THE ENERGY OF
enerPLUS

First Quarter Report

THREE MONTHS ENDED MARCH 31, 2010

SELECTED FINANCIAL RESULTS

	2010	2009
Financial (000's)		
Cash Flow from Operating Activities	**$ 189,357**	$ 169,388
Cash Distributions to Unitholders[1]	**95,712**	89,537
Excess of Cash Flow Over Cash Distributions	**93,645**	79,851
Net Income	**80,003**	51,786
Debt Outstanding – net of cash	**517,263**	739,170
Development Capital Spending[2]	**95,275**	96,588
Property and Land Acquisitions[2]	**41,327**	4,632
Divestments	**1,538**	13
Actual Cash Distributions to Unitholders per Trust Unit	**$ 0.54**	$ 0.61
Financial per Weighted Average Trust Units[3]		
Cash Flow from Operating Activities	**$ 1.07**	$ 1.02
Cash Distributions[1]	**0.54**	0.54
Excess of Cash Flow Over Cash Distributions	**0.53**	0.48
Net Income	**0.45**	0.31
Payout Ratio[4]	**51%**	53%
Adjusted Payout Ratio[2][4]	**101%**	110%
Selected Financial Results per BOE[5]		
Oil & Gas Sales[6]	**$ 47.65**	$ 35.24
Royalties	**(8.57)**	(6.43)
Commodity Derivative Instruments	**0.51**	5.38
Operating Costs	**(9.91)**	(9.95)
General and Administrative	**(2.46)**	(2.05)
Interest and Other Expenses	**(0.86)**	(0.91)
Taxes	**–**	(0.10)
Asset retirement obligations settled	**(0.56)**	(0.43)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 25.80**	$ 20.75
Weighted Average Number of Trust Units Outstanding[3]	**177,169**	165,716
Debt to Trailing 12 Month Cash Flow Ratio	**0.7x**	0.6x

SELECTED OPERATING RESULTS

For the three months ended March 31,	2010	2009
Average Daily Production		
Natural gas (Mcf/day)	**298,920**	338,857
Crude oil (bbls/day)	**30,974**	34,427
NGLs (bbls/day)	**3,925**	4,059
Total (BOE/day)	**84,719**	94,962
% Natural gas	**59%**	59%
Average Selling Price[(6)]		
Natural gas (per Mcf)	**$ 5.10**	$ 5.13
Crude oil (per bbl)	**73.86**	42.41
NGLs (per bbl)	**57.47**	40.59
CDN$/US$ exchange rate	**0.96**	0.80
Net Wells drilled	**137**	123
Success Rate[(7)]	**100%**	99%

(1) Calculated based on distributions paid or payable.
(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.
(3) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.
(4) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" below.
(5) Non-cash amounts have been excluded.
(6) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(7) Based on wells drilled, cased and tied in.

TRUST UNIT TRADING SUMMARY For the three months ended March 31, 2010	**TSX – ERF.un (CDN$)**	**U.S.* – ERF (US$)**
High	$ 24.96	$ 24.25
Low	$ 22.45	$ 20.85
Close	$ 24.07	$ 23.71

* U.S. Composite Exchange Data including NYSE.

2010 CASH DISTRIBUTIONS PER TRUST UNIT

Payment Month	CDN$	US$
January	$ 0.18	$ 0.17
February	0.18	0.17
March	0.18	0.18
First Quarter Total	**$ 0.54**	**$ 0.52**

This interim report contains certain forward-looking information and statements and contains references to contingent resources. We refer you to the end of the accompanying Management's Discussion and Analysis under "Forward-Looking Information and Statements" and "Information Regarding Contingent Resource Estimates" for our disclaimers on forward-looking information and statements and contingent resources, respectively, which apply to all other portions of this interim report. For information on the use of the terms "BOE" and "Mcfe" see the introductory paragraph under the Management's Discussion and Analysis section in this interim report and the disclaimer at the end of the accompanying Management's Discussion and Analysis. All amounts in this interim report are in Canadian dollars unless otherwise specified.

PRESIDENT'S MESSAGE

Strategic Execution

During the first quarter we continued to progress on our strategy to transition Enerplus into a growth and income oriented oil and gas producer. The addition of more early stage assets into our portfolio is critical to achieving the growth elements of our strategy. We are targeting to increase our interests in the Marcellus shale gas play principally in Pennsylvania and West Virginia, tight gas in the Deep Basin area of Canada and Bakken/tight oil in both Canada and the U.S. I am pleased to report that we have increased our interests in all of these play areas.

We increased our acreage position in the Marcellus play and now hold approximately 136,000 net acres of land primarily in Pennsylvania and West Virginia. As part of our recent acquisitions, Enerplus has secured lands where we will act as operator. We expect to drill our first operated well toward the end of 2010. To date our results in the Marcellus play have continued to meet or exceed our expectations with respect to production rates and assessments of contingent resources.

In April we acquired 154 new sections (approximately 100,000 net acres) of undeveloped land in southern Saskatchewan at a Crown land sale for $117 million. These lands are in an emerging Bakken play area and are contiguous to our existing land holdings. We now hold a 100% working interest in approximately 142,000 acres in the Freda Lake/Neptune area. To date we have drilled 4 wells on these lands, three of which have been completed applying multi-stage fracture technology, with the fourth well to be completed in the second quarter. We are encouraged by early test results in the area and will be doing further assessments once we are able to again access the area, post spring breakup. In aggregate we hold over 170,000 net acres of undeveloped land in the Bakken/tight oil areas of Saskatchewan, North Dakota and Manitoba which are in the early stages of development.

We have also increased our undeveloped land holdings in the Deep Basin area of western Canada where we now hold approximately 34,000 net acres of undeveloped land. Our primary focus in this area will be on the Montney and stacked zone potential in the Mannville. We have drilled two vertical wells on the lands and are currently evaluating these results.

We are also continuing with our plans to divest of non-core conventional assets to improve the focus in our asset base. We still expect to realize a minimum of $200 million of proceeds in the current year through a partial sale of the 14,000 BOE/day of conventional assets identified as non-core in our portfolio.

Our financial position and capacity remains strong. At the end of the quarter our unsecured $1.4 billion syndicated bank facility was totally undrawn. Our debt to trailing 12 month cash flow ratio is one of the lowest within our peer group at 0.7 times.

Operating Performance on Track

Our oil and gas production averaged 84,719 BOE/day during the quarter, on track with our expectations. Given the timing of our capital program, we expect our production will continue to increase throughout the year and meet our full year forecast of 86,000 BOE/day and our exit rate of 88,000 BOE/day, not including any acquisition or disposition activity that may occur throughout the year.

Our operations generated cash flow of $1.07/unit during the quarter which was up over the first quarter of 2009 primarily due to the strength of crude oil prices. Approximately 51% of our cash flow was distributed to our unitholders through our monthly distributions of $0.18/unit. We invested approximately $95 million in capital activities during the quarter and when combined with distributions, our adjusted payout ratio was approximately 101% of cash flow.

Operating costs of $9.96/BOE in the quarter were lower than our guidance of $10.90/BOE due primarily to the timing of annual maintenance activity expected in the second and third quarters. General and administrative costs of $2.56/BOE were also in line with our expectations.

Production and Capital Spending Summary, for the three months ended March 31, 2010

Play Type	Average Production Volumes	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	8,833	30
Crude Oil Waterflood (BOE/day)	15,964	20
Conventional Oil (BOE/day)	10,132	3
Total Crude Oil (BOE/day)	**34,929**	**$ 53**
Shallow Gas (Mcfe/day)	126,451	7
Tight Gas (Mcfe/day)	89,766	15
Marcellus Shale Gas (Mcfe/day)	2,696	15
Conventional Gas (Mcfe/day)	79,827	5
Total Gas (Mcfe/day)	**298,740**	**$ 42**
Company Total (BOE/day)	**84,719**	**$ 95***

* Net of $20 million in Alberta drilling royalty credits.

Drilling Activity (net wells), for the three months ended March 31, 2010

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-In	Wells On-stream	Dry & Abandoned Wells	Drilling Success Rate%
Bakken/Tight Oil	7.1	1.0	8.1	4.6	3.5	–	100%
Crude Oil Waterfloods	4.1	13.9	18.0	5.1	12.9	–	100%
Conventional Oil	1.5	0.8	2.3	2.3	–	–	pending
Total Oil	**12.7**	**15.7**	**28.4**	**12.0**	**16.4**	**–**	**100%**
Marcellus Shale Gas	2.7	–	2.7	2.7	–	–	pending
Shallow Gas	–	98.9	98.9	63.0	35.9	–	100%
Tight Gas	0.4	0.7	1.1	1.1	–	–	pending
Conventional Gas	–	6.3	6.3	3.0	3.3	–	100%
Total Gas	**3.1**	**105.9**	**109.0**	**69.8**	**39.2**	**–**	**100%**
Company Total	**15.8**	**121.6**	**137.4**	**81.8**	**55.6**	**–**	**100%**

Capital Program

We invested $95 million during the first quarter in capital programs, drilling 137.4 net wells across our portfolio of assets. Approximately 56% of our capital was invested in crude oil related development projects, primarily in our Bakken and crude oil waterflood resource plays. Our natural gas spending was concentrated in our Marcellus and tight gas resource plays, however, the majority of wells drilled during the quarter were located in our shallow gas resource play, taking advantage of the Alberta Drilling Royalty Credit program (“DRC”). We continue to expect to invest approximately $425 million in our assets during 2010; however, we may reallocate capital to oil related projects as we assess opportunities in our growth plays.

