PETROBANK ENERGY AND RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2002

MAY 16, 2003

TABLE OF CONTENTS

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	thousands of Canadian dollars	**"mmcf"**	1,000,000 cubic feet
"MM$"	millions of Canadian dollars	**"bcf"**	1,000,000,000 cubic feet
"bbl"	Barrel	**"mcf/d"**	one thousand cubic feet per day
"mbbl"	1,000 barrels	**"mcfe"**	1,000 cubic feet of gas equivalent
"mmbbl"	1,000,000 barrels	**"mmcf/d"**	one million cubic feet per day
"bbl/d"	barrel per day	**"boe"**	barrel of oil equivalent
"stb"	stock tank barrel	**"mboe"**	1,000 barrels of oil equivalent
“mstb”	1,000 stock tank barrels		
"NGL"	natural gas liquids	**"boe/d"**	barrel of oil equivalent per day
"mcf"	1,000 cubic feet	**"m3"**	cubic metre
		"US $"	United States Dollars

Note: for the purposes of this document, 6 mcf of natural gas and 1 bbl of NGL each equal 1 bbl of oil or 1 boe, such conversion not being based on either price or energy content.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"ABCA" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, together with any amendments thereto and all regulations promulgated thereunder;

"ARTC" means the Alberta royalty tax credit;

"Common Shares" means common shares in the share capital of the Company;

"GAAP" means Canadian generally accepted accounting principles;

"GLJ Report" means the independent engineering evaluation of Petrobank's crude oil and natural gas reserves prepared by Gilbert Laustsen Jung Associates Ltd. (**"GLJ"**), independent oil and gas reservoir engineers of Calgary, Alberta, dated February 25, 2003 and effective January 1, 2003;

"Petrobank" or the **"Company"** means Petrobank Energy and Resources Ltd.; and

"TSX" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT

Petrobank is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operations are the nature of the Company's involvement in the business of exploration for, and development and production of oil and natural gas reserves, fluctuations in prices received for oil and natural gas, fluctuations in interest rates and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis", incorporated by reference from the Company's 2002 Annual Report, and elsewhere in this Annual Information Form.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for management to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

THE COMPANY

Incorporation and Organization

The Company was incorporated under the ABCA on December 1, 1983 as "Petrobank Energy Resources Ltd.". On September 8, 1986, Articles of Amendment were filed to change the Company's name to "Petrobank Energy and Resources Ltd.". On September 8, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. On March 7, 2000, the Company filed Articles of Amendment to create the first series of Preferred Shares designated as Preferred Shares, Series A and on August 22, 2000 to create the second and third series of Preferred Shares designated as Preferred Shares, Series B and Series C. On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly owned subsidiary, Barrington Petroleum Ltd. ("Barrington").

The Company's principal office and registered office is located at Suite 2600, 240 - 4th Avenue S.W., Calgary, Alberta, T2P 4H4.

General Development of the Company

Three-Year History

Effective March 15, 2000, Caribou Capital Corp. invested an aggregate sum of $12,913,500 in the Company in exchange for 8,609,000 Preferred Shares and 19,218,000 share purchase warrants and its personnel assumed senior management positions within the Company.

On January 16, 2001, the Company disposed of its properties in the Alder Flats area of Alberta for net proceeds of $85.1 million.

On April 12, 2001, the Company acquired 97.2% of the outstanding common shares of Barrington for consideration of $0.68 per Barrington common share. The total cash purchase price totalled $52 million.

On April 23, 2001, the Company disposed of its properties in the Blood Magrath area of Alberta for net proceeds of $15.9 million. On July 18, 2001, Petrobank's plan of arrangement with Barrington was made effective whereby Petrobank acquired the remaining 2.8% interest in Barrington for consideration of $0.70 per Barrington common share or $1.3 million. In addition, the former holders of $50 million of Barrington gas linked notes paying interest at 12%, agreed to exchange their notes into $47.5 million of new Petrobank subordinated notes paying 9% interest. Barrington noteholders also subscribed for an additional $13 million of Petrobank subordinated notes.

Through the remainder of 2001, the Company completed a series of non-core area dispositions resulting in proceeds of $60.6 million.

In May 2002, the Company assumed the remaining work commitments on two incremental production (IP) blocks and three exploration blocks in Colombia. At December 31, 2002, the Company's remaining work commitments on these blocks totalled U.S. $46 million. The company commenced commercial production in Colombia in January 2003.

In November 2002, the Company reorganized its management into three business units; Canada, Latin America and Heavy Oil. The Heavy Oil business unit is operating through Petrobank's wholly owned subsidiary, Orion Oil Canada Ltd., which was created to undertake the world's first field pilot of the revolutionary THAI *in situ* heavy oil recovery and upgrading technology.

Trends

There are a number of trends that have been developing in the oil and gas industry that appear to be shaping the near future of the business. The first trend is the consolidation phase that the industry has been going through. This trend has affected companies of all sizes and the trend appears to be continuing.

The second trend that has been developing in the oil and gas industry is the reduced access to equity financing that the industry is currently experiencing. This trend can be partly attributed to the higher relative returns that have been experienced in other sectors of the market, as well as the general negative investor sentiment in the broader market. Many institutional investors who have traditionally invested in junior oil and gas securities have little cash for investment in new issues as a result of heavy unit redemptions in the past six to nine months. During the last two quarters this trend has been correcting somewhat and institutional investors appear to be beginning to refocus on traditional sectors for investment opportunities. Time is required to see if this trend results in additional investment in the junior oil and gas sector.

The third trend that has been developing in the oil and gas industry is the current influence of royalty trusts on the Canadian portion of the oil and gas industry. While American companies dominated the acquisition market in the first three quarters of 2001, royalty trusts recently have been acquiring companies and assets in Canada in order to grow their cash flows and distributions. Some oil and gas production companies have also reorganized themselves into royalty trusts to capture the attractive valuations presently awarded to such trusts by the equity markets. Should the energy royalty trusts continue to be able to access the capital markets on a more favourable basis, this could continue to change the structure of the Canadian oil and gas industry.

