PETROFUND ENERGY TRUST
Form 6-K
November 10, 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: November 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: November 9, 2004

By:

Hugo S^{t} J. A. Potts
Corporate Secretary

EXHIBIT

Exhibit	Description of Exhibit
1.	**Third Quarter Report dated November 9, 2004.**

EXHIBIT 1

444 - 7th Avenue S.W.
Suite 600
Calgary, Alberta
T2P 0X8
Telephone: (403) 218-8625
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News Release

Calgary - November 8, 2004

Petrofund Energy Trust (*TSX: PTF.UN; AMEX: PTF*) Announces Results for the Third Quarter of 2004

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

- Cash flow of $65 million, up 63% over the third quarter last year, due primarily to additional production from the Ultima acquisition and higher commodity prices.
- Average production of 34,950 boe per day, a 21% increase over Q3 of 2003.
- A third quarter payout ratio of 75%, and a 76% payout ratio for the 9 month period.
- Operating costs of $9.62 per boe, up 4% over last year.
- Third quarter general and administrative costs down 6% from last year to $1.17 per boe.
- A 0.8 debt to cash flow ratio.

Petrofund's third quarter report is presented below:

Petrofund Energy Trust

3rd Quarter Report
for three & nine months ended September 30, 2004 & 2003

FINANCIAL HIGHLIGHTS

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

	3 months ended September 30,			9 months ended September 30,		
	2004	2003(3)	Variance	2004	2003(3)	Variance
INCOME STATEMENT						
Revenues	$ 147,489	$ 95,976	54%	$ 360,158	$ 310,583	16%
Cash flow (1)	$ 65,075	$ 39,959	63%	$ 163,942	$ 144,339	14%
Per unit(2)	$ 0.65	$ 0.60	8%	$ 1.95	$ 2.43	(20)%
Per boe	$ 20.24	$ 15.08	34%	$ 20.02	$ 18.78	7%
Cash distributions paid per unit	$ 0.48	$ 0.54	(11)%	$ 1.44	$ 1.55	(7)%
Net income	$ 15,147	$ 15,104	-%	$ 23,593	$ 63,011	(63)%
Net income per unit						
Basic	$ 0.15	$ 0.23	(35)%	$ 0.28	$ 1.06	(74)%
Diluted	$ 0.15	$ 0.23	(35)%	$ 0.28	$ 1.06	(74)%
UNITS AND EXCHANGEABLE SHARES OUTSTANDING (2)						
Weighted average	100,267	66,143	52%	84,064	59,365	42%
Diluted	100,353	66,281	51%	84,211	59,491	42%
At period end	100,344	66,716	50%	100,344	66,716	50%
BALANCE SHEET						
Working capital (deficit)				$ (55,784)	$ (60,440)	8%
Property, plant and equipment, net				$ 1,230,636	$ 932,361	32%
Long-term debt				$ 199,474	$ 196,160	(2)%
Unitholders' equity				$ 1,031,226	$ 553,276	86%
TRUST UNIT TRADING (TSX: PTF.UN)						
High	$ 16.35	$ 16.70	(2)%	$ 19.24	$ 16.70	15%
Low	$ 14.62	$ 13.01	12%	$ 14.56	$ 10.69	36%
Close	$ 15.90	$ 16.00	(1)%	$ 15.90	$ 16.00	(1)%
Volume (units)	18,062	16,211	11%	43,036	38,391	12%
TRUST UNIT TRADING (AMEX: PTF)						
High	$ 12.83	$ 12.24	5%	$ 14.96	$ 12.24	22%
Low	$ 11.10	$ 9.51	17%	$ 10.95	$ 6.89	59%
Close	$ 12.60	$ 11.90	6%	$ 12.60	$ 11.90	6%
Volume (units)	27,123	28,370	(4)%	87,726	56,425	55%

1. Cash flow before changes in non-cash operating working capital balances.

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

2. See Notes 4 and 5 to Notes to the Interim Consolidated Financial Statements for details.
3. Certain numbers have been restated to conform to the 2004 presentation.

OPERATIONAL HIGHLIGHTS

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

	3 months ended September 30,			9 months ended September 30,		
	2004	**2003[3]**	**Variance**	**2004**	**2003[3]**	**Variance**
DAILY PRODUCTION						
Oil (bbls)	17,504	12,518	40%	13,934	12,053	16%
Natural gas (mmcf)	90,119	84,734	6%	82,623	84,324	(2)%
Natural gas liquids (bbls)	2,427	2,160	12%	2,181	2,043	7%
BOE (6:1)	34,950	28,801	21%	29,886	28,150	7%
Total production (mboe)	3,215	2,650	21%	8,189	7,685	7%
PRODUCTION PROFILE						
Oil	50%	43%		47%	43%	
Natural gas	43%	49%		46%	50%	
Natural gas liquids	7%	8%		7%	7%	
PRICES						
Oil (per bbl) [1]	$ 52.02	$ 37.80	38%	$ 47.88	$ 40.33	19%
Natural gas (per mcf) [1]	$ 6.50	$ 5.92	10%	$ 6.78	$ 6.87	(1)%
Natural gas liquids (per bbl) [1]	$ 43.68	$ 31.23	40%	$ 39.55	$ 35.12	13%
BOE (6:1)	$ 45.85	$ 36.18	27%	$ 43.97	$ 40.39	9%
Cash operating netback per BOE	$ 22.57	$ 18.41	23%	$ 22.46	$ 21.66	4%
LEASE OPERATING COSTS	$ 30,920	$ 24,482	(26)%	$ 74,388	$ 66,474	(12)%
Cost per boe	$ 9.62	$ 9.24	(4)%	$ 9.08	$ 8.65	(5)%
GENERAL & ADMINISTRATIVE COSTS	$ 3,764	$ 3,318	(13)%	$ 10,218	$ 10,099	(1)%
Cost per boe	$ 1.17	$ 1.25	6%	$ 1.25	$ 1.31	5%

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 and nine months ended September 30, 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 and nine months ended September 30, 2004 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 analysis included in this section is based on information available to October 31, 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 mcf/bbl. A boe may be misleading, particularly if used in isolation. A boe conversion of 6 mcf/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 Petrofund Corp.("PC"), etc. A reconciliation of cash flow provided by operating activities on the Consolidated Statement of Cash Flows to cash flow available for distribution is included in Note 7 of the Notes to the 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.

RESULTS SUMMARY

The results for the third quarter were impacted by a significant increase in production and a further increase in product prices. Production increased 6,149 boe/d from the third quarter of 2003 mainly due to the acquisition of Ultima Energy Trust on June 16, 2004. The increase from Ultima was offset by normal production declines and a disposition of properties effective December 31, 2003 which reduced volumes by approximately 1,500 boe/d. Average prices on a boe basis were up $1.58 from the second quarter of 2004 and up $9.67 from the same period in 2003. Due to this increase in volumes and prices, revenue was up 31% from the second quarter of 2004 and up 54% for three months ended September 30, 2004 from the same period in 2003. The increased revenue was partially offset by losses on hedging contracts mainly due to the strong oil prices. The cash loss on hedging contracts during the third quarter was $14.6 million. An additional non-cash loss of $15.3 million is recorded on the income statement reflecting the change in the fair value of the commodity contracts during the period.

