completing and operating wells is often uncertain. Paramount's drilling operations could be curtailed, delayed or cancelled as a result of numerous factors, many of which are beyond its control, including:

- adverse weather conditions;
- required compliance with governmental requirements; and
- shortages or delays in the delivery of equipment and services.

Paramount's operations are affected by operating hazards and uninsured risks, and a shutdown or slowdown of its operations will adversely affect Paramount's business.

There are many operating hazards in exploring for and producing oil and natural gas, including:

- Paramount's drilling operations could encounter unexpected formations or pressures that could cause damage to Paramount's employees or other persons, equipment and other property or the environment;

- Paramount could experience blowouts, accidents, oil spills, fires or incur other damage to a well that could require Paramount to re-drill the well or take other corrective action;

- Paramount could experience equipment failure that curtails or stops production; and

- Paramount's drilling and production operations, such as trucking of oil, are often interrupted by bad weather.

Any of these events could result in damage to, or destruction of, oil and natural gas wells, production facilities or other property. In addition, any of the above events could result in environmental damage or personal injury for which Paramount will be liable.

The occurrence of a significant event against which Paramount is not fully insured or indemnified could seriously harm Paramount's financial condition, operating results and ability to carry on its business.

If Paramount is unable to access its properties or conduct its operations due to surface conditions, Paramount's business will be adversely affected.

The exploration for and development of oil and natural gas reserves depends upon access to areas where operations are to be conducted. Oil and gas industry operations are affected by road bans imposed from time to time during the break-up and thaw period in the spring. Road bans are also imposed due to snow, mud and rock slides and periods of high water which can restrict access to Paramount's well sites and production facility sites.

Paramount conducts a portion of its operations in northern Alberta, northeastern British Columbia and the Northwest Territories of Canada, which Paramount is able to do only on a seasonal basis. Unless the surface is sufficiently frozen, Paramount is unable to access its properties, drill or otherwise conduct its operations as planned. In addition, if the surface thaws earlier than expected, Paramount must cease its operations for the season earlier than planned. In recent years, winters in Paramount's northern Alberta, northeastern British Columbia and Northwest Territories operating areas have been warmer than it has normally experienced, so its operating seasons have been shorter than in the past. Paramount's inability to access its properties or to conduct its operations as planned will result in a shutdown or slow down of its operations, which will adversely affect its business.

Aboriginal peoples may make claims regarding the lands on which Paramount's operations are conducted.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada, including some of the properties on which Paramount conducts its operations. If any aboriginal peoples file a claim claiming aboriginal title or rights to the lands on which any of Paramount's properties are located, and if any such claim is successful, it could have an adverse effect on Paramount's operations.

Paramount's hedging activities could result in losses.

The nature of Paramount's operations results in exposure to fluctuations in commodity prices and currency exchange rates. Paramount monitors and, when appropriate, utilize derivative financial instruments and physical delivery contracts to hedge its exposure to these risks. Paramount is exposed to credit related losses in the event of non-performance by counter parties to these financial instruments and physical delivery contracts. From time to time, Paramount enters into hedging activities in an effort to mitigate the potential impact of declines in oil and natural gas prices or increases in the value of the Canadian dollar versus the U.S. dollar.

If product prices or the value of the Canadian dollar increase above those levels specified in Paramount's various hedging agreements, Paramount could lose the cost of floors, or a ceiling or fixed price could limit Paramount from receiving the full benefit of commodity price increases or decreases in the value of the Canadian dollar.

In addition, by entering into these hedging activities, Paramount may suffer financial loss if:

- it is unable to produce oil or natural gas to fulfill its obligations;
- it is required to pay a margin call on a hedge contract; or
- it is required to pay royalties based on a market or reference price that is higher than its fixed or ceiling price.

Complying with environmental and other government requirements could be costly and could negatively affect Paramount's business.

Paramount's operations are governed by numerous Canadian and United States laws and regulations at the municipal, provincial, state and federal levels. These laws and regulations govern the operation and maintenance of Paramount's facilities, the discharge of materials into the environment, storage, treatment and disposal of wastes, remediation of contaminated sites, and other environmental protection issues. Paramount believes it is in material compliance with applicable requirements.

Under these laws and regulations, Paramount is currently conducting remediation projects at a variety of owned and operated locations. If environmental damage occurs, Paramount could be liable for personal injury, clean-up costs, remedial measures and other environmental and property damage, as well as administrative, civil and criminal penalties, and Paramount could also be required to cease production.

Changes in environmental requirements or newly discovered conditions could negatively affect Paramount's results of operations.

The costs of complying with new environmental laws, regulations or guidelines, or changes in enforcement policy, or newly discovered conditions, may have a material adverse effect on Paramount's financial condition or results of operations. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on Paramount's financial condition or results of operations.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol, which we refer to as the "Protocol", which requires, upon ratification, certain signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Canadian federal government ratified the Protocol. If certain conditions are met and the Protocol enters into force internationally, Canada will be required to reduce its greenhouse gas, or "GHG", emissions to 6 percent below 1990 levels by 2012. Currently, the Canadian upstream oil and gas sector is in discussions with various Canadian provincial and federal governments regarding the development of greenhouse gas reduction policies and regulations for the industry. It is premature to predict what impact these policies and regulations will have on our sector, but Paramount will face increases in operating costs in order to comply with GHG emissions target.

Other changes in environmental legislation may also require, among other things, reductions in emissions to the air from Paramount's operations, which would result in increased capital expenditures.

Factors beyond Paramount's control affect its ability to market production and could adversely affect Paramount's business.

Paramount's ability to market its oil and natural gas depends upon numerous factors beyond its control. These factors include:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- regulation of oil and natural gas marketing; and
- regulation of oil and natural gas sold or transported outside of Canada.

Because of these factors, Paramount could be unable to market all of the oil or natural gas it produces. In addition, Paramount may be unable to obtain favorable prices for the oil and natural gas it produces.

Paramount has marketing arrangements for its natural gas that subject Paramount to certain risks.

As a result of Paramount's commitment to market an average of 150 million GJ/d of natural gas over a five year term commencing March 2005 through a gas marketing limited partnership in which Paramount has an indirect 25 percent ownership interest, Paramount will be subject to greater risks respecting its ability to recover amounts due to it for such committed production than it would be if it were a party to a production commitment agreement with an investment grade party or a party that has posted security. If Paramount doesn't get paid by the gas marketing limited partnership for its committed production, Paramount may not be able to recover the amounts owing to it and this could have a material adverse effect on Paramount's financial condition.

Paramount does not control all of its operations.

Paramount does not operate all of its properties, so it has limited influence over the operations of some of its properties. Paramount's lack of control could result in the following:

- the operator might initiate exploration or development on a faster or slower pace than Paramount prefers;
- the operator might propose to drill more wells or build more facilities on a project than Paramount has funds for or that Paramount deems appropriate, which could mean that Paramount is unable to participate in the project or share in the revenues generated by the project even though Paramount paid its share of exploration costs; and
- if an operator refuses to initiate a project, Paramount might be unable to pursue the project.

Any of these events could materially reduce the value of Paramount's properties.

Essential equipment might not be available.

Oil and natural gas exploration and development activities depend upon the availability of drilling and related equipment in the particular areas in which those activities will be conducted. Demand for that equipment or access restrictions may affect the availability of that equipment and delay its exploration and development activities.

Paramount is a medium-sized company operating in a highly competitive industry and companies and other entities in the industry with greater resources or greater access to capital markets can outbid it for acquisitions or secure acquisitions which it cannot.