The Canadian/U.S. exchange rate also influences commodity prices for Canadian producers as there is a high correlation between Canadian and U.S. oil and natural gas prices. The recent strengthening of the Canadian dollar against the U.S. dollar has resulted in reduced netbacks for Canadian oil and gas producers.

BUSINESS OF THE COMPANY

Petrobank's business strategy is focused on return on shareholders' equity through the continued growth of the Western Canadian asset base combined with the pursuit and execution of higher impact international projects. In Western Canada, the Corporation operates primarily in four focus areas, Southeast Saskatchewan, Western Saskatchewan, Jumpbush Alberta and Northwest Alberta. Internationally, the Corporation has two IP blocks and three exploration blocks in Colombia.

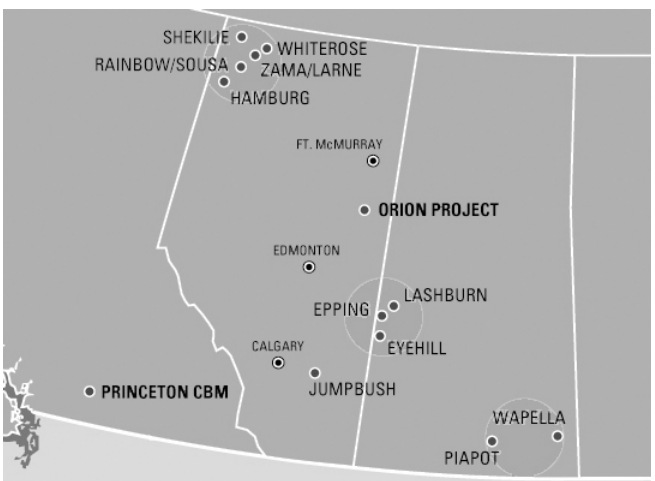
Production

Average daily production by major producing region is summarized as follows:

	Liquids - Bbls		Gas - Mcf		BOE (6:1)	
	2002 Average	Q1 2003	2002 Average	Q1 2003	2002 Average	Q1 2003
Southeast Saskatchewan	1,552	1,498	-	-	1,552	1,498
Northwest Alberta	327	423	10,796	7,309	2,126	1,641
Western Saskatchewan	291	452	-	13	291	454
Jumpbush	64	49	1,124	1,304	252	267
Other	389	335	2,621	2,294	826	717
Total - Canada	2,623	2,757	14,541	10,920	5,047	4,577
Colombia - Orito	-	378	-	-	-	378
Colombia - Neiva	-	317	-	-	-	317
Total - Colombia	-	695	-	-	-	695
Total	2,623	3,452	14,541	10,920	5,047	5,272

Principal Properties

Western Canadian Focus Areas



Southeast Saskatchewan

The 100 percent-owned Wapella property in southeastern Saskatchewan provides Petrobank with a stable base of low operating cost, medium-gravity oil from the Shaunavon and other Jurassic Age formations. Production averaged 1,552 barrels per day in 2002, with operating costs of approximately $5.50 per barrel. Our primary opportunity to add incremental value lies in implementing a waterflood to boost production and add reserves by increasing the overall recovery ratio of the original oil in place.

The waterflood project will require drilling of eight new infill wells plus conversion of five older producers into water injectors. With regulatory approvals pending, Petrobank anticipates the waterflood will may be initiated by the fourth quarter of 2003.

Western Saskatchewan

Petrobank's conventional heavy to medium-gravity crude oil properties in the Alberta-Saskatchewan border region represent classic exploitation and optimization scenarios for adding value at relatively low cost and low risk.

At its Lashburn property, Petrobank increased its working interest from 41 percent to 60 percent in the fourth quarter of 2002 to create a dominant position. Production was 300 barrels per day of 14° API oil net to Petrobank at year-end. Development of Lashburn will be aimed at increasing the recovery factor from the Waseca pool using horizontal wells. A new 3D seismic survey has identified up to six horizontal well locations. This $1.8 million drilling program is to commence as soon as possible after spring break-up. Each successful well is anticipated to deliver incremental production of approximately 100 barrels per day and reserves of approximately 90,000 barrels.

Petrobank's new, 100 percent-owned Sparky play at Eyehill saw nine wells drilled in 2002, of which eight were successful, resulting in combined production of 200 barrels per day of 19° API oil by year-end. An additional six wells have been drilled and cased for Sparky oil in the first quarter for 2003. Results from the latest wells will determine the economic viability of an infill drilling program on 20-acre spacing, followed by installation of an oil battery and initiation of a waterflood scheme in the third quarter of 2003. This project is aimed at increasing production to 800 barrels per day with reserve additions of approximately 800,000 barrels.

Petrobank also has a 100 percent interest in our Epping property where four wells were drilled and cased by mid-April, targeting 18°API Sparky oil. The Company expects to complete these wells and drill an additional three locations by June 2003.

Jumpbush Alberta

Petrobank's Jumpbush play on the Siksika First Nation Reserve in southern Alberta represents an opportunity to add production and reserves of natural gas and oil from an existing under-exploited asset. Jumpbush is being developed in partnership with the Siksika Energy and Resources Company, which owns a 30% working interest. The joint venture owns an under-utilized strategic gas plant in the area, with excess capacity of 11 mmcf/d, creating a decisive competitive advantage. Petrobank's production from Jumpbush at year-end 2002 was 1.2 mmcf/d of natural gas and 60 bbl/d of oil.

Petrobank is planning a $7.5 million, 32-well program at Jumpbush for 2003. The first phase will consist of two Glauconite oil wells (one vertical and one horizontal) and eight shallow (600 metre) Belly River and Medicine Hat natural gas wells. The second phase will have 17 Belly River and Medicine Hat natural gas wells plus, depending on first phase results, up to five additional vertical and horizontal Glauconite oil wells.

The shallow horizons at Jumpbush create a low-deliverability natural gas play, which offers strong economics for a producer that can control costs and achieve a high success rate. Target production rates are approximately 100 mcf/d per successful natural gas well. With 30 additional sections of undeveloped lands, Petrobank has a two-year inventory of development opportunities at Jumpbush, which the Company hopes to augment through further land acquisitions.

