PETROFUND ENERGY TRUST
Form 6-K
November 10, 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: November 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: November 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.	**Third Quarter Report dated November 8, 2005.**

EXHIBIT 1

444 - 7th Ave S.W
Suite 600
Calgary, Alberta
T2P 0X8
Telephone: (403) 218-8625
Fax: (403) 269-5858

News Release

Calgary November 8th, 2005

CALGARY October 5, 2004

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

Announces Results for the Third Quarter of 2005

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

-

Average production for the third quarter reached a record high of 37,485 boe per day. This was a 7% increase over the third quarter production of last year.

-

Cash flow increased 71% over the third quarter of 2004 to $111.1 million, which is also a new high for the Trust. On a per unit basis, cash flow increased 63% from a year ago to $1.06 per unit.

-

The third quarter payout ratio moved down to 45% from 75% in the comparable quarter of 2004 and from 56% in the second quarter of 2005.

-

Operating costs for the quarter increased to $10.31 per boe due to increasing industry costs. This was a 7% increase over the third quarter of last year but a 5.3% decrease from the second quarter of 2005.

-

Net income increased from $15.1 million in the third quarter of 2004 to $51.2 million in the third quarter of 2005, which equates to a per unit increase from $0.15 to $0.49.

-

General and administrative costs were up 20% from last year to $1.40 per boe due mainly to increasing compensation costs due to industry pressure.

-

The Trust exited the quarter with a 0.5:1.0 net debt to cash flow ratio based on annualized third quarter cash flow.

Petrofund's third quarter report is presented below:

3rd Quarter Report

for three & nine months ended September 30, 2005 & 2004

FINANCIAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

	3 months ended September 30,			9 months ended September 30,		
	2005	**2004**	**Variance**	**2005**	**2004**	**Variance**
INCOME STATEMENT						
Oil and natural gas sales [5]	$ 212,404	$ 147,489	44%	$ 540,003	$ 360,158	50%
Cash flow [1]	$ 111,122	$ 65,075	71%	$ 271,892	$ 163,942	66%
Per unit [2]	$ 1.06	$ 0.65	63%	$ 2.65	$ 1.95	36%
Per boe	$ 32.22	$ 20.24	59%	$ 27.47	$ 20.02	37%
Cash distributions paid per unit	$ 0.48	$ 0.48	-%	$ 1.44	$ 1.44	-%
Net income	$ 51,209	$ 15,147	238%	$ 110,645	$ 23,593	369%
Net income per unit						
Basic	$ 0.49	$ 0.15	227%	$ 1.08	$ 0.28	286%
Diluted	$ 0.49	$ 0.15	227%	$ 1.08	$ 0.28	286%
UNITS AND EXCHANGEABLE SHARES OUTSTANDING [2]						
Weighted average	105,018	100,267	5%	102,412	84,064	22%

Diluted	105,039	100,353	5%	102,441	84,211	22%
At period-end	105,046	100,344	5%	105,046	100,344	5%
BALANCE SHEET						
Working capital (deficit) [3]				$ 12,077	$ (55,784)	122%
Property, plant and equipment, net				$ 1,297,522	$ 1,230,636	5%
Long-term debt				$ 244,499	$ 199,474	23%
Unitholders equity				$ 1,084,746	$ 1,031,226	5%
MARKET CAPITALIZATION, as at September 30				$ 2,397,156	$ 1,595,476	50%
TOTAL CAPITALIZATION, as at September 30 [3],[4]				$ 2,629,578	$ 1,850,258	42%
TRUST UNIT TRADING (TSX: PTF.UN)						
High	$ 23.31	$ 16.35	43%	$ 23.31	$ 19.24	21%
Low	$ 19.30	$ 14.62	32%	$ 15.50	$ 14.56	6%
Close	$ 22.82	$ 15.90	44%	$ 22.82	$ 15.90	44%
Average daily volumes	147	287	(49)%	195	227	(14)%
TRUST UNIT TRADING (AMEX: PTF)						
High	$ 19.85	$ 2.83	55%	$ 19.85	$ 4.96	33%
Low	$ 15.72	$ 1.10	42%	$ 12.66	$ 0.95	16%
Close	$ 19.64	$ 2.60	56%	$ 19.64	$ 2.60	56%
Average daily volumes	579	431	34%	562	462	22%

(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.

OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

	3 months ended September 30,			**9 months ended September 30,**		
	2005	**2004**	**Variance**	**2005**	**2004**	**Variance**
DAILY PRODUCTION						
Oil (bbls)	18,451	17,504	5%	18,064	13,934	30%
Natural gas (mcf)	97,825	90,119	9%	94,384	82,623	14%
Natural gas liquids (bbls)	2,730	2,427	12%	2,457	2,181	13%
BOE (6:1)	37,485	34,950	7%	36,252	29,886	21%
Total production (mmboe)	3,449	3,215	7%	9,897	8,189	21%
PRODUCTION PROFILE						
Oil	49%	50%		50%	47%	
Natural gas	44%	43%		43%	46%	
Natural gas liquids	7%	7%		7%	7%	

PRICES [1]					
Oil (per bbl)	$ 69.37	$ 52.02	33%	$ 61.21	$ 47.88 28%
Natural gas (per mcf)	$ 9.10	$ 6.50	40%	$ 7.95	$ 6.78 17%
Natural gas liquids (per bbl)	$ 50.36	$ 43.68	15%	$ 49.27	$ 39.55 25%
BOE (6:1)	$ 61.57	$ 45.85	34%	$ 54.53	$ 43.97 24%
Cash operating netback per BOE	$ 34.67	$ 22.57	54%	$ 29.93	$ 22.46 33%
LEASE OPERATING COSTS	$ 35,558	$ 30,920	(15)%	$ 103,245	$ 74,388 (39)%
Cost per boe	$ 10.31	$ 9.62	(7)%	$ 10.43	$ 9.08 (15)%
GENERAL AND ADMINISTRATIVE COSTS	$ 4,816	$ 3,764	(28)%	$ 12,357	$ 10,218 (21)%
Cost per boe	$ 1.40	$ 1.17	(20)%	$ 1.25	$ 1.25 -%

(1)

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

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Management Discussion & Analysis

three and nine months ended September 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 nine months ended September 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) and Petrofund Ventures Trust, wholly owned subsidiaries of the Trust. This commentary is based on information available to November 8, 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 , pro 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 in the Trust s 2004 annual report, 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. The Trust undertakes no obligation to update or revise any forward looking financial statements, except as required by applicable securities laws.

RESULT SUMMARY

THIRD QUARTER 2005 VERSUS SECOND QUARTER 2005

The Trust generated cash flow of $111.1 million or $1.06 per unit in the third quarter of 2005 compared to $87.8 million or $0.86 per unit in the second quarter of 2005. The Trust maintained monthly cash distributions of $0.48 per unit in the third quarter of 2005. The Trust s payout ratio of 45% in the third quarter of 2005 compared to a payout ratio of 56% in the second quarter of 2005.

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The third quarter of 2005 was an active quarter for Petrofund in property acquisitions, plus drilling and development activities. Total expenditures for the quarter were $40.3 million. These activities provide new production in the third quarter and for the fourth quarter of 2005, as discussed further in the Operational Highlights.

