PETROFUND ENERGY TRUST
Form 6-K
May 13, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 6-K

REPORT OF FOREIGN ISSUER PURSUANT TO RULE 13A-16 OR 15D-16 OF THE SECURITIES EXCHANGE ACT OF 1934

For the month of: May 2004
Commission File Number: 00-115124

PETROFUND ENERGY TRUST

(Name of Registrant)

Barclay Centre 600 444 7Avenue SW Calgary, Alberta Canada T2P 0X8
(Address of Principal Executive Offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F:

Form 20-F _____ Form 40-F __**X**__

Indicate by check mark whether the registrant by furnishing 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:

Yes ______ No __**X**__

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): N/A

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PETROFUND ENERGY TRUST

Date: May 12, 2004

By:

Vince P. Moyer, CA

Senior Vice President, Finance and CFO

EXHIBIT

Exhibit	Description of Exhibit
1.	**First Quarter Report dated May 12, 2004.**

EXHIBIT 1

444 - 7th Avenue S.W.
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Calgary, Alberta
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News Release

CALGARY - May 12, 2004

Petrofund Energy Trust (*TSX: PTF.UN; AMEX: PTF*)
Reports its Results for the First Quarter of 2004

Petrofund Energy Trust is pleased to provide its results for the first quarter of 2004. Key items from the quarter include:

- Announcement of the Ultima Energy Trust merger, which is anticipated to close in the second quarter pending Ultima unitholder approval
- Cash distributions of $0.48 per unit in the quarter, unchanged from the comparable quarter of 2003
- Cash flow of $49 million, down 16% from Q1 of last year, primarily due to a 14% drop in commodity prices in terms of Canadian dollars
- A first quarter payout ratio of 73%
- Average production of 26,607 BOE per day, down 1% from Q1 of 2003
- Operating costs of $8.19 per BOE, up 1% from the same period in 2003
- General and administrative costs down 9% from Q1 of 2003 to $1.30 per BOE

Additional information on Petrofund's first quarter results are presented below:

FINANCIAL HIGHLIGHTS

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

For the three months ended March 31,		**2004**		**2003 %**	**Change**
INCOME STATEMENT					
Revenues	$	99,699	$	$115,695	(14)%
Cash flow [1]	$	49,047	$	$58,619	(16)%
Cash flow available for distribution [2]	$	40,426	$	$50,002	(19)%
Cash flow available for distribution per unit [2]					
Before allocation for capital	$	0.65	$	$ 1.06	(39)%
Allocation for capital	$	(0.10)	$	$ (0.14)	29%
After allocation for capital	$	0.55	$	$ 0.92	(40)%
Cash distributions paid per unit	$	0.48	$	$ 0.48	- %
Net income	$	7,629	$	$32,612	(77)%
Net income per unit					
Basic	$	0.10	$	$ 0.60	(83)%
Diluted	$	0.10	$	$ 0.60	(83)%
UNITS AND EXCHANGEABLE SHARES OUTSTANDING [3]					
Weighted average		73,674		54,130	36%
Diluted		73,872		54,270	36%
At period end		73,682		54,148	36%
BALANCE SHEET					
Working capital (deficit)	$	(66,085)	$	(30,037)	(120)%
Property, plant and equipment	$	883,191	$	838,008	5%
Long-term debt	$	90,040	$	213,328	58%
Unitholders' equity	$	615,952	$	462,702	33%
TRUST UNIT TRADING (TSX: PTF.UN)					
High	$	19.24	$	12.54	53%
Low	$	14.56	$	10.80	35%
Close	$	17.35	$	11.47	51%
Volume (units)		13,073		6,534	100%
TRUST UNIT TRADING (AMEX: PTF)					
High	$	14.96	$	8.55	75%
Low	$	10.95	$	6.89	59%
Close	$	13.22	$	7.85	68%
Volume (units)		40,537		8,496	377%

1. Cash flow before net change in non-cash operating working capital balances. (Non-GAAP measure - see special notes in the Management Discussion and Analysis.)
2. See Note 6 to the Notes to Interim Consolidated Financial Statements for details.
3. See Notes 3 and 4 to Notes to Interim Consolidated Financial Statements for details.

OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars except per unit amounts)

For the three months ended March 31,	**2004**	**2003**	**% Change**
DAILY PRODUCTION			
Oil (bbls)	11,579	11,264	3%
Natural gas (mmcf)	77,925	81,999	(5)%
Natural gas liquids (bbls)	2,040	1,996	2%
BOE (6:1)	26,607	26,927	(1)%
Total production (mboe)	2,421	2,423	- %
PRODUCTION PROFILE			
Oil	44%	42%	
Natural gas	48%	51%	
Natural gas liquids	8%	7%	
PRICES			
Oil (per bbl) (1)	$ 42.50	$ 47.79	(11)%
Natural gas (per mcf) (1)	$ 6.76	$ 8.10	(17)%
Natural gas liquids (per bbl) (1)	$ 37.06	$ 41.53	(11)%
BOE (6:1)	$ 41.15	$ 47.73	(14)%
Cash operating netback per BOE	$ 22.71	$ 26.97	(16)%
LEASE OPERATING COSTS	$ 19,829	$ 19,588	(1)%
Cost per boe	$ 8.19	$ 8.08	(1)%
GENERAL AND ADMINISTRATIVE COSTS	$ 3,138	$ 3,455	9%
Cost per boe	$ 1.30	$ 1.43	9%

1. Prices are before realized gains/losses on hedging 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 2003 have been restated.

Management Discussion and Analysis

three months ended March 31, 2004

SPECIAL NOTES

The following discussion and analysis of financial results should be read in conjunction with the unaudited consolidated financial statements for the three months ended March 31, 2004 included herein and the December 31, 2003 annual financial statements and management's discussion and analysis included in the Petrofund Energy Trust ("Petrofund" or the "Trust") 2003 annual report.

The discussion and analyses included in the section is based on information available to April 30, 2004.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent ("boe") basis, natural gas volumes have been converted to barrels of oil at 6,000 mcf/bbl. A boe 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.

Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow 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 flow 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 flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

Cash flow available for distribution is dependent on numerous factors including fluctuations in oil and natural gas prices; changes in the Canadian/U. S. dollar exchange rate; the size of the development drilling program including the portion funded from cash flow; and the level of debt within PC, etc. A reconciliation of cash flow provided by operating activities on the Consolidated Statement of Cash Flows to the cash flow available for distribution is included in Note 6 to the Notes to Interim Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This discussion may include statements about expected future events and/or financial results that are forward-looking in nature and subject to risks and uncertainties. For those statements, Petrofund claims the protection of the safe harbor for forward-looking statements provisions contained in the U.S. Private Securities Litigation Reform Act of 1995. Petrofund cautions that actual performance will be affected by a number of factors, many of which are beyond its control. These include general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations; changes in income tax regulations; increased competition; and fluctuations in commodity prices, foreign exchange and interest rates. In addition, there are numerous risks and uncertainties associated with oil and natural gas operations and the evaluation of oil and natural gas reserves as discussed in detail in Petrofund's Annual Information Form. As a result, future events and results may vary substantially from what Petrofund currently foresees.

HIGHLIGHTS FOR THE THREE MONTHS ENDED MARCH 31, 2004

- Petrofund announced the potential acquisition of Ultima Energy Trust.
- The Trust paid out cash distributions of $34.9 million or $0.48 per unit.
- The Trust's payout ratio for the three months ended March 31, 2004 was 73% compared to 45% in 2003 and 87% in the fourth quarter of 2003.
- Canadian product prices on a boe basis decreased 14% to $41.15/boe from $47.73/boe mainly due to the strengthening of the Canadian dollar from $0.66 U.S. to $0.76 U.S.
- The Trust generated cash flow of $49.0 million compared to $58.6 million for the same period in 2003.
- Production on a boe basis decreased 1% to 26,607 boe/d compared to the same period in 2003.

Net income decreased $25 million from $32.6 million, of which $12.4 million was non-cash loss on commodity contracts.

PETROFUND ACQUISITION OF ULTIMA ENERGY TRUST

On March 29, 2004, Petrofund announced that it had entered into an agreement providing for the combination of Petrofund and Ultima Energy Trust ("Ultima"). The transaction is subject to approval of the unitholders of Ultima at a meeting to be held on June 4, 2004 and regulatory approval.

Under the terms of the agreement, each Ultima unit will be exchanged for 0.442 of a Petrofund unit on a tax-deferred rollover basis and Petrofund will acquire all the assets and assume all of the liabilities of Ultima. Ultima unitholders will also receive an aggregate $10 million in the form of a one-time special distribution (approximately $0.17 per Ultima unit), payable prior to closing of the transaction. It is expected that approximately 26.4 million Petrofund Trust units will be issued to the Ultima Unitholders on closing.

Ultima has a diversified group of assets with a reserve life index over 10 years. Ultima had a production base of approximately 10,000 boe/d at December 31, 2003. The combined production of Petrofund and Ultima is expected to exceed 36,000 boe/d of which approximately 58% will be oil and natural gas liquids. Ultimas proved plus probable reserves were estimated at 41.4 mmboe as stated in their December 31, 2003 independent engineering report.

The transaction is expected to be accretive to cash flow, production and reserves per unit and result in lower per unit general and administrative costs; however, we do not expect the acquisition to affect the level of Petrofund's cash distributions. The increased size of Petrofund should provide it with a more competitive cost of capital and improve Petrofund's financing ability as well as its ability to compete for larger acquisitions.

As the consideration for Ultima is primarily Petrofund Trust units, the cash costs of the transaction will be financed using Petrofund's existing credit line.

OPERATIONAL HIGHLIGHTS

Petrofund was active operationally during the first quarter drilling 62 wells consisting of 51 working interest (8.5 net) and 11 farmout wells. This drilling activity resulted in 23 oil wells and 35 gas wells, for an overall 94% drilling success rate.

Northeast British Columbia

Petrofund participated in 25 (3.8 net) gas wells in the July Lake, Border and Doig areas. At July Lake, six highly successful underbalanced horizontal Jean Marie gas wells were drilled, including a 100% working interest well that flowed at a rate of 4.0 mmcf/d while drilling. At Border, low risk development on Petrofund's lands continued with the drilling of eighteen Bluesky/Gething gas wells. Petrofund's net production from these new drills is expected to stabilize near 3.0 mmcf/d (500 boe/d).

Northern Alberta

Twenty seven wells (3.9 net) were drilled at Mitsue, Niton, Pembina, Red Earth, Sunchild and Swan Hills, resulting in 9 gas wells and 14 oil wells. At Mitsue, a new activity area for Petrofund, 5 gas wells were drilled, including 3 operated by Petrofund. At Red Earth, several older Granite Wash oil wells were horizontally reentered with notable success. At Sunchild, a dual target gas well was drilled but has yet to be completed. The expected production from these new wells, net to Petrofund, amounts to approximately 300 boe/d.

Central Alberta

Drilling activity within Central Alberta during the quarter was limited to 3 farmout wells, but Petrofund expects to be more active during the remainder of the year as a result of our involvement in a development stage coalbed methane project near Red Deer. Petrofund is also readying to drill six high working interest conventional shallow gas wells at Three Hills Creek later this summer.

Southeast Saskatchewan

A total of seven (0.8 net) successful horizontal oil wells were drilled on Petrofund's land holdings in Alida, Queensdale and Weyburn. Petrofund's net production from these new wells is expected to be 175 boe/d.

CHANGES IN ACCOUNTING POLICIES

Asset Retirement Obligations

The Trust adopted the new Canadian accounting standard for accounting for asset retirement obligations ("ARO") effective January 1, 2004, as required by Canadian generally accepted accounting standards. The standard requires liability recognition for retirement obligations associated with our property, plant and equipment. The obligations are initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. Previously reclamation and abandonment liabilities were calculated and recorded on a unit of production basis. The change is discussed in detail in Note 2(a) to the Notes to Interim Consolidated Financial Statements.

As a result of adopting this standard, previously reported amounts for 2003 have been restated. Net property, plant and equipment on the Consolidated Balance Sheet as at December 31, 2003, increased by $18.6 million, future income taxes increased by $2.1 million and asset retirement obligations increased by $17.5 million with an offset of $1.0 million to Unitholders' Equity. Income for the three months ended March 31, 2003 increased by $435,000 ($265,000 after tax). Opening 2003 accumulated earnings decreased by $2.4 million ($700,000 after tax) to reflect the cumulative impact of accretion and depletion expense, less the previously recorded cumulative site restoration provision.

Income for three months ended March 31, 2004, increased by $860,000 ($510,000 after tax), which reflects the impact of accretion and depletion expense.

There was no impact on the Trust's cash flow as a result of adopting this new policy. See Note 2(a) and 6 for additional information on the future liability and the impact on the financial statements.