Northwest Alberta

Although Petrobank's northern Alberta properties will not experience significant development in 2003, they still offer opportunities to add value at low cost. Production from this area averaged 2,126 boe/d in 2002. At Zama, Petrobank purchased a minority partner's interests and conducted several recompletions and exited 2002 with natural gas production of 5.3 mmcf/d. No new drilling is planned in this area in 2003. At Larne, three shallow natural gas wells were drilled in 2002 to prove reserves on one block. Follow-up development of this shallow play awaits infrastructure development closer to the area. Petrobank plans recompletions in the Slave Point, Sulphur Point and other uphole horizons in 2003 to partially offset natural production declines in the area.

At Shekilie, Petrobank purchased its partner's majority interest, followed by one well recompletion and other surface facility optimizations. This program doubled the Keg River oil volume to 450 bbls/d and added one million barrels of proved reserves at an average finding and development cost of only $5.50 per barrel.

Colombia

Colombia is an oil-rich country with major potential for value-creation through the application of current technologies and exploitation strategies to under-capitalized producing fields. Petrobank has Incremental Production Contracts ("IPCs") in two such fields in southwestern Colombia. Petrobank's strategy is to realize near-term cash flow from these exploitation opportunities by applying North American technical and business models, followed by opportunity-driven exploration as the area's additional geological potential comes into focus. The Colombian government has encouraged foreign participation by making contracts available at very attractive fiscal terms. Each IPC provides that Petrobank will share in a portion (initially 79 percent in the case of the Orito IP block and 69 percent in the case of Neiva) of the incremental production from the field generated by its development activities. Each IPC has an established baseline of production which corresponds to the decline curve predicted by production from the past twenty years. Petrobank's net share is subject to an 8 percent royalty paid to the government.

Orito

Like many reservoirs in the region, the Orito Field in the Putumayo Basin of southwestern Colombia is a world-class reservoir in the latter stages of primary development. With an estimated 1.1 billion barrels of original oil in place, approximately 20 percent of which has been produced to date, Orito offers numerous opportunities to create value through in-fill drilling, field extension, facilities upgrades, secondary recovery and other techniques proven in Canada and elsewhere in the world.

Orito produced an average of 3,600 bbl/d from 41 wells in 2002. The area has extensive field infrastructure, good seismic control and connection to an underutilized export pipeline, enabling immediate fiscalization of any incremental oil production. Historically, Ecopetrol has managed the field without the capital resources needed for a comprehensive program of late-primary exploitation and secondary recovery. Our IPC creates a win-win opportunity, as Petrobank gains access to all existing infrastructure and data, while Ecopetrol participates in any incremental upside Petrobank generates over the life of the contract.

Orito contains three main oil-producing or prospective zones (Pepino, Villeta and Caballos). To significantly enhance current production, we will initially employ a combination of late-stage primary recovery techniques, such as drilling in-fill wells, changing from gas lift to electrical submersible pumps, and re-completing wells to enhance oil inflow. Reperforation and alteration of the lift methodology at one well recently increased production from 40 barrels per day to over 400 barrels per day. Additionally, Petrobank will drill new wells in under-developed areas of the field. Over the medium term, Petrobank anticipates launching a secondary recovery program involving injecting large volumes of water to increase recovery.

Neiva

The Neiva Field in the upper Magdalena Basin lies approximately 300 kilometres northeast of Orito. Neiva has shallow multi-zone reservoirs facilitating low-risk exploitation drilling. Production in 2002 averaged 3,900 barrels per day from 59 wells, with cumulative production at approximately 25 percent of the estimated 220 million barrels of original oil-in-place. This low-pressure system requires fundamental exploitation techniques to realize additional value. Success will be determined by Petrobank's ability to control capital costs.

Neiva's reservoir consists of sand-shale sequences totaling up to 1,500 feet of gross pay containing natural gas, oil and water. These sands may not be amenable to waterflood because of the multitude of individual sand shale sequences over a massive vertical column. Petrobank's program will include infill drilling, pump and gathering system optimization, and workovers focusing on re-perforation and scale treatment operations. Initial efforts have been focused on the shallower Honda and Doima/Chicoral zones. The deeper Tenay/Caballos zone offers potential for higher-risk, higher-productivity wells. Successful Tenay wells have averaged 1,500 barrels per day of initial production. Three existing Tenay wells have collectively produced more than 8 million barrels of oil to date. The Company has reprocessed and reinterpreted the existing 3D seismic over the field and is evaluating a range of go-forward development options in this zone.

LAND HOLDINGS

The undeveloped land holdings of the Company as at December 31, 2002, are set forth in the following table:

	Undeveloped Acres	
	Gross[(1)]	Net[(2)]
Alberta	255,000	211,000
Saskatchewan	270,000	258,000
Other	78,000	59,000
Total Canada	603,000	528,000
Colombia	478,000	328,000

Notes:

(1) "Gross" acres means the total number of acres in which the Company has an interest.

(2) "Net" acres refers to the Company's net working interest in the gross acres.

OIL AND GAS WELLS

The following table summarizes Petrobank's interests as at December 31, 2002 in oil and natural gas wells which are producing or which are considered capable of production. All significant non-producing oil and natural gas wells are within economic distance of transportation facilities.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	99	46.5	197	58.5	2	2.0	8	4.8
Saskatchewan	152	88.6	-	-	36	29.6	-	-
Other	12	0.8	-	-	-	-	-	-
Canada	263	135.9	197	58.5	38	31.6	8	4.8
Orito	42	33.2	-	-	60	47.4	-	-
Neiva	59	40.7	-	-	13	9.0	-	-
Colombia	101	73.9	-	-	73	56.4	-	-
Total	364	209.8	197	58.5	111	88.0	8	4.8

Notes:

(1) "Gross" wells refers to all wells in which Petrobank owns a working interest.

(2) "Net" wells refers to the aggregate of the percentage working interests of Petrobank in the gross wells, before the deduction of royalties.

