PETROFUND ENERGY TRUST
Form 6-K
August 12, 2005

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: August 2005

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: August 9, 2005

By:

signed "Hugo S^{t}J. A. Potts"

Hugo S^{t}J. A. Potts, Esq.

Corporate Secretary

EXHIBIT

Exhibit	Description of Exhibit
1.	**Second Quarter Report dated August 9, 2005.**

EXHIBIT 1

News Release

Calgary -August 9th, 2005

CALGARY -October 5, 2004

Petrofund Energy Trust (*TSX: PTF.UN; AMEX: PTF*)

Announces Results for the Second Quarter of 2005

Petrofund Energy Trust is pleased to provide its results for the second quarter of 2005. Key items from the quarter include:

-

Average production for the second quarter was 36,011 boe per day, a 28% increase over the second quarter of last year.

-

Cash flow increased 76% over the second quarter of 2004 to $87.8 million. On a per unit basis, cash flow increased 34% to from $0.64 to $0.86.

-

Second quarter payout ratio was 56%, compared to 80% in the second quarter of 2004 and 67% in the first quarter of 2005.

-

Operating costs for the quarter, which include a prior period adjustment of $1.01 per boe, increased to $10.89 per boe due to increasing industry costs. This was an 18% increase over the second quarter of last year.

-

Net income increased from $817,000 in the second quarter of 2004 to $40.2 million in the second quarter of 2005, which equates to a per unit increase from $0.01 to $0.40.

-

General and administrative costs were down 8% from last year to $1.19 per boe.

-

The Trust exited the quarter with a 0.9:1.0 net debt to cash flow ratio based on annualized second quarter cash flow.

-

Second quarter development capital was $30.6 million with an over all drilling success rate of 96%.

Petrofund's second quarter report is presented below:

2nd Quarter Report

for three & six months ended June 30, 2005 & 2004

FINANCIAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

	3 months ended June 30,			6 months ended June 30,		
	2005	2004	**Variance**	2005	2004	**Variance**
INCOME STATEMENT						
Oil and natural gas sales (5)	$ 172,831	$ 112,970	53%	$ 327,599	$ 212,669	54%
Cash flow (1)	$ 87,811	$ 49,820	76%	$ 160,770	$ 98,867	63%
Per unit (2)	$ 0.86	$ 0.64	34%	$ 1.59	$ 1.30	22%
Per boe	$ 26.80	$ 19.52	37%	$ 24.93	$ 19.88	25%
Cash distributions paid per unit	$ 0.48	$ 0.48	-%	$ 0.96	$ 0.96	-%
Net income	$ 40,193	$ 817	4,821%	$ 59,436	$ 8,446	604%
Net income per unit						
Basic	$ 0.40	$ 0.01	3,900%	$ 0.59	$ 0.11	436%
Diluted	$ 0.40	$ 0.01	3,900%	$ 0.59	$ 0.11	436%
UNITS AND EXCHANGEABLE SHARES OUTSTANDING (2)						
Weighted average	101,569	78,074	30%	101,088	75,874	33%
Diluted	101,593	78,229	30%	101,121	76,051	33%
At period-end	105,014	100,190	5%	105,014	100,190	5%
BALANCE SHEET						
Working capital (deficit) (3)				$ (47,812)	$ (30,955)	(55)%
Property, plant and equipment, net				$ 1,306,761	$ 1,251,484	4%
Long-term debt				$ 254,345	$ 212,537	20%
Unitholders' equity				$ 1,034,115	$ 1,063,704	1%
MARKET CAPITALIZATION, as at June 30				$ 2,047,767	$ 1,487,823	38%

TOTAL CAPITALIZATION, as at June 30 (3),(4)				$ 2,349,924	$ 1,731,615	36%
TRUST UNIT TRADING (TSX: PTF.UN)						
High	$ 19.97	$ 18.08	10%	$ 19.97	$ 19.24	4%
Low	$ 17.00	$ 14.70	16%	$ 15.50	$ 14.56	6%
Close	$ 19.50	$ 14.85	31%	$ 19.50	$ 14.85	31%
Average daily volumes	176	189	(7)%	219	197	12%
TRUST UNIT TRADING (AMEX: PTF)						
High	$ 16.25	$ 13.54	20%	$ 15.92	$ 14.96	9%
Low	$ 13.62	$ 10.95	24%	$ 12.66	$ 10.95	16%
Close	$ 15.92	$ 11.16	43%	$ 15.92	$ 11.16	43%
Average daily volumes	469	319	47%	554	477	16%

(1)

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

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

(2)

See Note 3 to Interim Consolidated Financial Statements.

(3)

Excludes net unrealized gains/losses on commodity contracts.

(4)

Total capitalization equals market capitalization plus net debt.

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

(5)

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

FINANCIAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

	3 months ended June 30,			6 months ended June 30,		
	2005	2004	**Variance**	2005	2004	**Variance**
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(4)

Total capitalization equals market capitalization plus net debt.

