PETROFUND ENERGY TRUST
Form 40-F
March 20, 2006

**United States Securities and Exchange Commission**

**Washington, D.C. 20549**
**Form 40-F**

(Check One)

[ ]

Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

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Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For Fiscal year ended:

December 31, 2005

Commission File number:

00-115124

PETROFUND ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Ontario, Canada

(Province or Other Jurisdiction of Incorporation or Organization)

1331

(Primary Standard Industrial Classification Code Number, if Applicable)

600, 444 7th Avenue S.W.
Calgary, Alberta Canada T2P 0X8
(403) 218-8625

(Address and Telephone Number of Registrant s Principal Executive Offices)

CT Corporation System

111 Eighth Avenue, 13$^{th}$ Floor

New York, New York 10011

U.S.A.

(212) 894-8700

(Name, Address (Including Zip Code) and Telephone Number (Including Area Code)
of Agent For Service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

| Title Of Each Class: | Name Of Each Exchange On Which Registered: |
| --- | --- |
| Trust Units | The American Stock Exchange |

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

þ

Annual Information Form

þ

Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report:

117,172,421 Trust Units

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act ). If Yes is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes [ ]

No þ

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13(d) or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

Yes þ

No [ ]

**UNDERTAKING AND CONSENT TO SERVICE OF PROCESS**

**Undertaking**

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission (the SEC ), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities registered pursuant to Form 40-F, the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

**Consent to service of Process**

The Registrant has previously filed with the SEC a written irrevocable consent and power of attorney on Form F-X in connection with the Trust Units.

**SIGNATURES**

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

**PETROFUND ENERGY TRUST**

Date: March 15, 2006

By:

*(signed) Jeffery E. Errico*

Jeffery E. Errico

President and Chief Executive Officer

**EXHIBIT INDEX**

| Exhibit No. | Description |
|---|---|
| 1 | Annual Information Form for the year ended December 31, 2005. |
| 2 | Management s Discussion and Analysis for the year ended December 31, 2005. |
| 3 | Audited Consolidated Financial Statements, including the notes thereto, dated December 31, 2005 and 2004 and for the years ended December 31, 2005, 2004 and 2003, together with the reports of the Independent Registered Chartered Accountants thereon. |
| 4 | Disclosures regarding the Registrant s Disclosure Controls and Procedures. |
| 5 | Disclosures regarding the Registrant s Audit Committee Financial Expert. |
| 6 | Disclosures regarding the Registrant s Code of Ethics. |
| 7 | Disclosures regarding the Registrant s Audit Committee Pre-Approval Policies and Procedures and Principal Accountant Fees and Services. |
| 8 | Consent of GLJ Petroleum Consultants Ltd. |
| 9 | Consent of Independent Registered Chartered Accountants. |
| 10 | Officers Certifications pursuant to Rule 13a-15(f) or Rule 15d-15(f). |
| 11 | Officers Certifications pursuant to Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code. |

**EXHIBIT 1**

Annual Information Form

For the year ended December 31, 2005

**PETROFUND ENERGY TRUST**

**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED DECEMBER 31, 2005**

**March 15, 2006**

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**INFORMATION PREPARED BY PETROFUND CORP.**

The information contained in this annual information form has been prepared by Petrofund Corp., who manages the Trust.

**FORWARD-LOOKING STATEMENTS**

Certain statements contained in this annual information form constitute forward-looking statements. The use of any of the words anticipate , continue , estimate , expect , may , project , should , believe and similar expressions identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and PC believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this annual report should not be unduly relied upon. These statements speak only as of the date of this annual information form.

In particular, this annual information form contains forward-looking statements pertaining to the following:

- the size of the Trust s oil and natural gas reserves;
- the net present value of future net revenue from the Trust s oil and natural gas reserves;
- projections of market prices and costs;
- projections of currency exchange rates and inflation rates;
- anticipated distributions on units of the Trust and the payout ratio;
- capital expenditures and the timing thereof;
- the source of funding for capital expenditures;
- abandonment and reclamation costs and the source of funding for such costs;

- the taxability of the Trust and PC;
- the Trust s expectation as to production of oil and natural gas;
- supply and demand for oil and natural gas;
- the Trust s expectations with respect to acquisitions and the properties obtained thereunder;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes; and
- the potential impact to the Trust of the Kyoto Protocol.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual information form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;

- geological, technical, drilling and processing problems; and

- the other factors described under Business Risks in this annual information form and in the annual report.

These factors should not be construed as exhaustive. Except as required by applicable securities laws, neither the Trust nor PC undertakes any obligation to publicly update or revise any forward-looking statements.

## DOLLAR AMOUNTS

Unless otherwise specified, all dollar amounts set out in this annual information form are in Canadian dollars.

## GLOSSARY OF TERMS

The following terms used herein have the meanings set out below:

| | |
|---|---|
| **AECO:** | The regional pricing hub for natural gas located at the storage facilities of Alberta Energy Company near Medicine Hat, Alberta. |
| **Aggregate Equivalent Vote Amount:** | With respect to any matter, proposition or question on which Unitholders are entitled to vote, consent or otherwise act, the number of votes that the holder of a Special Voting Unit would be entitled to had the holder exchanged all of the PC Exchangeable Shares held by the holder for Units immediately prior to the record date set for any such meeting. |
| **Bbl:** | Barrel. |
| **Bcf:** | Billions of cubic feet. |
| **Board or Board of Directors:** | The board of directors of PC. |
| **Boe:** | Barrels of oil equivalent, using a conversion factor of 6 Mcf of gas being equivalent to one Bbl of oil and one Bbl of NGLs being equivalent to one Bbl of oil. |
| **Boepd:** | Barrels of oil equivalent per day. |
| **Bpd:** | Barrels of oil or NGLs per day. |
| **Cash Retraction Notice:** | A notice to redeem PC Exchangeable Shares exercisable for a period of 5 business days from the date of expiry of the subject Dividend Period. |
| **Current Market Price:** | In respect of a Unit on any date, the weighted average trading price of a Unit on the TSX for the 10 trading days preceding that date. |
| **Distribution Payment Date:** | Each date on which a distribution is paid to Unitholders. |
| **Distribution Record Date:** | In respect of any distribution, the day on which Unitholders are identified for purposes of determining entitlement to such distribution. |
| **Dividend Period:** | A period within two business days of a Distribution Payment Date. |
| **Drip Price:** | In respect of a Unit on any Valuation Date, the most recently applicable price at which a holder of a Unit is entitled to purchase a Unit in respect of the Distribution to which the subject Valuation Date relates pursuant to any distribution re-investment plan which Petrofund may have in effect on such Valuation Date and which is available to the holders of Units generally. |
| **Exchange Ratio:** | At any time and in respect of each PC Exchangeable Share, shall initially be equal to one, and provided that PC shall not have declared a dividend in respect of the subject Dividend Period, shall be cumulatively increased on the expiry date of each Dividend Period by an amount equal to the (i) fraction having as its numerator the Per Share Dividend Amount relating to the subject expired Dividend Period, and having as its denominator the Current Market Price on the Valuation Date, or (ii) in the event that: (a) as at the subject Valuation Date, the Trust has in place a distribution re-investment plan which is available to the holders of Units generally, and (b) the holder has not delivered a Cash Retraction Notice in respect of the Distribution to which the expired Dividend Period relates within the time |

period provided for, the fraction having as its numerator the Per Share Dividend Amount relating to the subject expired Dividend Period, and having as its denominator the Drip Price in effect as at the Valuation Date.

| | |
|---|---|
| **gj:** | Gigajoule. |
| **GLJ:** | GLJ Petroleum Consultants Ltd., independent oil and gas reservoir engineers of Calgary, Alberta. |
| **GLJ Report:** | The report prepared by GLJ dated February 9, 2006 with respect to the petroleum, natural gas and NGL reserves of PC effective as at December 31, 2005. |
| **Internalization Transaction:** | The transaction approved at the annual and special meeting of Unitholders held on April 16, 2003, under which management of the Trust was internalized through the acquisition by PC of all of the issued and outstanding shares of NCEP Management and the consequent elimination of all management, acquisition and disposition fees payable to NCEP Management. |
| **Mbbls:** | Thousands of barrels. |
| **Mboe:** | Thousands of barrels of oil equivalent. |
| **Mcf:** | Thousands of cubic feet. |
| **Mcfpd:** | Thousands of cubic feet per day. |
| **mlt:** | Thousand long tons. |
| **MMboe:** | Millions of barrels of oil equivalent. |
| **MMBtu:** | Millions of British Thermal Units |
| **MMcf:** | Millions of cubic feet. |
| **MMcfpd:** | Millions of cubic feet per day. |
| **M$:** | Thousands of dollars. |
| **MM$:** | Millions of dollars. |
| **NCE Services or NMSI:** | NCE Management Services Inc. |
| **netback:** | The amount received from the sale of a barrel of oil, or barrel of oil equivalent, after the deduction of operating costs, royalty payments, cash hedging costs, and transportation expenses. |
| **NGL or NGLs:** | Natural gas liquids. |
| **NPI Agreements** | The PC NPI Agreement and the PVT NPI Agreement. |
| **PC** | Petrofund Corp. |
| **PC Exchangeable Share Provisions:** | The rights, privileges and conditions attaching to the PC Exchangeable Shares set forth in the Articles of PC. |
| **PC Exchangeable Shares:** | Non voting exchangeable shares in the capital of PC. |
| **PC NPI Agreement:** | The amended and restated NPI agreement dated November 8, 2005, and made effective October 1, 2005, and made between PC and the Trust. |
| **PC Support Voting and Exchange Agreement:** | The agreement dated April 29, 2003, between PC, the Trust, 1518274 Ontario Limited ("Exchangeco"), and Petro Assets whereby PC agrees to take certain actions and make certain payments and deliveries necessary to |

| | |
|---|---|
| | ensure that the Trust and Exchangeco will be able to make certain payments and to deliver or cause to be delivered Units in satisfaction of the obligations of the Trust and Exchangeco under the PC Exchangeable Share Provisions and the Voting Shareholder Agreement. |
| **Per Share Dividend Amount:** | A distribution relating to the subject Distribution Payment Date multiplied by the Exchange Ratio. |

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|---|---|
| **Petro Assets:** | Petro Assets Inc. |
| **Petrofund or the Trust:** | Petrofund Energy Trust. |
| **Previous Manager:** | NCE Petrofund Management Corp., the previous manager of the Trust. |
| **Properties:** | The interests, including working interests, royalty interests, and unit interests, in petroleum and natural gas rights held by PC and PVT. |
| **PVT:** | Petrofund Ventures Trust, a wholly owned subsidiary trust of Petrofund formally known as Ultima Ventures Trust. |
| **PVT NPI Agreement:** | The amended and restated NPI agreement dated November 8, 2005, and made effective October 1, 2005, and made between PC, as trustee of PVT, and the Trust. |
| **Redemption Date:** | The date which is 60 days after the date of delivery of a Redemption Notice. |
| **Redemption Price:** | A price per PC Exchangeable Share equal to the amount determined by multiplying the Exchange Ratio on the last business day prior to the applicable Redemption Date by the current market price on the last Business Day prior to such Redemption Date. |
| **Retracted Shares:** | Means the number of PC Exchangeable Shares redeemed in accordance with a Cash Retraction Notice. |
| **Retraction Date:** | The date that is 5 Business days after the date on which PC receives a retraction request in respect of the Retracted Shares. |
| **Special Resolution:** | A resolution approved in writing by Unitholders holding not less than 66 2/3% of the outstanding Trust Units or passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of the Unitholders called for the purpose of approving such resolution. |
| **Tax Act:** | Income Tax Act (Canada), as amended. |
| **TSX:** | Toronto Stock Exchange. |
| **Trustee:** | Computershare Trust Company of Canada, as trustee of the Trust. |
| **Trust Indenture:** | The amended and restated trust indenture made as of November 16, 2004, between PC and the Trustee. |
| **Trust Unit or Unit:** | A trust unit created pursuant to the Trust Indenture and representing a fractional undivided interest in the Trust. |
| **Ultima:** | Ultima Energy Trust. |
| **Unitholder:** | A holder from time to time of Trust Units. |
| **Valuation Date:** | The first Business Day following the Distribution Record Date in respect of the Distribution to which the expired Dividend Period |

| | |
|---|---|
| | relates. |
| **Voting Shareholder Agreement:** | The voting shareholder agreement made as of April 29, 2003, as amended as of April 12, 2004, between PC and Petrofund relating to, among other things, the election of the Board of Directors. |

**Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf/1 Bbl is based on energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

**PETROFUND ENERGY TRUST**

**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED DECEMBER 31, 2005**

**DATED MARCH 15, 2006**

# PETROFUND ENERGY TRUST

## General

The Trust is an open-ended investment trust created under the laws of the Province of Ontario on December 18, 1988 under the name "NCE Petrofund I". Active operations commenced March 3, 1989. On July 4, 1996, the name of the Trust was changed to "NCE Petrofund" and on November 1, 2003 the name was changed to its present name of "Petrofund Energy Trust". Effective September 7, 2001, the Trustee became the trustee of the Trust. The Trust is currently governed by the Trust Indenture. The executive office, head office and operations of the Trust are located at Suite 600, 444 - 7th Avenue S.W., Calgary, Alberta, T2P 0X8.

The Trust's primary source of income is from 99% net royalty interests granted by PC pursuant to the PC NPI Agreement and by PVT pursuant to the PVT NPI Agreement. The Trust may also purchase directly or indirectly securities of oil and gas companies, oil and gas properties and other related assets.

PC, formerly named NCE Petrofund Corp., was incorporated under the *Business Corporations Act* (Alberta) on March 17, 1988. PC acquires and manages producing oil and gas properties in western Canada. Pursuant to the PC NPI Agreement, the Trust receives a 99% net royalty interest in the oil and gas properties of PC. All of the issued and outstanding voting shares of PC are held by the Trust. The capital structure of PC also includes PC Exchangeable Shares. As at December 31, 2005 there were 283,025 PC Exchangeable Shares issued and outstanding, which were issued in connection with the Internalization Transaction. As at December 31, 2005, the PC Exchangeable Shares were exchangeable into 388,147 Trust Units, based on a ratio which is adjusted on each date the Trust pays a distribution to its Unitholders. The PC Exchangeable Shares are not listed securities on any stock exchange. See "Capital Structure of PC" for a description of the attributes of the PC Exchangeable Shares.

PVT is a trust created under the laws of the Province of Alberta on August 31, 1997. Following completion of the business combination of the Trust and Ultima pursuant to which on June 16, 2004 the Trust acquired all of the assets of Ultima, the sole beneficiary of PVT is the Trust. PVT was established for the purpose of, and its business is restricted to, purchasing, holding, operating and divesting petroleum, natural gas and related hydrocarbons and related facility interests including the development of petroleum and natural gas, the transportation, processing, marketing and sale thereafter and all business operations incidental or in anyway related to the foregoing. PC is presently the trustee of PVT. Pursuant to the PVT NPI Agreement, the Trust receives a 99% net royalty interest in the oil and gas properties of PVT.

Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Historically, the Trust's activities have been focused on the acquisition of net royalties from PC and, more recently, from PVT. For each property for which a net royalty is granted by PC or PVT, the Trust receives 99% of the revenue generated by the property net of operating costs, debt service charges, general and administrative costs and certain other taxes and charges. The Trust distributes to its Unitholders a majority of its cash flow in the form of monthly distributions, part of which is on a tax-advantaged basis. Cash flow includes royalty income and may include cash flow generated by properties and interests not currently subject to the Trust's net royalty interests.

**Subsidiaries**

The following are the names, the percentage of voting securities, and the jurisdiction governing the Trust's material subsidiaries and trusts, either direct or indirect, as at the date hereof:

| | Percentage of voting securities (directly or indirectly) | Nature of Entity | Jurisdiction of Incorporation/ Formation |
|---|---|---|---|
| Petrofund Corp. | 100% | Corporation | Alberta |
| Petrofund Ventures Trust | 100% | Trust | Alberta |

**Organizational Structure**

The following chart shows the structure of the Trust and its material subsidiaries at the date hereof:

**Notes:**

(1)

As at December 31, 2005, the Trust also had a total of 283,025 PC Exchangeable Shares outstanding that were exchangeable for 388,147 Trust Units.

(2)

Held by Petrofund Corp. as trustee for Petrofund Ventures Trust.

## GENERAL DEVELOPMENT OF THE BUSINESS OF THE TRUST

### General

The Trust was initially formed as a closed-end royalty trust for the purposes of acquiring royalty interests from PC. Effective February 2, 1999, the Trust was converted to an open-ended investment trust. The Trust Indenture, NPI Agreement and related agreements were amended to: (i) permit the Trust and PC to acquire, directly or indirectly, interests in resource issuers and/or resource properties and other related assets; (ii) remove certain financing restrictions applicable to the Trust and PC to permit the Trust and PC, subject to certain limitations, to raise or issue capital in connection with, or to finance, such acquisitions, either through the issuance of Trust Units or other equity or debt securities of the Trust or PC or through borrowing; and (iii) provide that Unitholders have the right to cause the Trust to redeem their Trust Units in certain circumstances.

Effective November 1, 2000, the Trust acquired all of the issued and outstanding shares of PC from a subsidiary of the Previous Manager for nominal consideration, resulting in PC becoming a wholly-owned direct subsidiary of the Trust. This change simplified the structure of the Trust and related entities and allows the Trust to present consolidated financial statements which fully reflect the assets and liabilities of the Trust and PC.

In conjunction with PC becoming a wholly-owned subsidiary of the Trust, the corporate governance of the Trust was changed so that the stewardship of the Trust and PC was undertaken by the Board of Directors of PC.

On March 10, 2003, the Trust entered into an agreement to internalize its management structure such that the Previous Manager, the then manager of the Trust, became a wholly-owned subsidiary of PC. Unitholder and regulatory approval of the Internalization Transaction was received at the annual and special meeting of Unitholders held on April 16, 2003. As a result of the Internalization Transaction, all management, acquisition and disposition fees payable to the Previous Manager were eliminated effective January 1, 2003. The cost of the Internalization Transaction was $30.9 million, including $2.5 million of transaction costs. The purchase price for the shares of the Previous Manager was satisfied by the issuance of 1,939,147 PC Exchangeable Shares plus a cash amount per PC Exchangeable Share equal to the distributions paid or payable per Trust Unit by the Trust to Unitholders of record from and after January 1, 2003 up to and including the closing date. In addition, at closing, PC paid $3.4 million in cash to fund the repayment of a debt owing by the Previous Manager and, in addition, certain senior executives of the Previous Manager were paid $780,000 in cash and issued 100,244 Trust Units plus an amount per Trust Unit equal to the distributions per Trust Unit paid to Unitholders of record of Trust Units during the period commencing on January 1, 2003 and ending on the closing date.

Management of the Trust is presently carried out by directors, officers and other employees of PC.

**Financings**

During the last three years, the Trust completed the following public offerings of Trust Units:

| Date | Trust Units | Price | Gross Proceeds |
|---|---|---|---|
| May, 2003 | 9,200,000 | $10.60 | $97,520,000 |
| December, 2003 | 6,600,000 | $16.20 | $106,920,000 |
| June, 2005 | 4,150,000 | $18.25 | $75,737,500 |
| November, 2005 | 12,500,000 [(1)] | $20.00 | $250,000,000 |

**Note:**

(1)

12,500,000 Subscription Receipts were issued. On December 15, 2005, these Subscription Receipts were automatically converted into Trust Units on a one-for-one basis.

In addition, on June 16, 2004, 26,449,102 Trust Units were issued to purchase Ultima.

**Acquisitions**

The following is a description of significant acquisitions made by PC in the last three completed financial years.

***2003***

*Solaris*

Effective January 1, 2003, PC acquired 100% of the outstanding common shares of Solaris Oil & Gas Inc. ("Solaris"), and on February 7, 2003, amalgamated Solaris in PC. PC paid $7.4 million in cash, and assumed debt and negative working capital of $1.2 million, for a total cost of the oil and gas properties of $8.6 million.

*Property Package*

In the second quarter of 2003, PC closed the acquisition of a diverse group of oil and gas properties for $61.7 million after adjustment. The purchase was accretive to distributable cash flow; production from the properties was approximately 2,300 Boepd of which 42% was gas. The properties contained a large percentage of unit production.

*Swan Hills*

On August 21, 2003, PC purchased a 7.22% interest in Swan Hills Unit #1 for $37.1 million from a private Canadian company. This acquisition increased the Trust s interest in the unit, bringing the Trust s total interest in the unit to 9.87%. This acquisition added approximately 1,100 Boepd of production.

***2004***

*Ultima Energy Trust*

On June 16, 2004, PC acquired Ultima. Under the terms of the agreement, each Ultima unit was effectively exchanged for 0.442 of a Trust Unit on a tax-deferred rollover basis and PC acquired all the assets and assumed all of the liabilities of Ultima. Ultima unitholders also received an aggregate $10 million one-time special distribution from Ultima of $0.167113 per Ultima unit on June 15, 2004. The aggregate cost of the transaction was $454.7 million consisting of 26.4 million Petrofund Trust units valued at $17.12 per unit, which was the weighted average trading price of the Units for the period commencing five days before and ending five days after the acquisition was announced, the assumption of debt and negative working capital of $104.4 million and transaction costs incurred by the Trust of $1.9 million.

Production from the Ultima properties from January 1, 2004, to the date of closing was approximately 9,900 Boepd of which 78% was oil and natural gas liquids.

The major properties acquired were Weyburn, Spirit River, Cherhill, Kerrobert, and Westerose. The Weyburn and Kerrobert properties have common ownership with Petrofund s existing holdings. Ultima s properties were held either by Ultima Energy Inc., as trustee for Ultima, or by Ultima Ventures Corp., as trustee for Ultima Ventures Trust, now PVT, a wholly owned subsidiary of Ultima Energy Trust. Ultima Energy Inc. was amalgamated into PC and Ultima Ventures Corp. was wound up and dissolved into PC, and all properties have now been transferred to and are held by PC on behalf of Petrofund, or PVT, now a wholly owned subsidiary of Petrofund.