OIL AND GAS RESERVES

GLJ has prepared the GLJ Report evaluating the proved and probable additional crude oil, NGL and natural gas reserves of Petrobank's properties, both in Canada and Colombia, as of January 1, 2003. In preparing its report, GLJ obtained basic information from Petrobank, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required by GLJ was obtained from public records, other operators and from GLJ's non-confidential files. GLJ did not independently verify the factual information that Petrobank provided to it or that it obtained from other sources. GLJ did not conduct a field inspection.

The following tables, based on the GLJ Report, show the estimated share as at the dates indicated of Petrobank's crude oil, natural gas and NGL reserves and the present value of estimated future cash flow for these reserves using escalated and constant prices and costs as indicated. **The present worth of estimated future cash flow is stated after provisions for estimated future capital expenditures and before provisions for future abandonment costs and provision for income taxes. The present worth of estimated future cash flow for Petrobank’s Colombia properties is presented in US $.**

CRUDE OIL AND NATURAL GAS RESERVES AND PRESENT WORTH OF ESTIMATED FUTURE CASH FLOW

Canada

Escalated Dollar Economics

	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	mstb	mstb	Mmcf	mmcf	mstb	mstb	M$	M$	M$	M$
Proved Developed										
Producing	4,653	3,977	16,390	12,775	167	119	106,767	75,758	67,419	61,147
Non-Producing	4	4	3,562	2,673	32	21	8,483	5,666	4,811	4,166
Proved Undeveloped	1,628	1,466	962	832	2	2	14,825	8,050	5,995	4,449
Total Proved	6,285	5,448	20,914	16,280	202	142	130,075	89,475	78,225	69,763
Probable Additional	4,906	4,308	14,713	11,573	83	58	94,144	47,363	36,640	29,347
Total Before Risk	11,191	9,756	35,627	27,853	285	200	224,219	136,837	114,865	99,110
Reduction Due to Risk	(2,453)	(2,154)	(7,357)	(5,786)	(41)	(29)	(47,072)	(23,681)	(18,320)	(14,674)
Total After Risk	8,738	7,602	28,270	22,067	244	171	177,147	113,156	96,545	84,436

Constant Dollar Economics

	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	mstb	mstb	Mmcf	mmcf	mstb	mstb	M$	M$	M$	M$
Proved Developed										
Producing	4,898	4,136	16,727	13,056	171	121	170,556	117,880	103,539	92,856
Non-Producing	4	4	3,490	2,634	32	20	11,949	7,914	6,695	5,780
Proved Undeveloped	1,664	1,480	980	841	2	2	35,643	21,693	17,490	14,328
Total Proved	6,566	5,620	21,197	16,531	205	143	218,148	147,487	127,724	112,964
Probable Additional	5,064	4,349	15,115	11,866	84	58	164,530	82,286	63,909	51,550
Total Before Risk	11,630	9,969	36,312	28,397	289	201	382,678	229,773	191,633	164,514
Reduction Due to Risk	(2,532)	(2,174)	(7,557)	(5,933)	(42)	(29)	(82,265)	(41,143)	(31,954)	(25,775)
Total After Risk	9,098	7,795	28,755	22,464	247	172	300,413	188,630	159,679	138,739

Colombia

Escalated Dollar Economics

	Remaining Reserves Crude Oil		Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
Reserve Category	Gross	Net	0%	10%	15%	20%
	mstb	mstb	M$	M$	M$	M$
Proved Developed						
Producing	119	113	1,746	1,619	1,564	1,513
Non-Producing	-	-	-	-	-	-
Proved Undeveloped	4,501	4,272	40,333	29,911	26,182	23,124
Total Proved	4,620	4,385	42,079	31,530	27,746	24,637
Probable Additional	3,710	3,521	36,453	20,725	16,337	13,182
Total Before Risk	8,330	7,906	78,532	52,255	44,083	37,819
Reduction Due to Risk	(1,855)	(1,761)	(18,227)	(10,363)	(8,168)	(6,591)
Total After Risk	6,475	6,146	60,306	41,892	35,914	31,228

Constant Dollar Economics

	Remaining Reserves Crude Oil		Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
Reserve Category	Gross	Net	0%	10%	15%	20%
	stb	stb	M$	M$	M$	M$
Proved Developed						
Producing	119	113	2,550	2,346	2,258	2,178
Non-Producing	-	-	-	-	-	-
Proved Undeveloped	3,921	3,722	65,825	50,987	45,587	41,110
Total Proved	4,040	3,835	68,376	53,333	47,845	43,288
Probable Additional	3,837	3,641	73,567	42,083	33,343	27,089
Total Before Risk	7,877	7,476	141,942	95,416	81,188	70,377
Reduction Due to Risk	(1,919)	(1,821)	(36,784)	(21,042)	(16,672)	(13,544)
Total After Risk	5,959	5,656	105,159	74,374	64,516	56,833

Notes:

(1) **"Gross"** reserves are defined as those accruing to the Company before deduction of all royalties and interests owned by others.

"Net" reserves are defined as those accruing to the Company after deduction of all royalties and interests owned by others.

(2) Probable additional cash flows presented in the GLJ Report are prepared at full value assuming that the quantities and values of the forecast production are unrisked. For the purpose of these tables, a risk factor of 50% has been applied to the probable additional reserves and cash flows to determine the "Total After Risk" estimates.

(3) **"Proved Reserves"** are those reserves estimated as recoverable under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economical and technically successful in the subject reservoir.

(a) **"Proved Developed Producing Reserves"** are those developed reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reason. An illustration of such a situation is where a well or zone is capable or production but is shut in because its deliverability is not required to meet contract commitments.

(b) **"Proved Developed Non-Producing Reserves"** are those developed reserves that are not currently producing due to lack of facilities and/or markets.

(c) **"Proved Undeveloped Reserves"** are proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreages are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled.

(4) **"Probable Additional Reserves"** are those reserves where the analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(5) Price Forecast

GILBERT LAUSTSEN JUNG ASSOCIATES LTD. PRICE FORECAST
EFFECTIVE DATE JANUARY 1, 2003

Natural Gas Prices

YEAR	AECO-C Spot (Cdn$/mmbtu)
2003	5.65
2004	5.00
2005	4.70
2006	4.85
2007	4.85
2008	4.85
2009	4.85
2010	4.90
2011	4.95
2012	5.05
2013	5.10

After 2013 prices were increased 1.5 percent per year.