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

(5)

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

OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

	3 months ended June 30,			**6 months ended June 30,**		
	2005	**2004**	**Variance**	**2005**	**2004**	**Variance**
DAILY PRODUCTION						

Oil (bbls)	17,500	12,679	38%	17,867	12,129	47%
Natural gas (mcf)	96,951	79,741	22%	92,635	78,833	18%
Natural gas liquids (bbls)	2,353	2,074	13%	2,318	2,057	13%
BOE (6:1)	36,011	28,043	28%	35,624	27,325	30%
Total production (mboe)	3,277	2,552	28%	6,448	4,973	30%
PRODUCTION PROFILE						
Oil	49%	45%		50%	44%	
Natural gas	44%	48%		43%	49%	
Natural gas liquids	7%	7%		7%	7%	
PRICES (5)						
Oil (per bbl)	$ 59.18	$ 47.01	26%	$ 56.93	44.86	27%
Natural gas (per mcf)	$ 7.65	$ 7.13	7%	$ 7.33	6.95	5%
Natural gas liquids (per bbl)	$ 51.10	$ 37.13	38%	$ 48.62	37.09	31%
BOE (6:1)	$ 52.69	$ 44.27	19%	$ 50.77	$ 42.75	19%
Cash operating netback per BOE	$ 29.28	$ 22.05	33%	$ 27.39	$ 22.38	22%
LEASE OPERATING COSTS	$ 35,677	$ 23,639	(51)%	$ 67,687	$ 43,468	(56)%
Cost per boe	$ 10.89	$ 9.26	(18)%	$ 10.50	$ 8.74	(20)%
GENERAL AND ADMINISTRATIVE COSTS	$ 3,902	$ 3,316	(18)%	$ 7,541	$ 6,454	(17)%
Cost per boe	$ 1.19	$ 1.30	8%	$ 1.17	$ 1.30	10%

Management Discussion & Analysis

three and six months ended June 30, 2005

The following Management Discussion and Analysis ("MD&A") of financial results should be read in conjunction with the unaudited Consolidated Financial Statements of Petrofund Energy Trust ("Petrofund" or the "Trust") for the six months ended June 30, 2005 and the December 31, 2004 audited Consolidated Financial Statements and Management's Discussion and Analysis included in the Trust's 2004 annual report. All oil and natural gas properties are held by Petrofund Corp. ("PC") a wholly owned subsidiary of the Trust. This commentary is based on information available to August 9, 2005. Additional information (including Petrofund's annual information form) can be obtained on SEDAR at www.sedar.com or on the Trust's website at www.petrofund.ca.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent ("boe") basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel (6 mcf/bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 mcf/1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON GAAP MEASURES

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 generally accepted accounting principles ("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 from operating activities before changes in non-cash working capital.

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

FORWARD-LOOKING STATEMENTS

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof affecting the economic performance of the

Trust. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

RESULT SUMMARY

SECOND QUARTER 2005 VERSUS FIRST QUARTER 2005

The Trust generated cash flow of $87.8 million or $0.86 per unit in the second quarter of 2005 compared to $73.0 million or $0.73 per unit in the first quarter of 2005. The Trust maintained monthly cash distributions of $0.16 per unit in the second quarter of 2005. The Trust's payout ratio of 56% in the second quarter of 2005 compared to payout ratio of 67% in the first quarter of 2005.

The second quarter of 2005 was an active quarter for Petrofund in property acquisitions, plus drilling and development activities. Total expenditures for the quarter were $104.1 million. These activities provide new production in the second quarter and for the third and fourth quarters of 2005, as discussed further in the Operational Highlights.

The Trust completed an equity offering raising gross proceeds of $75.7 million ($71.5 million net) in the second quarter of 2005. A total of 4,150,000 units were issued at $18.25 per unit.

Daily production volumes in the second quarter of 2005 of 36,011 boe were slightly above the first quarter volumes of 2005 of 35,234 boe. This increase resulted from acquisitions and development activities for the first and second quarters of 2005 offset by the natural production decline.

Net income of $40.2 million in the second quarter of 2005 increased from $19.2 million in the first quarter of 2005, mainly due to a change of $33.6 million in non-cash adjustments on commodity contracts. The Trust recognized an unrealized (non-cash) commodity gain of $9.7 million versus an unrealized (non-cash) commodity loss of $23.8 million in the first quarter of 2005. Both adjustments were a result of the accounting standard governing price risk management activity. In addition, the future income tax expense in the second quarter of 2005 was $10.4 million compared to $12.7 million recovery in the first quarter of 2005.

The cash loss on commodity contracts during the second quarter of 2005 was $8.0 million compared to an $8.2 million loss in the first quarter of 2005.

Royalties were 18% of revenue in the second quarter of 2005, compared to 20% for the three months ended March 31, 2005.

Lease operating costs on a unit basis increased to $10.89/boe in the second quarter of 2005 from $10.09/boe in the first quarter of 2005. Costs for repairs and maintenance continue to increase as a result of high levels of activity in the upstream sector. In addition, Petrofund incurred costs of $3.3 million or $1.01/boe from prior years' adjustments which includes a $1.0 million adjustment to processing fees for the years 2002 through 2004 from a partner operated facility.

HIGHLIGHTS OF THE THREE AND SIX MONTHS ENDED JUNE 30, 2005

The Trust paid out cash distributions of $0.48 per unit in the second quarter of 2005 as compared to $0.48 per unit in the second quarter of 2004.