Marcellus Shale Gas

Activity in the Marcellus shale gas play in the U.S. continued throughout the first quarter despite record snowfall causing extremely wet surface conditions. A total of 12 gross wells were drilled during the quarter (2.7 net wells) across seven counties in Pennsylvania and we now have six rigs working in the play. Both completion activities and pipeline projects experienced delays in the quarter due to weather however activities are now back on track. Well costs continue to meet our expectations of approximately $4.5 million per well. Drilling days are trending lower than expected even though we are drilling longer horizontal legs with increased frac stages. Lateral lengths have ranged from 2,500 feet to 5,200 feet with 7 - 10 frac stages per well. We have drilled our first multi-well pad site with five wells and have recently completed three of these wells. Average 24-hour test rates of the last 10 wells drilled were 4.5 MMcf/day with the best well in the northeast development area testing at 8.2 MMcf/day and the best well in the southwest area testing at 7.1 MMcf/day. Marcellus production volumes for the quarter averaged 2.7 MMcf/day net to Enerplus and as of May 1, production volumes had increased to approximately 6 MMcf/day net. We continue to expect our exit volumes will be in excess of 18 MMcf/day net. We currently have an approximate 20% working interest in 19 gross producing wells (15 horizontal wells and 4 vertical wells) and 39 gross wells awaiting tie-in and/or completion.

Bakken/Tight Oil

We continue to build momentum in our Bakken/tight oil resource play through the acquisition of approximately 108,000 net acres of undeveloped land year to date as well as successfully executing our capital program. Enerplus now holds over 170,000 net acres of undeveloped Bakken prospective lands in both Canada and the U.S. and we continue to look for additional opportunities to grow this land base on both sides of the border.

The southeast Saskatchewan Bakken play has become a meaningful new prospect area for Enerplus. In the last six months, we have drilled and completed 3 Bakken horizontal wells with multi-frac completions in the Freda/Neptune area. Preliminary test results are positive and we expect to contract two drilling rigs to further delineate and develop the play on these 100% operated lands. Given the similarity in well depths and reservoir quality to our joint-venture assets at Taylorton, we expect similar type curves for successful wells on these new lands. We believe the economics of these wells will be attractive and expect that ultimately the play could be developed on the basis of up to four horizontal wells per section on a risked basis.

At Fort Berthold, North Dakota, we participated in the drilling of 3 horizontal wells (2 with a 50% working interest) during the quarter and currently have 2 wells completed and producing. The average lateral length of these wells ranged from 4,000 feet to 4,300 feet with 12 stage completions and 24-hour initial test rates have averaged approximately 1,100 BOE/day per well. We expect to have 3 to 6 more wells completed by the end of the second quarter. Given the success in this area, we expect that we may direct more of our 2010 development capital spending to the Fort Berthold area.

At Sleeping Giant, Montana, we drilled a total of five gross wells (3.5 net to Enerplus) which have been completed using multi-stage fracturing technology. As of May 1, all of these wells were on stream. Production rates on these wells are encouraging and we are evaluating results in conjunction with an analysis of the entire Sleeping Giant field. While we still expect to drill an additional four operated wells and two non-operated wells at Sleeping Giant during the balance of the year, we will be evaluating these plans in relation to our field analysis work and our other development opportunities including refracs.

Corporate Conversion

As a result of the Canadian federal government's tax on trusts, we anticipate converting to a dividend paying corporation effective January 1, 2011. While our cash flows and the amount we distribute to unitholders will vary depending on commodity prices, production volumes and costs, we do not expect to adjust our monthly cash distributions solely as a result of our conversion to a corporation. We have approximately $3 billion in tax pools that can be used to provide shelter from cash taxes in Canada for three to five years beyond 2010 (depending on commodity prices, production volumes, capital spending and any acquisition and divestment activity we may transact) and expect to be taxable at an estimated rate of 10-15% following this period. Subject to the approval of our corporate conversion plan by the Board of Directors, we expect to proceed with a Special Meeting of Unitholders in December of this year and ultimately convert to a corporation on or about January 1, 2011.

We remain committed to providing investors with a superior investment within the oil and gas industry and believe that a business strategy that offers both growth and income can achieve this. We expect to continue to improve our asset base through the addition of earlier stage growth oriented assets to our portfolio and by divesting of non-core conventional properties. We believe this will create a stronger mix of assets that will improve our operating results and create value for our investors in both the near term and the future.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund

The following discussion and analysis of financial results is dated May 6, 2010 and is to be read in conjunction with:

- the audited consolidated financial statements as at and for the years ended December 31, 2009 and 2008; and
- the unaudited interim consolidated financial statements as at and for the three months ended March 31, 2010 and 2009.

All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. In accordance with Canadian practice 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 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.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for our disclaimer.

NON-GAAP MEASURES

Throughout the MD&A we use the term "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows prepared in accordance with GAAP. "Adjusted payout ratio" is calculated as cash distributions plus development capital and office expenditures divided by cash flow. The terms "payout ratio" and "adjusted payout ratio" do not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Refer to the Liquidity and Capital Resources section of the MD&A for further information.

OVERVIEW

Our first quarter operating results were in-line with expectations with production averaging 84,719 BOE/day, operating expenses of $9.96/BOE and development capital spending of $95.3 million. Despite decreased production levels, cash flow from operating activities increased 12% to $189.4 million compared to the first quarter of 2009 primarily due to the significant increase in realized crude oil prices.

We are maintaining our production guidance of 86,000 BOE/day and development capital spending guidance at $425 million. However we continue to evaluate the projects within our portfolio and may reallocate capital spending among our resource plays throughout the year given high quality oil development opportunities and the outlook for natural gas prices.

We continued to expand our land positions during the quarter, acquiring 4,200 net acres of operated land in the Marcellus play for US$23.9 million. In addition, subsequent to the quarter we successfully acquired land in the Marcellus, Saskatchewan Bakken and British Columbia Deep Basin.

RESULTS OF OPERATIONS

Production

Production in the first quarter of 2010 was in-line with our expectations averaging 84,719 BOE/day, a decrease of 11% from 94,962 BOE/day in the first quarter of 2009. During 2009 we significantly decreased our annual development capital program given the uncertainty surrounding commodity prices and as a result production levels declined throughout 2009. Based upon our capital spending plans for 2010, we anticipate that production levels will increase throughout the year and are expecting annual average production of 86,000 BOE/day and an exit rate of 88,000 BOE/day. This guidance does not contemplate any acquisition or divestment activities in 2010.

Average production volumes for the three months ended March 31, 2010 and 2009 are outlined below:

	Three months ended March 31,		
Daily Production Volumes	**2010**	**2009**	**% Change**
Natural gas (Mcf/day)	**298,920**	338,857	(12)%
Crude oil (bbls/day)	**30,974**	34,427	(10)%
Natural gas liquids (bbls/day)	**3,925**	4,059	(3)%
Total daily sales (BOE/day)	**84,719**	94,962	(11)%

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for the three months ended March 31, 2010 and 2009. It also compares the benchmark price indices for the same periods.

	Three months ended March 31,		
Average Selling Price(1)	**2010**	**2009**	**% Change**
Natural gas (per Mcf)	**$ 5.10**	$ 5.13	(1)%
Crude oil (per bbl)	**73.86**	42.41	74%
Natural gas liquids (per bbl)	**57.47**	40.59	42%
Per BOE	**47.65**	35.24	35%

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

	Three months ended March 31,		
Average Benchmark Pricing	**2010**	**2009**	**% Change**
AECO natural gas – monthly index (CDN$/Mcf)	**$ 5.36**	$ 5.63	(5)%
AECO natural gas – daily index (CDN$/Mcf)	**4.95**	4.92	1%
NYMEX natural gas – monthly index (US$/Mcf)	**5.38**	4.79	12%
NYMEX natural gas – monthly index CDN$ equivalent (CDN$/Mcf)	**5.60**	5.99	(7)%
WTI crude oil (US$/bbl)	**78.72**	43.08	83%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**82.00**	53.85	52%
CDN$/US$ exchange rate	**0.96**	0.80	20%

Record low temperatures across much of North America at the beginning of the year resulted in large storage withdrawals causing natural gas prices to increase. However, prices retreated through February and March as the cold weather moderated and more gas was injected into storage than originally predicted.

We realized an average price on our natural gas of $5.10/Mcf (net of transportation costs) during the first quarter of 2010, a decrease of 1% from $5.13/Mcf for the same period in 2009. The majority of our natural gas sales are priced with reference to the monthly and daily AECO indices. The decrease in our realized natural gas price during the first quarter is comparable to the average change in the combined indices.

The West Texas Intermediate ("WTI") crude oil price rose slightly during the quarter, opening at US$81.51/bbl and closing the quarter at US$83.76/bbl. Higher demand globally and positive reports of a strengthening economic recovery helped to increase prices. However, inventories of crude, gasoline and distillates remain at the upper end of the five year average and continue to dampen any further upward pressure on price.

The average price we received for our crude oil during the first quarter of 2010 was $73.86/bbl (net of transportation costs) representing a 74% increase from $42.41/bbl during the same period in 2009. In comparison, the WTI crude oil benchmark price, in Canadian dollars, increased 52% from the corresponding period in 2009. The difference between the change in the benchmark and our average price can be attributed to strengthening refinery demand and price differentials for our light and medium crude oil streams, which make up over half of our crude production. In addition the price realized on our light sweet oil produced in the U.S. strengthened due to increased pipeline capacity out of the region.

The Canadian dollar was significantly stronger during the first quarter of 2010 compared to the same period in 2009, due in part to the strengthening of crude oil prices and the strength of the Canadian economy relative to the U.S. The Canadian dollar averaged $0.96 U.S. during the first quarter of 2010 compared to $0.80 U.S. during the first quarter of 2009. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, a stronger Canadian dollar decreases the prices that we would have otherwise realized.

Price Risk Management

We continue to monitor our price risk management program with consideration given to our overall financial position together with the economics of our development capital program and potential acquisitions. Consideration is also given to the costs of our risk management program as we seek to limit our exposure to price downturns.

