

2005

enerPLUS
 RESOURCES FUND


THE ENERGY OF ENERPLUS

Third Quarter Report

Nine months ended September 30, 2005

SELECTED FINANCIAL AND OPERATING RESULTS

Nine months ended September 30,	2005	2004
Financial (000's)		
Net Income	\$ 270,539	\$ 143,804
Funds Flow from Operations ⁽¹⁾	503,193	390,565
Cash Distributed ⁽²⁾	363,050	317,388
Cash Withheld	140,143	73,177
Debt Outstanding ⁽³⁾	593,006	572,527
Development Capital Spending	229,646	134,179
Corporate and Property Acquisitions	591,456	621,808
Divestments	66,847	19,000
Weighted Average Number of Trust Units Outstanding	106,307	97,697
Debt/Trailing 12 Month Funds Flow Ratio ⁽¹⁾⁽³⁾	0.9x	1.2x
Financial per Unit		
Net Income	\$ 2.54	\$ 1.47
Funds Flow from Operations ⁽¹⁾	4.73	4.00
Cash Distributed ⁽²⁾	3.28	3.15
Cash Withheld	1.27	0.73
Payout Ratio	72%	81%
Selected Financial Results per BOE		
Oil & Gas Sales ⁽⁴⁾	\$ 47.98	\$ 40.39
Royalties	(9.66)	(8.31)
Financial Contracts ⁽⁵⁾	(4.40)	(3.20)
Operating Costs	(7.51)	(7.22)
General and Administrative ⁽⁵⁾	(1.19)	(0.98)
Interest and Foreign Exchange ⁽⁵⁾	(0.94)	(0.65)
Taxes	(0.38)	(0.25)
Restoration and Abandonment	(0.24)	(0.23)
Funds Flow from Operations ⁽¹⁾	\$ 23.66	\$ 19.55
Average Daily Production		
Natural gas (Mcf/day)	275,985	263,845
Crude oil (bbls/day)	27,343	24,475
NGLs (bbls/day)	4,569	4,480
Total (BOE/day) (6:1)	77,910	72,929
% Natural gas	59%	60%
Net Wells Drilled	281.4	241.8
Success Rate	99%	99%
Average Selling Price ⁽⁴⁾		
Natural gas (per Mcf)	\$ 7.35	\$ 6.56
Crude oil (per bbl)	\$ 54.85	\$ 42.85
NGLs (per bbl)	\$ 46.13	\$ 35.86
US\$ exchange rate	0.82	0.75

⁽¹⁾ See the definition of funds flow in Management's Discussion and Analysis

⁽²⁾ Calculated based on distributions paid or payable each month relating to the period

⁽³⁾ Debt is calculated net of cash

⁽⁴⁾ Including oil and gas transportation costs and before financial contracts

⁽⁵⁾ Non-cash amounts have been excluded

Trust Unit Trading Summary

For the three months ended September 30, 2005

	TSX - ERF.un (CDN\$)	NYSE - ERF (US\$)
High	\$55.14	\$47.52
Low	\$44.82	\$36.80
Close	\$54.91	\$47.20

2005 Cash Distributions per Trust Unit

		CDN\$	US\$
First Quarter Total		\$1.05	\$0.85
Second Quarter Total		\$1.07	\$0.88
Production Month	Payment Month		
July	September	\$0.37	\$0.32
August	October	0.37	0.31
September	November	0.42	0.35*
Third Quarter Total		\$1.16	\$0.98
Total Year-To-Date		\$3.28	\$2.71

* Calculated using an exchange rate of 1.19

PRESIDENT'S MESSAGE

Our third quarter has been very rewarding with the achievement of a number of significant accomplishments. We have achieved new highs in respect of production, drilling activity and capital spending year to date. Also, we are principally on track to achieve our full year development plans and production targets.

In our third quarter we successfully closed our acquisition of U.S. based Lyco Energy Corporation ("Lyco") for \$506 million thereby establishing a new significant core area for Enerplus in the U.S. We then followed that up with the announcement of our acquisition of Sleeping Giant LLC, another U.S. based private company, for \$109 million. This latter acquisition closed October 4th and increased our interest in the Sleeping Giant field, the principal producing field of Lyco, to an approximate 70% working interest. In conjunction with our strategic acquisitions in the U.S. we are in the process of establishing an office in Denver, Colorado to support our acquired operations and facilitate the potential for additional growth in the U.S.

In our second quarter report we advised that Total E&P Canada Ltd. ("Total"), a wholly-owned subsidiary of Total S.A., had made a takeover bid for Deer Creek Energy Ltd. ("Deer Creek") our operating partner in the Joslyn Creek oil sands project. Total was successful in acquiring over 82% of the Deer Creek common shares and has announced that they plan to acquire the balance of the outstanding shares through a subsequent acquisition transaction. We continue to work closely with Total on the advancement of the Joslyn Creek SAGD project as well as future plans for development of the mine potential on the Joslyn leases.

Commodity prices for both oil and natural gas continue to be strong for both the near and long term based upon current forward markets. World demand for oil and North American demand for natural gas combined with supply disruptions have kept the supply/demand equation in a very tight balance. In response to the continued strong outlook for commodity prices combined with our growing production levels, we increased our distribution per unit from 35 cents to 37 cents effective with the August 20th distribution and announced a further increase to 42 cents per unit to be effective with the November 20th distribution.

I wish to express my thanks to all of the staff at Enerplus for their diligence in execution on our oil and natural gas development projects, acquisition opportunities, continued improvement in our business processes and maintenance of field operations in a safe and responsible manner. We remain well positioned both financially and in respect of growth opportunities in the oil and natural gas industry.

FEDERAL GOVERNMENT CONSULTATION PAPER ON TRUSTS AND OTHER FLOW-THROUGH ENTITIES ("FTES").

In the Management's Discussion and Analysis - Non-Resident Ownership and Mutual Fund Trust Status section of our 2004 annual report, we indicated that we expected the Canadian federal government would invoke a consultation process relative to the status of trusts in the context of the Canadian tax environment. On September 8, 2005, the Department of Finance Canada released its much anticipated paper on "Tax and Other Issues Related to Publicly Listed Flow Through Entities" (the "FTE Paper") inviting interested parties to make a submission to the Finance Department by December 31, 2005.

We believe strongly in the benefits that trusts have had on the Canadian economy and the positive impact that cash distributions have had on our investors. We will be making a submission to the Department of Finance that will emphasize the contribution that Enerplus has made to the Canadian economy, our stakeholders and our productivity in making that contribution. A number of regulatory changes have been made recently, including limited liability legislation in various provincial jurisdictions and the forthcoming inclusion of trusts in the S&P/TSX Composite Index, which supports the recognition of trusts as an important investment option for both Canadian and foreign investors.

In our almost 20-year history, Enerplus has made cash distributions of over \$2.6 billion to its Unitholders, invested \$5 billion in building our business and raised \$3.2 billion of equity in the capital markets. Our current market capitalization is in the order of \$6 billion, our enterprise value is \$6.6 billion and we directly employ over 500 people across four provinces and indirectly, many more. Our simple average annual return to our Unitholders over the last 10 years has been over 20%. We are proud of our history and believe we offer a compelling example of how a trust can benefit the economy and its stakeholders and achieve sustainability as a long-term re-investing business.

We are fundamentally supportive of improving Canada's competitive access to capital and improvement in productivity through lower taxation of corporate entities and the dividends they pay. We do not however support any suggestion that additional government taxation of trusts will improve Canada's economy and its competitiveness. We believe the government may have reached some of their conclusions on income tax leakage on questionable assumptions, not the least of which includes no assessment of the spin off benefits from cash distributions being put into investor's hands, an assumption of the status quo with regard to the revenue base that would exist if trust businesses were conducted under a corporate structure and that the capital attracted to trust businesses would also be there to support these businesses if they were in corporate structures. We even question the definition of leakage when it includes the tax that they assume would be collected if the cash distributions were not going into pension funds, RRSPs and other such tax deferred accounts. These are the very investment vehicles Canadians have been encouraged to utilize to meet their retirement needs. So is there truly leakage or simply deferral that will ultimately be taxed when Canadians start to draw on these accounts in their retirement years? While we applaud the government's initiative on the consultative process that they have commenced, we don't believe it has garnered wide enough attention in the public realm and more importantly by those people most directly affected, being the investors in trusts. We recognize that a great number of our investors are individuals who deserve to have their voice heard in this public policy consultation process.

We have provided a brief summary of the questions posed for consideration in the consultative process in our Management's Discussion Analysis of this report under the heading "Update on Government Consultation Process". The announcement of the white paper and other comments made by government officials has created uncertainty in the minds of investors and we believe has resulted in a loss of market value across the income trust sector. The imposition of additional taxes on trusts would likely lead to a reduction in distributions which could have a further negative impact on the market value of income trusts.

We respectfully recommend that our Unitholders make some form of contact with the Canadian government to ensure that their voice is heard in this most important call for input into the consultation process. The following information will assist you in obtaining the full text of the FTE Paper as well as the contact information for the Department of Finance and your Member of Parliament so that you may voice your own concerns directly.

FTE White Paper: http://www.fin.gc.ca/toce/2005/toirplf_e.html

Written Submissions by e-mail: trusts-fiducies@fin.gc.ca

Minister of Finance
The Honourable Ralph Goodale
Department of Finance Canada
140 O'Connor Street
Ottawa, Ontario K1A 0A6
Phone: 613-996-4743
Fax: 613-996-9790
Email: goodale.r@parl.gc.ca

Your Member of Parliament www.canada.gc.ca/directories/direct_e.html

Enerplus Resources Fund is a member of the Canadian Association of Income Funds ("CAIF") and will support CAIF in making submissions as part of the consultation process.



Gordon J. Kerr
President & Chief Executive Officer

OPERATION'S OVERVIEW

We continue to experience record levels of activity in all areas of our operations as capital spending, drilling and production are all at the highest levels in Enerplus' 19-year history. Daily production averaged 79,406 BOE/day during the third quarter, higher than expected due to a one-time positive prior period adjustment in the quarter. We also closed the acquisition of Sleeping Giant LLC as a subsequent event on October 4, 2005 which will add 1,700 BOE/day to the fourth quarter. Despite these positive events, we continue to expect to meet our previous guidance of approximately 79,000 BOE/day for the full year and an exit rate of 86,000 BOE/day as a result of weather and construction delays that will defer an additional 1,800 BOE/day into early 2006. In total, we now estimate approximately 3,000 BOE/day of production (including 1,200 BOE/day highlighted in our second quarter) is expected to come on stream in early 2006 from our 2005 capital program which is not included in our 2005 exit rate forecast. The majority of the additional delayed production is associated with our oil development project at Bantry North and our coalbed methane development at Bashaw.