Financial Instruments

Effective January 1, 2004, Petrofund adopted the new Canadian Accounting Guideline 13 ("AcG-13") pertaining to hedging relationships. AcG-13 established certain conditions for applying hedge accounting. If hedge accounting is not applied, the fair values of derivative financial instruments are recorded as an asset or a liability on the balance sheet. Petrofund enters into numerous derivative financial instruments to reduce price volatility and establish minimum prices for a portion of its oil and natural gas production. These contracts are effective economic hedges, however, a number do not qualify for hedge accounting due to the very detailed and complex rules outlined in AcG-13. Petrofund has elected to use the fair value method of accounting for all derivative transactions as we believe it would be confusing if the Trust were to use hedge accounting for some of its hedging contracts and fair value accounting for others.

As of January 1, 2004, all outstanding derivative instruments have been recorded as assets or liabilities, as appropriate, at fair value. The net negative fair value of the contracts at January 1, 2004 of $6.8 million plus costs incurred on the acquisition of the derivative instruments in the amount of $0.8 million will be amortized to expense over the remaining term of the contracts. The total amount of $7.6 million, less $2.5 million amortized to expense in the first quarter of 2004, or $5.1 million has been recorded as a current asset or liability, as appropriate, on the balance sheet as "deferred loss/gain on the commodity contracts".

The amortized portion of the fair value of the contracts at January 1, 2004 and the net change in fair value of all such instruments from January 1 to March 31, 2004 in the amount of $12.6 million, which does affect cash flow, are recorded in the income statement on a separate line as "gain/loss on commodity contracts". This line item also includes realized cash gain/losses on commodity contracts, which were previously added or deducted from oil and natural gas sales. The comparative number for 2003 represents realized losses on commodity contracts which were netted against sales.

This policy is discussed in detail in Note 2(b) to the Notes to Interim Consolidated Financial Statements.

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior years, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs both increased by $1.4 million in the first quarters of 2004 and 2003 as a result of the change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

Product Prices

Product prices, unless otherwise noted, reflect actual prices received, excluding hedging and transportation costs. Prices for prior periods have been restated where applicable.

CASH DISTRIBUTIONS

Petrofund unitholders who held their units throughout the first quarter of 2004 received distributions of $0.48 in cash as compared to $0.48 in the first quarter of 2003. A cash distribution of $0.16 per unit was paid in April and $0.16 per unit has been announced for May.

The Trust generated cash flow available for distribution in the first quarter of $47.9 million, or $0.65 per unit before deducting $7.5 million or $0.10 per unit for reinvestment in capital projects. Of the remaining $40.4 million available, $34.9 million was paid out in distributions representing a payout ratio of 73 % (see Note 6).

For the 12 months ended March 31, 2004, the Trust generated cash flow available for distribution of $171.1 million, withheld $30.0 million for reinvestment in development drilling and other projects, and paid out distributions of $136.2 million, resulting in a payout ratio of 80%. The Trust is continuing its policy of stabilizing monthly distributions and reinvesting a portion of its cash flow for the long-term health of the Trust. In higher price environments, a larger percentage of the Trust's cash flow will be retained for reinvestment and to ensure more consistent monthly distributions. When prices are lower, less cash flow is required for capital expenditure as projects become less economic.

RESULTS OF OPERATIONS

Revenue and Production

The major factors impacting the results of the operations for the first quarter of 2004 were the disposition of properties effective December 31, 2003, which reduced production volumes by approximately 1,775 boe/d from the fourth quarter of 2003, and lower product prices. The WTI US price increased from US $33.86/bbl in the first quarter of 2003 to US $35.14/bbl, in the first quarter of 2004 however, the Canadian wellhead price decreased to $42.50/bbl from $47.79/bbl for the same periods as the Canadian dollar strengthened from $0.66 US to $0.76 US. The natural gas price declined 17% to $6.76/mcf. On a boe basis average prices were down 14% to $41.15/boe from $47.73/boe in the first quarter of 2003.

Revenues decreased 14% to $99.7 million in the first quarter of 2004 from $115.7 million in the first quarter of 2003, as production was down 1% and prices were down 14% on a boe basis.

Crude oil sales decreased 8% from $48.4 million in the first quarter of 2003 to $44.8 million in the first quarter of 2004. Oil production volumes increased 3% to 11,579 bbl/d in the first quarter of 2004 as compared to 11,264 in the first quarter of 2003. The average price was down 11% from $47.79/bbl in the first quarter of 2003 to $42.50/bbl in the corresponding period of 2004.

Natural gas sales decreased 20% from $59.8 million in the first quarter of 2003 to $48.0 million in the first quarter of 2004. Natural gas production declined 5% from 82.0 mmcf/d to 77.9 mmcf/d and the average natural

gas price was down 17% from $8.10/mcf to $6.76/mcf. AECO monthly natural gas prices decreased from $7.92/mcf in the first quarter of 2003 to $6.61/mcf in the first quarter of 2004

Sales of natural gas liquids decreased 7% to $6.9 million in the first quarter of 2004, from $7.5 million in the first quarter of 2003. Production was up 2% to 2,040 bbl/d from 1,996 bbl/d; however, average prices were down 11% to $37.06/bbl in the first quarter of 2004, from $41.53/bbl in the same period in the prior year.

Daily Production

For the three months ended March 31,	**2004**	**2003**
Oil (bbls)	11,579	11,264
Natural gas (mmcf)	77,925	81,999
Natural gas liquids (bbls)	2,040	1,996
Total (boe 6:1)	26,607	26,927

Sales Prices				
Average prices for the three months ended March 31,		**2004**		**2003**
Benchmark prices				
WTI oil (U.S.$/bbl)	$	$ 35.14	$	33.86
U.S. $ exchange rate		0.76		0.66
WTI oil (Cdn. equivalent/$bbl)	$	$ 46.24	$	51.30
AECO natural gas ($/mcf)	$	$ 6.61	$	7.92
Average Petrofund prices				
Oil	$	$ 42.50	$	47.79
Natural gas		6.76		8.10
Natural gas liquids		37.06		41.53
Weighted average (6:1)	$	$ 41.15	$	47.73

Production Revenue (millions)				
Revenue for the three months ended March 31,		**2004**		**2003**
Oil	$	44.8	$	48.4
Natural gas		48.0		59.8
Natural gas liquids		6.9		7.5
Total	$	99.7	$	115.7

Hedging and Risk Management

The Trust has implemented a formal risk management policy which provides the Risk Management Committee with the ability to use specified price risk management strategies for its crude, 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 to a maximum of 50% of its annual production for a maximum of two years beyond the current date.