The oil and natural gas industry is highly competitive. Paramount's competitors include companies and other entities, such as royalty trusts, in the industry that have greater financial and personnel resources and/or have greater access to capital markets than Paramount does. Paramount's ability to acquire additional properties and to discover reserves depends upon its ability to evaluate and select suitable properties and to complete transactions in a highly competitive and challenging environment.

Paramount is highly dependent on certain senior officers.

Paramount is highly dependent on its Chief Executive Officer and its President and Chief Operating Officer. The loss of either of these officers could impede the achievement of Paramount's objectives and could adversely affect Paramount's business and results of operations.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Computershare Investor Services Inc. located at the following address:

6th Floor, Watermark Tower
530 – Eighth Avenue SW
Calgary, Alberta T2P 3S8

MATERIAL CONTRACTS

In connection with the Trust Spinout, Paramount entered into an Arrangement Agreement dated February 28, 2005 with certain other parties. The full text of such Arrangement Agreement is included as Appendix C to Paramount's information circular in respect of the Arrangement dated February 28, 2005.

INTERESTS OF EXPERTS

Ernst & Young LLP, Chartered Accountants, are the Company's auditors and such firm has prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2004. Information relating to reserves in this annual information form dated March 30, 2005 was prepared by McDaniel & Associates Consultants Ltd. and Paddock Lindstrom & Associates Ltd. as independent qualified reserves evaluators.

The principals of each of McDaniel & Associates Consultants Ltd. and Paddock Lindstrom & Associates Ltd., in each case as a group, own beneficially, directly or indirectly, less than one percent of any class of Paramount's securities.

ADDITIONAL INFORMATION

Additional information relating to Paramount is available via the System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com.

Additional information, including directors' and officers' remuneration, principal holders of Paramount's securities, and options to purchase securities, is contained in the Information Circular for Paramount's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in Paramount's audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2004.

APPENDIX A

RESERVES AND OTHER OIL AND GAS INFORMATION FOR THE RETAINED ASSETS

RESERVES AND OTHER OIL AND GAS INFORMATION FOR THE RETAINED ASSETS

All reserves attributable to the Retained Assets were determined through an independent engineering evaluation completed by McDaniel, which was prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The McDaniel Report was prepared effective December 31, 2004. The following tables set forth information relating to the working interest share of reserves, net reserves after royalties and present worth values as at December 31, 2004 of the Retained Assets. The reserves are reported using constant price and costs as well as forecast prices and costs. Columns may not add in the following tables due to rounding.

All evaluations of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Retained Assets. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein. After tax amounts of future net revenue and the net present value of future net revenue are different than those provided in Appendix E to Paramount's information circular dated February 28, 2005 in respect of the Arrangement as the amounts presented below do not give effect to the reduction in tax pools available for claim which will result from the Trust Spinout as they did in Appendix E of such information circular.

Reserves Information

Reserves Data – Constant Price and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using constant price and costs.

	Natural Gas		Light and Medium Crude Oil		Natural Gas Liquids		Total	
Reserves Category	**Gross** (Bcf)	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Canada								
Proved							-	-
Developed Producing	83.7	71.6	1,627	1,560	796	569	16,380	14,069
Developed Non-Producing	32.7	29.2	316	315	177	139	5,939	5,316
Undeveloped	20.0	19.0	308	308	50	50	3,699	3,519
Total Proved	136.5	119.8	2,251	2,183	1,022	757	26,018	22,905
Probable	126.0	104.5	1,155	1,137	186	139	22,347	18,685
Total Proved Plus Probable Canada	262.5	224.2	3,406	3,320	1,208	897	48,364	41,590
United States								
Proved								
Developed Producing	0.4	0.3	2,104	1,619	-	-	2,165	1,667
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	0.4	0.3	2,104	1,619	-	-	2,165	1,667
Probable	-	-	431	322	-	-	437	327
Total Proved Plus Probable US	0.4	0.3	2,534	1,941	-	-	2,602	1,994
Total Company							-	-
Total Proved	136.8	120.1	4,354	3,802	1,022	757	28,183	24,572
Total Probable	126.1	104.5	1,586	1,459	186	139	22,784	19,012
Total Reserves	**262.9**	**224.6**	**5,941**	**5,261**	**1,208**	**896**	**50,967**	**43,584**

Net Present Value of Future Net Revenue – Constant Price and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the constant price and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $ Millions									
	Before Income Taxes Discounted at					After Income Taxes Discounted at				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Canada										
Proved										
Developed Producing	431.9	380.0	341.1	310.7	286.3	382.3	336.7	302.9	276.8	255.8
Developed Non-Producing	131.5	103.6	85.4	72.7	63.4	99.8	77.6	63.5	53.9	47.1
Undeveloped	77.2	48.7	33.7	25.0	19.5	59.8	36.8	25.0	18.2	14.1
Total Proved	640.6	532.3	460.2	408.4	369.2	541.8	451.1	391.4	348.9	317.0
Probable	583.6	432.8	334.7	267.8	220.3	419.4	316.3	248.1	201.0	167.1
Total Proved Plus Probable Cdn	1,224.2	965.1	794.8	676.2	589.6	961.2	767.4	639.5	549.9	484.0
United States										
Proved										
Developed Producing	36.0	29.2	24.5	21.1	18.6	36.0	29.1	24.4	21.1	18.6
Developed Non-Producing	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	35.7	28.9	24.2	20.9	18.4	35.7	28.8	24.1	20.8	18.4
Probable	8.3	5.0	3.3	2.3	1.7	8.2	5.0	3.3	2.3	1.7
Total Proved Plus Probable US	43.9	33.9	27.5	23.1	20.0	43.9	33.8	27.4	23.1	20.0
Total Company										
Total Proved	676.3	561.2	484.4	429.3	387.6	577.5	479.9	415.5	369.7	335.1
Total Probable	591.9	437.8	338.0	270.1	222.0	427.6	321.3	251.4	203.2	168.8
Total Reserves	**1,268.1**	**998.9**	**822.3**	**699.4**	**609.6**	**1,005.1**	**801.2**	**666.9**	**573.0**	**504.1**

Total Future Net Revenue – Constant Price and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using constant price and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties**[1]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,137.8	212.9	193.5	33.7	21.6	676.3	98.7	577.5
Proved Plus Probable	2,042.6	365.9	324.3	62.5	21.7	1,268.1	263.0	1,005.2

[1] Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, net profit interest payments and are net of the Alberta Royalty Tax Credit.

Future Net Revenue by Production Group - Constant Price and Costs

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using constant price and costs, discounted at 10 percent.

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%) ($ millions)
Proved	Associated and Non Associated Gas	396.1
	Light and medium crude oil	85.7
	Alberta Royalty tax credit and other income	2.6
Total Proved		484.4
Proved Plus Probable	Associated and Non Associated Gas	703.3
	Light and medium crude oil	114.9
	Alberta Royalty tax credit and other income	4.1
Total Proved Plus Probable		**822.3**

Reserves Data – Forecast Prices and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using McDaniel's forecast prices and costs.