***2005***

*Northern Crown*

Effective April 1, 2005, PC acquired all of the outstanding common shares of Northern Crown Petroleums Ltd. ("Northern Crown"), and on May 10, 2005, Northern Crown was dissolved and, pursuant to the terms of a distribution of assets and assumption of liabilities agreement, PC acquired all the assets and assumed all of the liabilities of Northern Crown. PC paid an aggregate cost of $32.7 million, including the assumption of debt and negative working capital. The acquisition was synergetic to Petrofund with the major properties acquired being located in the Bruce, Drowning Ford, Dyberg, Leduc, Macleod, Shaw Lake, and Siebert Lake areas of Alberta and the Browning, Florence, Hastings, and Steelman areas of Saskatchewan. The Leduc property and the Southeast Saskatchewan properties are contiguous with Petrofund s existing properties in those areas. The properties are complementary to Petrofund's internal development program as they contain considerable upside potential.

*Tahiti*

Effective May 1, 2005, PC acquired all of the issued and outstanding shares of Tahiti Gas Ltd. ("Tahiti"), and on May 31, 2005, Tahiti was dissolved and, pursuant to the terms of a distribution of assets and assumption of liabilities agreement, PC acquired all the assets and assumed all of the liabilities of Tahiti. The aggregate cost of the transaction was $23.4 million, including the assumption of debt and negative working capital. The acquisition was synergetic to Petrofund, as Tahiti s major properties are located in July Lake and Helmet areas of British Columbia where Petrofund has an existing operating base. The properties are also complementary to Petrofund's internal development program as they contain considerable upside potential.

*Kaiser Energy Ltd.*

Effective December 1, 2005, PC acquired 100% of the issued and outstanding shares of Kaiser Energy Ltd. ( Kaiser ). Following the acquisition, which was completed on December 15, 2005, Kaiser was dissolved and, pursuant to the terms of a distribution of assets and assumption of liabilities agreement, PC acquired all the assets and assumed all of the liabilities of Kaiser. The estimated aggregate cost of the transaction was $471.9 million, including the assumption of debt and negative working capital.

The transaction increased Petrofund's production by 14% to approximately 42,500 boepd. The almost 100% gas weighting of the acquired production strengthened Petrofund, by realigning the commodity balance to a 50% oil and 50% natural gas production ratio. Kaiser's assets also include 55,000 net acres of highly prospective undeveloped land on which Petrofund has already identified 166 (net) low to medium risk development drilling opportunities, which are expected to contribute positively to Petrofund's production in 2006, and thereafter.

The major properties acquired were Berland River, Drumheller, Herronton, Mitsue, Ribstone, Strachan, and Sugden. The Strachan property has common ownership with Petrofund s existing holdings.

## SIGNIFICANT ACQUISITIONS AND SIGNIFICANT DISPOSITIONS

There were no significant acquisitions or significant dispositions by the Trust or any significant probable acquisition by the Trust within or since the completion of the most recently completed financial year of the Trust except for the purchase of the shares of Kaiser Energy Ltd. (the "Acquisition") as described above under "General Development of the Business of the Trust - Acquisitions".

The Corporation filed a Form 51-102F4 dated January 27, 2006 in respect of the Acquisition (the "Business Acquisition Report") on SEDAR, which Business Acquisition Report is incorporated herein by this reference.

**RECENT DEVELOPMENTS**

There have been no significant or material developments concerning the Trust since the completion of the most recently completed financial year of the Trust.

# BUSINESS AND PROPERTIES

Overview

PC acquires, manages and disposes of petroleum and natural gas property rights and interests. As of December 31, 2005, PC's principal properties were located in Alberta, British Columbia, Manitoba and Saskatchewan. PC primarily produces light and medium oil, natural gas and natural gas liquids. As at December 31, 2005, PC's asset base included proved plus probable gross reserves (before deduction of royalties and without including any royalty interests) of 88.5MMbbls of oil, 389Bcf of natural gas and 9.0MMbbls of natural gas liquids based on forecast prices and cost assumptions, and an inventory of undeveloped land totalling 663,250 gross acres and 309,924 net acres. See "Statement of Reserves Data and Other Oil and Gas Information   Disclosure of Reserves Data" and "Statement of Reserves Data and Other Oil and Gas Information   Properties With No Attributed Reserves".

One of PC's ongoing objectives is to enhance reserves and production through acquisitions. With respect to acquisitions, PC operates in a competitive environment with both large and small competitors.

## Strategy

The Trust's objective is to maximize value and sustainability for its Unitholders. The Trust intends to execute its business strategy by:

- continuing to pursue selected acquisitions that meet its portfolio acquisition criteria;
- continuing to develop its existing properties to enhance production and increase reserves;
- maintaining a balanced portfolio of geographically and geologically diversified oil and gas properties;
- controlling costs through efficient operation of existing and acquired properties;
- maintaining a capital structure that provides flexibility in accessing debt and capital markets; and
- managing commodity price risk when appropriate through hedging agreements that will increase the level of predictability in prices for its oil and gas production.

**Key Factors for Success**

The success of the Trust in meeting its objectives lies in management s ability to positively influence three main factors:

- identify, pursue and acquire oil and gas properties and/or companies at prices that add value to the Trust;
- cost effectively add or extend reserves with farmouts and internal development and drilling; and
- manage and contain costs.

PC s ability to achieve these three factors depends mainly on the experience, knowledge, and capability of the management team. In addition to the factors over which management has influence, there are numerous other factors beyond management s control which will influence the success of the organization. These other potential risks are identified in the Risk Factors section of this document.

**Outlook for Next Year**

The level of cash flow for 2006 will be affected by oil and gas prices, the $US/$CDN exchange rate, and the Trust s ability to add reserves and production in a cost effective manner. Both product prices and the exchange rate showed significant volatility in 2005 and this trend is expected to continue in 2006. The acquisition market is expected to continue to be active and supply should be stable with recent release of a number of large property packages by various large producers. Nevertheless, competition for these assets is expected to be intense due to increased demand resulting from the increasing number of oil and gas companies that have converted to a trust structure. We expect prices for quality, long life assets to be at or near record levels. Petrofund expects to be an active participant in this market but success will be tempered by commitment to maintain historic discipline and bid only at levels consistent with the best long term interest of our unitholders.

Acquisition activities will be complemented by an extensive drilling and farmout program that will be conducted on our existing land base.

Although product prices have remained at high levels, the strength of the Canadian dollar in 2005 significantly moderated the net effect of these prices on Petrofund s cash flow. The exchange rate US$/CDN$ averaged $0.8254 in 2005, as compared to $0.769 in 2004, reaching a high of $0.8751 on December 14, 2005. We expect the Canadian dollar to remain fairly strong throughout 2006.

Petrofund pursues a well defined risk management program to help offset the effect of price fluctuations. This program utilizes collars as the main hedging tool but Petrofund also enters into fixed price transactions when commodity prices approach historic highs. To date, the Trust has not entered into any currency related transactions.

Properties

The following is a summary of PC's and PVT s properties as at December 31, 2005. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2005, and all references to PC refer, collectively, to both PC and PVT. Gross reserve amounts are stated, before deduction of royalties and without including any royalty interests, as at December 31, 2005, based on forecast costs and price assumptions as evaluated in the GLJ Report. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

| Property Name | Operator | Average Working Interest | Major Product | 2005 Average Production (Boepd) | Proved Plus Probable Gross Reserves (Mboe) |
|---|---|---|---|---|---|
| Weyburn | EnCana Oil & Gas Partnership | 21% | Oil | 5,686 | 41,557 |
| Swan Hills | Various | 11% | Oil | 1,903 | 11,001 |
| Pembina | PC and Others | 35% | Oil & Gas | 1,173 | 8,330 |
| Kerrobert | PC | 90% | Oil & Gas | 1,903 | 6,050 |

| | | | | | |
|---|---|---|---|---|---|
| Strachan | PC and Others | 75% | Gas | 1,066 | 5,397 |
| July Lake | PC and CNRL | 50% | Gas | 1,556 | 5,204 |
| Fort Saskatchewan | PC | 95% | Gas | 1,155 | 4,795 |
| Three Hills Creek | PC | 60% | Gas | 1,123 | 4,346 |
| Berland River | PC and Burlington | 85% | Gas | 115 | 4,176 |
| Willesden Green | PC and Penn West | 75% | Oil & Gas | 841 | 3,959 |
| Others | Various | Various | Oil & Gas | 20,470 | 67,475 |
| Total | | | | 36,991 | 162,290 |

*Weyburn, Saskatchewan*

The Weyburn Unit, operated by EnCana Oil & Gas Partnership, is situated 30 kilometres south of Weyburn in southeast Saskatchewan and is the third largest conventional oil pool in Western Canada. PC s ownership in this unit is 21%, including an 11.7136% net royalty interest that is treated as a working interest as PC takes its production in kind and pays its share of capital costs, operating costs, royalties, and abandonment costs.

This unit s reserves life index remains especially long at 19 years due to ongoing enhanced recovery operations by both water and $CO_2$ flooding. The unit s 2005 production averaged 27,076 Boepd compared to 23,405 Boepd in 2004. The unit s 2005 exit rate was 28,674 Boepd. PC s working interest production averaged 5,686 Boepd in 2005 and 6,022 Boepd in December 2005.

2005 was another very active year for development activity within the unit, with 52 highly successful horizontal infill wells drilled within the $CO_2$ and waterflood areas. PC s total proved plus probable reserves as of December 31, 2005 amounted to 41,557 Mboe, comprised of 40,751 Mbbl of oil and 806 Mbbl of NGL.

*Swan Hills, Alberta*

PC s Swan Hills property is located approximately 200 kilometres northwest of Edmonton, Alberta, and includes significant ownership in two major oil units, Swan Hills Unit #1 and House Mountain Unit #1. Both units exhibit long life reserves due to enhanced recovery through water flooding and/or miscible hydrocarbon flooding. In addition, an investigational $CO_2$ enhanced recovery project has been operating in Swan Hills Unit #1 since 2004. 2005 development activity in Swan Hills Unit #1 included the drilling of 7 infill wells and a significant upgrade of the water injection plant. PC s working interest Swan Hills production averaged 1,903 Boepd in 2005. PC s total proved plus probable reserves as of December 31, 2005, totalled 11,001 Mboe, consisting of 1.9 Bcf of gas, 9,998 Mbbl of oil and 692 Mbbl of NGL.

*Pembina, Alberta*

Located 100 kilometres southwest of Edmonton, Alberta, PC has significant holdings in six non-operated oil units and six operated properties. Four wells were drilled within the non-operated units in 2005. In addition, PC acquired some gas assets in Pembina via its acquisition of Kaiser Energy Ltd. in late 2005. PC s Pembina production averaged 1,173 Boepd in 2005. PC s total proved plus probable reserves as of December 31, 2005, totalled 8,330 Mboe, made up of 9.4 Bcf of gas, 6,243 Mbbl of oil and 521 Mbbl of NGL.

*Kerrobert, Saskatchewan*

PC s Kerrobert property is located approximately 25 kilometres north of Kindersley in west central Saskatchewan. Wells are largely operated, with a working interest averaging approximately 95%. PC drilled 19 wells here in 2005, consisting of 16 oil wells and 3 gas wells. PC s working interest production from this area averaged 1,903 Boepd in 2005. PC s total proved plus probable reserves as of December 31, 2005, were 6,050 Mboe, consisting of 6.4 Bcf of gas, 4,771 Mbbl of oil and 208 Mbbl of NGL.

*Strachan, Alberta*

PC s Strachan property is located approximately 160 kilometres northwest of Calgary, Alberta, and consists of a variety of operated and non-operated producing entities. The Strachan area is recognized for its multiple zone potential, including the Leduc, Nisku, Beaverhill Lake, Ellerslie, Ostracod, Cardium, Viking, and Glauconitic. Petrofund substantially increased its holdings in the Strachan area by acquiring Kaiser Energy Ltd.



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in December 2005. PC s Strachan production rate averaged 1,066 Boepd in 2005. Petrofund s 2005 exit production rate was 1,700 Boepd owing to nearly 700 Boepd being added by the Kaiser acquisition. PC s total proved plus probable reserves as of December 31, 2005, were 5,397 Mboe, consisting of 25.2 Bcf of gas, 123 Mbbl of oil and 1,071 Mbbl of NGL.

***July Lake, British Columbia***

PC s July Lake gas property is situated about 160 kilometres northeast of Fort Nelson in the extreme northeast portion of British Columbia. PC operates several high working interest gas wells and associated gas gathering and compression facilities, plus has a 34% working interest in 19 non-operated gas wells. In early 2005, PC did a corporate acquisition which added approximately 2 MMcfpd to PC s production base. In addition, Petrofund drilled four 100% working interest horizontal gas wells and constructed a central compressor-dehydration facility in the first quarter of 2005. PC s production averaged 1,556 Boepd in 2005. PC s total proved plus probable reserves as of December 31, 2005, were 5,204 Mboe, consisting of 31.2 Bcf of gas and 12 Mbbl of NGL.

***Fort Saskatchewan, Alberta***

PC operates its Fort Saskatchewan gas property located immediately east of Edmonton, Alberta. PC s Fort Saskatchewan property includes the Beaverhill Lake Viking Gas Unit #1 and several non-unit wells, most of which produce from a large mature Viking gas pool extending from Fort Saskatchewan, on the west side of the Elk Island National Park, to Beaverhill Lake east of Toefield, Alberta. PC s working interests throughout this area average 97%. During 2005, PC began producing 2 wells drilled in late 2004, one being an infill gas well within the Beaverhill Lake Gas Unit #1 and the other being a well drilled to exploit the deeper Mannville gas horizons. Both wells are excellent producers and accordingly PC is actively looking to identify follow-up locations using recently-run seismic. In addition, PC acquired the Fort Saskatchewan assets of a junior oil and gas company in mid 2005, which added 325 boepd to PC s already significant production base. PC s working interest production averaged 1,155 Boepd in 2005, a 20% increase from 2004. PC s total proved plus probable reserves as of December 31, 2005, amounted to 4,795 Mboe, made up of 28.7 Bcf of gas and 4 Mbbl of NGL.

***Three Hills Creek, Alberta***

PC s Three Hills Creek property is located approximately 16 km southeast of Red Deer, Alberta. PC has an extensive position in the area covering approximately one hundred sections of land. PC has a high working interest in these lands and operates most of its production. Productive horizons include the Lower Mannville, Blairmore, Viking, Belly River, and Edmonton Sands. During 2005, PC participated in drilling 6 conventional gas wells and 78 coalbed methane gas wells. PC s net production from the area in 2005 averaged 1,123 Boepd (largely gas). PC s total proved plus probable reserves as of December 31, 2005, were 4,346 Mboe, consisting of 23.7 Bcf of gas, 91 Mbbl of oil and 312 Mbbl of NGL.

***Berland River, Alberta***

PC s Berland River property is situated 250 kilometres northeast of Edmonton, Alberta. PC obtained this property by way of its acquisition of Kaiser Energy Ltd. as of December 1, 2005. On an annualized basis, Berland River contributed 115 Boepd to PC s 2005 production base. More importantly, PC s Berland River production for December 2005 was 1,383 Boepd. PC s total proved plus probable reserves as of December 31, 2005, were 4,176 Mboe, consisting of 22.4 Bcf of gas, 49 Mbbl of oil and 385 Mbbl of NGL.

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***Willesden Green, Alberta***

PC s Willesden Green property is situated approximately 50 kilometres west of Red Deer, Alberta. Willesden Green is a collection of several individual operated and non-operated oil and gas entities. Producing horizons include the Glauconitic (gas) and the Cardium (oil). PC s average working interest production in 2005 was 841 Boepd. PC s total proved plus probable reserves as of December 31, 2005, were 3,957 Mboe, comprised of 6.9 Bcf of gas, 2,628 Mbbl of oil and 177 Mbbl of NGL.

The above 10 properties account for approximately 60% of PC s total proved plus probable reserves as at December 31, 2005.

***Other Properties***

Petrofund has various interests in numerous other properties located in Alberta, British Columbia, Manitoba and Saskatchewan. Petrofund s proved plus probable reserves for these other properties as at December 31, 2005, amounted to approximately 67,475 Mboe. In total these properties represent approximately 40% of Petrofund s proved plus probable reserves as at December 31, 2005.

A map illustrating the approximate locations of PC's principal properties is set out below:

click the image to enlarge

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## 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 February 9, 2006. The effective date of the Statement is December 31, 2005, and the preparation date of the Statement is January 30, 2006. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3, and the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2, are attached as Appendices A and B to this Annual Information Form. All references to PC in this Statement refer, collectively, to both PC and PVT.

**Disclosure of Reserves Data**

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ with an effective date of December 31, 2005 contained in the GLJ Report dated February 9, 2006. The Reserves Data summarizes the oil, liquids and natural gas reserves of PC and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("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. PC engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. (As noted PC s reserves data disclosure is made in accordance with Canadian disclosure requirements and may differ from US domestic standards and practices.)

All of PC s reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Manitoba, and Saskatchewan.

**It should not be assumed that the estimates of future net revenue presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant price and cost assumptions and forecast price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to certain risks involved, see "Risk Factors".**

Petrofund is a taxable entity under the Tax Act and is taxable only on income that is not distributed or distributable to the Unitholders. As Petrofund distributes all its taxable income to Unitholders, and meets the requirements of the Tax Act applicable to it, future net revenue after income taxes is not included in the disclosure below.

***Reserves Data (Constant Prices and Costs)***

SUMMARY OF OIL AND GAS RESERVES

AND NET PRESENT VALUES OF FUTURE NET REVENUE

as of December 31, 2005

CONSTANT PRICES AND COSTS

| | RESERVES | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM OIL | | HEAVY OIL | | NATURAL GAS | | NATURAL GAS LIQUIDS | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| RESERVES CATEGORY | (Mbbl) | (Mbbl) | (Mbbl) | (Mbbl) | (MMcf) | (MMcf) | (Mbbl) | (Mbbl) |
| PROVED RESERVES | | | | | | | | |
| Developed Producing | 53,129 | 45,663 | 733 | 657 | 262,751 | 209,898 | 5,888 | 4,175 |
| Developed Non-Producing | 300 | 282 | 0 | 0 | 16,607 | 13,277 | 261 | 175 |
| Undeveloped | 15,093 | 12,918 | 0 | 0 | 21,631 | 17,689 | 276 | 186 |
| TOTAL PROVED RESERVES | 68,522 | 58,862 | 733 | 657 | 300,989 | 240,865 | 6,425 | 4,535 |
| PROBABLE | 20,470 | 17,420 | 267 | 237 | 93,439 | 75,056 | 2,704 | 2,059 |
| TOTAL PROVED PLUS PROBABLE | 88,992 | 76,282 | 1,000 | 895 | 394,428 | 315,920 | 9,129 | 6,594 |

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)

| RESERVES CATEGORY | 0 (MM$) | 5 (MM$) | 10 (MM$) | 12 (MM$) | 15 (MM$) | 20 (MM$) |
|---|---|---|---|---|---|---|
| PROVED RESERVES | | | | | | |
| Developed Producing | 3,321.6 | 2,485.3 | 2,009.7 | 1,871.8 | 1,701.1 | 1,483.8 |
| Developed Non-Producing | 119.6 | 81.2 | 63.0 | 58.1 | 52.2 | 44.9 |
| Undeveloped | 563.2 | 363.7 | 249.4 | 217.2 | 178.4 | 131.5 |
| TOTAL PROVED RESERVES | 4,004.4 | 2,930.2 | 2,322.1 | 2,147.1 | 1,931.7 | 1,660.2 |
| PROBABLE | 1,401.5 | 790.0 | 517.1 | 448.8 | 371.1 | 283.2 |
| TOTAL PROVED PLUS PROBABLE | 5,405.9 | 3,720.2 | 2,839.2 | 2,595.9 | 2,302.8 | 1,943.4 |

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)

as of December 31, 2005

CONSTANT PRICES AND COSTS

| RESERVES CATEGORY | REVENUE (M$) | ROYALTIES (M$) | OPERATING COSTS (M$) | DEVELOPMENT COSTS (M$) | WELL ABANDONMENT COSTS (M$) | FUTURE NET REVENUE BEFORE INCOME TAXES (M$) |
|---|---|---|---|---|---|---|
| Proved Reserves | 7,477,875 | 1,386,915 | 1,717,919 | 290,746 | 77,842 | 4,004,454 |
| Proved Plus Probable Reserves | 9,788,605 | 1,820,516 | 2,120,678 | 361,757 | 79,724 | 5,405,930 |

FUTURE NET REVENUE

BY PRODUCTION GROUP

as of December 31, 2005

CONSTANT 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 other by-products) | 1,270,825 |
| | Heavy Oil (including solution gas and other by-products) | 10,922 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 1,067,266 |

| | | |
|---|---|---|
| | Other Company revenue/costs | (26,920) |
| Proved Plus Probable Reserves | Light and Medium Crude Oil (including solution gas and other by-products) | 1,547,678 |
| | Heavy Oil (including solution gas and other by-products) | 12,927 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 1,290,487 |
| | Other company revenue/costs | (11,898) |

***Reserves Data (Forecast Prices and Costs)***

SUMMARY OF OIL AND GAS RESERVES

AND NET PRESENT VALUES OF FUTURE NET REVENUE

as of December 31, 2005

FORECAST PRICES AND ESCALATING COSTS

| | RESERVES | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM OIL | | HEAVY OIL | | NATURAL GAS | | NATURAL GAS LIQUIDS | |
| RESERVES CATEGORY | Gross (Mbbl) | Net (Mbbl) | Gross (Mbbl) | Net (Mbbl) | Gross (MMcf) | Net (MMcf) | Gross (Mbbl) | Net (Mbbl) |
| PROVED RESERVES | | | | | | | | |
| Developed Producing | 51,891 | 44,557 | 719 | 644 | 258,190 | 206,154 | 5,765 | 4,097 |
| Developed Non-Producing | 309 | 289 | 0 | 0 | 16,640 | 13,307 | 264 | 178 |
| Undeveloped | 15,139 | 13,166 | 0 | 0 | 21,695 | 17,742 | 275 | 187 |
| TOTAL PROVED RESERVES | 67,338 | 58,011 | 719 | 644 | 296,526 | 237,203 | 6,304 | 4,462 |
| PROBABLE | 20,202 | 17,265 | 267 | 237 | 92,146 | 73,972 | 2,680 | 2,046 |
| TOTAL PROVED PLUS PROBABLE | 87,540 | 75,276 | 987 | 880 | 388,672 | 311,174 | 8,985 | 6,508 |

| | NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) | | | | | |
|---|---|---|---|---|---|---|
| RESERVES CATEGORY | 0 | 5 | 10 | 12 | 15 | 20 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) |
| PROVED RESERVES | | | | | | |
| Producing | 2,511.3 | 1,950.8 | 1,631.5 | 1,537.8 | 1,420.7 | 1,268.9 |
| Non-Producing | 97.8 | 66.4 | 52.2 | 48.5 | 44.0 | 38.5 |
| Undeveloped | 442.0 | 280.8 | 189.9 | 164.5 | 134.0 | 97.4 |
| TOTAL PROVED RESERVES | 3,051.1 | 2,298.0 | 1,873.6 | 1,750.8 | 1,598.7 | 1,404.8 |
| PROBABLE | 1,129.8 | 627.6 | 409.7 | 356.0 | 295.3 | 227.3 |
| TOTAL PROVED PLUS PROBABLE | 4,180.9 | 2,925.6 | 2,283.3 | 2,106.8 | 1,894.0 | 1,632.1 |

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)

as of December 31, 2005

FORECAST PRICES AND ESCALATED COSTS

| RESERVES CATEGORY | REVENUE (M$) | ROYALTIES (M$) | OPERATING COSTS (M$) | DEVELOPMENT COSTS (M$) | WELL ABANDONMENT COSTS (M$) | FUTURE NET REVENUE BEFORE INCOME TAXES (M$) |
|---|---|---|---|---|---|---|
| Proved Reserves | 6,625,165 | 1,218,162 | 1,943,720 | 313,472 | 98,725 | 3,051,086 |
| Proved Plus Probable Reserves | 8,772,720 | 1,607,838 | 2,484,975 | 391,428 | 107,554 | 4,180,924 |

FUTURE NET REVENUE

BY PRODUCTION GROUP

as of December 31, 2005

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 other by-products) | 1,019,653 |

| | | |
|---|---|---|
| | Heavy Oil (including solution gas and other by-products) | 10,209 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 883,927 |
| | Other company revenue/costs | (40,204) |
| Proved Plus Probable Reserves | Light and Medium Crude Oil (including solution gas and other by-products) | 1,244,016 |
| | Heavy Oil (including solution gas and other by-products) | 12,014 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 1,056,479 |
| | Other company revenue/costs | (29,210) |

**Definitions and Other Notes**

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1.