Average daily production volumes in the third quarter of 2005 of 37,485 boe were above the second quarter of 2005 volumes of 36,011 boe. This increase resulted from acquisitions and development activities for the nine months ending September 30, 2005 offset by the natural production decline.

Net income of $51.2 million remained the same for the third and second quarters of 2005. Revenues increased 23% which reflects an increase of 17% in prices on a boe basis and a 4% increase in production. The increase in revenue has mainly been offset by a $20.9 million non-cash loss on commodity contracts and an increase of $9.0 million in depletion expense. The Trust recognized an unrealized (non-cash) commodity loss of $11.1 million versus an unrealized (non-cash) commodity gain of $9.7 million in the second quarter of 2005. Both adjustments were a result of the accounting standard governing price risk management activity. In addition, the future income tax in the third quarter of 2005 was a recovery of $1.9 million compared to $10.4 million expense in the second quarter of 2005, due to an increase in commodity contract, losses and other tax related asset balances.

The cash loss on commodity contracts during the third quarter of 2005 was $12.8 million compared to an $8.0 million loss in the second quarter of 2005.

Royalties represented amounts equal to 20% of revenue in the third quarter of 2005, compared to 18% for the three months ended June 30, 2005. The second quarter of 2005 was lower due to positive gas costs allowance adjustments.

Lease operating costs on a unit basis decreased to $10.31/boe in the third quarter of 2005 from $10.89/boe in the second quarter of 2005. In the second quarter of 2005, 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. Costs for repairs and maintenance continue to increase as a result of high levels of activity in the upstream sector.

HIGHLIGHTS OF THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2005

The Trust paid out cash distributions of $0.48 per unit in the third quarter of 2005, which equaled the $0.48 per unit in the third quarter of 2004. On September 13, 2005, the Trust announced October 2005 cash distributions of $0.17 per unit. Petrofund has since confirmed $0.17 per unit for November 2005 and based on current commodity prices and market conditions, Petrofund expects to maintain the $0.17 per unit distribution for December 2005 distribution month.

The Trust   s payout ratio for the nine months ended September 30, 2005 was 55% compared to 76% in 2004. The payout ratio in the third quarter of 2005 was 45% compared to 75% in the same quarter of 2004.

Net income increased to $51.2 million in the third quarter of 2005 versus $15.1 million in the third quarter of 2004, reflecting increased average production and higher prices.

The Trust generated cash flow of $111.1 million in the third quarter of 2005, an increase of 71% over the third quarter of 2004.

Average production on a boe basis increased 7% to 37,485 boe/d in the third quarter of 2005 from 34,950 boe/d in the third quarter of 2004. The change in production reflects 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 third quarter of 2005 were up 34% on a boe basis from the same period the prior year and 24% on a boe basis for the nine months ending September 30, 2005 compared to the same period in 2004.

Petrofund has a strong balance sheet with a net debt to cash flow ratio of 0.5:1.0 based on annualized third quarter 2005 cash flow.

To date in 2005, Petrofund has acquired interests in various oil and gas properties for $73.8 million (excluding 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 and Joarcam areas. These acquisitions added approximately 1,650 boepd of production to the Trust. Petrofund s internal estimate of its working interest of reserves additions is 4.6 million boe on a proved plus probable basis.

The Trust has a balanced production profile which averaged 43% natural gas and 57% oil and liquids for the nine months ended September 30, 2005.

The Trust completed a bought deal financing of 4.15 million Trust units, raising gross proceeds of $75.7 million ($71.4 million net) in the second quarter of 2005. The weighted average number of Trust units outstanding increased from 100.3 million in the third quarter of 2004 to 105.0 million in the third quarter of 2005. As at September 30, 2005 there were 105.0 million Trust units outstanding.

The Trust market capitalization as at September 30, 2005, was approximately $2.4 billion ($1.6 billion as at September 30, 2004).

OPERATIONAL HIGHLIGHTS

Despite persistent wet weather across the western provinces, Petrofund carried out an active drilling program in the third quarter by drilling 61 wells, consisting of 57 working interest wells (25.3 net) and 4 farmout wells. This drilling activity resulted in 38 oil wells, 20 gas wells, 1 abandoned well and 2 service wells, for an overall success rate of 98%.

Following is a brief rundown of the properties having noteworthy activity in the quarter.

Brassey, British Columbia

Four new Cadomin gas wells (0.6 net) were brought on-stream early this quarter, adding average production of 500 mcf/d to Petrofund s production.

Fort Saskatchewan, Alberta

Petrofund added 2 mmcf/d of new production near the end of the quarter through two recompletions and the tie-in of a well drilled in the first quarter.

Turin, Alberta

Originally delayed by wet weather last quarter, Petrofund equipped and tied in a Taber gas well early this quarter that is producing 700 mcf/d for Petrofund s account.

Three Hills Creek, Alberta

Petrofund equipped and tied in a 100% working interest Edmonton Sand gas well that produced 750 mcf/d for most of the quarter. Petrofund also continued its participation in coalbed methane development by drilling an additional 6 wells (2.1 net). Several well recompletions during the quarter resulted in 500 mcf/d of added production.

Minehead, Alberta

Three successful Cardium gas wells (1.2 net) were drilled and completed on Petrofund lands during the quarter. These wells are scheduled to come on-stream in the fourth quarter.

Kerrobert, Saskatchewan

Petrofund, as operator, drilled sixteen 100% working interest Viking oil wells early this quarter but completions were delayed by wet weather. All wells are expected to be completed and on-stream early in the fourth quarter.

Dodsland, Saskatchewan

Three 100% working interest Viking gas wells commenced production mid-quarter at a combined rate of 1 mmcf/d.

Silverton, Saskatchewan

Petrofund, as operator, began producing a horizontal Frobisher oil well drilled in the second quarter. This well has averaged 15 boe/d net to Petrofund.

Weyburn, Saskatchewan

A total of 15 wells (3 net) were drilled in the Weyburn Unit during the quarter, mainly within the carbon dioxide flood area. These new wells added 250 boe/d to Petrofund s production base.

Midale, Saskatchewan

Six Frobisher wells (0.4 net) were drilled in the Midale Unit this quarter, although wet weather has delayed them from coming on-stream until early in the fourth quarter of 2005. Also, a full-scale commercial carbon dioxide injection project commenced within the Midale Unit late this quarter. Carbon dioxide injection is expected to extend the economic life of this unit by 20-25 years and recover an additional 45 million barrels of oil gross, 3 million barrels net to Petrofund, based on an internal estimate.

CASH DISTRIBUTIONS

	3 months ended September 30,		**9 months ended September 30,**	
	2005	**2004**	**2005**	**2004**
	$		$	
Distributions paid per unit	0.48	$ 0.48	1.44	$ 1.44

Trust unitholders who held their units throughout the third 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 $0.17 per unit in October, has announced $0.17 per unit for November, and has indicated $0.17 per unit for December.

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

The Trust generated cash flow available for distribution before funding of capital expenditures in the third quarter of 2005 of $110.3 million (2004 - $63.8 million). The Trust paid out $50.1 million (2004 - $47.7 million) in distributions representing a payout ratio of 45% (2004 75%).

During the nine months ended September 30, 2005 the Trust generated cash flow available for distribution before funding capital expenditures of $268.9 million (2004 - $160.4 million). The Trust paid out $146.8 million (2004 - $121.8 million) in distributions representing a payout ratio of 55% (2004 76%).