As at March 31, 2004 Petrofund had 27.2 mmcf/d of natural gas and 5,331 bbl/d of crude hedged for the remainder of 2004. Crude oil hedges were unchanged and natural gas hedges increased only slightly from the previous quarter. The Trust's 2004 natural gas hedges include: 19.8 mmcf/d collared between $5.22/mcf-$7.32/mcf and 7.4 mmcf/d fixed at $5.80/mcf. The Trust will lose its floor protection on about 11% of the collared volumes if AECO drops below $4.74/mcf but will receive a premium of $1.06/mcf in this event. At the end of the quarter, Petrofund had 1,331 bbl/d of oil fixed at $38.21/bbl and 4,000 bbl/d collared between $31.58/bbl-$37.36/bbl for 2004. The Trust will lose its floor protection on 50% of the collared volume in the event WTI averages less than $27.76/bbl ($21.17 US). Under these transactions Petrofund will receive a premium of $3.93/bbl ($3.00 US) if WTI remains below the $27.76/bbl level.

For the first quarter of 2005, the Trust has 9.5 mmcf/d of natural gas hedged under a $5.80/mcf-$8.97/mcf three way collar and 3,000 bbl/d of oil hedged in three way collars between $33.92/bbl-$41.80/bbl.

Petrofund also contracted a portion of its Alberta power costs by fixing the price on two (2) Megawatts/hour (MW/h) of its Alberta consumption at $44.50/MWh for 2004 and 2005.

In April 2004, Petrofund entered into the following additional hedge transactions:

1. **9,475 mcf/d was collared between $6.33-10.92/mcf for November 1, 2004 through March 31, 2005 at AECO.**
2. **4,737 mcf/d was fixed at $6.85/mcf for May 1, 2004 through October 31, 2004.**

The Trust does not anticipate hedging additional volumes for the period up to September 30th of the year, however, Petrofund may enter into additional derivative transactions for the fourth quarter of 2004 and for 2005 as the market allows.

All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate at the close on March 31, 2004 ($1.3113 C$:US$). For a complete listing of all hedge transactions see Note 8 to the Notes to Interim Consolidated Financial Statements.

Gain/ (loss) on commodity contracts

For the three months ended March 31,	2004	2003
Realized gains/ (losses)	**$ (4,900)**	**$ (5,115)**
Change in fair value		
Fair value January 1, 2004	**(6,771)**	**-**
Fair value March 31, 2004	**(16,901)**	**-**
Change in fair value of financial instruments	**(10,130)**	**-**
Amortization of negative fair value at January 1, 2004	**(2,461)**	**-**
Total non-cash adjustment	**(12,591)**	**-**
Total	**$ (17,491)**	**$ (5,115)**

If oil and natural gas prices received by the Trust were adjusted for realized gains (losses) in accordance with the 2003 presentation, the prices would have decreased as follows:

Oil per bbl	**$ (4.91)**	**$ (2.69)**
Gas per mcf	**$ -**	**$ (0.29)**

The realized gain/(losses) on derivative instruments and the change in their fair value is dependent on future product prices, the volumes hedged, the exchange rate and the term of the contracts. As there has been significant variation in all these factors, which is unlikely to change, we can expect to see high volatility in these amounts and the changes could be significant.

ROYALTIES

For the three months ended March 31,	**2004**	**2003**
Royalties (millions)	$ 18.6	$ 24.2
Average royalty rate (%)	19%	21%
$/boe	$ 7.67	$ 9.99

Royalties were 19% of revenues in the first quarter of 2004, as compared to 21% in the first quarter of 2003 net of the Alberta Royalty Credit. The percentage decrease was mainly due to the 17% decline in the average natural gas price. The Crown royalty rate varies with prices.

Expenses	**2004**	**2003**
Expenses (millions)		
Lease operating	$ 19.8	$ 19.6
General & administrative	3.1	3.5
Net interest	**0.9**	**2.1**
Expenses per boe		
Lease operating	$ 8.19	$ 8.08
General & administrative	1.30	1.43
Net interest	**0.37**	**0.88**

FIELD OPERATING COSTS

Operating expenses, net of processing income, were $ 19.8 million in the first quarter of 2004 compared to $19.6 million in the first quarter of 2003. Operating costs on a boe basis increased marginally to $8.19 in 2004, compared to $8.08 for the same period in 2003. Operating costs tend to increase in the second and third quarter due to additional maintenance and workover activities.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative costs were $3.1 million in the first quarter of 2004, as compared to $3.5 million for the same period in 2003. Costs were down 9% to $1.30 per boe compared to $1.43 per boe in 2003. General and administrative costs per boe are expected to be approximately the same in the second quarter and decrease in the second half of the year if the acquisition of Ultima is completed.

INTEREST

Interest expense decreased to $906,000 in 2004 from $2.1 million in 2003 due to the decrease in the average loan balance outstanding and a decrease in the average prime rate.

DEPLETION, DEPRECIATION AND ACCRETION

The provision for depletion, depreciation and accretion increased from $27.6 million in the first quarter of 2003 to $29.5 million in the first quarter of 2004 due to the increase in the depletion rate from $11.38/boe in 2003 to $12.20/boe in 2004. The 6.7% increase in the depletion rate is mainly due to the negative adjustments to reserves

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ASSET RETIREMENT RESERVE

In the first quarter of 2004, Petrofund has set aside $363,000 in cash to fund future ARO costs. Petrofund has a cash ARO reserve of $4.1 million at March 31, 2004.

Effective January 1, 2004, Petrofund increased the reserve to $0.15/boe of production as compared to $0.075 in prior periods.

NET INCOME

Net income before the provision for income taxes decreased from $29.9 million in the first quarter of 2003 to $8.1 million for the same period in 2004. Net income was reduced by $12.6 million due to the non-cash adjustment as a result of recording commodity contracts at fair value in accordance with AcG-13 which was adopted January 1, 2004. Prior to this adjustment, net income for the first quarter of 2004 would have been $20.7 million. The remainder of the decrease from 2003 was due to the 16% decline in operating netbacks as prices were down 14% on a boe basis.

In the first quarter of 2004 future tax expense was $0.4 million as compared to a recovery of $3.1 million in 2003. This was partially due to the utilization of tax loss carry forwards in 2004.