*"Gross" means:*

(a)

in relation to PC s interest in production and reserves, its "PC gross reserves", which are PC s interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of PC. The Weyburn 11.7136 percent net royalty interest acquired with the Ultima transaction is treated as a gross interest as PC receives production in kind and is responsible for its share of capital costs, operating costs, royalties and abandonment costs;

(b)

in relation to wells, the total number of wells in which PC has an interest; and

(c)

in relation to properties, the total area of properties in which PC has an interest.

2.

*"Net" means:*

(a)

in relation to PC s interest in production and reserves, its "PC net reserves", which are PC s interest (operating and non-operating) share after deduction of royalty obligations, plus PC's royalty interest in production or reserves.

(b)

in relation to wells, the number of wells obtained by aggregating PC s working interest in each of its gross wells; and

(c)

in relation to PC s interest in a property, the total area in which PC has an interest multiplied by the working interest owned by PC.

3.

Definitions used for reserve categories are as follows:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

•

analysis of drilling, geological, geophysical and engineering data;

•

the use of established technology; and

•

specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates.

(a)

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

(b)

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

"Economic Assumptions" will be the prices and costs used in the estimate, namely: constant prices and

•

costs as at the last day of PC s financial year

•

forecast prices and costs

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a)

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

(i)

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

(ii)

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

(b)

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

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

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

•

At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

•

At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4.

*Forecast prices and costs*

Future prices and costs that are:

(a)

Generally acceptable as being a reasonable outlook of the future; and

(b)

If and only to the extent that, there are fixed or presently determinable future prices or costs to which PC is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that apply to PC.

5.

*Constant prices and costs*

Prices and costs used in an estimate that are:

(a)

PC s prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b)

If, and only to the extent that, there are fixed or presently determinable future prices or costs to which PC is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), PC prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

6.

The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. PC qualifies for the maximum ARTC.

7.

"Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

8.

"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, 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.

9.

"Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

10.

"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 defence, 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.

11.

"Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation, or injection for combustion.

12.

Numbers may not add due to rounding.

13.

The estimates of future net revenue presented in the tables above do not represent fair market value.

14.

Estimated further abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributable to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated further well abandonment costs.

15.

Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

16.

The extended character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

**Pricing Assumptions**

The following sets out the benchmark reference prices, as at December 31, 2005, reflected in the Reserves Data. These price assumptions and exchange rate assumptions were provided to PC by GLJ, PC s independent reserves evaluator.

SUMMARY OF PRICING ASSUMPTIONS

as of December 31, 2005

CONSTANT PRICES AND COSTS

| | OIL | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | WTI Cushing Oklahoma ($US/Bbl) | Edmonton Par Price 40° API ($Cdn/Bbl) | Hardisty Heavy 12° API ($Cdn/Bbl) | Cromer Medium 29.3° API ($Cdn/Bbl) | NATURAL GAS AECO Gas Price ($Cdn/MMBtu) | Edmonton Propane ($Cdn/Bbl) | Edmonton Butane ($Cdn/Bbl) | Edmonton Pentanes Plus ($Cdn/Bbl) | EXCHANGE RATE((1) ($US/$Cdn) |
| As at December 31, 2005 | 61.04 | 68.27 | 28.25 | 51.84 | 9.71 | 43.69 | 50.52 | 71.67 | 0.8577 |

Note:

(1)

The exchange rate used to generate the benchmark reference prices in this table.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

as of December 31, 2005

FORECAST PRICES AND COSTS

| | OIL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | WTI Cushing Oklahoma ($US/Bbl) | Edmonton Par Price 40° API ($Cdn/Bbl) | Hardisty Heavy 12° API ($Cdn/Bbl) | Cromer Medium 29.3° API ($Cdn/Bbl) | NATURAL GAS AECO Gas Price ($Cdn/MMBtu) | Edmonton Propane ($Cdn/Bbl) | Edmonton Butane ($Cdn/Bbl) | Edmonton Pentanes Plus ($Cdn/Bbl) | EXCHANGE RATE(1) ($US/$Cdn) | INFLATION RATES(2) %/Year |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Forecast: | | | | | | | | | | |
| 2006 | 57.00 | 66.25 | 33.25 | 55.75 | 10.60 | 42.50 | 49.00 | 67.00 | 0.85 | 2.0 |
| 2007 | 55.00 | 64.00 | 32.75 | 55.25 | 9.25 | 41.00 | 47.25 | 65.25 | 0.85 | 2.0 |
| 2008 | 51.00 | 59.25 | 32.50 | 51.25 | 8.00 | 38.00 | 43.75 | 60.50 | 0.85 | 2.0 |
| 2009 | 48.00 | 55.75 | 32.00 | 48.25 | 7.50 | 35.75 | 41.25 | 56.75 | 0.85 | 2.0 |
| 2010 | 46.50 | 54.00 | 32.00 | 46.75 | 7.20 | 34.50 | 40.00 | 55.00 | 0.85 | 2.0 |
| 2011 | 45.00 | 52.25 | 33.50 | 45.25 | 6.90 | 33.50 | 38.75 | 53.25 | 0.85 | 2.0 |
| 2012 | 45.00 | 52.25 | 33.50 | 45.25 | 6.90 | 33.50 | 38.75 | 53.25 | 0.85 | 2.0 |
| 2013 | 46.00 | 53.25 | 34.00 | 46.00 | 7.05 | 34.00 | 39.50 | 54.25 | 0.85 | 2.0 |
| 2014 | 46.75 | 54.25 | 34.75 | 47.00 | 7.20 | 34.75 | 40.25 | 55.25 | 0.85 | 2.0 |
| 2015 | 47.75 | 55.50 | 35.25 | 48.00 | 7.40 | 35.50 | 41.00 | 56.50 | 0.85 | 2.0 |
| 2016 | 48.75 | 56.50 | 36.00 | 48.75 | 7.55 | 36.25 | 41.75 | 57.75 | 0.85 | 2.0 |

Notes:

(1)

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

(2)

Inflation rates for forecasting prices and costs. Prices escalate 2.0% in 2017 and thereafter.

PC s weighted average prices received in 2005 after transportation and quality differentials were $61.54/Bbl for oil, $9.02/Mcf for natural gas, and $52.98/Bbl for natural gas liquids.

**Reconciliations of Changes in Reserves and Future Net Revenue**

RECONCILIATION OF

COMPANY NET RESERVES

BY PRINCIPAL PRODUCT TYPE

CONSTANT PRICES AND COSTS

| | LIGHT AND MEDIUM OIL | | | HEAVY OIL | | | ASSOCIATED AND NON ASSOCIATED GAS | | |
|---|---|---|---|---|---|---|---|---|---|
| | Net Proved | Net Probable | Net Proved Plus Probable | Net Proved | Net Probable | Net Proved Plus Probable | Net Proved | Net Probable | Net Proved Plus Probable |
| FACTORS | (Mbbl) | (Mbbl) | (Mbbl) | (Mbbl) | (Mbbl) | (Mbbl) | (MMcf) | (MMcf) | (MMcf) |
| December 31, 2004 | 59,740 | 16,319 | 76,059 | 872 | 210 | 1,082 | 183,628 | 45,682 | 229,310 |
| Extensions | 47 | -21 | 25 | 0 | 0 | 0 | 3,817 | 1,891 | 5,708 |
| Improved Recovery | 3,883 | 907 | 4,790 | 4 | 0 | 4 | 8,683 | 1,776 | 10,458 |
| Technical Revisions | 682 | -52 | 629 | -149 | -19 | -168 | -6,851 | -3,637 | -10,488 |
| Discoveries | 16 | 4 | 20 | 0 | 0 | 0 | 792 | 362 | 1,154 |
| Acquisitions | 263 | 124 | 386 | 20 | 50 | 70 | 76,582 | 28,543 | 105,125 |
| Dispositions | -282 | -55 | -337 | 0 | 0 | 0 | -86 | -18 | -103 |
| Economic Factors | -86 | 195 | 109 | -3 | -3 | -6 | 2,073 | 456 | 2,529 |
| Production | -5,400 | 0 | -5,400 | -87 | 0 | -87 | -27,773 | 0 | -27,773 |
| December 31, 2005 | 58,862 | 17,420 | 76,282 | 657 | 238 | 895 | 240,865 | 75,055 | 315,920 |

| | NATURAL GAS LIQUIDS | | | BARRELS OF OIL EQUIVALENT | | |
|---|---|---|---|---|---|---|
| | Net Proved | Net Probable | Net Proved Plus Probable | Net Proved | Net Probable | Net Proved Plus Probable |
| FACTORS | (Mbbl) | (Mbbl) | (Mbbl) | (Mboe) | (Mboe) | (Mboe) |
| December 31, 2004 | 4,477 | 1,742 | 6,219 | 95,694 | 25,884 | 121,578 |
| Extensions | 16 | 5 | 20 | 698 | 298 | 996 |
| Improved Recovery | 109 | 27 | 136 | 5,443 | 1,229 | 6,672 |
| Technical Revisions | -82 | -34 | -116 | -692 | -710 | -1,402 |
| Discoveries | 1 | 1 | 2 | 149 | 65 | 214 |
| Acquisitions | 658 | 307 | 965 | 13,704 | 5,238 | 18,942 |
| Dispositions | -29 | -5 | -34 | -325 | -63 | -388 |
| Economic Factors | 35 | 16 | 51 | 292 | 284 | 576 |
| Production | -649 | 0 | -649 | -10,764 | 0 | -10,764 |
| December 31, 2005 | 4,536 | 2,058 | 6,594 | 104,199 | 32,225 | 136,424 |

RECONCILIATION OF CHANGES IN

NET PRESENT VALUES OF FUTURE NET REVENUE

DISCOUNTED AT 10% PER YEAR

PROVED RESERVES

CONSTANT PRICES AND COSTS

| PERIOD AND FACTOR | 2005 (M$) |
|---|---|
| Estimated Net Present Value Before Tax at Beginning of Year | 1,156,672 |
| Oil and Gas Sales During the Period[(1)] | (481,790) |
| Changes due to Prices, Production Costs and Royalties Related to Forecast Production[(2)] | 1,001,636 |
| Development Costs During the Period[(3)] | 136,200 |
| Changes in Forecast Development Costs[(4)] | (178,330) |
| Changes Resulting from Extensions and Improved Recovery[(5)] | 137,275 |

| | |
|---|---|
| Changes Resulting from Discoveries(5) | 3,521 |
| Changes Resulting from Acquisitions of Reserves(5) | 317,374 |
| Changes Resulting from Dispositions of Reserves(5) | (6,933) |
| Accretion of Discount(6) | 115,667 |
| Net Change in Income Taxes(7) | N/A |
| Changes Resulting from Technical Reserves Revisions | 20,926 |
| All Other Changes(8) | 99,874 |
| Estimated Net Present Value Before Tax at End of Period | 2,322,092 |

**Notes:**

(1)

Company actual before income taxes, excluding G&A

(2)

The impact of changes in prices and other economic factors on future net revenue

(3)

Actual capital expenditures relating to the exploration and development and production of oil and gas reserves

(4)

The change in forecast development costs

(5)

End of period net present value of the related reserves

(6)

Estimated as 10% of the beginning of period net present value

(7)

The difference between forecast income taxes at beginning of period and the actual taxes for the period, plus forecast income taxes at the end of the period

(8)

Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2004 versus forecast, etc.

**Additional Information Relating to Reserves Data**

***Undeveloped Reserves***

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). In general, undeveloped reserves are scheduled to be developed within the next two years of the effective date of the GLJ Report. Capital expenditures to develop proved undeveloped reserves are estimated at $53.3 million in 2006 and $28.7 million in 2007. Capital expenditures to develop probable undeveloped reserves are estimated at $8.5 million in 2006 and $11.0 million in 2007.

***Significant Factors or Uncertainties***

Petrofund does not anticipate that any important economic factors or significant uncertainties would affect particular components of the reserves data. Notwithstanding that, a number of factors which are beyond Petrofund s and PC s control can significantly affect the reserves, including fluctuations in product pricing, royalty and tax regimes, changing operating and capital costs, surface access issues, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

***Future Development Costs***

The following table sets forth development costs deducted in the estimation of PC s future net revenue attributable to the reserve categories noted below.

| | Forecast Prices and Costs (M$) | | Constant Prices and Costs (M$) |
|---|---|---|---|
| Year | Proved Reserves | Proved Plus Probable Reserves | Proved Reserves |
| 2006 | 86,424 | 94,944 | 84,424 |
| 2007 | 42,050 | 53,097 | 41,226 |
| 2008 | 34,770 | 38,787 | 33,425 |
| 2009 | 27,076 | 33,404 | 25,512 |
| 2010 | 21,430 | 33,442 | 19,797 |
| Remainder | 101,722 | 137,754 | 86,362 |
| Total Undiscounted | 313,472 | 391,428 | 290,746 |
| Total Discounted at 10% | 222,912 | 272,285 | 213,027 |

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

**Other Oil and Gas Information**

***Oil And Gas Wells***

The following table sets forth the number and status of wells in which PC has a working interest as at December 31, 2005.

| | Oil Wells | | | | Natural Gas Wells | | | | Service Wells | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-Producing | | Producing | | Non-Producing | | | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 2,602 | 591.1 | 1,023 | 212.6 | 1,988 | 665.9 | 565 | 197.9 | 829 | 142.4 |
| British Columbia | 83 | 21.1 | 98 | 8.5 | 286 | 63.1 | 90 | 19.1 | 28 | 5.7 |
| Manitoba | 122 | 106.1 | 48 | 45.5 | 0 | 0 | 0 | 0 | 26 | 25.7 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Saskatchewan | 3,148 | 1,787.4 | 289 | 54.9 | 345 | 303.1 | 13 | 7.5 | 138 | 105.2 |
| Total | 5,955 | 2,505.7 | 1,458 | 321.5 | 2,619 | 1,032.1 | 668 | 224.5 | 1,021 | 279 |

***Properties with no Attributable Reserves***

The following table sets out PC s undeveloped land holdings as at December 31, 2005.

| | Undeveloped Acres | |
|---|---|---|
| | Gross | Net |
| Alberta | 442,089 | 208,733 |
| British Columbia | 126,018 | 39,824 |
| Manitoba | 1,361 | 1,341 |
| Saskatchewan | 93,782 | 60,026 |
| Total | 663,250 | 309,924 |

There are no material work commitments on the undeveloped land holdings.

PC expects that rights to explore, develop and exploit 29,000 net acres of its undeveloped land holdings will expire by December 31, 2006**.**

***Additional Information Concerning Abandonment and Reclamation Costs***

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date by PC for abandonment and reclamation activities. Costs to abandon and reclaim approximately 3500 net wells totalling $79.7 million net of salvage value ($27.1 million discounted at 10%) are included in the estimate of future net revenue. Facility abandonment costs and suspended well abandonment costs of $47.6 million ($15.4 million discounted at 10%) are not included in the estimate of future net revenue disclosed in the tables contained under Disclosure of Reserves Data . Abandonment and reclamation costs estimated for the next three years are $3.6 million in 2006, $3.9 million in 2007 and $5.9 million in 2008.

***Forward Contracts***

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2005, see Note 15 to the Trust s audited consolidated financial statement for the year ended December 31, 2005, which Note is incorporated herein by this reference.

***Tax Horizon***

As a result of the Trust's tax efficient structure, annual taxable income is transferred from its operating entities to the Trust and from the Trust to Unitholders. Therefore, it is expected that no income tax liability will be incurred by the Trust for so long as the Trust maintains its organizational tax structure. PC also will not be taxable so long as the interest on the notes held by the Trust, royalties under the NPI Agreements and other expenses in PC are sufficient to reduce taxable income to nil in the operating subsidiaries. PC is not expected to be taxable in 2006.

***Capital Expenditures***

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to PC s activities for the last three years:

| **For the years ended December 31,** | **2005** | **2004** | **2003** |
|---|---|---|---|
| Corporate and property acquisitions (1) | $561.1 | $32.1 | $115.6 |
| Property dispositions | (0.9) | (1.0) | (33.5) |
| **Total corporate and property acquisitions - cash** | 560.2 | 31.1 | 82.1 |
| Development expenditures: | | | |
| Land & seismic | 8.5 | 2.2 | 2.5 |
| Drilling & completion | 68.9 | 35.3 | 42.5 |
| Well equipping | 10.4 | 10.6 | 7.9 |
| Tie-ins | 14.3 | 5.4 | 5.2 |
| Facilities | 24.9 | 13.3 | 8.4 |

| | | | |
|---|---|---|---|
| $CO_2$ purchases | 17.7 | 8.4 | 3.5 |
| Other | 0.6 | 1.5 | 1.4 |
| **Total development expenditures - cash** | 145.3 | 76.7 | 71.4 |
| Total net capital expenditures cash | 705.5 | 107.8 | 153.5 |
| Corporate acquisitions - non-cash (2) | 178.5 | 570.0 | 4.7 |
| Current year ARO capitalized | 15.2 | 1.2 | 2.3 |
| **Total capital expenditures** (3) | $899.2 | $679.0 | $160.5 |

(1)

The corporate and property acquisition totals exclude the impact of non-cash items on corporate acquisitions such as future income taxes and ARO.

(2)

Includes non-cash items such as: Trust units issued, working capital assumed, future income tax adjustments for the difference between the cost and tax basis of assets acquired and asset retirement obligations recognized for corporate acquisitions.

(3)

Includes change in oil and natural gas royalty and property interest and goodwill.

***Exploration and Development Activities***

The following tables set forth the gross and net exploratory and development wells in which PC participated during the year ended December 31, 2005:

*Working Interest Wells*

| | Development Wells | | Exploration Wells | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Oil | 111 | 31.3 | 2 | 1.5 |
| Gas | 148 | 40.6 | 13 | 4.2 |
| Service | 5 | 2.2 | 0 | 0 |
| Dry | 2 | 1.8 | 1 | 1 |
| Total: | 266 | 75.9 | 16 | 6.7 |

*Farm-out Wells*

| | Development Wells | Exploration Wells |
|---|---|---|
| Oil | 0 | 5 |
| Gas | 8 | 6 |
| Service | 0 | 0 |
| Dry | 0 | 0 |
| Total: | 8 | 11 |

PC s most important current and likely exploration and development activities are described under "Business and Properties".

***Production Estimates***

The following table sets out the gross volume of PC s production estimated for the year ended December 31, 2006 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" using constant prices and costs.

| | Light and Medium Oil | Heavy Oil | Natural Gas | Natural Gas Liquids | BOE |
|---|---|---|---|---|---|
| | (Bpd) | (Bpd) | (Mcfpd) | (Bpd) | (Boepd) |
| Proved Producing | 17,108 | 274 | 111,152 | 2,274 | 38,182 |
| Total Proved | 17,542 | 274 | 121,603 | 2,248 | 40,332 |
| Proved plus Probable | 18,004 | 326 | 130,190 | 2,382 | 42,410 |

No one area accounts for 20% or more of the estimated production disclosed.