For the 12 months ended September 30, 2005, the Trust generated cash flow available for distribution of $340.0 million, and allocated $154.5 million of such amounts for investment in development drilling and other projects.

Distributions of $194.6 million were paid out in such period, representing a payout ratio of 57%. 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	1.4400 (3)	1.3680	0.0720
Cumulative	**$ 41.9250**	$ 10.0004	$ 31.9246

(2)

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

(2)

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

(3)

Petrofund estimates that approximately 95% to 100% of cash distributions paid in 2005 to Canadian and U.S. unitholders will be taxable. Any non-taxable amounts will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow experienced throughout the year.

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

This is a general guideline and not intended to be legal advice to any particular holder or potential holder of Petrofund Energy Trust. This information is not exhaustive of all possible U.S. income tax considerations. Unitholders or potential unitholder 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.

2005 MONTHLY CASH DISTRIBUTIONS

Actual Cash distributions paid for 2005 along with relevant payment dates are as follows:

Record Date	Payment Date	Distribution/Per Unit	
January 17	January 31	$ 0.16	
February 14	February 28	0.16	
March 16	March 31	0.16	
April 15	April 29	0.16	
May 16	May 31	0.16	
June 16	June 30	0.16	
July 15	July 29	0.16	
August 17	August 31	0.16	
September 16	September 30	0.16	
October 17	October 31	0.17	(Paid October 31, 2005)
November 16	November 30	0.17	(Announced November 7, 2005)
December 14	December 30	0.17	(Indicated September 13, 2005)

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 37,485 boe/d in the third quarter of 2005, an increase of 7% over average production volumes of 34,950 boe/d in the third quarter of 2004. The change in production reflects, PC s development drilling program, the Central Alberta acquisition in November 2004, the Turin area acquisition in January 2005, the Northern Crown and Tahiti acquisitions in May 2005, Joarcam area acquisition in July 2005, positive prior period adjustments (300 boe/d), offset by natural production decline.

	3 months ended September 30,		**9 months ended September 30,**	
Daily Production	**2005**	**2004**	**2005**	**2004**
Oil (bbls)	18,451	17,504	18,064	13,934
Natural gas (mcf)	97,825	90,119	94,384	82,623
Natural gas liquids (bbls)	2,730	2,427	2,457	2,181
Total (boe 6:1)	37,485	34,950	36,252	29,886

PRICING AND PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 44% to $212.4 million in the third quarter of 2005 from $147.5 million in the third quarter of 2004 due to a 7% increase in production and a 34% increase in prices on a boe basis.

For the nine month period ended September 30, 2005, revenue increased 50% to $540.0 million from $360.2 million in 2004 due to a 21% increase in production to 36,252 boe/d and an increase of 24% in the average price per boe to $54.53 in 2005 from $43.97 in 2004.

Crude oil sales increased to $117.8 million in the third quarter of 2005 from $83.7 million in the third quarter of 2004 due to a 5% increase in production from 17,504 bbl/d in the third quarter of 2004 to 18,451 bbl/d in the third quarter of 2005 and a 33% increase in the oil price received. The average WTI oil price reported increased from U.S. $43.88/bbl in 2004 to U.S. $63.19/bbl in the third quarter of 2005 or 44%, however, the Canadian par price at Edmonton increased only 36% from $56.25/bbl to $76.51/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged 0.83 in the third quarter of 2005 versus 0.77 in the third quarter of 2004. The average Canadian wellhead price received by Petrofund increased from $52.02/bbl in the third quarter of 2004 to $69.37/bbl in the third quarter of 2005. Petrofund s negative differential from Edmonton par was $4.23/bbl in the third quarter of 2004 versus $7.14/bbl in the third quarter of 2005 as quality differentials for medium crudes have increased.

During the nine month period ended September 30, 2005, crude oil sales increased 65% to $301.9 million in 2005 from $182.8 million in the same period of 2004. Oil production increased 30% to 18,064 bbl/d for the period, compared to 13,934 bbl/d for the same period in 2004. The average price received increased from $47.88/bbl in 2004 to $61.21/bbl in 2005. The WTI U.S. price increased from U.S. $39.11/bbl for nine months ending September 30, 2004 to U.S. $55.40/bbl in the same period in 2005.

Natural gas sales increased to $81.9 million in the third quarter of 2005 from $53.9 million in the third quarter of 2004 due to 9% increase in production and a 40% increase in the average prices received from $6.50/mcf in the third quarter of 2004 to $9.10/mcf in the third quarter of 2005. The monthly AECO price per mmbtu increased from $6.66

in the third quarter of 2004 to $8.17 in the third quarter of 2005. Production volumes averaged 97.8 mmcf/d in the third quarter of 2005 compared to 90.1 mmcf/d in the third quarter of 2004.

During the nine month period ended September 30, 2005, natural gas sales increased 33% to $204.8 million in 2005 from $153.6 million in 2004. Natural gas production increased 14% from 82.6 mmcf/d in 2004 to 94.4 mmcf/d in 2005. The average price received increased 17% from $6.78/mcf in 2004 to $7.95/mcf in 2005.

Sales of natural gas liquids and sulphur increased to $12.7 million in the third quarter of 2005 from $9.9 million in the third quarter of 2004 as natural gas liquids production increased 12% to 2,730 bbl/d in the third quarter of 2005 from 2,427 bbl/d in the third quarter of 2004. The average price received, excluding sulphur, increased 15% from $43.68/bbl in the third quarter of 2004 to $50.36/bbl in the third quarter of 2005.

For the nine month period ended September 30, 2005, sales of natural gas liquids and sulphur increased 40% from $23.8 million in 2004 to $33.3 million in 2005. Production volumes of natural gas liquids for these periods increased 13% from 2,181 bbl/d in 2004 to 2,457 bbl/d in 2005 and the average price, excluding sulphur, increased 25% from $39.55/bbl in 2004 to $49.27/bbl in 2005.

Average Prices (1)	**3 months ended September 30,**		**9 months ended September 30,**	
	2005	**2004**	**2005**	**2004**
Oil (per bbl)	$ 69.37	$ 52.02	$ 61.21	

$

47.88

Natural gas (per mcf)

9.10

6.50

7.95

6.78

Natural gas liquids (per bbl)

50.36

43.68

49.27

39.55

Weighted average (6:1)

$ 61.57

$

45.85

$

54.53

$

43.97

3 months ended September 30,

9 months ended September 30,

Production Revenue ($ millions) [1]

	2005	**2004**	**2005**	**2004**
Oil	$ 117.8	$ 83.7	$ 301.9	$ 182.8
Natural gas	81.9	53.9	204.8	153.6
Natural gas liquids & sulphur	12.7	9.9	33.3	23.8

Total

$ 212.4

$ 147.5

$ 540.0

$ 360.2

(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 September 30, 2005, Petrofund had 26.8 mmcf/d of natural gas and 5,000 bbl/d of crude oil hedged for the remainder of 2005 (approximately 28% of production) and 18.2 mmcf/d of natural gas and 4,500 bbl/d of crude oil hedged for 2006 (20% gas and 25% oil respectively). 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)					
	2005		**2006**			
Natural Gas	**Q4**	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Collars	12,632	10,658	9,474	14,211	14,211	4,737
Three way collars	7,895	5,132	9,474	4,737	4,737	1,579
Floors	6,316	2,369	9,474	-	-	-