With the acquisition of Sleeping Giant LLC and the initial drilling opportunities identified on the North Dakota lands acquired from Lyco, we are revising our capital expenditure guidance upward from \$345 million to \$355 million. This is a significant increase over our 2004 development spending of \$206 million which is supported by a robust opportunity set driven by high commodity prices, our new acquisitions and rigorous technical work being undertaken on our existing properties.

Operating costs were in line with expectations although increasing cost pressures will offset the positive effects of adding the low cost Lyco production to our portfolio. We expect full year operating costs to remain at our guidance of \$7.45/BOE. Operating costs averaged \$7.69/BOE in the third quarter and \$7.51/BOE for the first nine months of the year inclusive of one month of the lower operating cost Lyco production. Our cost mitigation efforts and a full quarter of the lower cost Lyco production in the fourth quarter is expected to lower our fourth quarter operating costs and allow us to achieve our full year operating cost guidance.

The safety performance of our employees year-to-date for recordable and lost time incidents are 0.57 and zero incidents respectively per 200,000 man-hours worked. The one employee lost time incident reported in our second quarter statistics was recategorized by Workers' Compensation as not "arising in the course of employment". Consequently, our safety record for 2005 stands at zero employee lost time incidents to date.

The year-to-date recordable and lost time incidents for contractors are 1.70 and 0.24 incidents, respectively, per 200,000 man-hours worked for our Canadian operations which was a significant improvement over our first half results. Including our U.S. operations, however, increases our contractor recordable and lost time incidents to 2.03 and 0.68 per 200,000 man-hours respectively. We have begun to implement our safety programs in the U.S. operations and expect the safety performance there to improve markedly in the months ahead. We remain committed to employee and contractor safety throughout our operations.

VALUE CREATION

Our development spending continues to track toward record levels for the year despite weather and construction delays and increasing demands on the service sector within the industry. Development spending for the quarter increased to \$92 million bringing the total dollars invested through the first three quarters to \$230 million. We expect robust fourth quarter spending of approximately \$125 million that could increase further given continued inflationary pressures on the industry.

In the third quarter, Enerplus participated in the drilling of 244 gross wells (98 net) with a continued success rate of over 99%. Our activities were focused on shallow gas drilling at Hanna and Verger, waterflood development at Pembina and Joarcam, and coalbed methane drilling at Bashaw and Joffre. With our year-to-date drilling activity at 281.4 net wells, we expect to drill over 400 net wells in 2005 as planned, a new record level of drilling for Enerplus.

Q3 2005 Drilling Activity	Crude Oil Wells		Natural Gas Wells		Service Wells		Dry & Abandoned		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated wells	18.0	15.8	111.0	59.8	0.0	0.0	0.0	0.0	129.0	75.6
Non-operated wells	30.0	4.9	82.0	17.4	2.0	0.0	1.0	0.1	115.0	22.4
Total wells	48.0	20.7	193.0	77.2	2.0	0.0	1.0	0.1	244.0	98.0
Year-to-date total	126.0	47.5	479.0	231.8	6.0	2.0	1.0	0.1	612.0	281.4

SHALLOW NATURAL GAS DEVELOPMENT

Shallow natural gas development continues to be a major component of our capital investment portfolio. Our 77 well program at Hanna initiated in the second quarter was completed in the third quarter with the drilling of 14 gross wells (11.5 net) in the Second White Specs formation. All of the Hanna wells were completed and tied in by September as planned. At Verger, we drilled and completed 50 gross wells (19.6 net) in the Milk River/Medicine Hat formation. We expect that all Verger wells will be tied in by November. Significant development is planned at Medicine Hat, Princess and Shackleton in the fourth quarter.

WATERFLOOD DEVELOPMENT

We continue to pursue an active development program on our crude oil waterflood properties. In the third quarter, development activity occurred mostly at our Pembina and Joarcam properties. At Pembina, we drilled 5 gross oil wells (100% WI) in the Cardium formation. We expect that all 5 wells will be tied in by November. At Joarcam, 4 gross oil wells (3.7 net) were drilled in the Viking formation and facility upgrades were completed to accommodate the incremental oil production from our drilling and optimization efforts. Four additional Viking oil wells are planned for Joarcam in the fourth quarter. Additional development activities for the remainder of the year include drilling, optimization and facility upgrades at Medicine Hat, Silver Heights and Virden. This activity also has the potential to establish additional development opportunities for 2006 and beyond.

JOINT VENTURE DEEP GAS

During the third quarter, we participated with experienced industry partners in the drilling of 19 gross wells (1.4 net) at our joint venture deep gas properties in the Deep Basin and Foothills areas of western Alberta and northeastern British Columbia. We expect development activity to increase as we enter the winter drilling season in the fourth quarter and are projecting 2005 drilling in this area to total 85 gross wells (6.0 net).

COALBED METHANE ("CBM")

Coalbed methane development primarily in the Horseshoe Canyon coal formation has become a significant component of our capital development portfolio. Unlike most other CBM production in North America, the Horseshoe Canyon coals produce dry gas and are therefore more attractive as they do not have the issues related to water production typically associated with CBM. In the third quarter, we invested approximately \$13 million in CBM development activities, mostly at our Bashaw and Joffre properties. At Bashaw, we have drilled 16 gross wells (11.9 net) of our 41 well drilling program for 2005. Extremely wet weather has delayed this project but we still expect to complete all drilling by year-end with initial production on stream in late 2005 and early 2006. At Joffre, we participated in the drilling of 11 gross wells (5.5 net) with additional wells planned for the fourth quarter. We expect to participate in the drilling of 78 gross wells (39 net) CBM wells in total at Joffre in 2005.

SLEEPING GIANT DEVELOPMENT

Since closing of the Lyco acquisition on August 30, 2005, Enerplus has invested approximately \$7 million to the end of the third quarter participating in the drilling of 3 gross wells in the Sleeping Giant project in Montana. With the acquisition of additional interests that closed on October 4, 2005 and the initial drilling in North Dakota, we expect to spend an additional \$7 million on drilling this year. In total, approximately \$27 million will be invested on drilling and development activities at our new U.S. properties in 2005 with expected initial production of approximately 1,700 BOE/day. This will include 9 gross development wells in the Sleeping Giant project and 2 exploratory wells (1 net) on our North Dakota acreage. Currently, we have no volumes in our production guidance associated with the North Dakota drilling.

OTHER CONVENTIONAL DEVELOPMENT

In the third quarter, Enerplus invested approximately \$10 million at Bantry North, a property acquired through the ChevronTexaco Corporation ("ChevronTexaco") asset acquisition. This investment was mainly for the construction of a facility to handle incremental production from existing wells and the 5 new oil wells drilled earlier this year in the Sunburst formation. The production handling facility will be completed on schedule in November of this year. However, delays in the construction of a non-operated sour gas facility and a metre station tie-in have delayed our ability to realize the full benefits of this project until the first quarter of 2006. We plan to drill 3 additional horizontal wells in the fourth quarter and more locations are tentatively planned for 2006.

During the third quarter, we invested approximately \$19 million in various other conventional oil and gas drilling and development activities throughout the Western Canadian Sedimentary Basin. We have initiated an oil infill drilling program in southeast Saskatchewan with the drilling of 3 gross wells (2.7 net) during the quarter and plan to drill another 3 wells in the fourth quarter.

OIL SANDS DEVELOPMENT

Development of the 10,000 bbl/day (1,600 bbl/day net) Phase II SAGD oil sands project at Joslyn continues on schedule with engineering, procurement, drilling and construction proceeding as planned. The SAGD Phase I facility is performing as designed and is providing useful information for the operation of SAGD Phase II. Production from the SAGD Phase I well pair has been producing below expectations due to restricted reservoir flow capacity. After technical analysis, the operator has concluded that a portion of the producing well was located too close to the underlying Devonian formation and has inhibited steam chamber development and the associated production. Production from this well pair is expected to average 200 barrels of bitumen per day for the year. Going forward, the new well pairs in the Phase II project have been designed to avoid this situation and we do not anticipate any material change to the commercial project expected well rates or recoveries.

In other efforts to enhance the commercial project, the operator, in cooperation with industry participants, initiated a pilot to explore the potential of burning emulsified bitumen as an alternative fuel to natural gas, a process known as multiphase superfine atomized residue or MSAR™. If successful, this type of process could materially reduce natural gas usage and associated operating costs for the SAGD commercial project although it could also increase capital costs. Detailed emissions data collected during the continuous burning of MSAR™ fuel will be used to evaluate future fuel alternatives that could be used to enhance the commercial project. Drilling of the initial 17 well pairs required for the Phase II project is well underway, with completion and initial steam injection planned for early 2006.

During the quarter, Total E&P Canada Ltd. ("Total") made an all-cash offer to acquire all of the issued and outstanding common shares of Deer Creek Energy Limited, the 84% working interest owner and operator of the Joslyn lease, for \$31.00 per share. Under the offer, Total acquired approximately 82.4% of the common shares of Deer Creek Energy Limited and plans to acquire the remaining common shares at the same offer price through a subsequent acquisition transaction.

Total has publicly discussed accelerating development of the project and including a large-scale upgrader in conjunction with the mining portion of the project. We are currently working with Total to determine how Enerplus and Total can work together to unlock the value of this extensive oil sands resource.

ACQUISITIONS AND DIVESTMENTS

We maintain a disciplined approach to evaluating conventional upstream opportunities within Canada and the U.S. In addition, we continue to examine oil sand developments and international projects that may provide attractive economics, accretion and growth.

Lyco Energy Corporation

On August 30, 2005, Enerplus closed the acquisition of Lyco Energy Corporation, a private oil and natural gas producer operating in Montana and North Dakota for total consideration of \$506 million. This was our single largest transaction to date and our first acquisition outside of Canada. Approximately 7,000 BOE/day of primarily operated production was acquired, weighted 92% to light sweet oil. The acquisition adds 22.5 million BOE of proved reserves and 31 million BOE of proved plus probable reserves with reserve life indices of 8.8 and 12.1 years respectively. In addition to the light oil producing assets in the Sleeping Giant project area of the Williston Basin in Montana, we acquired undeveloped land in Montana and three prospect areas in North Dakota which totalled approximately 120,000 net acres.

The Sleeping Giant project is a solution gas drive reservoir providing the potential for improved recovery through waterflooding, infill drilling to greater than 2 wells per section and/or possible CO₂ flooding, none of which are included in the independent engineering assessment. We have initiated drilling in North Dakota where our primary target is the Middle Bakken formation that could develop into an attractive resource play across our prospect area.