***Production History and Prices Received***

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netbacks for the periods indicated below:

| | | 2005 | | | |
|---|---|---|---|---|---|
| | | Quarter Ended | | | |
| | Total | Dec. 31 | Sept. 30 | June 30 | Mar. 31 |
| **Average Daily Production** | | | | | |
| Gas (MMcfpd) | 98.1 | 108.9 | 97.8 | 97.0 | 88.3 |
| Light and Medium Crude Oil (Bpd) (1) | 18,264 | 18,856 | 18,451 | 17,500 | 18,238 |
| NGLs (Bpd) | 2,383 | 2,164 | 2,730 | 2,353 | 2,283 |
| Combined (Boepd) | 36,991 | 39,178 | 37,485 | 36,011 | 35,234 |
| **Selling Price** | | | | | |
| Gas ($/Mcf) | $9.02 | $11.78 | $9.10 | $7.65 | $6.97 |
| Light and Medium Crude Oil ($/Bbl) (1) | $61.54 | $62.46 | $69.37 | $59.18 | $54.74 |
| NGLs ($/Bbl) | $52.98 | $65.46 | $50.36 | $51.10 | $46.04 |
| Combined ($/Boe) | $57.71 | $66.44 | $61.57 | $52.69 | $48.79 |
| **Cash Cost of Hedging** | | | | | |
| Gas ($/Mcf) | $0.14 | $0.28 | $0.21 | $0.02 | - |
| Light and Medium Crude Oil ($/Bbl) (1) | $5.48 | $5.38 | $6.49 | $5.01 | $5.02 |
| NGLs ($/Bbl) | - | - | - | - | - |
| Combined ($/Boe) | $3.03 | $0.66 | $3.72 | $2.45 | $2.60 |
| **Royalties, Net of ARTC** | | | | | |
| Gas ($/Mcf) | $2.01 | $2.80 | $2.01 | $1.47 | $1.62 |
| Light and Medium Crude Oil ($/Bbl) (1) | $10.83 | $11.12 | $12.20 | $9.76 | $10.13 |
| NGLs ($/Bbl) | $13.42 | $16.98 | $13.18 | $12.15 | $11.50 |
| Combined ($/Boe) | $11.54 | $14.07 | $12.21 | $9.49 | $10.04 |
| **Lease Operating Costs** | | | | | |
| Gas ($/Mcf) | $1.31 | $1.47 | $1.57 | $1.30 | $1.32 |
| Light and Medium Crude Oil ($/Bbl) (1) | $12.97 | $12.50 | $11.17 | $13.96 | $12.00 |
| NGLs ($/Bbl) | $9.39 | $9.39 | $9.99 | $9.19 | $9.03 |
| Combined ($/Boe) | $10.49 | $10.64 | $10.31 | $10.89 | $10.09 |
| **Transportation Costs** | | | | | |
| Gas ($/Mcf) | $0.12 | $0.10 | $0.15 | $0.12 | $0.13 |
| Light and Medium Crude Oil ($/Bbl) (1) | $0.48 | $0.40 | $0.49 | $0.43 | $0.58 |

| | | | | | |
|---|---|---|---|---|---|
| NGLs ($/Bbl) | $9.39 | $0.55 | $0.46 | $0.56 | $0.50 |
| Combined ($/Boe) | $10.49 | $0.51 | $0.66 | $0.58 | $0.64 |
| **Netback Received** | | | | | |
| Gas ($/Mcf) | $5.44 | $7.13 | $5.16 | $4.74 | $3.90 |
| Light and Medium Crude Oil ($/Bbl) (1) | $31.78 | $33.06 | $39.02 | $30.02 | $27.01 |
| NGLs ($/Bbl) | $29.65 | $38.54 | $26.73 | $29.20 | $25.03 |
| Combined ($/Boe) | $32.05 | $37.85 | $34.67 | $29.28 | $25.45 |

Note:

(1)

Heavy oil production is not significant and is included in light and medium crude oil.

## CAPITAL STRUCTURE OF PC

PC's authorized capital is comprised of an unlimited number of common shares and an unlimited number of PC Exchangeable Shares.

### Common Shares

PC has authorized for issuance an unlimited number of common shares of which, as at March 15, 2006, two (two as at December 31, 2005) common shares are issued and outstanding and held by Computershare Trust Company of Canada, as trustee of the Trust. The holders of common shares are entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of PC (other than meetings of a class or series of shares of PC other than the common shares as such). The holders of common shares are entitled to receive dividends as and when declared by the Board of Directors of PC on the common shares as a class, and subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of PC ranking in priority to the common shares in respect of dividends, to share rateably, together with the shares of any other class of shares of PC ranking equally with the common shares in respect of dividends. The holders of common shares are entitled to in the event of any liquidation, dissolution or winding up of PC, whether voluntary or involuntary, or any other distribution of the assets of PC among its shareholders for the purpose of winding up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of PC ranking in priority to the common shares in respect of return of capital on dissolution, to share rateably, together with the shares of any other class of shares of PC ranking equally with the common shares in respect of return of capital on dissolution, in such assets of PC as are available for distribution.

Pursuant to the Voting Shareholder Agreement, Unitholders are entitled to designate the individuals to be elected as directors of PC by resolution of Unitholders and, following such designation, the Trust will take all actions necessary to elect or appoint the nominees so designated as directors of PC. In addition, the Board of Directors may, between annual meetings, appoint one or more additional directors of PC to serve as directors until the next annual meeting, but the number of additional directors may not at any time exceed 1/3 of the number of directors for available office at the expiration of the last annual meeting of PC. In addition, pursuant to the Voting Shareholder Agreement, Unitholders designate the independent auditors to be appointed as auditors of the Trust and PC by resolution passed by Unitholders.

### PC Exchangeable Shares

PC is authorized to issue an unlimited number of PC Exchangeable Shares, of which, as at December 31, 2005, 283,025 PC Exchangeable Shares were issued and outstanding, which can be exchanged into 388,147 Trust Units. The PC Exchangeable Shares rank prior to the common shares of PC and any other shares ranking junior to the PC Exchangeable Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of PC, whether voluntary or involuntary, or any other distribution of the assets of PC among its shareholders for the purpose of winding up its affairs. Provided that same is declared during the Dividend Period, holders of PC Exchangeable Shares are entitled to receive, as and when declared by the board of directors of PC in its sole discretion, from time to time, non cumulative preferential cash dividends in an amount per share equal to the amount of the Distribution relating to the subject Distribution Payment Date multiplied by the Exchange Ratio as at the subject Distribution Payment Date. It is not anticipated that dividends will be declared or paid on the PC Exchangeable Shares; however, the Board of Directors has the right in its sole discretion to do so.

PC will not, without obtaining the approval of the holders of the PC Exchangeable Shares as set forth below:

(a)

pay any dividend on the common shares of PC or any other shares ranking junior to the PC Exchangeable Shares, other than stock dividends payable in common shares of PC or any such other shares ranking junior to the PC Exchangeable Shares;

(b)

redeem, purchase or make any capital distribution in respect of the common share of PC or any other shares ranking junior to the PC Exchangeable Shares;

(c)

redeem or purchase any other shares of PC ranking equally with the PC Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d)

issue any shares, other than PC Exchangeable Shares or common shares of PC, which rank superior to the PC Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

In the event that a dividend is not declared by PC prior to the expiry of a Dividend Period, each holder of PC Exchangeable Shares shall have the right, exercisable for a period of 5 business days from the date of expiry of the subject Dividend Period, to redeem such number of PC Exchangeable Shares (the "Cash Retracted Shares") as have a value (calculated as the amount equal to the Exchange Ratio as at the date of delivery of the notice of the holder to retract multiplied by the Current Market Price) equal to the aggregate amount of the dividend which would have been paid to the holder had a dividend been declared and paid in respect of the subject Dividend Period (the "Aggregate Dividend Amount") for an amount in cash equal to the Aggregate Dividend Amount.

A holder of PC Exchangeable Shares is entitled at any time to exchange each PC Exchangeable Shares into a set number of Trust Units determined by multiplying the number of PC Exchangeable Shares by the Exchange Ratio then in effect.

The PC Exchangeable Shares provide holders with a security having economic, ownership, and voting rights which are substantially equivalent to those of Trust Units.  The PC Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in the Exchange Ratio to reflect distributions paid by the Trust to Unitholders.  The PC Exchangeable Shares are provided equivalent voting rights as unitholders through the PC Support Voting and Exchange Agreement.  Pursuant to the PC Support Voting and Exchange Agreement, the Trust has issued a Special Voting Unit to Petro Assets, the holder of the PC Exchangeable Shares.  The Special Voting Unit entitles Petro Assets to such number of votes, exercisable at any meeting at which unitholders are entitled to vote, equal to the Aggregate Equivalent Vote Amount.

At any time on or after April 29, 2010, or at any time on or after the date when the aggregate number of issued and outstanding PC Exchangeable Shares is less than 100,000, holders of PC Exchangeable Shares may be required by PC to sell all of the then outstanding PC Exchangeable Shares in exchange for the payment of either cash, PC Exchangeable Shares or that number of Trust Units determined by multiplying the number of PC Exchangeable Shares by the Exchange Ratio then in effect.

The PC Exchangeable Shares are convertible, at the option of the holder thereof, into common shares of PC, on a one for one basis (the "Conversion Right"). Pursuant to the provisions of that Shareholders Agreement dated April 29, 2003, and made among Petrofund Energy Trust, Petrofund Corp., 1518274 Ontario Limited, and Petro Assets Inc., Petro Assets has agreed never to exercise the Conversion right in respect of any PC Exchangeable Shares held thereby.

# INFORMATION RELATING TO THE TRUST

## Trust Indenture

*General*

The Trust is an investment trust created pursuant to the Trust Indenture and governed by the laws of the Province of Ontario. The Trust has been established for the purpose of holding royalties granted by PC and acquiring, directly and indirectly, securities and royalties of oil and gas companies, oil and gas properties and other related assets. The following is a summary of certain provisions of the Trust Indenture. For a complete description of such Trust Indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at *www.sedar.com.*

*Trust Units*

An unlimited number of Trust Units are issueable pursuant to the Trust Indenture. As at December 31, 2005, 117,561,000 Trust Units and Trust Units issueable for PC Exchangeable Shares were issued and outstanding. Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Each outstanding Trust Unit is entitled to an equal share of distributions by the Trust and, in the event of termination of the Trust, the net assets of the Trust. All Trust Units rank equally. Each Trust Unit entitles the holder thereof to one vote at all meetings of Unitholders.

*Special Voting Units*

An unlimited number of Special Voting Units are also issueable pursuant to the Trust Indenture. Special Voting Units may only be issued by the Trust in conjunction with the issuance by the Corporation or an affiliate of exchangeable shares or exchangeable partnership interests. Each holder of a Special Voting Unit of record is entitled to vote at all meetings of Unitholders. The number of votes attached to each Special Voting Unit shall be that number of Trust Units into which the exchangeable shares issued in conjunction with the Special Voting Unit and at that time outstanding are then exchangeable. The holders of Trust Units and the holder of Special Voting Units vote together as a single class on all matters. Special Voting Units have the foregoing rights in respect of voting at all meetings of unitholders but have no other rights and, for greater certainty, Special Voting Units do not represent a beneficial interest in the Trust. In the event that exchangeable shares issued in conjunction with a Special Voting Unit cease to be outstanding, such Special Voting Unit shall be deemed to be cancelled.

A Special Voting Unit was issued in connection with the Internalization Transaction to Petro Assets, which company was issued PC Exchangeable Shares pursuant to the Internalization Transaction.

*Trustee*

The Trust Indenture provides that the Trustee is required to exercise its powers and carry out its functions thereunder as trustee honestly, in good faith, and in the best interests of the Trust and the Unitholders and, in connection therewith, will exercise that degree of care, diligence, and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee, where it has met its standard of care, will be indemnified out of the assets of the Trust for any actions, suits, or proceedings commenced against the Trustee in respect of the Trust and for costs, taxes, and other liabilities incurred by the Trustee in respect of the administration or termination of the Trust but will have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

*Issuance of Trust Units*

The Trust Indenture provides that Trust Units may be issued whether fully paid or in the context of an offering, on an instalment basis, subject to the approval of the Board of Directors, for the purposes of, among other things, acquiring, or raising capital to acquire, net royalty interests, securities of oil and gas companies and oil and gas properties and related assets. The Trust Indenture also provides that the Board of Directors may also authorize the creation and issuance from time to time of rights, warrants or options to subscribe for Trust Units or other securities convertible or exchangeable into Trust Units.

*Distributions*

The Trust makes monthly cash distributions of the distributable cash flow received by the Trust in each month. Distributions are made on the last business day of each month to Unitholders of record as at the close of business on the tenth business day preceding each such distribution date.

*Management of the Trust*

The Trust Indenture provides for the delegation to PC by the Trustee the authority to manage the business and affairs of the Trust and the authority to administer and manage the operations of the Trust. Without limiting the foregoing, the Trustee has delegated to PC: (i) the responsibility and authority for all matters relating to an offering of Units or any rights, warrants, options, or other securities to acquire Units or other securities of the Trust and all matters relating to the content and accuracy of disclosure contained in any offering documents, management proxy circulars, or continuous disclosure documents relating thereto; (ii) the ability and other responsibilities to exercise all rights, powers, and privileges in relation to all matters relating to any take-over bid, merger, amalgamation, arrangement, acquisition of all or substantially all of the assets of a person, or similar transaction or form of business combination; (iii) the voting of investments and securities held by the Trust; (iv) the responsibility and authority for all matters pertaining to the repurchase and retraction of Units pursuant to the Trust Indenture; (v) the responsibility and authority for entering into and the amendment of the provisions of the NPI Agreements; (vi) the responsibility and authority for any borrowing, securing of credit, or granting of security by the Trust and related matters; (vii) the responsibility and authority to approve financial statements of the Trust and to furnish to Unitholders reports required under the Trust Indenture or by law; (viii) the responsibility and authority to call, hold, and distribute materials in respect of meetings of Unitholders; (ix) the responsibility and authority to arrangement for payment of all costs and expenses incurred by the Trustee or any third party on account of the Trust in connection with the establishment and ongoing management of the Trust (but excluding any expenses deducted in determining royalty income for purposes of the NPI Agreements); and (x) the responsibility and authority for all matters pertaining to tax and other matters.

PC has accepted such delegation and has agreed that it shall exercise its powers and carry out its functions honestly, in good faith and with a view to the best interests of the Trust and the Unitholders, and, in connection therewith, shall exercise that degree of care, skill, and diligence that a reasonably prudent person would exercise in comparable circumstances.

*Retraction Right in Respect of Trust Units*

Trust Units are retractable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting retraction. Upon receipt of the retraction request by the Trust, all rights to and under the Trust Units tendered for retraction shall be surrendered and the holder thereof shall be entitled to receive a price per Trust Unit (the "Retraction

Price") equal to the lesser of: (i) 95% of the "market price" (as defined in the Trust Indenture) of the Trust Units on the principal market on which the Trust Units are listed for trading during the 10 trading day period commencing immediately after the date on which the Trust Units were surrendered for



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retraction (the "Retraction Date"); and (ii) the "closing market price" (as defined in the Trust Indenture) on the principal market on which the Trust Units are quoted for trading on the Retraction Date.

The aggregate Retraction Price payable by the Trust in respect of any Trust Units surrendered for retraction during any calendar month shall be satisfied by way of a cash payment on the last day of the following month; provided that the entitlement of Unitholders to receive cash upon the retraction of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month shall not exceed $100,000 provided that such limitation may be waived in the discretion of the Trustee. If at the time any Units are tendered for retraction the Units are not listed on a Canadian stock exchange, are not traded in a manner that provides representative fair market value prices for the Units or the normal trading of the Units is suspended or halted, the retraction price of Units will be equal to 95% of the fair market value as of the Retraction Date as determined by the Board of Directors.

If a Unitholder is not entitled to receive cash upon the retraction of Trust Units as a result of the foregoing limitations, then the Retraction Price shall, subject to any applicable regulatory approvals, be paid and satisfied by way of a distribution in specie of debt securities of PC then held by the Trust (the "PC Notes") having a term determined by the Board of Directors ending not more than five years after the date of issue and a rate of interest which is no less than the then highest rate of interest charged by the Trust to PC. If the Trust does not hold PC Notes having a sufficient principal amount outstanding to effect such payment, the Trust will be entitled to create and, subject to any applicable regulatory approvals, issue in satisfaction of the Retraction Price its own debt securities (the "Trust Retraction Notes") having such terms and conditions as the Trustee may determine and with recourse of the holder limited to the assets of the Trust.

**The retraction right described above will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. The PC Notes, Trust Retraction Notes, or other assets which may be distributed in specie to Unitholders in connection with a retraction will not be listed on any stock exchange and no market is expected to develop in such PC Notes or Trust Retraction Notes.**

*Meetings of Unitholders*

The Trust Indenture provides that the following must be approved by Special Resolution: (i) removing or appointing the Trustee (subject to exceptions such as the Trustee failing to qualify to act as trustee and insolvency-related events); (ii) amendments to the Trust Indenture (except as described under "Information Relating to the Trust - Trust Indenture - Amendments to the Trust Indenture"); (iii) subdivisions or consolidations of Trust Units; (iv) the termination of the Trust; (v) the sale of the property of the Trust as an entirety or substantially as an entirety; (viii) directing the Trustee to exercise, or refrain from exercising, any power under the Trust Indenture; (ix) directing the Trustee with respect to legal proceedings in connection with the Trust; and (x) approving the disposition of properties having a value in excess of 35% of the asset value of the properties of the Trust.

The Trust holds meetings of Unitholders on an annual basis for the purposes of electing the directors of PC.

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened if requested by the holders of not less than 25% of the Trust Units then outstanding by a written requisition. A requisition must specify the purpose for which the meeting is to be called.

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*Amendments to the Trust Indenture*

Except as specifically provided otherwise, the Trust Indenture may only be amended by Special Resolution.

The Trustee is entitled to make certain amendments to the Trust Indenture without the approval of the Unitholders. These include amendments for the purposes of ensuring compliance with applicable laws, ensuring the Trust satisfies the requirements of the Tax Act to be a unit trust and mutual fund trust, providing additional protection for Unitholders, removing conflicts or inconsistencies (if such amendment is not detrimental to the interests of the Unitholders) and correcting ambiguities or errors (provided the rights of the Trustee and the Unitholders are not prejudiced thereby).

*Mutual Fund Trust*

Under the Trust Indenture, PC may require declarations as to the jurisdictions in which beneficial holders of Trust Units are resident. Pursuant to the Trust Indenture, except to the extent permitted under the Tax Act, the Trust shall endeavour to satisfy the requirements of the Tax Act to maintain its status as a mutual fund trust.

*Termination of the Trust*

Unless the Trust is terminated earlier, the Trustee will commence to wind up the affairs of the Trust on December 31, 2066. If, in the opinion of the Board of Directors of PC, it would be in the best interests of the Unitholders to wind up the Trust, the Trust will be wound up. In addition, the Unitholders may, by Special Resolution, decide to terminate the Trust. Upon a decision to terminate the Trust, the Trustee will sell the assets of the Trust and distribute the net proceeds to Unitholders, or wind up the Trust as otherwise directed by the Unitholders or the Board of Directors.

*Borrowing*

The Trust and PC may finance the acquisition of securities and royalties of oil and gas companies, oil and gas properties and related assets and capital expenditures in respect thereof through the issuance of equity or debt securities.

The Trust and PC are also permitted to borrow funds and to grant security in respect of their assets, in priority to the royalty granted by PC, for the purposes of financing the purchase of oil and gas properties and related assets, capital expenditures in respect thereof or the purchase of securities and royalties of oil and gas companies or to facilitate the repurchase of Trust Units.

The maximum amount which may be borrowed for such purposes shall not exceed 40% of the aggregate Asset Value of all properties and other resource assets (including, where applicable, those being acquired) held by Petrofund, PC and their subsidiaries and 40% of the net asset value of non-reserve based assets. "Asset Value" is defined as the present worth of all of the estimated pre-tax net cash flow from the proved plus probable reserves shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using forecast price and cost assumptions.

In calculating the 40% borrowing restriction, amounts borrowed by the Trust or PC which the Trust or PC has the right to effectively repay or cause to be repaid through the issuance of Trust Units will not form part of the 40% borrowing restriction provided the Trust or PC, as applicable, has agreed to cause payment of such indebtedness to be made through the issuance of Trust Units prior to the maturity of such indebtedness to the extent necessary to ensure that the aggregate borrowings of the Trust and PC do not then otherwise exceed the 40% borrowing restriction on maturity of the indebtedness.

*Reporting to Unitholders*

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, and the unaudited interim financial statements of the Trust will be mailed to Unitholders within the periods prescribed by securities legislation unless, in each case, such mailing is not required by applicable securities law. The year end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the NPI Agreement, the Trust Indenture, and, subject to the provisions of the Trust Indenture, a listing of the registered holders of Trust Units.

**NPI Agreements**

Under the NPI Agreements, PC and PVT grant net royalties to the Trust of 99% of the revenue received in respect of each property held by PC and PVT net of certain related costs and expenses.

The net royalty consists of a 99% share of the royalty income from PC's and PVT s properties. Net royalty income is gross production revenue less the following amounts:

•

all operating costs;

•

debt service charges;

•

general and administrative costs;

•

taxes or other charges payable by PC and PVT;

•

acquisition costs incurred in acquiring new properties; and

•

amounts paid into the cash reserve established by PC and PVT to fund the payment of operating costs, capital expenditures, reclamation obligations, general and administrative costs, and debt service charges.