Total mcf/d	**26,843**	**18,159**	**28,422**	**18,948**	**18,948**	**6,316**

11

Average Prices ($/mcf)

2005

2006

Q4

2006

Q1

Q2

Q3

Q4

Collar ceiling price

$

12.87

$

12.84

$

14.94

$

12.14

$

12.14

$

12.14

Collar floor price

7.04

7.92

7.39

8.09

8.09

8.09

Three way ceiling price

10.49

9.69

11.77

8.99

8.99

8.99

Three way floor price

6.28

7.17

6.52

7.39

7.39

7.39

Three way floor short

5.23

5.92

5.47

6.07

6.07

6.07

Floor price

$

8.44

$

8.44

$

8.44

$

-

$

-

$

-

Average Volumes (bbl/d)

2005

2006

Oil

Q4

2006

Q1

Q2

Q3

Q4

Collared

1,000

4,000

5,000

5,000

4,000

2,000

Three way collars

4,000

500

1,000

1,000

-

-

Total bbl/d

5,000

4,500

6,000

6,000

4,000

2,000

	Average Prices ($ /bbl)					
	$	$	$	$	$	$
Collar ceiling price	69.76	87.20	85.52	88.60	88.50	86.16
Collar floor price	48.83	58.91	56.28	58.72	59.59	61.05
Three way ceiling price	45.35	65.26	61.62	68.89	-	-
Three way floor price	34.30	47.67	46.51	48.83	-	-
	$	$	$	$	$	$
Three way floor short	29.65	41.86	40.69	43.02	-	-

	2005		**2006**			
Alberta Power	**Q4**	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
	$	$	$	$	$	$
Fixed MW/h	2.0	2.0	2.0	2.0	2.0	2.0
	$	$	$	$	$	$
Fixed price ($/MWh)	44.50	57.00	57.00	57.00	57.00	57.00

Three-way Collars

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

After September 30, 2005 and as at October 31, 2005, Petrofund had entered into the following additional hedge (not included in the table above):

1)

Collar for April 1, 2006 to October 31, 2006 for 4.7 mmcf/d of natural gas between $8.97/mcf and $14.78/mcf.

Petrofund has no sales volumes hedged after December 31, 2006. All foreign exchange calculations in this section of the report incorporate the Bank of Canada U.S. dollar rate at the close on September 30, 2005 of CDN $1.1627:U.S. $1.

ROYALTIES

	3 months ended September 30,		9 months ended September 30,	
	2005	**2004**	**2005**	**2004**
Royalties ($ millions)	$ 42.1	$ 27.6	$ 105.0	$ 69.2
Average royalty rate (%)	20	19	19	19

$/boe

$

12.21

$

8.58

$

10.61

$

8.45

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $42.1 million in the third quarter of 2005 from $27.6 million in the third quarter of 2004, net of the Alberta Royalty Credit (ARC). Royalties, as a percentage of revenues before hedging losses, increased to 20% of revenues in the third quarter of 2005 from 19% of revenues in the third quarter of 2004.

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

EXPENSES

	3 months ended September 30,		9 months ended September 30,	
	2005	**2004**	**2005**	**2004**
Expenses ($ millions)				
Lease operating				

$

35.6

$

30.9

$

103.2

$

74.4

Transportation

2.3

1.8

6.2

4.3

General & administrative

4.8

3.8

12.4

10.2

Financing costs

2.1

1.7

6.9

3.8

Expenses per boe

Lease operating

$

10.31

$

9.62

$

10.43

$

9.08

Transportation

0.66

0.55

0.63

0.52

General & administrative

1.40

1.17

1.25

1.25

Financing costs

0.62

0.55

0.69

0.46

Lease Operating

Oil and gas lease operating expenses increased 15% to $35.6 million in the third quarter of 2005 from $30.9 million in the third quarter of 2004 due to a 7% increase in production and an 7% increase in costs on a boe basis. Operating costs on a boe basis increased to $10.31 in the third quarter of 2005 from $9.62 in the third quarter of 2004.

Operating costs for the nine month period ended September 30, 2005 were up 15% to $10.43 per boe compared to $9.08 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.

The most significant contributor to the higher per unit operating costs to date in 2005 has been a general industry increase for all types of services and supplies including surface and downhole well repair and maintenance costs and facility maintenance work. In addition, the current high product price environment is driving average operating costs higher because marginal, higher cost properties continue to generate positive cash flow at higher than historical per unit costs and, as a result, remain on production longer. Operating costs in the fourth quarter of 2005 are expected to continue in the mid $10 per boe range.

Transportation Costs

Transportation costs on a boe basis were $0.66 in the third quarter of 2005 as compared to $0.55 for the third quarter of 2004 this increase mainly is due to a general increase in trucking costs of clean oil.

Transportation costs on a boe basis were $0.63 in the nine months ending September 30, 2005 as compared to $0.52 for the nine months ending September 30, 2004 reflecting general increase in trucking costs of clean oil and higher transportation costs associated with the Ultima properties.

General & Administrative (G&A)

G&A costs on a boe basis were $1.40 per boe in the third quarter of 2005 as compared to $1.17 per boe in the same period in 2004. General and administrative costs, net of overhead recoveries, increased to $4.8 million in the third quarter of 2005 from $3.8 million in the third quarter of 2004, mainly due to higher employee compensation costs. G&A costs in the third quarter of 2005 included $126,000 directly relating to the external costs associated with compliance with Section 404 of the Sarbanes-Oxley Act (SOX 404) which equates to $0.04 per boe.

General and administrative costs for the nine month period ended September 30, 2005, were $12.4 million compared to $10.2 million in 2004. Costs were $1.25 per boe in 2005 compared to $1.25 per boe in 2004. We expect our G&A costs to be approximately $1.30 per 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 $2.1 million in the third quarter of 2005 from $1.7 million in the third quarter of 2004 due to the increase in the average loan balance outstanding in the third quarter of 2005 of $245.9 million versus $195.6 million in the third quarter of 2004.

Interest and other financing costs for nine months ended September 30, 2005, increased to $6.9 million in 2005 compared to $3.8 million in 2004, which reflects the increase in the average loan balance outstanding in 2005 of $251.7 million from $138.7 million in 2004. Net debt as a percentage of total capitalization is 9% in 2005 compared to 14% in 2004.

The bank loan outstanding at September 30, 2005, was $244.5 million as compared to $214.4 million at December 31, 2004, $10.0 million of debt was repaid in the third quarter of 2005. At September 30, 2005, 100% of our debt was based on floating interest rates.

DEPLETION, DEPRECIATION & ACCRETION

Depletion, depreciation and accretion expense increased to $51.0 million in the third quarter of 2005 from $42.0 million in the third quarter of 2004 due to an increase in production and an increase in the depletion rate. The rate per boe increased to $14.80 in the third quarter of 2005 from $13.06 in the third 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 nine months ended in September 30, 2005, was $142.0 million or $14.34 per boe as compared to $104.6 million or $12.78 per boe for the same period in 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 September 30, 2005. The Federal Large Corporations Tax rate is being reduced in stages, so that by 2008, the tax will be eliminated.