Sleeping Giant LLC

In a follow-on transaction to our purchase of Lyco Energy Corporation, on September 21, 2005, we announced our agreement to acquire Sleeping Giant LLC, a private U.S. oil and natural gas producer whose assets increase our working interest in the Sleeping Giant project in Montana. On October 4, 2005, we closed the acquisition for total consideration of approximately \$109 million including deal costs and assumed debt net of working capital. The acquisition increases our ownership in the Sleeping Giant project to approximately 70% adding approximately 1,700 BOE/day of production weighted 90% to light sweet oil. An estimated 5 million BOE of proved reserves and 7 million BOE of proved plus probable reserves were acquired with an 8.4 and 11.6 year reserve life index respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated November 7, 2005 and is to be read in conjunction with:

- the MD&A and audited consolidated financial statements as at and for the years ended December 31, 2004 and 2003; and
- the unaudited interim consolidated financial statements as at September 30, 2005 and for the three and nine months ended September 30, 2005 and 2004.

All amounts are stated in Canadian dollars unless otherwise specified. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading.

NON-GAAP MEASURES

Throughout the MD&A, we use the terms funds flow from operations ("funds flow") and cash available for distribution. These terms as presented do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP"), and therefore they may not be comparable with the calculation of similar measures for other entities. Funds 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 GAAP. Funds flow is used by management to analyze operating performance, leverage and liquidity. All references to funds flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital. Cash available for distribution is calculated using funds flow less cash discretionary amounts of withheld for acquisitions, capital expenditures and debt repayment. Refer to the Cash Available for Distribution section of the MD&A for a quantitative reconciliation of "funds flow" to cash flow from operating activities.

OVERVIEW

Continued strong commodity prices along with higher production from our recent acquisitions and development program helped increase funds flow from operations during the quarter. With the closing of the acquisitions of TriLoch Resources Inc. ("TriLoch") on July 1, 2005 and Lyco Energy Corporation ("Lyco") on August 30, 2005, we added approximately 8,500 BOE/day of production and 26.3 million BOE of total proved reserves, replacing approximately 91% of projected 2005 total production. In response to the increased funds flow from operations, we recently announced a 14% increase in our monthly distributions to CDN \$0.42 per unit, effective for the November 2005 distribution. On October 4, 2005 we closed the acquisition of Sleeping Giant LLC ("Sleeping Giant"), a private U.S. company. The results of the Sleeping Giant acquisition will be included with our fourth quarter.

RESULTS OF OPERATIONS

Production

Production averaged 79,406 BOE/day during the third quarter of 2005, an increase of 5% from 75,502 BOE/day during the second quarter of 2005. This increase in production is attributable to our development capital program, our recent acquisitions and reduced downtime due to the completion of facility maintenance. In addition, the quarter included approximately \$5.0 million of revenue (net of royalties) and 2,300 BOE/day (800 BOE/day year-to-date) of production related to a non-recurring prior period adjustment.

For the three months ended September 30, 2005 production was 1% higher than the comparable period in 2004, and year-to-date 2005 production was 7% higher than 2004. This increased production was primarily due to acquisitions and development capital spending, partly offset by the disposition of properties in the first quarter of 2005.

Average production volumes for the three and nine months ended September 30, 2005 and 2004 are outlined below:

Daily Production Volumes	Three months ended September 30,			Nine months ended September 30,		
	2005	2004	% Change	2005	2004	% Change
Natural gas (Mcf/day)	278,356	277,641	0%	275,985	263,845	5%
Crude oil (bbls/day)	28,475	27,757	3%	27,343	24,475	12%
Natural gas liquids (bbls/day)	4,538	4,449	2%	4,569	4,480	2%
Total daily sales (BOE/day)	79,406	78,480	1%	77,910	72,929	7%

We expect increased production volumes during the remainder of the year due to our recent acquisitions and our development capital program. We anticipate production will average approximately 79,000 BOE/day during 2005. We have experienced some delays with our development capital program and as a result we expect approximately 3,000 BOE/day of production to be deferred into the first quarter 2006. We continue to expect a 2005 exit production rate of approximately 86,000 BOE/day weighted 54% natural gas and 46% crude oil and natural gas liquids.

Pricing

Our earnings, funds flow and financial condition are dependent on the prices received for our natural gas and crude oil production. Natural gas and crude oil prices have fluctuated widely during recent years and continue to be volatile.

The following table compares the Fund's average selling price for the three and nine months ended September 30, 2005 and 2004. It also compares the benchmark price indices for the same periods.

Average Selling Price ⁽¹⁾	Three months ended September 30,			Nine months ended September 30,		
	2005	2004	% Change	2005	2004	% Change
Natural gas (per Mcf)	\$ 8.09	\$ 6.39	27%	\$ 7.35	\$ 6.56	12%
Crude oil (per bbl)	\$ 65.35	\$ 47.67	37%	\$ 54.85	\$ 42.85	28%
Natural gas liquids (per bbl)	\$ 48.60	\$ 41.52	17%	\$ 46.13	\$ 35.86	29%
Per BOE	\$ 54.57	\$ 41.86	30%	\$ 47.98	\$ 40.39	19%

⁽¹⁾ Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Average Benchmark Pricing	Three months ended September 30,			Nine months ended September 30,		
	2005	2004	% Change	2005	2004	% Change
AECO (30 day) natural gas (per Mcf)	\$ 8.17	\$ 6.66	23%	\$ 7.42	\$ 6.69	11%
NYMEX natural gas (US\$ per Mcf)	\$ 8.25	\$ 5.84	41%	\$ 7.12	\$ 5.84	22%
NYMEX natural gas (CDN\$ per Mcf)	\$ 9.94	\$ 7.58	31%	\$ 8.68	\$ 7.79	11%
WTI crude oil (US\$ per bbl)	\$ 63.19	\$ 43.88	44%	\$ 55.40	\$ 39.11	42%
WTI crude oil (CDN\$ per bbl)	\$ 76.13	\$ 56.99	34%	\$ 67.56	\$ 52.15	30%
CDN\$/US\$ exchange rate	\$ 0.83	\$ 0.77	8%	\$ 0.82	\$ 0.75	9%

We realized an average price for our natural gas of \$8.09/Mcf (net of transportation) during the three months ended September 30, 2005, an increase of 27% from \$6.39/Mcf for the same period in 2004. In comparison, the AECO monthly index price for natural gas increased 23% and the NYMEX price, after adjusting for the change in the US\$ exchange rate, increased 31% for the same period. For the nine months ended September 30, 2005 our realized price for natural gas increased 12% compared to the same period in 2004. This was comparable to the increase in the natural gas benchmarks for the same period.

The average price we received for our crude oil during the three months ended September 30, 2005 increased 37% to \$65.35/bbl (net of transportation) from \$47.67/bbl during the same period of 2004. In comparison, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the U.S. dollar exchange rate, increased 34% over the corresponding period of 2004. For the nine months ended September 30, 2005 our realized crude oil price increased 28% compared to a 30% increase in the benchmark pricing over the same period. Our recent acquisitions have increased the volume of light sweet oil production and as a result we expect a more favourable relationship between our realized price and the underlying Canadian dollar denominated WTI benchmark price going forward.

The Canadian dollar strengthened 8% and 9% for the three and nine months ended September 30, 2005 respectively compared to the same period in 2004. As most of our crude oil and a portion of our natural gas are priced in reference to U.S. dollar denominated benchmarks, the strengthening Canadian dollar reduced the prices that we would have otherwise realized.

Price Risk Management

Our commodity price risk management program incurred cash costs of \$44.0 million during the third quarter of 2005 compared to \$29.6 million during the corresponding period of 2004. During the nine months ended September, 2005 cash costs were \$93.7 million compared to \$63.9 million for the same period in 2004. The increase in cash costs during 2005 compared to 2004 was primarily due to record high oil and natural gas prices which exceeded our calls. The majority of these calls, put in place in 2003 and 2004, will expire by December 31, 2005, with some gas positions extending until October 2006.

Risk Management Cash Costs (\$ millions except per unit amounts)	Three months ended September 30, 2005		Three months ended September 30, 2004	
	Crude oil	\$ 32.2	\$ 12.30/bbl	\$ 24.7
Natural gas	11.8	\$ 0.46/Mcf	4.9	\$ 0.19/Mcf
Net cost	<u>\$ 44.0</u>	<u>\$ 6.03/BOE</u>	<u>\$ 29.6</u>	<u>\$ 4.10/BOE</u>

Risk Management Cash Costs (\$ millions except per unit amounts)	Nine months ended September 30, 2005		Nine months ended September 30, 2004	
	Crude oil	\$ 73.6	\$ 9.86/bbl	\$ 49.4
Natural gas	20.1	\$ 0.27/Mcf	14.5	\$ 0.20/Mcf
Net cost	<u>\$ 93.7</u>	<u>\$ 4.40/BOE</u>	<u>\$ 63.9</u>	<u>\$ 3.21/BOE</u>

We continue to adjust our risk management strategies in response to the increasing price environment, the economics of our acquisitions and development projects along with our overall financial position. We entered into very few price risk management transactions in the third quarter and we are not anticipating entering into any transactions in the fourth quarter. However, this strategy may change in the future as management is constantly comparing the cost of hedging with the benefit of price protection. Based on the existing price risk management positions and in the context of the current commodity price environment, the overall program cost for 2006 is expected to decrease compared to 2005.

The following table summarizes the effects that our financial contracts have had on income for the three and nine months ended September 30, 2005 and 2004.

Commodity Derivative Instruments	Three months ended September 30, 2005		Three months ended September 30, 2004	
	(\$ Millions)	(Per BOE)	(\$ Millions)	(Per BOE)
Financial contracts not qualifying for hedge accounting:				
Change in fair value - other financial contracts	\$ (3.5)	\$ (0.48)	\$ 27.1	\$ 3.76
Amortization of deferred financial assets	0.8	0.10	4.2	0.58
Cash costs of financial contracts	37.9	5.19	25.1	3.47
	\$ 35.2	\$ 4.81	\$ 56.4	\$ 7.81
Financial contracts qualifying for hedge accounting:				
Cash costs of financial contracts	6.1	0.84	4.5	0.63
Total cost of financial contracts	\$ 41.3	\$ 5.65	\$ 60.9	\$ 8.44

Commodity Derivative Instruments	Nine months ended September 30, 2005		Nine months ended September 30, 2004	
	(\$ Millions)	(Per BOE)	(\$ Millions)	(Per BOE)
Financial contracts not qualifying for hedge accounting:				
Change in fair value - other financial contracts	\$ 4.2	\$ 0.20	\$ 71.8	\$ 3.59
Amortization of deferred financial assets	2.8	0.13	15.0	0.75
Cash costs of financial contracts	80.3	3.77	50.3	2.52
	\$ 87.3	\$ 4.10	\$ 137.1	\$ 6.86
Financial contracts qualifying for hedge accounting:				
Cash costs of financial contracts	13.4	0.63	13.6	0.68
Total cost of financial contracts	\$ 100.7	\$ 4.73	\$ 150.7	\$ 7.54

The unrealized gain on our financial contracts of \$3.5 million for the three months ended September 30, 2005 represents the change in fair value of financial contracts not qualifying for hedge accounting. Similarly the unrealized loss of \$4.2 million for the nine months ended September 30, 2005 represents the change in fair value from December 31, 2004 to September 30, 2005. As the forward markets for natural gas and crude oil fluctuate and existing contracts are realized, changes in fair value are reflected as a non-cash charge or non-cash increase to earnings.