Our existing financial derivative contracts are designed to protect a portion of our natural gas sales through March 2011 and a portion of our crude oil sales and electricity consumption through December 2011. In particular for 2010 we have sought more certainty in our cash flow to support our growth activities. See Note 8 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at April 23, 2010 expressed as a percentage of our anticipated net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)		
	April 1, 2010 – October 31, 2010	**November 1, 2010 – December 31, 2010**	**January 1, 2011 – March 31, 2011**	**April 1, 2010 – June 30, 2010**	**July 1, 2010 – December 31, 2010**	**January 1, 2011 – December 31, 2011**
Purchased Puts (downside protection)	$ 5.52	$ 5.52	–	–	–	–
%	11%	11%	–	–	–	–
Sold Puts (limiting downside protection)	$ 4.01	$ 4.22	$ 4.39	$ 47.50	$ 47.50	$ 55.00
%	11%	19%	15%	18%	18%	4%
Swaps (fixed price)	$ 6.48	$ 6.39	$ 6.39	$ 78.04	$ 78.32	$ 88.76
%	34%	30%	30%	48%	50%	11%
Purchased Calls (repurchasing upside)	$ 6.38	$ 7.25	$ 6.88	$ 92.68	$ 92.68	$ 105.00
%	6%	9%	15%	26%	26%	4%

Based on weighted average price (before premiums), estimated 2010 average annual production of 86,000 BOE/day, net of royalties and assuming a 18% royalty rate.

Accounting for Price Risk Management

During the first quarter of 2010 our commodity price risk management program generated cash gains of $8.0 million on our natural gas contracts and cash losses of $4.1 million on our crude oil contracts. The natural gas cash gains are due to contracts which provided floor protection that was above market prices. The crude oil cash losses are the result of crude oil prices rising above our swap positions. In comparison, our commodity price risk management program resulted in cash gains of $14.3 million on our natural gas contracts and $31.6 million on our crude oil contracts in the first quarter of 2009.

As the forward markets for natural gas and crude oil fluctuate, new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or non-cash gain in earnings. At March 31, 2010 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented gains of $56.3 million and losses of $26.9 million respectively. In comparison, at December 31, 2009 the fair value of our natural gas and crude oil derivative instruments represented gains of $20.4 million and losses of $20.3 million respectively. The change in the fair value of our commodity derivative instruments during the quarter resulted in an unrealized gain of $36.0 million for natural gas and an unrealized loss of $6.6 million for crude oil. See Note 8 for details.

The following table summarizes the effects of our financial contracts on income:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended March 31, 2010**		**Three months ended March 31, 2009**	
Cash gains/(losses):				
Natural Gas	**$ 8.0**	**$ 0.30/Mcf**	$ 14.3	$ 0.47/Mcf
Crude Oil	**(4.1)**	**$ (1.47)/bbl**	31.6	$ 10.21/bbl
Total cash gains/(losses)	**$ 3.9**	**$ 0.51/BOE**	$ 45.9	$ 5.38/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ 36.0**	**$ 1.34/Mcf**	$ 33.0	$ 1.08/Mcf
Change in fair value – crude oil	**(6.6)**	**$ (2.37)/bbl**	(20.3)	$ (6.56)/bbl
Total non-cash gains/(losses)	**$ 29.4**	**$ 3.86/BOE**	$ 12.7	$ 1.48/BOE
Total gains/(losses)	**$ 33.3**	**$ 4.37/BOE**	$ 58.6	$ 6.86/BOE

Revenues

Crude oil and natural gas revenues in the first quarter of 2010 were $363.3 million ($369.7 million, net of $6.4 million of transportation costs), an increase of 21% or $62.1 million compared to $301.2 million ($307.5 million, net of $6.3 million of transportation costs) in the first quarter of 2009. The increase in crude oil and natural gas liquids prices, which were slightly offset by lower production, resulted in higher overall revenues.

Analysis of Sales Revenue[(1)] ($ millions)	**Crude oil**	**NGLs**	**Natural Gas**	**Total**
Quarter ended March 31, 2009	$ 131.4	$ 14.8	$ 155.0	$ 301.2
Price variance[(1)]	87.7	6.0	(0.5)	93.2
Volume variance	(13.2)	(0.5)	(17.4)	(31.1)
Quarter ended March 31, 2010	**$ 205.9**	**$ 20.3**	**$ 137.1**	**$ 363.3**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three months ended March 31, 2010 and 2009, royalties were $65.4 million and $55.0 million, respectively, representing approximately 18% of oil and gas sales, net of transportation costs.

The Province of Alberta announced modifications to its royalty framework as the result of a competitiveness review. Effective January 1, 2011 the maximum royalty rate is expected to be reduced from the current levels of 50% for both conventional oil and natural gas to 40% for conventional oil and 36% for natural gas. Other changes include permanently instating a maximum 5% royalty rate on conventional oil and natural gas during the first year of production. The changes are expected to be finalized during the third quarter of 2010. We do not expect the changes to significantly impact our current royalty rates.

Operating Expenses

Operating expenses for the first quarter of 2010 were in-line with expectations at $9.96/BOE or $75.9 million, compared to $9.84/BOE or $84.1 million for the same period in 2009. Our operating expenses were lower on a total dollar basis compared to 2009 mainly due to lower power costs, however lower production levels have increased operating costs on a BOE basis.

We are maintaining our annual guidance for operating costs of approximately $10.90/BOE as we expect annual maintenance costs and planned turnarounds to occur during the second and third quarters, which ultimately increases operating costs per BOE.

General and Administrative Expenses ("G&A")

During the first quarter of 2010 G&A expenses totaled $2.56/BOE or $19.5 million compared to $2.21/BOE or $18.9 million in the first quarter of 2009. Our cash G&A before corporate conversion costs increased by approximately $0.8 million mainly due to higher office lease charges and increased staff levels at our U.S. office. Reduced production levels during 2010 increased G&A on a BOE basis compared to the prior year.

During the quarter our G&A expenses included non-cash charges for our trust unit rights incentive plan of $0.8 million or $0.10/BOE compared to $1.4 million or $0.16/BOE for 2009. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. The decrease of $0.6 million related primarily to the forfeiture of rights as a result of staff reductions during the quarter. See Note 7 for further details.

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

	Three months ended March 31,	
General and Administrative Costs ($ millions)	**2010**	**2009**
Cash G&A, before corporate conversion costs	**$ 18.3**	$ 17.5
Corporate conversion costs	**0.4**	–
Trust unit rights incentive plan (non-cash)	**0.8**	1.4
Total G&A	**$ 19.5**	$ 18.9

(Per BOE)	**2010**	**2009**
Cash G&A, before corporate conversion costs	**$ 2.41**	$ 2.05
Corporate conversion costs	**0.05**	–
Trust unit rights incentive plan (non-cash)	**0.10**	0.16
Total G&A	**$ 2.56**	$ 2.21

We continue to expect annual G&A costs to be $2.45/BOE including non-cash costs of $0.20/BOE. In addition we expect corporate conversion costs to be approximately $0.10/BOE.

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap ("CCIRS"). See Note 5 for further details.

Interest on long-term debt for the three months ended March 31, 2010 totaled $9.2 million, a $3.6 million increase from the same quarter of 2009. Although we had lower debt levels during 2010, our interest expense increased as a result of our new senior unsecured notes that were issued in June of 2009 at higher rates. Our average interest rate during 2010 was 5.5% compared to 2.3% for the same period in 2009.

For the three months ended March 31, 2010 non-cash interest gains were $1.7 million compared to non-cash interest losses of $6.4 million in 2009. The changes in the fair value of our interest rate swaps and the interest component on our CCIRS cause non-cash interest to fluctuate between periods.

The following table summarizes the cash and non-cash interest expense recorded:

	Three months ended March 31,	
Interest Expense ($ millions)	**2010**	**2009**
Interest on long-term debt	**$ 9.2**	$ 5.6
Non-cash interest loss/(gain)	**(1.7)**	6.4
Total Interest Expense	**$ 7.5**	$ 12.0

As a result of the additional senior unsecured notes issued on June 18, 2009, approximately 77% of our debt was based on fixed interest rates while 23% had floating interest rates at March 31, 2010. In comparison, at March 31, 2009 approximately 25% of our debt was based on fixed interest rates and 75% was floating.

Foreign Exchange

For the three months ended March 31, 2010 we recorded foreign exchange gains of $10.4 million compared to losses of $0.9 million during the same quarter of 2009. Unrealized gains on the translation of our U.S. dollar denominated senior notes accounted for the majority of the gain in 2010. See Note 6 for further details.

Capital Expenditures

Development capital spending during the first quarter of 2010 of $95.3 million (net of $20 million DRC) was in line with our expectations and comparable to $96.6 million for the same period in 2009. Spending during the quarter was focused on our Bakken/tight oil and crude oil waterflood resource plays as well as development of our Marcellus shale gas play in the U.S. We continue to evaluate our portfolio of projects and may consider shifting more of our capital spending towards oil related projects given the lower expected returns for conventional natural gas projects.

Property and land acquisitions for the first quarter of 2010 totaled $41.3 million compared to $4.6 million for the same period in 2009. Spending during the quarter included the acquisition of 4,200 net acres of operated working interest land in the Marcellus shale gas play for US$23.9 million along with US$9.0 million of spending associated with our Marcellus carry obligation. At March 31, 2010 our remaining carry obligation is US$228.3 million.

Subsequent to the quarter we acquired a 100% working interest in approximately 100,000 acres of undeveloped crown land in Saskatchewan for $117 million. This acreage is contiguous to our existing land holdings in the Bakken play area. We also acquired an additional 6,000 net acres of operated working interest land in the Marcellus shale gas play and 6,300 net acres of Deep Basin crown land in British Columbia.

