THE ENERGY OF
enerPLUS

Second Quarter Report

SIX MONTHS ENDED JUNE 30, 2009

SELECTED FINANCIAL RESULTS

	Three months ended June 30,		Six months ended June 30,	
(in Canadian dollars)	**2009**	**2008**	**2009**	**2008**
Financial (000's)				
Cash Flow from Operating Activities	**$ 210,608**	$ 364,457	**$ 379,996**	$ 620,673
Cash Distributions to Unitholders[1]	**89,610**	202,346	**179,147**	394,704
Excess of Cash Flow Over Cash Distributions	**120,998**	162,111	**200,849**	225,969
Net Income/(Loss)	**(3,569)**	112,230	**48,217**	233,624
Debt Outstanding – net of cash	**713,536**	1,027,578	**713,536**	1,027,578
Development Capital Spending	**35,562**	88,008	**134,805**	214,270
Acquisitions	**28,416**	1,740	**30,393**	1,766,809
Divestments	**1,723**	86	**1,736**	2,208
Actual Cash Distributions paid to Unitholders	**$ 0.54**	$ 1.26	**$ 1.15**	$ 2.52
Financial per Weighted Average Trust Units[2]				
Cash Flow from Operating Activities	**$ 1.27**	$ 2.22	**$ 2.29**	$ 3.98
Cash Distributions per Unit[1]	**0.54**	1.26	**1.08**	2.52
Excess of Cash Flow Over Cash Distributions	**0.73**	0.99	**1.21**	1.45
Net Income/(Loss)	**(0.02)**	0.68	**0.29**	1.50
Payout Ratio[3]	**43%**	56%	**47%**	64%
Adjusted Payout Ratio[3]	**61%**	80%	**83%**	99%
Selected Financial Results per BOE[4]				
Oil & Gas Sales[5]	**$ 35.60**	$ 80.56	**$ 35.42**	$ 71.85
Royalties	**(6.28)**	(15.14)	**(6.36)**	(13.46)
Commodity Derivative Instruments	**4.95**	(7.03)	**5.16**	(4.35)
Operating Costs	**(9.58)**	(9.43)	**(9.77)**	(9.21)
General and Administrative	**(2.27)**	(1.67)	**(2.16)**	(1.75)
Interest and Other Income and Foreign Exchange	**1.02**	(1.32)	**0.07**	(1.10)
Taxes	**(0.21)**	(1.78)	**(0.15)**	(1.49)
Asset Retirement Obligations Settled	**(0.29)**	(0.52)	**(0.36)**	(0.51)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 22.94**	$ 43.67	**$ 21.85**	$ 39.98
Weighted Average Number of Trust Units Outstanding[2]	**166,264**	164,483	**165,807**	155,984
Debt to Trailing Twelve Month Cash Flow Ratio[6]	**0.7x**	0.9x	**0.7x**	0.9x

SELECTED OPERATING RESULTS

	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Average Daily Production				
Natural gas (Mcf/day)	**338,193**	359,349	**338,538**	333,559
Crude oil (bbls/day)	**33,715**	35,486	**34,075**	34,376
Natural gas liquids (bbls/day)	**4,420**	4,810	**4,241**	4,712
Total daily sales (BOE/day)	**94,501**	100,188	**94,739**	94,681
% Natural gas	**60%**	60%	**60%**	59%
Average Selling Price(5)				
Natural gas (per Mcf)	**$ 3.49**	$ 9.87	**$ 4.31**	$ 8.79
Crude oil (per bbl)	**59.80**	114.04	**51.06**	100.47
NGLs (per bbl)	**35.47**	80.55	**37.91**	75.29
CDN$/US$ exchange rate	**0.86**	0.99	**0.83**	0.99
Net Wells drilled	**5**	72	**128**	197
Success Rate(7)	**100%**	100%	**99%**	100%

(1) Calculated based on distributions paid or payable.
(2) Weighted average trust units outstanding for the period, includes the equivalent exchangeable partnership units.
(3) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" in the following Management's Discussion and Analysis.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(6) Including the trailing 12 month cash flow of Focus Energy Trust for 2008.
(7) Based on wells drilled and cased.