Capital taxes of $1.0 million in the third quarter of 2005 (2004 $788,000) 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, which holds certain Saskatchewan properties, 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 third quarter of 2005 was a recovery of $1.9 million compared to $6.1 million recovery in the third quarter of 2004 as a result of a decrease in non-capital losses available.

NET INCOME

	3 months ended September 30,		9 months ended September 30,	
	2005	2004	2005	2004
Net income ($000 s)	$ 51,209	$ 15,147	$ 110,645	$ 23,593
Net income per Trust unit				
Basic	$ 0.49	$ 0.15	$ 1.08	$ 0.28
Diluted	$ 0.49	$ 0.15	$ 1.08	$ 0.28

Net income before taxes increased from $9.1 million in the third quarter of 2004 to $49.5 million in the third quarter of 2005 mainly due to a 44% increase in revenues reflected by 7% increase in production and a 34% increase in prices on a boe basis. These increases have been offset by a 15% increase in lease operating costs and a 22% increase in depletion.

The Trust recognized a net loss on commodity contracts of $24.0 million in the third quarter of 2005 compared to $29.9 million loss in the third quarter of 2004. The unrealized (non-cash) gain on commodity contracts was $11.1 million in the third quarter of 2005 compared to a $15.3 million loss in the third 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 nine months ended September 30, 2005 was $106.9 million compared to $30.3 million for the same period in the prior year. This is mainly due to a 50% increase in oil and natural gas sales. Production increased 21% and prices increased 24% on a boe basis. These increases have been offset by a 39% increase in lease operating costs and a 36% increase in depletion.

Total cash netbacks increased by $45.1 million for three months ended September 30, 2005 compared to the same period in 2004. On a boe basis cash netbacks were up to $32.29 in the third quarter of 2005 from $20.59 in the third quarter of 2004.

Total Cash Netbacks	**3 months ended September 30,**				**9 months ended September 30,**			
	2005		**2004**		**2005**		**2004**	
Operating netback	$	34.67	$	22.57	$	29.93	$	22.46
Financing costs		0.62		0.53		0.69		0.46
General and administrative								

1.40

1.17

1.25

1.25

Capital and current taxes

0.36

0.28

0.36

0.34

Total cash netback per BOE

$

32.29

$

20.59

$

27.63

$

20.41

As a result of the changes discussed above, net income increased to $51.2 million in the third quarter of 2005 from the $15.1 million reported in the third quarter of 2004.

Operating Netbacks for the three months ended September 30, 2005

Oil $/bbl

Gas $/mcf

NGL $ /bbl

Total $ /boe

Selling price

$

69.37

$

9.10

$

50.36

$

61.57

Cash cost of hedging

(6.49)

(0.21)

-

(3.72)

Net selling price

62.88

8.89

50.36

57.85

Royalties, net of ARC

12.20

2.01

13.18

12.21

Operating

11.17

1.57

9.99

10.31

Transportation

0.49

0.15

0.46

0.66

Operating netback

$

39.02

$

5.16

$

26.73

$

34.67

16

Operating Netbacks three months ended September 30, 2004

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$	$		
	52.02	6.		

50

$

43.68

$

45.85

Cash cost of hedging

(8.62)

(0.09)

-

(4.53)

Net selling price

43.40

6.41

43.68

41.32

Royalties, net of ARC

9.04

1.17

9.36

8.58

Operating

11.48

1.27

8.48

9.62

Transportation

0.31

0.14

0.41

0.55

Operating netback

$

22.57

$

3.83

$

25.43

$

22.57

The operating netback increased by $112.5 million for nine months ending September 30, 2005. On a boe basis operating netback increased to $29.93 in 2005 from $22.46 in 2004.

Operating Netbacks for the nine months ended September 30, 2005

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe

Selling price

$

61.21

$

7.95

$

49.27

$

54.53

Cash cost of hedging

(5.52)

(0.08)

-

(2.93)

Net selling price

55.69

7.87

49.27

51.60

Royalties, net of ARC

10.72

1.70

12.36

10.61

Operating

13.09

1.25

9.52

10.43

Transportation

0.50

0.13

0.51

0.63

Operating netback

$

31.38

$

4.79

$

26.88

$

29.93

Operating Netbacks for the nine months ended September 30, 2004

	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price				
Cash cost of hedging				
Net selling price				
Royalties, net of ARC				
Operating				
Transportation				
Operating netback				

CAPITAL EXPENDITURES

Acquisitions

During the nine months ended September 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, $6.3 million to acquire property interests in the Turin area effective January 1, 2005 and $11.8 million to acquire property interest in the Joarcam area effective July 1, 2005. These acquisitions added approximately 1,650 boepd of production to the Trust. On these acquisitions, Petrofund s internal estimate of its working interest of reserves is 4.6 million boe on a proved plus probable basis.

Dispositions

During the nine months ended September 30, 2005, PC disposed of minor properties for net proceeds of $871,000, which included one non-core area in the Acheson area of Alberta for $863,000.

Development Activities

During the three months ended September 30, 2005, PC incurred $29.9 million in drilling and development activities compared to $20.5 million in the three months ended September 30, 2004. A total of 61 wells were drilled, of which 20 were gas, 38 oil, 2 service wells and 1 dry and abandoned well for an overall success rate of 98%.

During the nine months ended September 30, 2005, PC incurred $108.9 million in drilling and development activities as compared to $47.9 million in the nine months ended September 30, 2004. A total of 197 wells were drilled, of which 96 were gas, 93 oil, 4 service wells and 4 dry and abandoned wells for an overall success rate of 98%.

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

	3 months ended September 30,		**9 months ended September 30,**	
	2005	**2004**	**2005**	**2004**
Corporate and property acquisitions (1)	$ 11,245	$ (6,234)	$ 73,826	$ 3,344
Property dispositions				

(871)

-

(871)

-

10,374

(6,234)

72,955

3,344

Development expenditures:

Land & seismic

1,114

468

6,519

1,435

Drilling & completion

12,489

11,731

49,391

25,875

Well equipping

2,571

3,051

8,571

5,083

Tie-ins

2,729

1,085

10,961

3,334

Facilities

5,684

1,876

19,789

6,541

CO2 purchases

5,197

2,275

13,375

5,663

Other

111

-

302

-

Total

29,895

20,486

108,908

47,931

Total net capital expenditures   cash

40,269

14,252

181,863

51,275

Corporate acquisitions - non-cash (2)

16

-

16,411

559,831

Current year ARO capitalized

490

204

2,229

540

Total capital expenditures (3)

$

40,775

$

14,456

$

200,503

$

611,646

(1)

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

(2)

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

(3)

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

We expect total development expenditures for 2005 to be approximately $150 million. We are planning a similar level of expenditure for 2006 in our capital program however, we may increase our capital as we identify and execute on more of the opportunities within our existing properties.

ASSET RETIREMENT FUND

As at September 30, 2005, PC had $8.5 million set aside in cash to fund future abandonment costs. This cash fund is in place to fund significant future reclamation costs, such as the decommissioning of a major facility. PC performs well reclamation and abandonments, flare pit remediation work, etc. on a routine basis, which reduces cash flow available for distribution to proactively address environmental concerns. Petrofund incurred $339,000 for these activities in the third quarter of 2005 compared to $1.2 million in the third quarter of 2004. Reclamation and abandonment costs incurred for the nine months ended September 30, 2005, were $1.8 million as compared to $3.2 million in 2004. PC expects to spend a further $500,000 on reclamation and abandonment work in the remainder of 2005.