Gross production revenues essentially consist of cash proceeds from the sale of oil, natural gas and other substances produced from PC's and PVT s properties, any drilling credits resulting from any expenditures made on the properties (other than drilling credits applied to capital expenditures), amounts arising out of "take or pay" contracts for oil, gas and other products and any other consideration received by PC and PVT as a result of its ownership of the properties with the exception of revenues from the rental, sale or exchange of tangible assets and the proceeds from any unitization or pooling equalization payments relating to tangible assets and excluding the proceeds from the sale of any properties.

Operating costs are all expenditures from or allocated to a property made in connection with the maintenance of a property or any activities related to producing, gathering, treating, storing, compressing, processing and transporting oil, gas and other substances including, without limitation, overriding royalties and lessor royalties.

PC and PVT are required to pay the royalty on the last business day of each month.

The properties in respect of which the Trust has net royalties may be encumbered by security granted by PC to secure its loan obligations. The obligations of PC and PVT to pay net royalties to the Trust are not secured. Borrowing is subject to the 40% borrowing restriction referred to under "Governance of the Trust and PC - Trust Indenture - Borrowing".

**Distribution Reinvestment and Unit Purchase Plan**

The Trust has a distribution reinvestment and unit purchase plan (the "Plan"). The Plan allows Unitholders resident in Canada to acquire additional Trust Units by reinvesting their cash distributions or by making optional cash payments. Only Unitholders who are resident in Canada and hold in excess of 100 Trust Units may participate in the Plan. The Plan is not available to Unitholders who are residents of the United States or other foreign jurisdictions.

**Distribution Policy**

A major objective of the Trust s distribution policy is to provide unitholders with relatively stable and predictable monthly distributions despite potentially significant variations in product prices. A second objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of cash flow.

The percentage of cash flow from operations paid to Unitholders each quarter will vary according to a number of factors assessed by management including:

- Fluctuations in oil and gas prices.
- Changes in the $Canadian/$US exchange rate.
- The size of the development drilling programs and the portion funded from cash flow.
- The level of debt within PC.

Although the payout ratio will vary significantly from quarter to quarter, the objective is to pay less than 80% of cash flow to unitholders over the long term. The payout ratio was 73% in 2004 and 70% in 2003. The payout ratio in 2005 was 67%, 56%, 45%, and 44% in the first, second, third and fourth quarters respectively.

**Distributions**

The following cash distributions per Trust Unit in respect of the quarters indicated have been made to Unitholders since 2003:

| | Cash Distributions | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| First Quarter | $0.48 | $0.48 | $0.48 |
| Second Quarter | $0.48 | $0.48 | $0.53 |
| Third Quarter | $0.48 | $0.48 | $0.54 |
| Fourth Quarter | $0.51 | $0.48 | $0.54 |
| Total Annual | $1.95 | $1.92 | $2.09 |

**Credit Facility Limitations on Distributions**

PC has a revolving working capital operating facility of $50 million and a syndicated facility of $540 million. Interest rates fluctuate under the syndicated facility with Canadian prime and U.S. base rates plus between 0 and 25 basis points, as well as with Canadian banker s acceptance and LIBOR rates between 75 basis points and 125 basis points, depending, in each case, upon PC s debt to cash flow ratio. Substantially all of the credit facility is financed with banker's acceptances, resulting in an average reduction in interest rates of 0.76% per annum.

The limit of the syndicated facility is subject to adjustment from time to time to reflect changes in PC's asset base. PC had long-term debt outstanding of $462.8 million at December 31, 2005, compared to $214.4 million at the end of the prior year.

The revolving period on the syndicated facility ends on April 28, 2006, unless extended for a further 364 day period. There are no principal repayments required during the revolving period. PC may request the facility be extended no earlier than 90 days and no later than 60 days prior to the end of the revolving period at which time lenders may extend the facility for an additional one year period. In the event the lenders elect not to extend the revolving period, no payments are required to be made to non-extending lenders for a period of one year. However, during that year, PC will be required to maintain certain minimum balances on deposit with the syndicate agent. At the end of the one year period, the entire amount becomes due and payable. If this event were to occur, it is likely that PC would be forced to suspend royalty payments to the Trust, which, in turn, would be unable to make distributions to Unitholders. The revolving period has been extended each year by the lenders since the inception of the Trust.

In addition from time to time, the lenders have the right to review the borrowing base of PC s properties. If the borrowings exceed the re-determined borrowing base, on 60 days notice from the lender, PC is required to reduce its borrowing to the re-determined borrowing base. If, during the 60 day period, borrowings exceed the borrowing base by less than five percent, PC is permitted to make a cash payment to the Trust for one normal monthly distribution to unitholders. However, if the excess borrowings are greater than five percent, no distributions are permitted.

The credit facility is secured by a debenture in the amount of $900 million under which a Canadian chartered bank, as principal and as agent for the other lenders, received a first ranking security interest on all of PC's assets. The loan is the legal obligation of PC. Unitholders have no direct liability to the lenders or to PC should the assets securing the loan generate insufficient cash flow to repay the obligation.

Stability Rating

Dominion Bond Rating Service Limited ("**DBRS**") has assigned a stability rating of STA-5 (low) to the Trust Units. The stability rating is based on a rating scale developed by DBRS that provides an indicator of both the stability and sustainability of an income fund's distributions per unit. Ratings categories range from STA-1 to STA-7, with STA-1 being the highest. In addition, DBRS further separates the ratings into "high", "middle" and "low" subcategories to indicate where they fall within the rating category. Ratings take into consideration the seven main factors of: (1) operating and industry characteristics; (2) asset quality; (3) financial flexibility; (4) diversification; (5) size and market position; (6) sponsorship/governance; and (7) growth. In addition, consideration is given to specific structural or contractual elements that may eliminate or mitigate risks or other potentially negative factors.

Specifically, income funds rated as STA-5 are considered by DBRS to have weak distribution per unit stability and sustainability. An income fund rated as STA-5 is subject to many of the same cyclical, seasonal and economic factors as the higher STA-4 rating category, but the lack of diversification is generally more pronounced and such income funds will tend to be below average in several areas.

A rating is not a recommendation to buy, sell or hold any security and may be subject to revision or withdrawal at any time by DBRS.

**DIRECTORS AND OFFICERS**

The Board of Directors of PC currently consist of eight individuals, all of whom were nominated for election of PC by Unitholders.

The name, municipality of residence, position held by each of the directors and executive officers of PC and period each director has served as a director are set out below:

| Name and Municipality of Residence | Position | Director Since |
|---|---|---|
| John F. Driscoll<br>Toronto, Ontario | Chairman and Director | July 15, 1988 |
| Jeffery E. Errico<br>Calgary, Alberta | President, Chief Executive Officer and Director | April 16, 2003 |
| Jeffrey D. Newcommon<br>Calgary, Alberta | Executive Vice-President | |
| Glen C. Fischer<br>Calgary, Alberta | Senior Vice-President, Operations | |
| Edward J. Brown<br>Calgary, Alberta | Vice-President, Finance and Chief Financial Officer | |
| Noel F. Cronin<br>Calgary, Alberta | Vice-President, Production | |
| James E. Allard(1)(4)<br>Calgary, Alberta | Director | April 16, 2003 |
| Sandra S. Cowan(2)<br>Toronto, Ontario | Director | January 17, 2002 |
| Arthur E. Dumont(2)(4)<br>Calgary, Alberta | Director | July 28, 2004 |
| Gary L. Lee(1)(3)<br>Calgary, Alberta | Director | July 28, 2004 |
| Wayne M. Newhouse(3)(4)<br>Calgary, Alberta | Director | April 16, 2003 |

| | | |
|---|---|---|
| Frank Potter(1)(2)(3) | Director | November 1, 2000 |
| Toronto, Ontario | | |

**Notes:**

(1)

Member of the Audit Committee.

(2)

Member of the Governance Committee.

(3)

Member of the Human Resources and Compensation Committee.

(4)

Member of the Reserves Audit and EH&S Committee.

(5)

The term of office of each director is from the date of the meeting at which he or she is elected until the next annual meeting or until his or her successor is elected or appointed.

Set forth below are the particulars of the principal occupations of each director and officer of PC for the past several years.

John F. Driscoll is the founding President, Chairman and Chief Executive Officer of Sentry Select Capital Corp. He also founded and has been Chairman of NCE Resources Group since 1984, and Chairman and founder of Petrofund Energy Trust since 1988. He has been Chairman of Inter Pipeline Fund, Strategic Energy Fund, and Endev Energy since October 2002, May 2002, and August 2002 respectively. Mr. Driscoll has been President, since 1981, of J.F. Driscoll Investment Corp., a company specializing in investment management and related advisory and consulting services. Mr. Driscoll received his Bachelor of Science degree from the Boston College Business School and attended the New York Institute of Finance for advanced business studies. He has more than 30 years of diversified business experience. He is a member of the CFA Institute (formerly the Association for Investment Management and Research) and also attained the professional manager designation with the Canadian Institute of Management. He has founded numerous public partnerships as well as public and private energy and investment related companies. During the last 20 years, issuers of which Mr. Driscoll was Chairman or Chief Executive Officer have invested or managed the investment of more than $6 billion. He is Vice-Chair of the Royal Ontario Museum Foundation Board of Directors.

Jeffery E. Errico is a Professional Engineer with a Bachelor of Applied Science Degree in Chemical Engineering from the University of British Columbia. Prior to joining Petrofund he gained extensive experience in the areas of economic evaluations, reservoir, and operations engineering having served as a senior executive for several oil and gas companies. Mr. Errico joined Petrofund in 1995, and has played a key role in its growth from 450 to the current 42,500 Boepd of production. He was appointed President in 2002 and CEO in 2003.

Glen C. Fischer is a Professional Engineer who received a Degree in Mechanical Engineering from the University of Calgary. He has over 20 years of engineering and management experience in the oil and gas industry and from 1984 to 1996 was Manager, Engineering & Operations for ATCOR Ltd. and its successor Canadian Forest Oil Ltd. Mr. Fischer joined Petrofund in July, 1996.

Edward J. Brown is a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto with majors in finance and economics. He has over 25 years of international finance and management experience having held several senior financial positions in the energy industry. Prior to joining Petrofund in 2005, Mr. Brown was the senior financial officer at Duke Energy Field Services Canada and provided advisory and consulting services. From 1984 to 2002, he held a number of senior executive positions at TransCanada PipeLines Limited in both Calgary and Toronto. From 1978 to 1984, Mr. Brown practiced public accounting most recently as a senior audit manager for KPMG a national public accounting firm, headquartered in Toronto. Mr. Brown is a member of Financial Executives International and a member of the Institute of Chartered Accountants of both Alberta and Ontario. He is past Chair, Financial Executives International Canada. Mr. Brown joined Petrofund in April 2005.

Jeffrey D. Newcommon received his Bachelor of Arts degree in Finance and Economics from the University of Western Ontario in 1983. From 1984 to 1995 he held various positions with Canadian Hunter Exploration Ltd., including, most recently, Land Manager. He joined Petrofund in April, 1995.

Noel F. Cronin is a Professional Engineer with over 20 years of diversified experience in the petroleum industry in western Canada, including reservoir management/exploitation, economic evaluations, joint interests, and production operations. He has worked for various Calgary-based oil and gas producers during his career and joined Petrofund as Production Manager in 1997.

James E. Allard received a Bachelor of Science degree in Business Administration from the University of Connecticut and completed the Advanced Management Program at Harvard University. Mr. Allard has focused his career in international finance and the petroleum industry for the past 40 years serving as CEO, CFO and director of a number of publicly traded and private companies during that period. During the past five years he has continued to serve on the board of the Alberta Securities Commission, act as the sole external trustee and advisor to a mid-sized pension plan and serve as a director and advisor to several companies. From 1981 to 1995, he served as a senior executive officer of Amoco Corporation as well as a director of Amoco Canada, then Canada s largest natural gas producer.

Sandra S. Cowan is Partner and General Counsel of EdgeStone Capital Partners, an independent private equity firm managing over $1 billion of private capital. Prior to joining EdgeStone in 2001, Ms. Cowan practiced law for over 15 years, most recently as a senior partner of Goodman and Carr LLP. Her practice specialized in private equity and corporate finance transactions, including fund formation, mergers, acquisitions and divestitures, cross-border and public market transaction. Ms. Cowan has an LLB from the University of Western Ontario and serves on a number of private and public boards.

Arthur E. Dumont is a Professional Engineer with a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan. Mr. Dumont has over 36 years of professional experience in oil and gas, serving as president of several well known Calgary based companies. He is currently President and C.E.O. of Technicoil Corporation and serves on a number of boards and volunteer committees. Mr. Dumont is based in Calgary and was a director of Ultima prior to its recent acquisition by Petrofund.

Gary L. Lee is currently a director and principal of North West Capital Inc., a private merchant banking firm based in Calgary. Prior to joining North West Capital he was a lawyer with extensive experience in energy related transactions and financings. He has been actively involved as a principal and adviser in organizing and financing several oil and gas companies and oilfield service companies. Mr. Lee was a director of Ultima Energy Trust until it was acquired by Petrofund in June 2004.

Wayne M. Newhouse is a Professional Engineer and oil and gas executive with over 40 years of broad industry experience. Since 1995, Mr. Newhouse has served as President of two private oil and gas companies, as well as being a director of several publicly traded companies. From 1989 to 1994, Mr. Newhouse served as Senior Vice President, Production and Senior Vice President, Exploration and International Development with Norcen Energy Resources Ltd.

Frank Potter attended Royal Military College of Science, and is a Fellow of the Institute of Canadian Bankers. Mr. Potter has been the Chairman since 1995 of Emerging Markets Advisors, Inc., a Toronto-based consultancy that assists corporations in making and managing direct investments internationally. Prior thereto, Mr. Potter was executive director of The World Bank Group in Washington, and was subsequently senior advisor at the federal Department of Finance. Mr. Potter is a director of a number of public and private corporations and public service organizations.

## AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

The Mandate and Terms of Reference of the Audit Committee of the board of director s is attached hereto as Appendix "C". The members of the Audit Committee are James E. Allard, Gary L. Lee, and Frank Potter.

### Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

### Relevant Education and Experience

Please refer to the biography section above.

### Pre-Approval of Policies and Procedures

The Audit Committee shall have the sole authority to pre-approve all audit and non-audit services not prohibited by applicable law or the rules of the Toronto Stock Exchange or the American Stock Exchange to be provided by the Trust s independent registered chartered accountants including the remuneration and the terms of engagement.



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**External Auditor Service Fees**

***Audit Fees***

The aggregate fees billed by the Corporation s independent registered chartered accountants in each of the last two fiscal years for audit services were $214,380 in 2005 and $196,300 in 2004. The audit fees relate to professional services rendered by Deloitte & Touche LLP for the audit of the Trust s annual financial statements and the review of the Trust s quarterly financial statements.

***Audit Related Fees***

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Corporation s independent registered chartered accountants other than services reported above were $284,752 in 2005 and $47,025 in 2004. These fees relate to procedures performed in connection with prospectus offering documents, the French translation of these documents and related documents incorporated by reference, and fees related to Sarbanes-Oxley 404 compliance.

***Tax Fees***

The aggregate fees billed in each of the last two fiscal years for tax and tax related fees were nil in 2005 and $31,428 in 2004. The majority of fees billed in 2004 relate to the Internalization Transaction, which is disclosed in the Consolidated Income Statement and in note 12 to the Consolidated Income Statement.

**Ownership of Trust Units by Directors and Officers**

As at December 31, 2005, the directors and executive officers of PC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, an aggregate of 1,111,670 Trust Units representing less than 1% of the issued and outstanding Trust Units and 283,025 PC Exchangeable Shares representing 100% of the issued and outstanding PC Exchangeable Shares, which are exchangeable into 388,147 Trust Units.

**Corporate Cease Trade Orders or Bankruptcies**

None of the directors of executive officers of PC or a Unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust have been subject to:

(a)

a cease trade or similar order or an order that denied the issuer access to any statutory exemptions for a period of more than 30 consecutive days; or

(b)

was declared bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy and insolvency or been subject to or instituted any proceedings, arrangement, or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

**Penalties or Sanctions**

None of the directors or executive officers of PC, or a Unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust, have been subject to any penalties or sanctions under securities legislations, or any other penalties or sanctions imposed by a Court or regulatory body, that would likely be considered important to a reasonable investor in making investment decisions.

**Personal Bankruptcies**

None of the directors or executive officers of PC have in the ten years preceding the date of this Renewal Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement, or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold their assets.

**Conflicts Of Interest**

Circumstances may arise where members of the Board of Directors or officers of PC serve as directors or officers of corporations or other entities which are in competition to the interests of PC and the Trust. No assurances can be given that opportunities identified by such board members or officers will be provided to PC and the Trust.

The Business Corporations Act (Alberta) provides that in the event that a director or officer has an interest in a contract or proposed contract or agreement, the director or officer shall disclose his interest in such contract or agreement and such director shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under such Act. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of such Act.

## PRICE RANGE AND TRADING VOLUME OF TRUST UNITS

The Trust is listed and posted for trading on the TSX under the symbol "PTF.UN" and on the American Stock Exchange under the symbol "PTF". The following sets forth the price ranges and trading volumes of the Common Shares on the TSX and AMEX for the periods indicated.

| | TSX | | | AMEX (US$) | | |
|---|---|---|---|---|---|---|
| | Price Range | | | Price Range | | |
| | High | Low | Volume | High | Low | Volume |
| **2005** | | | | | | |
| January | $17.05 | $15.50 | 4,317,300 | $13.75 | $12.66 | 10,281,800 |
| February | $18.85 | $16.95 | 6,488,600 | $15.34 | $13.68 | 11,473,700 |
| March | $19.33 | $16.25 | 5,573,100 | $16.05 | $13.40 | 17,476,300 |
| April | $18.57 | $17.00 | 3,377,900 | $15.22 | $13.62 | 10,786,800 |
| May | $18.79 | $17.47 | 3,426,800 | $15.04 | $13.90 | 8,093,900 |
| June | $19.97 | $18.25 | 4,445,700 | $16.25 | $14.63 | 11,125,100 |
| July | $21.12 | $19.57 | 2,648,800 | $17.25 | $15.94 | 9,351,500 |
| August | $22.98 | $19.30 | 2,751,500 | $19.26 | $15.72 | 16,038,100 |
| September | $23.31 | $20.90 | 3,882,500 | $19.85 | $17.55 | 11,669,700 |
| October | $23.17 | $19.05 | 3,270,700 | $19.88 | $16.10 | 16,006,000 |
| November | $21.80 | $20.02 | 5,260,700 | $18.47 | $16.84 | 10,135,100 |
| December | $21.43 | $20.30 | 7,317,680 | $18.50 | $17.30 | 8,508,800 |

**ESCROWED SECURITIES**

There are 45,196 Trust Units (which represents less than 1% of the Trust Units outstanding as at December 31, 2005) remaining in escrow, of the original 100,244 Trust Units which were issued to executive management in connection with the internalization of management. They are released as to five percent of the original number issued at the end of each quarter to March 31, 2008. The escrow agent is Goodman and Carr LLP.

# RISK FACTORS

The following are certain risk factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units.

## Industry-Related Risks

### Volatility in Oil and Natural Gas Prices

The monthly cash distributions the Trust pays to Unitholders are highly dependant on the prices received for PC s oil and natural gas production. Oil and natural gas prices can fluctuate significantly on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and PC. These factors include: political conditions throughout the world, worldwide economic conditions, weather conditions, the supply and price of foreign oil and natural gas, the level of consumer demand, the price and availability of alternative fuels, the proximity to, and capacity of, transportation facilities, the effect of worldwide energy conservation measures and government regulations.

### Foreign Currency Exchange Rates and Interest Rates

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that fluctuates over time. A material increase in the value of the Canadian dollar which occurred from 2004 to 2005 negatively impacted the Trust s net production revenue. The Canadian dollar averaged US 0.83 in 2005 versus US 0.77 in 2004. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of the Trust s reserves as determined by independent evaluators.

### Operations

PC s operations are subject to all of the risks normally associated with drilling for and the production and transportation of oil and natural gas. Such risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings, and fires, all of which could result in personal injury, loss of life, property damage, and environmental damage. PC has safety and environmental policies and liability insurance in place to protect operators and employees, as well as to meet regulatory requirements. Not all risks, however, are insurable and therefore PC cannot fully insure against all such risks. PC may become liable for damages arising from such events which cannot be insured against or which we may elect not to insure because of high premium costs or other reasons. See "Environmental Concerns".

Continuing production from a property, and to some extent the marketing of production there from, are largely dependant upon the ability of the operator of the property. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. PC markets and hedges a portion of its oil and natural gas production with a number of counterparties and therefore is subject to the risk that these parties may not be able to meet all their commitments under these contracts. A reduction of the distributions could result in such circumstances.

**Expansion of Operations**

The operations and expertise of management of the Trust are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, the Trust may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, wind power generation, or an interest in an oil sands project. Expansion of activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may result in future operational and financial conditions of the Trust being adversely affected.

**Competition**

There is strong competition relating to all aspects of the oil and natural gas industry. The Trust competes for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity, and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Trust. There are numerous trusts in the oil and natural gas industry that are competing for the acquisition of properties with longer life reserves and with exploitation and developmental opportunities. As a result of the increasing competition, it may be more difficult to acquire reserves on beneficial terms.

**Environmental Concerns**

The oil and natural gas industry is subject to extensive environmental and safety regulations pursuant to local, provincial, and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders. Such legislation may be changed to impose higher standards and potentially more costly obligations. PC has established a reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations based on its current knowledge. There can be no assurance that PC will be able to satisfy its actual future environmental and reclamation obligations. While PC has established a reserve for extraordinary and significant site reclamation or abandonment costs, actual abandonment costs incurred in the ordinary course of business during a specific period reduce the amounts available for distribution to Unitholders. PC maintains insurance coverage considered to be customary in the industry, it is not fully insured against certain environmental risks, either because such insurance is not available, or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (compared to sudden and catastrophic damages) is not available. In addition, the December 1997, Kyoto Protocol with respect to the reduction of greenhouse gases has been ratified by Canada. It is not possible at this time to assess the potential impact on the business and operations of the Trust, and they could be significant.