The Trust's payout ratio for the six months ended June 30, 2005 was 61% compared to 77% in 2004. The payout ratio in the second quarter of 2005 was 56% compared to 80% in the same quarter of 2004.

Net income increased to $40.2 million in the second quarter of 2005 versus $817,000 in the second quarter of 2004.

The Trust generated cash flow of $87.8 million, an increase of 76% over the second quarter of 2004.

Average production on a boe basis increased 28% to 36,011 boe/d in the second quarter of 2005 from 28,043 boe/d in the second quarter of 2004. The change in production reflects the acquisition of Ultima Energy Trust ("Ultima") in June of 2004, PC's development drilling program, the Central Alberta acquisition in November 2004 and the 2005 acquisitions listed later in this section, offset by natural production decline.

Average prices in the second quarter of 2005 were up 19% on a boe basis from the same period the prior year and 19% on a boe basis for the six months ending June 30, 2005 compared to the same period in 2004.

Petrofund has a strong balance sheet with a net debt to cash flow ratio of 0.9:1.0 of annualized second quarter 2005 cash flow.

To date in 2005, Petrofund has acquired interests in various oil and gas properties for $62.6 million (excluding the non-cash working capital assumed of $4.8 million, future income taxes of $10.4 million and asset retirement obligations of $1.2 million), which includes the purchase of Northern Crown Petroleums Ltd. ("Northern Crown"), Tahiti Gas Ltd. ("Tahiti") and property interests in the Turin area. These acquisitions are expected to add approximately 1,365 boepd of production to the Trust. Petrofund's internal estimate of reserves additions is 4.0 million boe on a proved plus probable basis.

The Trust completed a "bought deal" financing of Trust units, raising gross proceeds of $75.7 million ($71.5 million net) in the second quarter of 2005.

The Trust has a balanced production profile which averaged 43% natural gas and 57% oil and liquids in the first half of 2005.

The weighted average Trust units outstanding increased from 78.1 million in the second quarter of 2004 to 101.6 million in the second quarter of 2005. As at June 30, 2005 there was 105.0 million Trust units outstanding.

The Trust market capitalization as at June 30, 2005, was approximately $2.0 billion ($1.5 billion June 30, 2004).

OPERATIONAL HIGHLIGHTS

Petrofund continued with its aggressive drilling program in the second quarter of 2005. In spite of adverse weather conditions, a total of 48 wells were drilled, comprising 46 working interest wells (14.7 net) and two farmout wells. This activity resulted in 30 oil wells, 16 gas wells and two abandoned wells for an overall success rate of 96%.

Significant second quarter activity included the following projects:

July Lake, British Columbia

Petrofund equipped and pipeline connected four 100% owned gas wells drilled earlier this year. Production from these new drills averaged 4.3 mmcf/d for the quarter.

Turin, Alberta

Petrofund drilled four wells during the quarter, resulting in two gas wells, one oil well and one dry hole. Two of these three wells (one gas well is yet to be equipped), together with four other wells drilled in the first quarter, are producing 150 boe/d net to Petrofund's production base.

Weyburn, Saskatchewan

A total of 10 wells (2.0 net) were drilled in the Weyburn Unit during the quarter, the majority of these within the carbon dioxide flood area. Petrofund's net incremental production from these new wells is approximately 200 boe/d.

Armisie, Alberta

Approximately 400 boe/d of production from this area was restored during the second quarter after it had been shut-in for most of the first quarter due to capacity restrictions at a third party gas processing facility.

Three Hills Creek, Alberta

Petrofund drilled a 100% working interest gas well in the second quarter but wet weather delayed completion and tie-in of the well until the third quarter. This well is expected to produce approximately 1 mmcf/d. In addition, Petrofund increased production by an incremental 750 mcf/d through its 35% working interest in a 28 well coalbed methane gas project that commenced production in the second quarter.

Silverton, Saskatchewan

Petrofund, as operator, drilled a successful horizontal Frobisher oil well that is expected to come on stream in the third quarter at approximately 30 boe/d net.

Swan Hills, Alberta

Six infill oil wells (0.7 net) were drilled in the Swan Hills Unit #1 during the second quarter. Based on initial test rates, these six new wells, plus a seventh well drilled earlier, boosted Petrofund's production by 100 boe/d net.

Brassey, British Columbia

Four successful gas wells (0.6 net) were drilled and completed on Petrofund lands during the quarter. These wells are scheduled to start producing in the third quarter and, in total, are expected to add 600 mcf/d net to Petrofund's production.

Dodsland, Saskatchewan

Three 100% working interest Viking gas wells were drilled and cased during the quarter, but wet weather delayed completion until the third quarter. It is expected that these wells will collectively produce 750 mcf/d.

CASH DISTRIBUTIONS

	3 months ended June 30,		**6 months ended June 30,**	
	2005	**2004**	**2005**	**2004**
Distributions paid per unit	$ 0.48	$ 0.48	$ 0.96	$ 0.96

Trust unitholders who held their units throughout the second quarter of 2005 received cash distributions of $0.48 per unit as compared to $0.48 per unit in 2004. For 2005 the Trust distributed $0.16 per unit in July, has announced $0.16 per unit for August, and has indicated $0.16 per unit for September.