Royalties were 19% of revenue, a reduction of 2% from the same period in 2003, and operating costs increased by $0.38 per boe. General and administrative costs were $ 1.17 per boe, a decrease of $0.08 per boe from 2003.

Net income for the three months ended September 30, 2004 was $15.1 million, the same as the corresponding amount in the prior year. Net income for the three months in 2004 was reduced by $15.3 million for the unrealized loss on commodity contracts (excluding the future income tax impact) versus nil in 2003 as a result of the adoption of the new policy on hedging relationships effective January 1, 2004 and net income was increased by $4.6 million due to a higher future income tax recovery.

Net income before income taxes for the nine months ended September 30, 2004 was $30.3 million as compared to $31.3 million for the same period in the prior year. Net income for 2004 was impacted by a non-cash loss of $32.6 million on commodity contracts and 2003 net income was reduced by $30.9 million for the cost of the internalization of the management contract.

Net income decreased $39.4 million in the nine months ended September 30, 2004 from 2003 due to a change in future income taxes of $38.9 million. A recovery of $32.6 million was recorded in 2003 reflecting income tax rate reductions enacted in that year, versus a future tax provision of $6.4 million recorded in 2004.

HIGHLIGHTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2004

- Petrofund closed the acquisition of Ultima Energy Trust on June 16, 2004.
- The Trust paid out cash distributions of $47.7 million or $0.48 per unit in the three months ended September 30, 2004.
- The Trust's payout ratio for the nine months ended September 30, 2004 was 76% compared to 65% in 2003. The payout ratio in the third quarter of 2004 was 75% as compared to 92% in the same quarter of 2003.
- Production on a boe basis increased 21% to 34,950 boe/d from 28,801 in the prior year and from 28,043 in the second quarter.
- Third quarter Canadian product prices on a boe basis increased to $45.85/boe from $36.18/boe in the in the prior year and from $44.27 in the second quarter.
- The Trust generated cash flow of $65.1 million in the third quarter of 2004 as compared to $40.0 million in the third quarter of 2003.

PETROFUND ACQUISITION OF ULTIMA ENERGY TRUST

On June 16, 2004 Petrofund acquired all the assets and assumed all liabilities of Ultima Energy Trust ("Ultima"). This report reflects the results of operations from Ultima's properties beginning June 17, 2004.

Petrofund acquired Ultima for an aggregate cost of $567.4 million consisting of 26.4 million Petrofund Trust units valued at $17.12 per unit, the assumption of debt and negative working capital of $119.7 million and transaction costs incurred of $1.9 million.

OPERATIONAL HIGHLIGHTS

Despite being hampered by wet weather throughout much of the quarter, a total of 51 gross wells (11.6 net) and six farmout wells were drilled on Company lands during the quarter. This drilling resulted in 33 oil wells, 22 gas wells, one miscible injector and one dry hole for an overall 98% success rate for the quarter. Year to date, a total of 129 gross wells (28.0 net) and 24 farmout wells were drilled on Company lands, resulting in 75 oil wells and 71 gas wells for a 95% success rate.

In addition, the Trust also continued to optimize its base production during the quarter through a series of well workovers, well recompletions, production equipment upgrades and facility additions.

Northern Alberta

Fifteen wells (3.3 net) were drilled at Petrofund's Westerose, Pembina, Brazeau, Minehead, Swan Hills and Red Earth properties, resulting in ten oil wells and 5 gas wells. Most notably, Petrofund as operator drilled a 90% working interest horizontal Banff oil well at Cherhill that is now producing 200 boe/d net. At Minehead, Petrofund participated in drilling three high working interest Cardium gas wells which are scheduled to come on-stream early next quarter, netting the Company an incremental 1.75 mmcf/d of gas. At Brazeau, Petrofund participated in the drilling of an infill Rock Creek gas well that flow tested 1.0 mmcf/d gross. At Spirit River, Petrofund as operator recompleted an existing well for Charlie Lake gas that is now producing 750 mcf/d net to Petrofund.

Central Alberta

Twenty six wells (3.8 net) were drilled at Bodo, Consort, Stanmore, Eyehill, Three Hills Creek and Medicine River, yielding 11 oil wells, 14 gas wells & one dry hole. Petrofund directed considerable attention towards the continued development of its Three Hills Creek gas property through its participation in the drilling of six coalbed methane gas wells along with the construction of an associated gathering and processing facility. These Three Hills Creek wells, along with others drilled earlier this year, are expected to net Petrofund an incremental 1.5 mmcf/d by mid next quarter. In addition, the Company realized a 900 mcf/d net production gain by bringing four previously drilled Edmonton Sand gas wells on-stream during the quarter.

At Ferrier, Petrofund as operator successfully recompleted two existing wells for Ellerlsie gas. These wells are expected to produce 600 mcf/d net next quarter once necessary facility additions are constructed.

Southeastern Saskatchewan

A total of fifteen oil wells (4.5 net) were successfully drilled on Petrofund's lands at Silverton, Queensdale, Midale and Weyburn. At Silverton, Petrofund drilled a 100% working interest Frobisher oil well that is scheduled to come on-stream early next quarter at 150 boe/d.

Petrofund also participated in the drilling of two Frobisher oil wells at Queensdale that are now producing 75 boe/d net to the Company's 50% working interest. Eleven horizontal wells (2.2 net) were drilled in the Weyburn Unit during the quarter and are expected to add 300 boe/d net to Petrofund.

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 the 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. Net income for the three and nine months ended September 30, 2003 increased by $170,000 and $785,000, respectively. 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.

Net income before tax for the three and nine months ended September 30, 2004, increased by $1.1 million ($657,000 after tax) and $3.0 million ($1.8 million after tax) respectively, 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 Notes 2(a) and 8 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.

All outstanding derivative instruments as at January 1, 2004 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 are being amortized to expense over the remaining term of the contracts. The total amount of $7.6 million plus $1.4 million relating to Ultima, less $6.9 million amortized to expense in the nine months ended September 30, 2004, has been recorded as a current asset or liability, as appropriate, on the balance sheet at September 30, 2004 as "deferred loss/gain on 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 September 30, 2004 in the amount of $32.6 million are recorded in the income statement on a separate line as "gain/loss on commodity contracts". This is an increase of $15.3 million in the third quarter. This line item also includes realized losses on commodity contracts, of $14.6 million in the third quarter of 2004 and $28.3 million for the nine month period which were previously deducted from oil and natural gas sales. The comparative numbers for 2003 represent realized losses on commodity contracts which were netted against sales.

This policy is discussed in detail in Note 2(b) to the Notes to the 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 $1.8 million in the third quarter of 2004 and $4.3 million for the nine months ended September 30, 2004. The comparative numbers for 2003 were $1.4 million and $4.1 million, respectively.

This change in classification has no impact on cash flow or net income.

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 third quarter of 2004 received distributions of $0.48 in cash as compared to $0.54 in the third quarter of 2003. A cash distribution of $0.16 per unit was paid in October and $0.16 per unit has been announced for November and indicated for December.