## Business-Related Risks

**Reserves**

The value of the Trust Units depends upon, among other things, the reserves attributable to PC s properties. The reserves and recovery information contained in PC s independent reserve evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve evaluator. The reserve report was prepared using certain commodity price assumptions that are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Trust, the present value of estimated future net cash flows for the Trust s reserves would be reduced and the reduction could be significant.

**Depletion of Reserves**

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline. As the Trust will not be reinvesting the majority of its cash flow, absent acquisitions and development activities, the Trust s production levels and reserves will decline. PC s reserves and production, and therefore its cash flows, are highly dependant upon its success in exploiting its reserve base and acquiring additional reserves. To the extent that external sources of capital, including the issuance of additional

Trust Units, become limited or unavailable, the Trust s ability to make the necessary capital investments to maintain or expand reserves will be impaired.

**Marketability of Production**

The marketability of PC's production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines, and processing facilities. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production and transportation, tax and energy policies, general economic conditions, and changes in supply and demand all could adversely affect PC's ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on the Trust's business could be substantial. The availability of markets is beyond PC's control.

**Assessments of Value of Acquisitions**

Acquisitions of resource issuers and resource assets are based in large part on engineering and economic assessments made by independent engineers. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond PC s control. In particular, the prices of and markets for resource products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that PC uses for its year end reserve evaluations, and these assessments may differ significantly from the assessments of the firm used by PC. Any such instance may offset the return on and value of the Trust Units.

**Reliance on Third Party Operators**

Continuing production from a property and marketing of product produced from the property are dependent to a large extent on the ability of the operator of the property. PC currently operates properties that represent approximately 50% of its total daily production. To the extent the operator fails to perform these functions properly or becomes insolvent, revenue may be reduced.

**Enforcement of Operating Agreements**

Operations of the wells on properties not operated by PC are generally governed by operating agreements, which typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to PC, the Trust, or the Unitholders. PC, as owner of working interests in properties not operated by it, will generally have a cause of action for damages arising from a breach of such duty. Although not established by definitive legal precedent, it is unlikely that the Trust, or Unitholders, would be entitled to bring suit against third-party operators to enforce the terms of the operating agreements; thus, Unitholders will be dependent on PC, as owner of the working interest, to enforce such rights.

**Borrowing**

PC has secured credit facilities with variable interest rates. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount of PC's revenues required to be applied to its debt service before payment of any amounts to the Trust. Certain covenants contained in PC's agreements with its lenders may also limit the amounts paid to the Trust and the distributions paid by the Trust to Unitholders.

PC's lenders have been provided with security over substantially all of the assets of PC. If PC becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell PC's properties. The proceeds of any such sale would be applied to satisfy amounts owed to PC's lenders and other creditors and only the remainder, if any, would be available to the Trust.

PC acknowledges that the credit facilities may not be adequate and additional funds may not be attainable. The syndicated facility is available on a one year revolving basis. If the revolving period at which the lenders may extend the facility is not renewed for an additional one year period, the loan will convert to a one year term with payments due in three consecutive quarterly amounts equal to one-twentieth of the loan amount with an additional payment due on the last day of the term equal to the balance outstanding. If this occurs, PC will have to arrange alternate financing. There is no assurance that such financing will be available or be available on favourable terms. Trust distributions may be materially reduced in these circumstances and the failure to obtain suitable replacement financing may have a material adverse effect on the Trust.

**Delays in Distributions**

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of PC's properties, and by those operators to PC, payments between any of these parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties, or the establishment by the operator of reserves for such expenses. Any of these delays could adversely affect Trust distributions.

**Unforeseen Title Defects**

Although title reviews are conducted prior to any purchase of resource issuers or resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise to defeat PC's title to certain assets. A reduction of the distributable cash flow of the Trust and possible reduction of capital could result from such defects.

**Sensitivity Analysis**

As discussed above Petrofund is subject to numerous business and industry related risks.

In 2005, PC s cash flow from operating activities was $337.2 million, and net income was $210.7 million. The sensitivity of PC s cash flow and net income before income taxes to oil price, gas price, $US/$Cdn exchange rate, and the prime interest rate is listed below.

The table below shows sensitivities to pre-hedging cash flow as a result of product price and operational changes. The table is based on actual 2005 prices received for the fourth quarter of 2005 and the fourth quarter of 2005 production volumes of 39,178 Boepd. These sensitivities are approximations only and are not necessarily valid at other price and production levels. As well, hedging activities can significantly affect these sensitivities.

| | Change | M$ | $/Unit per year |
|---|---|---|---|
| Price per barrel of oil* | US$1.00 WTI | $7,457 | $0.063 |
| Price per Mcf of natural gas* | Cdn$0.25 | $7,556 | $0.064 |
| US/Cdn exchange rate | $0.01 | $6,215 | $0.053 |
| Interest rate on debt ($125 million) | 1% | $4,627 | $0.039 |
| Oil production volumes * | 100 Bpd | $1,846 | $0.016 |
| Gas production volumes * | 1MMcfpd | $3,268 | $0.028 |

*After adjustment for estimated royalties.

## Risks Related to the Securities Markets and the Ownership of Trust Units

### Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in PC. The Trust Units are also dissimilar to conventional debt instruments in that there is no principal amount owing directly to Unitholders. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders do not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions.

**The Trust Units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.**

The after-tax return from an investment in Units to Unitholders subject to Canadian income tax can be made up of both a return on and a return of capital. That composition may change over time, thus affecting a Unitholder's after-tax return.

### Trading Price of Trust Units

The price per Trust Unit is a function of anticipated Trust Unit distributions, the properties acquired by the Trust, and its ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Trust Units will have no value when reserves from the properties can no longer be economically produced or marketed and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment. Investors in Trust Units will have to obtain the return of capital invested out of cash flow derived from their investments in the Trust Units during the period when reserves can be economically recovered. Accordingly, there is no assurance that the distributions Unitholders receive over the life of their investment will meet or exceed their initial capital investment.

**Reliance on Petrofund Corp. and Others**

Unitholders are entirely dependent on the management of PC with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to properties, and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team of PC could have a detrimental effect on the Trust. PC currently operates properties that represent approximately 50% of its total daily production. Investors who are not willing to rely on the management of PC should not invest in the Trust Units.

**Unitholder Limited Liability**

Because of uncertainties in the law relating to investment trusts there is a risk that a Unitholder could be held personally liable for obligations of the Trust (to the extent that claims are not satisfied by the Trust) in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contract including claims in tort, claims for taxes and possibly certain other statutory liabilities. The Trust Indenture requires that the operations of the Trust be conducted in such a way as to minimize any such risk and, in particular, where feasible, every written contract or commitment of the Trust must contain an express disavowal of liability upon the Unitholders and a limitation of liability to Trust property. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent as a shareholder is protected from the liabilities of a corporation. It is unlikely, however, that personal liability will attach in Canada to the holders of Trust Units for claims arising out of any agreement or contract containing such a disavowal and limitation of liability. It is also considered unlikely that personal liability will attach in Canada to the holders of Trust Units for claims in tort, claims for taxes and possibly certain other statutory liabilities. In the event that a Unitholder is required to satisfy any obligation of the Trust, such Unitholder will be entitled to reimbursement from any available assets in the Trust.

The *Trust Beneficiaries' Liability Act*, 2004 (Ontario) was proclaimed in force as of December 16, 2004. The legislation provides that unitholders will not be liable, as beneficiaries of a trust, for any act, default, obligation, or liability of the trust or its trustee that arises after the legislation came into force.

**Retraction Right**

Cash payments for Trust Units surrendered for retraction are subject to limitations and any notes issued in lieu of a cash payment will not be listed on any stock exchange and no market is expected to develop for such notes.

**Additional Financing**

An objective of the Trust is to continually add to its reserves through acquisitions and through development, and because the Trust does not reinvest its cash flow, the success of the Trust is in part dependent on its ability to raise capital from time to time. Holders of Trust Units may also suffer dilution in connection with future issuances of Trust Units, whether issued pursuant to a financing or acquisition or otherwise. Conversely to the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, the Trust's and PC's ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that the Trust is required to use cash flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of distributions paid by the Trust to Unitholders may be reduced.

**Mutual Fund Trust**

Pursuant to the Tax Act, in order for the Trust to qualify as "mutual fund trust" for the purposes of the Tax Act, it is required, among other things, that (i) the Trust not be considered to be a trust established or maintained primarily for the benefit of non-residents of Canada; or (ii) the Trust satisfies certain conditions as to the nature of the assets of the Trust as specified in the Tax Act (the "Asset Test"). The Trust Indenture provides that, except to the extent permitted under the Tax Act, the Trust shall endeavour to satisfy the requirements of the

Tax Act to qualify as a "mutual fund trust" at all times. The Trust believes it has at all material times satisfied the Asset Test and, accordingly, for purposes of the requirements of these provisions should qualify as a "mutual fund trust" under the current provisions of the Tax Act.

**Changes in Legislation**

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the status of mutual fund trusts and resource allowance, will not be changed in a manner which will adversely affect the Trust and Unitholders. There can be no assurance that tax authorities having jurisdiction will agree with how the Trust calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Trust or the Unitholders.

**Changes in the Trust's Status under Tax Laws**

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with how the Trust calculates its income for tax purposes or could change administrative practises to the detriment of the Trust or the detriment of its Unitholders.

PC intends that the Trust will continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and its Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties held by the Trust. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

- The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.

- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

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Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESTs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

In addition, PC may take certain measures in the future to the extent it believes necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Tax Act.



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## INDUSTRY REGULATIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of PC in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and PC is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

### Pricing and Marketing Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "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 licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. 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 other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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 lack of firm 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, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

### The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, 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); (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.

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

**Provincial Royalties and Incentives**

***General***

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, natural gas liquids, sulphur, and natural gas 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 subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. 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. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, 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.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "Technical Paper"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry (to a maximum of $2,000,000) to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, 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. In addition, the percentage of ARTC that PC will be required to include in federal taxable income will be 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008;

70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.



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***Alberta***

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24 month, 8,000 $m^3$ exemption is available to production from a reactivated well that has not produced for: (i) a 12 month period, if resuming production in October, November, or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in February 1993, or later. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992, is entitled to a 12 month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells), and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per $m^3$ and 25% at prices at and above $210 per $m^3$. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. The ARTC rate is 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 a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting 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 for the program. Such rules will not presently preclude PC from being eligible for the ARTC program.

***British Columbia***

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of the 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 type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. 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 a prescribed minimum price. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("Strategy"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

***Saskatchewan***

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of 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 a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". 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".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic meters in a month.

•

A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

•

The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

**Land Tenure**

Crude oil and natural gas located in the western 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, licences, 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 currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "AEPEA"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The APEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increase penalties. PC is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the APEA and similar legislation in other jurisdictions in which it operates. PC believes that it is in material compliance with applicable environmental laws and regulations. PC also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. In April 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ( LFEs ), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 mt, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any director or executive officer, or to the knowledge of PC, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of outstanding Trust Units, or any associate or affiliate of any of the foregoing, in any transaction within the three most recently completed financial years except for the following.

John F. Driscoll is the Chairman of Board of PC. The Previous Manager was purchased by PC from Petro Assets pursuant to the Internalization Transaction. Petro Assets was owned by the Driscoll Family Trust (a trust established for the family of John F. Driscoll). Subsequent to closing of the Internalization Transaction, Sentry Select Capital Corp. ( Sentry ) agreed to provide certain management services to the Trust and PC and at Sentry's cost until December 31, 2003. Sentry is a company in which John F. Driscoll owns a controlling interest. See "General Development of the Business of the Trust - General".

## TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Trust Units is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

## LEGAL PROCEEDINGS

There were no outstanding legal proceedings material to the Trust to which the Trust is a party or in respect of which any of its properties is subject, nor are there any such proceedings known to be contemplated.

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Trust has not, within the most recently completed financial year, entered into any contracts which are material to the Trust. Further, there are no material contracts entered into before the most recently completed financial year, which are still material and still in effect.

## INTEREST 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 Trust during, or related to, the Trust's most recently completed financial year other than GLJ, the independent reserve evaluator, and Deloitte & Touche LLP, the Trust's independent registered chartered accountants. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities of the Trust or the property of the Trust or of the Trust'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 PC or of any of the Trust's associates or affiliates.

## ADDITIONAL INFORMATION

Additional information relating to the Trust is available on SEDAR at www.sedar.com and on the Trust s website at www.petrofund.ca.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Trust s securities, and securities authorized for issuance under share compensation plans, if applicable, is contained in the Trust s information circular for its most recent annual meeting of Unitholders that involved the election of directors, and additional financial information is provided in the Trust s comparative financial statements (and related management s discussion and analysis) for its most recently completed financial year.

For additional copies of this annual information form please contact:

Petrofund Corp.

444 - 7th Avenue S.W.

Suite 600

Calgary, Alberta

T2P 0X8

Attention: Investor Relations

**APPENDIX A**

**REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

Management of Petrofund Corp. (the "Company"), on behalf of Petrofund Energy Trust, 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 consist of the following:

(a)

(i)

proved and proved plus probable oil and gas reserves estimated as at December 31, 2005, 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, 2005, using constant prices and costs; and

(ii)

the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

(c)

reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Audit and EH&S Committee of the Board of Directors (the Reserves EH&S Committee ) has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves EH&S Committee, approved:

(a)

the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(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.

| | |
|---|---|
| (signed) "*Jeffery E. Errico*" | (signed) "*Glen C. Fischer*" |
| Jeffery E. Errico | Glen C. Fischer |
| President and Chief Executive Officer | Senior Vice President, Operations |
| | |
| (signed) "*Wayne M. Newhouse*" | (signed) "*James E. Allard*" |
| Wayne M. Newhouse | James E. Allard |
| Director and Chairman of the Reserves EH&S Committee | Director and Member of the Reserves EH&S Committee |

March 15, 2006

**APPENDIX B**

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

To the board of directors of Petrofund Corp. (the "Company"):

1.

We have prepared an evaluation of the Company's reserves data as at December 31, 2005. The reserves data consist of the following:

(a)

(i)

proved and proved plus probable oil and gas reserves estimated as at December 31, 2005, 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, 2005, using constant prices and costs; and

(ii)

the related estimated future net revenue.

2.

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

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

3.

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

4.

The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

| Description and Preparation Date of Report | Location of Reserves (County or Foreign Geographic Area) | Net Present Value of Future Net Revenue (M$ before income taxes, 10% discount rate - $M) | | | |
|---|---|---|---|---|---|
| | | Audited | Evaluated | Reviewed | Total |
| January 30, 2006 | Canada | | $1,917,333 | $365,965 | $2,283,298 |

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 date.

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada

Dated:  February 9, 2006

*(signed) "Bryan M. Joa"*

Bryan M. Joa, P. Eng.

VP Corporate Evaluations

**APPENDIX C**

**Mandate and Charter of the Audit**

**Committee of the Board of Directors**

**I.**

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**I.**

**TERMS OF REFERENCE**

**WHEREAS** Petrofund Corp. is a wholly-owned subsidiary of Petrofund Energy Trust (the "**Trust**")**;**

**AND WHEREAS** Petrofund Corp. is responsible for the overall governance of the Trust pursuant to the trust indenture of the Trust;

**AND WHEREAS** Petrofund Corp. is, in turn, governed by its board of directors (the "**Board**")**;**

**AND WHEREAS**, financial reporting and disclosure by the Trust constitute a significant aspect of the management of the Trust's business and affairs;

**AND WHEREAS** the objective of the monitoring of the Trust's financial reporting and disclosure (the **Financial Reporting Objective** ) by the Board is to gain reasonable assurance of the following:

(a)

that the Trust complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

(b)

that the accounting principles, significant judgments and disclosures that underlie or are incorporated in the Trust's financial statements are the most appropriate in the prevailing circumstances;

(c)

that the Trust's quarterly and annual financial statements are accurate and present fairly the Trust's financial position and performance in accordance with Canadian (and if applicable, the United States of America) generally accepted accounting principles; and

(d)

that appropriate information concerning the financial position and performance of the Trust is disseminated to the public in a timely manner;

**AND WHEREAS**, the Board is of the view that the Financial Reporting Objective cannot be reliably met unless the following activities (the **Fundamental Activities** ) are conducted effectively:

(i)

the Trust's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Trust's financial transactions;

(ii)

the Trust's internal financial controls are regularly assessed for effectiveness and efficiency;

(iii)

the Trust's quarterly and annual financial statements are properly prepared by management;

(iv)

the Trust's quarterly financial statements are reviewed by an independent external auditor appointed by the Unitholders of the Trust (the **external auditors** ) and the annual financial statements are reported on by the external auditors; and

(v)

the Disclosure Policy of the Trust, and in particular the financial components of such Disclosure Policy, are complied with by management and the Board;

**AND WHEREAS**, to assist the Board in its monitoring of the Trust's financial reporting and disclosure, the Board has established, and hereby continues the existence of, a committee of the Board known as the Audit Committee (the **Committee** );

The following shall be the mandate and charter of the Committee:

**II.**

**OPERATING PRINCIPLES**

The Committee shall fulfill its responsibilities within the context of the following principles:

2.

Committee Values

The Committee expects the management of the Trust to operate in compliance with any applicable code of conduct and corporate policies; with laws and regulations governing the Trust; and to maintain strong financial reporting and control processes.

3.

Communications

The Chairman of the Committee (and others on the Committee) expects to have direct, open and frank communications throughout the year with management, the Chairs of other committees, the Trust s external auditors and other key Committee advisors as applicable.

4.

Financial Literacy

All Committee members should be sufficiently versed in financial matters to understand the Trust's accounting practices and policies and the major judgments involved in preparing the financial statements.

5.

Annual Audit Committee Work Plan

The Committee, while not responsible for the planning or conduct of audits, may develop an annual audit committee work plan responsive to the Committee's responsibilities as set out in this charter. In addition, the Committee shall review the process developed by management in conjunction with the external auditors for review of important financial topics that have the potential to impact the Trust's financial disclosure.

6.

Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management, and the Trust s external auditors.

7.

Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the Trust s external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at least one week in advance of meeting dates.

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8.

External Resources

To assist the Committee in discharging its responsibilities, the Committee may, in addition to the Trust s external auditors, at the expense of the Trust, retain one or more persons having special expertise.

9.

In Camera Meetings

At the end of, or during, each meeting of the Committee, the members of the Committee shall meet in private sessions with the Trust s external auditors and with members of management, as required.

10.

Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next meeting.

11.

The External Auditors

The Committee expects that, in discharging their responsibilities to Unitholders of the Trust, the Trust s external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues to the Committee.

**III.**

**COMPOSITION AND MEETINGS**

12.

The Committee shall consist of at least three members of the Board appointed annually by the Board:

(i)

each of whom shall be an independent director (within the meaning of National Instrument 58-101 Disclosure of Corporate Governance Practices) and free from any interest and any business or other relationship that could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Trust (other than interests and relationships arising from holding units of the Trust);

(ii)

at least one of whom meets the Securities and Exchange Commission definition of **Financial Expert** ; and

(iii)

none of whom is an officer or employee of the Trust.

The composition of the Committee shall also satisfy such other independence, financial literacy, and other requirements of law, the Toronto Stock Exchange and the American Stock Exchange as may be applicable from time to time. The Board shall appoint one member as Chairman of the Committee.

13.

The members of the Committee may be removed or replaced, and any vacancies on the Committee shall be filled by, the Board. If and whenever a vacancy shall exist, the remaining members of the Committee may exercise all of its powers and responsibilities so long as a quorum remains in office.

14.

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings may be called by the Chairman of the Committee, at the request of two members of the Committee, or at the request of the Trust s external auditors. A meeting of the Committee may be called by letter, telephone, facsimile, email, or other communication equipment, by giving at least 48 hours notice, provided that no notice of a meeting shall be necessary if all of the members are present either in person or by means of conference telephone or if those absent have waived notice or otherwise signified their consent to the holding of such meeting.

15.

Any member of the Committee may participate in the meeting of the Committee by means of conference telephone or other communication equipment, and the member participating in a meeting pursuant to this paragraph shall be deemed, for purposes hereof, to be present in person at the meeting.

16.

The Board and the Committee may, from time to time, appoint any person who need not be a member, to act as a secretary at any meeting.

17.

The Committee may invite such officers, directors and employees as it may see fit, from time to time, to attend meetings of the Committee.

18.

Any matters to be determined by the Committee shall be decided by a majority of votes cast at a meeting of the Committee called for such purpose. Actions of the Committee may be taken by an instrument or instruments in writing signed by all of the members of the Committee, and such actions shall be effective as though they had been decided by a majority of votes cast at a meeting of the Committee called for such purpose.

19.

In the absence of the Chairman of the Committee, the members of the Committee shall appoint an acting Chairman.

20.

A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director in a timely fashion and the Committee shall report to the Board periodically, but no less than once annually.

**IV.**

**RESPONSIBILITIES AND DUTIES**

To fulfill its responsibilities and duties:

**Financial Reporting**

21.

the Committee shall review the Trust's annual and quarterly financial statements, including the Trust s disclosures under **Management Discussion and Analysis** , with management and the Trust s external auditors to gain reasonable assurance that the statements are accurate, complete, represent fairly the Trust's financial position and performance and are in accordance with Canadian (and if applicable, the United States of America) GAAP and report thereon to the Board before such financial statements are approved by the Board;

22.

the Committee shall receive from the Trust s external auditors reports on the results of their audit or review, respectively, of the annual and quarterly financial statements;

23.

the Committee may receive from management a copy of the representation letter provided to the Trust s external auditors and receive from management any additional representations required by the Committee;

24.

the Committee may review with management and, if appropriate, recommend approval to the Board of news releases and reports to Unitholders containing financial information before they are issued by the Trust and review generally with management the nature of the financial information and earnings guidance provided to analysts and rating agencies; and

25.

the Committee may review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms, and similar disclosure documents to be issued by the Trust.