	Natural Gas		**Light and Medium Crude Oil**		**Natural Gas Liquids**		**Total**	
Reserves Category	**Gross** (Bcf)	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Canada								
Proved								
Developed Producing	83.7	71.6	1,628	1,563	796	570	16,381	14,074
Developed Non-Producing	32.7	29.2	316	315	177	139	5,939	5,317
Undeveloped	20.0	19.0	308	308	50	50	3,699	3,519
Total Proved	136.5	119.8	2,252	2,186	1,022	759	26,019	22,910
Probable	126.1	104.5	1,155	1,139	186	140	22,350	18,689
Total Proved Plus Probable Canada	262.5	224.3	3,407	3,324	1,208	899	48,368	41,599
United States								
Proved								
Developed Producing	0.4	0.3	2,108	1,623	-	-	2,169	1,671
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	0.4	0.3	2,108	1,623	-	-	2,169	1,671
Probable	-	-	431	322	-	-	437	327
Total Proved Plus Probable US	0.4	0.3	2,539	1,945	-	-	2,606	1,998
Total Company								
Total Proved	136.8	120.1	4,359	3,809	1,022	759	28,188	24,580
Total Probable	126.1	104.5	1,586	1,461	186	140	22,787	19,016
Total Reserves	**262.9**	**224.6**	**5,946**	**5,269**	**1,208**	**899**	**50,975**	**43,597**

Net Present Value of Future Net Revenue – Forecast Prices and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the McDaniel's forecast prices and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $Millions									
	Before income Taxes Discounted at					**After Income Taxes Discounted at**				
Reserves Category	**0 %**	**5%**	**10%**	**15%**	**20%**	**0%**	**5 %**	**10%**	**15%**	**20%**
Canada										
Proved										
Developed Producing	399.9	354.8	320.9	294.3	272.7	357.3	317.0	287.1	263.8	245.0
Developed Non-Producing	116.2	92.3	76.7	65.8	57.8	89.7	70.0	57.5	49.1	43.1
Undeveloped	70.2	43.9	30.1	22.2	17.3	55.3	33.6	22.5	16.3	12.4
Total Proved	586.3	491.1	427.7	382.3	347.8	502.3	420.6	367.1	329.1	300.5
Probable	520.8	386.8	299.7	240.4	198.3	373.6	282.2	221.7	180.0	150.0
Total Proved Plus Probable Canada	1,107.1	877.9	727.4	622.7	546.1	875.9	702.9	588.9	509.1	450.5
United States										
Proved										
Developed Producing	29.8	25.3	21.9	19.4	17.4	29.8	25.3	21.9	19.4	17.4
Developed Non-Producing	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)	(04)	(0.3)	(0.3)	(0.2)	(0.2)
Undeveloped	-	-	-	-	-		-	-	-	-
Total Proved	29.5	25.0	21.6	19.1	17.2	29.5	24.9	21.6	19.1	17.2
Probable	6.0	3.9	2.7	1.9	1.4	6.0	3.9	2.7	1.9	1.4
Total Proved Plus Probable United States	35.5	28.8	24.3	21.0	18.6	35.5	28.8	243	21.0	18.6
Total Company										
Total Proved	615.8	516.0	449.4	401.4	365.0	531.7	445.6	388.7	348.3	317.7
Total Probable	526.8	390.7	302.4	242.3	199.7	379.6	286.1	224.4	181.9	151.4
Total Reserves	**1,142.6**	**906.7**	**751.7**	**643.7**	**564.7**	**911.3**	**731.7**	**613.2**	**530.1**	**469.1**

Total Future Net Revenue by Production Group - Forecast Prices and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using McDaniel's forecast prices and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties** [1]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,096.0	199.1	219.8	35.8	25.7	615.8	84.0	531.8
Proved Plus Probable	1,950.5	340.7	374.4	65.7	27.1	1,142.6	231.2	911.3

[1] Royalties includes crown royalties, freehold royalties, overriding royalties, mineral taxes, net profit interest payments and are net of the Alberta Royalty Tax Credit.

Future Net Revenue by Production Group - Forecast Prices and Costs

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using McDaniel's forecast prices and costs, discounted at 10 percent.

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10% ($millions)
Proved	Associated and Non Associated Gas	370.4
	Light and medium crude oil	76.5
	Alberta Royalty tax credit and other income	2.5
Total Proved		449.4
Proved Plus Probable	Associated and Non Associated Gas	646.9
	Light and medium crude oil	100.7
	Alberta Royalty tax credit and other income	4.1
Total Proved Plus Probable		**751.7**

Summary of Pricing and Inflation Rate Assumptions

The following table summarizes the prices and costs used in the McDaniel Report in calculating the net present value of future net revenue attributable to reserves.

Constant Price and Costs

	Propane (Edmonton Reference Price) (Cdn$/Bbl)	Field Butane (Edmonton Reference Price) (Cdn$/Bbl)	Natural Gasolines and Condensate (Edmonton Reference Price (Cdn$/Bbl)	Edmonton Light Crude Oil (Cdn$/Bbl)	Bow River Medium Crude Oil (Cdn$/Bbl)	Natural Gas (Plantgate Pool Price) ($/GJ)	Exchange Rate[1] (US$/Cdn$)
2004	35.71	42.06	54.36	50.96	26.27	6.17	0.83

(1) Exchange rates used to generate the benchmark reference prices in this table.

Forecast Prices and Costs

	U.S. Henry Hub Gas Price (US$/MMbtu)	Alberta Average Plantgate (Cdn$/MMbtu)	WTI Crude Oil (US$/Bbl)	Edmonton Light Crude Oil (Cdn$/Bbl)	Bow River Medium Crude Oil (Cdn$/Bbl)	Edmonton NGL MIX (Cdn$/Bbl)	Inflation Rates[1] (%/year)	Exchange Rate[2] (US$/Cdn$)
2005	6.35	6.65	42.00	49.60	37.00	37.20	2%	0.83
2006	6.05	6.40	39.50	46.60	37.10	35.10	2%	0.83
2007	5.75	6.20	37.00	43.50	34.60	33.00	2%	0.83
2008	5.45	5.90	35.00	41.10	32.70	31.20	2%	0.83
2009	5.35	5.80	34.50	40.50	32.20	30.80	2%	0.83

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table summarizes the gross proved undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	2004	2003	2002	2001	2000
Natural Gas (Bcf)	20.0	15.1	22.8	24.7	1.0
Light and medium crude oil (MBbl)	308	-	408	-	-
Natural Gas Liquids (MBbl)	49	56	119	-	-

These reserves are classified as proved undeveloped if they are expected to be recovered from new wells on previously undrilled acreage with untested reservoir characteristics, or they are reserves from existing wells that require major capital expenditures to bring them on production.

The following table summarizes the gross probable undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	2004	2003	2002	2001	2000
Natural Gas (Bcf)	40.8	16.9	45.8	31.7	27.7
Light and medium crude oil (MBbl)	396	-	469	431	-
Natural Gas Liquids (MBbl)	-	9	71	-	-

These reserves are classified as probable undeveloped when analysis of drilling, geological, geophysical and engineering data does not demonstrate them to be proved under current technology and existing economic conditions; however, this analysis does suggest that there is a likelihood of their existence and future recovery.

Future Development Costs

The following table describes the estimated future development costs deducted in the estimation of future net revenue. The costs are per reserve category and quoted for no discount and a discount rate of ten percent.

Reserve Category	2005E		2006E		2007E		2008E		2009E	
($millions)	0%	10%	0%	10%	0%	10%	0%	10%	0%	10%
Proved:										
Constant Price Case	24.8	23.7	3.5	3.1	-	-	0.1	0.1	0.1	-
Forecast Price Case	25.3	24.1	3.2	3.2	-	-	0.1	0.1	0.1	-
Proved & Probable Reserves:										
Constant Price Case	40.1	39.2	8.7	7.6	0.6	0.5	7.5	5.4	0.1	-
Forecast Price Case	40.9	39.0	9.1	7.9	0.6	0.5	8.2	5.8	0.1	-

It is expected that funding for future development costs will come from the Company's cash flow, a properly managed debt funding program and, in some cases, equity issues.