Trust Unit Trading Summary for the three months ended June 30, 2009	**TSX – ERF.un (CDN$)**	**U.S.* – ERF (US$)**
High	$ 27.70	$ 25.13
Low	$ 20.42	$ 16.06
Close	$ 25.13	$ 21.49

* U.S. Composite Exchange Data including NYSE.

2009 Cash Distributions Per Trust Unit Payment Month	**CDN$**	**US$**
First Quarter Total	**$ 0.61**	**$ 0.49**
April	$ 0.18	$ 0.15
May	0.18	0.16
June	0.18	0.16
Second Quarter Total	**$ 0.54**	**$ 0.47**
Total Year-to-Date	**$ 1.15**	**$ 0.96**

This interim report contains certain forward-looking information and statements. We refer you to the end of the accompanying Management's Discussion and Analysis under "Forward-Looking Information and Statements" for our disclaimer on forward-looking information and statements which applies to all other portions of this interim report. For information on the use of the term "BOE" see the introductory paragraph under the Management's Discussion and Analysis section in this interim report. All amounts in this interim report are in Canadian dollars unless otherwise specified.

president's message

I am pleased to report that Enerplus' operating and financial performance for the second quarter of 2009 is on track and meeting the expectations set out at the start of 2009. While our cash flows have been significantly impacted by the dramatic drop in commodity prices when compared to this time last year, our production volumes, development capital spending plans and operating and general and administrative expenses are on target. We continue to maintain our discipline regarding development spending and have preserved our balance sheet strength.

Production during the quarter averaged approximately 94,500 BOE/day, virtually unchanged from the first quarter of 2009 and approximately 6% lower than the second quarter of 2008. Our production levels benefited this quarter from an accelerated capital program during the winter drilling season as well as production optimization and reduced downtime. Due to lower development capital activity, planned facility turnarounds in the third quarter and the natural decline of our asset base, we are expecting production for the remainder of the year to fall from second quarter levels. Therefore, we are maintaining our annual average production guidance of 91,000 BOE/day with an exit rate of approximately 88,000 BOE/day based on our development capital budget of $300 million.

Natural gas prices continued to weaken throughout the second quarter as increased supply, higher than average inventory levels, and weak demand added further pressure to an already depressed natural gas market. We realized an average selling price on our natural gas of $3.49/Mcf during the second quarter of 2009, a decrease of 65% from $9.87/Mcf for the same period in 2008. Crude oil prices rebounded from the extreme weakness seen in the first quarter as the global economy showed early signs of stabilizing. Oil prices remain significantly lower than this time last year due to lower global demand for crude oil relative to 2008 combined with higher than average global inventories. We realized an average selling price on our crude oil of $59.80/bbl for the second quarter, a 48% decrease from $114.04/bbl during the same period in 2008. We realized cash gains of approximately $21 million on our natural gas hedges and approximately $22 million on our crude oil hedges during the quarter. For the remainder of 2009, we have downside price protection in place for approximately 25% of our natural gas production at an effective price of $7.60/Mcf and approximately 27% of our oil production at an effective price of over US$98.00/bbl based on current forward market prices.

Our cash flow from operations during the second quarter was $210.6 million, 42% lower than the second quarter of 2008, but 24% higher than the first quarter of 2009. Approximately 43% of our cash flow was distributed to our unitholders during the quarter compared to 56% last year as we maintained monthly distributions at $0.18/unit throughout the quarter. We invested $35.6 million in our assets through development capital spending this quarter, and when combined with the amount paid in distributions to our unitholders, we realized an adjusted payout ratio of 61% for the quarter versus 80% last year. Our adjusted payout ratio has averaged 83% for the first half of 2009 as we continue to prudently manage our spending. We expect our full year adjusted payout ratio to be in the order of 100% excluding the impact of acquisitions.