The Trust generated cash flow available for distribution in the third quarter of $63.8 million before deducting $15.0 million for reinvestment in capital projects. Distributions of $47.7 million were paid out in the quarter representing a payout ratio of 75% (see Note 7).

For the 12 months ended September 30, 2004, the Trust generated cash flow available for distribution of $201.9 million, allocated $72.4 million for reinvestment in development drilling and other projects, and the deferred capital obligation and paid out distributions of $158.0 million, resulting in a payout ratio of 78%.

The Trust is continuing its policy of stabilizing monthly distributions and reinvesting a portion of its cash flow for the long-term benefit of the Trust.

RESULTS OF OPERATIONS

Revenue and Production

Revenues increased 54% to $147.5 million in the third quarter of 2004 from $96.0 million in the third quarter of 2003. Production was up 21%, and prices were up 27% on a boe basis.

For the nine month period ended September 30, 2004, revenue increased 16% to $360.2 million from $310.6 million in 2003 due to a 7% increase in production to 29,886 boe/d and a 9% increase in the average price per boe to $43.97 in 2004 from $40.39 in 2003.

Crude oil sales increased 92% to $83.7 million in the third quarter of 2004 from $43.5 million in the third quarter of 2003. Oil production volumes increased 40% to 17,504 bbl/d as compared to 12,518 in the third quarter of 2003. The average price was up 38% to $52.02/bbl from $37.80/bbl. The WTI benchmark price increased 45% during the same period; however, the appreciation of the Canadian dollar offset part of the WTI increase.

During the nine month period ended September 30, 2004, crude oil sales increased 38% to $182.8 million from $132.7 million in 2003. Oil production increased 16% to 13,934 bbl/d for the period as compared to 12,053 bbl/d for the same period in 2003. The average price increased from $40.33/bbl in 2003 to $47.88/bbl in 2004.

Natural gas sales increased 17% from $46.1 million in the third quarter of 2003 to $53.9 million in the third quarter of 2004. Natural gas production was up 6% from 84.7 mmcf/d to 90.1 mmcf/d, and the average natural gas price was up 10% to $6.50/mcf from $5.92/mcf. Also, AECO monthly natural gas prices increased 10% in the third quarter of 2004 over the third quarter of 2003.

During the nine month period ended September 30, 2004, natural gas sales decreased 3% to $153.6 million from $158.1 million in 2003. Natural gas production decreased 2% from 84.3 mmcf/d in 2003 to 82.6 mmcf/d in 2004. The average price was down 1% from $6.87/mcf in 2003 to $6.78/mcf in 2004.

Sales of natural gas liquids increased 55% to $9.9 million in the third quarter of 2004, from $6.4 million in the third quarter of 2003. Production was up 12% to 2,427 bbl/d from 2,160 bbl/d; and the average price was up 40% to $43.68/bbl from $31.23/bbl.

For the nine month period ended September 30, 2004, sales of natural gas liquids increased 20% to $23.8 million in 2004 from $19.8 million in 2003. Production volumes increased 7% from 2,043 bbl/d to 2,181 bbl/d and the average price increased 13% from $35.12/bbl in 2003 to $39.55/bbl in 2004.

Daily Production

	3 months ended September 30,		9 months ended September 30,	
	2004	**2003**	**2004**	**2003**
Oil (bbls)	17,504	12,518	13,934	12,053
Natural gas (mmcf)	90,119	84,734	82,623	84,324
Natural gas liquids (bbls)	**2,427**	**2,160**	**2,181**	**2,043**
Total (boe 6:1)	34,950	28,801	29,886	28,150

Sales Prices

Average prices	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Benchmark prices				
WTI oil (U.S.$/bbl)	$ 43.88	$ 30.20	$ 39.11	$ 30.99
U.S. $ exchange rate	0.77	0.72	0.75	0.70
WTI oil (Cdn. equivalent/$/bbl)	$ 56.99	$ 41.94	$ 52.15	$ 44.27
AECO natural gas ($/mmbtu)	$ 6.66	$ 6.29	$ 6.69	$ 7.07
Average Petrofund prices				
Oil (per bbl)	$ 52.02	$ 37.80	$ 47.88	$ 40.33
Natural gas (per mcf)	6.50	5.92	6.78	6.87
Natural gas liquids (per bbl)	**43.68**	**31.23**	**39.55**	**35.12**
Weighted average (boe 6:1)	**$ 45.85**	**$ 36.18**	**$ 43.97**	**$ 40.39**

Production Revenue (millions)

Revenue	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Oil	$ 83.7	$ 43.5	$ 182.8	$ 132.7
Natural gas	53.9	46.1	153.6	158.1
Natural gas liquids/sulphur	**9.9**	**6.4**	**23.8**	**19.8**
Total	**$ 147.5**	**$ 96.0**	**$ 360.2**	**$ 310.6**

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 40% of its annual production for up to eighteen months beyond the current date.

As at September 30th, 2004 Petrofund has hedged 31.3 mmcf/d of gas and 7,500 bbl/d of crude for the remainder of 2004. Crude oil hedges for 2004 were unchanged over the quarter while natural gas hedges decreased by 2.8 mmcf/d as contracts expired. The Trust's 2004 gas hedges include: 26.5 mmcf/d collared between $5.81/mcf-$10.23/mcf and 4.8 mmcf/d fixed at $6.15/mcf. The Trust will lose its floor protection on about 24% 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's 2004 crude hedges include 2,000 bbl/d fixed at $35.64/bbl and 5,500 bbl/d collared between $30.56/bbl-$35.99/bbl. The Trust will lose its floor protection on 64% of the collared volume in the event WTI averages less than $26.43/bbl. Under these transactions Petrofund will receive a premium of $4.33/bbl if WTI remains below the $26.43/bbl level.

For the first quarter of 2005, the Trust has 28.4 mmcf/d of gas collared between $6.09/mcf-$11.49/mcf. The Trust will lose its floor protection on 33% of this volume should AECO average less than $4.74/mcf. The Trust collared the price at AECO on an additional 4.75 mmcf/d for the summer of 2005 between $6.33/mcf-$8.44/mcf. No gas has been hedged beyond October 31, 2005. Over the quarter Petrofund collared an additional 1,000 bbl/d for the first half of 2005 between $49.83/bbl and $62.45/bbl increasing hedge levels for the first half to 4,000 bbl/d (3,500 bbl/d annualized). The trust has no oil fixed in 2005, as 100% of the hedges are WTI collars ranging between $35.08/bbl-$43.37/bbl. The trust will lose its floor protection on 93% of the collared volume if WTI averages less than $29.24/bbl. Under these transactions Petrofund will receive a premium of $4.76/bbl if WTI remains below the $29.24/bbl level.

Petrofund has contracted to control a portion of its Alberta power costs by fixing the price on three (3) Megawatts/hour (MW/h) of its Alberta consumption at $46.65/MWh for 2004. In 2005, the Trust has two (2) Megawatts/hour (MW/h) fixed at $44.50/MWh.