Petrofund monitors the distribution payout with respect to forecasted funds flow, debt levels and spending plans. The level of cash retained historically has varied between 10% and 30% of annual funds flow; however, Petrofund adjusts payout levels in an effort to balance the investor's desire for near-term distributions with the Trust's requirement to maintain a prudent capital structure.

The Trust generated cash flow available for distribution before reserve for capital expenditures in the second quarter of 2005 of $86.9 million (2004 - $48.7 million). The Trust paid out $48.8 million (2004 - $39.2 million) in distributions representing a payout ratio of 56% (2004 -80%).

During the six months ended June 30, 2005 the Trust generated cash flow available for distribution before reserve for capital expenditures of $158.6 million (2004 - $96.6 million). The Trust paid out $96.7 million (2004 - $74.1 million) in distributions representing a payout ratio of 61% (2004 - 77%).

For the 12 months ended June 30, 2005, the Trust generated cash flow available for distribution of $293.6 million, and allocated $60.0 million for investment in development drilling and other projects.

Distributions of $192.3 million were paid out, representing a payout ratio of 65%. For a detailed analysis of cash flow available for distribution and distributions paid refer to Note 8 to the Interim Consolidated Financial Statements.

CASH DISTRIBUTION PAID HISTORY (1)

Calendar Year	**Distributions** (2)	**Taxable Portion**	**Return of Capital**
1989 to 1996	$ 20.8950	$ -	$ 20.8950
1997	2.3700	-	2.3700
1998	1.4400	-	1.4400
1999	1.8300	-	1.8300
2000	3.9900	2.4633	1.5267
2001	4.2400	2.6771	1.5629
2002	1.7100	0.9365	0.7735
2003	2.0900	1.0706	1.0194
2004	1.9200	1.4849	0.4351
2005 Y-T-D	0.9600 (3)	0.9120	0.0480
Cumulative	**$ 41.4450**	**$ 9.5444**	**$ 31.9006**

(1)

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

(2)

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

(3)

Petrofund estimates that approximately 95% of cash distributions paid in 2005 to Canadian and U.S. unitholders will be taxable and the remaining 5% will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow experienced throughout the year.

For U.S. taxpayers, the taxable portion of the cash distribution is considered to be a dividend for U.S. tax purposes and it is expected that the dividend should be a "Qualified Dividend" eligible for the reduced tax rate.

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

Taxation of Cash Distributions

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

RESULTS OF OPERATIONS

PRODUCTION

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

Production volumes averaged 36,011 boe/d in the second quarter of 2005, an increase of 28% over average production volumes of 28,043 boe/d in the second quarter of 2004. The change in production reflects the acquisition of Ultima in June of 2004, PC's development drilling program, the Central Alberta acquisition in November 2004, Turin area in January 2005 and the Northern Crown and Tahiti acquisitions in May 2005, offset by natural production decline.

13

	3 months ended June 30,		6 months ended June 30,	
Daily Production	**2005**	**2004**	**2005**	**2004**
Oil (bbls)	17,500	12,679	17,867	12,129
Natural gas (mcf)	96,951	79,741	92,635	78,833
Natural gas liquids (bbls)	2,353	2,074	2,318	2,057
Total (boe 6:1)	36,011	28,043	35,624	27,325

PRICING AND PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 53% to $172.8 million in the second quarter of 2005 from $113.0 million in the second quarter of 2004 due to a 28% increase in production and a 19% increase in prices on a boe basis.

For the six month period ended June 30, 2005, revenue increased 54% to $327.6 million from $212.7 million in 2004 due to a 30% increase in production to 35,624 boe/d and an increase of 19% in the average price per boe to $50.77 in 2005 from $42.75 in 2004.

Crude oil sales increased to $94.2 million in the second quarter of 2005 from $54.2 million in the second quarter of 2004 due to a 38% increase in production from 12,679 bbl/d in the second quarter of 2004 to 17,500 bbl/d in the second quarter of 2005 and a 26% increase in the oil price. The average WTI oil price increased from $38.31 US/bbl in 2004 to $53.20 US/bbl in the second quarter of 2005 or 39%, however, the Canadian par price at Edmonton increased only 30% from $50.61/bbl to $65.76/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged $0.80 in the second quarter of 2005 versus $0.74 in the second quarter of 2004. The average Canadian wellhead price received by Petrofund increased from $47.01/bbl in the second quarter of 2004 to $59.18/bbl in the second quarter of 2005. Petrofund's differential from Edmonton par was $3.60/bbl in the second quarter of 2004 versus $6.58/bbl in the second quarter of 2005 as quality differentials for medium crudes have increased.

During the six month period ended June 30, 2005, crude oil sales increased 86% to $184.1 million in 2005 from $99.0 million in 2004. Oil production increased 47% to 17,867 bbl/d for the period, compared to 12,129 bbl/d for the same period in 2004. The average price increased from $44.86/bbl in 2004 to $56.93/bbl in 2005. The WTI U.S. price increased from $36.73 US/bbl for six months ending June 30, 2004 to $51.52 US/bbl in the same period in 2005.

Natural gas sales increased to $67.5 million in the second quarter of 2005 from $51.7 million in the second quarter of 2004 due to 22% increase in production and a 7% increase in the average prices received from $7.13/mcf in the second quarter of 2004 to $7.65/mcf in the second quarter of 2005. The monthly AECO price per mmbtu increased from $6.80 in the second quarter of 2004 to $7.37 in the second quarter of 2005. Production volumes averaged 97.0 mmcf/d in the second quarter of 2005 compared to 79.7 mmcf/d in the second quarter of 2004.