Oil Prices

YEAR	WTI @ Cushing	Edmonton – 40 API	Cromer – 29 API	Bow River at Hardisty
2003	25.50	38.50	33.00	29.50
2004	22.00	32.50	29.00	25.50
2005	21.00	30.50	27.00	24.50
2006	21.00	30.50	27.50	25.00
2007	21.25	30.50	27.50	25.00
2008	21.75	31.00	28.00	25.50
2009	22.00	31.50	28.50	26.00
2010	22.25	32.00	29.00	26.50
2011	22.50	32.50	29.50	27.00
2012	23.00	33.00	30.00	27.50
2013	23.25	33.50	30.50	28.00

After 2013, prices were increased 1.5 percent per year.

(6) Product prices in the constant price evaluations are based on actual prices received for oil, natural gas liquids and natural gas at December 31, 2002.

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the effective date of the GLJ Report. In addition, operating and capital costs have not been increased on an inflationary basis.

(7) ARTC varies from a maximum of 75% of $2.0 million when the oil price is below US $15 per barrel to a minimum of 25% of $2.0 million when the oil price is above US$30 per barrel. For the cash flow projection, the ARTC program was assumed to stay in place for a period of 10 years.

(8) GLJ estimates the total capital costs net to Petrobank to achieve the estimated future net proved and probable production revenues set out in the GLJ Report, based on escalating cost assumptions, to be $22.6 million (discounted at 10%) for Canada and US $27.3 million (discounted at 10%) for Colombia.

GLJ estimates the total capital costs net to Petrobank to achieve the estimated future net proved and probable production revenues set out in the GLJ Report, based on constant cost assumptions, to be $22.5 million (discounted at 10%) for Canada and US $27.0 million (discounted at 10%) for Colombia.

(9) Cash flow is income derived from the sale of net reserves, less all capital costs, production taxes, and operating costs and before provision for future abandonment costs, income taxes and administrative overhead costs.

RECONCILIATION OF RESERVES

A reconciliation of the Company's Canadian oil and natural gas reserves for the two-year period ended December 31, 2002 is set out below. All Colombian reserves as at December 31, 2002 were added during 2002.

CANADA

	Gross				
Crude Oil (Mbbls)	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	-	-	-	-	-
Discoveries	344	-	344	63	407
Acquisitions	4,658	795	5,453	1,116	6,569
Dispositions	1,397	(434)	963	(177)	786
Revisions of prior estimates	(1,527)	(54)	(1,581)	(150)	(1,731)
Production	(833)	-	(833)	-	(833)
January 1, 2002	4,039	307	4,346	852	5,198
Discoveries	440	1,368	1,808	1,322	3,130
Acquisitions	777	115	892	356	1,248
Dispositions	(23)	-	(23)	(18)	(41)
Revisions of prior estimates	273	(157)	115	(59)	56
Production	(853)	-	(853)	-	(853)
January 1, 2003	4,653	1,632	6,285	2,453	8,738

Natural Gas (Bcf)	Gross				
	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	0.3	1.4	1.7	0.6	2.2
Discoveries	2.3	0.3	2.7	0.1	2.8
Acquisitions	27.8	28.5	56.2	11.9	68.2
Dispositions	6.1	(4.5)	1.6	(4.1)	(2.5)
Revisions of prior estimates	(12.0)	(21.1)	(33.1)	(2.0)	(35.1)
Production	(4.0)	-	(4.0)	-	(4.0)
January 1, 2002	20.4	4.6	25.0	6.5	31.5
Discoveries	1.6	1.7	3.3	2.2	5.5
Acquisitions	0.7	0.2	0.9	0.4	1.3
Dispositions	(0.6)	(0.6)	(1.2)	(0.2)	(1.4)
Revisions of prior estimates	(0.4)	(1.4)	(1.8)	(1.5)	(3.3)
Production	(5.3)	-	(5.3)	-	(5.3)
January 1, 2003	16.4	4.5	20.9	7.4	28.3

NGL's (Mbbls)	Gross				
	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	-	1	1	-	1
Discoveries	165	2	167	1	168
Acquisitions	477	611	1,088	144	1,232
Dispositions	29	(91)	(62)	(41)	(103)
Revisions of prior estimates	(355)	(466)	(821)	(66)	(887)
Production	(72)	-	(72)	-	(72)
January 1, 2002	244	57	301	38	339
Discoveries	18	(2)	16	3	19
Acquisitions	8	14	22	8	30
Dispositions	-	-	-	-	-
Revisions of prior estimates	1	(34)	(33)	(7)	(40)
Production	(104)	-	(104)	-	(104)
January 1, 2003	167	35	202	42	244

DRILLING ACTIVITY

The following table summarizes the Company's drilling results for the years ended December 31, 2002 and 2001.

	Year ended December 31,			
	2002		2001	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil				
Canada	18	14.6	16	12.4
Colombia	2	1.6	-	-
Natural Gas	7	6.0	10	6.5
Dry & Abandoned	13	13.0	3	3.0
Total	40	35.2	29	21.9

Notes:

(1) "Gross" wells refers to all wells in which the Company has either a working interest or a royalty interest.

(2) "Net" wells refers to the aggregate of the percentage working interests of the Company in the gross wells, and, in some cases, subject to adjustment after payout.