All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate closing on September 30, 2004 ($1.2616 C$:US$). For a complete listing of all hedge transaction details please see Note 10 to the Interim Consolidated Financial Statements.

Gain/ (loss) on commodity contracts

Revenue	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Realized gains/(losses)	$ (14,559)	$ (642)	$ (28,347)	$ (7,514)
Change in fair value				
Fair value, beginning of period	**(24,970)**	**-**	**(6,771)**	**-**
Fair value of Ultima contracts acquired -		-	(5,584)	-
Fair value September 30, 2004	**(38,096)**	**-**	**(38,096)**	**-**
Change in fair value of financial instruments	**(13,126)**	**-**	**(25,741)**	**-**
Amortization of negative fair value				
at January 1, 2004	**(1,540)**	**-**	**(6,168)**	**-**
Amortization of Ultima contracts	(678)	-	(678)	-
Total non-cash adjustments	**(15,344)**	**-**	**(32,587)**	**-**
Total	**$ (29,903)**	**$ (642)**	**$ (60,934)**	**$ (7,514)**

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	$ (8.62)	$ (0.29)	$ (6.93)	$ (1.09)
Gas per mcf	$ (0.09)	$ (0.04)	$ (0.09)	$ (0.17)

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

Royalties, net of incentives	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Royalties (millions)	$ 27.6	$ 20.6	$ 69.2	$ 65.8
Average royalty rate	19%	21%	19%	21%
$/boe	**$8.58**	**$ 7.77**	**$ 8.45**	**$ 8.56**

Royalties, net of the Alberta Royalty Credit, were 19% of revenues for the three and nine months ending September 30, 2004, as compared to 21% for the same periods in the prior year. The decrease in mainly due to the increase in the relative percentage of oil production which has a lower royalty rate than gas.

Expenses (millions)	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Lease operating	$30.9	$ 24.5	$ 74.4	$ 66.5
Transportation	1.8	1.4	4.3	4.1
General & administrative	**3.8**	**3.3**	**10.2**	**10.1**
Net interest	**1.7**	**2.5**	**3.8**	**7.0**

Expenses per boe	**3 months ended September 30,**		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Lease operating	$ 9.62	$ 9.24	$ 9.08	$ 8.65
Transportation	0.55	0.52	0.52	0.54
General & administrative	1.17	1.25	1.25	1.31
Net interest	**0.53**	**0.95**	**0.46**	**0.91**

FIELD OPERATING COSTS

Operating expenses, net of processing income, were $30.9 million in the third quarter of 2004 as compared to $24.5 million in the third quarter of 2003. Operating costs on a boe basis increased 4% to $9.62 in 2004, as compared to $9.24 for the same period in 2003. For the nine month period ended September 30, 2004, operating costs were up 6% to $9.08 per boe as from $8.65 in the prior year.

Fixed costs, including lease rentals, property taxes, cost of field services and employees continue to increase. Repair and maintenance and workover expenditures are generally higher in the third quarter of the year.

TRANSPORTATION COSTS

Transportation costs which range from $0.52 per boe to $0.55 per boe were previously deducted from sales revenue. Due to the changes in the accounting policy, sales revenues have been increased by this amount and the costs disclosed as a separate item.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative costs were $3.8 million in the third quarter of 2004 compared to $3.3 million in the third quarter of 2003. Costs were down 6% on a boe basis to $1.17 as compared to $1.25 in 2003 due to increased production. General and administrative costs for the third quarter include $251,000 with respect to the proposed reclassification of units and for activities undertaken to meet the requirements of Section 302 and Section 404 of the Sarbanes Oxley Act.

General and administrative costs for the nine month period ended September 30, 2004, were $10.2 million in 2004 compared to $10.1 million in 2003. Costs, on a per boe basis, were down 5% to $1.25 per boe compared to $1.31 per boe in 2003. Management was successful in maintaining its general and administrative costs at approximately the same level as the prior year while at the same time increasing production by 7%.

INTEREST

Interest expense decreased to $1.7 million in the third quarter of 2004 from $2.5 million for the same period as 2003 and to $3.8 million for the nine month period ended September 30, 2004, from $7.0 million in 2003. The decreases reflect lower average loan balances outstanding and a decrease in the average prime rate.

DEPLETION, DEPRECIATION AND ACCRETION

The provision for depletion, depreciation and accretion increased from $28.6 million in the third quarter of 2003 to $42.0 million in the third quarter of 2004 due to the increase in the depletion rate from $10.81/boe in 2003 to $13.06/boe in 2004. The increase in the depletion rate is due to the increased acquisition costs of properties and the negative adjustments to reserves at December 31, 2003.

The provision for depletion, depreciation and accretion for the nine months ended in September 30, 2004, was $104.6 million or $12.78 per boe as compared to $85.6 million or $11.13 per boe for 2003.

ASSET RETIREMENT RESERVE

In the third quarter of 2004, Petrofund has set aside $482,000 in cash to fund future ARO costs. The total ARO reserve at September 30, 2004 was $6.6 million.

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

TAXABILITY OF DISTRIBUTIONS

Proposed amendments to the Income Tax Act on December 20, 2002 clarify that taxpayers, including the Trust, should be accounting for royalty revenue on an accrual rather than a cash basis. While these amendments are technically not effective until passed into law, in the view of the Department of Finance, the amendments are merely clarifying the correct method of accounting. The amendments are not controversial and accordingly are expected to be passed into law shortly. As a result, the Trust commenced to account for its royalty revenue on an accrual basis. This change, along with the significant increase in cash flow due to the increase in production and product prices, will increase the taxable portion of distributions to unitholders which is expected to be in the 80% range for the year.

NET INCOME

Net income for the three months ended September 30, 2004 was $15.1 million, the same as the corresponding amount in the prior year. Net income for the three months in 2004 was reduced by $15.3 million for the unrealized loss on commodity contracts versus nil in 2003 as a result of the adoption of the new policy on hedging relationships effective January 1, 2004 and net income was increased by $4.6 million due to a higher future income tax recovery.

Net income before income taxes for the nine months ended September 30, 2004 was $30.3 million as compared to $31.3 million for the same period in the prior year. Net income for 2004 was impacted by a non-cash loss of $32.6 million on commodity contracts and 2003 net income was reduced by $30.9 million for the cost of the internalization of the management contract. Net income decreased $39.4 million in the nine months ended September 30, 2004 from 2003 due to a change in future income taxes of $38.9 million. A recovery of $32.6 million was recorded in 2003 reflecting income tax rate reductions, enacted in that year, versus a future tax provision of $6.4 million recorded in 2004.