Total net capital expenditures for the first quarter of 2010 and 2009 are outlined below:

	Three months ended March 31,	
Capital Expenditures ($ millions)	**2010**	**2009**
Development expenditures[1][2]	**$ 77.1**	$ 76.6
Plant and facilities	**18.2**	20.0
Development Capital	**95.3**	96.6
Office	**0.4**	0.6
Sub-total	**95.7**	97.2
Property and land acquisitions[2][3]	**41.3**	4.6
Property dispositions[3]	**(1.5)**	–
Total Net Capital Expenditures	**$ 135.5**	$ 101.8
Total Capital Expenditures financed with cash flow	**$ 93.6**	$ 79.9
Total Capital Expenditures financed with cash, debt and equity	**43.4**	21.9
Proceeds received on property dispositions	**(1.5)**	–
Total Net Capital Expenditures	**$ 135.5**	$ 101.8

(1) Development expenditures are net of DRC.
(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.
(3) Net of post-closing adjustments.

We are maintaining our 2010 guidance of $425 million for annual development capital spending, net of DRC.

Depletion, Depreciation, Amortization and Accretion (“DDA&A”)

DDA&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2010 DDA&A totaled $159.5 million or $20.92/BOE compared to $162.6 million or $19.02/BOE during the same period in 2009. The increase in depletion per BOE is due to the negative reserve revisions recorded at December 31, 2009.

No impairment of our assets existed at March 31, 2010 using year-end reserves updated for development activity and management’s estimates of future prices.

Goodwill

The goodwill balance of $602.8 million is a result of previous corporate acquisitions and represents the excess of the total purchase price over the fair value of the net identifiable assets and liabilities acquired. The goodwill balance with respect to our U.S operations is exposed to foreign currency fluctuations as it is translated into Canadian dollars at the period end exchange rate. No goodwill impairment existed as of March 31, 2010.

Asset Retirement Obligations

In connection with our operations, we anticipate we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. Total future asset retirement obligations included on our balance sheet are estimated by management based on our net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. We have estimated the net present value of our total asset retirement obligations to be approximately $230.5 million at March 31, 2010.

Actual asset retirement costs are incurred at different times compared to the recording of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2030 and 2049.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax basis of assets and liabilities. A portion of the future income tax liability recorded on the balance sheet will be recovered through earnings before 2011. After conversion to a corporation on or about January 1, 2011 the balance will be realized as future income tax assets and liabilities are realized or settled.

Our future income tax recovery was $0.5 million for the quarter ended March 31, 2010 compared to a recovery of $26.1 million for the same period in 2009. The decreased recovery is due to higher net income in the first quarter of 2010 and rate reductions of $8.3 million recorded during the first quarter of 2009.

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund, which ultimately transfers both income and future income tax liability to our unitholders. As a result minimal cash income taxes are generally paid by our Canadian operating entities. Effective January 1, 2011 we expect to convert to a corporation and will be subject to normal Canadian corporate taxes. Within the context of current commodity prices and capital spending plans, we do not expect to pay current taxes in Canada until 2013 to 2015 as we expect to utilize our tax pools to reduce Canadian tax otherwise payable. This estimate does not include the effect of future acquisitions or divestments.

The amount of current taxes recorded throughout the year with respect to our U.S. operations is dependent upon income levels and the timing of both capital expenditures and the repatriation of funds to Canada. For the first quarter of 2010 we recorded no current income taxes compared to $0.8 million for the same period in 2009. The decrease in current taxes on our U.S. operations is due to an increase in capital expenditures during the first quarter of 2010. We expect current income and withholding taxes to average approximately 5% of cash flow from U.S. operations in 2010.

Net Income

Net income for the first quarter of 2010 was $80.0 million or $0.45 per trust unit compared to $51.8 million or $0.31 per trust unit for the same period in 2009. The $28.2 million increase in net income was primarily due to increased oil prices which resulted in an increase in oil and gas sales revenue of $62.1 million (net of transportation costs), increased foreign exchange gains of $11.3 million, partially offset by a decrease in commodity derivative instrument gains of $25.3 million and a decrease in future income tax recoveries of $25.6 million.

Cash Flow from Operating Activities

Cash flow for the three months ended March 31, 2010 was $189.4 million or $1.07 per trust unit compared to $169.4 million or $1.02 per trust unit for the same period in 2009. The increase in cash flow per unit was primarily due to the significant increase in crude oil prices partially offset by the decrease in production.

Selected Financial Results

Per BOE of production (6:1)	Three months ended March 31, 2010 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total	Three months ended March 31, 2009 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total
Production per day			**84,719**			94,962
Weighted average sales price[(2)]	**$ 47.65**	**$ –**	**$ 47.65**	$ 35.24	$ –	$ 35.24
Royalties	**(8.57)**	**–**	**(8.57)**	(6.43)	–	(6.43)
Commodity derivative instruments	**0.51**	**3.86**	**4.37**	5.38	1.48	6.86
Operating costs	**(9.91)**	**(0.05)**	**(9.96)**	(9.95)	0.11	(9.84)
General and administrative	**(2.46)**	**(0.10)**	**(2.56)**	(2.05)	(0.16)	(2.21)
Interest expense, net of other income	**(1.18)**	**0.23**	**(0.95)**	(0.63)	(0.76)	(1.39)
Foreign exchange gain/(loss)	**0.32**	**1.05**	**1.37**	(0.28)	0.18	(0.10)
Current income tax	**–**	**–**	**–**	(0.10)	–	(0.10)
Restoration and abandonment cash costs	**(0.56)**	**0.56**	**–**	(0.43)	0.43	–
Depletion, depreciation, amortization and accretion	**–**	**(20.92)**	**(20.92)**	–	(19.02)	(19.02)
Future income tax recovery/(expense)	**–**	**0.06**	**0.06**	–	3.05	3.05
Total per BOE	**$ 25.80**	**$ (15.31)**	**$ 10.49**	$ 20.75	$ (14.69)	$ 6.06

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three months ended March 31, 2010 and 2009:

(CDN$ millions, except per unit amounts)	Three months ended March 31, 2010 Canada	U.S.	Total	Three months ended March 31, 2009 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	**283,460**	**15,460**	**298,920**	325,799	13,058	338,857
Crude oil (bbls/day)	**23,936**	**7,038**	**30,974**	25,381	9,046	34,427
Natural gas liquids (bbls/day)	**3,925**	**–**	**3,925**	4,059	–	4,059
Total Daily Sales (BOE/day)	**75,105**	**9,614**	**84,719**	83,740	11,222	94,962
Pricing[(1)]						
Natural gas (per Mcf)	**$ 4.99**	**$ 7.07**	**$ 5.10**	$ 5.12	$ 5.38	$ 5.13
Crude oil (per bbl)	**73.78**	**74.14**	**73.86**	43.26	40.04	42.41
Natural gas liquids (per bbl)	**57.47**	**–**	**57.47**	40.59	–	40.59
Capital Expenditures						
Development capital and office	**$ 57.8**	**$ 37.9**	**$ 95.7**	$ 86.6	$ 10.6	$ 97.2
Acquisitions of oil and gas properties	**5.2**	**36.1**	**41.3**	4.4	0.2	4.6
Dispositions of oil and gas properties	**(1.5)**	**–**	**(1.5)**	–	–	–
Revenues						
Oil and gas sales[(1)]	**$ 306.5**	**$ 56.8**	**$ 363.3**	$ 262.3	$ 38.9	$ 301.2
Royalties[(2)]	**(52.0)**	**(13.4)**	**(65.4)**	(46.5)	(8.5)	(55.0)
Commodity derivative instruments gain/(loss)	**33.3**	**–**	**33.3**	58.6	–	58.6
Expenses						
Operating	**$ 72.4**	**$ 3.5**	**$ 75.9**	$ 80.3	$ 3.8	$ 84.1
General and administrative	**16.7**	**2.8**	**19.5**	17.0	1.9	18.9
Depletion, depreciation, amortization and accretion	**142.8**	**16.7**	**159.5**	138.9	23.7	162.6
Current income taxes expense/(recovery)	**–**	**–**	**–**	–	0.8	0.8

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. Royalties include state production tax.

Quarterly Financial Information

Crude oil and natural gas sales increased during the first half of 2008 due to increased commodity prices and increased production from the Focus acquisition. Oil and natural gas sales decreased in the latter part of 2008 with the sharp decline in commodity prices caused by the global credit crisis and were flat during 2009 as rising crude oil prices largely offset the declining natural gas prices and production levels. During the first quarter of 2010 oil and gas sales increased slightly as lower production levels were more than offset by higher commodity prices compared to the fourth quarter of 2009.

Net income has been affected by fluctuating commodity prices and risk management costs along with the fluctuating Canadian dollar.

Quarterly Financial Information ($ millions, except per trust unit amounts)	**Oil and Gas Sales(1)**	**Net Income**	**Net Income per trust unit** Basic	Diluted
2010				
First quarter	**$ 363.3**	**$ 80.0**	**$ 0.45**	**$ 0.45**
2009				
Fourth Quarter	$ 333.3	$ 2.7	$ 0.02	$ 0.02
Third Quarter	292.1	38.2	0.23	0.23
Second Quarter	306.2	(3.6)	(0.02)	(0.02)
First quarter	301.2	51.8	0.31	0.31
Total	$ 1,232.8	$ 89.1	$ 0.53	$ 0.53
2008				
Fourth Quarter	$ 418.3	$ 189.5	$ 1.15	$ 1.15
Third Quarter	647.8	465.8	2.82	2.82
Second Quarter	734.4	112.2	0.68	0.68
First Quarter	503.7	121.4	0.82	0.82
Total	$ 2,304.2	$ 888.9	$ 5.54	$ 5.53

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

LIQUIDITY AND CAPITAL RESOURCES

Credit Facility

Our $1.4 billion bank credit facility is an unsecured, covenant-based, three-year term agreement maturing November 2010, a copy of which was filed on March 18, 2008 as a "Material Document" on the Fund's SEDAR profile at www.sedar.com. Borrowing costs under the facility range between 55.0 and 110.0 basis points over bankers' acceptance rates, with our current borrowing cost being 55.0 basis points over bankers' acceptance rates. Our borrowing costs are likely to increase upon renewal of our credit facility as extension fees and pricing for drawn and undrawn balances have increased in the marketplace. We expect to renew our credit facility during the second quarter of 2010 prior to its maturity. At March 31, 2010 the entire facility was undrawn and we were in compliance with all covenants under the facility.