The amortization of deferred financial assets is a result of our adopting the accounting rules for hedging relationships. On January 1, 2004, we recorded a deferred financial asset representing the fair value of the financial contracts that ceased to qualify for hedge accounting. The asset has been included in deferred charges and amortization of this asset was \$0.8 million for the three months ended September 30, 2005 and \$2.8 million for the nine months ended September 30, 2005, leaving an unamortized balance of \$0.4 million. Our current commodity risk management positions are fully described in Note 7.

Our funds flow remains sensitive to effects of changing prices and exchange rates as demonstrated by the following table:

Sensitivity Table	Estimated Effect on Annual Funds Flow per Trust Unit
Change of \$0.15 per Mcf in the price of AECO natural gas	\$0.07
Change of US\$1.00 per barrel in the price of WTI crude oil	\$0.06
Change of 1,000 BOE/day in production	\$0.13
Change of \$0.01 in the US\$/CDN\$ exchange rate	\$0.10
Change of 1% interest rate	\$0.04

These sensitivities reflect all commodity contracts as described in Note 7 and are based on current forward markets. To the extent the market price of crude oil and natural gas change to levels that are above the ceiling or below the floor price limits set by existing commodity contracts, the above sensitivity will no longer be relevant.

REVENUES

Crude oil and natural gas revenues increased 25% during the third quarter compared to the second quarter of 2005, due to increased production and commodity prices. Crude oil and natural gas revenues for the three months ended September 30, 2005 were \$398.7 million (\$404.8 million, net of \$6.1 million transportation) compared to \$302.2 million (\$308.2 million, net of \$6.0 million transportation) for the same period in 2004. For the nine months ended September 30, 2005 revenues were \$1,020.5 million (\$1,040.8 million, net of \$20.3 million transportation) compared to \$807.1 million (\$825.7, net of \$18.6 million transportation) during the same period in 2004.

The increased revenues for the three and nine months ended September 30, 2005 of \$96.5 million or 32% and \$213.4 million or 26%, respectively, are due to higher crude oil and natural gas prices as well as increased production resulting from our recent acquisitions and development capital program.

Analysis of Sales Revenue ⁽¹⁾

(\$ millions)	Crude Oil	NGLs	Natural Gas	Total
Quarter ended September 30, 2004	\$ 121.8	\$ 16.9	\$ 163.5	\$ 302.2
Price variance ⁽¹⁾	46.3	3.0	43.4	92.7
Volume variance	3.1	0.3	0.4	3.8
Quarter ended September 30, 2005	\$ 171.2	\$ 20.2	\$ 207.3	\$ 398.7

(\$ millions)	Crude Oil	NGLs	Natural Gas	Total
Year-to-date ended September 30, 2004	\$ 287.3	\$ 44.0	\$ 475.8	\$ 807.1
Price variance ⁽¹⁾	89.7	12.8	57.7	160.2
Volume variance	32.5	0.7	20.0	53.2
Year-to-date ended September 30, 2005	\$ 409.5	\$ 57.5	\$ 553.5	\$1,020.5

⁽¹⁾ Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

ROYALTIES

Due to increased production and higher commodity prices, royalties paid to various government entities and other land and mineral rights owners increased for the three and nine months ended September 30, 2005 compared to the same periods in 2004. We are incurring U.S. state production tax as a result of the Lyco acquisition and have included this tax with royalties. Royalties are approximately 20% of oil and gas sales, net of transportation, and are expected to remain at this level for the remainder of 2005.

OPERATING EXPENSES

Operating expenses for the third quarter of 2005 were \$7.69/BOE or 2% lower than the second quarter of 2005. Rising industry costs were partially off-set by lower operating cost properties acquired through the Lyco acquisition along with a prior period production adjustment that had no associated operating costs.

Operating expenses for the three months ended September 30, 2005 were \$56.2 million or \$7.69/BOE compared to \$53.0 million or \$7.34/BOE for the third quarter of 2004. For the nine months ended September 30, 2005 operating costs were \$159.7 million or \$7.51/BOE compared to \$144.3 million or \$7.22/BOE for the same period in 2004. With the anticipated production increases during the final quarter of the year and the benefits of our U.S. production, operating costs per BOE are expected to moderate. We continue to expect operating costs to average \$7.45/BOE for the year.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses for the three months ended September 30, 2005 were \$17.4 million or \$2.38/BOE compared to \$7.9 million or \$1.10/BOE for the third quarter of 2004. G&A expenses totaled \$38.1 million or \$1.79/BOE for the nine months ended September 30, 2005 compared to \$21.9 million or \$1.10/BOE for the same period in 2004. The main reason for these increases over 2004 related to the non-cash charge for our trust unit rights incentive plan. These charges were \$7.6 million and \$12.8 million for the three and nine months ended September 30, 2005. This non-cash charge is based on the excess of the trust unit price over the exercise price of the rights. See Note 6 for a description of our rights plan.

Our cash G&A costs per BOE increased from prior years as the increased industry activity has put pressure on compensation and other service costs. However, we continue to expect cash G&A costs to remain at our previous guidance of \$1.27/BOE for the year.

As a result of our recent trust unit price appreciation, we are increasing our total G&A cost estimate from \$1.65/BOE to \$1.75/BOE for 2005.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs (\$ millions)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Cash	\$ 9.8	\$ 6.5	\$ 25.3	\$ 19.6
Trust unit rights incentive plan (non-cash)	7.6	1.4	12.8	2.3
Total G&A	\$ 17.4	\$ 7.9	\$ 38.1	\$ 21.9
(Per BOE)				
Cash	\$ 1.34	\$ 0.91	\$ 1.19	\$ 0.98
Trust unit rights incentive plan (non-cash)	1.04	0.19	0.60	0.12
Total G&A	\$ 2.38	\$ 1.10	\$ 1.79	\$ 1.10

INTEREST EXPENSE

Interest expense in the third quarter of 2005 was comparable to the second quarter of 2005. Interest expense increased to \$6.0 million for the third quarter of 2005 from \$5.7 million during the same period in 2004. Interest expense increased to \$17.7 million for the nine months ended September 30, 2005 from \$14.6 million during the same period in 2004. Increases in the prime lending rate and the average debt outstanding for the three and nine months ended September 30, 2005 compared to the same periods in 2004 caused the increase in interest expense.

At September 30, 2005, approximately 22% of our debt was subject to fixed interest rates while 78% was subject to floating rates of interest.

FOREIGN EXCHANGE

Non-cash gains or losses result from translating our US\$54 million senior unsecured notes into Canadian dollars at period end. In addition, we incur minimal cash gains or losses from day-to-day transactions denominated in U.S. dollars. We experienced a foreign exchange loss of \$0.8 million during the three months ended September 30, 2005 compared to a gain of \$4.1 million for the same period in 2004. We experienced a loss of \$2.0 million for the nine months ended September 30, 2005 compared to a gain of \$1.5 million during the same period of 2004. See Note 5 for details.

CAPITAL EXPENDITURES

We spent \$91.8 million and \$229.6 million on development drilling and facilities for the three and nine months ended September 30, 2005, respectively, compared to \$48.5 million and \$133.3 million during the same periods in 2004. We achieved a success rate of over

99% with our drilling program as 98.0 net wells were drilled during the third quarter and 281.4 net wells were drilled year-to-date for 2005, focusing primarily on shallow gas development, waterflood development, coalbed methane and our SAGD project at Joslyn Creek.

We acquired Lyco on August 30, 2005 for \$506.4 million and TriLoch on July 1, 2005 for \$77.8 million. See Note 4 for further disclosure. In addition, on October 4, 2005 we acquired Sleeping Giant for \$109 million. See Note 8 for further disclosure.

In addition to the corporate acquisitions, property acquisitions of \$1.7 million and \$7.3 million for the three and nine months ended September 30, 2005, respectively, were minimal compared to \$20.2 million and \$489.6 million for the same periods in 2004. The ChevronTexaco asset acquisition was included with the 2004 results. Our non-core divestment program raised \$0.4 million and \$66.9 million for the three and nine months ended September 2005, respectively, compared to \$16.5 million and \$19.0 million for the same periods in 2004.

Total net capital expenditures for 2005 and 2004 are outlined below.

Capital Expenditures (\$ millions)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Development expenditures	\$ 64.7	\$ 33.0	\$ 174.9	\$ 99.0
Plant and facilities	27.1	15.5	54.7	34.3
Development Capital	91.8	48.5	229.6	133.3
Office	1.1	0.4	3.3	0.9
Sub-total	92.9	48.9	232.9	134.2
Acquisitions of oil and gas properties	1.7	20.2	7.3	489.6
Corporate acquisitions	584.2	–	584.2	132.2
Dispositions of oil and gas properties	(0.4)	(16.5)	(66.9)	(19.0)
Total Net Capital Expenditures	\$ 678.4	\$ 52.6	\$ 757.5	\$ 737.0

We have increased our estimate of 2005 development capital expenditures from \$345 million to \$355 million, due to the acquisition of Sleeping Giant LLC and drilling opportunities on the North Dakota lands acquired from Lyco.

DEPLETION, DEPRECIATION, AMORTIZATION AND ACCRETION (“DDA&A”)

DDA&A of property, plant and equipment is recognized using the unit-of-production method based on proved reserves on a country by country basis.

For the three months ended September 30, 2005, DDA&A increased to \$13.47/BOE compared to \$12.58/BOE during the corresponding period in 2004. For the nine months ended September 30, 2005, DDA&A increased to \$12.75/BOE compared to \$11.80/BOE during the corresponding period in 2004. The increase in DDA&A is primarily due to our recent acquisitions, which were acquired in a higher commodity price environment.

No impairment of the Fund's assets existed at September 30, 2005 using year-end reserves updated for acquisitions, divestitures, production and management's estimates of future prices.

TAXES

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In our current Canadian structure, payments are made between the operating entities and the Fund, ultimately transferring both income and future income tax liability to our unitholders. Therefore, no cash income taxes have been paid by our Canadian operating entities, and as such, the future income tax liability recorded on the balance sheet is recovered through earnings over time.