HISTORY

The following table shows the Company's average working interest production volumes before deduction of royalties payable to others, average netbacks received and oil and gas capital expenditures incurred for each of the last eight fiscal quarters and the years then ended:

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Production					
Oil and Natural Gas Liquids (bbl/d)	2,704	2,541	2,596	2,652	2,623
Gas (mcf/d)	17,323	16,546	13,134	11,244	14,541
Total (boe/d)	5,591	5,299	4,785	4,526	5,047

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Production					
Oil and Natural Gas Liquids (bbl/d)	271	3,297	2,978	3,322	2,480
Gas (mcf/d)	5,583	16,198	9,143	12,730	11,047
Total (boe/d)	1,202	5,997	4,502	5,444	4,321

Crude Oil and NGL Netback ($ per bbl)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Sales revenue (1)	29.48	30.98	32.74	31.27	31.11
Royalties (2)	5.34	6.82	7.39	7.20	6.68
Operating costs (3)	5.73	5.51	6.24	7.32	6.21
Netback	18.41	18.65	19.11	16.75	18.22

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Sales revenue (1)	36.66	32.05	32.18	19.96	28.09
Royalties (2)	5.62	5.66	5.85	2.94	4.79
Operating costs (3)	5.11	8.22	6.81	5.58	6.81
Netback	25.93	18.17	19.52	11.44	16.49

Natural Gas Netbacks ($ per mcf)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Sales revenue (1)	3.21	3.99	3.63	5.09	3.89
Royalties (2)	0.70	0.88	0.71	1.03	0.82
Operating costs (3)	1.14	1.15	1.15	1.40	1.20
Netback	1.37	1.96	1.77	2.66	1.87

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Sales revenue (1)	8.95	6.11	4.63	2.81	5.13
Royalties (2)	1.91	0.79	0.90	0.56	0.88
Operating costs (3)	0.51	1.18	0.92	1.19	1.03
Netback	6.53	4.14	2.81	1.06	3.22

Notes:

(1) After reduction for hedging costs.

(2) After inclusion of ARTC.

(3) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Oil and Gas Capital Expenditures ($000's)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Land	214	2,345	379	2,904	5,842
Seismic	(269)	(27)	549	516	769
Drill and complete	5,507	1,845	2,419	19,118	28,889
Facilities and equipment	585	391	314	365	1,655
Property acquisitions	-	-	1,336	4,791	6,127
Other	876	328	816	926	2,946
	6,913	4,882	5,813	28,620	46,228

Capital expenditures in 2002 include $15.6 million of expenditures in Colombia, which are detailed on page 37 of the Annual Report which information is incorporated herein by reference.

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Land	640	2,191	1,049	1,835	5,715
Seismic	39	29	49	2,117	2,234
Drill and complete	186	4,962	1,886	2,329	9,363
Facilities and equipment	364	1,848	1,175	312	3,699
Other	138	188	260	262	848
	1,367	9,218	4,419	6,855	21,859

FUTURE COMMITMENTS

At December 31, 2002, the Company had in place contracts for the following:

Product	Period	Volume	Fixed Price	Index
Crude Oil	Calendar 2003	1,000 bbl/day	US $22.70	WTI
	Calendar 2003	500 bbl/day	US $25.90	WTI
	Calendar 2004	1,000 bbl/day	US $24.00	WTI

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract that expires October 31, 2012. The wellhead price under this contract, at December 31, 2002, was set at $3.14 per GJ. The contract provides for an annual price escalation between 4 percent and 10 percent, based on hydroelectric and natural gas price inflation. Broader price redeterminations are to be made in 2007 and 2012, resulting in a new price that can vary from 65 percent to 135 percent of the previous year’s price based on prevailing natural gas prices.

The Company is also committed to natural gas deliveries of 5,275 GJ per day at the Malin, Oregon delivery point until October 31, 2005. In connection with this commitment, the Company holds an equivalent amount of firm transportation service on the ANG and PGT pipeline systems at a cost of $0.52 per GJ. The Company receives the market price at the delivery point, less the relevant transportation charges.

See Note 15 to Financial Statements on pages 59 and 60 of the Annual Report which information is incorporated herein by reference.

EXPLORATION AND DEVELOPMENT

Exploration and development plans are discussed under the headings “Principal Properties” on pages 4 through 7 and “Management Discussion and Analysis” on pages 28 through 40 of the Annual Report which information is incorporated herein by reference. Petrobank’s current capital budget contemplates spending $40 million in Canada and US $45 million in Colombia in 2003.