During the six month period ended June 30, 2005, natural gas sales increased 23% to $122.9 million in 2005 from $99.7 million in 2004. Natural gas production increased 18% from 78.8 mmcf/d in 2004 to 92.6 mmcf/d in 2005. The average price increased 5% from $6.95/mcf in 2004 to $7.33/mcf in 2005.

Sales of natural gas liquids and sulphur increased to $11.1 million in the second quarter of 2005 from $7.0 million in the second quarter of 2004 as natural gas liquids production increased 13% to 2,353 bbl/d in the second quarter of 2005 from 2,074 bbl/d in the second quarter of 2004. The average price, excluding sulphur, increased 38% from $37.13/bbl in the second quarter of 2004 to $51.10/bbl in the second quarter of 2005.

For the six month period ended June 30, 2005, sales of natural gas liquids and sulphur increased 47% from $14.0 million in 2004 to $20.6 million in 2005. Production volumes of natural gas liquids increased 13% from 2,057 bbl/d to 2,318 bbl/d, and the average price, excluding sulphur, increased 31% from $37.09/bbl in 2004 to $48.62/bbl in 2005.

	3 months ended June 30,		**6 months ended June 30,**	
Average Prices (1)	**2005**	**2004**	**2005**	**2004**
Oil (per bbl)	$ 59.18	$ 47.01	$ 56.93	$ 44.86
Natural gas (per mcf)	7.65	7.13	7.33	6.95
Natural gas liquids (per bbl)	51.10	37.13	48.62	37.09
Weighted average (6:1)	$ 52.69	$ 44.27	$ 50.77	$ 42.75

Production Revenue ($ millions) [1]	3 months ended June 30, 2005	3 months ended June 30, 2004	6 months ended June 30, 2005	6 months ended June 30, 2004
Oil	$ 94.2	$ 54.2	$ 184.1	$ 99.0
Natural gas	67.5	51.7	122.9	99.7
Natural gas liquids & sulphur	11.1	7.0	20.6	14.0
Total	$ 172.8	$ 112.9	$ 327.6	$ 212.7

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

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

As at June 30, 2005, Petrofund had 22.9 mmcf/d of natural gas and 5,000 bbl/d of crude oil hedged for remainder of 2005 and 6.3 mmcf/d of natural gas and 2,750 bbl/d of crude oil hedged for 2006. A summary of the hedged volumes and prices by quarter is shown in the following table (see Note 9 to the Interim Consolidated Financial Statements for a detailed disclosure of all derivative financial instruments and their corresponding mark-to-market values):

Average Volumes (mcf/d)

Natural Gas	2005	2005 Q3	2005 Q4	2006	2006 Q1	2006 Q2	2006 Q3	2006 Q4
Fixed	2,369	4,737	-	-	-	-	-	-
Collars	14,211	18,948	9,474	1,184	4,737	-	-	-
Three way collars	6,316	4,737	7,895	5,132	9,474	4,737	4,737	1,579
Total mcf/d	**22,896**	**28,422**	**17,369**	**6,316**	**14,211**	**4,737**	**4,737**	**1,579**

Average Prices ($/mcf)

	2005	2005 Q3	2005 Q4	2006	2006 Q1	2006 Q2	2006 Q3	2006 Q4
Fixed price	$ 7.06	$ 7.06	$ -	$ -	$ -	$ -	$ -	$ -
Collar ceiling price	10.36	8.73	11.98	13.61	13.61	-	-	-
Collar floor price	6.65	6.33	6.96	7.28	7.28	-	-	-
Three way ceiling price	9.21	7.92	10.49	9.92	11.77	8.99	8.99	8.99
Three way floor price	6.04	5.80	6.28	7.10	6.52	7.39	7.39	7.39
Three way floor short	$ 4.99	$ 4.75	$ 5.23	$ 5.87	$ 5.47	$ 6.07	$ 6.07	$ 6.07

16

	Average Volumes (bbl/d)							
	2005			2006				
Oil	**2005**	**Q3**	**Q4**	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Collared	1,000	1,000	1,000	2,250	3,000	3,000	2,000	1,000
Three way collars	4,000	4,000	4,000	500	1,000	1,000	-	-
Total bbl/d	**5,000**	**5,000**	**5,000**	**2,750**	**4,000**	**4,000**	**2,000**	**1,000**

17

	Average Prices ($ /bbl)							
	2005			2006				
Oil	2005	**Q3**	**Q4**	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Collar ceiling price	$ 72.61	$ 72.83	$ 72.38	$ 83.28	$ 81.18	$ 86.19	$ 86.09	$ 79.65
Collar floor price	50.55	50.77	50.33	59.69	55.96	60.25	61.27	61.27
Three way ceiling price	47.39	47.39	47.39	68.78	64.95	72.60	-	-
Three way floor price	35.75	35.75	35.75	50.25	49.02	51.47	-	-
Three way floor short	$ 30.97	$ 30.97	$ 30.97	$ 44.12	$ 42.89	$ 45.34	$ -	$ -

	2005			2006				
Alberta Power	2005	**Q3**	**Q4**	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Fixed MW/h	2.0	2.0	2.0	-	-	-	-	-

Fixed price ($/MWh)	$ 44.50	$ 44.50	$ 44.50	$ -	$ -	$ -	$ -	$ -

Three-way Collars

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

After June 30, 2005 and as at August 9, 2005, Petrofund had entered into the following additional hedges (not included in the table above):

1)

Collar for November 1, 2005 to March 31, 2006 for 4.7 mmcf/d of natural gas between $7.39/mcf and $16.14/mcf.