Netback	3 months ended September 30, 2004	2003	9 months ended, September 30, 2004	2003
Weighted average selling price	$ 45.85	$ 36.18	$ 43.97	$ 40.39
Cash cost of oil and natural gas hedging	**(4.53)**	**(0.24)**	**(3.46)**	**(0.98)**
Net weighted average selling price	41.32	35.94	40.51	39.41
Royalties, net of ARTC	8.58	7.77	8.45	8.56
Operating costs	9.62	9.24	9.08	8.65
Transportation	**0.55**	**0.52**	**0.52**	**0.54**
Operating Netback	22.57	18.41	22.46	21.66
Interest expense	0.53	0.95	0.46	0.91
General and administrative	1.17	1.25	1.25	1.31
Capital and current taxes	**0.28**	**0.34**	**0.34**	**0.35**
Total cash netback per BOE before the effects of the internalization of the management contract	20.59	15.87	20.41	19.09
Internalization of management contract-		**0.03**	**-**	**1.04**
Total cash netback per BOE after the effects of the **internalization of the management contract**	**$ 20.59**	**$15.84**	**$ 20.41**	**$18.05**

QUARTERLY FINANCIAL DATA

($millions, except per unit amounts)	Net Oil and Natural Gas Sales (1)	Net Income	Net income per unit (2) Basic	Diluted
2004				
First quarter	$81.1	$7.6	$0.10	$0.10
Second quarter	89.9	0.8	0.01	0.01
Third quarter	119.9	15.1	0.15	0.15
2003				
First quarter	$71.9	$32.6	$0.60	$0.60
Second quarter	55.5	15.3	0.26	0.26
Third quarter	50.9	15.1	0.23	0.23
Fourth quarter	52.0	24.3	0.35	0.35
2002				
Fourth quarter	$68.6	$5.4	$0.10	$ 0.10

GOODWILL

The goodwill balance of $176.6 million was created as a result of the acquisition of Ultima and was determined based on the excess of total consideration paid plus the future income tax liability less the fair value assigned to Ultima's assets.

Accounting standards require that the goodwill balance be assessed for impairment at least annually and if an impairment exists that it be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of September 30, 2004.

CAPITAL EXPENDITURES

During the nine months ended September 30, 2004, $47.9 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 $68.0 million range.

During the third quarter of 2004, Petrofund drilled 51 gross wells and entered into farmout agreements with various industry partners, which resulted in 57 wells being drilled on Petrofund's undeveloped land base. The drilling activity resulted in 33 oil wells and 22 natural gas wells for an overall success rate of 98%.

A summary of capital expenditures for the three and nine month periods appears below. Of the total amounts, $452 million was financed by the issue of 26.4 million Petrofund units with an assigned value of $17.12 per unit and the remainder was financed by cash and the assumption of debt on the Ultima acquisition.

	Ending September 30, 2004	
	3 months	**9 months**
Acquisitions / dispositions	$(6,117)*	$ 563,292*
Finding and development cost:		
Land and seismic	468	1,435
Drilling and completions	11,731	25,875
Well equipping	3,051	5,083
Tie-ins	1,085	3,334
Facilities	1,876	6,541
Other	2,275	5,663
Total	20,486	47,931
Total net capital expenditures	$ 14,369	$611,223

* Includes goodwill of $176,585, which reflects a credit adjustment for working capital and transaction costs on Ultima acquisition of $5,855 in the third quarter.

DEBT

As at September 30, 2004, the amount outstanding on the credit facility was $199.5 million as compared to the $325 million available. The facility will be utilized for acquisitions and for additional development activities which are expected to be in the $20.0 million range for the fourth quarter of 2004.

The revolving period on the syndicated facility has been extended for an additional 364-day period ending May 28, 2005. The maximum on the facility was increased to $325 million on June 30, 2004 as a result of the Ultima acquisition.

WORKING CAPITAL

The working capital deficit was $55.8 million on September 30, 2004, an increase of $25.8 million from the $30.0 million deficit as at December 31, 2003. The decrease in distributions payable at September 30, 2004 of $26.3 million was due to the payout of the deferred capital obligation of $34.9 million with respect to the Weyburn unit interest acquired as part of the Ultima transaction. This decrease was offset by the net increase in liabilities of $31.3 million as a result of recording the unrealized losses on commodity contracts at fair value. In addition, current assets, at December 31, 2003 included $22.4 million due on the sale of properties which was collected in early 2004.

LIQUIDITY AND CAPITAL RESOURCES

During the nine months ended September 30, 2004, the Trust generated cash flow of $163.9 million and paid out $121.8 million in distributions. The excess was used to fund the Trust's capital expenditure program.

Total long-term debt and capital leases increased by $89.2 million to $199.5 million at September 30, 2004 from $110.3 million as at December 31, 2003 primarily due to the Ultima acquisition.

Details of all the changes to long-term debt are as follows:

$(thousands)	**3 months**	**9 months**
Cash flow from operating activities	$ 65,075	$163,942
Proceeds received from issuance of Trust units	1,642	3,351
Net change in non-cash working capital balances	(2,395)	24,797
Distributions paid	(47,684)	(121,759)
Expenditures on oil & natural properties, net	(14,252)	(151,971)
Asset retirement reserve	(482)	(1,228)
Redemption of exchangeable shares	(450)	(1,352)
Capital lease repayments	(90)	(264)
(Increase) decrease in cash	11,625	(5,283)
Miscellaneous	74	608
	$ 13,063	$(89,159)

The ratio of long-term debt to annualized cash flow based on the three months ended September 30, 2004 was 0.8:1.0.

Capitalization Analysis

($ thousands, except per unit & % amounts)	**2004**
Working capital (deficiency)	$ (55,784)
Bank debt	199,474
Net debt obligation	$ 255,258
Units outstanding & issuable for exchangeable shares	100,344
Market price at September 30, 2004	$ 15.90
Market capitalization	$1,595,476
Total capitalization	$ 1,850,258
Net debt as a percentage of total capitalization	14%

Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

UNITHOLDERS' EQUITY

The Trust had 99,405,256 Trust units outstanding at September 30, 2004, compared to 72,688,577 Trust units at the end of 2003. An additional 26,449,102 Trust units were issued on June 16, 2004 to the former unitholders of Ultima.

During this period no exchangeable shares were converted to Trust units, however, 71,377 shares were redeemed for cash during the quarter leaving 780,094 exchangeable shares outstanding at September 30, 2004, which can be converted, at the option of the unitholder into 939,147 Trust units.

BUSINESS RISKS

The success of the Trust in meeting its objective of stable distributions over the long term depends mainly on management's ability to:

1) Identify and acquire oil and gas properties and/or companies at prices that add value to the Trust.

2) Cost effectively add or extend reserves with internal development and drilling or farmouts.

3) Manage and control costs.

There are numerous factors beyond management's control that have a major influence on distribution levels including product prices, unforeseen production declines and cost increases from major suppliers. (A detailed assessment of risk factors and offsetting strategies appears elsewhere in this report).

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes. The table is based on actual average prices received for the nine months ended September 30, 2004 and current production volumes. 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.

Sensitivity Analysis

	$/unit Change	**$000's**	**per year**
Price per barrel of oil and gas liquids*	$ 1.00 U.S.	$ 7,483	$ 0.0746
Price per mcf of natural gas*	$0.25 Cdn.	$ 6,283	$ 0.0626
US/Cdn exchange rate	$ 0.01	$ 4,430	$ 0.0441
Interest rate on debt ($200 million)	1%	$ 2,000	$ 0.0200
Oil production volumes*	100 bbl/day	$ 1,399	$ 0.0139
Gas production volumes*	1 mmcf/day	$ 1,893	$ 0.0189

* After adjustment for estimated royalties.

