

PETRO-REEF RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2004

APRIL 25, 2005

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
mbbls	thousand barrels
mmbbls	million barrels
mstb	1,000 stock tank barrels
bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
stb	standard tank barrels

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
mcf	billion cubic feet
GJ	gigajoule
mm	Million

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
M ³	cubic metres
mboe	1,000 barrels of oil equivalent
\$000s or M\$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf/1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;
- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems.

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

“Sproule Report” means the report of Sproule Associates Limited evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2004;

"Gross" means:

- (a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
- (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (c) in relation to properties, the total area of properties in which the Corporation has an interest.

"Petro-Reef" means the common shares in the capital of Petro-Reef Resources Ltd.

"Net" means:

- (a) in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves.
- (b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
- (c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"SAL" means Sproule Associates Limited

"NI 51-101" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2004.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks, may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND AND DEVELOPMENT OF BUSINESS

The Corporation was incorporated as 394537 Alberta Ltd. on December 12, 1988, as a wholly owned subsidiary of Devnic Energy Inc. By Certificate of Amendment, 394537 Alberta Ltd. changed to Petro-Reef Resources Ltd. effective February 23, 1989.

On December 16, 1992 the Donhuysen family and the Werner family purchased the control block of 4,588,600 common shares in the Corporation from Devnic Energy Inc. and Fortune Equity Inc. On the same date the Corporation also purchased from Devnic Energy Inc. all of its outstanding working interests in certain key parcels of land and the wells and assets thereon.

On December 16, 1992 the Corporation raised \$208,710 by two private placements at \$0.07 per share for 838,725 common shares and \$0.25 per share for 600,000 shares respectively. These shares were purchased by the principals of the Corporation and the funds raised were added to the Corporation's working capital.

On November 19, 1993 the Corporation raised \$550,000 by private placement for 2,202,000 shares at \$0.25 per share. The funds were added to the Corporation's working capital.

On September 15, 1994 a private placement consisting of 435,502 units at a price of \$1.50 per unit was closed to raise \$653,253. Each unit sold consisted of one common share and one purchase warrant exercisable to acquire one additional share by September 15, 1996 at a price of \$2.00 per common share.

Subsequently the price of the warrants were reduced to an exercise price of \$0.50 per share with 240,000 warrants exercised by the expiry date of September 15, 1996.

On a closing date of September 27, 1999 the Corporation purchased certain petroleum and natural gas property working interests and overriding royalty interests by the issuance of 3,665,868 common shares in the Corporation.

On October 9, 2001 the Corporation entered into an operating line of credit with the National Bank Of Canada with a credit facility in the form of a revolving operating demand loan with a limit of one million (\$1,000,000) dollars and a non-revolving acquisition demand loan with a maximum limit of one-half million (\$500,000) dollars.

On December 30, 2003 the operating line of credit was increased to two million (\$2,000,000) dollars with the non-revolving demand loan for acquisitions and development remaining at one-half million (\$500,000) dollars.

At December 31, 2004, there were 17,738,937 Petro-Reef shares issued and outstanding.

Unless otherwise stated, “Petro-Reef”, the “Corporation”, or the “Company” means Petro-Reef Resources Ltd. Petro-Reef’s principal office is located at 2020, 800 – 5th Avenue S.W., Calgary, Alberta, Canada, T2P 3T6.

The Petro-Reef shares trade on the TSX Venture Exchange under the symbol “PER”.

EXPLORATION AND DEVELOPMENT STRATEGY

The business plan of Petro-Reef is to create sustainable and profitable growth in the oil and gas industry in Western Canada. To accomplish this, Petro-Reef continues to pursue an integrated growth strategy through exploratory and development drilling.

Petro-Reef uses the following exploration and development criteria for each prospect area, to assure high profitability and rate of return on capital investment:

- (1) Each exploration and development prospect must exhibit:
 - a) a minimum three (3) zones each with commercial hydrocarbon potential
 - b) a minimum 10:1 profit to capital risk ratio.
 - c) a minimum thirty (30%) percent rate of return on capital invested with a payout of three (3) years or less.
 - d) a minimum economic life of 15 years.
- (2) The use of 2-D and 3-D seismic to identify and confirm low to medium risk potential drilling locations using state of the art technology developed by Petro-Reef.
- (3) An existing infrastructure where increased activity is possible.
- (4) A high degree of near term market access.

The management of Petro-Reef has experience in all areas of the Western Sedimentary Basin and has the ability to expand its scope of activity as opportunities arise. The Corporation has focused its initial prospect areas in Central Alberta immediately north and west of the City of Edmonton.

The Board of Directors of Petro-Reef may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated April 14, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is April 25, 2005.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by SAL contained in the SAL Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged SAL to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's 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 and natural gas liquid reserves may be greater than or less than the estimates provided herein.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the independent qualified reserves evaluator are attached in Appendix 1 hereto.

DISCLOSURE OF RESERVES DATA
Reserves Data (Constant Prices and Costs)
Reserves Gross and Net (Constant Prices and Costs)

Summary of Oil and Gas Reserves as of December 31, 2004 Constant Prices and Costs										
<u>Reserves</u>										
	Light and Medium Oil		Heavy Oil		Natural Gas Liquids (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserves Category	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
Proved										
Developed Producing	0.0	0.0	0.0	0.0	1,588	1,321	0	0	14.7	11.6
Developed Non-Producing	0.0	0.0	0.0	0.0	57	57	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	312	249	0	0.0	0.0	0.0
Total Proved	0.0	0.0	0.0	0.0	1,957	1,628	0	0	14.7	11.6
Probable	0.0	0.0	0.0	0.0	1,094	941	0	0	5.6	4.6
Total Proved Plus Probable	0.0	0.0	0.0	0.0	3,051	2,569	0	0	20.3	16.3

Present Value of Future Net Revenue (Constant Prices and Costs)

Summary of Net Present Values of Future Net Revenue as of December 31, 2004 Constant Prices and Costs										
	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (% / Year)					After Income Taxes Discounted at (% / Year)				
Reserves Category	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)
Proved										
Developed Producing	7,303	6,406	5,742	5,230	4,825	7,182	6,316	5,672	5,174	4,778
Developed Non-Producing	199	141	102	75	56	133	94	67	49	36
Undeveloped	980	817	697	606	535	674	576	505	450	407
Total Proved	8,482	7,364	6,540	5,911	5,416	7,989	6,986	6,244	5,674	5,222
Probable	4,365	3,336	2,718	2,304	2,007	3,036	2,308	1,888	1,614	1,422
Total Proved Plus Probable	12,848	10,699	9,257	8,215	7,423	11,025	9,294	8,132	7,288	6,644

Notes:

- 1) NPV of FNR include all resource income:
 - Sale of oil, gas, by-product reserves
 - Processing third party reserves
 - Other income

- 2) Income Taxes
 - Includes all resource income
 - Apply appropriate income tax calculations
 - Include prior tax pools

Future Net Revenue (Constant Prices and Costs)

N1 51-101 Total Future Net Revenue (Undiscounted) as of December 31, 2004 Constant Prices and Costs								
Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Proved	13,875	2,377	2,838	60	118	8,482	490	7,992
Proved Plus Probable	21,367	3,799	4,543	60	118	12,848	1,823	11,025

**By Production Group-Future Net Revenue before Income Tax
(Using Constant Prices and Costs – Using a discount rate of 10% percent).**

<p align="center">Net Present Value of Future Net Revenue By Production Group As of December 31, 2004 Constant Prices and Costs</p>		
Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% / Year) (M\$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	6,540
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	9,257

Notes:

- 1) NPV of FNR include all resource income:
 - Sale of oil, gas, by-product reserves
 - Processing third party reserves
 - Other income

- 2) Income Taxes
 - Includes all resource income
 - Apply appropriate income tax calculations
 - Include prior tax pools

Reserves Data (Forecast Prices and Costs)
Reserves Gross and Net (Forecast Prices and Costs)

**Summary of Oil and Gas Reserves
as of December 31, 2004
Forecast Prices and Costs**

Reserves										
	Light and Medium Oil		Heavy Oil		Natural Gas Liquids (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserves Category	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Gross (MMcf)	Net (MMcf)	Net (MMcf)	Net (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
Proved										
Developed Producing	0.0	0.0	0.0	0.0	1,573	1,309	0	0	14.6	11.6
Developed Non-Producing	0.0	0.0	0.0	0.0	57	57	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	312	249	0	0.0	0.0	0.0
Total Proved	0.0	0.0	0.0	0.0	1,942	1,615	0	0	14.6	11.6
Probable	0.0	0.0	0.0	0.0	1,083	928	0	0	5.5	4.5
Total Proved Plus Probable	0.0	0.0	0.0	0.0	3,025	2,543	0	0	20.1	16.1

Present Value of Future Net Revenue (Forecast Prices and Costs)

**Summary of Net Present Values of
Future Net Revenue
as of December 31, 2004
Forecast Prices and Costs**

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (% / Year)					After Income Taxes Discounted at (% / Year)				
Reserves Category	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)
Proved										
Developed Producing	6,411	5,753	5,247	4,847	4,523	6,411	5,749	5,240	4,837	4,510
Developed Non-Producing	109	78	56	41	31	109	78	56	41	31
Undeveloped	758	652	571	508	457	612	544	490	446	409
Total Proved	7,278	6,483	5,875	5,397	5,011	7,132	6,371	5,786	5,324	4,950
Probable	3,445	2,738	2,290	1,980	1,753	2,466	1,939	1,622	1,412	1,262
Total Proved Plus Probable	10,722	9,221	8,165	7,377	6,764	9,598	8,309	7,408	6,736	6,211

Future Net Revenue (Forecast Prices and Costs)

<p align="center"><u>N1 51-101</u> Total Future Net Revenue (Undiscounted) as of December 31, 2004 Forecast Prices and Costs</p>								
Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Proved Reserves	12,651	2,139	3,036	63	136	7,278	142	7,136
Proved Plus Probable	19,356	3,404	5,022	63	145	10,722	1,124	9,598

**By Production Group-Future Net Revenue before Income Tax
(Using Forecast Prices and Costs – Using a discount rate of 10 Percent)**

Net Present Value of Future Net Revenue By Production Group As of December 31, 2004 Forecast Prices and Costs		
Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% / Year) (M\$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	5,711
Proved Plus		
Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	0
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including by-products but excluding solution gas from oil wells)	8,001

PRICING ASSUMPTIONS

Constant Prices Used in Estimates

Oil:

Edmonton Par 46.51 \$/stb

Natural Gas:

Alberta AECO-C 6.78 \$/Mcf

Natural Gas By Products:

Butanes 39.78 \$/bbl

Pentanes Plus 51.80 \$/bbl

Exchange Rate

0.832 \$U.S./\$Cdn.