DIRECTORS AND OFFICERS OF PETROBANK

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Petrobank are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Kevin L. Adair Calgary, Alberta, Canada	Vice President Latin America	Vice President of Latin America since November 2002. Vice President Business Development and Marketing of the Company from March 2000 to October 2002; President and Chief Operating Officer of the Company from April 1998 to March 2000; Executive Vice-President and Chief Operating Officer of the Company from December 1997 to March 1998.
Chris J. Bloomer Calgary, Alberta, Canada	Vice President Heavy Oil	Vice President Heavy Oil since January 2003, Managing Director of Korn/Ferry International (Calgary) from May 1999 to December 2002, President and Chief Operating Officer of Canadian TALON Resources, Ltd. from August 1997 to May 1999.
John A. Brussa (1)/(3) Calgary, Alberta, Canada	Director	Director of the Company since March 2000; Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP since 1987. Director of several public companies.
M. Bruce Chernoff (1)/(2)/(3) Calgary, Alberta, Canada	Director	Director of the Company since March 2000; President and Director of Caribou Capital Corp. ("Caribou"), a private investment company, since June 1999; Chairman of Harvest Energy Corp. since July 2002; Executive Vice-President and Chief Financial Officer of the Company from March 2000 to October 2001; Executive Vice-President and Chief Financial Officer of Pacalta Resources Ltd. from February 1999 to May 1999; Executive Vice-President of Pacalta from March 1997 to January 1999. Director of several public companies.
Louis L. Frank North Woodstock, New Hampshire, U.S.A.	Director	Director of the Company since September 1993; Independent Consultant; Director and founder of Loon Mountain Recreation Corp.; President of Recco Inc., a private oil and gas development and real estate development company.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Garry Hides Calgary, Alberta, Canada	Vice President Land	Vice President Land of Petrobank since October 2001; Manager Land of the Company from November 1997 to September 2001.
Rene Laprade Calgary, Alberta, Canada	Vice President Operations	Vice President Operations of the Company since October 2001; Manager Operations of Barrington from May 2001 to September 2001; Independent Consultant from May 2000 to May 2001, Vice President Operations of Petrorep Resources from June 1995 to May 2000.
Ken C. McCagherty Calgary, Alberta, Canada	Director	President of West Energy Limited Ltd. (a private oil and gas company) since January 2003. Director of the Company since October 2001. Senior Vice President and Chief Operating Officer of the Company from October 2001 to November 2002; Vice-President and Chief Operating Officer of the Company from March 2000 to October 2001. Vice-President and Director of Caribou from June 1999 to December 2001; Director, Special Projects of Pacalta Resources Ltd. from October 1998 to May 1999; Engineering Consultant from October 1997 to September 1998.
Kenneth R. McKinnon Calgary, Alberta, Canada	Corporate Secretary and Director	Director of the Company since March 2000 and Corporate Secretary of the Company since November 1997; Chief Corporate Affairs Officer and General Counsel of Critical Mass Inc. since September 2000; Vice President, Finance and Chief Financial Officer of the Company from November 1997 to March 2000.
Jerald L. Oaks (1)/(2) Englewood, Colorado, U.S.A.	Director	Director of the Company since September 1993; Professional Engineer, President of Oaks Resources Management Inc. since June 1986.
David J. Rain Calgary, Alberta, Canada	Vice President Finance and Chief Financial Officer	Vice President Finance and CFO of the Company since October 2001; Director, Corporate Finance of the Company from March 2000 to October 2001. Vice President, Finance and CFO of Caribou since June 1999; Treasurer and Corporate Controller of Pacalta Resources Ltd. from May 1997 to May 1999.
Doreen Scheidt Calgary, Alberta, Canada	Corporate Controller	Corporate Controller of the Company since December 2001; Manager, Operations Accounting of Northstar Energy Company, formerly Morrison Petroleums Ltd., from November 1994 to November 2001.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
R. Gregg Smith Calgary, Alberta, Canada	Vice President Canada	Vice President Canada since March 2003, various positions at Hunt Oil Company of Canada Ltd. including Exploration Manager, Senior Geophysicist and Exploration Team Leader from July 2000 to August 2002, Senior Geophysicist of Newport Petroleum Ltd. from July 1998 to July 2000, Senior Geophysicist of Pinnacle Resources Ltd. from August 1997 to July 1998.
James D. Tocher [(2)/(3)] Calgary, Alberta, Canada	Chairman of the Board	Chairman of the Board of the Company since September 1993; Chief Executive Officer from September 1993 to March 2000; Chairman of the Board of VX Optronics Corp., (a private technology company), since March 1989.
John D. Wright Calgary, Alberta, Canada	President, Chief Executive Officer and Director	President, Chief Executive Officer and Director of the Company since March 2000; General Manager of Ecuadorian Operations of Alberta Energy Company from May 1999 to December 1999; President and CEO of Pacalta Resources Ltd. from May 1996 to May 1999. Director of two other public companies.

Notes:
(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee

The term of office of each director expires at the next annual meeting of shareholders.

As at April 21, 2003, the directors and senior officers of Petrobank, as a group, beneficially owned, directly or indirectly, 13,518,435 Common Shares constituting approximately 29.7% of the issued and outstanding Common Shares.

PERSONNEL

As at December 31, 2002, Petrobank had 37 employees in Canada and 19 in Colombia.

DIVIDEND RECORD

Petrobank has not declared or paid any dividends on its Common Shares since its incorporation, and does not foresee the declaration or payment of any dividends on the Common Shares in the near future. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of Petrobank's earnings, financial requirements and other conditions existing at such future time. Pursuant to the terms of the loan agreement with its current banker, the Company cannot declare or pay dividends on its Common Shares without obtaining the bank's consent.

MARKET FOR SECURITIES

The Company's outstanding Common Shares and Subordinated Notes are listed and posted for trading on the TSX under the trading symbols "PBG" and "PBG.N", respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the headings "Management's Discussion and Analysis" contained on pages 28 through 40 and "Quarterly Summary" contained on pages 62 and 63 of Petrobank's Annual Report for the year ended December 31, 2002, which information is incorporated herein by reference.

SELECTED FINANCIAL INFORMATION

The following table sets forth selected financial information of the Company for the three years ended December 31, 2002. Amounts are expressed in thousands of dollars, except for share amounts.

	Year Ended December 31		
	2002	2001	2000
Oil and natural gas revenue	50,458	46,117	46,392
Cash flow from operations (1)	22,806	18,549	25,281
Per share – basic $ (2)	0.45	0.46	0.74
Per share – diluted $	0.40	0.39	0.62
Net income	6,191	5,283	9,826
Net income (loss) attributable to common shareholders	(430)	431	9,218
Per share – basic $	(0.01)	0.01	0.27
Per share – diluted $	(0.01)	0.01	0.23
Capital expenditures	46,228	21,859	34,921
Working capital (deficiency)	(5,151)	25,410	(2,523)
Net debt (3)	62,495	31,266	22,868
Total assets	150,618	146,337	112,410

Notes:

(1) Calculated based on cash flow from operations before changes in other non-cash items.

(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes and adding back $1.5 million of non-recurring well control costs in 2001.

(3) Includes working capital, long-term debt, and subordinated notes that are reflected as equity on the balance sheet.

INDUSTRY CONDITIONS

Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Petrobank does not expect that any of these controls or regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size.

Crude oil and natural gas located in Alberta, Saskatchewan and British Columbia are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is privately owned and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions.

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of oil other than heavy oil, and not exceeding two years in the case of heavy oil, so long as an order approving any such export has been obtained from the National Energy Board. Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the National Energy Board and the issue of a license requires the approval of the Canadian federal government. The term of the license may not exceed 25 years.

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the Government of Canada through the National Energy Board. Producers and exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet criteria prescribed by the National Energy Board. Natural gas exports for a term of two years or less, or for 2 to 20 years in quantities not more than 1.1 million cubic feet per day may be made under a National Energy Board order, or, in the case of exports for a longer duration or larger volumes, under a National Energy Board license and Canadian federal government approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the removal of natural gas from those provinces for consumption elsewhere. They do so based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate deduction and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the government by virtue of the ARTC program. The ARTC program is based on a price sensitive formula, and ranges between 75%, for prices for oil at or below $100 per cubic meter ($15.90 per barrel), to 25%, for prices above $210 per cubic meter ($33.39 per barrel). In general, the ARTC rate is applied to a maximum of $2,000,000 of government royalties payable for each producer or associated group of producers. Government royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);

- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports); or

- disrupt normal channels of supply.