OUTLOOK FOR 2004

As discussed in previous reports, 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 continue to be volatile.

The acquisition market is expected to continue to be active. The supply of properties has increased recently; 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 above 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 third quarter were reviewed earlier in this report.

CONTRACTUAL OBLIGATIONS

During the second quarter, PC acquired an additional interest in the Weyburn Unit as part of the Ultima acquisition. This resulted in additional commitments for CO2 purchases. Subsequent to June 30, 2004 PC renewed its office lease and extended the term. As a result, PC has contractual obligations which range from $12.0 million to $14.8 million over the next five years. Full details are provided in Note 9 to the Interim Consolidated Financial Statements.

OFF-BALANCE SHEET ARRANGEMENTS/ VARIABLE INTEREST ENTITIES

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

CRITICAL ACCOUNTING ESTIMATES

The Trust has established procedures and internal control systems in place to ensure timely and accurate preparation of management, financial and other reports. Disclosure controls are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis.

The Trust's financial and operating results incorporate a number of estimates including:

(a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
(b) estimated capital expenditures on projects that are in progress;
(c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;
(d) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
(e) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

The estimates are prepared by qualified individuals who have knowledge of operations and related activities. Prior estimates are compared to actual results to confirm or improve accrual procedures and to make more informed decisions on future estimates.

NON-RESIDENT OWNERSHIP

Non-resident ownership levels of the Trust have been increasing by approximately 1% to 2% each month. Based on information provided by our transfer agent, Petrofund estimates that nonresident ownership was approximately 67% as of September 30, 2004. In response to this rate of increase and non-residency limitations outlined in the Draft changes to the Tax Act released by the Canadian Federal Government on September 16, 2004, Petrofund has proposed a reclassification of trust unit capital (press released on October 13, 2004).

If approved at a meeting of unitholders on November 16, 2004, the reclassification will result in two classes of units: Class R Units, which can only be held by Canadian residents, and Class N Units, which will contain no residency restriction. These changes will allow the Trust flexibility in addressing the non-residency restrictions proposed by the government. Additional information regarding the proposed reclassification is detailed in an Information Circular which was mailed to unitholders in October, and which is also available on SEDAR and Petrofund's website.

Consolidated Balance Sheet

(thousands of dollars) (unaudited)

As at September 30, 2004 and at December 31, 2003		**2004**		**2003**
				(Restated Note 2)
Current assets				
Cash	$	7,465	$	2,182
Accounts receivable		35,620		48,268
Deferred hedging loss on commodity contracts *(Note 2(b))*		2,384		-
Commodity contracts *(Notes 2(b) and 10)*		449		-
Prepaid expenses		9,514		10,036
Total current assets		55,432		60,486
Asset retirement reserve *(Note 8(b))*		6,556		3,779
Goodwill *(Notes 1(a) and (b))*		176,585		-
Oil and gas royalty and property interests, at cost less accumulated depletion and depreciation of $585,036 (2003 - $482,349)		1,230,636		898,263
	$	1,469,209	$	962,528
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$	48,969	$	36,684
Current portion of capital lease obligations		700		356
Deferred hedging gain on commodity contracts *(Note 2(b))*		282		-
Commodity contracts *(Notes 2(b) and 10)*		34,106		-
Distributions payable to Unitholders *(Note 7)*		27,159		53,452
Total current liabilities		111,216		90,492
Long-term debt *(Note 6)*		199,474		109,707
Capital lease obligations		-		608
Commodity contracts *(Notes 2(b) and 10)*		4,439		-
Future income taxes		72,569		79,065
Asset retirement obligations *(Notes 2(a) and 8(a))*		50,285		34,363
Total liabilities		437,983		314,235
Unitholders' equity				
Unitholders' capital *(Note 4)*		1,476,835		1,020,677

Exchangeable shares *(Note 5)*		10,518		10,518
Accumulated earnings		221,846		198,253
Accumulated cash distributions *(Note 7)*		(677,973)		(581,155)
Total unitholders' equity		1,031,226		648,293
	$	1,469,209	$	962,528

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

Consolidated Statement of Operations and Accumulated Earnings

(thousands of dollars except per unit amounts) (unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2004	**2003**	**2004**	**2003**
		(Restated Note 2)		(Restated Note 2)
Revenues				
Oil and gas sales	$ 147,489	$ 95,976	$ 360,158	$ 310,583
Royalties, net of incentives	(27,578)	(20,582)	(69,173)	(65,816)
Gain(loss) on commodity contracts *(Note 2(b))*	(29,903)	(642)	(60,934)	`
	90,008	74,752	230,051	244,767
Expenses				
Lease operating	30,920	24,482	74,388	66,474
Transportation costs *(Note 2(c))*	1,753	1,377	4,264	4,130
Interest on long-term debt	1,703	2,511	3,792	7,012
General and administrative	3,764	3,318	10,218	10,099
Capital taxes	788	675	2,444	1,870
Depletion, depreciation and accretion	41,982	28,635	104,619	85,563
Internalization of management contract	-	88	-	30,850
	80,910	61,086	199,725	205,998
Income before provision for income taxes	9,098	13,666	30,326	38,769
Provision for (recovery of) income taxes				
Current	100	231	368	794
Future	(6,149)	(1,669)	6,365	(32,550)
	(6,049)	(1,438)	6,733	(31,756)
Net income	15,147	15,104	23,593	70,525
Accumulated Earnings, beginning of period	206,699	158,214	199,200	113,341
Retroactive application of change in accounting policy *(Note 2(a))*	-	615	(947)	(2,419)
Accumulated Earnings, beginning of period as restated	206,699	158,829	198,253	110,922
Accumulated Earnings, end of period	$ 221,846	$ 173,933	$ 221,846	$ 181,447

Net income per Trust unit								
Basic	$	0.15	$	0.23	$	0.28	$	1.06
Diluted	$	0.15	$	0.23	$	0.28	$	1.06

The accompanying notes to the 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)

	Three months ended September 30,		Nine months ended September 30,	
	2004	**2003**	**2004**	**2003**
		(Restated Note 2)		(Restated Note 2)
Cash provided by (used in) operating activities				
Net income	$ 15,147	$ 15,104	$ 23,593	$ 63,011
Add items not affecting cash:				
Depletion, depreciation and accretion	41,982	28,635	104,619	85,563
Commodity contracts	15,344	-	32,587	-
Future income taxes	(6,149)	(1,669)	6,365	(32,550)
Actual abandonment costs incurred *(Note 8(a))*	(1,249)	(2,199)	(3,222)	(2,535)
Internalization of management contract	-	88	-	30,850
Cash flow from operating activities	65,075	39,959	163,942	144,339
Net change in non-cash working capital balances	(2,395)	15,397	24,797	34,885
Cash provided by operating activities	62,680	55,356	188,739	179,224
Financing activities				
Bank loan	(12,989)	29,909	89,767	(22,793)
Distributions paid *(Note7)*	(47,684)	(34,650)	(121,759)	(91,077)
Redemption of exchangeable shares	(450)	(1,047)	(1,352)	(1,745)
Capital lease repayments	(90)	(971)	(264)	(2,859)
Issuance of trust units *(Note 4)*	1,642	12,439	3,351	108,151
Cash provided by (used in) financing activities	(59,571)	5,680	(30,257)	(10,323)
Investing activities				
Asset retirement reserve *(Note 8)*	(482)	(198)	(1,228)	(576)
Acquisition of property interests	(14,252)	(59,920)	(151,971)	(161,986)
Proceeds on disposition of property interests	-	5,397	-	6,013
Internalization of management contract	-	(88)	-	(8,009)
Cash used in investing activities	(14,734)	(54,809)	(153,199)	(164,558)
Net change in cash	(11,625)	6,227	5,283	4,343
Cash (bank overdraft), beginning of period	19,090	(3,456)	2,182	(1,572)
Cash, end of period	$ 7,465	$ 2,771	$ 7,465	$ 2,771