2)

Collar for April 1, 2006 to October 31, 2006 for 4.7 mmcf/d of natural gas between $7.39/mcf and $10.55/mcf.

3)

Collar for January 1, 2006 to March 31, 2006 for 1,000 bbl/d of crude (WTI) between $61.27/bbl and $98.03/bbl.

4)

Collar for April 1, 2006 to June 30, 2006 for 1,000 bbl/d of crude (WTI) between $61.27/bbl and $99.26/bbl.

5)

Collar for July 1, 2006 to September 30, 2006 for 1,000 bbl/d of crude (WTI) between $61.27/bbl and $98.95/bbl.

Petrofund has no volumes hedged after December 31, 2006. All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate at the close on June 30, 2005 of CDN $1.2254:US$.

GAIN (LOSS) ON COMMODITY CONTRACTS ($ thousands)

	3 months ended June 30,		6 months ended June 30,	
	2005	**2004**	**2005**	**2004**
Realized cash losses	$ (8,023)	$ (8,888)	$ (16,189)	$(13,788)
Change in fair value				
Fair value, beginning of period	(35,090)	(16,901)	(11,318)	(6,771)
Fair value of Ultima contracts required	-	(5,584)	-	(5,584)
Less fair value, end of period	(25,262)	(24,970)	(25,262)	(24,970)
Change in fair value of financial instruments	9,828	(2,485)	(13,944)	(12,615)
Amortization of deferred commodity contracts	(91)	(2,167)	(150)	(4,628)
Total non-cash adjustments	9,737	(4,652)	(14,094)	(17,243)
Total	$ 1,714	$ (13,540)	$(30,283)	$ (31,031)

ROYALTIES

	3 months ended June 30,		6 months ended June 30,	
	2005	**2004**	**2005**	**2004**
Royalties ($ millions)	$ 31.1	$ 23.0	$ 63.0	$ 41.6
Average royalty rate (%)	18	20	19	20
$/boe	$ 9.49	$ 9.02	$ 9.76	$ 8.36

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $31.1 million in the second quarter of 2005 from $23.0 million in the second quarter of 2004, net of the Alberta Royalty Credit ("ARC"). Royalties, as a percentage of revenues before hedging losses, decreased to 18% of revenues in the second quarter of 2005 from 20% of revenues in the second quarter of 2004.

For the six months period ended June 30, 2005 royalties were 19% in 2005 compared to 20% in 2004. We expect royalties to remain at approximately 20% of oil and gas sales for the remainder of the year.

EXPENSES

	3 months ended June 30,		6 months ended June 30,	
	2005	**2004**	**2005**	**2004**
Expenses ($ millions)				
Lease operating	$ 35.7	$ 23.6	$ 67.7	$ 43.5
Transportation	1.9	1.2	3.9	2.5
General & administrative	3.9	3.3	7.5	6.5

Financing costs	2.6	1.2	4.7	2.1

Expenses per boe				
Lease operating	$ 10.89	$ 9.26	$ 10.50	$ 8.74
Transportation	0.58	0.45	0.61	0.50
General & administrative	1.19	1.30	1.17	1.30
Financing costs	0.79	0.46	0.73	0.42

Lease Operating

Oil and gas lease operating expenses increased 51% to $35.7 million in the second quarter of 2005 from $23.6 million in the second quarter of 2004 due to a 28% increase in production and an 18% increase in costs on a boe basis. Operating costs on a boe basis increased to $10.89 in the second quarter of 2005 from $9.26 in the second quarter of 2004. Costs in the second quarter of 2005 include prior years' adjustments of $3.3 million or $1.01 per boe.

Operating costs for the six month period ended June 30, 2005 were up 20% to $10.50 per boe compared to $8.74 per boe in the prior year. Costs for repairs and maintenance continue to increase as a result of high level of activity in the upstream sector. In addition, Petrofund incurred costs of $5.9 million or $0.91 per boe from prior years' adjustments.

The most significant contributor to the higher per unit operating costs to date in 2005 has been a general industry increases for all types of services and supplies including surface and downhole well repair and maintenance costs and facility maintenance work. In addition, the current high product price environment is driving average operating costs higher because marginal, higher cost properties continue to generate positive cash flow at higher than historical per unit costs and, as a result, remain on production longer. Operating costs in the second half of 2005 are expected to remain above $10.00 per boe.

Transportation Costs

Transportation costs on a boe basis were $0.58 in the second quarter of 2005 as compared to $0.45 for the second quarter of 2004, which reflects the higher transportation costs associated with the Ultima properties.

Transportation costs on a boe basis were $0.61 in the six months ending June 30, 2005 as compared to $0.50 for the six months ending June 30, 2004, which reflects the higher transportation costs associated with the Ultima properties.