Forecast Prices Used in Estimates

<p align="center">Summary of Pricing and Inflation Rate Assumptions as of December 31, 2004 <u>Forecast Prices and Costs</u></p>								
	Oil							
Year	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/ bbl)	Natural Gas ¹ AECO Gas Prices (\$Cdn/MMBtu)	Pentanes Plus F.O.B Field Gate (\$Cdn/bbl)	Butanes F.O.B. Field Gate (\$Cdn/bbl)	Inflation Rate ² (%/Yr)	Exchange Rate ³ (\$US/\$Cdn)
Historical								
2001	25.94	39.06	31.56	6.23	42.46	27.93	2.0	0.646
2002	26.09	40.12	35.46	4.04	40.80	25.39	2.7	0.637
2003	31.14	43.23	37.53	6.66	44.16	34.55	2.5	0.716
2004	41.41	52.91	45.72	6.87	53.90	41.38	2.5	0.770
Forecast								
2005	44.29	51.25	44.53	6.97	52.49	38.20	2.5	0.840
2006	41.60	48.03	41.87	6.66	49.19	34.01	2.5	0.840
2007	37.09	42.64	37.27	6.21	43.67	30.20	2.5	0.840
2008	33.46	38.31	33.43	5.73	39.23	27.13	2.5	0.840
2009	31.84	36.36	31.70	5.37	37.24	25.75	1.5	0.840
Thereafter			Escalation Rates of 1.5%					

- 1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- 2) Inflation rates for forecasting prices and costs.
- 3) Exchange rates used to generate the benchmark reference prices in this table.

Notes: Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

Reconciliation of Company Net Reserves (After Royalty) By Principal Product Type as of December 31, 2004 Forecast Prices and Costs									
	Light and Medium Oil			Associated and Non-Associated Gas			Heavy Oil		
Factors	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)
December 31, 2003	15.9	11.4	27.3	1,362	1,166	2,527	5.7	7.4	13.1
Extensions	-	-	-	243	364	607	0.3	0.1	0.4
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	(14.6)	(11.4)	(26.0)	93	(602)	(509)	6.1	(3.0)	3.1
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1.3)	0	(1.3)	(84)	0	(84)	(0.5)	0	(0.5)
December 31, 2004	0	0	0	1,614	928	2,542	11.6	4.5	16.1

- (1) A reconciliation of reserves estimates may be presented using either constant prices and costs or forecast prices and costs provide that the price and cost case is indicated in the disclosure.
- (2) The numbers may not match due to rounding.
- (3) Technical revision includes reserves reclassification.

Future Net Revenue Reconciliation (Constant Prices & Costs)

For Proven Reserves Only @ 10% Discount of Net Present Value

	Oil & Non-Associated Gas Proven Only @ 10% NPV (M\$)
Starting Balance @ January 1, 2004	5,212
2004 Production	-1,453
Acquisitions	0
Discoveries ⁽¹⁾	1,056
Net Revisions ⁽²⁾	1,429
Closing Balance December 31, 2004	6,244

Note (1) Discoveries of proved reserves were assigned by the independent reserves evaluator to two (2) new wells in the Alexander Field.

Note (2) Net Revisions of \$1,429,100 were mainly due to reserve additions from the probable to proven category from 2003 to the end of December 31, 2004 as well as revisions from proved undeveloped to proven developed producing.

Additional changes were due to changes used in the Constant Price forecasts for January 1, 2004 and December 31, 2004 as follows:

	January 1, 2004 Price (\$)	December 31, 2004 Price (\$)
Oil : Edmonton Par	40.68	46.51
Natural Gas (AECO-C)	6.88	6.78
Natural Gas By Products:		
Butanes	-	39.78
Pentanes Plus	35.66	51.80
Exchange Rate	0.8191	0.8320

The difference in future development costs of proven undeveloped reserves from January 1, 2004 to December 31, 2004 is as a result of:

- a) development expenditures made during fiscal year 2004 and;
- b) change in development cost of proven undeveloped reserves as of December 31, 2004.

CHANGES IN TAX POOLS

The net change in income taxes are due to expenditures on properties during fiscal year 2004.

The changes in tax pools for fiscal year ending Dec. 31, 2004 are as follows:

	COGPE		CDE		CEE		Class 39 & 41	Class 8	Total
	Regular	Successor	Regular	Successor	Regular	Successor			
	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
Opening balance per Tax return	695,904	654,349	662,273	6,516	2,443,693	129,877	1,106,188	24,439	5,723,239
Additions for 2004	120,386	-	14,340	-	557,580	-	449,674	6,745	1,148,725
Tax pool available	816,250	654,349	676,613	6,516	3,001,273	129,877	1,555,862	31,184	6,868,150
Tax claim rate	10%	10%	30%	30%	100%	100%	25%	20%	
Current year claim	81,248	65,435	202,984	1,955	31,445	129,877	332,756	5,562	851,262
Closing balance per Tax return	731,228	588,914	473,629	4,561	2,969,828	-	1,223,106	25,622	6,091,743

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved Undeveloped Reserves

Proved Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production and meet the proved developed or proved developed producing reserves classification. Total net capital expenditures for 2005 are anticipated to be \$38,000.

Probable Undeveloped Reserves

No probable undeveloped reserves were assigned by the independent qualified reserves evaluator, therefore no capital expenditures are anticipated. All probable category reserves are probable developed. All probable developed reserves will be moved to proven developed producing by additional drilling on undeveloped off-set company owned lands during 2005 and 2006 and by reserve additions based on exponential decline analysis.

Significant Factors or Uncertainties

There are no economic factors or significant uncertainties that affect particular components of the reserves data.

Future Development Costs

Development Costs of Future Net Revenue

Proved Reserves (Constant Prices and Costs)		Proved Reserves (Forecast Prices and Costs)		Proved Plus Probable Reserves (Forecast Prices and Costs)	
Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%
\$60,000	\$51,000	\$63,000	\$52,000	\$63,000	\$52,000

Development Costs of Future Net Revenue (by year)

- a) Proved Reserves (Constant Prices and Costs)
 - 2005 \$38,000
 - 2006 0
 - 2007 0
 - 2008 0
 - 2009 0
- b) Proved Reserves (Forecast Prices and Costs)
 - 2005 \$38,000
 - 2006 0
 - 2007 0
 - 2008 0
 - 2009 0
- c) Proved Plus Probable Reserves (Forecast Prices and Costs)
 - 2005 \$38,000
 - 2006 0
 - 2007 0
 - 2008 0
 - 2009 0

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

Petro-Reef's two main properties representing 96.8% of its net present value (for proved plus probable reserves using 10% discounted values – before income taxes) are located in Central Alberta.

Producing Versus Non-Producing Reserves

Following are properties to which reserves have been attributed and are capable of producing but which are not producing as of the effective date, the percentage of those reserves to the total reserves, and the percentage of those reserves that are non-producing as of the date of this statement.

Alexander

Total Proved plus Probable Reserves (@ Dec. 31, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	3,438	1315	1118

Total Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0		0	0
Percentage of Total Reserves Non-Producing	%	%		%	%
	0	0		0	0

Total Proved plus Probable Non-Producing Reserves (@ April 01, 2005)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0		0	0
Percentage of Total Reserves Non-Producing	%	%		%	%
	0	0		0	0

* Includes solution gas

Morinville

Total Proved plus Probable Reserves

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	3,334	1671	1392

Total Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
	0	0	1329	437	349
Percentage of Total Reserves Non-Producing	%	%		%	%
	0	0		26.2%	25.1%

Total Proved plus Probable Non-Producing Reserves (@ April 01, 2005)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	0	0	0
	%	%		%	%
	0	0		0	0

* Includes solution gas

Other Properties

Other properties represent 3.2% of the total net present value (before income tax) with approximately 90% of those properties producing. The other properties are all non-operated.

Producing Versus Non-Producing Oil & Gas Wells:

Following is a list of oil and gas wells (gross and net) which are producing and non-producing. All the oil and gaswells are in Central Alberta Canada.

Production is as of the preparation date of April 01, 2005

	Oilwells		Gaswells	
	Gross	Net	Gross	Net
Producing	0	0	15	4.158
Non-Producing @ April 01, 2005	0	0	0	0

Note: Only wells which have reserves assigned by the qualified independent reserves evaluator have been reported.

Properties With No Attributed Reserves

Unproved Properties ⁽¹⁾

Location	Gross (Acres)	Net (Acres)
Alexander (Qui Barre)	10,194	3,725
Morinville	7,840	2,356
Total Unproved Properties	18,034	6,081

Note 1: Unproved Properties are those lands which have no reserves assigned by the independent reserves assigned by the independent reserves evaluator.

There are no work commitments required for fiscal year 2005.

The net area of unproved property which is expected to expire in fiscal year 2005 is 244 acres.

Forward Contracts

The Company is not bound by any agreement (including any transportation agreement) which would preclude it from fully realizing future market prices for oil or gas.

Additional Information Concerning Abandonment and Reclamation Costs.

- a) Petro-Reef estimates abandonment and reclamation cost based on historical average costs for the area net of salvage value at \$30,000 per well.
- b) Future net wells for which such costs shall be incurred are:
 - (i) For Wells where reserves are assigned equals 4.158 net wells.
 - (ii) For Wells where no reserves are assigned equals 1.7325 net wells
- c) Undiscounted cost to the Company = \$176,715 for reclamation and abandonment.
- d) The qualified independent reserves evaluator has estimated \$121,000 for abandonment and reclamation net to the Company before recovery of equipment or salvage value. Therefore \$55,715 was not deducted as abandonment and reclamation costs in estimating the future net revenue.
- e) The company expects to pay approximately \$50,000 in the next three years for reclamation and abandonment.

Tax Horizon

The Company does not expect to be required to pay income taxes for its 2005 financial year. It is anticipated that taxes will become payable for fiscal year 2006.