GOODWILL

The goodwill balance of $190.2 million arose as a result of the Ultima and Central Alberta acquisitions in 2004 and Northern Crown and Tahiti acquisitions in 2005. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets acquired in each transaction.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no indication of goodwill impairment as of September 30, 2005.

DEBT

As at September 30, 2005, the amount outstanding on our credit facility was $244.5 million, with $170.5 million available to finance future activities.

LIQUIDITY AND CAPITAL RESOURCES

Working capital was $12.1 million at September 30, 2005, an increase of $61.4 million from the $49.3 million deficit as at December 31, 2004. The September 30, 2005 and December 31, 2004 working capital exclude net unrealized gains/losses on commodity contracts. Current assets increased $23.7 million from $48.6 million at December 31, 2004 to $72.3 million at September 30, 2005. Current liabilities decreased $37.7 million from $97.9 million at December 31, 2004 to $60.2 million at September 30, 2005. This decrease in liabilities reflects decrease trade payables and a decrease in distributions payable to Unitholders.

During the third quarter of 2005 the Trust generated cash flow of $111.1 million and paid out $50.1 million in distributions. The excess of $61.0 million was used to partially fund the Trust s capital expenditure program.

In June 2005, the Trust completed a bought deal financing of Trust units, raising gross proceeds of $75.7 million ($71.4 million net). A total of 4.15 million units were issued at $18.25 per unit. The net proceeds were used to pay down debt and fund capital expenditures.

Total long-term debt increased to $244.5 million at September 30, 2005, from $214.4 million at December 31, 2004, due to the funding of acquisitions and development activities.

The changes in total long-term debt for the three and nine months ended September 30 were due to:

3 months ended September 30,

9 months ended September 30,

($ thousands)

2005

2004

2005

2004

Cash flow

$

111,122

$

65,075

$ 271,892

$

163,942

Proceeds received from issuance of Trust units

452

1,642

77,874

3,351

Net change in non-cash working capital balances

(21,083)

(2,395)

(39,516)

24,797

Distributions paid

(50,150)

(47,684)

(146,837)

(121,759)

Expenditures on oil & natural properties, net

(40,269)

(14,252)

(181,863)

(51,275)

Assumption of debt, net of cash on acquisitions

-

-

88

(100,696)

Asset retirement reserve

(518)

(482)

(1,485)

(1,228)

Redemption of exchangeable shares

(258)

(450)

(904)

(1,352)

Capital lease repayments

(74)

(90)

(608)

(264)

(Increase) decrease in cash

10,624

11,625

(8,726)

(5,283)

Miscellaneous

-

74

-

608

$

9,846

$

13,063

$ (30,085)

$

(89,159)

We anticipate we will continue to have adequate liquidity to fund future working capital and planned capital expenditures during 2005 primarily through cash flow from operations and utilization of our credit facility.

Capitalization Analysis

($ thousands, except per unit and percent amounts)

2005

2004

Working capital (deficiency) [1]

$

12,077

$

(55,784)

Bank debt

244,499

199,474

Net debt obligation

$

232,422

$

255,258

Units outstanding and issuable for Exchangeable Shares

105,046

100,344

Market Price at September 30,

$

22.82

$

15.90

Market capitalization

$

2,397,156

$

1,595,476

Total capitalization

$

2,629,578

$

1,850,258

Net debt as a percentage of total capitalization

9%

14%

(1)

Excludes net unrealized losses on commodity contracts.

Based on annualized third quarter 2005 cash flow, Petrofund s net debt to cash flow ratio is 0.5:1.0. 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.

UNITHOLDERS EQUITY

The weighted average Trust units/exchangeable shares outstanding are as follows:

3 months ended September 30,

9 months ended September 30,

2005

2004

2005

2004

Basic

105,017,651

100,266,733

102,412,474

84,064,168

Diluted

105,039,185

100,353,257

102,441,345

84,210,974

Trust units/exchangeable shares outstanding:

As at September 30,

2005

2004

Trust units outstanding

104,507,120

99,405,256

Trust units issuable for exchangeable shares

539,147

939,147

05,046,267 00,344,403

The Trust had 104,507,120 Trust units outstanding at September 30, 2005 compared to 99,405,256 Trust units at the end of September 30, 2004. The weighted average number of Trust units outstanding including Trust units issuable for Exchangeable Shares, was 105,017,651 Trust units for the third quarter of 2005 as compared to 100,266,733 for 2004. During the nine months ending September 30, of 2005, 316,251 Exchangeable Shares were exchanged for 400,000

Trust units and 37,779 were redeemed for cash leaving 402,618 Exchangeable Shares outstanding at September 30, 2005 which are exchangeable into 539,147 Trust units.

FINANCIAL INSTRUMENTS

The net negative fair value of the commodity contracts at September 30, 2005 of $36.3 million has been recorded on the balance sheet as commodity contracts under assets or liabilities, as appropriate. The negative change in the fair value of the contracts, for the nine months ended September 30, 2005 of $25.0 million (2004 - $25.7 million) is recorded in the income statement on a

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separate line as loss on commodity contracts . The line item also includes realized losses on commodity contracts of $12.8 million for three months ended September 30, 2005 compared to $14.6 million for three months ended September 30, 2004.

Deferred Commodity Contracts ($000 s)

	Jan 1, 2005	**Amortized to Expense**	**September 30, 2005**
Current Asset			
Deferred loss	$ 517	$ (388)	$ 129
Current Liability			
Deferred gain	(184)	146	(38)
	$ 333	$ (242)	

$

91

Commodity Contracts ($000 s)

Jan 1,

2005

Change in

Fair Value

September 30,

2005

Current Asset

Commodity contracts

$

3,281

$

(2,536)

$

745

Current Liability

Commodity contracts

(14,599)

(22,452)

(37,051

)

$

(11,318)

$

(24,988)

$

(36,306

)

NON-RESIDENT OWNERSHIP

Based on information available to the Trust, Petrofund estimated that non-resident ownership was approximately 74% as of October 31, 2005. While there are, at present, no restrictions or deadlines on Petrofund pertaining to non-resident ownership levels, the Trust will continue to provide non-resident ownership level updates on a quarterly basis. Petrofund continues to monitor developments in this area.

OFF-BALANCE SHEET ARRANGEMENTS

The Trust has no off-balance sheet financing arrangements.

OUTLOOK FOR 2005

The level of cash flow for 2005 will be affected by oil and gas prices, the Canadian U.S. dollar exchange rate and the Trust s ability to add reserves and production in a cost effective manner. Both product prices and the exchange rate showed volatility in 2005 to date and this trend is expected to continue for the remainder of 2005. The acquisition market is expected to continue to be active. 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. The Trust expects prices for quality, long life assets to be at or near record levels. Petrofund expects to be an active participant in this market but success will be tempered by a commitment to maintain historic discipline and bid only at levels consistent with the best long term interest of our unitholders.

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

Although product prices have remained at high levels, the strengthening of the Canadian dollar in the third quarter of 2005 moderated the net effect of these prices on Petrofund s cash flow. The WTI price increased 44% to U.S. $63.19/bbl in 2005 from U.S. $43.88/bbl in the third quarter of 2004, however, as the (U.S./CDN) exchange rate averaged 0.83 in 2005 as compared to 0.77 in the third quarter of 2004 the par price at Edmonton was up only 36%. The Trust expects the Canadian dollar to remain strong throughout 2005.