**Accounting Policies**

26.

the Committee may review with management and the Trust s external auditors the appropriateness of the Trust's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto, and to obtain reasonable assurance that they are in compliance with GAAP; and report thereon to the Board; and

27.

the Committee may review with management and the Trust s external auditors the quality of earnings of the Trust's underlying accounting policies, key estimates, judgments, and reserves.

**Risk and Uncertainty**

28.

acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Trust, to determine the Trust's tolerance for risk and to approve risk management policies, the Committee may focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(a)

reviewing with management the Trust's tolerance for financial risks;

(b)

reviewing with management its assessment of the significant financial risks facing the Trust;

(c)

reviewing with management the Trust's policies and any proposed changes thereto for managing those significant financial risks; and

(d)

reviewing with management its plans, processes and programs to manage and control such risks;

29.

the Committee may review with management policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

30.

the Committee may review with management foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

31.

the Committee may review with management the adequacy of insurance coverage maintained by the Trust; and

32.

the Committee may review with management, the Trust s external auditors and the Trust's legal counsel, any legal claim or other contingency, including tax assessments, which could have a material effect upon the financial position or operating results of the Trust and the manner in which these matters have been disclosed in the financial statements.

**Financial Controls and Control Deviations**

33.

the Committee may review the plans of management with the Trust s external auditors to gain reasonable assurance of the comprehensiveness and co-ordination of the combined evaluation of the Trust s internal financial controls to identify significant deficiencies or material weaknesses in the quality, adequacy and effectiveness of those controls; and

34.

the Committee may receive regular reports from management and the Trust s external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto.

**Compliance with Laws and Regulations**

35.

the Committee may review regular reports from management and others (e.g. external auditors, external, and internal counsel) with respect to the Trust's compliance with laws and regulations and any legal matters that may have a material impact on the Trust, including:

(a)

tax and financial reporting laws and regulations;

(b)

legal withholding requirements;

(c)

environmental protection laws and regulations; and

(d)

other laws and regulations and any other legal matters (including the status of pending litigation) that may expose directors to liability;

36.

the Committee may review with management reports from the Reserve Committee with respect to matters having a potential material financial impact;

37.

the Committee may review with management the status of the Trust's tax returns and those of its subsidiaries;

38.

the Committee may review with management the organization, responsibilities, plans, results, budget, and staffing of the Trust s legal and compliance function;

39.

the Committee may review with management, and any outside professionals as the Committee considers appropriate, the effectiveness of the Trust s disclosure control and procedures;

40.

the Committee may review with management, and any outside professionals as the Committee considers appropriate, important trends and developments in financial reporting practices and requirements and their effect on the Trust s financial statements;

41.

the Committee may obtain reports from management and the Trust s external auditors regarding compliance with all applicable legal and regulatory requirements, including the U.S. Foreign Corrupt Practices Act; and

42.

the Committee shall with management prepare the report for the Trust s proxy statement that would be required by the Securities and Exchange Commission were the Trust a U.S. company.

**Relationship with Independent External Auditors**

43.

the Committee shall recommend to the Board the nomination of the Trust s external auditors and have direct responsibility for the appointment, compensation, and oversight of the work of the external auditors;

44.

the Committee shall have the sole authority to pre-approve all audit and non-audit services not prohibited by applicable law or the rules of the Toronto Stock Exchange or the American Stock Exchange to be provided by the Trust s external auditors including the remuneration and the terms of engagement;

45.

the Committee shall review the performance of the Trust s external auditors annually, or more frequently as required;

46.

the Committee may receive annually from the Trust s external auditors an acknowledgement in writing that Unitholders, as represented by the Board and the Committee, are their primary client;

47.

the Committee may review with the lead audit partner whether any of the audit team members receive any discretionary compensation from the audit firm with respect to non-audit services performed by the Trust s external auditors;

48.

the Committee may obtain and review with the lead audit partner and a more senior representative of the Trust s external auditor, annually or more frequently as the Committee considers appropriate, a report by the external auditors describing: the external auditor s internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental professional or other regulatory authorities, within the preceding five years respecting independent audits carried out by the external auditor, and any steps taken to deal with these issues; and (to assess the external auditor s independence) all relationships between the external auditors and the Trust;

49.

the Committee may review the experience, qualifications, and performance of the senior members of the Trust s external auditor team;

50.

the Committee may pre-approve the hiring of any employee or former employee of the Trust's external auditors who was a member of the Trust s external audit team during the preceding three fiscal years and pre-approve the hiring of any employee or former employee of the external auditors (within the preceding three fiscal years) for senior positions within the Trust regardless of whether that person was a member of the Trust s audit team;

51.

the Committee may receive from the Trust s external auditors, and review with the external auditors, a report describing critical accounting policies and practices used in preparing the Trust s financial statements, all alternative treatments of financial information that were discussed with management, their ramifications, and the external auditors' preferred treatment and other material written communications between management and the external auditors, in addition to reviewing with the external auditors any audit problems or difficulties and management s response;

52.

the Committee may review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, the extent to which the external audit can be co-ordinated with management, and the materiality levels that the external auditors propose to employ;

53.

the Committee may meet regularly with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee; and

54.

the Committee may establish effective communication processes with management and the external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee.

**Other Responsibilities**

55.

the Committee may periodically review the form, content and level of detail of financial reports to the Board;

56.

the Committee may approve annually the reasonableness of the expenses of the Chairman of the Board and the President and Chief Executive Officer;

57.

the Committee may after consultation with the Chief Financial Officer and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Trust's accounting and financial personnel and other resources;

58.

the Committee may review with management and the lead audit partner of the Trust s external auditors the scope, planning and staffing of the proposed audit for the upcoming year;

59.

the Committee may review, in advance, the appointment of the Trust's senior financial executives;

60.

the Committee may investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

61.

the Committee may review reports from management, the external auditors, and/or the Chairs of other Committees on their review of the Trust's policies on political donations and commissions paid to suppliers or others;

62.

the Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls, or auditing matters, and the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters or fraudulent activities;

63.

the Committee may provide oversight to the disclosure committee on behalf of the Board; and

64.

the Committee may perform such other functions as may from time to time be assigned to the Committee by the Board.

**V.**

**GENERAL**

65.

In discharging its duties under this mandate and charter, each member of the Committee shall be entitled to rely in good faith upon:

(a)

financial statements of the Trust (which are the responsibility of management) represented to him or her by an officer or in a written report of the external auditors to present fairly the financial position and results of the Trust in accordance with generally accepted accounting principles;

(b)

any report of a lawyer, accountant, engineer, appraiser, or other person whose profession lends credibility to a statement made by any such person; and

(c)

the integrity of those persons and organizations within and outside the Trust from whom he or she receives information, and the accuracy of the financial and other information provided to the Committee by such persons or organizations.

66.

In discharging its duties under this mandate and charter, each member of the Committee shall be obliged only to exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this mandate and charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the Financial Reporting Objective is being met and to enable the Committee to report thereon to the Board.

36

67.

The Committee shall have full access to books, records, facilities, and personnel of the Trust and shall have the authority to retain independent counsel and other advisors, as it deems necessary to carry out its duties.

68.

The Trust shall furnish the Committee with appropriate funding, as determined by the Committee, for payment of compensation to the external auditors and to any advisors employed by the Committee.

69.

From time to time, as requested by the Board, the Committee shall review the description of the Committee's mandate and charter and activities to be included in the Trust's statement of corporate governance practices.

**EXHIBIT 2**

Management s Discussion and Analysis

for the year ended December 31, 2005

**FINANCIAL HIGHLIGHTS**

(thousands of Canadian dollars and units, except per unit amounts and as indicated)

| **For the years ended December 31,** | **2005** | **2004** | **Variance** |
|---|---|---|---|
| **INCOME STATEMENT** | | | |
| Oil and natural gas sales [5] | $ 779,630 | $ 517,081 | 51 % |
| Cash flow [1] | $ 398,003 | $ 236,245 | 68 % |
| Per unit basic and diluted [2] | $ 3.84 | | |

$

2.68

43

%

Per boe

$

29.48

$

20.54

44

%

Cash distributions paid per unit

$

1.95

$

1.92

2

%

Payout ratio (6)

51%

73%

(30)

%

Net income

$

210,668

$

74,359

183

%

Net income per unit

Basic

$

2.03

$

0.84

142

%

Diluted

$

2.03

$

0.84

142

%

**UNITS AND EXCHANGEABLE SHARES OUTSTANDING** (2)

Weighted average

103,660

88,169

18

%

Diluted

103,724

88,292

17

%

At year-end

117,561

100,451

17

%

**BALANCE SHEET**

| | | | | |
|---|---|---|---|---|
| Working capital (deficit) [3] | $ 31,897 | $ (49,310) | 165 | % |
| Property, plant and equipment, net | $ 1,777,922 | $ 1,246,694 | 43 | % |
| Total assets | $ 2,267,119 | $ 1,486,412 | 53 | % |
| Long-term debt | $ 462,783 | $ 214,414 | 116 | % |
| Unitholders equity | $ 1,385,343 | $ 1,026,526 | 35 | % |
| **MARKET CAPITALIZATION,** as at December 31 | $ 2,408,816 | $ 1,568,036 | 54 | % |
| **TOTAL CAPITALIZATION,** as at December 31 [3], [4] | $ 2,839,702 | $ 1,831,760 | 55 | % |
| **TRUST UNIT TRADING (TSX: PTF.UN)** | | | | |
| High ($CDN) | $ 23.31 | $ 19.24 | 21 | % |
| Low ($CDN) | $ 15.50 | $ 14.52 | 7 | % |
| Close ($CDN) | $ 20.49 | $ 15.61 | 31 | % |
| Average daily volumes | 210 | 216 | (3) | % |
| **TRUST UNIT TRADING (AMEX: PTF)** | | | | |
| High ($US) | $ 19.88 | $ 14.96 | 33 | % |
| Low ($US) | $ 12.66 | $ 10.95 | 16 | % |
| Close ($US) | $ | $ | 35 | % |

| | | | |
|---|---|---|---|
| | 17.64 13.04 | | |
| Average daily volumes | 559 476 | 17 | % |

(1)

Cash flow before net changes in non-cash operating working capital

(Non-GAAP measure, see special notes in the Management s Discussion and Analysis).

(2)

See Note 9 to the Consolidated Financial Statements.

(3)

Excludes net unrealized gains/losses on commodity contracts.

(4)

Total capitalization equals market capitalization plus net debt

(Non-GAAP measure, see special notes in the Management s Discussion and Analysis).

(5)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

(6)

Cash distributions paid divided by cash flow before capital reinvestment.

**OPERATIONAL HIGHLIGHTS**

(thousands of Canadian dollars, except per unit amounts and as indicated)

| **For the years ended December 31,** | **2005** | **2004** | **Variance** |
|---|---|---|---|
| **DAILY PRODUCTION** | | | |
| Oil (bbls) | 18,264 | 15,084 | 21 % |
| Natural gas (mmcf) | 98.1 | 84.5 | 16 % |
| Natural gas liquids (bbls) | 2,383 | 2,262 | 5 % |
| BOE (6:1) | 36,991 | 31,429 | 18 % |
| **Total annual production (mboe)** | 13,501 | 11,503 | |

17

%

**PRODUCTION PROFILE**

Oil

49%

48%

Natural gas

45%

45%

Natural gas liquids

6%

7%

**AVERAGE PRICES** (1)

Oil (per bbl)

$

61.54

$

48.83

26

%

Natural gas (per mcf)

$

9.02

$

6.87

31

%

Natural gas liquids (per bbl)

$

52.98

$

41.96

26

%

Per BOE (6:1)

$

57.71

$

44.93

28

%

**CASH OPERATING NETBACK PER BOE** (2)

$

32.05

$

23.01

39

%

**PROVEN PLUS PROBABLE RESERVES** (3)

Crude oil (millions of barrels)

88.5

86.0

3

%

| | | | | |
|---|---|---|---|---|
| Natural gas (billions of cubic feet) | 388.7 | | 283.7 37 | % |
| Natural gas liquids (millions of barrels) | 9.0 | | 8.3 10 | % |
| Millions of barrels of oil equivalent at 6:1 | 162.3 | | 141.6 15 | % |
| **LEASE OPERATING COSTS** | $ | $ | | |
| | 141,578 | | | |

103,610

(37)

%

Cost per boe

$

10.49

$

9.01

(16)

%

**GENERAL AND ADMINISTRATIVE COSTS**

$

17,174

$

14,441

(19)

%

Cost per boe

$

1.27

$

1.26

(1)

%

(3)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

(2)

Cash operating netback per BOE is calculated as the selling price less the cash cost of hedging less royalties, net of ARC, lease operating costs and transportation costs, by product, divided by the total production volumes in each period. For details by product type see the section Net Income in the Management s Discussion and Analysis.

(3)

Reserves at December 31, 2005 and 2004 are based on total proved plus probable gross reserves (as defined in National Instrument 51-101 ( NI 51-101 )), being working interest reserves prior to deduction of royalties.

*Management s Discussion & Analysis*

***SPECIAL NOTES***

The following Management s Discussion and Analysis ( MD&A ) of financial results should be read in conjunction with the audited Consolidated Financial Statements of Petrofund Energy Trust ( Petrofund or the Trust ) for the fiscal years ended December 31, 2005 and 2004 included in this 2005 annual report. All oil and natural gas properties are held by Petrofund Corp. ( PC ) and Petrofund Ventures Trust ( PVT ), wholly owned subsidiaries of the Trust. This commentary is based on information available to, and is dated, February 14, 2006. Additional information (including Petrofund s annual information form AIF ), when filed, can be obtained on SEDAR at www.sedar.com or on the Trust s website at www.petrofund.ca.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent ( boe ) basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel (6 mcf/1 bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion 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. Reserves at December 31, 2005, and 2004 are based on total proved plus probable gross reserves (as defined in National Instrument 51-101 ( NI 51-101 )), being working interest reserves prior to deduction of royalties.

***NON GAAP MEASURES***

The Trust uses adjusted cash flow (before changes in non-cash operating working capital and before capital reinvestment) to analyze operating performance and leverage. Adjusted cash flow (before changes in non-cash operating working capital) and adjusted cash flow before capital reinvestment before changes in working capital and before settlement of asset retirement obligations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles ( Canadian GAAP ) and may not be comparable with the calculation of similar measures for other entities. Cash flow (before changes in non-cash operating working capital) and cash flow from operations before changes in working capital and before settlement of asset retirement obligations as presented is not intended to represent operating cash flows or operating profits for the period, nor should it be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow (before changes in non-cash operating working capital) and cash flow from operations before changes in working capital and before settlement of asset retirement obligations are based on cash flow from operating activities before changes in non-cash operating working capital or before changes in non-cash working capital and before settlement of asset retirement obligations, as applicable.

The Trust also uses net debt . Net debt as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Net debt as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of derivative contracts.

The Trust also uses payout ratio as cash distributions paid divided by cash flow before capital reinvestment. Payout ratio as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities.

Cash operating netback per BOE is calculated as the selling price less the cash cost of hedging less royalties, net of Alberta Royalty Credit ( ARC ), lease operating costs and transportation costs, by product, divided by the total production volumes in each period. For details by product type see the section Net Income in the Management s Discussion and Analysis.

The Trust uses certain key performance indicators and industry benchmarks such as operating netbacks ( netbacks ), finding, development and acquisition costs ( FD&A ), and total capitalization to analyze financial and operating performance. These performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other entities.

These measures should be given careful consideration by the reader.

***FORWARD-LOOKING STATEMENTS***

Certain statements contained in this annual report constitute forward-looking statements. The use of any of the words anticipate , continue , estimate , expect , may , project , should , believe and similar expressions are inte forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and PC believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this annual report should not be unduly relied upon. These statements speak only as of the date of this annual report.

In particular, this annual report contains forward-looking statements pertaining to the following:

- the size of the Trust s oil and natural gas reserves;
- projections of market prices and costs;
- anticipated distributions on units of the Trust and the payout ratio;
- capital expenditures and the timing thereof;
- supply and demand for oil and natural gas;
- the Trust s expectations with respect to acquisitions and the properties obtained thereunder;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual report:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems; and
- the other factors described under Business Risks in this annual report and in the AIF.

These factors should not be construed as exhaustive. Except as required by applicable securities laws, neither the Trust nor PC undertakes any obligation to publicly update or revise any forward-looking statements.

***2005 HIGHLIGHTS***

The Trust paid out cash distributions of $1.95 per unit in 2005, compared to $1.92 per unit in 2004 (2003 - $2.09 per unit). Petrofund has since paid/distributed $0.20 per unit for January

2006, announced distributions of $0.20 per unit for February and based on current commodity prices and market conditions has indicated distributions of $0.20 per unit for March 2006.

The Trust s payout ratio for 2005 was 51% compared to 73% in 2004 (2003 70%). The lower payout ratio enabled the Trust to fund 100% of its 2005 development expenditures from retained cash flow before capital reinvestment.

The Trust generated cash flow before non-cash operating working capital of $398.0 million in 2005, an increase of 68% over 2004. This increase reflects increased average production and higher prices. Net income increased to $210.7 million in 2005 versus $74.4 million in 2004. The net income also includes an unrealized (non-cash) gain on commodity contracts of $6.3 million in 2005 versus an unrealized (non-cash) loss on commodity contracts of $6.2 million in 2004 as well as a future income tax recovery of $6.7 million in 2005 versus $7.1 million expense in 2004.

Average production on a boe basis increased 18% to 36,991 boe/d in 2005 from 31,429 boe/d in 2004. The change in production reflects PC s development drilling program, the acquisition of Ultima Energy Trust ( Ultima ) in June 2004, the Central Alberta acquisitions in November 2004 and the 2005 acquisitions listed later in this section, offset by natural production decline.

Average prices in 2005 were up 28% on a boe basis from the prior year and were $57.71 per boe for 2005 compared to $44.93 per boe in 2004.

Petrofund has a strong balance sheet with a net debt to cash flow ratio as at December 31, 2005, of 1.1:1.0 based on 2005 cash flow before non-cash operating working capital.

On November 16, 2005 Petrofund entered into an agreement to acquire 100% of Kaiser Energy Ltd. ( Kaiser ), effective December 1, 2005. Kaiser held (or held prior to the completion of the acquisition by Petrofund), either directly or indirectly, interests in Canadian Acquisition Limited Partnership ( Canadian Partnership ) and certain properties to be transferred to Kaiser (collectively, the Kaiser Entities ). Petrofund added $489.7 million to oil and gas properties (excluding non-cash negative working capital of $14.9 million, future income taxes of $157.2 million and asset retirement obligations of $4.9 million). This acquisition added approximately 5,400 boepd production to the Trust and working interest reserves additions of 20 million boe on a proved plus probable basis.

In 2005, Petrofund further acquired interests in various oil and gas properties for $74.0 million (excluding non-cash negative working capital assumed of $4.8 million, future income taxes of $10.4 million and asset retirement obligations of $1.2 million), which includes the purchase of Northern Crown Petroleums Ltd. ( Northern Crown ), Tahiti Gas Ltd. ( Tahiti ) and property interests in the Turin and Joarcam areas. These acquisitions added approximately 1,650 boepd of production to the Trust. Petrofund s internal estimate of reserves acquired, at the time of acquisition, was 4.6 million boe on a proved plus probable basis.

The Trust has a balanced production profile which averaged 45% natural gas and 55% oil and liquids for the fiscal year ended December 31, 2005.

The Trust completed a bought deal financing of 4.15 million Trust units, raising gross proceeds of $75.7 million ($71.4 million net) in the second quarter of 2005. The Trust also

completed a bought deal financing of 12.5 million Trust units, raising gross proceeds of $250 million ($237 million net) in the fourth quarter of 2005. The weighted average number of Trust units/Exchangeable shares outstanding increased from 88.2 million in 2004 to 103.7 million in 2005. As at December 31, 2005 there were 117.6 million Trust units/Exchangeable shares outstanding.

The Trust s total capitalization as at December 31, 2005, was approximately $2.8 billion ($1.8 billion as at December 31, 2004).

***CASH DISTRIBUTIONS***

| **For the years ended December 31,** | **2005** | **2004** | **2003** |
|---|---|---|---|
| | $ | $ | $ |
| Distributions paid per unit | 1.95 | 1.92 | 2.09 |

Trust unitholders who held their units in 2005 received aggregate cash distributions of $1.95 per unit as compared to $1.92 per unit in 2004 (2003 - $2.09 per unit). For 2006, the Trust distributed $0.20 per unit in January, has announced a distribution of $0.20 per unit for February, and has indicated a distribution of $0.20 per unit for March.

Petrofund focuses on the ability to maintain distribution levels. As part of this strategy, the Trust has lowered its payout ratio over the past two years in response to increasing oil and gas prices which currently exceed historical highs. At the same time, the Trust has allocated a higher percentage of cash flow for capital reinvestment. Petrofund monitors the distribution payout with respect to forecasted funds flow, debt levels and pending plans. The level of cash retained has historically varied between 10% and 30% of annual funds flow; however, Petrofund adjusts the payout levels in an effort to balance the desire for distributions with the requirement to maintain a prudent capital structure. To reflect the treatment of capital expenditures funded from cash flow, the Trust has modified the calculation of Distributions payable to Unitholders by applying the portion of capital expenditures funded from cash flow rather than an estimated amount as a reduction of Distributions payable up to the amount available for such purposes. Any remaining cash flow continues to be shown as Distributions payable to Unitholders at the end of the period.

During 2005, the Trust generated cash flow available for distribution before capital reinvestment of $394.2 million (2004 - $231.5 million). The Trust paid out $202.3 million (2004 - $169.5 million) in distributions representing a payout ratio of 51% (2004 73%). In the fourth quarter, the Trust generated cash flow available for distribution of $125.3 million before deducting $88.0 million for capital expenditures and paid out $55.5 million in distributions for a payout ratio of 44%. For a detailed analysis of cash flow available for distributions refer to Note 8 to the Consolidated Financial Statements.