2009 Production and Development Activity

	Three months ended June 30, 2009				Six months ended June 30, 2009			
	Production Volumes	Capital Spending	Wells Drilled		Production Volumes	Capital Spending	Wells Drilled	
Play Type	**(BOE/day)**	**($ millions)**	**Gross**	**Net**	**(BOE/day)**	**($ millions)**	**Gross**	**Net**
Shallow Gas	23,644	$ 0.4	4	1	24,026	$ 29.6	121	105
Crude Oil Waterfloods	16,158	5.2	–	–	16,162	13.5	2	1
Tight Gas	16,371	6.2	–	–	15,882	35.3	20	11
Bakken/Tight Oil	10,477	6.4	1	–	10,644	17.5	2	1
Conventional Oil & Gas	27,851	12.5	6	4	28,025	25.7	36	10
Total Conventional	**94,501**	**30.7**	**11**	**5**	**94,739**	**121.6**	**181**	**128**
Oil Sands	–	4.9	–	–	–	13.2	–	–
Total	**94,501**	**$ 35.6**	**11**	**5**	**94,739**	**$ 134.8**	**181**	**128**

Our development capital program for the quarter was significantly lower than the first quarter due to weakening gas prices, traditionally slower activity due to winter break-up and the conservative approach we have taken on our spending to preserve our balance sheet. Approximately $36 million was invested during the quarter with year-to-date capital spending totaling approximately $135 million. Our shallow gas activities have been concentrated at Shackleton, Bantry and Verger with 105 net infill wells drilled year-to-date. Tight gas activity has centred at Tommy Lakes with the completion of a successful 14 well program earlier this year, including the first horizontal well drilled on our lands. The horizontal well is producing as expected with initial production rates of approximately 4 MMcf/day and reserve estimates of approximately 3.5 Bcf, roughly three times that of a vertical well. Our tight oil development activities have been focused primarily at Sleeping Giant where we had a drilling program early in the year and continued an active refrac program. The remainder of our development spending has been on production optimization in various fields within our waterflood resource play and our conventional oil and gas assets.

For the remainder of the year, our development capital spending will focus on crude oil projects, royalty incentive supported natural gas drilling in Alberta and new growth projects. Our crude oil program is planned to target the expansion of the refrac program at Sleeping Giant as well as a possible resumption of our drilling program in this area later this year. We plan to initiate a small drilling program in Manitoba and southeast Saskatchewan and expect to continue optimization projects across a variety of crude oil properties. We also plan to leverage off of the Drilling Royalty Credit program implemented by the Alberta government to support our natural gas drilling efforts in Alberta. We have suspended further drilling in Shackleton due to the weak natural gas price environment and will continue to monitor gas prices to determine if this program will be resumed later this year. In spite of the weakness in natural gas prices we shut in only a limited amount of natural gas production (less than 250 BOE/day) during the quarter. We do not currently anticipate any additional shut-ins however we will continue to evaluate the economics of all our production and will make further decisions as warranted.

Our growth activities are focused in the tight gas and Bakken/tight oil resource plays. We have acquired modest land positions in both the Montney region in British Columbia and Alberta and the Nordegg region in Alberta, and we have recently completed an agreement for the joint development of our interests in the Nordegg region with another industry partner. Both of these growth plays are in the early stages and we plan to continue to build positions and evaluate opportunities going forward. We also plan to drill initial wells on our southeast Saskatchewan Bakken lands acquired in 2008. We continue to expect to spend $300 million on our overall development capital in 2009 however we will continue to review our spending plans in relation to commodity prices.

Acquisition Activity

We continue to evaluate acquisition opportunities that will add meaningful growth in reserves and production, focusing primarily on tight gas opportunities in British Columbia and Alberta, tight oil opportunities in Saskatchewan and North Dakota, as well as shale gas opportunities in the United States. In May, we purchased a 25% working interest in 44 sections of prospective Bakken land in southeast Saskatchewan and entered into a material area of mutual interest agreement with an industry partner, investing a total of $25 million. This acquisition has added approximately 200 BOE/day of non-operated Bakken production to our existing tight oil portfolio and we plan to participate in the drilling of 7 gross wells during the remainder of 2009 spending approximately $5 million. This acquisition builds on our existing portfolio of Bakken prospects in Saskatchewan and Montana and will provide future growth potential in this tight oil resource play.