Other Oil and Gas Information

Oil and Gas Properties and Wells

As at December 31, 2004, Paramount had an interest in 1,331 gross (701.3 net) producing and non-producing oil and natural gas wells attributable to the Retained Assets as follows:

	Producing		Non-producing[(1)]	
As at December 31, 2004	**Gross[(2)]**	**Net[(3)]**	**Gross**	**Net**
Crude oil wells				
Alberta	128	61.5	56	26.3
British Columbia	-	-	3	1.8
Saskatchewan	4	1.0	1	0.3
Northwest Territories	4	3.6	12	10.0
Montana	22	18.5	3	2.3
North Dakota	38	20.6	9	5.1
Subtotal	196	105.2	84	45.8
Natural gas wells				
Alberta	507	257.1	395	230.3
British Columbia	22	10.2	32	19.3
Saskatchewan	2	0.3	4	4.0
Northwest Territories	15	9.6	34	16.7
Montana	21	1.6	16	0.8
California	-	-	3	0.4
Subtotal	567	278.8	484	271.5
Total	**763**	**384.0**	**568**	**317.3**

(1) "Non-producing" wells are wells which Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.
(2) "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be convertible to a working interest.
(3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth Paramount's land position attributable to the Retained Assets at December 31, 2004 and 2003. The Company's holdings total 5,759,314 gross (3,399,828 net) acres. Approximately 88 percent of the Company's gross land holdings are considered undeveloped and approximately 34 percent of the undeveloped land is located in Alberta.

	2004		2003	
(thousands of acres)	**Gross (1)**	**Net(2)**	**Gross**	**Net**
Undeveloped Land				
Alberta	1,699	1,200	1,495	1,093
British Columbia	348	258	263	183
Saskatchewan	17	13	29	24
Northwest Territories	1,235	661	948	412
Montana, North Dakota	102	40	101	35
Other	1,644	822	1,664	832
Subtotal	5,045	2,994	4,499	2,580
Acreage Assigned Reserves				
Alberta	558	327	542	299
British Columbia	46	18	37	10
Saskatchewan	4	3	6	4
Northwest Territories	76	43	60	29
Montana, North Dakota	29	15	29	16
Subtotal	714	406	673	356
Total Acres	**5,759**	**3,400**	**5,172**	**2,936**

[(1)] "Gross" acres means the total acreage in which Paramount has a working interest, or a royalty interest that may be converted to a working interest.
[(2)] "Net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

As of December 31, 2004, the Company had 2,498,516 (1,313,917 net) acres of undeveloped lands attributable to the Retained Assets that were due to expire in 2005. Of this total, 19,261 (14,317 net) acres of undeveloped lands due to expire in 2004 have had dry and abandoned wells drilled on them. The other 2,479,255 (1,299,600 net) acres have not been tested as of December 31, 2004.

Forward Contracts

The Company's future commitments as at December 31, 2004 to sell natural gas and oil and natural gas liquids are set forth at note 11 of the Company's financial statements included in the Company's annual report, which information is incorporated by reference herein.

In March, 2005, Paramount acquired an indirect 25 percent ownership interest in a gas marketing limited partnership. In conjunction with the acquisition of the ownership interest, Paramount agreed to make available for delivery an average of 150 million GJ/d of natural gas over a five year term, to be marketed on Paramount's behalf by the gas marketing limited partnership. Paramount expects to receive prices at or above market for such natural gas.

Abandonment & Reclamation Costs

As at December 31, 2004, the Company had 740.1 net wells capable of production and injection wells attributable to the Retained Assets for which it expected to incur abandonment and reclamation costs.

The Company's estimates of abandonment and reclamation costs attributable to the Retained Assets, net of estimated salvage value, for surface leases, wells, facilities and pipelines, undiscounted and discounted at 10 percent, are $53.9 million and $32.4 million, respectively. The future net revenue disclosed in this Appendix A based on the McDaniel Report does not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The McDaniel Report deducted $21.7 million (undiscounted) and $9.0 million (10 percent discount) for abandonment and reclamation costs for wells only in estimating the future net revenue disclosed herein.

The Company does not expect to pay any material amounts with respect to abandonment and reclamation costs in the next three financial years.

Tax Horizon

Based on the current tax regime, and the Company's tax pools following the Trust Spinout and anticipated level of operations, the Company is not expected to be cash taxable in 2005, and does not expect to become cash taxable in the near future.

Costs Incurred

The following table summarizes the costs incurred by Paramount for property acquisitions, exploration and development costs attributable to the Retained Assets

Cost Type ($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**
Acquisitions					
Proved Properties	129.9	49.3	-	80.6	-
Unproved Properties	36.9	3.8	5.3	22.2	5.6
Exploration	54.0	13.3	8.0	10.9	21.8
Development (including facilities)	135.8	52.3	16.9	7.5	59.1
Total	**356.6**	**118.7**	**30.2**	**121.2**	**86.5**

Exploration and Development Activities

The following table summarizes the results of Paramount's drilling activity attributable to the Retained Assets for each of the last two fiscal years. The working interest in certain of these wells may change after payout.

	2004		**2003**	
	Gross[(1)]	**Net**[(2)]	**Gross**	**Net**
Development Wells[(3)]				
Gas	108	58.5	75	51.5
Oil	3	2.4	5	2.4
Standing/service	-	-	-	-
Dry	9	4.9	7	3.6
Oilsands evaluation	17	17.0	-	-
Subtotal	137	82.8	87	57.5
Exploratory Wells[(4)]				
Gas	57	39.3	42	29.2
Oil	1	0.9	3	2.0
Standing/service	-	-	-	-
Dry	3	3.0	6	2.2
Subtotal	61	43.2	51	33.4
Total Wells	**198**	**126.0**	**138**	**90.9**
Success Rate	**93%**	**93%**	**91%**	**94%**

[(1)] "Gross" wells means the number of wells in which Paramount has a working interest or a royalty interest that may be converted to a working interest.
[(2)] "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.
[(3)] "Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.
[(4)] "Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool that is partly discovered.

The total capital budget for Paramount for 2005 (assuming completion of the Trust Spinout) is estimated by Paramount at $240 million. Approximately 40 percent of the 2005 capital spending will occur in the first quarter and will be focused in the winter access areas, which are in northern Alberta and Northwest Territories. The following table describes the expected 2005 capital budget by operating unit.

Area	**2005E** ($ millions)
Kaybob	$ 45
Grande Prairie	50
Northwest Alberta/Cameron Hills, NWT	20
Liard, NWT/Northeast British Columbia	60
Southern	50
Heavy oil	15
Total	**$240.00**

[(1)]McDaniel has estimated Paramount's 2005 capital expenditures (assuming completion of the Trust Spinout) to be $40.9 million in its evaluation.

Production Estimates

The following table summarizes the total estimated production of Paramount, after giving effect to the Trust Spinout, for 2005 using constant price and costs.

	Estimated Production – Constant Prices and Costs	
	Proved	Proved Plus Probable
Canada		
Natural gas (MMcf)	32,361	37,431
Light and medium crude oil (MBbls)	615	682
Natural gas liquids (MBbls)	236	262
Total Canada (MBoe)	**6,245**	**7,183**
USA		
Natural gas (MMcf)	84	86
Light and medium crude oil (MBbls)	282	284
Natural gas liquids (MBbls)	-	-
Total USA (MBoe)	**296**	**298**
Total Production (MBoe)	**6,541**	**7,481**

The following table summarizes the total estimated production of Paramount, after giving effect to the Trust Spinout, for 2005 using forecast prices and costs.

	Estimated Production – Forecast Prices and Costs	
	Proved	**Proved Plus Probable**
Canada		
Natural gas (MMcf)	32,361	37,431
Light and medium crude oil (MBbls)	615	682
Natural gas liquids (MBbls)	236	262
Total Canada (Mboe)	**6,245**	**7,183**
USA		
Natural gas (MMcf)	84	86
Light and medium crude oil (MBbls)	282	284
Natural gas liquids (MBbls)	-	-
Total USA (MBoe)	**296**	**298**
Total Production (MBoe)	**6,541**	**7,481**

Production History

The following tables summarize daily sales volume results for Paramount, after giving effect to the Trust Spinout, on a quarterly and annual basis for 2004 and 2003 respectively.