Distribution Policy

The amount of cash distributions paid to unitholders is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to anticipated cash flows, debt levels, capital spending plans and capital market conditions. The level of cash withheld varies and is dependent upon numerous factors, the most significant of which include the prevailing commodity price environment, our current levels of production, debt obligations, funding requirements for our development capital program and our access to equity markets.

We have maintained our monthly distribution rate of $0.18 per unit since February 2009 and have been able to manage our distribution levels and capital spending in order to minimize increases in our debt levels and preserve our balance sheet strength.

Sustainability of our Distributions and Asset Base

As an oil and gas producer we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future crude oil and natural gas production is highly dependent on our success in exploiting our asset base and acquiring or developing additional reserves. To the extent we are unsuccessful in these activities, our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions to our unitholders may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During the first quarter of 2010 cash distributions of $95.7 million were funded entirely through cash flow of $189.4 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 51% for the first quarter of 2010 compared to 53% for the same period in 2009. Our adjusted payout ratio, which is calculated as the sum of cash distributions plus development capital and office expenditures divided by cash flow, was 101% for the first quarter of 2010 compared to 110% for the first quarter of 2009. The decrease in our payout ratio and adjusted payout ratio is mainly due to the increase in cash flow. See "Non-GAAP Measures" above.

For the three months ended March 31, 2010, our cash distributions exceeded our net income by $15.7 million (2009 – $37.7 million). Non-cash items such as changes in the fair value of our derivative instruments and future income taxes cause net income to fluctuate between periods but do not reduce or increase our cash flow. Future income taxes can fluctuate from period to period as a result of changes in tax rates as well as changes in interest, royalties and dividends from our operating subsidiaries paid to the Fund. In addition, we believe that other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical cost of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

It is not practical to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities in the oil and gas sector due to the nature of reserve reporting, natural reservoir declines and the risks involved with capital investment. As a result, we do not distinguish maintenance capital separately from development capital spending. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income:

($ millions, except per unit amounts)	Three months ended March 31, 2010	Year ended December 31, 2009	Year ended December 31, 2008
Cash flow from operating activities	**$ 189.4**	$ 775.8	$ 1,262.8
Cash distributions	**95.7**	368.2	786.1
Excess of cash flow over cash distributions	**$ 93.7**	$ 407.6	$ 476.7
Net income	**$ 80.0**	$ 89.1	$ 888.9
(Shortfall)/excess of net income over cash distributions	**$ (15.7)**	$ (279.1)	$ 102.8
Cash distributions per weighted average trust unit	**$ 0.54**	$ 2.17	$ 4.89
Payout ratio(1)	**51%**	47%	62%
Adjusted Payout ratio(1)(2)	**101%**	83%	106%

(1) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" above.

(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.

Debt

Total debt at March 31, 2010 was $543.3 million comprised solely of senior unsecured notes including the current portion of $35.8 million and the long-term portion of $507.5 million. This represents a decrease of $15.6 million from $558.9 million at December 31, 2009. This decrease in our debt is entirely due to the strengthening Canadian dollar versus the U.S. dollar which impacts the value of our U.S. denominated debentures when they are translated to Canadian dollars at March 31, 2010.

Our working capital at March 31, 2010, excluding cash, current deferred financial assets and credits and future income taxes increased by $16.5 million compared to December 31, 2009. This change is due to lower accounts payable and increased accounts receivable balances at March 31, 2010.

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

Financial Leverage and Coverage	March 31, 2010	December 31, 2009
Long-term debt to cash flow (12 month trailing)(1)	**0.7x**	0.6x
Cash flow to interest expense (12 month trailing)(2)	**23.3x**	25.4x
Long-term debt to long-term debt plus equity(1)	**11%**	10%

(1) Long-term debt including current portion is measured net of cash.
(2) Interest expense excluding non-cash items.

Unitholders have no direct liability should cash flow be insufficient to repay amounts associated with our bank facility and senior unsecured notes. The agreements stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At March 31, 2010, we were in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow. Refer to "Debt of Enerplus" in our Annual Information Form for the year ended December 31, 2009 for a detailed description of these covenants.

We expect to have adequate liquidity under our bank credit facility, from cash flow and from our asset disposition program to fund planned development capital spending and working capital requirements for 2010.

Principal payments of US$35 million on our senior unsecured notes are required on June 19, 2010 and are more fully discussed in Note 4.

ACCUMULATED DEFICIT

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on the actual cash flow generated in the period, whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, derivative instrument mark-to-market gains and losses, unit based compensation charges and future income tax provisions.

TRUST UNIT INFORMATION

We had 177,370,000 trust units outstanding at March 31, 2010 compared to 165,828,000 trust units at March 31, 2009 and 177,061,000 trust units outstanding at December 31, 2009. Trust units outstanding at March 31, 2010 include 4,292,000 exchangeable limited partnership units which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (1,824,000 trust units). During the first quarter of 2010, 2,090,000 partnership units were converted into 888,000 trust units.

During the first quarter of 2010, 309,000 trust units (2009 – 238,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights incentive plan, net of redemptions. This resulted in $7.0 million (2009 – $5.4 million) of additional equity to the Fund. For further details see Note 7.

The weighted average basic number of trust units outstanding for the three months ended March 31, 2010 was 177,169,000 (2009 – 165,716,000). At April 28, 2010 we had 177,490,000 trust units outstanding including the equivalent limited partnership units.

INCOME TAXES

The following is a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Unitholders

We qualify as a mutual fund trust under the Income Tax Act (Canada) and accordingly, trust units of Enerplus are qualified investments for RRSPs, RRIFs, RESPs, DPSPs and TFSAs. Each year we have historically transferred all of our taxable income to our unitholders by way of distributions.

In computing income, unitholders are required to include the taxable portion of distributions received in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

For 2010, we estimate that 95% of cash distributions will be taxable and 5% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

U.S. unitholders who received cash distributions are subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable portion of the distribution as computed under Canadian tax law and the non-taxable portion of the distribution. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

For U.S. taxpayers the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. The 15% preferred rate of tax on "Qualified Dividends" is currently scheduled to expire at the end of 2010. We are unable to determine if or to what extent the preferred rate of tax on "Qualified Dividends" may be extended.

For 2010, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

In April 2010, we estimated our non-resident ownership to be 69%.

CORPORATE CONVERSION

Effective January 1, 2011 we expect we will convert to a corporation from our current structure as an income trust. While we originally did not expect the conversion to be taxable, there are some alternatives that we are considering that could make the conversion taxable for our Canadian unitholders. We continue to expect the conversion will be non-taxable for our U.S. unitholders. We will finalize our conversion plans and the taxability thereof later in the year.

2010 GUIDANCE

There have been no changes to our 2010 guidance since year-end. The summary below does not include any potential acquisitions or divestments:

Summary of 2010 Expectations	Target	Comments
Average annual production	86,000 BOE/day	
Exit rate 2010 production	88,000 BOE/day	Assumes $425 million development capital spending, net of $33 million of Alberta DRC credits
2010 production mix	57% gas, 43% liquids	
Average royalty rate	20%	Percentage of gross sales
Operating costs	$10.90/BOE	
G&A costs	$2.45/BOE	Includes non-cash charges of $0.20/BOE (trust unit rights incentive plan)
U.S. income and withholding tax – cash costs	5%	Applied to net cash flow generated by U.S. operations
Average interest and financing costs	8%	Based on current fixed rate contracts, forward interest rates and anticipated credit facility renewal costs
Corporate conversion and simplification	$3 million or $0.10/BOE	Fees related to our conversion from a trust to a corporation and simplification of our underlying corporate structure
Development capital spending	$425 million, net of Alberta DRC credits of $33 million	Within the context of current commodity prices
Marcellus carry commitment	$64 million	Will be reported as a property acquisition

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on January 1, 2010 and ending on March 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS")

In October 2009 the Accounting Standards Board ("AcSB") issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for financial periods beginning on January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Enerplus for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

There have been no material changes to Enerplus' transition plan or IFRS that would impact the accounting policy choices or voluntary exemptions we expect to adopt at the transition date, January 1, 2010. For a discussion of our approach to the IFRS transition and a summary of the expected impact please refer to our 2009 MD&A as filed February 24, 2010 on www.sedar.com.

Additional Information

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "target", "budget", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: asset dispositions and the use of proceeds therefrom; our corporate strategy, including transition from an income trust to a corporate form and the timing thereof; expected oil, natural gas and natural gas liquids production volumes and product mix; future oil and natural gas prices and the Fund's commodity risk management programs; cash flow sensitivities to commodity price, production, foreign exchange and interest rate changes; expected operating, G&A and trust conversion expenses and royalty and interest rates; capital expenditures and the allocation thereof; future well and operating results; future acquisitions and production and reserves growth; receipt of required regulatory approvals; the amount of future abandonment and reclamation costs and asset retirement obligations; taxes payable by the Fund and its subsidiaries; the tax pools of the Fund and its subsidiaries; renewal of our credit facility and the borrowing costs associated with the credit facility; credit risk mitigation programs; future debt levels, financial capacity, liquidity and capital resources; cash distributions and dividends and the tax treatment thereof; future contractual commitments; our transition to IFRS and the impact of that change on our financial results; reliance on industry partners to develop and expand our assets and operations; and future environmental and asset retirement obligations and the costs associated therewith.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; certain commodity price and other cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund its capital and operating requirements as needed; and the extent of its liabilities. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of the Fund's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of the Fund or by third party operators of the Fund's properties, increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in the Fund's public disclosure documents (including, without limitation, those risks and contingencies described above and under "Risk Factors and Risk Management" in this MD&A and under "Risk Factors" in the Fund's Annual Information Form dated March 12, 2010, which is available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which forms part of our Form 40-F filed with the SEC on March 12, 2010 and available at www.sec.gov.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

INFORMATION REGARDING CONTINGENT RESOURCE ESTIMATES

This MD&A contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Enerplus will produce any portion of the volumes currently classified as contingent resources. The resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

The primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Marcellus properties as "reserves" consist of: additional delineation drilling to establish economic productivity in the development areas, limitations to development based on adverse topography or other surface restrictions, the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the lands, and access to confidential information of other operators in the area. Significant negative factors related to the estimate include: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, ongoing litigation related to minimum royalties payable to freehold landowners, and other issues related to oil and gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the acquired interests in the Marcellus properties, including commodity price fluctuations, project costs, Enerplus' ability to make the necessary capital expenditures to develop the properties, reliance on Enerplus' industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described under "Risk Factors" in our annual information form for the year ended December 31, 2009, a copy of which is available on our SEDAR profile at www.sedar.com and on our website at www.enerplus.com, and which forms part of our annual report on Form 40-F filed with the U.S. Securities and Exchange Commission at www.sec.gov.