The changes in tax pools are as follows:

	COGPE		CDE		CEE		Class 39 & 41	Class 8	Total
	Regular	Successor	Regular	Successor	Regular	Successor			
Opening balance per Tax return	695,904	654,349	662,273	6,516	2,443,693	129,877	1,106,188	24,439	5,723,239
Additions for 2004	120,386	-	14,340	-	557,580	-	449,674	6,745	1,148,725
Tax pool available	816,250	654,349	676,613	6,516	3,001,273	129,877	1,555,862	31,184	6,868,150
Tax claim rate	10%	10%	30%	30%	100%	100%	25%	20%	
Current year claim	81,248	65,435	202,984	1,955	31,445	129,877	332,756	5,562	851,262
Closing balance per Tax return	731,228	588,914	473,629	4,561	2,969,828	-	1,223,106	25,622	6,091,743

Exploration and Development Activities

Wells for fiscal year 2004

Exploration wells 1

Development wells 1

Wells for fiscal year 2004

Gaswells 2

Oilwells 0

Dry Holes 0

Production Estimates ⁽¹⁾

Production estimates for 2005 (based on Company Interest) are: ⁽¹⁾

a) Using Constant Prices and Costs

Oil 0 Bbl
 Gas 564 MMCF
 NGL 2,900 Bbl

b) Using Forecast Prices and Costs

Proved: Oil 0 Bbl
 Gas 564 MMCF
 NGL 2,900 Bbl

Proved Plus Probable:
 Oil 0 Bbl
 Gas 672 MMCF
 NGL 2,900 Bbl

Note (1) Production estimates are based on the independent evaluators proved plus probable reserves and revenues, and do not include reserves added during fiscal year 2005 for exploration and development drilling. Assuming that the Corporation arranges for financing, the Corporation anticipates drilling eleven (11) wells before year end.

Note (2) Production estimates are taken from the evaluation by the independent reserves Evaluator and in the Companies opinion are extremely conservative as required by N1 51-101.

Of the above referenced production 96.8% is represented by two (2) properties:

- a) Morinville
- b) Alexander

2005 Pro-Forma Budget and Cash Flow

The following table represents the pro-forma budget and cash flow for 2005 as prepared by management in respect of revenues expected, less expenses (royalties, operating, interest, general and administrative and professional fees), cash flow, capital expenditures, and net cash flow for the periods indicated.

PETRO-REEF CASH FLOW AND PRO-FORMA BUDGET FOR 2005 QUARTER ENDED

	<u>March 31</u>	<u>June 30</u>	<u>Sept. 30</u>	<u>Dec. 31</u>	<u>Total</u>
Gross Crude Oil & ⁽¹⁾ Natural Gas Revenue (\$000)	875	720	1500	2700	5795
Expenses ⁽²⁾					
Royalties & Operating (\$000)	350	288	600	1080	2318
Interest (\$000)	15	18	23	15	71
General and Administrative (\$000)	<u>120</u>	<u>243</u>	<u>142</u>	<u>150</u>	<u>655</u>
Total Expenses	485	549	765	1245	3116
Cash Flow (\$000) ⁽³⁾ (before Capital)	<u>390</u>	<u>171</u>	<u>735</u>	<u>1455</u>	<u>2751</u>
Capital Cost (\$000)					
- Drilling, Completion & Tie-In	65	712	1536	1455	3768
- Re-Completion	35	50	250	300	635
- Seismic	25	130	0	0	155
- Plants, Pipelines etc.	<u>84</u>	<u>0</u>	<u>720</u>	<u>150</u>	<u>954</u>
	209	892	2506	1905	5512
Net Cash Flow (After Capital)	181	(721)	(1771)	(450)	(2761)

- Notes: 1) Due to plant shut down from May 29 to June 13 for maintenance, revenue will be reduced.
- 2) Royalties and Operating expense are estimated at 40% of gross revenue.
- 3) An assumption has been made that financing of approximately five million (\$5,000,00) will be done by the end of June 2005. These funds are anticipated to be raised through a combination of internally generated cash flow, bank financing, and an equity issue in the form of a private placement.
- 4) **The Petro-Reef Cash Flow and Pro-Forma Budget is a forward – looking statement.**

2004 PRODUCTION & REVENUE SUMMARY

Month	Production BOE / Day	Production BOE / Month	Price \$/ BOE	Royalty Expenses \$/BOE	Gross Revenue \$ After Royalties	Operating Expenses \$	Netback \$/BOE	Cash Flow \$
JAN	91.13	2,825.17	48.62	4.36	125,051.82	43,047.14	29.03	82,004.68
FEB	125.55	3,641.01	36.66	3.78	119,724.93	42,704.64	21.15	77,020.29
MAR	110.25	3,417.61	37.31	4.18	113,236.24	48,280.94	19.01	64,955.30
3 Month Average	108.98	3,294.60	40.86	4.11	119,337.66	44,677.57	23.06	74,660.09
APR	192.35	5,770.79	40.39	2.69	217,594.04	61,999.80	29.96	155,594.24
MAY	128.79	3,992.75	45.26	3.86	165,327.07	43,759.92	30.45	121,567.15
JUN	115.56	3,466.69	41.91	3.99	131,441.26	48,927.05	23.80	82,514.21
3 Month Average	145.57	4,410.08	42.52	3.51	171,454.12	51,562.26	27.07	119,891.87
JUL	119.85	3,715.14	41.03	3.68	138,739.72	37,332.76	27.30	101,406.96
AUG	125.99	3,905.77	38.32	6.06	125,980.85	80,493.17	11.65	45,487.68
SEP	275.27	8,257.77	34.04	7.62	218,130.75	58,482.77	19.33	159,647.98
3 Month Average	173.70	5,292.89	37.80	5.79	160,950.44	58,769.57	19.43	102,180.87
OCT	272.50	8,447.87	40.55	8.51	270,626.20	55,010.69	25.52	215,615.51
NOV	269.00	8,070.05	39.73	10.57	235,331.72	52,887.68	22.61	182,444.04
DEC	237.63	7,465.90	43.05	12.93	224,859.85	47,822.46	23.71	177,037.39
3 Month Average	259.71	7,994.61	41.11	10.67	243,605.92	51,906.94	23.95	191,698.98
Average for 2004	171.99	5,248.04	40.57	6.02	173,837.04	51,729.09	23.38	122,107.95
Total for 2004	-	62,936	-	-	2,086,044	620,749	-	1,465,295

* Note: Cash flow on this production and revenue summary is before ARTC, general and administrative costs, interest expense, and before income tax.

Production History

The following table summarizes certain information in respect of production, product prices received, royalties paid, operating expenses, and resulting netbacks for the periods indicated.

	<u>QUARTER ENDED</u>			
	<u>2004</u>			
	<u>Mar. 31</u>	<u>June 30</u>	<u>Sept. 30</u>	<u>Dec. 31</u>
Production per Quarter (BOE)	9,884	13,230	15,879	23,984
Average Daily Production ⁽¹⁾				
- Light & Medium Crude Oil (Bbl/day)	8.00	7.62	3.82	2.14
- Natural Gas (Mcf/day) ⁽³⁾	589	731	966	1,455
- NGLs (Bbl/day)	2.62	16.06	8.48	0
- Combined (BOE/day)	109	146	173	260
Average Price Received				
- Light & Medium Crude Oil (\$/Bbl)	43.69	46.58	47.04	43.73
- Natural Gas (\$/Mcf)	6.43	6.96	6.16	6.48
- NGLs (\$/Bbl)	41.06	41.56	49.10	54.82
- Combined (\$/BOE)	40.86	42.52	37.80	41.11
Royalties Paid				
- Light & Medium Crude Oil (\$/Bbl)	3.45	4.19	3.76	3.16
- Natural Gas (\$/Mcf)	0.70	0.60	1.15	1.73
- NGLs (\$/Bbl)	5.00	5.05	3.06	-
- Combined (\$/BOE)	4.11	3.51	5.79	10.67
Operating Expenses				
Combined (\$/BOE)	13.56	11.69	11.10	6.49
Netback Received ⁽²⁾				
Combined (\$/BOE)	23.06	27.07	19.43	23.95

Notes:

- (1) Before deduction of royalties
- (2) Netbacks are calculated by subtracting royalties and operating costs from revenues.
- (3) Natural gas production is reported as part of the combined BOE/day by converting at 6 MCF per 1 Bbl.

SELECTED FINANCIAL INFORMATION

Selected Financial Information for the Company is shown in the following table for two years with year ends of December 31.

	2004	(Restated) 2003	(Not-Restated) 2002
FINANCIAL			
Crude Oil and Natural Gas Revenue net of royalties and ARTC	\$2,162,656	\$894,261	\$643,712
Cash Flow from Operations	\$1,514,596	\$17,029	\$168,213
Net (Loss) Earnings from Operations	(\$542,087)	(\$156,741)	(\$126,498)
Net (Loss) Earnings per Share, Basic and Diluted	(\$0.03)	(\$0.01)	(\$0.01)
Capital Expenditures	\$1,148,725	\$1,557,439	\$872,447
Total Assets	\$8,691,850	\$8,174,724	\$6,686,347
Bank Loan	\$700,000	1,150,000	-
Shareholder's Equity	\$4,021,269	\$4,247,706	\$4,343,876

The following table summarizes the results of the eight most recently completed quarters.

Summary of Quarterly Results For The Last Eight Quarters				
		Oil & Gas Sales Net of Royalties And ARTC	Net Earnings (Loss)	Basic and Diluted Earnings per share
2003			(Restated)	
	Q1	\$211,493	(\$609)	\$0.00
	Q2	\$176,756	\$14,964	\$0.00
	Q3	\$119,614	(\$113,592)	\$0.00
	Q4	<u>\$386,398</u>	<u>(\$57,504)</u>	(\$0.01)
Total		\$894,261	(\$156,741)	
2004				
	Q1	\$354,288	(\$81,806)	\$0.00
	Q2	\$531,591	(\$75,371)	\$0.00
	Q3	\$499,139	\$34,086	\$0.00
	Q4	<u>\$777,638</u>	<u>(\$418,996)</u>	(\$0.03)
Total		<u>\$2,162,656</u>	<u>(\$542,087)</u>	

Note: The 2003 Q4 loss of \$156,741 includes \$94,111 of stock based compensation expense.

MANAGEMENT DISCUSSION AND ANALYSIS OF OPERATING RESULTS

Refer to Appendix 3.

DIVIDEND POLICY

Petro-Reef has not paid any dividends to-date on the issued and outstanding Petro-Reef shares. The Board of Directors of Petro-Reef will determine the timing, payment and amount of dividends, if any, that may be paid by Petro-Reef from time to time based upon, among other things, the cash flow, results of operations and financial condition of Petro-Reef, the need for funds to finance ongoing operations and other business considerations as the Board of Directors considers relevant. The Corporation's credit facility stipulates that dividends may not be paid as long as that facility remains outstanding without the consent of the Corporation's bankers.