	2004	Q4	Q3	Q2	Q1
SALES - Canada					
Produced gas (MMcf/d)	74.6	79.0	91.7	67.2	60.0
Light and medium crude oil (Bbls/d)	1,986	1,660	1,859	2,750	1,680
Natural gas liquids (Bbls/d)	587	590	559	281	918
SALES - United States					
Produced gas (MMcf/d)	0.3	0.3	0.2	0.4	0.5
Light and medium crude oil (Bbls/d)	830	978	782	765	793
Natural gas liquids (Bbls/d)	21	2	42	22	17
SALES – Total					
Produced gas (MMcf/d)	74.9	79.3	91.9	67.6	60.5
Light and medium crude oil (Bbls/d)	2,816	2,638	2,641	3,515	2,473
Natural gas liquids (Bbls/d)	608	592	601	303	935

	2003	Q4	Q3	Q2	Q1
SALES - Canada					
Produced gas (MMcf/d)	74.5	69.2	55.7	65.4	108.5
Light and medium crude oil (Bbls/d)	3,273	2,519	3,262	3,671	3,653
Natural gas liquids (Bbls/d)	665	425	827	731	664
SALES - United States					
Produced gas (MMcf/d)	0.7	0.4	0.7	0.8	0.8
Light and medium crude oil (Bbls/d)	1,024	838	1,036	1,075	1,149
Natural gas liquids (Bbls/d)	25	-	42	39	27
SALES – Total					
Produced gas (MMcf/d)	75.2	69.6	56.4	66.2	109.3
Light and medium crude oil (Bbls/d)	4,297	3,357	4,298	4,746	4,802
Natural gas liquids (Bbls/d)	690	425	869	770	691

(1) NI 51-101 came into effect on September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. As such, for the fourth quarter of 2003 and subsequent periods natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

The following tables summarize the average netbacks received by Paramount, after giving effect to the Trust Spinout, on a quarterly and annual basis for 2004 and 2003 respectively.

	Net Product Price Results – 2004				
	2004	Q4	Q3	Q2	Q1
Produced gas ($/Mcf)					
Price, before transportation	7.07	7.38	6.57	7.61	6.83
Transportation	(0.46)	(0.41)	(0.41)	(0.51)	(0.54)
Royalties	(0.97)	(0.53)	(0.95)	(1.19)	(1.35)
Operating costs(2)	(1.18)	(1.11)	(0.96)	(1.48)	(1.29)
Netback excluding realized financial instruments	4.46	5.33	4.25	4.43	3.65
Realized financial instruments	0.15	0.17	0.10	(0.17)	0.51
Netback including realized financial instruments	4.61	5.50	4.35	4.26	4.16
Total Conventional Oil ($/Bbl)					
Price, before transportation	45.61	45.52	47.39	46.88	41.97
Transportation	(1.20)	(1.15)	(1.12)	(1.13)	(1.43)
Royalties	(7.93)	(10.03)	(10.18)	(6.26)	(5.61)
Operating costs(2)	(10.24)	(10.10)	(11.35)	(9.81)	(9.81)
Netback excluding realized financial instruments	26.24	24.24	24.74	29.68	25.12
Realized financial instruments	(4.20)	(6.29)	1.64	(5.49)	(6.42)
Netback including realized financial instruments	22.04	17.95	26.38	24.19	18.70
Natural Gas Liquids ($/Bbl)					
Price, before transportation	43.56	47.00	44.27	38.40	42.65
Transportation	-	-	-	-	-
Royalties	(13.18)	(15.94)	(15.01)	(17.70)	(8.82)
Operating costs(2)	(9.69)	(11.61)	(9.23)	(14.95)	(7.11)
Netback	20.69	19.45	20.03	5.75	26.72

	Net Product Price Results – 2003				
	2003	Q4	Q3	Q2	Q1
Produced Gas ($/Mcf)					
Price, before transportation	6.47	5.41	6.42	6.59	7.11
Transportation	(0.56)	(0.55)	(0.55)	(0.54)	(0.59)
Royalties	(0.89)	0.09	(1.53)	(0.81)	(1.23)
Operating costs(2)	(1.08)	(0.71)	(1.61)	(1.28)	(0.91)
Netback excluding realized financial instruments	3.94	4.24	2.73	3.96	4.38
Realized financial instruments	(0.71)	0.33	(0.71)	(1.04)	(1.17)
Netback including realized financial instruments	3.23	4.57	2.02	2.92	3.21
Total Conventional Oil ($/Bbl)					
Price, before transportation	40.09	37.08	38.26	38.61	45.38
Transportation	(1.07)	(1.40)	(1.01)	(0.97)	(1.00)
Royalties	(7.34)	(6.43)	(6.89)	(6.96)	(8.77)
Operating costs(2)	(10.28)	(11.76)	(12.39)	(10.22)	(7.35)
Netback excluding realized financial instruments	21.40	17.49	17.97	20.46	28.26
Realized financial instruments	(3.92)	(4.50)	(3.30)	(2.35)	(5.64)
Netback including realized financial instruments	17.48	12.99	14.67	18.11	22.62
Natural Gas Liquids ($/Bbl)					
Price, before transportation	33.57	35.43	31.07	31.43	38.01
Transportation	-	-	-	-	-
Royalties	(7.38)	(9.89)	(5.45)	(9.88)	(5.45)
Operating costs(2)	(10.25)	(31.57)	(9.58)	(6.76)	(1.68)
Netback	15.94	(6.03)	16.04	14.79	30.88

(1) NI 51-101 came into effect on September 30, 2003. NI 51-101 requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. As such, for the fourth quarter of 2003

and subsequent periods natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

(2) Operating costs include all costs related to the operation of wells, facilities and gathering systems. Processing revenue has been deducted from these costs.

The following table summarizes production volumes from Paramount's major producing properties for 2004 and 2003, after giving effect to the Trust Spinout.

Production Volume	**2004**	**2003**
Natural gas (MMcf)		
Kaybob	2,465	711
Grande Prairie	6,711	4,522
Northwest Alberta/Cameron Hills, NWT	7,397	8,140
Liard, NWT/Northeast British Columbia	5,926	4,235
Southern	3,947	3,483
Northeast Alberta	598	5,914
Non-core	356	443
Total	**27,400**	**27,448**
Light and medium crude oil (MBbl)		
Kaybob	42	74
Grande Prairie	128	531
Northwest Alberta/Cameron Hills, NWT	275	133
Liard, NWT/Northeast British Columbia	-	-
Southern	580	825
Non-core	6	5
Total	**1,031**	**1,568**
Natural gas liquids (MBbl)		
Kaybob	37	23
Grande Prairie	86	114
Northwest Alberta/Cameron Hills, NWT	16	30
Liard, NWT/Northeast British Columbia	4	3
Southern	78	72
Non-core	1	9
Total	**222**	**251**

APPENDIX B

RESERVES INFORMATION
FOR THE SPINOUT ASSETS

RESERVES INFORMATION FOR THE SPINOUT ASSETS

All reserves attributable to the Spinout Assets were determined through an independent engineering evaluation completed by Paddock Lindstrom, which was prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The Paddock Lindstrom Report was prepared effective December 31, 2004. The following tables set forth information relating to the working interest share of reserves, net reserves after royalties and present worth values as at December 31, 2004 of the Spinout Assets. The reserves are reported using constant price and costs as well as forecast prices and costs. Columns may not add in the following tables due to rounding.