With the Lyco and Sleeping Giant acquisitions, we are expecting to incur some ongoing corporate income tax in the United States and cross-border withholding tax on funds repatriated into Canada. Taxable income in the United States will be reduced through interest

charges and our capital expenditure program. For the three months ended September 30, 2005, the Fund recorded a current income and withholding tax expense of \$3.1 million.

For the three months ended September 30, 2005 a future income tax recovery of \$4.2 million was recorded in income compared to \$26.8 million for the same period in 2004. For the nine months ended September 30, 2005, a future income tax recovery of \$50.9 million was recorded in income compared to \$72.0 million for the same period in 2004. Net income of the operating companies and the tax recovery fluctuate based on royalty and interest payments to the Fund. In order to maximize tax pool deductions, the amount of cash withheld for debt repayment was increased in certain subsidiaries and as a result, the future income tax recovery was reduced in the third quarter.

SELECTED FINANCIAL RESULTS

Per BOE of production (6:1)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Production per day	79,406	78,480	77,910	72,929
Weighted average sales price ⁽¹⁾	\$ 54.57	\$ 41.86	\$ 47.98	\$ 40.39
Royalties	(10.77)	(8.68)	(9.66)	(8.31)
Financial contracts	(5.65)	(8.44)	(4.73)	(7.54)
Add back: Non-cash financial contracts	(0.38)	4.34	0.33	4.34
Operating costs	(7.69)	(7.34)	(7.51)	(7.22)
General and administrative	(2.38)	(1.10)	(1.79)	(1.10)
Add back: Non-cash G&A expense (trust unit rights)	1.04	0.19	0.60	0.12
Interest expense, net of interest and other income	(0.66)	(0.79)	(0.73)	(0.64)
Foreign exchange (loss)/gain	(0.11)	0.57	(0.10)	0.07
Add back: Non-cash foreign exchange gain	(0.48)	(0.57)	(0.11)	(0.08)
Current income tax	(0.42)	–	(0.14)	–
Capital taxes	(0.26)	(0.21)	(0.24)	(0.25)
Restoration and abandonment cash costs	(0.22)	(0.22)	(0.24)	(0.23)
Funds flow from operations	26.59	19.61	23.66	19.55
Restoration and abandonment cash costs	0.22	0.22	0.24	0.23
Non-cash items				
Depletion, depreciation, amortization and accretion	(13.47)	(12.58)	(12.75)	(11.80)
Financial contracts	0.38	(4.34)	(0.33)	(4.34)
G&A expense (trust unit rights)	(1.04)	(0.19)	(0.60)	(0.12)
Foreign exchange	0.48	0.57	0.11	0.08
Future income tax recovery	0.58	3.72	2.39	3.60
Total net income per BOE	\$ 13.74	\$ 7.01	\$ 12.72	\$ 7.20

⁽¹⁾ Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

CANADIAN AND U.S. FINANCIAL RESULTS

(\$ millions)	Three months ended September 30, 2005		Nine months ended September 30, 2005	
	Canada	United States	Canada	United States
Production per day (BOE/day)*	76,889	2,517	77,062	848
Revenues				
Oil and gas sales	\$ 387.9	\$ 16.9	\$ 1,023.9	\$ 16.9
Royalties**	(75.6)	(3.1)	(202.4)	(3.1)
Financial Contracts – Qualified Hedges	(6.1)	–	(13.4)	–
Other Financial Contracts	(35.3)	0.1	(87.4)	0.1
	270.9	13.9	720.7	13.9
Expenses				
Operating	55.8	0.4	159.3	0.4
General and Administrative	17.1	0.3	37.8	0.3
Transportation	6.1	–	20.3	–
Depletion, depreciation, amortization and accretion	91.7	6.6	264.5	6.6
Current income and withholding taxes	–	3.1	–	3.1
	170.7	10.4	481.9	10.4
Income before capital and future taxes, interest and foreign exchange	\$ 100.2	\$ 3.5	\$ 238.8	\$ 3.5

* United States production per day (BOE/day) represents average daily production for the three and nine months ended September 30, 2005. United States operations commenced with the closing of the Lyco acquisition on August 30, 2005, therefore only one month of production is included.

** Royalties include state production tax.

FUNDS FLOW FROM OPERATIONS AND NET INCOME

Funds flow from operations for the third quarter of 2005 was 25% higher than the second quarter. For the three months ended September 30, 2005, funds flow from operations was \$194.2 million or \$1.77 per trust unit compared to \$141.6 million or \$1.36 per trust unit for the same period in 2004. For the nine months ended September 30, 2005, funds flow from operations was \$503.2 million or \$4.73 per trust unit compared to \$390.6 million or \$4.00 per trust unit for the same period in 2004. Funds flow from operations increased as a result of higher production and commodity prices in 2005, offset in part by cash losses from our price risk management program, higher operating and general and administration costs.

Net income for the third quarter of 2005 was \$100.3 million or \$0.91 per trust unit compared to \$50.6 million or \$0.49 per trust unit for the third quarter of 2004. Net income for the nine months ended September 30, 2005 was \$270.5 million or \$2.54 per trust unit compared to \$143.8 million or \$1.47 per trust unit for the same period in 2004. The increase during 2005 compared to 2004 is mainly attributed to higher production and commodity prices as well as favourable changes in the fair values of financial contracts over the periods.

CASH AVAILABLE FOR DISTRIBUTION

We monitor the distribution payout with respect to forecasted funds flows, debt levels and capital development opportunities. The level of cash retained typically varies between 10% and 30% of annual funds flow, however we are prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure. Our payout ratio for the three and nine months ended September 30, 2005 was 70% and 72%, respectively, compared to a payout ratio of 77% and 81% for the same periods in 2004. The monthly cash distribution will increase to \$0.42 per trust unit for the distribution payable on November 20, 2005.

The following table reconciles Enerplus' funds flow from operations with the cash available for distribution to unitholders.

Reconciliation of Cash Available for Distribution (\$ millions except per trust unit amounts)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Funds flow from operations activities	\$ 180.7	\$ 153.7	\$ 486.2	\$ 404.5
Change in non-cash operating working capital	13.5	(12.1)	17.0	(13.9)
Funds flow from operations	\$ 194.2	\$ 141.6	\$ 503.2	\$ 390.6
Cash withheld for acquisitions, capital expenditures and debt repayment*	(58.2)	(32.5)	(140.1)	(73.2)
Cash available for distribution**	\$ 136.0	\$ 109.1	\$ 363.1	\$ 317.4
Cash available for distribution per trust unit	\$ 1.16	\$ 1.05	\$ 3.28	\$ 3.15
Payout ratio	70%	77%	72%	81%

* Cash withheld for acquisitions, capital expenditures and debt repayment is a discretionary amount and represents the difference between cash flow from operations less distributions.

** Cash available for distribution will differ from Cash Distributions to Unitholders on the Consolidated Statements of Cash Flows due to the timing of distribution announcement and actual payments.

QUARTERLY FINANCIAL INFORMATION

Generally, oil and gas sales have increased due to higher prices and production. Production has increased both through acquisitions and capital development during the last two years, while the overall price increase has been offset by an increased Canadian/U.S. dollar exchange rate. Net income has been affected by the fluctuations in oil and gas sales, risk management costs, and the Canadian dollar. Increasing operating costs, changes to accounting policies adopted during 2003 and 2004, and changes in fair values of our financial contracts continue to cause net income to fluctuate between quarters.

Quarterly information is summarized in the following table:

Quarterly Financial Information (\$ millions, except per trust unit amounts)	Oil and Gas Sales ⁽¹⁾	Net Income	Net income per trust unit	
			Basic	Diluted
2005				
Third quarter	\$ 398.7	\$ 100.3	\$ 0.91	\$ 0.91
Second quarter	\$ 320.0	\$ 108.0	\$ 1.03	\$ 1.03
First quarter	\$ 301.8	\$ 62.2	\$ 0.60	\$ 0.59
2004				
Fourth quarter	\$ 317.5	\$ 114.5	\$ 1.10	\$ 1.10
Third quarter	302.2	50.6	0.49	0.49
Second quarter	265.6	48.0	0.51	0.51
First quarter	239.3	45.2	0.48	0.48
Total	\$ 1,124.6	\$ 258.3	\$ 2.60	\$ 2.60
2003 (Restated) ⁽²⁾				
Fourth quarter	\$ 201.5	\$ 40.6	\$ 0.45	\$ 0.45
Third quarter	219.7	59.2	0.67	0.67
Second quarter	233.5	53.4	0.64	0.64
First quarter	281.1	94.8	1.14	1.14
Total	\$ 935.8	\$ 248.0	\$ 2.88	\$ 2.87

⁽¹⁾ Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

⁽²⁾ Restated to reflect the adoption of new accounting policies (AcG-13, CICA 3110)

LIQUIDITY AND CAPITAL RESOURCES

Long-term debt at September 30, 2005 was \$625.6 million, an increase of \$40.6 million from December 31, 2004. The increase in debt is due to our expanded development capital program and our recent Lyco acquisition, partially offset by the increase in funds flow from operations. Long-term debt at September 30, 2005 is comprised of \$294.6 million of bank indebtedness along with \$62.7 million and \$268.3 million of Canadian dollar equivalent debt related to the US\$54 million and US\$175 million senior unsecured notes, respectively.

Net working capital, excluding deferred credits, as at September 30, 2005 decreased by \$9.5 million compared to September 30, 2004. However, both the overall amounts of current assets of \$223.2 million (2004 - \$103.9 million) and current liabilities of \$318.4 million (2004 - \$189.6 million) have increased substantially due to activity. Higher commodity prices plus increased cash distributions also contributed to the overall increases in current assets and current liabilities.

The fair value of instruments that do not qualify as hedges have been recorded as deferred credits and included in current liabilities on the balance sheet. These costs will fluctuate depending on the commodity prices at the time of settlement and will be paid with future production that is not yet reflected in the financial statements. Therefore, in the context of liquidity, deferred credits have been excluded from working capital.

We continue to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	September 30, 2005	December 31, 2004
Long-term debt to funds flow*	0.9x	1.1x
Funds flow to interest expense	27.3x	26.0x
Long-term debt to long-term debt plus equity*	19%	23%

Funds flow and interest expense are 12-months trailing (calculated based on the last 12 months after adjusting for acquisitions).

*Long-term debt is calculated net of cash

Enerplus has an \$850 million bank credit facility (the "Bank Credit Facility") through its wholly-owned subsidiary EnerMark Inc. The Bank Credit Facility is an unsecured, covenant-based, three-year committed credit agreement with nine North American banks. We have the ability to extend the facility each year or repay the entire balance at the end of the three-year term. As at September 30, 2005, we had \$555.4 million of available borrowing capacity under this facility, which currently extends to November, 2008. This bank debt carries floating interest rates that are expected to range between 60.0 and 115.0 basis points over Bankers Acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should funds flow be insufficient to repay this indebtedness.