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized by its Articles of Incorporation to issue an unlimited number of Common Shares. Each Common Share gives the holder thereof the right to notice of and to attend and to vote at all meetings of shareholders (except meetings at which only the holders of a specified class are entitled to vote). The holders of Common Shares are entitled to receive dividends, if, as and when declared by the Board of Directors of the Corporation subject to the rights of the holders of preferred shares. In the event of voluntary or involuntary liquidation, dissolution or winding-up, the remaining assets of the Corporation available for distribution will be distributed to the holders of the Common Shares, subject to the rights of holders of preferred shares. Holders of the Common Shares have no pre-emptive, redemption or conversion rights. All outstanding Common Shares are issued as fully paid and non-assessable.

MARKET FOR SECURITIES

The Petro-Reef Shares are listed and posted for trading on the TSX Venture Exchange and trade under the symbol "PER".

The following sets forth the price range and trading volume of the Petro-Reef Shares on the TSX Venture Exchange (as reported by the exchange) for the periods indicated.

	<u>Price Range (\$)</u>		
<u>2004</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
January	0.95	0.70	92,700
February	0.77	0.60	153,600
March	0.85	0.62	94,140
April	0.72	0.65	137,840
May	0.60	0.41	117,640
June	0.75	0.47	280,418
July	0.70	0.45	163,850
August	0.75	0.55	189,666
September	0.56	0.50	72,000
October	0.55	0.50	59,560
November	0.72	0.54	116,200
December	0.74	0.50	205,400
2005			
January	0.70	0.52	168,030
February	0.60	0.53	99,800
March	0.60	0.50	75,400

DIRECTORS AND OFFICERS

The following table sets forth, in respect of each officer and/or director, all positions currently held with the Corporation, present principal occupation or employment, material occupations, positions currently held and the approximate number of Common Shares of the Corporation beneficially owned directly or indirectly as of April 25, 2005. The information contained herein is based upon information furnished by the respective directors and/or officers to the Corporation. Directors and/or officers are listed in alphabetical order.

Nominee	Year first became a Director or Officer of the Corporation	Office or Position in the Corporation	Principle Occupation	Common Shares Beneficially owned Directly or Indirectly
Gary W. Coleman (1) (2) (3)	1992	Director	Owner and President of Coleman & Associates Psychotherapy Ltd., founded in April, 1984.	900,000
Jack P. Donhuysen (2) (5)	2004	Director	Founder and President of Status Engineering Associates Ltd., founded in June, 1986.	34,000
Theodore M. Donhuysen (5)	1992	Vice-President, Exploration and Production, Chief Operating Officer and Director	Vice-President, Exploration and Production, Chief Operating Officer and Director of the company since July 9, 2003; prior thereto President, Chief Executive Officer and Director of the Company since December 1992; prior thereto President of Hi-Lite Creations Ltd. a private Alberta Corporation, since January 1992; prior thereto Chief Executive Officer of Devnic Energy Ltd. a public Alberta Corporation, since August 1987; prior thereto President of Devnic Resources Ltd. a private Alberta Corporation, since December 1982; prior thereto Geological Consultant.	3,104,536 ⁽⁷⁾
R. Greg Powers QC	1994	Secretary	Greg Powers has been a Partner of Baker & McKenzie LLP since July 1, 2002 Prior to that he was Counsel to the law firm of Thackray Burgess from January 1, 2001 until July 1, 2002, a partner in the law firm of Donahue Powers Wells from March 1993 until January 1, 2001, and a partner in the law firm of Howard, Mackie for 15 years prior to January 1, 2001. He has been involved in the practice of corporate finance, securities and acquisitions, with particular emphasis on the oil and gas industry since 1970. He served on the Canadian Institute of Chartered Accountants, Full Cost Accounting Task Force, 1986 as an advisor on corporate and securities matters and is a past Director and Treasurer of the Canadian Petroleum Law Foundation. He has lectured at various seminars on corporate finance and securities matters. Greg has been a director and officer of several public and private companies.	200,000

Alan P. Hallman (3) (4)	2001	Director	President of Hallman and Associates Inc., since December 1997; prior thereto Executive Director, Alberta Growth Summit, office of the Premier, Calgary, Alberta, since October 1996; prior thereto Director of Research, Office of the Government Leader, Whitehorse, Yukon Territory, since May 1995; prior thereto Director of Community Relations, Office of the Premier, Calgary Alberta, since January 1993.	15,000
Robert N. Maertens-Poole (4)	1994	Chief Financial Officer and Director	Owner & President of Robert N. Maertens-Poole Professional Corporation, Chartered Accountants, founded in 1975.	297,000
Huba A. Sebo (1) (2) (5)	2004	Director	Mortgage Broker for Jencor Mortgage Corporation, founded in 1996.	98,500
Dennis K. Ulrich (1) (4)	2002	Director	President and co-owner of Pakowki Ranching Co. Ltd., since 1979; President and co-owner of D & K Mobile Welding Ltd., since 1985.	468,643
Joseph Werner (3)	1992	President, Chief Executive Officer & Director	President, Chief Executive Officer and Director of the Company, since July 9, 2003; prior thereto Chairman of the Board, Chief Financial Officer and Director of the Company since December 1992; prior thereto Financial Officer of Hi-Lite Creations Ltd., a private Alberta Corporation, since January 1992; prior thereto President & Chief Financial Officer of Devnic Energy Ltd. a public Alberta Corporation, since August 1987; prior thereto Geophysical Consultant for 12 years.	3,317,193 ⁽⁸⁾

As at December 31, 2004, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly, 8,434,872 Common Shares or approximately 47.55% of the issued and outstanding Common Shares.

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

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation Committee.
- (3) Member of the Corporate Governance Committee.
- (4) Member of the Executive Committee.
- (5) Member of the Reserves Committee.
- (6) All of the proposed directors have been directors of the Corporation, continuously, since the date they were first elected, except for Mr. Coleman who was a director until 1998 and again served as a director of the Corporation last year.
- (7) Theodore M. Donhuysen owns or controls, directly or indirectly, greater than 10% of the issued common shares. Northfork Energy Inc. of which Mr. Donhuysen and his wife are 50% of the shareholders holds common shares of 397,412.
- (8) Joseph Werner owns or controls, directly or indirectly, greater than 10% of the issued common shares. Orphan Holdings Inc. of which Mr. Werner and his wife are all the shareholders holds 1,317,412 common shares.
- (9) The term of office of each director expires at the next Annual Meeting of Shareholders of the Corporation.

AUDIT AND RESERVES COMMITTEE INFORMATION**Audit and Reserves Committee Mandate and Terms of Reference**

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Appendix 2. The members of the Audit Committee are Gary W. Coleman, Huba A. Sebo, and Dennis K. Ulrich.

Composition of the Audit Committee

To the extent the members of the Audit Committee are not considered to be financially literate under Multilateral Instrument 52-110, those members intend to take such courses as may be necessary to so qualify.

Pre Approval of Policies and Procedures

Both the Chairman of the Audit Committee is charged with the responsibility of approving all non-audit services before they are authorized and reporting such approvals to the committee at the next meeting.

External Auditor Service Fees**Audit Fees**

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were an estimated \$26,560 for 2004 and \$14,000 for 2003.

Audit and Related Fees

There were no aggregate fees billed in each of the last two fiscal years for assurance related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, and tax advice or tax planning were zero (0) for 2004 and \$6,250 for 2003.

All Other Fees

No fees were billed in either of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above.

HUMAN RESOURCES

Petro-Reef currently employs 4 full time employees and 4 part time consultants.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are PriceWaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

CIBC Mellon Trust Company, is the transfer agent and registrar of the Petro-Reef shares located at Suite 600, 333 – 7th Avenue S.W., Calgary, Alberta, T2P 2Z1.

LEGAL PROCEEDINGS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Corporation to be contemplated.

CORPORATE CEASE TRADE ORDERS OR BANKRUPTCIES

None of the directors or officers of the Corporation, and no shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has, within the ten years prior to the date of this Annual Information Form, been a director, officer or a promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person.

None of the directors or officers of the Corporation, and no shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has, within the ten years preceding the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or comprise with creditors or had a receiver, receiver –manager or trustee appointed to hold the assets of the individual.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of directors or executive officers of the Corporation, any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares of the Corporation, or any known associate or affiliate of such persons in any transactions within the three most recently completed financial years of the Corporation or during the current financial year which has materially affected, or would materially affect, the Corporation.

MATERIAL CONTRACTS

The Corporation has not entered into any material contracts that are not in the ordinary course of business within the most recently completed financial year.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Sproule Associates Limited, the Corporation's independent engineering evaluator. None of the principals of Sproule Associates Limited had any registers or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation, except for R. Gregory Powers QC, the Secretary of the Corporation, is a partner at Baker, McKenzie, which law firm renders legal services to the Corporation.

INDUSTRY CONDITIONS

Introduction

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry. Although it is not expected that these controls and regulations will affect the operations of Petro-Reef in a manner materially different than it would affect other oil and gas companies of a similar size, the controls and regulations should be considered carefully by investors. All current legislation is a matter of public record and Petro-Reef is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Oil

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, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of crude oil other than heavy crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold is determined by negotiation between natural gas producers, marketers and purchasers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of two years or less or for a term of between 2 and 20 years (in quantities of not more than 30,000 10³m³/d) may be made pursuant to an NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the availability of sufficient pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, pro-rationing of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade, and further provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period or in such other representative period as the parties may agree), (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export-price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives

In addition to federal regulation, 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 crude oil, sulphur, natural gas and natural gas liquids production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable

generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

From time to time the governments of Canada and the western provinces have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The Alberta government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas from Crown lands is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC program is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for oil at or below \$100 per cubic metre and 25% for prices above \$210 per cubic metre. In general, the ARTC rate is currently applied to a maximum of \$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations 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 applicable government department for the previous quarterly period. On December 22, 1997, the Alberta government announced that it would conduct a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than \$10,000 in royalties per year and non-corporate entities from qualifying from the program.

Natural gas is considered either "non-associated gas" or "associated gas". The royalty and production tax classifications of gas production ("fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas" and "old gas") are applicable to each of the two gas types. The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

Producers of oil and natural gas in British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil (whether it was produced from a pool discovered before or after October 31, 1975), whether the oil is considered incremental or produced from a well shut-in for at least 36 months immediately preceding January 1, 1998 and which resumed production on or after such date, the quantity of oil produced in a month and the value of the oil. Oil produced from pools discovered after June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production. Subject to minimum royalties described in the following sentence, the royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at

prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. In Alberta, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

The current structure for federal taxation of resource income contains the following initiatives applicable to the oil and gas industry which are being phased in over a five year period commencing in 2003:

- (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%; and
- (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. Also, the percentage of the ARTC that will be required to include in federal taxable income will be increased (also on a phased-in basis) to 100% in 2012 and beyond.