All evaluations of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditure for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representatives of the fair market value of the Spinout Assets. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein. After tax amounts of future net revenue and the net present value of future net revenue are shown below for the Spinout Assets, but they were not shown in Appendix F to Paramount's information circular dated February 28, 2005 in respect of the Arrangement. If the Spinout Assets were owned by the Trust, as the information was presented in Appendix F to such information circular, the tax efficient structure of the Trust should preclude income taxes from being payable in the Trust or its subsidiaries and, accordingly, after tax amounts were not shown.

Reserves Information

Reserves Data – Constant Price and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using constant price and costs.

	Natural Gas		**Light and Medium Crude Oil**		**Natural Gas Liquids**		**Total**	
Reserves Category	**Gross** (Bcf))	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Proved								
Developed Producing	170.8	133.2	3,988	3,266	4,756	3,131	37,212	28,595
Developed Non-Producing	19.7	15.0	351	279	325	227	3,959	3,005
Undeveloped	19.9	14.9	-	-	240	171	3,552	2,660
Total Proved	210.4	163.1	4,339	3,546	5,320	3,529	44,723	34,259
Probable	95.3	73.5	1,755	1,411	1,902	1,299	19,540	14,957
Total Proved Plus Probable	**305.7**	**236.6**	**6,094**	**4,956**	**7,222**	**4,827**	**64,263**	**49,217**

Net Present Value of Future Net Revenue – Constant Price and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the constant price and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $ Millions									
	Before Income Taxes Discounted at					After Income Taxes Discounted at				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved										
Developed Producing	923.3	748.9	635.8	556.2	496.9	768.0	627.7	537.7	474.4	427.2
Developed Non-Producing	91.9	76.0	65.6	58.0	52.1	60.4	50.5	44.3	39.7	36.2
Undeveloped	71.9	47.5	34.2	25.9	20.3	48.4	31.8	22.7	17.2	13.4
Total Proved	1,087.2	872.5	735.6	640.1	569.2	876.9	709.9	604.7	531.3	476.8
Probable	442.1	292.6	213.8	165.4	132.9	293.5	196.6	145.2	113.4	91.9
Total Proved Plus Probable	**1,529.3**	**1,165.1**	**949.4**	**805.5**	**702.1**	**1,170.4**	**906.5**	**749.9**	**644.8**	**568.8**

Total Future Net Revenue – Constant Price and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using constant price and costs.

Reserves Category ($millions)	**Royalties**[1]	**Royalties**[1]	**Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,850.0	382.0	334.8	25.4	20.7	1,087.2	210.3	876.9
Proved Plus Probable	2,651.0	551.0	475.3	72.8	22.6	1,529.3	358.9	1,170.3

[1] Royalties includes crown royalties, and overriding royalties and are net of other income.

Future Net Revenue by Production Group - Constant Price and Costs

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using constant price and costs, discounted at 10 percent.

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%) ($ millions)
Proved	Associated and Non Associated Gas	621.6
	Light and medium crude oil	110.0
	Other revenue	4.0
Total Proved		735.6
Proved Plus Probable	Associated and Non Associated Gas	805.2
	Light and medium crude oil	140.1
	Other revenue	4.2
Total Proved Plus Probable		**949.4**

Reserves Data – Forecast Prices and Costs

The following table summarizes the reserves evaluated at December 31, 2004 using Paddock Lindstrom's forecast prices and costs.

	Natural Gas		Light and Medium Crude Oil		Natural Gas Liquids		Total	
Reserves Category	**Gross** (Bcf)	**Net** (Bcf)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBbl)	**Net** (MBbl)	**Gross** (MBoe)	**Net** (MBoe)
Proved								
Developed Producing	170.8	134.2	3,988	3,295	4,756	3,200	37,210	28,867
Developed Non-Producing	19.7	15.1	351	281	325	230	3,959	3,033
Undeveloped	19.9	15.2	-	-	240	174	3,552	2,700
Total Proved	210.4	164.5	4,339	3,576	5,320	3,605	44,722	34,600
Probable	95.3	74.6	1,746	1,421	1,902	1,331	19,532	15,185
Total Proved Plus Probable	**305.7**	**239.1**	**6,085**	**4,998**	**7,222**	**4,936**	**64,254**	**49,785**

Net Present Value of Future Net Revenue – Forecast Prices and Costs

The following table summarizes the net present values of future net revenue attributable to reserves evaluated at December 31, 2004 for the Paddock Lindstrom forecast prices and costs case. The net present values are reported before income tax and after income tax at discount values of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

	Net Present Values of Future Net Revenue, $ Millions									
Reserves Category	**Before Income Taxes Discounted at**					**After Income Taxes Discounted at**				
($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved										
Developed Producing	866.7	709.1	608.6	538.0	485.3	731.9	601.0	519.0	461.7	419.0
Developed Non-Producing	89.5	73.8	64.1	57.1	51.7	58.9	49.0	43.3	39.2	36.0
Undeveloped	72.6	47.3	33.9	25.8	20.3	48.0	31.4	22.5	17.0	13.4
Total Proved	1,028.9	830.2	706.6	620.9	557.3	838.8	681.4	584.7	517.9	468.4
Probable	429.8	276.7	201.0	155.9	125.9	285.0	185.7	136.3	106.7	86.9
Total Proved Plus Probable	**1,458.7**	**1,106.8**	**907.6**	**776.8**	**683.2**	**1,123.8**	**867.1**	**721.0**	**624.6**	**555.3**

Total Future Net Revenue by Production Group - Forecast Prices and Costs

The following table summarizes the total undiscounted future net revenue evaluated at December 31, 2004 using Paddock Lindstrom's forecast prices and costs.

Reserves Category ($ millions)	**Revenue**	**Royalties**[(1)]	**Operating Costs**	**Development Costs**	**Well Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	1,819.8	357.1	381.8	25.7	26.4	1,028.9	190.0	838.8
Proved Plus Probable	2,645.6	516.9	565.3	73.7	31.0	1,458.7	334.9	1,123.8

[(1)] Royalties includes crown royalties, and overriding royalties and are net of other income.

__Future Net Revenue by Production Group - Forecast Prices and Costs__

The following table summarizes the net present value of future net revenue by production group evaluated at December 31, 2004 using Paddock Lindstrom's forecast prices and costs, discounted at 10 percent.

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%) ($ millions)
Proved	Associated and Non Associated Gas	612.3
	Light and medium crude oil	90.5
	Other revenue	3.8
Total Proved		706.6
Proved Plus Probable	Associated and Non Associated Gas	789.8
	Light and medium crude oil	113.8
	Other revenue	4.0
Total Proved Plus Probable		**907.6**

__Summary of Pricing and Inflation Rate Assumptions__

The following table summarizes the prices and costs used in the Paddock Lindstrom Report in calculating the net present value of future net revenue attributable to reserves.

Constant Price and Costs

	Segregated Condensate (Cdn$/Bbl)	**Edmonton Butane** (Cdn$/Bbl)	**Edmonton Propane** (Cdn$/Bbl)	**Edmonton Light Crude Oil** (Cdn$/Bbl)	**Bow River Medium Crude Oil** (Cdn$/Bbl)	**Estimated Corporate Average Plantgate** (Cdn$/Mcf)	**Exchange Rate**[1] (US$/Cdn$)
2004	54.36	42.06	35.71	50.96	26.27	6.50	0.82

(1) Exchange rates used to generate the benchmark reference prices in this table.