Netback		**2004**		**2003**
Production (BOE) per day		26,607		26,927
Weighted average selling price	$	41.15	$	47.73
Cost of oil and natural gas hedging		(2.02)		(2.11)
Net weighted average selling price		39.13		45.62
Royalties, net or ARTC		(7.67)		(9.99)
Operating costs		(8.19)		(8.08)
Cost of transportation		(0.56)		(0.58)
Operating Netback		22.71		26.97
Interest expense		(0.37)		(0.88)
General and administrative		(1.30)		(1.43)
Capital and current taxes		(0.32)		(0.43)
Total cash netback per BOE before the effects of the internalization				

of the management contract		20.72		24.23
Internalization of management contract		-		(0.68)
Total cash netback per BOE after the effects of the internalization of the management contract	$	20.72	$	23.55

CAPITAL EXPENDITURES

During the three months ended March 31, 2004, $12.6 million was incurred for development drilling, production enhancement, and other activities. Total expenditure for these activities for all of 2004 is expected to be in the $60 million range.

During the first quarter of 2004, Petrofund drilled 52 well working interest wells and entered into farmout agreements with various industry partners, which resulted in 11 wells being drilled on Petrofund's undeveloped land base. The drilling activity resulted in 23 oil wells and 35 natural gas wells for an overall success rate of 94%.

Petrofund completed the sale of various non-core properties effective December 31, 2003. Proceeds from these sales were used to reduce debt outstanding and to fund additional capital expenditures.

A summary of expenditures for the period appears below:

For the three months ended March 31,		**2004**
Acquisitions	$	1,090
Finding and development cost:		
Land and seismic		607
Drilling and completions		5,686
Well equipping		1,198
Tie-ins		1,081
Facilities		2,546
Other		1,498
Total		12,616
Total net capital expenditures	$	13,706

DEBT

As at March 31, 2004, the amount outstanding on the credit facility was $89.8 million as compared to the $265 million available. The facility will be utilized for additional development activities of approximately $50 million for the remainder of 2004 and to fund Ultima's long-term debt if the acquisition is completed.

The revolving period on the syndicated facility has been extended for an additional 364-day period ending May 28, 2005. Petrofund will be approaching the banking syndicate for an increase in the borrowing limit pending the acquisition of Ultima.

WORKING CAPITAL

The working capital deficit was $66.1 million on March 31, 2004, an increase of $36.1 million from the $30.0 million deficit as at December 31, 2003. The increase was mainly due to the application of the cash received on the sale of properties in the first quarter of 2004 to long-term debt, and the negative fair value of the commodity contracts recorded on the balance sheet of $10.0 million net.

LIQUIDITY AND CAPITAL RESOURCES

During the three months ended March 31, 2004, the Trust generated cash flow of $48.8 million and paid out $34.9 million in distributions. The majority of the excess was used to fund the Trust's capital expenditure program.

Total long-term debt and capital leases decreased $20.3 million to $90.0 million at March 31, 2004 from $110.3 million as at December 31, 2003 mainly due to the increase in the working capital deficit. The major changes in total long-term debt were due to:

	$000's
Cash flow from operations	$ 50,209

Proceeds received from issuance of Trust units	907
Increase in working capital deficit	25,846
Distributions paid	(34,910)
Expenditures on oil & natural properties, net	(13,706)
Asset retirement reserve	(363)
Redemption of exchangeable shares	(451)
Capital lease repayments	(86)
Actual abandonment costs incurred	(1,162)
Increase in cash	(6,415)
Miscellaneous	406
	$ 20,275

Capitalization Analysis		
($ thousands, except per unit & % amounts)		**2004**
Working capital (deficiency)	$	(66,085)
Bank debt		89,838
Capital lease obligation		202
Net debt obligation	$	156,125
Units outstanding & issuable for exchangeable shares		73,682
Market price at March 31, 2004	$	17.35
Market capitalization	$	1,278,390
Total capitalization	$	1,434,515
Net debt as a percentage of total capitalization		11%

UNITHOLDERS' EQUITY

The Trust had 72,743,253 Trust units outstanding at March 31, 2004, compared to 72,688,577 Trust units at the end of 2003. During this period no Exchangeable Shares were converted to Trust units. During the quarter 23,031 were redeemed for cash leaving 828,440 Exchangeable Shares outstanding at March 31, 2004, which can be converted, at the option of the unitholder into 939,147 Trust units.

OUTLOOK FOR 2004

As discussed in the Trust's annual report, the level of cash flow for 2004 will be affected by oil and gas prices, the Canadian - US dollar 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 2003 and this trend is expected to continue in 2004. The acquisition market is expected to continue to be active and supply should increase, nevertheless, competition for these assets is expected to be fierce 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 a 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. Activities for the first quarter of 2004 were reviewed earlier in this report.

Production volumes in the fourth quarter of 2003 were in the 29,000 boe/d range, which have declined to 26,607 boe/d in the first quarter of this year due to the sale of properties at the end of 2003. The third and fourth quarters also reflected " flush" production from a number of oil and natural gas well that come on production during this period. If the Ultima acquisition is successful, production volumes for the second half of the year are expected to be in the 36,000 boe/d range.

CONTRACTUAL OBLIGATIONS

There has been no change to contractual obligations disclosed in the Trust's annual report.

OFF-BALANCE SHEET ARRANGEMENTS/ VARIABLE INTEREST ENTITIES

The Trust has no off-balance sheet arrangements or variable interest entities.

Consolidated Balance Sheet
(thousands of dollars) (Unaudited)

As at March 31, 2004 and at December 31, 2003	**2004**	**2003**
Assets		
Current assets		
Cash	$ 8,597	$ 2,182
Accounts receivable	21,953	48,268
Deferred hedging loss on commodity contracts (Note 2(b))	5,718	-
Commodity contracts (Note 2(b))	193	-
Prepaid expenses (Note 2(b))	8,964	10,036
Total current assets	45,425	60,486
Asset retirement reserve (Note 7)	4,142	3,779
Oil and gas royalty and property interests,		
at cost less accumulated depletion and depreciation		
of $511,342 (2003 - $482,349)	883,191	898,263
	$ 932,758	$ 962,528
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 35,963	$ 36,684
Current portion of capital lease obligations	676	356
Deferred hedging gain on commodity contracts (Note 2(b))	587	-
Commodity contracts (Note 2(b))	15,316	-
Distributions payable to Unitholders	58,968	53,452
Total current liabilities	111,510	90,492
Long-term debt	89,838	109,707
Capital lease obligations	202	608
Commodity contracts (Note 2(b))	1,778	-
Future income taxes	79,508	79,065
Asset retirement obligations (Notes 2(a) and 7)	33,970	34,363
Total liabilities	316,806	314,235
Unitholders' equity		
Unitholders' capital (Note 3)	1,021,584	1,020,677
Exchangeable shares (Note 4)	10,518	10,518
Accumulated earnings	205,882	198,253
Accumulated cash distributions (Note 6)	(622,032)	(581,155)
Total unitholders' equity	615,952	648,293
	$ 932,758	$ 962,528

The accompanying notes to interim consolidated financial statements are an integral part of this consolidated balance sheet.