USE OF "BOE" AND "MMCFE"; PRESENTATION OF PRODUCTION INFORMATION

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. "MMcfe" means million cubic feet of gas equivalent. Enerplus has adopted the standard of one barrel of oil to six thousand cubic feet of gas (1 barrel: 6 Mcf) when converting oil to MMcfes. MMcfes may be misleading, particularly if used in isolation. An MMcfe conversion ratio of 1 barrel: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In accordance with Canadian practice, production volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated.

Consolidated Balance Sheets

(CDN$ thousands) unaudited	March 31, 2010	December 31, 2009
Assets		
Current assets		
Cash	**$ 26,099**	$ 73,558
Accounts receivable	**148,220**	142,009
Deferred financial assets *(Note 8)*	**56,316**	20,364
Future income taxes	**–**	4,995
Other current	**5,982**	5,041
	236,617	245,967
Property, plant and equipment *(Note 2)*	**4,956,432**	5,000,523
Goodwill	**602,808**	607,438
Deferred financial assets *(Note 8)*	**618**	1,997
Other assets *(Note 8)*	**50,156**	49,591
	5,610,014	5,659,549
	$ 5,846,631	$ 5,905,516
Liabilities		
Current liabilities		
Accounts payable	**$ 248,150**	$ 257,519
Distributions payable to unitholders	**31,928**	31,871
Current portion of long-term debt *(Note 4)*	**35,832**	36,631
Future income taxes	**1,690**	–
Deferred financial credits *(Note 8)*	**45,916**	37,437
	363,516	363,458
Long-term debt *(Note 4)*	**507,530**	522,276
Deferred financial credits *(Note 8)*	**57,701**	54,788
Future income taxes	**549,241**	561,585
Asset retirement obligations *(Note 3)*	**230,541**	230,465
	1,345,013	1,369,114
Equity		
Unitholders' capital *(Note 7)*	**5,723,105**	5,715,614
Accumulated deficit	**(1,475,992)**	(1,460,283)
Accumulated other comprehensive income/(loss)	**(109,011)**	(82,387)
	4,138,102	4,172,944
	$ 5,846,631	$ 5,905,516

Consolidated Statements of Accumulated Deficit and Accumulated Other Comprehensive Income

Three months ended March 31 (CDN$ thousands) unaudited	2010	2009
Accumulated income, beginning of period	**$ 3,264,936**	$ 3,175,819
Net income	**80,003**	51,786
Accumulated income, end of period	**3,344,939**	3,227,605
Accumulated cash distributions, beginning of period	**(4,725,219)**	(4,357,018)
Cash distributions	**(95,712)**	(89,537)
Accumulated cash distributions, end of period	**(4,820,931)**	(4,446,555)
Accumulated deficit, end of period	**$ (1,475,992)**	$ (1,218,950)
Accumulated other comprehensive income, beginning of period	**$ (82,387)**	$ 48,606
Other comprehensive income/(loss)	**(26,624)**	24,516
Accumulated other comprehensive income, end of period	**$ (109,011)**	$ 73,122
Total accumulated deficit and accumulated other comprehensive income/(loss)	**$ (1,585,003)**	$ (1,145,828)

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Income

Three months ended March 31 (CDN$ thousands) unaudited	2010	2009
Revenues		
Oil and gas sales	**$ 369,640**	$ 307,515
Royalties	**(65,367)**	(55,038)
Commodity derivative instruments *(Note 8)*	**33,347**	58,645
Other income/(loss)	**264**	144
	337,884	311,266
Expenses		
Operating	**75,927**	84,130
General and administrative	**19,534**	18,870
Transportation	**6,355**	6,301
Interest *(Note 5)*	**7,490**	11,997
Foreign exchange *(Note 6)*	**(10,409)**	853
Depletion, depreciation, amortization and accretion	**159,475**	162,560
	258,372	284,711
Income/(loss) before taxes	**79,512**	26,555
Current taxes	**–**	839
Future income tax recovery	**(491)**	(26,070)
Net Income	**$ 80,003**	$ 51,786
Net income per trust unit		
Basic	**$ 0.45**	$ 0.31
Diluted	**$ 0.45**	$ 0.31
Weighted average number of trust units outstanding (thousands)		
Basic	**177,169**	165,716
Diluted	**177,523**	165,716

Consolidated Statements of Comprehensive Income

Three months ended March 31 (CDN$ thousands) unaudited	2010	2009
Net income	**$ 80,003**	$ 51,786
Other comprehensive income/(loss), net of tax:		
Change in cumulative translation adjustment	**(26,624)**	24,516
Other comprehensive income/(loss)	**(26,624)**	24,516
Comprehensive income	**$ 53,379**	$ 76,302

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	2010	2009
Operating Activities		
Net income	**$ 80,003**	$ 51,786
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	**159,475**	162,560
Change in fair value of derivative instruments *(Note 8)*	**(23,181)**	(16,721)
Unit based compensation *(Note 7 (d))*	**759**	1,379
Foreign exchange on translation of senior notes *(Note 6)*	**(15,366)**	8,237
Future income tax	**(491)**	(26,070)
Amortization of senior notes premium	**(180)**	(202)
Asset retirement obligations settled *(Note 3)*	**(4,291)**	(3,652)
	196,728	177,317
Decrease/(Increase) in non-cash operating working capital	**(7,371)**	(7,929)
Cash flow from operating activities	**189,357**	169,388
Financing Activities		
Issue of trust units, net of issue costs *(Note 7)*	**6,732**	5,400
Cash distributions to unitholders	**(95,712)**	(89,537)
Increase in bank credit facilities	**–**	66,917
Decrease/(Increase) in non-cash financing working capital	**57**	(11,549)
Cash flow from financing activities	**(88,923)**	(28,769)
Investing Activities		
Capital expenditures	**(95,730)**	(99,874)
Property and land acquisitions	**(41,327)**	(1,977)
Property dispositions	**1,538**	13
Purchase of marketable securities	**(566)**	–
Increase in non-cash investing working capital	**(11,722)**	(46,401)
Cash flow from investing activities	**(147,807)**	(148,239)
Effect of exchange rate changes on cash	**(86)**	823
Change in cash	**(47,459)**	(6,797)
Cash, beginning of year	**73,558**	6,922
Cash, end of period	**$ 26,099**	$ 125
Supplementary Cash Flow Information		
Cash income taxes (received)/paid	**$ (8,281)**	$ –
Cash interest paid	**$ 1,475**	$ 2,701

See accompanying notes to the Consolidated Financial Statements

Notes to Consolidated Financial Statements

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, 2009. 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, 2009. All amounts are stated in Canadian dollars unless otherwise specified.

2. PROPERTY, PLANT AND EQUIPMENT

($ thousands)		March 31, 2010		December 31, 2009
Property, plant and equipment	**$**	**8,926,864**	$	8,827,191
Accumulated depletion, depreciation and accretion		**(3,970,432)**		(3,826,668)
Net property, plant and equipment	**$**	**4,956,432**	$	5,000,523

Capitalized development general and administrative ("G&A") expenses of $4,589,000 are included in property, plant and equipment ("PP&E") for the three months ended March 31, 2010 (March 31, 2009 – $6,249,000). Excluded from PP&E for the depletion and depreciation calculation is $579,162,000 (December 31, 2009 – $462,989,000) related to undeveloped land and oil sands projects which have not yet commenced commercial production.

3. ASSET RETIREMENT OBLIGATIONS

The following is a reconciliation of the asset retirement obligations:

($ thousands)		Three months ended March 31, 2010		Year ended December 31, 2009
Asset retirement obligations, beginning of period	**$**	**230,465**	$	207,420
Changes in estimates		**(101)**		20,140
Property acquisition and development activity		**1,241**		4,420
Dispositions		**(449)**		(553)
Asset retirement obligations settled		**(4,291)**		(13,802)
Accretion expense		**3,676**		12,840
Asset retirement obligations, end of period	**$**	**230,541**	$	230,465

4. DEBT

($ thousands)		March 31, 2010		December 31, 2009
Current:				
Current portion of long-term debt	**$**	**35,832**	$	36,631
		35,832		36,631
Long-term:				
Bank credit facility		**–**		–
Senior notes:				
CDN$40 million (Issued June 18, 2009)		**40,000**		40,000
US$40 million (Issued June 18, 2009)		**40,624**		41,864
US$225 million (Issued June 18, 2009)		**228,510**		235,485
US$54 million (Issued October 1, 2003)		**54,842**		56,516
US$175 million (Issued June 19, 2002)*		**143,554**		148,411
		507,530		522,276
Total debt	**$**	**543,362**	$	558,907

* A portion of which has been classified as current.