**CASH DISTRIBUTION PAID HISTORY** (1)

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held, as described below. For additional information, please see our website at www.petrofund.ca.

| **Calendar Year** | **Distributions** [2] | **Taxable Portion** | **Return of Capital** |
|---|---|---|---|
| | $ | $ | $ |
| 1989 to 1996 | 20.8950 | - | 20.8950 |
| 1997 | 2.3700 | - | 2.3700 |
| 1998 | 1.4400 | - | 1.4400 |
| 1999 | 1.8300 | - | 1.8300 |
| 2000 | 3.9900 | 2.4633 | 1.5267 |
| 2001 | 4.2400 | 2.6771 | 1.5629 |
| 2002 | 1.7100 | 0.9365 | 0.7735 |
| 2003 | 2.0900 | 1.0706 | 1.0194 |
| 2004 | 1.9200 | 1.4849 | 0.4351 |
| 2005 | 1.9500 [3] | 1.9184 | 0.0316 |
| | $ | $ | $ |
| **Cumulative** | 42.4350 | 10.5508 | 31.8842 |

(1)

Applies to unitholders who are residents of Canada and hold their units as capital property.

(2)

Based on cash distributions paid in the calendar year and adjusted for unit splits.

(3)

Petrofund estimates that approximately 98% of cash distributions paid in 2005 to Canadian Unitholders will be taxable. U.S. unitholders will also be taxable. Any non-taxable amounts will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow experienced throughout the year.

For U.S. taxpayers, the taxable portion of the cash distribution is considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a Qualified Dividend eligible for the reduced tax rate. The non-taxable portion of the cash distribution is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

This is a general guideline and not intended to be legal advice to any particular holder or potential holder of units of the Trust. This information is not exhaustive of all possible U.S. income tax considerations. Unitholders or potential unitholders of the Trust should consult their own legal and tax advisers as to the particular tax consequences of holding their Trust units.

**CASH FLOW**

| ($000 s) | 2005 | 2004 | 2003 |
|---|---|---|---|
| | $ | | |
| **Cash provided by operating activities** | 337,223 | $ | |
| | | | 243,652 |
| $ | | | |
| | | | 192,163 |
| Increase (decrease) in non-cash working capital | | | |
| 60,780 | | | |
| | | | (7,407) |
| | | | (4,578) |

| | | | |
|---|---|---|---|
| **Cash flow before non-cash operating working capital** | 398,003 | 236,245 | 187,585 |
| Redemption of exchangeable shares | (1,154) | (1,803) | (2,792) |
| Asset retirement reserve fund | (2,025) | (1,725) | (776) |
| Capital lease repayment | (608) | (356) | (3,305 |
| Amortization of the cost of commodity contracts | - | (821) | - |
| **Cash flow before capital reinvestment** | $ | $ | $ |
| | 394,216 | 231,540 | 180,712 |

**MONTHLY CASH DISTRIBUTIONS**

Actual cash distributions paid for per Trust unit along with relevant payment dates for 2005, 2004 and 2003 are as follows:

| **Record Date** [(1)] | **Payment Date** [(1)] | **2005** | **2004** | **2003** |
|---|---|---|---|---|
| | | $ | $ | $ |
| January 17 | January 31 | 0.16 | 0.16 | 0.15 |
| February 14 | February 28 | 0.16 | 0.16 | 0.16 |
| March 16 | March 31 | 0.16 | 0.16 | 0.17 |
| April 15 | April 29 | 0.16 | 0.16 | 0.17 |
| May 16 | May 31 | 0.16 | 0.16 | 0.18 |
| June 16 | June 30 | 0.16 | 0.16 | 0.18 |
| July 15 | July 29 | 0.16 | 0.16 | 0.18 |
| August 17 | August 31 | 0.16 | 0.16 | 0.18 |
| September 16 | September 30 | 0.16 | 0.16 | 0.18 |
| October 17 | October 31 | 0.17 | 0.16 | 0.18 |
| November 16 | November 30 | 0.17 | 0.16 | 0.18 |
| December 14 | December 30 | 0.17 | 0.16 | 0.18 |

| | | | |
|---|---|---|---|
| | $ | $ | $ |
| | 1.95 | 1.92 | 2.09 |

(1) Dates relate to 2005 only.

***RESULTS OF OPERATIONS***

**FOURTH QUARTER 2005 VERSUS FOURTH QUARTER 2004**

The Trust generated cash flow of $126.1 million or $1.17 per unit in the fourth quarter of 2005 compared to $72.3 million or $0.72 per unit in the fourth quarter of 2004. The Trust increased monthly cash distributions to $0.17 per unit in the fourth quarter of 2005. The Trust s payout ratio of 44% in the fourth quarter of 2005 compared to a payout ratio of 67% in the fourth quarter of 2004.

The fourth quarter of 2005 was an active quarter for Petrofund with the acquisition of Kaiser, plus ongoing drilling and development activities. Total capital expenditures for the quarter were $508.4 million. These activities provided new production in the fourth quarter of 2005, as discussed further in the Operational Highlights.

Average daily production volumes in the fourth quarter of 2005 of 39,178 boe were above the fourth quarter of 2004 volumes of 36,025 boe. This increase resulted from acquisitions and development activities in 2005 partially offset by the natural production decline.

Net income increased to $100.1 million in the fourth quarter of 2005 compared to $50.8 million in the fourth quarter of 2004. Revenues increased 53% which reflects an increase of 40% in prices on a boe basis and a 9% increase in production. The increase in revenue has partly been offset by a $11.9 million loss on commodity contracts and an increase of $12.4 million in depletion expense. The Trust recognized an unrealized (non-cash) commodity gain of $31.6 million versus an unrealized (non-cash) commodity gain of $26.4 million in the fourth quarter of 2004. Both adjustments were a result of the mark-to-market fair value accounting. In addition, the future income tax in the fourth quarter of 2005 was a recovery of $2.5 million compared to $774,000 expense in the fourth quarter of 2004, due to an increase in commodity contract losses and other tax related asset balances.

The cash loss on commodity contracts during the fourth quarter of 2005 was $11.9 million compared to a $14.1 million loss in the fourth quarter of 2004.

Royalties were 21% of revenue in the fourth quarter of 2005, compared to 20% for the fourth quarter of 2004.

Lease operating costs on a unit basis increased to $10.64/boe in the fourth quarter of 2005 from $8.82/boe in the fourth quarter of 2004. Costs for repairs and maintenance continue to increase as a result of high levels of activity in the upstream sector.

**PRODUCTION**

In accordance with Canadian practice, production volumes and reserves are reported on a working interest basis, before deduction of Crown and other royalties, unless otherwise indicated.

Annual production volumes averaged 36,991 boe/d in 2005, an increase of 18% over average production volumes of 31,429 boe/d in 2004. The change in production reflects, PC s development drilling program, the acquisition of Ultima in June 2004, the Central Alberta PNG Partnership and 1024373 Alberta Ltd. ( Central Alberta acquisition ) acquisition in November 2004, the Turin area acquisition in January 2005, the Northern Crown and Tahiti acquisitions in May 2005, the Joarcam area acquisition in July 2005, the Kaiser acquisition in December 2005 and positive prior period adjustments (136 boe/d), partially offset by natural production decline.

| **For the years ended December 31,** | **2005** | **2004** | **2003** |
|---|---|---|---|
| **Daily Production** | | | |
| Oil (bbls) | 18,264 | 15,084 | 12,454 |
| Natural gas (mmcf) | 98.1 | 84.5 | 83.3 |
| Natural gas liquids (bbls) | 2,383 | 2,262 | 2,079 |
| **Total** (boe 6:1) | 36,991 | 31,429 | 28,418 |

**PRICING & PRICE RISK MANAGEMENT**

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 51% to $779.6 million in 2005 from $517.1 million in 2004 due to a 17% increase in production and a 28% increase in prices on a boe basis.

Crude oil sales increased to $410.2 million in 2005 from $269.6 million in 2004 due to a 21% increase in production from 15,084 bbl/d in 2004 to 18,264 bbl/d in 2005 and a 26% increase in the oil price received. The average WTI oil price increased from U.S. $41.40/bbl in 2004 to U.S. $56.56/bbl in 2005 or 37%; however, the Canadian par price at Edmonton increased only 31% from $52.54/bbl to $68.72/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged 0.83 in 2005 versus 0.77 in 2004. The average Canadian wellhead price received by Petrofund increased to $61.54/bbl in 2005 from $48.83/bbl in 2004.

About 60% of the Trust s crude production was sold directly to refiners in 2005 with the balance being delivered to marketers. Petrofund intends to maintain this sales mix in 2006.

Crude differentials widened considerably in Western Canada during 2005 though Petrofund was partly shielded from the deterioration in these differentials due to its high quality portfolio. Petrofund s differential to Edmonton postings before hedging increased to $7.18/bbl in 2005 from $3.71/bbl in 2004 (2003 - $3.98/bbl). Heavy oil differentials are expected to remain weak but the expectation is for more stable differentials for the lighter and medium sour crudes comprising the bulk of the Trust s portfolio (97% light and medium crudes). Petrofund does, however, expect its overall differential from Edmonton to increase in 2006.

Natural gas sales increased to $322.9 million in 2005 from $212.6 million in 2004 due to a 16% increase in production and a 31% increase in the average prices received from $6.87/mcf in 2004 to $9.02/mcf in 2005. The monthly AECO price per mmbtu increased from $6.79 in 2004 to $8.48 in 2005. Production volumes averaged 98.1 mmcf/d in 2005 compared to 84.5 mmcf/d in 2004. Petrofund sold 32% of its production in 2005 to aggregators at netback pricing, up from 30% in 2004. Netbacks from these markets are below those otherwise available to the Trust at AECO; however, the average aggregator discount to AECO for Petrofund improved in 2005 by $0.24/mcf. The Trust sold the remaining 68% of its production on daily and monthly spot market pricing in Alberta, Saskatchewan and British Columbia. Petrofund intends to maintain this sales mix in 2006.

Sales of natural gas liquids and sulphur increased to $46.5 million in 2005 from $34.9 million in 2004 as production increased to 2,383 bbl/d in 2005 from 2,262 bbl/d in 2004. The average price increased from $41.96/bbl in 2004 to $52.98/bbl in 2005. The majority of the Trust s NGLs (88%) are sold to one buyer under one-year contract terms at market sensitive pricing with the remainder widely distributed among any number of buyers. The Trust has optimized netbacks by aggregating its NGL production with a single buyer. Alberta NGL netbacks lagged crude oil during the year in a pattern similar to the prior year but pricing was stable over the period with no periods of extreme weakness. The condensate market in Western Canada was exceptionally tight in the fourth quarter with prices trading well in excess of WTI. Petrofund expects pricing for 2006 to remain strong for its NGLs and condensate.

Crude oil accounted for 49% of production in 2005 (2004 48%, 2003 44%), while natural gas constituted 45% of production in 2005 (2004 45%, 2003 49%). Natural gas liquid volumes accounted for 6% of total production in 2005 (2004 and 2003 7%). The Trust continues to maintain a balance between oil and natural gas production.

| **Average prices received for the years ended December 31,** | **2005** | **2004** | **2003** |
|---|---|---|---|
| | $ | $ | $ |
| Oil (per bbl) (1) | 61.54 | 48.83 | 39.16 |
| Natural gas (per mcf) (1) | 9.02 | 6.87 | 6.63 |
| Natural gas liquids (per bbl) (1) | 52.98 | 41.96 | 35.05 |
| | $ | $ | $ |
| Weighted average per BOE (6:1) | 57.71 | 44.93 | 39.15 |

(1)

Prices are before realized gains/losses on commodity contracts and before transportation costs which were previously deducted from oil and natural gas prices and are now disclosed separately on the income statement. Prices previously reported for prior years have been restated.

| **Production Revenue** ($millions) | **2005** | **2004** | **2003** |
|---|---|---|---|
| | $ | $ | $ |
| Oil | 410.2 | 269.6 | 178.0 |
| Natural gas | 322.9 | 212.6 | 201.5 |
| Natural gas liquids & sulphur | 46.5 | 34.9 | 26.8 |
| | $ | $ | $ |
| **Total** | 779.6 | 517.1 | 406.3 |

The Trust has a formal risk management policy which permits the risk management committee to use specified price risk management strategies for up to 40% of crude oil, natural gas and NGL production including: fixed price contracts; costless collars; the purchase of floor price options; and other derivative financial instruments to reduce price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust s future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to cash distributions as well as to ensure Petrofund realizes positive economic returns from its capital development and acquisition activities.

As at December 31, 2005, Petrofund had 27.6 mmcf/d of natural gas and 4,500 bbl/d of crude oil hedged for the remainder of 2006 (approximately 25% of production). A summary of the hedged volumes and prices in place at December 31, 2005, by quarter is shown in the following table (see Note 15 to the Consolidated Financial Statements for a detailed disclosure of all derivative financial instruments and their corresponding mark-to-market values):

| | | **Average Volumes (mcf/d)** | | | |
|---|---|---|---|---|---|
| **Natural Gas** | **2006** | **Q1** | **Q2** | **Q3** | **Q4** |
| Collars | 20,132 | 14,211 | 28,422 | 28,422 | 9,474 |
| Three way collars | 5,132 | 9,474 | 4,737 | 4,737 | 1,579 |
| Floors | 2,369 | 9,474 | - | - | - |
| **Total mcf/d** | 27,633 | 33,159 | 33,159 | 33,159 | 11,053 |

| | | Average Price ($/mcf) | | | |
|---|---|---|---|---|---|
| **Natural Gas** | **2006** | **Q1** | **Q2** | **Q3** | **Q4** |
| | $ | $ | $ | $ | $ |
| Collar ceiling price | 13.51 | 16.29 | 12.58 | 12.58 | 12.58 |
| Collar floor price | 8.82 | 8.09 | 9.06 | 9.06 | 9.06 |
| Three way ceiling price | 9.69 | 11.77 | 8.99 | 8.99 | 8.99 |
| Three way floor price | 7.17 | 6.52 | 7.39 | 7.39 | 7.39 |
| | $ | $ | $ | $ | $ |
| Three way floor short | 5.92 | 5.47 | 6.07 | 6.07 | 6.07 |

| | | Average Volumes (bbl/d) | | | |
|---|---|---|---|---|---|
| **Oil** | **2006** | **Q1** | **Q2** | **Q3** | **Q4** |
| Collared | 4,000 | 5,000 | 5,000 | 4,000 | 2,000 |
| Three way collars | 500 | 1,000 | 1,000 | - | - |
| **Total bbl/d** | **4,500** | **6,000** | **6,000** | **4,000** | **2,000** |

| | | Average Price ($/bbl) | | | |
|---|---|---|---|---|---|
| **Oil** | **2006** | **Q1** | **Q2** | **Q3** | **Q4** |
| | $ | $ | $ | $ | $ |
| Collar ceiling price | 87.22 | 85.54 | 88.62 | 88.52 | 86.18 |
| Collar floor price | 58.92 | 56.29 | 58.73 | 59.61 | 61.06 |
| Three way ceiling price | 65.28 | 61.64 | 68.91 | - | - |
| Three way floor price | 47.69 | 46.52 | 48.85 | - | - |
| | $ | $ | $ | $ | $ |
| Three way floor short | 41.87 | 40.71 | 43.03 | - | - |

| **Alberta Power** | **2006** | **Q1** | **Q2** | **Q3** | **Q4** |
|---|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Fixed, MW/h | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| | $ | $ | $ | $ | $ |
| Fixed price ($/MWh) | 57.00 | 57.00 | 57.00 | 57.00 | 57.00 |

**Three-way Collars**

A three-way collar is transacted by selling a call to create a ceiling, buying a put to create a floor, then selling a put below the floor to create a floor short. For example, a three-way collar of $35 - $40 - $50 would result in the following prices received. For market prices above the ceiling ($50), Petrofund receives $50. For market prices between the ceiling and the floor ($40 - $50), Petrofund receives the market price. For market prices between the floor and the floor short ($35 - $40), Petrofund receives $40. For market prices below the floor short ($35), Petrofund receives the market price plus $5.

After December 31, 2005 and as at February 14, 2006, Petrofund entered into the following additional hedges (not included in the table above):

(1)

A collar for July 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $75.50/bbl.

(2)

A swap for April 1, 2006 to October 31, 2006, for 4.7 mmcf/d of natural gas at $9.49/mcf, at AECO pricing.

(3)

A collar for October 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $84.75/bbl.

(4)

A collar for January 1, 2007 to March 31, 2007, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $82.55/bbl.

(5)

A collar for July 1, 2006 to September 30, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $86.00/bbl.

(6)

A collar for October 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $90.00/bbl.

(7)

A collar for January 1, 2007 to March 31, 2007, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $90.25/bbl.

(8)

A collar for November 1, 2006 to March 31, 2007, for 4.7 mmcf/d of natural gas at $9.45 and $12.86/mcf, at AECO pricing.

Petrofund has no sales volumes hedged after March 31, 2007. All foreign exchange calculations in this section of the report incorporate the Bank of Canada U.S. dollar rate at the close on December 31, 2005 of CDN $1.163:U.S. $1.

**ROYALTIES**

| **For the years ended December 31,** | **2005** | **2004** | **2003** |
|---|---|---|---|
| | $ | $ | $ |
| Royalties (millions) | 155.8 | 100.2 | 84.8 |

| | | | |
|---|---|---|---|
| Average royalty rate (%) | 20.0 | 19.4 | 20.9 |
| | $ | $ | $ |
| $/boe | 11.54 | 8.71 | 8.18 |

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $155.8 million in 2005 from $100.2 million in 2004 (2003 $84.8 million) net of the Alberta Royalty Credit ( ARC ). Royalties, as a percentage of revenues before hedging losses, increased to 20% of revenues in 2005 from 19.4% of revenues in 2004 (2003 20.9%).

| **EXPENSES** | | | |
|---|---|---|---|
| **For the years ended December 31,** | **2005** | **2004** | **2003** |
| **Expenses (millions)** | | | |
| | $ | $ | $ |
| Lease operating | 141.6 | 103.6 | 91.3 |
| Transportation costs | 8.1 | 5.9 | 5.5 |
| General & administrative | 17.2 | 14.4 | 13.0 |
| Financing costs | 10.6 | 5.8 | 8.7 |
| **Expenses per boe** | | | |
| | $ | $ | $ |
| Lease operating | 10.49 | 9.01 | 8.80 |
| Transportation costs | 0.60 | 0.51 | 0.53 |
| General & administrative | 1.27 | 1.26 | 1.26 |
| Financing costs | 0.79 | 0.51 | 0.84 |

**Lease Operating**

Operating costs for 2005 were up 16% to $10.49 per boe compared to $9.01 per boe in 2004 (2003 $8.80). Costs for repairs and maintenance continue to increase as a result of the high level of activity in the upstream sector.

The most significant contributor to the higher per unit operating costs to date in 2005 has been a general industry increase for all types of services and supplies including surface and downhole well repair and maintenance costs and facility maintenance work. In addition, the current high product price environment is driving average operating costs higher because marginal, higher cost properties continue to generate positive cash flow at higher than historical per unit costs and, as a result, remain on production longer. The Trust anticipates lease operating costs in 2006 will continue to increase at a rate similar to that of 2005.

**Transportation Costs**

Transportation costs on a boe basis were $0.60 in 2005 as compared to $0.51 in 2004 (2003 - $0.53), reflecting general increases in trucking costs of clean oil.

**General & Administrative ("G&A") Costs**

General and administrative costs for 2005, were $17.2 million compared to $14.4 million in 2004 (2003 - $13.0 million). Costs were $1.27 per boe in 2005 compared to $1.26 per boe in 2004 (2003 - $1.26 per boe). G & A costs in 2005 include $3.6 million of compensation expense related to the restricted unit plan ( RUP ) and the long-term incentive plan ( LTIP ) compared to $1.5 million in 2004. The compensation expense is based on the unit price of the Trust units at December 31, 2005, of $20.49 per unit (December 31, 2004  $15.61 per unit). See Notes 13 and 14 of the Consolidated Financial Statements for details of the Trust s incentive plans.

G & A costs in 2005 include $370,000 or $0.03 per boe for external costs associated with Section 404 of the Sarbanes Oxley Act ( SOX 404 ) compared to $212,000 in 2004 or $0.09 per boe.

The Trust expects its per boe G&A costs to increase by approximately 20% in 2006, which mainly reflects increases in employee compensation expenses.

**Financing Costs**

Financing costs and increases in loan balances as noted below reflect funding of expenditures associated with PC s active property acquisitions, and drilling and development programs.

Interest and other financing costs for 2005, increased to $10.6 million in 2005 compared to $5.8 million in 2004 (2003 - $8.7 million), which reflects the increase in the average loan balance outstanding in 2005 of $270.1 million from $157.5 million in 2004 and an increase in the average prime loan rate from 4.0% in 2004 to 4.4% in 2005. Net debt as a percentage of total capitalization is 15.2% in 2005 compared to 14.9% in 2004 (2003  9.2%).

The bank loan outstanding at December 31, 2005, was $462.8 million as compared to $214.4 million at December 31, 2004. An amount of $248.3 million of debt was incurred in the fourth quarter of 2005 which was mainly incurred to finance the acquisition of Kaiser. At December 31, 2005, 100% of PC s debt was based on floating interest rates.

***DEPLETION, DEPRECIATION & ACCRETION***

Depletion, depreciation and accretion expense increased to $202.8 million in 2005 from $153.1 million in 2004 (2003 - $118.3 million) due to the increase in production and an increase in the depletion rate. The rate per boe increased to $15.02 in 2005 from $13.31 in 2004 (2003 - $11.41). The increase in the rate over 2004 and into 2005 reflects the increasing cost of acquisitions. The unproved properties are included in the depletion and depreciation expense calculation.