Most of Enerplus' development capital is discretionary and can be revised downward in the event of a significant commodity price downturn or similar economic event.

TRUST UNIT INFORMATION

We had 117,234,000 trust units outstanding at September 30, 2005 compared to 103,875,000 trust units at September 30, 2004 and 104,124,000 at December 31, 2004. The weighted average basic number of trust units outstanding for the nine months ended September 30, 2005 was 106,307,000 (2004 - 97,697,000).

On July 1, 2005 the Fund acquired all of the issued and outstanding shares of TriLoch in exchange for 1,632,516 trust units.

On August 9, 2005 the Fund announced the closing of its subscription receipt financing related to the Lyco acquisition. A total of 10,637,500 subscription receipts were issued at a price of CDN\$46.25 per receipt for gross proceeds of approximately \$492.0 million, which included the full exercise by the underwriters of their options to purchase an additional 3,037,500 subscription receipts. With the closing of the Lyco acquisition on August 30, 2005, subscription receipt holders received one trust unit for each subscription receipt held. Holders of the subscription receipts received the August 2005 cash distribution of \$0.37 per trust unit and this amount has been included in cash distributions to unitholders.

For the three months ended September 30, 2005, 192,000 trust units (2004 - 151,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights plan. This resulted in \$6.8 million (2004 - \$4.9 million) of additional equity to the Fund. For the nine months ended September 30, 2005, 840,000 trust units (\$28.0 million additional equity) were issued pursuant to DRIP and the trust unit options and rights plans compared to 725,000 trust units (\$21.0 million additional equity) during the same period in 2004. For further details see Note 6.

CANADIAN AND U.S. TAXPAYERS

Enerplus estimates that 95% to 100% of cash distributions paid to Canadian and U.S. unitholders in 2005 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 that 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.

As of October, 2005, we estimated our non-resident ownership to be approximately 72%.

UPDATE ON GOVERNMENT CONSULTATION PROCESS

In September 2005, the Canadian Federal Government released a public consultation paper entitled "Tax and Other Issues Related to Publicly Listed Flow-Through Entities". The purpose of this paper was to promote discussion on issues related to business income trusts and other flow-through entities such as partnerships and royalty trusts ("FTEs").

The paper outlines the following questions for consideration and consultation:

- Does the tax advantage of FTEs relative to public corporations have a significant impact on how business is organized in Canada?
- Have FTEs had a significant impact on tax revenues? Is there potential for revenue losses to grow in the years to come?
- What impacts are FTEs having on investment decisions and the allocation of capital in Canada? Is the overall impact on the economy positive or negative?
- Given the important role that tax-exempt investors play in Canadian capital markets, and could play in the FTE market, what impact could this have on government royalties and economic efficiency?
- Overall, are there public policy concerns about FTEs and how the tax system influences their existence, and if so, what actions should be considered to address these concerns?

The Federal Government has requested comments on the paper by December 31, 2005. At this point, we are unable to identify the impact, if any, the consultation paper may have on Enerplus and our unitholders. Of particular concern is the government's focus on tax revenues and equalizing the tax treatment between corporations and FTEs. Some alternatives identified in the paper would have minimal impact on Enerplus, such as better integrating personal and corporate income taxes on dividends to reduce double taxation. At the same time, alternatives such as taxing FTEs in a similar fashion as corporations would have a negative impact on our cash flow and distributions. The government's consultation paper does not deal with the issue of non-resident ownership of Canadian trusts. However, we understand the government continues to study this issue with a view to ensuring the Canadian tax payable by non-residents is appropriate. It is too early in the process to speculate on the outcome.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In June 2005, the AcSB issued Section 3831, *Non-Monetary Transactions*, which replaces Section 3830 and requires all non-monetary transactions to be measured at fair value unless:

- the transaction lacks commercial substance;
- the transaction is an exchange of a product or property held for sale in the ordinary course of business for a product or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange;
- neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable; or
- the transaction is a non-monetary, non-reciprocal transfer to owners that represent a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted as of the beginning of a period beginning on or after July 1, 2005. We do not expect the adoption of this section will have any material impact on our results of operations or financial position.

U.S. Pronouncements

In December 2004, the FASB issued Statement 153, *Exchanges of Nonmonetary Assets*, an amendment of APB Opinion 29, *Accounting for Nonmonetary Transactions*. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance test and fair value is determinable, the transaction must be accounted for at fair value resulting in the recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

ADDITIONAL INFORMATION

Additional information relating to Enerplus Resources Fund, including the Fund's Annual Information Form, is available under the Fund's profile on the SEDAR website at www.sedar.com and at www.enerplus.com.

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", "expects", "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 Enerplus. 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.

CONSOLIDATED BALANCE SHEETS

(CDN\$ thousands)	September 30, 2005 (Unaudited)	December 31, 2004
Assets		
Current assets		
Cash	\$ 32,578	\$ –
Accounts receivable	163,970	107,996
Other current	26,654	9,602
	223,202	117,598
Property, plant and equipment (Note 3)	3,501,212	3,029,007
Goodwill (Note 4)	220,951	29,082
Deferred charges (Note 2)	2,181	5,061
	\$ 3,947,546	\$ 3,180,748
Liabilities		
Current liabilities		
Accounts payable	\$ 275,041	\$ 179,568
Distributions payable to unitholders	43,384	36,443
Deferred credits (Note 2)	47,527	42,303
	365,952	258,314
Long-term debt	625,584	584,991
Future income taxes	376,499	235,551
Asset retirement obligations	102,526	105,978
	1,104,609	926,520
Equity		
Unitholders' capital (Note 6)	3,408,028	2,831,277
Accumulated income	1,246,676	976,137
Accumulated cash distributions	(2,161,779)	(1,811,500)
Cumulative translation adjustment (Note 5)	(15,940)	–
	2,476,985	1,995,914
	\$ 3,947,546	\$ 3,180,748

CONSOLIDATED STATEMENTS OF INCOME

(CDN\$ thousands except per trust unit amounts) (Unaudited)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Revenues				
Oil and gas sales	\$ 404,834	\$ 308,265	\$ 1,040,768	\$ 825,688
Royalties	(78,659)	(62,665)	(205,484)	(165,976)
Derivative instruments (Note 7)				
Financial contracts - qualified hedges (Note 2)	(6,149)	(4,517)	(13,444)	(13,644)
Other financial contracts (Note 2)	(35,162)	(56,402)	(87,262)	(137,059)
Interest and other income	1,161	19	2,093	1,862
	286,025	184,700	736,671	510,871
Expenses				
Operating	56,186	53,000	159,698	144,338
General and administrative (Note 6)	17,373	7,943	38,048	21,921
Transportation	6,177	6,033	20,314	18,565
Interest on long-term debt	5,973	5,735	17,698	14,551
Foreign exchange loss/(gain) (Note 5)	805	(4,127)	2,046	(1,466)
Depletion, depreciation, amortization and accretion	98,413	90,776	271,171	235,838
	184,927	159,360	508,975	433,747
Income before taxes	101,098	25,340	227,696	77,124
Capital taxes	1,924	1,553	5,016	5,338
Current and withholding taxes	3,062	–	3,062	–
Future income tax recovery	(4,235)	(26,817)	(50,921)	(72,018)
Net Income	\$ 100,347	\$ 50,604	\$ 270,539	\$ 143,804
Net income per trust unit				
Basic	\$ 0.91	\$ 0.49	\$ 2.54	\$ 1.47
Diluted	\$ 0.91	\$ 0.49	\$ 2.54	\$ 1.47
Weighted average number of trust units outstanding (thousands)				
Basic	109,924	103,781	106,307	97,697
Diluted	110,231	103,993	106,383	98,015

CONSOLIDATED STATEMENTS OF ACCUMULATED INCOME

(CDN\$ thousands) (Unaudited)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Accumulated income, beginning of period as previously reported	\$ 1,146,329	\$ 811,021	\$ 976,137	\$ 690,046
Adjustments due to change in accounting policy	–	–	–	27,775
Accumulated income, beginning of period after adjustments	1,146,329	811,021	976,137	717,821
Net income	100,347	50,604	270,539	143,804
Accumulated income, end of period	\$ 1,246,676	\$ 861,625	\$ 1,246,676	\$ 861,625

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CDN\$ thousands) (Unaudited)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Operating Activities				
Net income	\$ 100,347	\$ 50,604	\$ 270,539	\$ 143,804
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion	98,413	90,776	271,171	235,838
Non-cash financial contracts (Note 2)	(2,763)	31,304	6,952	86,776
Non-cash foreign exchange loss (Note 5)	(3,483)	(4,131)	(2,295)	(1,539)
Unit based compensation (Note 6)	7,565	1,458	12,758	2,340
Future income tax recovery	(4,235)	(26,817)	(50,921)	(72,018)
Asset retirement costs incurred	(1,613)	(1,578)	(5,011)	(4,636)
	194,231	141,616	503,193	390,565
(Increase)/decrease in non-cash operating working capital	(13,495)	12,055	(17,030)	13,964
	180,736	153,671	486,163	404,529
Financing Activities				
Issue of trust units, net of issue costs (Note 6)	473,710	4,868	494,904	307,198
Cash distributions to unitholders	(130,057)	(109,020)	(350,279)	(314,075)
Increase/(decrease) in bank credit facilities	71,260	(1,487)	42,888	235,949
Decrease in non-cash financing working capital	6,135	60	6,941	3,344
	421,048	(105,579)	194,454	232,416
Investing Activities				
Capital expenditures	(92,958)	(48,894)	(232,908)	(134,179)
Property acquisitions	(1,610)	(20,155)	(7,291)	(489,624)
Property dispositions	312	16,465	66,847	19,000
Corporate acquisitions, net of cash acquired	(483,013)	–	(483,013)	(121,171)
Decrease in non-cash investing working capital	9,003	4,492	9,266	8,613
	(568,266)	(48,092)	(647,099)	(717,361)
Effect of exchange rate changes on cash	(940)	–	(940)	–
Change in cash	32,578	–	32,578	(80,416)
Cash, beginning of period	–	–	–	80,416
Cash, end of period	\$ 32,578	\$ –	\$ 32,578	\$ –
Supplementary Cash Flow Information				
Cash income taxes paid	\$ –	\$ –	\$ –	\$ –
Cash interest paid	\$ 4,228	\$ 3,393	\$ 14,521	\$ 10,691

CONSOLIDATED STATEMENTS OF ACCUMULATED CASH DISTRIBUTIONS

(CDN\$ thousands) (Unaudited)	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Accumulated cash distributions, beginning of period	\$ 2,031,722	\$ 1,593,244	\$ 1,811,500	\$ 1,388,189
Cash distributions to unitholders	130,057	109,020	350,279	314,075
Accumulated cash distributions, end of period	\$ 2,161,779	\$ 1,702,264	\$ 2,161,779	\$ 1,702,264

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts) (Unaudited)

1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2004. The note disclosure requirements for annual statements provide additional disclosure to that required for these interim statements. Accordingly, these interim statements should be read in conjunction with the Fund's consolidated financial statements for the year ended December 31, 2004. The disclosures provided below are incremental to those included in the 2004 annual consolidated financial statements.