All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental

The oil and natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with oil and gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to prevent pollution from former operations. Also, environmental laws may impose upon "responsible persons" remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. A breach of environmental laws may result in the imposition of fines and penalties, in addition to the costs of abandonment and reclamation.

All applicable environmental laws are consolidated in the *Environmental Protection and Enhancement Act*. Under this Act, environmental standards and requirements that apply to compliance, cleanup and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental increase in the cost of conducting oil and natural gas operations in Alberta.

Petrobank is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Petrobank believes that it is in material compliance with environmental laws and regulations applicable as at the date hereof.

In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on Petrobank cannot be determined at this time.

Colombia

The Company is the owner of interests in, and is engaged in the exploration for, and development and production of oil from two incremental production contracts (Orito and Neiva) and three exploration contracts granted by Empresa Colombiana de Petroleos ("Ecopetrol"), the Colombian national oil company. Each concession is governed by a separate contract with Ecopetrol. Generally, the contracts cover a specific period and require certain expenditures in the early years of the contract in order to advance to subsequent development phases. The Company's current activities are currently focused on its incremental production contracts which provide that the Company is permitted to carry out development activities on the blocks and share in incremental production generated above a predefined baseline. The Company's initial participation levels at Orito and Neiva are 79% and 69%, respectively. These participation levels decline on a contract by contract basis once the ratio of cumulative total revenues to total costs (R factor) exceeds 1.5 times. At R factors above 2.5 times the participation levels at Orito and Neiva are fixed at 39.5% and 34.5%, respectively.

Royalties are calculated on a field-by-field basis using a sliding scale that ranges from 8% (for production up to 5,000 barrels per day) up to a maximum of 25% (for production above 600,000 barrels per day).

The Company's oil production is currently being sold pursuant to a sales contract with Ecopetrol whereby the price paid, adjusted for quality differences, for each barrel of oil sold is determined based on the monthly average of WTI less a variable differential as follows:

Average WTI (US$/bbl)	Differential (US$/bbl)	
	Orito	Neiva
$15 or less	$3.60	$6.30
$15.01 to $20.00	$4.10	$7.30
$20.01 to $25.00	$4.60	$8.30
$25.01 to $30.00	$5.60	$8.80
Over $30	$6.60	$9.30

The Company or Ecopetrol may cancel this sales contract on one month's notice after which, the Company may elect to export its oil production directly.

Development plans are submitted to Ecopetrol for approval for all exploration and development activities conducted on the Company's Colombian properties. In addition, the Company files an environmental management plan (PMA) covering the contemplated activities with the Ministry of the Environment. PMA's are submitted to demonstrate compliance with applicable Colombian law but advance approval is not required to commence activities within existing development areas (Orito and Neiva). In exploration areas an approved PMA is required before work commences.

The Company's pretax income from Colombian sources, as defined under Colombian law, is subject to Colombian income taxes at a statutory rate of 38.5%, although a "presumptive" minimum income tax based on net assets, may apply in years of little or no net income which may be recovered against future cash taxes otherwise payable. The Company's income after Colombian income taxes is subject to a Colombian remittance tax that accrues at a rate of 7%, which may be eliminated under certain circumstances if the Company reinvests such income in Colombia.

RISK FACTORS

An investment in Petrobank may be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Petrobank's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Petrobank competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Petrobank also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Petrobank also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for Petrobank.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of Petrobank. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time to time. See "Industry Conditions". Petrobank's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. See "Industry Conditions - Environmental Regulation".

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Petrobank's net production revenue and overall value and could result in ceiling test writedowns. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Petrobank's reserves. Petrobank might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petrobank's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Company are in part determined by the borrowing base of the Company. A substantial material decline in prices from historical average prices could further reduce the Company's borrowing base, therefore reducing the bank credit available to the Company and possibly require that a portion of the Company's bank debt be repaid.

The Company uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from the Company's proved oil and natural gas reserves, those excess costs would be required to be charged to operations.

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

From time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Petrobank maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Petrobank could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent Petrobank is not the operator of its oil and gas properties, Petrobank will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Petrobank which could result in a reduction of the revenue received by Petrobank.

There are numerous uncertainties inherent in estimating quantities of reserve and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated effective January 1, 2003 by GLJ. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional financing which may not be available or, if available, may not be available on favourable terms.

In addition to the risks faced by Canadian oil and gas companies, the Company is subject to risks related to its foreign operations in Colombia as a portion of the Company's business regulated by the laws and regulations of Colombia, including those related to the development, production, marketing, transportation of crude oil and natural gas, taxation and environmental and safety matters. The Company may be adversely affected by changes in governmental policies or social instability or other political or economic developments in Colombia that are outside the Company's control including among other things, expropriation, risks of war and terrorism, foreign exchange and repatriation restrictions, changing political conditions and monetary fluctuations and changing governmental policies including taxation policies.

Certain directors of Petrobank are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Please also see the information under the heading “Risks and Uncertainties” in the Annual Report on pages 38 and 39 which information is incorporated herein by reference.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular of the Company dated April 21, 2003 provided for the annual and special meeting of the shareholders of the Company to be held on May 22, 2003. Additional financial information is also provided in the Company's consolidated financial statements for the year ended December 31, 2002 which are contained in the Annual Report of the Corporation for the year ended December 31, 2002.

Upon request the Company will provide to any person:

1. One copy of this Annual Information Form together with one copy of any document, or the pertinent pages of any document incorporated by reference in the Annual Information Form;

2. One copy of the Company's consolidated financial statements contained in the Annual Report for the year ended December 31, 2002, together with the report of the auditors thereon, and one copy of any of the Company's interim financial statements subsequent to such audited consolidated financial statements;

3. One copy of the Company's Management Proxy Circular provided for the annual and special meeting of the shareholders of the Company to be held on May 22, 2003; and

4. When the Company's securities are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of the Company's securities, also upon request to the Company, one copy of any other document that is incorporated by reference in the preliminary or final short form prospectus, as the case may be.

Copies of these documents may be obtained in some cases upon payment of a reasonable charge upon request to:

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