Consolidated Statement of Operations and Accumulated Earnings
(thousands of dollars except per unit amounts) (Unaudited)

For the three months ended March 31,		**2004**		**2003**
Revenues				
Oil and gas sales	$	99,699	$	115,695
Royalties, net of incentives		(18,578)		(24,226)
Gain/loss on commodity contracts (Note 2(b))		(17,491)		(5,115)
		63,630		86,354
Expenses				
Lease operating		19,829		19,588
Transportation costs (Note 2(c))		1,355		1,406
Interest on long-term debt		906		2,129
General and administrative		3,138		3,455
Capital taxes		737		639
Depletion, depreciation and accretion		29,546		27,581
Internalization of management contract		-		1,647
		55,511		56,445
Income before provision for income taxes		8,119		29,909
Provision for (recovery of) income taxes				
Current		47		395
Future		443		(3,098)
		490		(2,703)
Net income		7,629		32,612
Accumulated earnings, beginning of year		199,200		113,341
Retroactive application of change in accounting policy (Note (2a))		(947)		(2,419)
Accumulated earnings, beginning of year, as restated		198,253		110,922
Accumulated earnings, end of period	$	205,882	$	143,534
Net income per Trust unit				
Basic	$	0.10	$	0.60
Diluted	$	0.10	$	0.60

The accompanying notes to interim consolidated financial statements are an integral part of these consolidated statements.

Consolidated Statement of Cash Flows
(thousands of dollars except per unit amounts) (Unaudited)

For the three months ended March 31,		**2004**		**2003**
Cash provided by (used in):				
Operating activities				
Net income	$	7,629	$	32,612
Add items not affecting cash:				
Depletion, depreciation and accretion		29,546		27,581
Gain/loss on commodity contracts		12,591		-
Future income taxes		443		(3,098)
Actual abandonment costs incurred (Note 7(a))		1,162)		(123)
Internalization of management contract		-		1,647
Cash flow		49,047		58,619
Net change in non-cash operating working capital balances		25,846		23,443
Cash provided by operating activities		74,893		82,062
Financing activities				
Bank loan		(19,869)		(5,803)
Distributions paid (Note 6)		(34,910)		(25,987)
Redemption of exchangeable shares		(451)		-
Capital lease repayments		(86)		(935)
Issuance of Trust units (Note 3)		907		431
Cash used in financing activities		(54,409)		(32,294)
Investing activities				
Asset retirement reserve (Note 7(b))		(363)		(182)
Acquisition of property interests		(13,706)		(24,456)
Internalization of management contract		-		(1,647)
Cash used in investing activities		(14,069)		(26,285)
Net change in cash		6,415		23,483
Cash (bank overdraft), beginning of year		2,182		(1,572)
Cash, end of period	$	8,597	$	21,911
Interest paid during the period	$	944	$	2,276
Income taxes paid during the period	$	55		$ 139

The accompanying notes to interim consolidated financial statements are an integral part of these consolidated statements.

Notes to Interim Consolidated Financial Statements

March 31, 2004 and 2003

(unaudited)
(thousands of dollars except per unit amounts unless otherwise stated)

1. INTERIM FINANCIAL STATEMENTS

These unaudited interim consolidated financial statements follow the same accounting policies and methods of their application as the most recent annual financial statements except as disclosed in Note 2 below. The note disclosure requirements for annual statements provide additional disclosures to that required for interim statements. Accordingly, these statements should be read in conjunction with the audited consolidated financial statements of Petrofund Energy Trust ("Petrofund" or the "Trust") as at December 31, 2003 and 2002 and for each of the years in the three-year period ended December 31, 2003.

2. RETROACTIVE CHANGE IN ACCOUNTING POLICIES

(a) Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the new Canadian accounting standard for accounting for Asset Retirement Obligations ("ARO"). This standard requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. The liability is accreted each period for the change in present value and the accretion expense is charged to income. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life.

Previously, the Trust recognized a provision for future site reclamation and abandonment (

"SR&A") costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The Trust has estimated the net present value of its total ARO to be $34.4 million as at December 31, 2003, based on a total future liability of $85.5 million. These payments are expected to be made over the next 35 years. The Trust's credit adjusted risk free rate of 6.5 per cent and an inflation rate of 1.5 per cent were used to calculate the present value of the ARO.

Income for the three months ended March 31, 2003 and 2004 increased by $265,000 and $510,000 respectively as a result of adopting this policy, with negligible impact on per income per unit.

The impact of this change on the balance sheet is as follows:

	Net	Future	ARO	Change in Accumulated Earnings		
December 31, 2003 Restatement	**PP&E**	**Tax**	**Liability**	**Prior 2003**	**2003**	**Total**
Balance, beginning of period	$879,633	$77,005	$16,846			$199,200
Initial fair value of ARO liability	32,771	-	32,771			-
Depletion expense	(14,141)	-	-	$(11,977)	$(2,164)	(14,141)
Accretion expense	-	-	10,230	(7,986)	(2,244)	(10,230)
Previously recorded SR&A provision expense	-	-	(25,484)	19,284	6,200	25,484
Future income tax adjustment	-	2,060	-	(1,740)	(320)	(2,060)
Change in accounting policies	18,630	2,060	17,517	(2,419)	1,472	(947)
	$898,263	$79,065	$34,363	($2,419)	$1,472	$198,253

Balance, beginning of period
as "Restated"

(b) Financial Instruments

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13), effective for fiscal years commencing on or after July 1, 2003. AcG-13 established certain conditions for when hedge accounting may be applied. If hedge accounting is not applied, the fair values of derivative financial instruments are recorded as an asset or a liability on the balance sheet. Petrofund adopted the guideline effective January 1, 2004.