Forecast Prices and Costs

	U.S. Henry Hub Gas Price (US$/MMbtu)	**Average AGRP** (Cdn$/MMbtu)	**WTI** (US$/Bbl)	**Edmonton Reference Price** (Cdn$/Bbl)	**Condensate** (Cdn$/Bbl)	**Butane** (Cdn$/Bbl)	**Propane** (Cdn$/Bbl)	**Inflation Rates**[1] (%/year)	**Exchange Rate**[2] (US$/Cdn$)
2005	6.30	6.55	42.00	50.22	50.22	37.16	30.13	0.02	0.82
2006	6.10	6.34	40.00	47.76	47.76	34.87	28.66	0.02	0.82
2007	5.90	6.07	37.50	44.69	44.69	32.18	26.81	0.02	0.82
2008	5.70	5.81	35.00	41.62	41.62	29.14	24.97	0.02	0.82
2009	5.50	5.54	33.00	39.16	39.16	27.41	23.50	0.02	0.82

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table summarizes the gross proved undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	2004	2003	2002	2001	2000
Natural Gas (Bcf)	19.9	3.5	3.9	-	4.3
Light and medium crude oil (MBbl)	-	437	437	328	-
Natural Gas Liquids (MBbl)	240	55	46	-	-

These reserves are classified as proved undeveloped if they are expected to be recovered from new wells on previously undrilled acreage with untested reservoir characteristics, or they are reserves from existing wells that require major capital expenditures to bring them on production.

The following table summarizes the gross probable undeveloped reserves for the most recent five financial years, using forecast prices and costs.

Product	2004	2003	2002	2001	2000
Natural Gas (Bcf)	40.2	2.7	3.3	1.4	11.3
Light and medium crude oil (MBbl)	225	109	219	202	-
Natural Gas Liquids (MBbl)	484	38	30	5	5

These reserves are classified as probable undeveloped when analysis of drilling, geological, geophysical and engineering data does not demonstrate them to be proved under current technology and existing economic conditions; however, this analysis does suggest that there is a likelihood of their existence and future recovery.

Future Development Costs

The following table describes the estimated future development costs deducted in the estimation of future net revenue. The costs are per reserve category and quoted for no discount and a discount rate of ten percent.

Reserve Category	**2005E**		**2006E**		**2007E**		**2008E**		**2009E**	
($millions)	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**	**0%**	**10%**
Proved:										
Constant Price Case	18.7	17.8	5.9	5.1	-	-	-	-	-	-
Forecast Price Case	18.7	17.8	5.9	5.1	-	-	-	-	-	-
Proved & Probable Reserves:										
Constant Price Case	62.4	59.5	9.0	7.8	-	-	-	-	0.1	-
Forecast Price Case	62.4	59.5	9.0	7.8	-	-	-	-	0.1	-

APPENDIX C

EFFECT OF THE TRUST SPINOUT ON PARAMOUNT

EFFECT OF THE TRUST SPINOUT ON PARAMOUNT

GENERAL

Following the completion of the Trust Spinout, Paramount will continue to be an independent Canadian energy company involved in the exploration, development, production, processing, transportation and marketing of natural gas and oil, and is expected to have production of approximately 20,000 Boe/d initially. Paramount's principal properties will be located primarily in Alberta, the Northwest Territories and British Columbia in Canada. Paramount will also have properties in Saskatchewan and offshore the East Coast in Canada, and in Montana, North Dakota and California in the United States.

RESERVES

Following completion of the Trust Spinout, the reserves of Paramount as of December 31, 2004 will be as set forth in Appendix A.

BUSINESS FOCUS

Following completion of the Trust Spinout, Paramount's remaining assets will be concentrated in its four existing core areas of Grande Prairie; Northwest Alberta/Cameron Hills, NWT; Liard, NWT/Northeast British Columbia; and Southern, and Paramount will continue to operate in the West Kaybob area. Paramount will continue to operate as a growth-oriented exploration and development company and will continue to pursue long term exploration, development and exploitation opportunities in the Colville Lake area of the Northwest Territories and steam-assisted gravity drainage developments in the bitumen areas of Northeast Alberta.

RELATIONSHIP BETWEEN PARAMOUNT AND THE TRUST AFTER THE TRUST SPINOUT

Although Paramount will initially own 19 percent of the outstanding units of the Trust, Paramount and the Trust will be separate entities.

Following completion of the Trust Spinout, approximately 100 of Paramount's employees will become employees of the Trust. The Trust will also have access to certain of Paramount's remaining employees under a services agreement pursuant to which Paramount will assist the Trust with the operation of its properties and the administration of the Trust. Either party will have the ability to terminate the services agreement upon six months' prior written notice to the other party. It is anticipated that the Trust will ultimately operate completely independently from Paramount with its own full complement of management and employees.

DIRECTORS AND MANAGEMENT

The Trust Spinout is not expected to result in any change to Paramount's directors or senior management.

SHARE CAPITAL

The authorized and issued share capital of Paramount will change upon completion of the Trust Spinout. See the section entitled "Description of Share Capital" in Appendix E to the information circular of Paramount dated February 28, 2005 in respect of the Trust Spinout, which is incorporated by reference herein.

APPENDIX D

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Paramount Resources Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2004. The reserves data consists of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	February 1, 2005	Canada/U.S.A.	-	$751,732	-	$751,732
Paddock Lindstrom & Associates Ltd.	January 28, 2005	Canada	-	$907,597	-	$907,597
Totals				**$1,659,329**		**$1,659,329**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) Paddock Lindstrom & Associates Ltd.
Calgary, Alberta, Canada

March 9, 2005

APPENDIX E

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Paramount Resources Ltd. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Audit Committee has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information contained in the Company's annual information form accompanying this report;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) Clayton H. Riddell
Chief Executive Officer

(signed) Bernard K. Lee
Chief Financial Officer

(signed) James H. T. Riddell
Director

(signed) John B. Roy
Director

March 30, 2005

APPENDIX F

AUDIT COMMITTEE CHARTER

PARAMOUNT RESOURCES LTD.
AUDIT COMMITTEE
CHARTER

(Adopted by the Board of Directors on March 23, 2004)

A. PURPOSE

The overall purpose of the Audit Committee (the "Committee") is to ensure that the Corporation's management has designed and implemented an effective system of internal financial controls and disclosure controls and procedures, to review and report on the integrity of the consolidated financial statements of the Corporation, to review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts and to review the Corporation's externally disclosed oil and gas reserves estimates including reviewing the qualifications of, and procedures used by, the independent engineering firm responsible for evaluating the Corporation's reserves.

B. COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Committee shall consist of at least three members of the Board of Directors (the "Board"), all of whom shall be "unrelated directors", as that term is defined in section 473(2) of the Corporate Governance Guidelines of the Toronto Stock Exchange[1] who meet the requirements of Section 3.5(1) of National Instrument 51-101[2] and the requirements of Section 1.4 of the proposed Multilateral Instrument 52-110[3].

2. All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issuer that can be reasonably expected to be raised by the issuer's financial statements).

3. The Audit Committee shall be responsible for assessing, on a periodic basic, whether any member of the Committee meets the criteria for being a "financial expert" pursuant to Section 407 of the Sarbanes-Oxley Act.

4. The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

5. Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

6. The Corporate Secretary of the Corporation shall be the secretary of the Committee, unless otherwise determined by the Committee.

7. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

8. The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.

9. Meetings of the Committee shall be conducted as follows:

(b) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

(c) the external auditors shall receive notice of and have the right to attend all meetings of the Committee; and

(d) the following management representatives shall be invited to attend all meetings, except executive sessions and private sessions with the external auditors:

President and Chief Operating Officer
Chief Financial Officer
Controller
Corporate Secretary

(e) other management representatives shall be invited to attend as necessary.

10. The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

11. The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Chairman of the Corporate Governance Committee whenever independent consultants are engaged.