General & Administrative ("G&A")

G&A costs on a boe basis were $1.19 per boe in the second quarter 2005 as compared to $1.30 per boe in the same period 2004. General and administrative costs, net of overhead recoveries, increased to $3.9 million in 2005 from $3.3 million in 2004. G&A costs in the second quarter of 2005 included $101,000 directly relating to the external costs associated with compliance with Section 404 of the Sarbanes-Oxley Act ("SOX 404") which equates to $0.03 per boe.

General and administrative costs for the six month period ended June 30, 2005, were $7.5 million in 2005 compared to $6.5 million in 2004. Costs were down 10% to $1.17 per boe compared to $1.30 per boe in 2004. We are maintaining our G&A cost target of approximately $1.25/boe for 2005.

Financing Costs

Financing costs and increases in loan balances as noted below reflects PC's active property acquisitions, plus drilling and development activities.

Interest and other financing costs increased to $2.6 million in the second quarter of 2005 from $1.2 million in the second quarter of 2004 due to the increase in the average loan balance outstanding in the second quarter of 2005 was $275.8 million versus $130.7 million in the second quarter of 2004.

Interest and other financing costs for six months ended June 30, 2005, increased to $4.7 million in 2005 compared to $2.1 million in 2004, which reflects the increase in the average loan balance outstanding in 2005 of $254.5 million from $110.3 million in 2004.

The bank loan outstanding at June 30, 2005, was $254.3 million as compared to $214.4 million at December 31, 2004. At June 30, 2005, 100% of our debt was based on floating interest rates.

DEPLETION, DEPRECIATION & ACCRETION

Depletion, depreciation and accretion expense increased to $47.2 million in the second quarter of 2005 from $33.1 million in the second quarter of 2004 due to the increase in production and an increase in the depletion rate. The rate per boe increased to $14.41 in the second quarter of 2005 from $12.97 in the second quarter of 2004. The

increase in the rate over 2004 and into 2005 reflects the increasing cost of acquisitions. Unproved properties are included in the depletion and depreciation expense calculation.

The provision for depletion, depreciation and accretion for the six months ended in June 30, 2005, was $90.9 million or $14.10 per boe as compared to $62.6 million or $12.60 per boe for 2004.

INCOME TAXES

Current taxes consist of the Federal Large Corporations Tax and some minor amounts relating to income taxes of corporate entities acquired. The Federal Large Corporations Tax is based primarily on the debt and equity balances of the Trust's 100% owned subsidiary, PC as at June 30, 2005. The Federal Large Corporations Tax rate is being reduced in stages over a period of five years, so that by 2008, the tax will be eliminated.

Capital taxes of $1.4 million in the second quarter of 2005 (2004 - $919,000) are primarily the Saskatchewan Capital Tax and Resource Surcharge, which is based upon gross revenues earned in Saskatchewan. On March 23, 2005, Saskatchewan Finance passed its 2005 budget that included an amendment to subject Trusts to the Corporation Capital Tax Resources Surcharge ("Resource Surcharge") effective April 1, 2005. Previously, the resource surcharge did not apply to resource trusts and therefore Petrofund Ventures Trust ("PVT"), a 100% owned subsidiary of the Trust, was not previously impacted by the resource surcharge. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan at a rate of 3.6 percent on revenue from wells drilled prior to October 1, 2002 and a rate of two percent on revenue from wells drilled on or after October 1, 2002. PVT has estimated that cash flow will be reduced by approximately $500,000 per quarter, commencing in the second quarter of 2005.

Future income tax liabilities arise due to the differences between the tax basis of PC's assets and their respective accounting carrying cost. The future income tax expense in the second quarter of 2005 was $10.4 million compared to $12.1 million expense in the second quarter of 2004 as a result of a decrease in the statutory rate.

NET INCOME

	3 months ended June 30,		**6 months ended June 30,**	
	2005	**2004**	**2005**	**2004**
Net income ($000's)	$ 40,193	$ 817	$ 59,436	$ 8,446
Net income per Trust unit				
Basic	$ 0.40	$ 0.01	$ 0.59	$ 0.11
Diluted	$ 0.40	$ 0.01	$ 0.59	$ 0.11

Net income before taxes increased from $13.1 million in the second quarter of 2004 to $50.8 million in the second quarter of 2005 mainly due to a 53% increase in revenues reflected by a 28% increase in production and a 19% increase in prices on a boe basis. These increases have been offset by a 51% increase in lease operating costs and a 43% increase in depletion.

The Trust recognized a net gain on commodity contracts of $1.7 million in the second quarter of 2005 compared to $13.5 million loss in the second quarter of 2004. The unrealized (non-cash) gain on commodity contracts was $9.7 million in the second quarter of 2005 compared to $4.6 million loss in the second quarter of 2004.

The increase in depletion is due to increased production and the increase in the depletion rate reflecting the increasing cost of acquisitions.

Net income before income taxes for the six months ended June 30, 2005 was $57.4 million compared to $21.2 million for the same period in the prior year. This is mainly due to a 54% increase in oil and natural gas sales. Production increased 30% and prices increased 19% on a boe basis. These increases have been offset by a 56% increase in lease operating costs and a 45% increase in depletion.