Petrofund enters into numerous derivative financial instruments to reduce price volatility and establish minimum prices for a portion of its oil and natural gas production. These contracts are effective economic hedges, however, a number do not qualify for hedge accounting due to the very detailed and complex rules outlined in AcG-13. Petrofund has elected to use the fair value method of accounting for all derivative transactions

As of January 1, 2004, all outstanding derivative instruments have been recorded as assets or liabilities, as appropriate, at fair value. The net negative fair value of the contracts at January 1, 2004 of $6.8 million plus costs incurred on the acquisition of the derivative instruments in the amount of $0.8 million will be amortized to expense over the remaining term of the contracts. The total amount of $7.6 million, less $2.5 million amortized to expense in the first quarter of 2004, or $5.1 million has been recorded as a current asset or liability on the balance sheet as deferred loss/gain on the commodity contracts. The negative fair value of the contracts at March 31, 2004 of $16.9 million has been recorded on the balance sheet as "commodity contracts under asset or liabilities", as appropriate.

The change in the fair value of the contracts from January 1, 2004 to March 31, 2004 of $10.1 million plus the amortized amount as noted above is recorded in the income statement on a separate line as "gain/loss on commodity contracts". The line item also includes realized cash gain/loss on the commodity contracts which were previously deducted from or added to oil and natural gas sales. The comparative number for 2003 represents realizes losses on commodity contracts which were previously netted against sales.

(c) Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior years, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standard, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs both increased by $1.4 million in the first quarters of 2004 and 2003 as a result of the change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

3. TRUST UNITS

Authorized: unlimited number of trust units	**Number of units**	**$000's**
Issued		
December 31, 2003	**72,688,577**	**$1,020,677**
Options exercised	**53,666**	**796**
Commission and issue cost adjustment	**-**	**94**
Unit purchase plan	**1,010**	**17**
March 31, 2004	**72,743,253**	**$1,021,584**

The weighted average Trust units/Exchangeable Shares outstanding are as follows:

For the period ended March 31,	**2004**	**2003**
Basic	73,673,783	54,129,971
Diluted	73,872,208	54,270,294

Trust units/Exchangeable Shares, at end of period:

For the period ended March 31,	**2004**	**2003**
Trust units outstanding	72,743,253	54,148,003
Trust units issuable on exchangeable shares	939,147	-
	73,682,400	54,148,003

8.

EXCHANGEABLE SHARES

The number of Exchangeable Shares to be issued in connection with the internalization of the management contract was determined based on a negotiated value of $12.17 per share as set out in the Information Circular dated March 10, 2003. For accounting purposes, the 1,939,147 Exchangeable Shares were deemed to be issued at a value of $11.20 per share, being the average trading value of the Trust units for the last ten days prior to the closing date. Initially, each Exchangeable Share was exchangeable into one Trust Unit. The exchange ratio is adjusted from time to time to reflect the per unit distributions paid to unitholders after the closing date. Under the terms of the Exchangeable Share Agreement, the holder of the Exchangeable Shares is entitled to redeem for cash the number of shares equal to the cash distributions that would have been received had the Exchangeable Shares been converted to Trust units. As a result of the redemption feature, the number of Trust units issuable upon conversion is expected to remain constant over time. As the substance of this feature is to allow the holder of the Exchangeable Shares to receive cash distributions, the redemption has been accounted for as a distribution of earnings rather than a return of capital. At March 31, 2004, 828,440 Exchangeable Shares were outstanding, at an exchange ratio of 1.13363 per Trust unit.

Issued and Outstanding	**Number of Shares**	**$000's**
December 31, 2003	851,471	$ 10,518
Redemption of shares	(23,031)	-
Balance at end of period	828,440	10,518
Exchange ratio, end of period	1.13363	-
Trust units issuable upon conversion	939,147	$ 10,518

5. BANK LOAN

The revolving period on the bank loan has been extended for an additional 364 day period ending May 28, 2005 with all other terms and conditions remaining the same.

6. DISTRIBUTIONS ACCRUING TO UNITHOLDERS

Under the terms of the Trust Indenture, the Trust makes monthly distributions within a specified period following the end of each month ("Cash Distribution Date"). Distributions are equal to amounts received by the Trust on the Cash Distribution Date less permitted expenses. Distributions to Unitholders coincide with cash receipts of royalty income from the Trust. An overall analysis is as follows:

For the period ended	Cash Distribution Date	2004	2003
November 30	January 31$	0.16	$ 0.15
December 31	February 28	0.16	0.16
January 31	March 310.16		0.17
Cash distributions per Trust unit		$ 0.48	$ 0.48

Reconciliation of Distributions Accruing to Unitholders

For three months ended March 31,	**2004**	**2003**
Distributions payable, beginning of period	$ 53,452	$ 30,065
Distributions accruing during the period		
Cash flow provided by operating activities	74,893	82,062
Net change in non-cash operating working capital balance	(25,846)	(23,443)
Amortization of the cost of commodity contracts	(221)	-
Redemption of exchangeable shares	(451)	-
Asset retirement reserve	(363)	(182)
Capital lease repayment	(86)	(935)
Capital expenditures	(7,500)	(7,500)
Total distributions accruing during the period	40,426	50,002
Distributions paid	(34,910)	(25,987)
Distributions payable, end of period	$ 58,968	$ 54,080
Distributions accruing to unitholders per Trust unit		
Basic	$ 0.55	$ 0.92
Diluted	$ 0.55	$ 0.92

Accumulated Cash Distributions

For three months ended March 31,	**2004**	**2003**
Accumulated cash distributions, beginning of period	$ 581,155	$ 427,651
Distributions accruing during the period	40,426	50,002
Redemption of exchangeable shares	451	-

Accumulated cash distributions, end of period	$ 622,032	$ 477,653

7. ASSET RETIREMENT OBLIGATIONS and RESERVE FUND

(a) Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Trust's net ownership interest in wells and facilities and the estimated timing of the costs to be incurred in future periods. The following reconciles the Trust's outstanding ARO for the periods indicated:

For the period ended March 31,	**2004**	**2003**
Balance at beginning of year	$ 16,846	$ 15,298
Initial fair value of ARO liability	32,771	30,497
Accretion expense	10,230	7,986
Previous recorded SR&A provision	(25,484)	(19,284)
Balance as at January 1, 2004 and 2003	34,363	34,497
Increase in liabilities during the period	215	569
Accretion expense during the period	554	561
Actual costs incurred during the period	(1,162)	(123)
Balance at end of period	$ 33,970	$ 35,504

(b) Asset Retirement Reserve Fund

Previously this cash fund was increased at $0.075 per boe produced. Effective January 1, 2004, this was increased to $0.15 per boe produced. The total amount of the reserve fund at March 31, 2004 is $4.1 million.