2. Deferred Charges and Deferred Credits

Deferred Charges

Deferred charges as at December 31, 2004	\$ 5,061
Amortization of deferred financial assets	(2,733)
Amortization of debt issue costs	(147)
Deferred charges as at September 30, 2005	\$ 2,181

Deferred Credits

Deferred credits as at December 31, 2004	\$ 42,303
Change in fair value - other financial contracts ⁽¹⁾	4,219
Financial contracts assumed through Lyco acquisition	1,005
Deferred credits as at September 30, 2005	\$ 47,527

⁽¹⁾ Changes in the fair value of financial contracts that do not qualify for hedge accounting are taken into income during the period as other financial contracts and reflected as an increase or decrease in the deferred financial liability.

The following table summarizes the income statement effects of other financial contracts:

Other Financial Contracts	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Change in fair value	\$ (3,483)	\$ 27,119	\$ 4,219	\$ 71,779
Amortization of deferred financial assets	720	4,185	2,733	14,997
Realized cash costs, net	37,925	25,098	80,310	50,283
Other financial contracts	\$ 35,162	\$ 56,402	\$ 87,262	\$ 137,059

In addition, during the three months and nine months ended September 30, 2005 we realized cash costs of \$6,149,000 and \$13,444,000 respectively, net of gains and losses from financial contracts that qualified as hedges compared to cash costs of \$4,517,000 and \$13,644,000 during the same periods in 2004.

3. Property, Plant and Equipment

	September 30, 2005	December 31, 2004
Property, plant and equipment	\$ 5,043,817	\$ 4,305,584
Accumulated depletion and depreciation	(1,542,605)	(1,276,577)
Net property, plant and equipment	\$ 3,501,212	\$ 3,029,007

Capitalized general and administrative expenses of \$7,825,000 (2004 - \$5,967,000) are included in property, plant and equipment ("PP&E") for the nine months ended September 30, 2005. Excluded from PP&E for the depletion and depreciation calculation is \$52,991,000 (2004 - \$28,638,000) related to the Joslyn development project that has not commenced commercial production.

4. Corporate Acquisitions

The estimated allocation to the fair value of the assets acquired and liabilities assumed, plus the future tax cost are summarized as follows:

(\$ thousands)	Lyco August 30, 2005	TriLoch July 1, 2005
Property, plant and equipment	\$ 506,379	\$ 77,786
Goodwill (with no tax base)	179,019	18,450
Future income taxes	(179,019)	(18,450)
	506,379	77,786
Cash	27,231	-
Non-cash working capital deficiency	(31,664)	(399)
Net assets acquired	\$ 501,946	\$ 77,387

The estimated allocation of fair value to the assets acquired and liabilities assumed may be subject to changes as additional information becomes available.

(a) Lyco Energy Corporation ("Lyco")

On August 30, 2005, the Fund acquired all the outstanding common shares and retired the debt inclusive of mandatorily redeemable preferred shares of Lyco, a private U.S. company operating in the states of Montana and North Dakota. Total consideration was approximately \$501,946,000, and the Fund assumed a net working capital deficiency of \$4,433,000. Goodwill of \$179,019,000 was recorded based on the excess of the consideration paid over value assigned to the identifiable assets and liabilities including the future tax cost. The acquisition, which was financed through an equity offering and available credit facilities, has been accounted for using the purchase method of accounting for business combinations. Results from operations of Lyco subsequent to August 30, 2005 are included in the Fund's consolidated financial statements.

(b) TriLoch Resources Inc. ("TriLoch")

On July 1, 2005 the Fund acquired all the outstanding common shares of TriLoch, a public Alberta corporation operating in southern Alberta, in exchange for 1,632,516 trust units of the Fund with a recorded value of \$69,088,000. Total consideration was \$77,387,000 consisting of units, deal costs and the retirement of TriLoch bank indebtedness. The Fund also assumed a working capital deficiency of \$399,000. Goodwill has been recorded as a result of the excess of the consideration paid over the value allocated to the identifiable assets and liabilities including the future tax cost. This acquisition has been accounted for using the purchase method of accounting for business combinations. Results from operations of TriLoch subsequent to July 1, 2005 are included in the Fund's consolidated financial statements.

5. Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Unrealized foreign exchange gain on translation of U.S. dollar denominated senior notes	\$ (3,483)	\$ (4,131)	\$ (2,295)	\$ (1,539)
Realized foreign exchange loss	4,288	4	4,341	73
Foreign exchange loss/(gain)	\$ 805	\$ (4,127)	\$ 2,046	\$ (1,466)

The US\$54,000,000 senior unsecured notes that are exposed to foreign currency fluctuations are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

The U.S. operations acquired through the acquisition of Lyco on August 30, 2005 are operated on a self-sustaining basis. Assets and liabilities of these operations are translated into Canadian dollars at rates of exchange in effect at the balance sheet date, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the foreign currency translation adjustment as part of unitholders equity.

6. Fund Capital

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

	Nine months ended September 30, 2005		Year ended December 31, 2004	
	Units	Amount	Units	Amount
Issued:				
Balance before Contributed Surplus, beginning of period	104,124	\$ 2,826,641	94,349	\$ 2,510,011
Issued for cash:				
Pursuant to public offerings	10,638	466,885	8,800	286,248
Pursuant to rights plan	627	18,747	648	16,947
Trust unit rights incentive plan (non-cash) - exercised	-	3,444	-	1,396
DRIP*, net of redemptions	212	9,299	302	11,114
Issued for acquisition of corporate and property interests	1,633	69,062	25	925
	117,234	3,394,078	104,124	2,826,641
Contributed Surplus (Trust Unit Rights Plan)	-	13,950	-	4,636
Balance, end of period	117,234	\$ 3,408,028	104,124	\$ 2,831,277

* Distribution Reinvestment and Unit Purchase Plan

On August 9, 2005, the Fund completed a Canadian equity offering of 10,637,500 subscription receipts at a price of \$46.25 per subscription receipt for gross proceeds of \$491,984,000 (\$466,885,000 net of issuance costs). The subscription receipts were exchanged for an equal number of trust units on August 30, 2005 upon the closing of the Lyco transaction. The holders of the subscription receipts received the August 2005 cash distribution of \$0.37 per trust unit and this amount has been included in cash distributions to unitholders.

On July 1, 2005, the Fund issued 1,632,516 trust units pursuant to the acquisition of TriLoch valued at \$42.32 per trust unit, being the weighted average trading price of the Fund's trust units on the Toronto Stock Exchange during the five day trading period surrounding the announcement of the TriLoch transaction, for a recorded value of \$69,062,000 after issuance costs.

	Nine months ended September 30, 2005	Year ended December 31, 2004
Contributed Surplus		
Balance, beginning of period	\$ 4,636	\$ 1,364
Trust unit rights incentive plan (non-cash) - exercised	(3,444)	(1,396)
Trust unit rights incentive plan (non-cash) - expensed	12,758	4,668
Balance, end of period	\$ 13,950	\$ 4,636

(b) Trust Unit Rights Incentive Plan

As at September 30, 2005, a total of 2,131,000 rights pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") at an average exercise price of \$37.68 were outstanding. This represents 1.8% of the total trust units outstanding of which 194,000 rights with an average exercise price of \$30.46 were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first, second and third quarters of 2005 reduced the exercise price by \$0.35 (effective July 2005), \$0.40 (effective October 2005) and \$0.41 (effective January 2006), respectively.

Activity for the rights issued pursuant to the Rights Plan is as follows:

	Nine months ended September 30, 2005		Year ended December 31, 2004	
	Number of Rights (000's)	Weighted Average Exercise Price ⁽¹⁾	Number of Rights (000's)	Weighted Average Exercise Price ⁽¹⁾
Trust unit rights outstanding				
Beginning of period	2,401	\$ 34.33	2,192	\$ 30.05
Granted	437	46.99	1,002	40.22
Exercised	(627)	29.90	(644)	26.16
Cancelled	(80)	36.65	(149)	30.94
End of period	<u>2,131</u>	<u>37.68</u>	<u>2,401</u>	<u>34.33</u>
Rights exercisable at the end of the period	194	\$ 30.46	551	\$ 27.84

⁽¹⁾ Exercise price reflects grant prices less reduction in strike price discussed above.

Non-cash compensation costs of \$7,565,000 (\$0.07 per unit) and \$12,758,000 (\$0.12 per unit) related to the rights granted after January 1, 2003 have been charged to general and administrative expense during the three and nine months ended September 30, 2005, respectively. The non-cash compensation expense for the three and nine months ended September 30, 2004 was \$1,458,000 (\$0.01 per unit) and \$2,340,000 (\$0.02 per unit) respectively.

The following table outlines the estimated compensation cost associated with the rights issued during 2002 and the pro forma effects on net income and net income per unit, had CICA Handbook section 3870 been applied retroactive to 2002.

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Net income as reported	\$ 100,347	\$ 50,604	\$ 270,539	\$ 143,804
Compensation expense for rights issued in 2002	(2,193)	(1,480)	(3,812)	(3,054)
Pro forma net income	<u>\$ 98,154</u>	<u>\$ 49,124</u>	<u>\$ 266,727</u>	<u>\$ 140,750</u>
Net income per trust unit - basic				
Reported	\$ 0.91	\$ 0.49	\$ 2.54	\$ 1.47
Pro forma	\$ 0.89	\$ 0.47	\$ 2.51	\$ 1.44
Net income per trust unit - diluted				
Reported	\$ 0.91	\$ 0.49	\$ 2.54	\$ 1.47
Pro forma	\$ 0.89	\$ 0.47	\$ 2.51	\$ 1.44

(c) Basic and Diluted per Trust Unit Calculations

Net income per trust unit has been determined based on the following:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	2005	2004
Weighted average units	109,924	103,781	106,307	97,697
Dilutive impact of rights ⁽¹⁾	307	212	76	318
Diluted trust units	110,231	103,993	106,383	98,015

⁽¹⁾ Some of the outstanding rights were anti-dilutive and therefore have been excluded in the diluted trust unit calculation.

7. Financial Instruments

The Fund's financial instruments presented on the balance sheets consist of accounts receivable, other current assets, a portion of deferred charges, current liabilities and long-term debt.