Bank Credit Facility

The Fund currently has a $1.4 billion unsecured covenant based facility that matures November 18, 2010. The facility is extendible each year with a bullet payment of outstanding debt required at maturity. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on the Fund's ratio of senior debt to earnings before interest, taxes and non-cash items. The weighted average interest rate on the facility for the three months ended March 31, 2010 was 0.9% (March 31, 2009 – 1.4%). No amounts were outstanding under the facility as at March 31, 2010.

Senior Notes

The terms and rates of the Fund's outstanding senior unsecured notes are detailed below:

($ thousands)

Issue Date	Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
June 18, 2009	CDN$40,000	6.37%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$40,000	6.82%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$225,000	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in 5 equal annual installments beginning June 18, 2017
October 1, 2003	US$54,000	5.46%	April 1 and October 1	October 1, 2015	Principal payments required in 5 equal annual installments beginning October 1, 2011
June 19, 2002	US$175,000	6.62%	June 19 and December 19	June 19, 2014	Principal payments required in 5 equal annual installments beginning June 19, 2010

In September 2007 the Fund entered into foreign exchange swaps that effectively fix the five principal payments on the US$54,000,000 senior unsecured notes at a CDN/US exchange rate of 0.98 or CDN$55,080,000.

Concurrent with the issuance of the US$175,000,000 senior notes on June 19, 2002, the Fund entered into a cross currency and interest rate swap ("CCIRS") with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was effectively fixed at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

5. INTEREST EXPENSE

($ thousands)	Three months ended March 31, 2010	2009
Realized		
Interest on long-term debt	**$ 9,216**	$ 5,554
Unrealized		
Loss/(gain) on cross currency interest rate swap	**(633)**	7,964
Loss/(gain) on interest rate swaps	**(913)**	(1,319)
Amortization of the premium on senior unsecured notes	**(180)**	(202)
Interest expense	**$ 7,490**	$ 11,997

6. FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2010	2009
Realized		
Foreign exchange loss/(gain)	**$ (2,436)**	$ 2,364
Unrealized		
Foreign exchange loss/(gain) on translation of U.S. dollar denominated senior notes	**(15,366)**	8,238
Foreign exchange loss/(gain) on cross currency interest rate swap	**6,014**	(8,318)
Foreign exchange loss/(gain) on foreign exchange swaps	**1,379**	(1,431)
Foreign exchange loss/(gain)	**$ (10,409)**	$ 853

7. UNITHOLDERS' CAPITAL

($ thousands)	Three months ended March 31, 2010	Year ended December 31, 2009
Trust units	**$ 5,623,440**	$ 5,580,933
Exchangeable limited partnership units	**72,989**	108,539
Contributed surplus	**26,676**	26,142
Balance, end of period	**$ 5,723,105**	$ 5,715,614

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	Three months ended March 31, 2010		Year ended December 31, 2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**174,349**	**$ 5,580,933**	162,514	$ 5,328,629
Issued for cash:				
Pursuant to public offerings	**–**	**–**	10,406	213,531
DRIP*, net of redemptions	**264**	**5,932**	1,061	24,120
Pursuant to rights incentive plan	**45**	**800**	4	85
Non-cash:				
Exchangeable limited partnership units exchanged	**888**	**35,550**	364	14,568
Trust unit rights incentive plan	**–**	**225**	–	–
	175,546	**5,623,440**	174,349	5,580,933
Equivalent exchangeable partnership units	**1,824**	**72,989**	2,712	108,539
Balance, end of period	**177,370**	**$ 5,696,429**	177,061	$ 5,689,472

* Distribution Reinvestment and Unit Purchase Plan

(b) Exchangeable Limited Partnership Units

The exchangeable limited partnership units issued by a subsidiary of the Fund are convertible at any time into trust units at the option of the holder at a ratio of 0.425 of an Enerplus trust unit for each limited partnership unit. The partnership unitholder also receives cash distributions and has voting rights in accordance with the 0.425 exchange ratio. The Board of Directors may redeem the exchangeable limited partnership units after January 8, 2017, unless certain conditions are met to permit an earlier redemption date. The exchangeable limited partnership units are not listed on any stock exchange and are not transferable.

During the period January 1, 2010 to March 31, 2010, 2,090,000 exchangeable limited partnership units were converted into 888,000 trust units. As at March 31, 2010, the 4,292,000 outstanding exchangeable partnership units represent the equivalent of 1,824,000 trust units.

(thousands)	Three months ended March 31, 2010		Year ended December 31, 2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**6,382**	**$ 108,539**	7,238	$ 123,107
Exchanged for trust units	**(2,090)**	**(35,550)**	(856)	(14,568)
Balance, end of period	**4,292**	**$ 72,989**	6,382	$ 108,539

(c) Contributed Surplus

($ thousands)	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	**$ 26,142**	$ 19,600
Trust unit rights incentive plan (non-cash) – exercised	**(225)**	–
Trust unit rights incentive plan (non-cash) – expensed	**759**	6,542
Balance, end of period	**$ 26,676**	$ 26,142

(d) Trust Unit Rights Incentive Plan

As at March 31, 2010 a total of 6,527,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") were outstanding at an average exercise price of $32.48. This represented 3.7% of the total trust units outstanding, of which 3,210,000 rights, with an average exercise price of $40.99, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of the Fund at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the three months ended March 31, 2010 did not reduce the exercise price of the outstanding rights.

Non-cash compensation costs of $759,000 ($nil per unit) related to rights issued were charged to general and administrative expense during the three months ended March 31, 2010 (March 31, 2009 – $1,378,000, $0.01 per unit). Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	Three months ended March 31, 2010		Year ended December 31, 2009	
	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 year	**5,250**	**$ 34.84**	4,001	$ 45.05
Granted	**1,690**	**23.58**	2,001	17.28
Exercised	**(45)**	**17.53**	(4)	22.40
Forfeited and expired	**(368)**	**27.06**	(748)	38.61
End of year	**6,527**	**$ 32.48**	5,250	$ 34.84
Rights exercisable at the end of the period	**3,210**	**$ 40.99**	2,393	$ 46.03

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

(e) Basic and Diluted per Trust Unit Calculations

Basic per-unit calculations are calculated using the weighted average number of trust units and exchangeable limited partnership units (converted at the 0.425 exchange ratio) outstanding during the period. Diluted per-unit calculations include additional trust units for the dilutive impact of rights outstanding pursuant to the Rights Incentive Plan.

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

	Three months ended March 31,	
(thousands)	**2010**	**2009**
Weighted average units	**177,169**	165,716
Dilutive impact of rights	**354**	–
Diluted trust units	**177,523**	165,716

(f) Long Term Incentive Unit Plans

For the three months ended March 31, 2010 the Fund recorded cash compensation costs of $3,676,000 (2009 – $3,119,000) with respect to its Performance Trust Unit ("PTU") and Restricted Trust Unit ("RTU") plans which are included in general and administrative expenses.

At March 31, 2010 there were 204,000 PTU's outstanding and 1,088,000 RTU's outstanding.

8. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Carrying Value and Fair Value of Non-Derivative Financial Instruments

i. Cash

Cash is classified as held-for-trading and is reported at fair value, based on a Level 1 designation.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables which are reported at amortized cost. At March 31, 2010 the carrying value of accounts receivable approximated their fair value.

iii. Marketable Securities

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. During the first quarter of 2010 the Fund did not hold any investments in publicly traded marketable securities.

Marketable securities without a quoted market price in an active market are reported at cost unless an other than temporary impairment exists. As at March 31, 2010 the Fund reported investments in marketable securities of private companies at cost of $50,156,000 (December 31, 2009 – $49,591,000) in Other Assets on the Consolidated Balance Sheet.

Realized gains and losses on marketable securities are included in other income.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable as well as distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At March 31, 2010 the carrying value of these accounts approximated their fair value.

v. Long-term Debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at amortized cost. At March 31, 2010 the bank credit facility was undrawn.

Senior Unsecured Notes

The senior unsecured notes, which are classified as other liabilities, are carried at their amortized cost and translated to Canadian dollars at the period end exchange rate. The following table details the amortized cost of the notes expressed in U.S. and Canadian dollars as well as the fair value expressed in Canadian dollars:

Principal Private Placement amount ($ thousands)	**Amortized Cost**	**Reported CDN$ Amortized Cost**	**CDN$ Fair Value**
CDN$40,000	CDN$40,000	$ 40,000	**$ 43,397**
US$40,000	US$40,000	40,624	**45,645**
US$225,000	US$225,000	228,510	**267,793**
US$54,000	US$54,000	54,842	**58,140**
US$175,000	US$176,630	179,386	**192,233**
		$ 543,362	**$ 607,208**

(b) Fair Value of Derivative Financial Instruments

The Fund has assessed the relative inputs used in the determination of the fair value of all its derivative financial instruments and has determined that a fair value classification of Level 2 is appropriate for each of the instruments. A Level 2 assignment is appropriate where observable inputs other than quoted prices are used in the fair value determination.

The Fund's derivative financial instruments are classified as held for trading and are reported at fair value with changes in fair value recorded through earnings. The deferred financial assets and credits on the Consolidated Balance Sheet result from recording derivative financial instruments at fair value. At March 31, 2010 a current deferred financial asset of $56,316,000, a current deferred financial credit of $45,916,000, a non-current deferred financial asset of $618,000 and a non-current deferred financial credit of $57,701,000 are recorded on the Consolidated Balance Sheet.

The deferred financial credit relating to crude oil instruments is $26,902,000 at March 31, 2010 including deferred premiums of $9,524,000. The deferred financial asset relating to natural gas instruments is $56,316,000 at March 31, 2010 including deferred premiums of $4,974,000.

The following table summarizes the fair value as at March 31, 2010 and change in fair value for the period ended March 31, 2010.