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

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CORPORATE DEVELOPMENTS

S&P Confirms Inclusion of Income Trusts In S&P/TSX Composite Index

On October 11, 2005 Standard & Poor s confirmed that it will proceed with its previously announced schedule for including income trusts in the S&P/TSX Composite Index. Following market close on December 15, 2005, income trusts, including Petrofund, will be added to the index at 50 per cent of their full float adjusted weight and at full weighting on the March 17, 2006 market close.

Federal Tax Consultation Process

In September of 2005, the Department of Finance issued a consultation paper outlining issues related to the tax treatment of certain entities including income trusts. The launch of this paper and a subsequent moratorium on advance tax rulings on proposed conversions of corporations to income trusts has created uncertainty in the market as to what future actions the government might take. This uncertainty has had a negative effect on the income trust public market.

The income trust sector, with its recent growth, has provided the average Canadian investor with an income vehicle with unique advantages. In addition, energy trusts are making significant investments in the finding and development of new oil and gas reserves. As a result, we believe that the overall impact of income trusts like Petrofund is positive to the Canadian economy.

The consultation process announced by the Department of Finance indicated they would seek input from concerned parties before they make any decisions which would impact the income trust sector and its investors. Petrofund will be active in this consultation process and will be making our views known to the Department of Finance through participation in a submission by the Canadian Association of Income Funds as well as our own corporate submission.

Sarbanes-Oxley Update

On July 31, 2002, the United States Congress enacted the Sarbanes-Oxley Act (SOX) that applies to all companies registered with the Securities and Exchange Commission (SEC). On March 2, 2005, the SEC announced a one year extension of the compliance date for all foreign private issuers. As a result of this extension, Petrofund is currently required to comply with section 404 of the SOX legislation as of December 31, 2006. Section 404 requires that management identify, document, and assess Internal Control over Financial Reporting and issue a report on their assessment of its effectiveness. The Trust has implemented a comprehensive program for meeting the requirements of section 404 by December 31, 2006.

SENSITIVITY ANALYSIS

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes that can significantly affect cash flow and results of operations. The table is based on actual 2005 prices received for the third quarter of 2005 and production volumes of 37,500 boe/d. These sensitivities are approximations only and are not necessarily valid at other price and production levels. As well, hedging activities can significantly affect these sensitivities.

	Change
	$000 s

$/unit

per year

Price per barrel of oil*

$

1.00 U.S. WTI

$

7,607

$

0.072

Price per mcf of natural gas*

$

0.25 CDN

$

7,052

$

0.067

US/Cdn exchange rate

$

0.01

$

6,185

$

0.059

Interest rate on debt ($245 million)

1%

$

2,445

$

0.023

Oil production volumes*

100 bbl/day

$

2,076

$

0.020

Gas production volumes*

1 mmcf/day

$

2,624

$

0.025

*After adjustment for estimated royalties.

QUARTERLY REVIEW

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

2005

2004

2003

Q3

Q2

Q1

Q4

Q3

Q2

Q1

Q4

Daily Production

Oil (bbls)

18,451

17,500

18,238

18,508

17,504

12,679

11,579

13,645

Natural gas (mcf)

97,825

96,951

88,271

90,089

90,119

79,741

77,925

80,286

Natural gas liquids (bbl)

2,730

2,353

2,283

2,502

2,427

2,074

2,040

2,185

BOE (6:1)

37,485

36,011

35,234

36,025

34,950

28,043

26,607

29,211

Prices (5)

Oil (per bbl)

$

69.37

$

59.18

$

54.74

$

50.96

$

52.02

$

47.01

$

42.50

$

36.07

Natural gas (per mcf)

$

9.10

$

7.65

$

6.97

$

7.12

$

6.50

$

7.13

$

6.76

$

5.87

Natural gas liquids (per bbl)

$

50.36

$

51.10

$

46.04

$

48.20

$

43.68

$

37.13

$

37.06

$

34.86

BOE (6:1)

$

61.57

$

52.69

$

48.79

$

47.33

$

45.85

$

44.27

$

41.15

$

35.60

Operational Highlights

Oil and natural gas sales [5]

$

212,404

$

172,831

$

154,768

$

156,922

$

147,489

$

112,970

$

99,699

$

95,763

Net oil and natural gas sales [1]

$

170,309

$

141,722

$

122,924

$

125,866

$

119,911

$

89,953

$

81,121

$

76,778

Cash flow [2]

$

111,122

$

87,811

$

72,959

$

72,302

$

65,075

$

49,820

$

49,047

$

43,246

Per unit

$

1.06

$

0.86

$

0.73

$

0.72

$

0.65

$

0.64

$

0.67

$

0.63

Per boe

$

32.22

$

26.80

$

23.01

$

21.81

$

20.24

$

19.52

$

20.26

$

16.09

Cash distribution paid

$

50,150

$

48,793

$

47,894

$

47,734

$

47,684

$

39,165

$

34,910

$

36,248

Cash distribution paid per unit

$

0.48

$

0.48

$

0.48

$

0.48

$

0.48

$

0.48

$

0.48

$

0.54

Net income

$

51,209

$

40,193

$

19,243

$

50,765

$

15,147

$

817

$

7,629

$

24,266

Net income per unit

- Basic

$

0.49

$

0.40

$

0.19

$

0.51

$

0.15

$

0.01

$

0.10

$

0.35

- Diluted

$

0.49

$

0.40

$

0.19

$

0.51

$

0.15

$

0.01

$

0.10

$

0.35

Cash operating netback per BOE

$

34.67

$

29.28

$

25.45

$

24.40

$

22.57

$

22.05

$

22.71

$

18.72

Lease operating costs

$

35,558

$

35,677

$

32,010

$

29,222

$

30,920

$

23,639

$

19,829

$

24,777

Cost per BOE

$

10.31

$

10.89

$

10.09

$

8.82

$

9.62

$

9.26

$

8.19

$

9.22

General & administrative costs

$

4,816

$

3,902

$

3,639

$

4,223

$

3,764

$

3,316

$

3,138

$

2,948

Costs per BOE

$

1.40

$

1.19

$

1.15

$

1.27

$

1.17

$

1.30

$

1.30

$

1.10

24

QUARTERLY REVIEW - continued

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

2005

2004

2003

Q3

Q2

Q1

Q4

Q3

Q2

Q1

Q4

Balance sheet

Working capital (deficit) (3)

$

12,077

$

(47,812)

$

(59,531)

$

(49,310)

$

(55,784)

$

(30,955)

$

(56,093)

$

(30,006)

Property, plant and

equipment, net

$

1,297,522

$

1,306,761

$

1,259,248

$

1,246,694

$

1,230,636

$

1,251,484

$

883,191

$

868,263

Long-term debt

$

244,499

$

254,345

$

239,237

$

214,414

$

199,474

$

212,537

$

90,040

$

110,315

Unitholders equity

$

1,084,746

$

1,034,115

$

992,882

$

1,026,526

$

1,031,226

$

1,063,704

$

615,952

$

648,293

Units and Exchangeable Shares Outstanding

Weighted average

105,018

101,569

100,603

100,396

100,267

78,074

73,674

68,498

Diluted

105,039

101,593

100,644

100,466

100,353

78,229

73,872

68,691

At period end

105,046

105,014

100,746

100,451

100,344

100,190

73,682

73,628

Market Capitalization

$

2,397,156

$

2,047,767

$

1,777,156

$

1,568,036

$

1,595,476

$

1,487,823

$

1,278,390

$

1,383,465

Total Capitalization (3) (4)