Land Tenure

Crude oil and natural gas located in the western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial and federal authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("Protocol"). The Protocol calls for Canada to reduce, during the period between 2008 and 2012, its greenhouse gas emissions to a level that is 6% below the 1990 level of such emissions in Canada. The Protocol has become legally binding as 55 countries have ratified it, covering at least 55% of the emissions addressed by the Protocol. When the Government of Canada implements the Protocol, it is expected to affect the operation of all industries in Canada, including the oil and natural gas industry. As details of implementation of this Protocol have yet to be announced, the affect on our operations cannot be determined at this time.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business. The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. The continued tight supply demand balance for natural gas is causing significant elasticity in pricing. Despite record drilling activity, a strong economy, weather, fuel switching and demand for electrical generation there still exists a tight supply causing prices to remain high.

Crude oil is influenced by the world economy and OPEC's ability to adjust supply to world demand. Recently crude oil prices have been kept high by political events causing disruptions in the supply of oil, and concern over potential supply disruptions triggered by the ongoing conflict in the Middle East. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also declines.

A second trend within the Canadian oil and gas industry is recent growth in number of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the consolidation phase the industry has just been through. Many are able to raise capital and recruit well qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that Kyoto will have on the sector. Generally during the past year the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry. The Corporation must compete with the numerous new companies and their new stories in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. Some companies will have to rely on internally generated funds to conduct their exploration and developmental programs.

A fourth trend affecting the Canadian oil and gas industry is increasing third party costs for all drilling, completion, tie-in and service activities. These cost increases reflect the record drilling levels in the industry as a result of higher commodity prices and have the effect of lengthening the payout on most capital investments.

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.

RISK FACTORS

An investment in the Common Shares is speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and 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 Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material 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 encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain noncore assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of risk. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. See "Industry Conditions." The Corporation's operations may require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects and the obtaining of such licenses and permits may delay operations of the Corporation.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases." The Corporation's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject the Corporation to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those in the *Climate Change and Emissions Management Act* (Alberta) (yet to be proclaimed), may require the reduction of emissions or emissions intensity produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of the Corporation.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. See "Industry Conditions".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The Corporation's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Corporation's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

The exchange rate between the Canadian and U.S. dollar also affects the profitability of the Corporation and the Canadian dollar has strengthened recently against the U.S. dollar.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation are in part determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation 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 Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation 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 Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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 Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation 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.

Title to Assets

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. It is the practice of the Corporation in acquiring significant oil and gas leases or interest in oil and gas leases to fully examine the title to the interest under the lease. In the case of minor acquisitions the Corporation may rely upon the judgment of oil and gas lease brokers or landmen who perform the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. The Corporation believes that this practice is widely followed in the oil and gas industry. Nevertheless, there may be title defects which affect lands comprising a portion of the Corporation's properties. To the extent title defects do exist, it is possible that the Corporation may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom, including many factors beyond the Corporation's control. The reserve and associated cash flow information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

In accordance with applicable securities laws, SAL, the independent reserves evaluator, has used both constant and forecast price and cost estimates in calculating reserve quantities included herein. Actual future net revenue will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and revenues derived therefrom will vary from the estimates contained in the SAL Report, and such variations could be material. The SAL Report is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the SAL Report will be reduced to the extent that such activities do not achieve the level of success assumed in the SAL Report. The SAL Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's resources since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although prior to drilling the Corporation will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expend, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

The Corporation's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Corporation or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Corporation's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Corporation's results of operations and business.

Uncertainty of Global Financial Markets

On September 11, 2001, the United States was the subject of terrorist attacks resulting in significant loss of life and property damage. The events of September 11, 2001 and the response of the United States and other nations have created an environment of uncertainty in global financial markets, the effect of which could have a material impact upon the Corporation, its business and its ability to finance operations.

Dividends

The Corporation does not currently pay any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its property and assets, however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations.

Conflicts of Interest

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's Information Circular - Proxy Statement for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements for the year ended December 31, 2004 and the related management's discussion and analysis for the most recently completed financial year.

The Corporation will provide to any person or corporation, upon request to the Corporation:

- (a) when the securities of the Corporation are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:
 - (i) one copy of Petro-Reef's annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated therein by reference;
 - (ii) one copy of the comparative financial statements of Petro-Reef for its most recently completed financial year in respect of which such financial statements have been issued, together with the report of the auditor thereon, and one copy of any interim financial statements of Petro-Reef subsequent to the financial statements for its most recent financial year;
 - (iii) one copy of the information circular of Petro-Reef in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that circular, as appropriate, and
 - (iv) one copy of any other document that is incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or
- (b) at any other time, a copy of the documents referred to in clauses (a)(i), (ii) or (iii) above, provided the Corporation may require a payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of Petro-Reef.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph and any other document incorporated herein by reference are available on the foregoing basis and upon request by contacting the Corporation at its offices at 2020, 800 – 5th Avenue S.W., Calgary, Alberta T2P 3T6, or by phone at (403) 265-6444, fax at (403) 264-1348 or e-mail at petroreef@shawcable.com.

APPENDIX 1
FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Petro-Reef Resources Ltd. (the “Company”) are 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 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.

An independent qualified reserves evaluator has evaluated and reviewed the Company’s reserve data.

The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

- a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator;
- b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and because of the proposal to change the independent qualified reserves evaluator to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and
- c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors 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 Reserves Committee, approved

- a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information; and
- b) the filing of the report of the independent qualified reserves evaluator 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.

"Joseph Werner"
Joseph Werner
President & C.E.O.

"Theodore M. Donhuysen"
Theodore M. Donhuysen
Vice President Exploration & Production
C.O.O.

"Robert N. Maertens-Poole"
Robert N. Maertens-Poole
C.F.O.

"Gary W. Coleman"
Gary W. Coleman
Director

"Alan P. Hallman"
Alan P. Hallman
Director

"Dennis K. Ulrich"
Dennis K. Ulrich
Director

"Jack P. Donhuysen"
Jack P. Donhuysen
Director

"Huba A. Sebo"
Huba A. Sebo
Director

CONSENT RESOLUTONS OF THE RESERVES AUDIT COMMITTEE

OF

**PETRO-REEF RESOURCES LTD.
(the "Company")**

We, the undersigned, being all the members of the reserves audit committee of the Company, hereby consent to and approve in writing the following resolutions as of the 11 day of April, 2005.

APPROVAL OF RESERVES REPORT

WHEREAS the reserves audit committee has been provided with the 2005 P&NG Reserves Report dated December 31, 2004, prepared by Sproule Associates Limited.

AND WHEREAS the committee has reviewed the report and has found its conclusions to be acceptable.

BE IT RESOLVED that:

1. The P&NG Reserves Report dated December 31, 2004, prepared by Sproule Associates Limited (the "Report"), be and the same is hereby accepted; and
2. The reserves audit committee recommends to the Board of Directors of the Company that the Report be approved.

EXECUTION IN COUNTERPARTS

BE IT RESOLVED that these resolutions may be signed by the members of the reserves audit committee in as many counterparts as may be necessary, each of which so signed shall be deemed to be an original and such counterparts together shall constitute one and the same instrument.

"Jack P. Donhuysen"
JACK P. DONHUYSEN

"Ted M. Donhuysen"
TED M. DONHUYSEN

"Huba A. Sebo"
HUBA A. SEBO

FORM 51-101F2

**REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR**

Report on Reserves Data

To the board of directors of Petro-Reef Resources (the "Company"):

1. We have evaluated of the Company's Reserves data as at December 31, 2004. The Reserves data 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.
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 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 audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location Of Reserves (Country)	Net Present Value of Future Net Revenue (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Petro-Reef Resources Ltd., as of December 31, 2004, Prepared February to March 2005.	Canada				
Total			Nil	8,165	Nil	8,165

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 this evaluation for events and circumstances occurring after the preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
 Calgary, Alberta
 April 4, 2005

Reza M. Saedi, P. Eng.,
 Project Leader and
 Senior Petroleum Engineer

Michael W. Maughan, C.P.G., P. Geol.
 Manager, Geoscience, and Associate

Ken H. Crowther, P. Eng. President

APPENDIX 2

AUDIT AND RESERVES COMMITTEE MANDATE AND TERMS OF REFERENCE

PURPOSE

The purpose of the Audit and Reserves Committees (the "Committees") is to assist the board of directors (the "Board") of the Corporation in fulfilling its oversight responsibility by generally:

- (i) reviewing financial information provided to the Corporation's shareholders, the financial control system which management has established and the audit process;
- (ii) reviewing estimates of the oil, natural gas and natural gas liquids reserves of the Corporation prepared by management and by any independent consultants; and
- (iii) assuring the external auditor's and independent consulting engineer's independence.

COMPOSITION

1. Each Committee shall be composed of a minimum of three external directors, which may include the non-executive Chairman.
2. The members of the Committee shall be appointed or re-appointed at the meeting of the Board immediately following each annual meeting of the shareholders of the Corporation. Each member of the Committee shall continue to be a member thereof until his successor is appointed, unless he shall resign or be removed by the Board or he shall otherwise cease to be a director of the Corporation. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and shall be filled by the Board if the membership of the Committee is less than three directors as a result of the vacancy.
3. The Board or, in the event of its failure to do so, the members of the Committee, shall appoint a chairman (the "Chairman") from among their number. If the Chairman of the Committee is not present at any meeting of the Committee, the Chairman of the meeting shall be chosen by the Committee from among the members present.

MEETINGS AND MINUTES

1. The time and place of meetings of the Committee and the procedure at such meetings shall be determined from time to time by the members thereof, subject to the following: (a) The Committee shall meet at least four times per year. The meetings shall be scheduled to permit timely review of the interim and annual financial statements and the annual independent engineering reports on the Corporation's reserves. Additional meetings will be held as deemed necessary by the Chairman of the Committee or as requested by any member, the President, the Chief Financial Officer or by the external auditors.

- (b) A quorum for a meeting shall be a majority of the Committee members, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to and hear each other.
 - (c) Notice of the time and place of every meeting shall be given to each member not less than 24 hours before the time of the meeting, provided that meetings may be held without formal notice if all of the members are present and do not object to notice not having been given or if those absent waive notice in any manner before or after the meeting. Notices of meetings may be given verbally or in writing or by electronic communication and need not be accompanied by an agenda or any other material.
 - (d) The external auditor shall be given notice of, and shall be entitled to attend, each meeting of the Committee which deals with financial statements or financial controls.
 - (e) The Audit Committee shall at all times have the right to determine who shall and shall not be present at any part of the meetings of the Committee, and shall regularly meet with the external auditor without management present.
2. At each meeting, the Committee shall designate a Secretary for the meeting who may be a member of the Committee, an officer or employee of the Corporation or any other person considered appropriate by the Committee. All deliberations, recommendations and decisions of the Committee shall be recorded by the Secretary in the minutes of the meetings of the Committee. A verbal report on such meeting shall be made by the Chairman of the Committee to the Board at the next Board meeting and the minutes of such meeting shall be circulated to the Committee and the Board prior to the next following Committee and Board meetings, respectively.