($ thousands)	**Interest Rate Swaps**	**Cross Currency Interest Rate Swap**	**Foreign Exchange Swaps**	**Electricity Swaps**	**Commodity Derivative Instruments**		**Total**
					Oil	**Gas**	
Deferred financial assets/(credits), beginning of period	$ (6,064)	$ (63,336)	$ 1,997	$ (2,481)	$ (20,344)	$ 20,364	$ (69,864)
Change in fair value gain/(loss)	913(1)	(5,381)(2)	(1,379)(3)	(366)(4)	(6,558)(5)	35,952(5)	23,181
Deferred financial assets/(credits), end of period	**$ (5,151)**	**$ (68,717)**	**$ 618**	**$ (2,847)**	**$ (26,902)**	**$ 56,316**	**$ (46,683)**
Balance sheet classification:							
Current asset/(liability)	**$ (3,792)**	**$ (12,375)**	**$ –**	**$ (2,847)**	**$ (26,902)**	**$ 56,316**	**$ 10,400**
Non-current asset/(liability)	**$ (1,359)**	**$ (56,342)**	**$ 618**	**$ –**	**$ –**	**$ –**	**$ (57,083)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (loss of $6,014) and interest expense (gain of $633).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

The following table summarizes the income statement effects of commodity derivative instruments:

($ thousands)	Three months ended March 31, 2010	2009
Gain/(loss) due to change in fair value	**$ 29,394**	$ 12,665
Net realized cash gain/(loss)	**3,953**	45,980
Commodity derivative instruments gain	**$ 33,347**	$ 58,645

(c) Commodity Risk Management

The Fund is exposed to commodity price fluctuations as part of its normal business operations, particularly in relation to its crude oil and natural gas sales. The Fund manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts. The Fund's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. The Fund's outstanding commodity derivative contracts as at April 23, 2010 are summarized below:

Crude Oil:

		WTI US$/bbl		
	Daily Volumes bbls/day	**Purchased Call**	**Sold Put**	**Fixed Price and Swaps**
Term				
Apr 1, 2010 – Dec 31, 2010				
Purchased Call	3,500	$ 95.00	–	–
Purchased Call	3,000	$ 90.00	–	–
Purchased Call	500	$ 92.50	–	–
Swap	1,500	–	–	$ 78.45
Swap	1,000	–	–	$ 78.80
Swap	1,000	–	–	$ 68.05
Swap	500	–	–	$ 69.33
Swap	500	–	–	$ 72.15
Swap	500	–	–	$ 74.30
Swap	500	–	–	$ 76.20
Swap	500	–	–	$ 76.38
Swap	500	–	–	$ 78.15
Swap	1,000	–	–	$ 79.20
Swap	500	–	–	$ 80.00
Swap	1,000	–	–	$ 83.40
Swap	1,000	–	–	$ 78.00
Swap	500	–	–	$ 80.15
Swap	500	–	–	$ 81.55
Swap(1)	500	–	–	$ 84.35
Swap(1)	500	–	–	$ 80.65
Swap(1)	500	–	–	$ 82.00
Swap(1)	500	–	–	$ 83.55
Sold Put	4,000	–	$ 47.50	–
Sold Put(1)	1,000	–	$ 47.50	–
Jul 1, 2010 – Dec 31, 2010				
Swap(1)	500	–	–	$ 85.65
Jan 1, 2011 – Dec 31, 2011				
Purchased Call	1,000	$ 105.00	–	–
Swap	1,000	–	–	$ 87.65
Swap(1)	500	–	–	$ 85.20
Swap(2)	500	–	–	$ 88.95
Swap(2)	500	–	–	$ 91.20
Swap(2)	500	–	–	$ 91.88
Sold Put	1,000	–	$ 55.00	–

(1) Financial contracts entered into during the first quarter of 2010.
(2) Financial contracts entered into subsequent to March 31, 2010.

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
Apr 1, 2010 – May 31, 2010					
Purchased Call(1)	9.5	$ 5.80	–	–	–
Apr 1, 2010 – Oct 31, 2010					
Swap	23.7	–	–	–	$ 7.33
Swap(1)	4.7	–	–	–	$ 5.60
Swap(1)	4.7	–	–	–	$ 5.77
Purchased Call(1)	9.5	$ 6.54	–	–	–
Apr 1, 2010 – Dec 31, 2010					
Put Spread	4.7	–	$ 5.28	$ 3.96	–
Put Spread	4.7	–	$ 5.44	$ 3.96	–
Put Spread	9.5	–	$ 5.59	$ 3.96	–
Put Spread	4.7	–	$ 5.70	$ 4.22	–
Apr 1, 2010 – Mar 31, 2011					
Swap	14.2	–	–	–	$ 6.20
Swap	4.7	–	–	–	$ 6.23
Swap	4.7	–	–	–	$ 6.24
Swap	4.7	–	–	–	$ 6.25
Swap	4.7	–	–	–	$ 6.17
Swap(1)	9.5	–	–	–	$ 6.07
Nov 1, 2010 – Mar 31, 2011					
Swap	9.5	–	–	–	$ 6.81
Swap	9.5	–	–	–	$ 6.77
Swap	4.7	–	–	–	$ 6.66
Purchased Call(1)	4.7	$ 7.91	–	–	–
Purchased Call(1)	4.7	$ 7.39	–	–	–
Purchased Call(1)	9.5	$ 6.86	–	–	–
Sold Put(1)	19.0	–	–	$ 4.48	–
Jan 1, 2011 – Mar 31, 2011					
Purchased Call(1)	14.2	$ 6.38	–	–	–
Sold Put(1)	9.5	–	–	$ 4.37	–
Sold Put(1)	4.7	–	–	$ 4.03	–
Apr 1, 2010 – Oct 31, 2010					
Physical	2.0	–	–	–	$ 2.77

(1) Financial contracts entered into during the first quarter of 2010.

In addition to the positions shown above, during the first quarter of 2010, the Fund entered into the following fixed basis swaps for volumes delivered to AECO and Sumas, for which it receives Nymex less differentials:

Term	Volume MMbtu/day	Contract	Differential US$/MMbtu
April 1 – October 31, 2010	25,000	AECO Swap to Nymex	($0.35) – ($0.37)
April 1 – October 31, 2010	10,000	AECO Swap to % of Nymex	93%
April 1 – October 31, 2010	5,000	Sumas Swap to Nymex	($0.26)

The following sensitivities show the impact to after-tax net income of the respective changes in forward crude oil and natural gas prices as at March 31, 2010 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	**25% decrease in forward prices**	**25% increase in forward prices**
Crude oil derivative contracts	**$ 58,192**	**$ (43,685)**
Natural gas derivative contracts	**$ 15,058**	**$ (15,853)**

Electricity:

The fund is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rated electricity derivative contracts on a portion of its electricity requirements. The Fund's outstanding electricity derivative contracts as at April 23, 2010 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
April 1, 2010 – December 31, 2010	4.0	$ 77.50
April 1, 2010 – December 31, 2010	2.0	$ 68.75
April 1, 2010 – December 31, 2010	3.0	$ 49.50
April 1, 2010 – December 31, 2010	3.0	$ 52.25
April 1, 2010 – December 31, 2010	2.0	$ 49.00
April 1, 2010 – December 31, 2011	3.0	$ 66.00
January 1, 2011 – December 31, 2011	3.0	$ 55.00
January 1, 2011 – December 31, 2011	3.0	$ 57.25
January 1, 2011 – December 31, 2011(1)	3.0	$ 49.00

(1) Financial contracts entered into during the first quarter of 2010.

9. COMMITMENTS AND CONTINGENCIES

In conjunction with the Marcellus acquisition on September 1, 2009 the Fund has committed to pay 50% of the sellers' future drilling and completion costs up to an aggregate amount of US$246,600,000. Our outstanding commitment balance at March 31, 2010 is approximately US$228,291,000. We expect the remainder of the commitment will be incurred over the next four years.

Board of Directors

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Calgary, Alberta

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Gordon J. Kerr
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Enerplus Resources Fund
Calgary, Alberta

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Calgary, Alberta

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Calgary, Alberta

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Managing Director
EnCap Investments L.P.
Houston, Texas

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Health, Safety, Regulatory & Environmental Committee
(12) Chairman of the Health, Safety, Regulatory & Environmental Committee

Officers

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President & Chief Executive Officer

Ian C. Dundas
Executive Vice President

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Corporate & Investor Relations

Ray J. Daniels
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Jennifer F. Koury
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Eric G. Le Dain
Vice President, Strategic Planning, Reserves & Marketing

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Robert W. Symonds
Vice President, Canadian Operations

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

Corporate Information

Operating Companies Owned by Enerplus Resources Fund
EnerMark Inc.
Enerplus Resources Corporation
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation
FET Operational Partnership

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Transfer Agent
Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

Independent Reserve Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates Inc.
Dallas, Texas

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF.un
New York Stock Exchange: ERF

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Abbreviations

AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
AOCI accumulated other comprehensive income
API American Petroleum Institute
bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf billion cubic feet
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
COGPE Canadian oil and gas property expense
CTA cumulative translation adjustment
F&D Costs finding and development costs
FD&A Costs finding, development and acquisition costs
FDC future development capital
GORR gross overriding royalty
HH "Henry Hub" A reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract
Mbbls thousand barrels
MBOE thousand barrels of oil equivalent
Mcf thousand cubic feet
Mcfe thousand cubic feet equivalent
Mcf/day thousand cubic feet per day
Mcfe/day thousand cubic feet equivalent per day
MMbbl(s) million barrels
MMBOE million barrels of oil equivalent
MMBtu million British Thermal Units
MMBtu/day million British Thermal Units per day
MMcf million cubic feet
MMcfe million cubic feet equivalent
MMcf/day million cubic feet per day
MMcfe/day million cubic feet equivalent per day
MWh megawatt hour(s) of electricity
NGLs natural gas liquids
NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory authorities (pertaining to reserve reporting in Canada)
OCI other comprehensive income
P+P Reserves proved plus probable reserves
PDP Reserves proved developed producing reserves
RLI reserve life index
SAGD steam assisted gravity drainage
WI percentage working interest ownership
WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

THE ENERGY OF

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