$

2,629,578

$

2,349,924

$

2,075,924

$

1,842,745

$

1,850,258

$

1,731,315

$

1,434,515

$

1,523,786

Trust Unit Trading (TSX:PTF.UN)

High

$

23.31

$

19.97

$

19.33

$

17.15

$

16.35

$

18.08

$

19.24

$

19.15

Low

$

19.30

$

17.00

$

15.50

$

14.52

$

14.62

$

14.70

$

14.56

$

15.89

Close

$

22.82

$

19.50

$

17.64

$

15.61

$

15.90

$

14.85

$

17.35

$

18.79

Average daily volumes

147

176

264

185

287

189

204

234

Trust Unit Trading (AMEX:PTF)

High

$

19.85

$

16.25

$

16.05

$

13.65

$

12.83

$

13.54

$

14.96

$

14.55

Low

$

15.72

$

13.62

$

12.66

$

12.16

$

11.10

$

10.95

$

10.95

$

11.90

Close

$

19.64

$

15.92

$

14.62

$

13.04

$

12.60

$

11.16

$

13.22

$

14.46

Average daily volumes

579

469

643

518

431

319

633

436

(1)

Net after royalties.

(2)

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

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

(3)

Excludes net unrealized gains/losses on commodity contracts.

(4)

Total capitalization equals market capitalization plus net debt.
(Non-GAAP measures, see special notes in Management Discussion and Analysis).

(5)

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

Consolidated Balance Sheet

(thousands of dollars) (unaudited)

As at September 30, 2005 and December 31, 2004

		2005		2004
Assets				
Current assets				
Cash	$	7,993	$	-
Accounts receivable		47,671		37,713
Deferred loss on commodity contracts		129		517
Commodity contracts (*Note 9)*		745		3,281
Prepaid expenses		16,591		10,847
Total current assets		73,129		

52,358

Asset retirement reserve fund *(Note 7(b))*

8,538

7,053

Goodwill *(Note 2)*

190,247

180,307

Oil and natural gas royalty and property interests,

at cost less accumulated depletion and depreciation

of $772,403 (2004 - $632,668)

1,297,522

1,246,694

$

1,569,436

$

1,486,412

Liabilities and Unitholders Equity

Current liabilities

Bank overdraft

$

-

$

733

Accounts payable and accrued liabilities

42,052

60,961

Current portion of capital lease obligations

-

608

Deferred gain on commodity contracts

38

184

Commodity contracts (*Note 9)*

37,051

14,599

Distributions payable to Unitholders (*Note 8)*

18,126

35,568

Total current liabilities

97,267

112,653

Long-term debt *(Note 6*)

244,499

214,414

Future income taxes

87,658

81,411

Asset retirement obligations (*Note 7(a))*

55,266

51,408

Total liabilities

484,690

459,886

Unitholders equity

Unitholders capital *(Note 3)*

1,560,317

1,477,963

Exchangeable shares *(Note 4*)

6,038

10,518

Accumulated earnings

383,257

272,612

Accumulated cash distributions *(Note 8*)

(864,866)

(734,567)

Total unitholders equity

1,084,746

1,026,526

$

1,569,436

$

1,486,412

The accompanying notes to the Interim Consolidated Financial Statements are an integral part of this consolidated balance sheet.

Consolidated Statement of Operations and Accumulated Earnings

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

	3 months ended September 30,		9 months ended September 30,	
	2005	**2004**	**2005**	**2004**
Revenues				
Oil and natural gas sales	$ 212,404	$ 147,489	$ 540,003	$ 360,158
Royalties	(42,095)	(27,578)	(105,048)	(69,173)
Loss on commodity contracts	(23,971)	(29,903)	(54,254)	(60,934)
	146,338	90,008	380,701	230,051
Expenses				
Lease operating	35,558	30,920	103,245	74,388
Transportation costs	2,291	1,753	6,222	4,264
Financing costs	2,123	1,703	6,858	3,792
General and administrative	4,816	3,764	12,357	10,218
Capital taxes	1,023	788	3,167	2,444
Depletion, depreciation and accretion	51,027	41,982	141,960	104,619
	96,838	80,910	273,809	199,725
Income before provision for income taxes	49,500	9,098	106,892	30,326
Provision for (recovery of) income taxes				
Current	202	100	418	368
Future	(1,911)	(6,149)	(4,171)	6,365
	(1,709)	**(6,049)**	**(3,753)**	**6,733**
Net income	51,209	15,147	110,645	23,593
Accumulated earnings, beginning of period	332,048	206,699	272,612	198,253
Accumulated earnings, end of period	$ 383,257	$ 221,846	$ 383,257	$ 221,846
Net income per Trust unit (*Note 3*)				
Basic	$ 0.49	$ 0.15	$ 1.08	$ 0.28
Diluted	$ 0.49	$ 0.15	$ 1.08	$ 0.28

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) (unaudited)

	3 months ended September 30,		9 months ended September 30,	
	2005	**2004**	**2005**	**2004**
Cash provided by (used in):				
Operating activities				
Net income	$ 51,209	$ 15,147	$ 110,645	$ 23,593
Add items not affecting cash:				
Depletion, depreciation and accretion	51,027	41,982	141,960	104,619
Commodity contracts unrealized loss	11,136	15,344	25,230	32,587
Future income taxes (recovery)	(1,911)	(6,149)	(4,171)	6,365
Actual abandonment costs incurred (*Note 7(b)*)	(339)	(1,249)	(1,772)	(3,222)
	111,122	65,075	271,892	163,942
Net change in non-cash operating working capital balances	(21,083)	(2,395)	(39,516)	24,797
Cash provided by operating activities	90,039	62,680	232,376	188,739
Financing activities				
Long-term debt	(9,846)	(12,989)	30,085	(20,640)
Distributions paid (*Note 8*)	(50,150)	(47,684)	(146,837)	(121,759)
Redemption of exchangeable shares *(Note 4)*	(258)	(450)	(904)	(1,352)
Capital lease repayments	(74)	(90)	(608)	(264)
Issuance of Trust units (*Note 3)*	452	1,642	77,874	3,351
Cash used in financing activities	(59,876)	(59,571)	(40,390)	(140,664)
Investing activities				
Asset retirement reserve (*Note 7(b))*	(518)	(482)	(1,485)	(1,228)
Corporate acquisitions (*Note 2 (a)(b))*	42	5,636	(56,058)	(1,800)
Property acquisitions	(11,287)	598	(17,768)	(1,544)
Property dispositions	871	-	871	-
Development expenditures	(29,895)	**(20,486)**	(108,908)	(47,931)
Cash acquired on acquisitions *(Note 2 (b))*	-	-	88	**9,711**
Cash used in investing activities	(40,787)	(14,734)	(183,260)	(42,792)
Net change in cash	(10,624)	(11,625)	8,726	5,283

Cash (bank overdraft), beginning of period	18,617	19,090	(733)	2,182
Cash, end of period				