ROLE AND RESPONSIBILITIES

The Committee shall have the following functions, duties and responsibilities:

- A. Audit Matters – Audit Committee**
 - 1. Review the annual financial statements with management and the external auditor prior to their submission to the Board for approval and issuance of the external auditor’s opinion.
 - 2. Review annually the results of the external auditor's audit of the Corporation's financial statements, and their management letter, and report to the Board any matter remaining unresolved and generally be responsible for overseeing the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting.
 - 3. Review annually the results of the external auditor's procedures relating to the state of the Corporation's internal control systems and report to the Board the results of the review.
 - 4. Review, making specific inquiry regarding payment of taxes and employee remittances, the unaudited quarterly financial statements with management and approve the same.
 - 5. Review, prior to issuance, the press release and shareholders' report prepared to accompany the quarterly financial statements.

6. Review, prior to issue or review by the Board, all continuous disclosure and other documents of the Corporation that include financial statements either directly or incorporated by reference.
7. Annually review senior management's expense claims.
8. Review the quality of service and performance of the external auditor and recommend annually to the Board the appointment or reappointment of an external auditor.
9. Review annually external audit fees.
10. Review annually and report to the Board on the insurable risks and insurance coverages of the Corporation.
11. Review annually and report to the Board on outstanding litigation, claims or other contingencies, including tax assessments which could have a material effect.
12. Review any non-audit related services provided by the external auditor and the fees related thereto and assess the impact of such non-audit related services on the independence of the external auditors.
13. Receive annually a report of management as to its internal control processes.
14. Review and pre-approve any non-audit services to be provided by the external auditors and consider the impact on the independence of such auditors and in connection therewith the Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member reports to the Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Committee from time to time in connection therewith.
15. Ensure that adequate procedures are in place for review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements and periodically assess the adequacy of such procedures.
16. Establish a procedure for:
 - (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and
 - (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
17. Review and approve the Corporation's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of the Corporation. All employees of the Corporation are to cooperate as requested by the Committee.

B. Reserve Matters – Reserves Committee

The Committee is responsible for:

1. reviewing the Corporation's procedures relating to the disclosure of information with respect to oil and gas activities including reviewing its procedures for complying with its disclosure requirements and restrictions set forth under applicable securities requirements;
2. reviewing the Corporation's procedures for providing information to the independent evaluator;
3. meeting, as considered necessary, with management and the independent evaluator to determine whether any restrictions placed by management affect the ability of the evaluator to report without reservation on the Reserves Data (as defined in NI 51-101) (the "Reserves Data") and to review the Reserves Data and the report of the independent evaluator thereon (if such report is provided);
4. reviewing the appointment of the independent evaluator and, in the case of any proposed change to such independent evaluator, determining the reason therefore and whether there have been any disputes with management;
5. providing a recommendation to the Board of Directors as to whether to approve the content or filing of the statement of the Reserves Data and other information that may be prescribed by applicable securities requirements including any reports of the independent engineer and of management in connection therewith;
6. reviewing the Corporation's procedures for reporting other information associated with oil and gas producing activities; and
7. generally reviewing all matters relating to the preparation and public disclosure of estimates of the Corporation's reserves.

APPENDIX 3

PETRO-REEF RESOURCES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Contents:	Page
Management's Discussion and Analysis	1
Reserves Report	19
Financial Statements with Notes	39

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the audited financial statements and notes, contained in the annual report for 2004 and is based on information available to April 25, 2005.

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit	Mbbls	thousands of barrels
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mcf/d	thousand cubic feet per day
Bcf	billion cubic feet	MMbbls	millions of barrels
BOE	barrel of oil equivalent (1 BOE = 6 Mcf)	MMcf	million cubic feet
Bopd	Barrels of oil per day	MMcf/d	million cubic feet per day
GJ	Gigajoule	FNR	future net revenue
GJs/d	Gigajoules per day	NGL	natural gas liquids
		NPV	net present value

NOTE:

In this report all currency values are in Canadian Dollars.

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements that involve substantial known and unknown risks and uncertainties, certain of which are beyond Petro-Reef's control, including: the impact of general economic conditions in Canada, the United States and worldwide; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations of companies with respect to announced transactions and final valuations thereof; and obtaining required approvals of regulatory authorities.

Petro-Reef's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits, including the amount of proceeds, that Petro-Reef will derive therefrom.

**PETRO-REEF RESOURCES LTD.
CORPORATE INFORMATION**

DIRECTORS AND OFFICERS

Joseph Werner ⁽³⁾
Chief Executive Officer
President & Director
Calgary, Alberta

Theodore M. Donhuysen ⁽⁵⁾
Vice-President Exploration and Production
Chief Operating Officer & Director
Calgary, Alberta

Robert N. Maertens-Poole ⁽⁴⁾
Chief Financial Officer
Treasurer and Director
Calgary, Alberta

Alan P. Hallman ^{(3) (4)}
Director
Calgary, Alberta

Dennis K. Ulrich ^{(1) (4)}
Director
Medicine Hat, Alberta

Gary W. Coleman ^{(1) (2) (3)}
Director
Calgary, Alberta

Jack P. Donhuysen ^{(2) (5)}
Director
Calgary, Alberta
Committee.

Huba A. Sebo ^{(1) (2) (5)}
Director
Calgary, Alberta

R. Greg Powers ⁽⁶⁾
Corporate Secretary
Legal Counsel
Calgary, Alberta

Head Office
2020 800 – 5th Avenue S.W.
Calgary, Alberta, Canada T2P 3T6
Telephone: (403) 265-6444
Facsimile: (403) 264-1348
E-Mail: petroreef@shawcable.com

Auditors
PricewaterhouseCoopers LLP
Chartered Accountants
3100 111 5th Avenue S.W.
Calgary, Alberta T2P 5L3

Bank
National Bank of Canada
301 6th Avenue S.W.
Calgary, Alberta T2P 4M9

Registrar and Transfer Agent
CIBC Mellon Trust Company
600 333 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Stock Listing
TSX Venture Exchange
Trading Symbol PER

- (1) Member of the Audit Committee.
- (2) Member of the Compensation
- (3) Member of the Executive Committee.
- (4) Member of the Governance Committee.
- (5) Member of the Reserves Committee.
- (6) Baker & McKenzie
2600 255 5th Avenue S.W.
Calgary, Alberta T2P 3G6

Petro-Reef Resources Ltd. is a Calgary based crude oil and natural gas exploration and production company with producing properties in Alberta, Canada.

Petro-Reef Resources Ltd. had cash flow from crude oil and natural gas operations in 2004 of \$1,514,596 compared to \$17,029 (restated) in 2003.

Production for 2004 was 62,936 barrels of oil equivalent, an increase of one hundred thirty-one percent over the production for 2003 of 27,221 barrels of oil equivalent. Note that natural gas is converted to a barrel of oil equivalent (BOE) using six thousand cubic feet equal to one BOE unless otherwise stated. This conversion conforms to the Canadian Securities Regulators National Instrument 51-101. A BOE is a very approximate comparative measure that could be misleading in some cases, particularly if used in isolation.

Petro-Reef's production in 2004 came from the two core properties. They are Peavey/Morinville which produced about twenty-four percent (24%), and Alexander/Qui Barre which produced about seventy-five percent (75%). The remaining percentage came from minor working interest and royalty properties. About ninety-three percent (93%) of the production was natural gas with about seven percent (7%) as crude oil and natural gas liquids.

In 2004 no new wells were drilled in the Peavey/Morinville area. Two new wells were drilled in the Alexander/Qui Barre area. The results of activity in 2004 for both areas as well as future plans are detailed in the following pages.

Activities during the year included drilling, completions, tie-ins, work-overs/re-completions as well as 2D and 3D seismic.

The company continues to use the following exploration criteria on each prospect to assure high profitability and rate of return on capital investment:

- 1) Each exploration prospect must exhibit
 - a) A minimum three hydrocarbon zone potential.
 - b) Each zone must show the potential for:
 - (i) 10:1 profit to capital risk ratio
 - (ii) a minimum of 30% rate of return on capital invested.
 - (iii) minimum life of 15 years.
- 2) The use of 2-D and 3-D seismic to identify and confirm potential drilling locations using state-of-the-art technology.

PETRO-REEF RESOURCES LTD.

Highlights of Financial and Operations Results for Fiscal Years 2004 and 2003.

<u>Financial</u>	Year Ended December 31, 2004	Year Ended December 31, 2003 (Restated)	<u>% Change</u>
Crude oil and Natural Gas Revenue	\$2,162,656	\$894,261	142
Cash flow from operations	\$1,514,596	\$17,029	8794
Net earnings (loss) from operations	(\$542,087)	(\$156,741)	246
Net earnings (loss) per share	(\$0.03)	(\$0.01)	-
Capital Expenditures	\$1,148,725	\$1,557,439	-26
Bank Loan	\$700,000	\$1,150,000	-61
Shareholder's equity	\$4,021,269	\$4,247,706	-5
Common shares outstanding Weighted average	17,701,232	17,688,937	0.07
<u>Operations</u>	Year Ended December 31, 2004	Year Ended December 31, 2003	<u>% Change</u>
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	13	6	117
Natural Gas (mcf/day)	954	409	111
Total BOE/day	172	74	112
Average Selling Price			
Crude Oil (\$per Bbl)	45.25	43.21	5
Natural Gas (\$per mcf)	6.51	6.66	-7
NGL (\$per Bbl)	48.25	44.14	9
<u>Operations</u>	December 2004	December 2003	<u>% Change</u>
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	0	9	-100
Natural Gas (mcf/day)	1,437	1,172	23
Total BOE/day	240	205	17
Average Selling Price			
Crude Oil (\$/Bbl)	-	35.39	-100
NGL (\$/Bbl)	-	20.12	-100
Natural Gas (\$/mcf)	6.38	6.45	-1

TWO YEAR REVIEW

	2004	2003
FINANCIAL		(Restated)
Crude Oil and Natural Gas Revenue Net of royalties and ARTC	\$2,162,656	\$894,261
Net (Loss) Earnings from Operations	(\$542,087)	(\$156,741)
Net (Loss) Earnings per Share	(\$0.03)	(\$0.01)
Capital Expenditures	\$1,148,725	\$1,557,439
Total Assets	\$8,691,850	\$8,174,724
Bank Loan	\$700,000	\$1,150,000
Shareholder's Equity	\$4,021,268	\$4,247,706
Common Shares Outstanding		
End of Period	17,738,937	17,688,937
Weighted Average	17,701,232	17,688,937
OPERATIONS		
Average Production		
Crude Oil and NGLs (Bbls/day)	13	6
Natural Gas (Mcf/day)	954	409
Total BOE per day 6:1	172	74
Finding & Development Cost per BOE ⁽¹⁾	\$9.61	\$18.00
Netbacks (\$per BOE) ⁽³⁾	\$23.70	\$23.95
Reserve Replacement Ratio	0.66	3.2
Average Selling Price		
Crude Oil (\$per BOE)	\$45.25	\$43.21
Natural Gas (\$per BOE)	\$37.02	\$39.96
NGL (\$per BOE)	\$48.25	\$44.14
Reserves (Proved plus Probable)		
Crude Oil and NGLs (Bbls)	16,300	40,400
Natural Gas (MMcf)	2,569	2,527
Total BOE	444,467	461,600
Present Value of Reserves (MS) ⁽²⁾		
Undiscounted before Taxes	\$12,848	\$13,277
Discounted before Taxes at 10%	\$9,294	\$9,490
Established Reserve Life Index (P+P)	32.6 yrs	24.4 yrs
Proven Reserve Life Index	18.3 yrs	15.4 yrs

(1) After revisions due to policy 51-101.