Total cash netbacks increased by $37.5 million for three months ended June 30, 2005 compared to the same period in 2004. On a boe basis cash netbacks were up to $26.85 in the second quarter of 2005 from $19.84 in the second quarter of 2004.

Total Cash Netbacks	3 months ended June 30, 2005	2004	6 months ended June 30, 2005	2004
Operating netback	$ 29.28	$ 22.05	$ 27.39	$ 22.38
Financing costs	0.79	0.46	0.73	0.42
General and administrative	1.19	1.30	1.17	1.30
Capital and current taxes	0.45	0.45	0.37	0.39
Total cash netback per BOE	$ 26.85	$ 19.84	$ 25.12	$ 20.27

As a result of the changes discussed above, net income increased to $40.2 million in the second quarter of 2005 from the $817,000 reported in the second quarter of 2004.

Operating Netbacks for the three months ended June 30, 2005

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$ 59.18	$ 7.65	$ 51.10	$ 52.69
Cash cost of hedging	(5.01)	(0.02)	-	(2.45)
Net selling price	54.17	7.63	51.10	50.24
Royalties, net of ARC	9.76	1.47	12.15	9.49
Operating	13.96	1.30	9.19	10.89
Transportation	0.43	0.12	0.56	0.58
Operating netback	$ 30.02	$ 4.74	$ 29.20	$ 29.28

Operating Netbacks three months ended June 30, 2004

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$ 47.01	$ 7.13	$ 37.13	$ 44.27
Cash cost of hedging	(6.51)	(0.22)	-	(3.49)
Net selling price	40.50	6.91	37.13	40.78
Royalties, net of ARC	8.54	1.58	8.71	9.02
Operating	11.29	1.24	8.50	9.26
Transportation	0.19	0.12	0.45	0.45
Operating netback	$ 20.48	$ 3.97	$ 19.47	$ 22.05

The operating netback increased by $61.4 million for six months ending June 30, 2005. On a boe basis operating netback increased to $27.39 in 2005 from $22.38 in 2004.

Operating Netbacks for the six months ended June 30, 2005

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$ 56.93	$ 7.33	$ 48.62	$ 50.77
Cash cost of hedging	(5.01)	(0.01)	-	(2.51)

24

Net selling price	51.92	7.32	48.62	48.26
Royalties, net of ARC	9.95	1.54	11.82	9.76
Operating	13.87	1.13	9.37	10.50
Transportation	0.51	0.12	0.53	0.61
Operating netback	$ 27.59	$ 4.53	$ 26.90	$ 27.39

25

Operating Netbacks for the six months ended June 30, 2004

	Oil $/bbl	**Gas $/mcf**	**NGL $ /bbl**	**Total $ /boe**
Selling price	$ 44.86	$ 6.95	$ 37.09	$ 42.75
Cash cost of hedging	(5.75)	(0.11)	-	(2.77)
Net selling price	39.11	6.84	37.09	39.98
Royalties, net of ARC	7.54	1.48	9.90	8.36
Operating	11.60	1.05	7.67	8.74
Transportation	0.20	0.13	0.43	0.50
Operating netback	$ 19.77	$ 4.18	$ 19.09	$ 22.38

CAPITAL EXPENDITURES

Acquisitions

During the six months ended June 30, 2005, PC spent $37.5 million to acquire Northern Crown Petroleums Ltd. ("Northern Crown") effective May 10, 2005, $23.4 million to acquire Tahiti Gas Ltd. ("Tahiti") effective May 1, 2005 and $6.3 million to acquire property interests in the Turin area effective January 1, 2005. These acquisitions are expected to add approximately 1,365 boepd of production to the Trust. On these acquisitions, Petrofund's internal estimate of reserves is 4.0 million boe on a proved plus probable basis.

Development Activities

During the three months ended June 30, 2005, PC incurred $30.6 million in drilling and development activities as compared to $14.8 million in the three months ended June 30, 2004. A total of 48 wells were drilled, of which 16 were gas, 30 oil and 2 dry and abandoned for an overall success rate of 96%

During the six months ended June 30, 2005, PC incurred $79.0 million in drilling and development activities as compared to $27.4 million in the six months ended June 30, 2004. A total of 133 wells were drilled, of which 72 were gas, 56 oil, 1 service well and 4 dry and abandoned for an overall success rate of 97%.

A summary of capital expenditures for the three and six month's periods is as follows ($ thousands):

	3 months ended June 30,		**6 months ended June 30,**	
	2005	**2004**	**2005**	**2004**
Corporate and property acquisitions (1)	$ 56,330	$ 8,488	$ 62,581	$ 9,578
Development expenditures:				
Land & seismic	1,436	360	5,405	967
Drilling & completion	14,504	8,458	36,902	14,144
Well equipping	949	834	6,000	2,032
Tie-ins	3,881	1,168	8,232	2,249

Facilities	5,389	2,119	14,105	4,665
CO^2 purchases	4,360	1,890	8,178	3,388
Other	104	-	191	-
Total	30,623	14,829	79,013	27,445
Total net capital expenditures -cash	86,953	23,317	141,594	37,023
Corporate acquisitions - non-cash (2)	16,395	559,831	16,395	559,831
Current year ARO capitalized	736	121	1,739	336