Interest paid during the period	$	2,504	$	2,585	$	3,671	$	7,020
Income taxes paid during the period	$	141	$	212	$	247	$	587

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

Notes to Interim Consolidated Financial Statements
September 30, 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.

(a) Acquisition of Ultima Energy Trust

On June 16, 2004 Petrofund Energy Trust acquired Ultima Energy Trust ("Ultima") and its wholly owned subsidiaries. After the amalgamation of Ultima Energy Inc., a subsidiary of Ultima, into Petrofund Corp. ("PC") and the wind-up of the inactive subsidiaries, the only remaining Ultima entity is Ultima Ventures Trust. The name of this entity has been changed to Petrofund Ventures Trust. The consolidated financial statements of Petrofund Energy Trust include the results of the Ultima entities effective June 17, 2004.

(b) Goodwill

Under the terms of section 1581 of the CICA handbook, goodwill must be recorded upon a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment each reporting period. Impairment is determined based on the fair value of the reporting entity (the consolidated Trust) compared to the book value of the reporting entity. Any impairment will be charged to the earnings in the period in which the fair value of the reporting entity is below the book value.

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.

Net income before income taxes for the three and nine months ended September 30, 2004 increased by $1.1 million ($657,000 after tax) and $3.0 million ($1.8 million after tax) respectively; as a result of adopting this policy, with negligible impact on net income per unit.

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

December 31, 2003 Restatement	**Net PP&E**	**Future Tax**	**ARO Liability**	**Change in Accumulated Earnings 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)
Balance, beginning of period as Restated	$ 898,263	$ 79,065	$ 34,363	$ (2,419)	$ 1,472	$198,253

(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.

All outstanding derivative instruments as of January 1, 2004, 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 are being amortized to expense over the remaining term of the contracts. The total amount of $7.6 million plus $1.4 million relating to Ultima, less $6.9 million amortized to expense in the nine months ended September 30, 2004 or $2.1 million, has been recorded as a current asset or liability on the balance sheet as deferred loss/gain on the commodity contracts at September 30, 2004. The negative fair value of the commodity contracts at September 30, 2004 of $38.1 million has been recorded on the balance sheet as "commodity contracts" under assets or liabilities, as appropriate.

The change in the fair value of the contracts from January 1, 2004 to September 30, 2004 of $25.7 million plus the amortized amount of $6.8 million is recorded in the income statement on a separate line as "gain/loss on commodity contracts". The line item also includes realized losses on commodity contracts of $28.3 million which were previously deducted from oil and natural gas sales. The comparative numbers for 2003 represent realized losses on commodity contracts which were previously netted against sales.

Deferred Hedging	Jan 1, 2004	Ultima Acquisition	Amortized to Expense	Sept. 30, 2004
Current Asset				
Deferred hedging loss	$ 8,075	$ 1,357	$ (7,167)	$ 2,265
Cost of deferred hedging	820	-	(701)	119
	8,895	1,357	(7,868)	2,384
Current Liability				
Deferred hedging gain	(1,304)	-	1,022	(282)
	$ 7,591	$ 1,357	$ (6,846)	$ 2,102

Commodity Contracts	Jan 1, 2004	Ultima Acquisition	Change in Fair Value	Sept. 30, 2004
Current Asset				
Commodity contracts	$ 1,304	$ -	$ (855)	$ 449
Current Liability				
Commodity contracts	(8,075)	(5,584)	(20,447)	(34,106)
Long-term Liability				
Commodity contracts	-		- (4,439)	(4,439)
	$ (6,771)	$ (5,584)	$ (25,741)	$ (38,096)

(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 $1.8 million in the third quarter of 2004 and $1.4 million in 2003 and $4.3 million and $4.1 million for the nine months ended September 30, 2004 and 2003 respectively. 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. ACQUISITION

Ultima Energy Trust

On June 16, 2004, Petrofund Energy Trust acquired Ultima Energy Trust for 0.442 of a Petrofund unit on a tax-free rollover basis. The value assigned to each Petrofund unit was $17.12 based on the weighted average trading price of the Trust units for the period commencing five days before and ending five days after the acquisition was announced. Petrofund issued 26.4 million Trust units which were distributed to former unitholders of Ultima.

The acquisition was accounted for using the purchase method. A summary of the estimated net assets acquired is as follows:

	$000's
Current assets	$ 23,601
Asset retirement reserve	1,549
Goodwill	176,585
Oil and gas royalty and property interests	384,987
Current liabilities	(17,791)
Long-term debt	(110,407)
Asset retirement obligations	(16,672)
Future income taxes	12,861
	$454,713

4. TRUST UNITS

Authorized: unlimited number of Trust units	Number **of units**	**$000's**
Issued		
December 31, 2003	**72,688,577**	**$1,020,677**
Issued for Ultima Energy Trust acquisition (Note 3)	**26,449,102**	**452,817**
Options exercised	**226,799**	**2,644**
Unit purchase plan	**3,979**	**63**
Unit incentive plans	36,799	634
September 30, 2004	**99,405,256**	**$1,476,835**

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

	3 months ended September 30,		**9 months ended September 30,**	
	2004	**2003**	**2004**	**2003**
Basic	100,266,733	66,142,502	84,064,168	59,364,939
Diluted	100,353,257	66,280,745	84,210,974	59,491,134

Trust units/Exchangeable Shares, at end of period**:**

For the period ended September 30,	**2004**	**2003**
Trust units outstanding	99,405,256	64,776,420
Trust units issuable on exchangeable shares	939,147	1,939,147
	100,344,403	66,715,567

5.

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 September 30, 2004, 780,094 Exchangeable Shares were outstanding, at an exchange ratio of 1.20389 per Trust unit.

Issued and Outstanding	**Number of Shares**	**$000's**
December 31, 2003	851,471	$ 10,518
Redemption of shares	(71,377)	-
Balance at end of period	780,094	10,518
Exchange ratio, end of period	1.20389	-
Trust units issuable upon conversion	939,147	$ 10,518

6. 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. The maximum on the credit facility was increased to $325 million on June 30, 2004.