(2) Using Constant Prices and Costs.

(3) Using a conversion of 6,000 cubic feet of natural gas for one barrel of oil equivalent.

(4) Includes natural gas liquids (NGL)

(5) Crude Oil sales were non-operated and reported with total oil and gas sales combined.

Netbacks are calculated by subtracting royalty expenses and operating expenses from revenue per barrel of oil equivalent. These calculations are before Alberta Royalty Tax Credits.

Reserve Replacement Ratio for a given year is calculated by dividing total reserves at the end of the year by the total reserves at the beginning of the year. The reserve replacement ratio for 2004 using proved reserves only was 1.13 to 1.

Operating costs for 2004 averaged in excess of fifty-one thousand dollars (\$51,000) per month, an increase from an average of about twenty-two thousand dollars (\$22,000) per month for 2003. The increased costs were as a result of costs of field work required to produce the one new well drilled in June 2004 and the re-completion, and reworking of more wells than in 2003. The primary increase is related to increased production from one hundred and nine barrels per day at the end of Q1 to two hundred and sixty barrels per day at the end of Q4.

General and administration costs increased from about twenty-seven thousand dollars per month in 2003 to about thirty-three thousand dollars per month for 2004. Except for some minor increases the largest was due to additional reporting requirements, legal, accounting, engineering and associated services and related third party charges.

Capital expenditures for 2004 were \$1,148,725, down from 2003 expenditures of \$1,557,439 of the total more than one million dollars are attributable to exploration costs (CEE) and class 39 and 41 tax categories.

The asset value of proved reserves at constant price and cost before income tax was \$7,989,000 for 2004. In 2003 the comparable value is \$6,873,000. These figures are taken from the Sproule Associates Limited report for each year.

There are no long-term financial liabilities and there have been no dividends declared.

Reserve fluctuated during 2004 because of changes in volumes of product produced and with changes in product price. Since Petro-Reef produces about ninety-three percent (93%) natural gas, natural gas prices fluctuations had more impact than prices for crude oil. The following table shows natural gas prices received by Petro-Reef for the last two years.

Product Price for Natural Gas (\$ per Gigajoule)
 Years: 2004-2003

Month of:	Price Per GJ Year 2004	Price Per GJ Year 2003
January	6.659749	6.643443
February	5.757239	8.516847
March	5.881507	8.081131
Average Price per Quarter:	6.099498	7.747140

April	6.274938	6.432713
May	6.950898	6.497444
June	6.564088	6.272281
Average Price per Quarter:	6.596645	6.400812

July	6.479279	5.478141
August	5.724071	5.700614
September	5.326431	5.328396
Average Price per Quarter:	5.843260	5.502383

October	6.170750	5.245812
November	5.878970	4.989099
December	6.382450	6.178671
Average Price per Quarter:	6.1440570	5.471194
Average Price for Year	6.17	\$6.28

Note: 1 gigajoule = 1.054615 thousand cubic feet

Selected Financial Information for the Company is shown in the following table for two years with year ends of December 31.

	2004	(Restated) 2003
<u>FINANCIAL</u>		
Crude Oil and Natural Gas Revenue net of royalties and ARTC	\$2,162,656	\$894,261
Cash Flow from Operations	\$1,514,596	\$17,029
Net (Loss) Earnings from Operations	(\$542,087)	(\$156,741)
Net (Loss) Earnings per Share, Basic and Diluted	(\$0.03)	(\$0.01)
Capital Expenditures	\$1,148,725	\$1,557,439
Total Assets	\$8,691,850	\$8,174,724
Bank Loan	\$700,000	1,150,000
Shareholder's Equity	\$4,021,269	\$4,247,706

The following table summarizes the results of the eight most recently completed quarters.

<u>Summary of Quarterly Results For The Last Eight Quarters</u>				
		Oil & Gas Sales Net of Royalties And ARTC	Net Earnings (Loss)	Basic and Diluted Earnings per share
2003			(Restated)	
	Q1	\$211,493	(\$609)	\$0.00
	Q2	\$176,756	\$14,964	\$0.00
	Q3	\$119,614	(\$113,592)	\$0.00
	Q4	<u>\$386,398</u>	<u>(\$57,504)</u>	(\$0.01)
Total		\$894,261	(\$156,741)	
2004				
	Q1	\$354,288	(\$81,806)	\$0.00
	Q2	\$531,591	(\$75,371)	\$0.00
	Q3	\$499,139	\$34,086	\$0.00
	Q4	<u>\$777,638</u>	<u>(\$418,996)</u>	(\$0.03)
Total		<u>\$2,162,656</u>	<u>(\$542,087)</u>	

The results of Operations 2004 and 2003 are set out in the following tables under three categories.

- 1) Land acquisitions
- 2) Petro-Reef operated wells
- 3) Wells where Petro-Reef is not the operator

Joint venture partnerships are involved in both the operated and non-operated drilling and accounts for the varying interests held by Petro-Reef.

LAND ACQUISITIONS NET OF DISPOSITIONS - MINERALS ONLY & BEFORE RENTALS & SURFACE LEASES					
<u>YEAR</u>	<u>PERIOD</u>	<u>GROSS ACRES</u>	<u>NET ACRES</u>	<u>COST (NET)</u>	<u>COMMENTS</u>
2003	Q1	0	0	\$287	Lease Service only
	Q2	160	70	\$4,677	
	Q3	480	212	\$26,593	
	Q4	640	282	\$26,594	
<u>2003</u> <u>(Total)</u>		<u>1280</u>	<u>564</u>	<u>\$58,151</u>	
2004	Q1	6	3	\$480	
	Q2	-	-	\$466	Lease Service only
	Q3	1,189	404	\$16,140	
	Q4	1,829	724	\$61,506	
<u>2004</u> <u>(Total)</u>		<u>3,024</u>	<u>1,113</u>	<u>\$78,592</u>	

Lease Service only costs refers to third party land company expenses.

Petro-Reef Resources Ltd. Operated Wells						
Year	Drilling Completion & Workovers	Cost	Status	PER % W.I.	PER % GORR	Comments
Year 2003						
Q1						
Q2						
Q3	05-31-55-26W4	\$460,710	Capped Gaswell	44.00%		
Q4						
Year 2004						
Q1	14-30-55-26W4	\$722		24.00%		
Q2	14-30-55-26W4	\$147,450		24.00%		
Q2	05-31-55-26W4	\$21,093		44.00%		
Q3	14-30-55-26W4	\$23,319		24.00%		
Q3	05-31-55-26W4	\$17,741		44.00%		
Q3	09-30-56-24W4	\$4,755		71.50%	0.855%	
Q3	05-25-56-25W4	\$192		39.00%	0.33%	
Q4	14-30-55-26W4	\$1,757		24.00%		
Q4	05-31-55-26W4	\$219		44.00%		
Q4	05-25-56-25W4	\$18,612		39.00%	0.33%	
Note (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in (Proved Reserves Only)						

Petro-Reef Resources Ltd. Operated Wells

Year	Equipping & Tie-In	Cost	Status	PER % W.I.	PER % GORR	First Month Production BOE/D	First Month Revenue (Net PER)	Revenue December (Net PER)	Reserves (1) (Net PER)	Comments
Year 2003										
Q1										
Q2										
Q3										
Q4	05-31-55-26W4	\$176,761	Producing Gaswell	44.00%		134.00	\$131,109	\$131,109	Well being Evaluated	Froze off @ -62 degrees celsius Jan 10/04. Repaired facility & ran pump. Well back on stream Feb 22/04
Year 2004										
Q1	10-30-56-27W4	\$22,260		35.13%						
Q1	05-31-55-26W4	\$93,669		44.00%						
Q1	09-30-56-24W4	\$39,216		71.50%	0.855	424.74	\$16,982	\$161,110	575	
Q2	05-31-55-26W4	\$34,438		44.00%						
Q2	09-30-56-24W4	\$35,710		71.50%	0.855					
Q3	14-30-55-26W4	\$57,570		34.00%		1,660.22	\$36,725	\$659,674	229	
Q3	05-31-55-26W4	\$4,444		44.00%						
Q3	09-30-56-24W4	\$231		71.50%	0.855					
Q4	14-30-55-26W4	\$278		34.00%						
Q4	05-31-55-26W4	(\$61)		44.00%	0.33%					

Note (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in (Proved Reserves Only)

Petro-Reef Resources Ltd. Non-Operated Wells										
Year	Drilling Completion & Workovers	Cost	Status	PER % W.I.	PER % GORR	First Month Production BOE/D	First Month Revenue (Net PER)	Revenue December (Net PER)	Reserves (1) (Net PER)	Comments
Year 2003	Note: There were no wells drilled in 2003 where Petro-Reef was not the operator									
Year 2004										
Q4	06-07-56-25W4	\$7,581	Producing Gaswell	12.50%						
Q4	01-20-56-27W4	\$3,895	Producing Gaswell	1.04%						
Year	Equipping & Tie-In	Cost	Status	PER % W.I.	PER % GORR	First Month Production BOE/D	First Month Revenue (Net PER)	Revenue December (Net PER)	Reserves (1) (Net PER)	Comments
Year 2003	Note: There were no wells drilled in 2003 where Petro-Reef was not the operator									
Year 2004										
Q4	06-07-56-25W4	\$9,397	Producing Gaswell	60.9375		147..30	\$3,795	\$3,683		
Q4	01-20-56-27W4	\$4,236	Producing Gaswell	1.04%		9.35	\$226	\$227	2	
Q4	15-25-56-25W4	\$2,756	Producing Gaswell	1.2750257	9.00%	98.20	\$3,610	\$8,311	31	
Note (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in (Proved Reserves Only)										

In the coming year the company may continue to have a working capital deficit, however, the company's cash available for the year will continue to be positive.