8. DERIVATIVE FINANCIAL INSTRUMENTS AND PHYSICAL CONTRACTS

The Trust enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and natural gas production. These include fixed price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments as at March 31, 2004, and the related unrealized gains or losses, are summarized separately below:

Natural Gas	**Term**	**Unrealized VolumePrice mcf/d$/mcf**	**Delivery Point**	**Gain (Loss) $000's**
Collar	April 1, 2004 to October 31, 2004	9,475$5.17-$7.28	AECO	$ (468)
Collar	April 1, 2004 to October 31, 2004	9,475$5.07-$6.81	AECO	(793)
Collar	April 1, 2004 to October 31, 2004	1,895$5.28-$7.39	AECO	(95)
Fixed	April 1, 2004 to October 31, 2004	4,737$5.33	AECO	(1,443)
Fixed	April 1, 2004 to October 31, 2004	4,737$6.26	AECO	(534)
Collar	April 1, 2004 to October 31, 2004	1,895$5.28-$7.65	AECO	(70)
Collar	November 1, 2004 to 9,475 March 31, 2005	*(1) AECO		(464)
Total				$(3,867)

*(1) At Prices above $8.97/mcf Petrofund receives $8.97/mcf.
At Prices between $5.80/mcf and $8.97/mcf Petrofund receives the market price.
At Prices below $4.74/mcf Petrofund receives a premium of $1.06/mcf.

Oil	Term	Volume bbl/d	Price $/bbl	Delivery Point	Unrealized Gain (Loss) $000's
Fixed Price	April 1, 2004 to June 30, 2004	2,000	$39.17	Edmonton	$ (1,252)
Fixed Price	July 1, 2004 to December 31, 2004	1,000	$37.26	Edmonton	(1,111)
Three Way Collar	January 1, 2004 to June 30, 2004	2,000	*(1)	Edmonton	(2,072)
Collar	April 1, 2004 to June 30, 2004	2,000	$31.47-$36.98	Edmonton	(1,623)
Three Way Collar	July 1, 2004 to December 31, 2004	2,000	*(2)	Edmonton	(2,171)
Collar	July 1, 2004 to September 30, 2004	2,000	$31.47-$36.72	Edmonton	(1,414)
Collar	October 1, 2004 to December 31, 2004	2,000	$31.47-$36.72	Edmonton	(1,213)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	*(3)	Edmonton	(1,555)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	*(4)	Edmonton	(346)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	*(5)	Edmonton	(470)
Total					$(13,227)

*(1) At Prices above $37.70 Petrofund receives $37.70/bbl.
At Prices between $31.47 and $37.70/bbl Petrofund receives the market price.
At Prices below $27.86 Petrofund receives a premium of $3.93/bbl.

*(2) At Prices above $38.03 Petrofund receives $38.03/bbl.
At Prices between $31.81 and $38.03/bbl Petrofund receives the market price.
At Prices below $28.19 Petrofund receives a premium of $3.93/bbl.

*(3) At Prices above $38.03 Petrofund receives $38.03/bbl.
At Prices between $31.47 and $38.03/bbl Petrofund receives the market price.
At Prices below $26.22 Petrofund receives a premium of $5.25/bbl.

*(4) At Prices above $44.34 Petrofund receives $44.34/bbl
At Prices between $35.16 and $44.34/bbl Petrofund receives the market price.
At Prices below $31.47 Petrofund receives a premium of $3.93/bbl.

*(5) At Prices above $43.02 Petrofund receives $43.02/bbl.
At Prices between $35.14 and $43.02/bbl Petrofund receives the market price.
At Prices below $30.16 Petrofund receives a premium of $5.25/bbl.

The oil hedges are transacted in U.S. dollars. They have been converted to Canadian dollars at the March 31, 2004 closing rate of $1.3113 C$:US$.

Electricity	Term	Volume MW/h	Price $/MWh	Delivery Point	Unrealized Gain (Loss) $000's
Fixed Price	February 1, 2004 to December 31, 2005	2.0	$44.50 Power Pool	Alberta	$ 193
Total					$ 193

Derivative financial instruments and physical hedge contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counter parties. Market risk relating to changes in value or settlement cost of the Trust's derivative financial instruments is essentially offset by gains or losses on the underlying physical sales.

9. POTENTIAL ACQUISITION

On March 29, 2004 Petrofund Energy Trust ("Petrofund") and Ultima Energy Trust ("Ultima") announced that they have entered into an agreement providing for the combination of the two entities.

Under the terms of the agreement, each Ultima unit will be exchanged for 0.442 of a Petrofund unit on a tax-deferred rollover basis. In addition, Ultima unitholders will receive an aggregate of $10 million in the form of a one-time special distribution payable prior to the closing of the transaction. The transaction is subject to regulatory approval and the approval of Ultima unitholders by a majority of at least two thirds voting at a meeting to be held on or about June 4, 2004. The transaction is expected to close on June 16, 2004.

This transaction will be accounted for as an acquisition of Ultima by Petrofund.

NON-RESIDENT OWNERSHIP

As at April 30, 2004, based on the information provided by our transfer agent, Petrofund estimates that nonresident ownership of the Trust was approximately 69%. Management of the Trust continues to review its options to achieve non-resident ownership levels below 50% by the January 1, 2007 deadline proposed by the Federal Government. The Ultima Energy Trust merger is a positive first step toward reducing non-resident ownership levels as the proportion of Ultima units that are held by non-residents is significantly lower than that of Petrofund, such that the non-resident ownership levels of the combined entity going forward will be lower than Petrofund's current 69%.

Petrofund Energy Trust is a Calgary based royalty trust that acquires and manages producing oil and gas properties in Western Canada. The Trust makes monthly cash distributions to unitholders, which are derived from the Trust's cash flow from these properties. Petrofund Energy Trust was founded in 1988 and was one of the first oil and gas royalty trusts in Canada.

This news release may include statements about expected future events and/or financial results that are forward-looking in nature and subject to risks and uncertainties. For those statements, we claim the protection of the safe harbor for forward-looking statements provisions contained in the U.S. Private Securities Litigation Reform Act of 1995. Petrofund Energy Trust cautions that actual performance will be affected by a number of factors, many of which are beyond its control. Future events and results may vary substantially from what Petrofund Energy Trust currently foresees. Discussion of the various factors that may affect future results is contained in Petrofund Energy Trust's recent filings with the Securities and Exchange Commission and Canadian securities regulatory authorities.

In regards to barrels of oil equivalent (BOE), 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.

PETROFUND ENERGY TRUST

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