7. 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
February 29	April 30 0.16		0.17
March 31	May 31 0.16		0.18
April 30	June 30 0.16		0.18
May 31	July 31 0.16		0.18
June 30	August 31	0.16	0.18
July 31	September 30	0.16	0.18
Cash distributions per Trust unit		$ 1.44	$ 1.55

Reconciliation of Distributions Accruing to Unitholders

	3 months ended September 30,		9 months ended September 30,	
	2004	2003	2004	2003
Distributions payable, beginning of period	$26,029	$60,054	$53,452	$30,065
Distributions accruing during the period				
Cash flow provided by operating activities	62,680	55,356	188,739	179,224
Net change in non-cash operating working capital balance	2,395	(15,397)	(24,797)	(34,885)
Amortization of the cost of commodity contracts	(238)	-	(701)	-
Redemption of exchangeable shares	(450)	(1,047)	(1,352)	(1,745)
Asset retirement reserve	(482)	(198)	(1,228)	(576)
Capital lease repayment	(90)	(971)	(264)	(2,859)
Cash flow before capital reinvestment	63,815	37,743	160,397	139,159
Weyburn capital lease obligations	(1)	-	(34,931)	-
Capital expenditures	(15,000)	(7,500)	(30,000)	(22,500)
Total distributions accruing during the period	48,814	30,243	95,466	116,659
Distributions paid	(47,684)	(34,650)	(121,759)	(91,077)
Distributions payable, end of period	$ 27,159	$ 55,647	$27,159 $	55,647

Accumulated Cash Distributions

	3 months ended September 30,		9 months ended September 30,	
	2004	2003	2004	2003
Accumulated cash distributions,				
Beginning of period	$ 628,709	$514,765	$ 581,155	$427,651
Distributions accruing during the period	48,814	30,243	95,466	116,659
Redemption of exchangeable shares	450	1,047	1,352	1,745
Accumulated cash distributions, end of period	$677,973	$546,055	$677,973	$546,055

8. 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 September 30,	**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, as restated	34,363	34,497
Increase in liabilities during the period	540	1,706
Accretion expense during the period	1,932	1,683
Actual costs incurred during the period	(3,222)	(2,535)
Acquisition of Ultima properties	16,672	-
Balance at end of period	$ 50,285	$ 35,351

(b) Asset Retirement Reserve Fund

Previously this cash fund was being built up at a rate of $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 September 30, 2004 is $6.6 million, which includes the addition of $1.5 million on the acquisition of Ultima.

9. LONG-TERM COMMITMENTS

In the second quarter of 2004, PC acquired an additional interest in the Weyburn unit as a part of the Ultima acquisition which resulted in an increase in CO2 purchase commitments. Subsequent to end of the quarter, PC renewed its office lease and extended the term. The table below has been updated to reflect these changes.

(thousands of dollars)	**2004**	**2005**	**2006**	**2007**	**2008**
Capital leases	$ 0.4	$ 0.6	$ -	$ -	$ -
Office lease		1.6	1.8	2.1	2.22.3
Processing and transportation agreement		1.8	1.8	2.0	2.12.2
CO2 purchases	8.8	10.6	9.3	7.9	7.5
	$ 12.6	$ 14.8	$ 13.4	12.2	$ 12.0

10. 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 gas production. These include fixed price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments and related contracts as at September 30, 2004 and the related unrealized gains or losses are summarized separately below:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery Point	Unrealized Gain (Loss) $000's
Collar	April 1, 2004 to October 31, 2004	9,475	$5.17-$7.28	AECO	$ -
Collar	April 1, 2004 to October 31, 2004	9,475	$5.07-$6.81	AECO	-
Collar	April 1, 2004 to October 31, 2004	1,895	$5.28-$7.39	AECO	-
Fixed	April 1, 2004 to October 31, 2004	4,737	$5.33	AECO	(50)
Fixed	April 1, 2004 to October 31, 2004	4,737	$6.26	AECO	84
Collar	April 1, 2004 to October 31, 2004	1,895	$5.28-$7.65	AECO	-
Fixed	May 1, 2004 to October 31, 2004	4,737	$6.86	AECO	166
Three Way Collar	November 1, 2004 to March 31, 2005	9,475	$4.74-$5.80-$8.97	AECO	(1,040)
Collar	November 1, 2004 to March 31, 2005	9,475	$6.23-$10.82	AECO	(406)
Collar	November 1, 2004 to March 31, 2005 to	9,475	$6.23-$14.67	AECO	(32)
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	(39)
Total		$(1,317)			

Oil	Term	Volume bbl/d	Price $/bbl	Delivery Point	Unrealized Loss $000's
Fixed Price	January 1, 2004 to December 31, 2004	1,000	$35.01	Edmonton $	(2,469)
Fixed Price	July 1, 2004 to December 31, 2004	1,000	$36.27	Edmonton	(2,339)
Three Way Collar	January 1, 2004 to December 31, 2004	800	$25.23-$30.28-$34.57	Edmonton	(1,986)
Three Way Collar	January 1, 2004 to December 31, 2004	700	$26.49-$31.54-$37.85	Edmonton	(1,535)
Three Way Collar	July 1, 2004 to December 31, 2004	2,000	$26.83-$30.61-$36.59	Edmonton	(5,824)
Collar	October 1, 2004 to December 31, 2004	2,000	$30.28-$35.32	Edmonton	(4,851)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	$25.23-$30.28-$36.59	Edmonton	(7,113)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	$30.04-$33.82-$42.65	Edmonton	(5,076)
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	$28.76-$33.81-$41.39	Edmonton	(5,400)
Collar	January 1, 2005 to March 31, 2005	1,000	$49.20-$61.82	Edmonton	(243)
Three Way Collar	April 1, 2005 to June 30, 2005	1,000	$44.15-$50.46	Edmonton	(141)
Total		$(36,977)			

The oil hedges are transacted in U.S. dollars. They have been converted to Canadian dollars at the September 30, 2004 closing rate of $1.2616 C$:US$.

Electricity	Term	Volume MW/h	Price $/MWh	Delivery Point	Unrealized Gain $000's
Fixed Price	February 1, 2004 to December 31, 2005	2.0	$44.5	Alberta Power Pool	$189
Fixed Price	January 1, 2004 to December 31, 2004	1.0	$51.0	Alberta Power Pool	10
Total		$199			

Derivative financial instruments and physical hedge contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counterparties. 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 product sales.

11. SUBSEQUENT EVENT

On October 13, 2004, Petrofund announced that it is holding a special meeting of unitholders to consider, and if thought fit, approve amendments to its trust indenture that would provide for a reclassification of its trust unit capital (the "Reclassification"). Under the Reclassification, existing units of the Trust will be reclassified into Class R Units, which can only be held by Canadian residents, and Class N Units, which will contain no residency restrictions. Unitholders will also be asked to consider other amendments to Petrofund's trust indenture at the special meeting

The Reclassification is aimed at enhancing the Trust's ability to regulate non-resident ownership of units to ensure the Trust continues to qualify as a mutual fund trust under the Income Tax Act (Canada) (the "Tax Act"), while maintaining active markets for the units and the ability to raise capital in Canada and the United States.

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 that 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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