The company expects to incur capital costs of approximately \$4,000,000 for drilling, \$2,000,000 for compression and dehydration and \$150,000 for seismic in 2005.

The company is not nor does it expect to be in default of any of its obligations.

The company's short term requirements for cash are met by current cash flow from operations and bank financing. Long term cash requirements will depend on the success of the drilling program. Currently long term financing is done with bank financing and current cash flow from operations. Consideration for future financing will include increase in our bank financing, issuance of shares from treasury and additional farm-outs.

The National Bank of Canada has made available to Petro-Reef two sources of financing. Credit Facility A is a revolving line of credit for two million dollars (\$2,000,000) at prime plus one percent (1 ¼%); Credit Facility B is for acquisitions and development in the amount of five hundred thousand dollars (\$500,000) at prime plus one and one-half percent (1½%). The bank has waived in writing the violation of the working capital ratio covenant.

The terms of the Company's bank facility includes certain financial statement covenants. At December 31, 2004, The Company was in violation of the working capital covenant. The bank has waived this covenant breach as at December 31, 2004.

Petro-Reef has no off-balance sheet arrangements.

There were no related party transactions consummated by Petro-Reef in 2004.

As the time of writing this report Petro-Reef is not considering any proposed acquisitions or dispositions outside the normal course of business. If, as and when a transaction is proposed, and finalized it shall be reported as required.

In the Peavey/Morinville prospect area no new wells were drilled in 2004. The emphasis during 2003 and in 2004 was to develop production from several capped natural gas wells which either had not been tied-in for production or were candidates for re-completion in up-hole horizons which had previously tested or indicated by log analysis that they were capable of commercial production.

In the Alexander/Qui Barre area Petro-Reef operated the drilling of one well in which Petro-Reef has a thirty-four percent working interest. Another outside operated well was drilled in which Petro-Reef has a very small interest (1.04%). Both wells were drilled in late June 2004 and were successful natural gas producers.

The present office lease agreement expires on September 30, 2005. Future lease payments to the end of the lease term under the company's office lease will total \$31, 531.

The results from the Petro-Reef operated well were reported in news releases dated August 03, 2004 and November 26, 2004 as follows:

August 03, 2004:

“Petro-Reef Resources Ltd. drilled a well in its core area in central Alberta in July 2003 with encouraging initial indications of production potential for crude oil and natural gas. In November 2003 this well was placed on production and by July 2004 was reaching economic limits. As a result the producing zone was shut in and an up-hole zone completed. The upper zone would appear to have stabilized at a production rate of about 720 thousand cubic feet of natural gas per day. Petro-Reef has a 44% working interest in this well.

During the last week of June 2004 Petro-Reef drilled an offsetting well on the same geologic structure. The location was picked based on an earlier 3D seismic program in the area. A back-pressure test has now been completed in a lower Cretaceous zone which is expected to be placed on production at a rate of four million cubic feet of natural gas per day. To produce this gas a pipeline of about one half a mile will be required. Work has begun on the pipeline and it is expected to be ready by mid-August. Actual production may be delayed depending on the availability of production equipment. Petro-Reef has a 34% working interest in this well.”

November 26, 2004:

“Petro-Reef Resources Ltd. drilled a well in central Alberta in the last week of June 2004 which tested “sweet” natural gas in a lower Cretaceous zone. After the installation of production equipment and a sales pipeline the well was placed on production on August 25, 2004 at a rate of about four million cubic feet per day. The production from this well increased the average daily production net to Petro-Reef for September 2004 to 276 barrels of oil equivalent per day. For September 2003 the comparative production was 65 barrels of oil equivalent per day. For the first eight months of 2004 the comparative production was 120 barrels of oil equivalent per day. The production for September 2004 represents increases of three hundred twenty-five percent (+325%) and one hundred thirty percent (+130%) respectively over the values for September 2003 and the first eight months of 2004.

After ninety days of production the well has averaged 219 barrels of oil equivalent per day net to Petro-Reef. At December 31, 2003 proved recoverable reserves net to Petro-Reef before deductions, established by an independent engineering evaluation were 278,200 barrels of oil equivalent. Based on company estimates and production statistics available to date the proved recoverable reserves net to Petro-Reef before deductions are 1,305,600 barrels of oil equivalent, an increase of three hundred sixty-nine percent (+369%). Petro-Reef has a 34% working interest in this well. Petro-Reef has also identified additional drilling opportunities in off-setting acreage in which it has working interests.”

The proved recoverable reserves net to Petro-Reef in the news release were calculated internally. The reserve values calculated by Sproule Associates Limited were calculated using more stringent assumptions which came into existence after the date of the news release. The result was a considerably lower value.

A follow-up location was picked to be drilled in January-February 2005. Due to various delays this well will not be drilled before late April or early May, field conditions permitting.

Plans for the Alexander/Qui Barre area are to drill additional wells, both development and exploration. The approximately eight square miles of 3D seismic acquired in 2003 has been interpreted with results that indicate at least ten potential drilling locations. These locations will be used to validate much of the acreage in the area. With success these wells will lead to further development and other exploration drilling. In March 2005 an additional six square mile 3D seismic survey was acquired contiguous with the previous 3D survey. The data have been processed and are ready to interpret.

The new survey on a preliminary look is expected to add to drillable locations for the future.

The financial statements of Petro-Reef Resources Ltd. have been prepared in accordance with accounting principles generally accepted in Canada. Management has made the necessary estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses in the preparation of the financial statements. Accordingly, actual results may differ from estimated amounts but management does not believe such differences will materially affect the company's financial position or results of operations.

Effective January 1, 2003, the company adopted a new Canadian accounting guideline relating to full cost accounting for oil and gas operations.

Prior to adopting the new standard, the ceiling test limit on the aggregate carrying value of oil and gas property, plant and equipment was based on the sum of the undiscounted cash flows expected from the production of proved reserves using year end pricing, the lower of cost or market of unproved properties and the cost of major development projects less the estimated future costs for administration, financing, asset retirement obligations and income taxes.

A property, plant and equipment ceiling test write down of approximately \$850,000, net of income tax, as at December 31, 2003 would have been required had the new standard not been adopted.

Effective January 1, 2004, the Company adopted the new Canadian accounting standard for asset retirement obligations. The new standard requires the Company to record the present value of future asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The associated asset retirement costs are capitalized as part of the carrying amount of the property, plant and equipment and depleted and depreciated using a unit of production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each period to reflect the passage of time (accretion), and changes in the estimated future cash flows underlying the obligation. The effect of adoption of the new standard on the financial statements is disclosed below.

The effect of this change in accounting policy has been recorded retroactively with restatement of prior year. The effect of the adoption is presented below as increases (decreases):

	<u>2004</u>	<u>2003</u>
Asset retirement costs, included in property, plant and equipment	\$ 122,861	\$122,861
Accumulated depletion and depreciation on asset retirement costs, included in property, plant and equipment	57,029	41,294
Asset retirement obligations	150,456	190,436
Accumulated future site restoration liability	-	(50,575)
Future income tax liability	(4,569)	(16,466)
Deficit	(83,062)	(41,828)

Stock options

Effective January 1, 2003, the company prospectively adopted the new Canadian accounting standard with respect to stock based compensation. The standard requires that the fair value method of accounting be applied for stock options awarded to directors, officers and employees after January 1, 2003. Compensation expense is recorded over the vesting period using the estimated fair value of the option on the grant date. Consideration paid on the exercise of stock options is recorded as share capital".

The authorized share capital of the company is comprised of an unlimited number of preferred shares and an unlimited number of common shares. Details of the changes in the company's issued share capital during 2004 and 2003 are as follows:

		2004		2003
	Number of shares	Amount \$	Number of shares	Amount \$
Common shares				
Balance – Beginning of year	17,688,937	4,743,176	17,688,937	4,743,176
Issued for the exercise of stock options	50,000	29,700	-	49,000
Balance – End of year	17,738,937	4,772,876	17,688,937	4,743,176

Basic and diluted earnings (loss) per common share are calculated using the weighted average number of common shares outstanding during the year of 17,701,232 (2003 – 17,688,937).

The increase in share capital as a result of the exercise of stock options is comprised of the amount of cash received of \$15,000 and the compensation expense previously recognized of \$14,700.

The company has a stock option plan for directors, officers and key employees. The exercise price of each option equals the market price of the company's stock on the date of grant. Options are vested over three years and expire after a maximum exercise period of five years from the date of issuance. A summary of the status of the company's stock option plan as of December 31, 2004 and 2003 and changes during the year is presented below:

		2004		2003
	Shares	Weighted-average Exercise price \$	Shares	Weighted-average Exercise price \$
Outstanding-Beginning of year	1,310,000	0.42	1,150,000	0.67
Granted	350,000	0.70	960,000	0.40
Exercised	(50,000)	0.30	-	-
Expired	(100,000)	42	(800,000)	0.49
Options outstanding at year end	1,510,000	0.49	1,310,000	0.42

The following table summarizes information about fixed stock options outstanding at December 31, 2004:

		Options outstanding		Options exercisable	
Range of Exercise price	Number outstanding	Weighted – Average remaining contractual life	Weighted - average Exercise price (\$/share)	Number exercisable	Weighted - average Exercise price (\$/share)
\$0.30 - \$0.71	1,510,000	3.27 years	0.49	1,160,000	0.43

Contributed surplus

	2004	2003
	\$	\$
Balance – Beginning of year	\$94,111	-
Stock based compensation expense	\$300,649	\$94,111
Adjustment for options exercised in the year	(\$14,700)	-
Balance – End of year	\$380,060	\$94,111

Compensation cost of \$300,649 has been recognized for stock options granted after January 1, 2004.

Adjustments for options exercised in 2004 were \$14,700. At year end the total contributed surplus was \$380,060.

The fair value of options granted to employees and directors was estimated at the date of the grant using a Black-Scholes option pricing model with the following assumptions:

Volatility factor of expected market price (%)	133
Weighted average risk-free interest rate (%)	4.24
Weighted average expected life in years	3
Weighted average expected annual dividends per share	-