C. ROLES AND RESPONSIBILITIES

1. The overall duties and responsibilities of the Committee shall be as follows:

(a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements and management's discussion and analysis;

(b) to establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

(c) to ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of internal financial controls and disclosure controls and procedures;

(d) to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate;

(e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;

(f) to assist the Board in the discharge of its responsibilities relating to the evaluation and disclosure of its oil and gas reserves and oil and gas activities and the approval and filing of all necessary statements and reports related thereto;

(g) to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;

(h) to report regularly to the Board on the fulfillment of its duties and responsibilities;

(i) to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation; and

(j) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.

2. The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(b) to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Corporation, and to monitor and verify the independence of such external auditors;

(c) to review and approve the fee, scope and timing of the audit and other related services rendered by the external auditors;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) to review with the external auditors, upon completion of their audit:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) co-operation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

(viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;

(f) to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles;

(g) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation; and

(h) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management.

3. The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

(a) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(b) review compliance under the Corporation's Code of Business Conduct Policy with those matters addressed in the policy which affect the financial integrity of the Corporation and to periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(c) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.

4. The Committee is also charged with the responsibility to:

(a) review and recommend to the Board for its approval, the Corporation's annual financial statements, management's discussion and analysis, annual information form and annual earnings press releases before the Corporation publicly discloses this information;

(b) review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;

(c) review and approve the financial sections of:

(i) the annual report to shareholders;

(ii) the annual information form;

(ii) prospectuses;

(iv) other public reports requiring approval by the Board; and

(v) press releases related thereto,

and report to the Board with respect thereto;

(d) review regulatory filings and decisions as they relate to the Corporation's consolidated financial statements;

(e) review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(f) review and report on the integrity of the Corporation's consolidated financial statements;

(g) review the minutes of any audit committee meeting of subsidiary companies;

(h) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

(i) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts; and

(j) develop a calendar of activities to be undertaken by the Committee for each ensuing year related to the Committee's duties and responsibilities as set forth in this Charter and to submit the calendar in the appropriate format to the Board of Directors within a reasonable period of time following each annual general meeting of shareholders.

5. The duties and responsibilities of the Committee as they relate to the Corporation's oil and gas reserves estimates are to:

(a) review, with reasonable frequency, the Corporation's procedures relating to the disclosure of information with respect to oil and gas activities, including its procedures for complying with the disclosure requirements and restrictions of all applicable laws, rules, regulations and policies including National Instrument 51-101 and amendments thereto;

(b) review the appointment of the independent engineering firm responsible for evaluating the Corporation's reserves, and in the case of any proposed change in such appointment, determine the reasons for the proposal and whether there have been disputes between the appointed reserves evaluator and Management of the Corporation;

(c) review, with reasonable frequency, the Corporation's procedures for providing information to the reserves evaluator;

(d) before recommending approval of the filing of reserves data and the report of the reserves evaluator as required under all applicable laws, rules, regulations and policies including National Instrument 51-101 and amendments thereto, meet with Management and the reserves evaluator to:

(i) determine whether any restrictions affect the ability of the reserves evaluator to report on reserves data without reservation, and

(ii) review the reserves data and the report of the reserves evaluator

(e) review, discuss with and make recommendations to the Board with respect to:

(i) approving the content and filing of the reserves statement;

(ii) the filing of the report of the reserves evaluator; and

(iii) the content and filing of the report of Management and Directors;

as required or specified under all applicable laws, rules, regulations and policies including National Instrument 51-101 and amendments thereto.

D. ANNUAL REVIEW AND ASSESSMENT

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Corporate Governance Committee for consideration and recommendations.

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[1] "unrelated director" means a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interest of the company, other than interests and relationships arising from shareholding.

[2] 3.5 **Reserves Committee**
(1) The board of directors of a reporting issuer may, subject to subsection (2), delegate the responsibilities set out in section 3.4 to a committee of the board of directors, provided that a majority of the members of the committee
(a) are individuals who are not and have not been, during the preceding 12 months:
(i) an officer or employee of the reporting issuer or of an affiliate of the reporting issuer;
(ii) a person who beneficially owns 10 percent or more of the outstanding voting securities of the reporting issuer; or
(iii) a relative of a person referred to in subparagraph (a)(i) or (ii), residing in the same home as that person; and
(b) are free from any business or other relationship which could reasonably be seen to interfere with the exercise of their independent judgement.)
(2) Despite subsection (1), a board of directors of a reporting issuer shall not delegate its responsibility under paragraph 3.4(e) to approve the content or the filing of the information.

[3] 1.4 **Meaning of Independence** --
(1) A member of an audit committee is independent if the member has no direct or indirect material relationship with the issuer.
(2) For the purposes of subsection (1), a material relationship means a relationship which could, in the view of the issuer's board of directors, reasonably interfere with the exercise of a member's independent judgement.
(3) Despite subsection (2), the following individuals are considered to have a material relationship with an issuer:
(a) an individual who is, or has been, an employee or executive officer of the issuer, unless the prescribed period has elapsed since the end of the service or employment;
(b) an individual whose immediate family member is, or has been, an executive officer of the issuer, unless the prescribed period has elapsed since the end of the service or employment;
(c) an individual who is, or has been, an affiliated entity of, a partner of, or employed by, a current or former internal or external auditor of the issuer, unless the prescribed period has elapsed since the person's relationship with the internal or external auditor, or the auditing relationship, has ended;
(d) an individual whose immediate family member is, or has been, an affiliated entity of, a partner of, or employed in a professional capacity by, a current or former internal or external auditor of the issuer, unless the prescribed period has elapsed since the person's relationship with the internal or external auditor, or the auditing relationship, has ended;
(e) an individual who is, or has been, or whose immediate family member is or has been, an executive officer of an entity if any of the issuer's current executive officers serve on the entity's compensation committee, unless the prescribed period has elapsed since the end of the service or employment;
(f) an individual who
(i) has a relationship with the issuer pursuant to which the individual may accept, directly or indirectly, any consulting, advisory or other compensatory fee from the issuer or any subsidiary entity of the issuer, other than as remuneration for acting in his or her capacity as a member of the board of directors or any board committee, or as a part-time chair or vice-chair of the board or any board committee; or
(ii) receives, or whose immediate family member receives, more than $75,000 per year in direct compensation from the issuer, other than as remuneration for acting in his or her capacity as a member of the board of directors or any board committee, or as a part-time chair or vice-chair of the board or any board committee, unless the prescribed period has elapsed since he or she ceased to receive more than $75,000 per year in such compensation.

(g) an individual who is an affiliated entity of the issuer or any of its subsidiary entities.
(4) For the purposes of subsection (3), the prescribed period is the shorter of
(a) the period commencing on March 30, 2004 and ending immediately prior to the determination required by subsection (3); and
(b) the three year period ending immediately prior to the determination required by subsection (3).
(5) For the purposes of clauses (3)(c) and (3)(d), a partner does not include a fixed income partner whose interest in the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with an internal or external auditor if the compensation is not contingent in any way on continued service.
(6) For the purposes of clause (3)(f), compensatory fees and direct compensation do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the issuer if the compensation is not contingent in any way on continued service.
(7) For the purposes of subclause 3(f)(i), the indirect acceptance by a person of any consulting, advisory or other compensatory fee includes acceptance of a fee by
(a) a person's spouse, minor child or stepchild, or a child or stepchild who shares the person's home; or
(b) an entity in which such person is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the issuer or any subsidiary entity of the issuer.
(8) Despite subsection (3), a person will not be considered to have a material relationship with the issuer solely because he or she
(a) has previously acted as an interim chief executive officer of the issuer, or
(b) acts, or has previously acted, as a chair or vice-chair of the board of directors or any board committee, other than on a full-time basis.