The carrying value of cash, accounts receivable, current liabilities and outstanding bank credit facility balances approximate their fair value. Other current assets are comprised of prepaid expenses and marketable securities. The marketable securities are carried on the balance sheet at the lower of cost and fair value. The fair value of the marketable securities at September 30, 2005 exceeded the cost of these securities by \$14,381,000. The Fund carried US\$54,000,000 of fixed rate debt. In addition, it carried US\$175,000,000 of fixed rate debt that was converted to CDN\$268,328,000 floating rate debt through a cross-currency swap with a syndicate of financial institutions. At September 30, 2005 the fair value of the senior unsecured notes was \$63,355,000 (for the US\$54,000,000 notes) and \$215,880,000 (for the US\$175,000,000 notes) respectively. In addition, the remaining \$411,000 in deferred charges related to derivative instruments that no longer qualify for hedge accounting treatment will be amortized in the next quarter.

The estimated fair values have been determined based on available market information and appropriate valuation methods. The actual amounts realized may differ from these estimates.

(a) Derivative Financial Instruments

The Fund uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at September 30, 2005 with reference to forward prices and market valuations provided by independent sources.

The fair values of derivative financial instruments are as follows:

Interest Rate and Cross Currency Swaps

The Fund has entered into interest rate swaps on \$75,000,000 of notional debt at rates varying from 3.74% to 4.12% before banking fees that are expected to range between 0.60% and 1.15%. These interest rate swaps mature between June 2006 and January 2007. The fair value of the \$75,000,000 interest rate swaps as at September 30, 2005 represents an unrealized cost of \$705,000. These swaps have been designated as hedges for accounting purposes.

The fair value of the cross currency swap related to the US\$175,000,000 senior unsecured notes as at September 30, 2005 represents an unrealized cost of \$59,274,000 where as the fair value of the underlying debt instrument as at September 30, 2005 represents an unrealized gain of \$52,448,000. The cross currency swap has been designated as a hedge for accounting purposes.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. The fair value of the financial crude oil contracts that do not qualify for hedge accounting are described in Note 2. The fair value of the financial crude oil contracts that qualify for hedge accounting reflects an unrealized cost of \$18,691,000 at September 30, 2005.

The following table summarizes the Fund's crude oil risk management positions at November 7, 2005:

Term	Daily Volumes bbls/day	WTI US\$/bbl		
		Sold Call	Purchased Put	Sold Put
October 1, 2005 - December 31, 2005				
3-way option	1,500	\$30.00	\$27.23	\$23.00
3-way option	1,500	\$30.00	\$25.35	\$22.00
Costless Collar *	1,500	\$40.10	\$31.00	–
Put*	1,500	–	\$41.50	–
Put	1,500	–	–	\$35.00
October 1, 2005 - December 31, 2005				
Put *	1,500	–	\$34.25	–
October 1, 2005 - December 31, 2005				
Put ⁽¹⁾	330	–	\$35.00	–
Call ⁽¹⁾	330	\$48.00	–	–
October 1, 2005 - June 30, 2006				
3-way option	1,500	\$45.80	\$31.50	\$27.50
Put *	1,500	–	\$41.50	–
Put	1,500	–	–	\$35.00
January 1, 2006 - June 30, 2006				
Costless Collar *	1,500	\$35.35	\$30.00	–
Costless Collar *	1,500	\$37.00	\$30.00	–
October 1, 2005 - December 31, 2006				
Put*	1,500	–	\$50.00	–
Put	1,500	–	–	\$41.00
October 1, 2005 - December 31, 2006				
Put*	1,500	–	\$53.00	–
Put	1,500	–	–	\$43.00
January 1, 2006 - December 31, 2006				
Put*	1,500	–	\$53.00	–
Put	1,500	–	–	\$43.00

* Financial contracts that qualify as hedges.

⁽¹⁾ Acquired through the acquisition of Lyco

Natural Gas Instruments

Enerplus has physical and financial contracts in place on its natural gas production as described below. The fair value of the financial natural gas contracts that do not qualify for hedge accounting at September 30, 2005 is described in Note 2. The fair value of the financial natural gas contracts that qualify for hedge accounting reflects an unrealized cost of \$63,246,000 at September 30, 2005.

The following table summarizes the Fund's natural gas risk management positions at November 7, 2005:

Term	Daily Volumes MMcf/day	AECO CDN\$/Mcf			
		Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
October 1, 2005 - October 31, 2005					
3-way option	9.5	\$8.23	\$6.33	\$5.01	—
Costless Collar *	4.8	\$8.44	\$5.54	—	—
Costless Collar *	4.8	\$8.44	\$5.80	—	—
Put*	9.5	—	\$6.33	—	—
October 1, 2005 - December 31, 2005					
3-way option	9.5	\$6.65	\$5.61	\$4.75	—
3-way option	9.5	\$6.60	\$5.65	\$4.75	—
3-way option	9.5	\$6.86	\$5.81	\$4.75	—
Put *	9.5	—	\$6.39	—	—
November 1, 2005 - March 31, 2006					
3-way option	9.5	\$9.92	\$7.12	\$5.80	—
Put*	9.5	—	\$7.91	—	—
Put*	9.5	—	\$7.91	—	—
Put*	9.5	—	\$7.91	—	—
October 1, 2005 - October 31, 2006					
Swap *	9.5	—	—	—	\$5.47
Swap *	4.8	—	—	—	\$5.25
Swap *	4.8	—	—	—	\$5.24
Swap *	4.8	—	—	—	\$5.28
April 1, 2006 - October 31, 2006					
Put*	9.5	—	\$7.38	—	—
Put*	9.5	—	\$7.38	—	—
Put*	9.5	—	\$7.38	—	—
2005 - 2010					
Physical (escalated pricing)	2.0	—	—	—	\$2.52

* Financial contracts that qualify as hedges.

Electricity Instrument

The Fund has entered into an electricity swap contract that has fixed the price of electricity on 5MWh of Alberta Power Pool electricity consumption at \$49.99/MWh from January 1, 2005 to December 31, 2006. This has been designated as a hedge and the fair value of this instrument as at September 30, 2005 reflects an unrealized gain of \$230,000.

8. Events Subsequent to September 30, 2005

(a) Acquisition of Sleeping Giant LLC

On October 4, 2005, the Fund acquired all of the issued and outstanding shares of Sleeping Giant LLC, a private U.S. company, for total consideration of approximately US\$93,000,000 (CDN\$109,000,000). The acquisition was funded through existing credit facilities. The purchase price allocation has not yet been determined.

BOARD OF DIRECTORS

Douglas R. Martin ⁽¹⁾⁽²⁾

Edwin Dodge ⁽³⁾⁽⁹⁾⁽¹¹⁾

Gordon J. Kerr

Robert L. Normand ⁽⁶⁾⁽⁹⁾

Glen D. Roane ⁽⁵⁾⁽¹⁰⁾

W. C. (Mike) Seth ⁽⁷⁾

Donald T. West ⁽⁷⁾⁽¹²⁾

Harry B. Wheeler ⁽⁵⁾⁽⁸⁾

Robert L. Zorich ⁽⁴⁾⁽¹¹⁾

⁽¹⁾ Chairman of the Board

⁽²⁾ *Ex-Officio* member of all Committees of the Board

⁽³⁾ Member of the Corporate Governance and Nominating Committee

⁽⁴⁾ Chairman of the Corporate Governance and Nominating Committee

⁽⁵⁾ Member of the Audit and Risk Management Committee

⁽⁶⁾ Chairman of the Audit and Risk Management Committee

⁽⁷⁾ Member of the Reserves Committee

⁽⁸⁾ Chairman of the Reserves Committee

⁽⁹⁾ Member of the Compensation and Human Resources Committee

⁽¹⁰⁾ Chairman of the Compensation and Human Resources Committee

⁽¹¹⁾ Member of the Environment, Health and Safety Committee

⁽¹²⁾ Chairman of the Environment, Health and Safety Committee

OFFICERS

Gordon J. Kerr

President & Chief Executive Officer

Heather J. Culbert

Senior Vice President, Corporate Services

Ian C. Dundas

Senior Vice President, Business Development

Garry A. Tanner

Senior Vice President & Chief Operating Officer

Eric P. Tremblay

Senior Vice President, Capital Markets

Robert J. Waters

Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza

Vice President, Investor Relations

Rodney D. Gray

Vice President, Finance

Larry P. Hammond

Vice President, Operations

David A. McCoy

Vice President, General Counsel & Corporate Secretary

Daniel M. Stevens

Vice President, Development Services

Wayne G. Ford

Controller, Operations

Christina Meeuwsen

Assistant Corporate Secretary

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS RESOURCES FUND

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Oil & Gas Ltd.
Enerplus Commercial Trust
Lyco Energy Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

TRANSFER AGENT

CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1-800-387-0825
Email: inquiries@cibcmellon.com

CO-TRANSFER AGENT

Mellon Investor Services L.L.C.
Ridgefield, New Jersey

INDEPENDENT RESERVE ENGINEERS

Sproule Associates Limited
Calgary, Alberta

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

DeGoyler MacNaughton
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

New York Stock Exchange: ERF
Toronto Stock Exchange: ERF.un

DISTRIBUTION REINVESTMENT AND UNIT PURCHASE PLAN

Enerplus Resources Fund offers a convenient method for Canadian residents to reinvest cash distributions or invest additional funds into new trust units with the Distribution Reinvestment and Unit Purchase Plan ("the Plan").

Benefits of the Plan include:

- Existing unitholders can purchase new units of the Fund each month by automatically reinvesting cash distributions.
- Participants receive a 5% discount off the purchase price when reinvesting cash distributions.
- Current unitholders can also make optional cash payments each month to purchase additional units. The optional cash payments can be a minimum of \$250 up to a maximum of \$5,000, or the amount of cash distributions received each month.
- No commissions, service charges or brokerage fees are payable in conjunction with the Plan.

If your units are held through a broker, investment dealer or other financial intermediary, you must direct that company to enroll your units into the Plan.

To obtain more information, please contact our Investor Relations Department at 1-800-319-6462, in Calgary at (403) 298-2200; by fax at (403) 298-2211; or by email at investorrelations@enerplus.com. Information on the Plan is also available on our website at www.enerplus.com.

NOTES

NOTES

ABBREVIATIONS

AECO	Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes
bbbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
BOE(s)/day	barrel of oil equivalent per day (6 Mcf of gas:1 BOE)
CBM	coalbed methane, otherwise known as natural gas from coal - NGC
GAAP	Generally accepted accounting principles
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcfd/day	million cubic feet per day
MWh	Megawatt hour(s) of electricity
NGLs	natural gas liquids
NYSE	New York Stock Exchange
SAGD	steam assisted gravity drainage
SEDAR	System for Electronic Document Analysis and Retrieval
TSX	Toronto Stock Exchange
WI	percentage working interest ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

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