Updated Resource Estimate at Kirby Oil Sands Lease

In April, we announced the deferral of our Kirby oil sands project due to inflated cost structures and a weak commodity price environment. Despite the deferral, we reiterated our plans to complete the regulatory application for the initial 10,000 bbl/day commercial project and to obtain an updated resource estimate. The regulatory application for the first phase of the project continues to move forward and we expect to receive regulatory approval early in 2010. We have also updated our resource estimate based on new data obtained from our 2008 seismic program. Our third party independent reserve engineers have provided an updated best estimate of contingent resources of approximately 507 million barrels, an increase of 22% from the 414 million barrel best estimate provided in 2008 and 108% higher than the original independent best estimate assessed when we purchased the Kirby lease in 2007. We believe there is further opportunity to increase the resource estimate at Kirby and long-term value in the project. We will continue to monitor economic, regulatory and technical developments should we revisit our plans for Kirby at a later date. For additional information on contingent resource estimates, see "Information Regarding Contingent Resource Estimates" at the end of the Management's Discussion and Analysis section of this interim report.

Senior Unsecured Note Issuance

In June 2009, we issued approximately $340 million in long-term debt by way of private placement in the form of senior notes with terms of 6 and 12 years. We used the proceeds from the senior notes to repay a portion of our outstanding bank debt, increasing the unused credit capacity on our bank credit facility to over $1.3 billion at the end of the quarter. The placement of senior notes provides us greater flexibility in managing our long-term debt portfolio, as our existing notes are scheduled for repayment between 2010 and 2015. It also diversifies our credit sources by replacing short-term debt with the assurance of long-term debt commitments at attractive rates. Our balance sheet remains strong with a debt to trailing 12 month cash flow ratio of 0.7x at the end of the quarter. This strength will be essential as we pursue our strategy of acquiring assets in emerging North American resource plays.

Corporate Conversion Update

As the implementation of the SIFT tax effective January 1, 2011 approaches, we continue to develop plans for the conversion to a corporation by late 2010. We remain committed to our business strategy of paying a significant portion of our cash flow directly to our investors regardless of our legal structure. The conversion to a corporation would be a change to our legal structure only and not a change to our fundamental business model of being a distribution-oriented entity in the oil and gas industry. A conversion proposal would be subject first to Board approval and a subsequent vote by unitholders for acceptance.

Strategic Focus

We remain committed to managing our business prudently throughout these challenging economic times. Our strong financial position and acquisition experience has positioned us to take advantage of strategic asset opportunities both in Canada and the United States that will help to evolve and improve our organization. We are keenly focused on reducing costs and increasing efficiencies on our existing asset base through disciplined spending of our development capital while preserving our drilling inventory for periods of higher prices with better economic returns. We are also in the process of identifying existing assets that may not be core to our long-term business strategy for disposition at a later time. We believe there is an opportunity to improve our business during this period of economic recovery that will position us strongly for the future.

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

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated August 6, 2009 and is to be read in conjunction with:

- the audited consolidated financial statements as at and for the years ended December 31, 2008 and 2007 and accompanying management's discussion and analysis; and
- the unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2009 and 2008.

All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the accompanying unaudited interim consolidated financial statements. 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 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.

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 on forward-looking information and statements.

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. "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 second quarter operating results were on target with expectations as production averaged 94,501 BOE/day, operating costs were \$9.93/BOE and general and administrative costs were \$2.49/BOE. Development capital spending slowed to \$35.6 million reflecting our conservative approach in the current commodity price environment. We are continuing to closely evaluate our capital projects and will adjust our spending accordingly should commodity price levels change significantly.

The decrease in commodity price levels has directly impacted our cash flow and earnings. Our cash flow totaled \$210.6 million for the quarter, a 42% decrease from \$364.5 million in the second quarter of 2008. We also had a \$3.6 million net loss during the quarter compared to net income of \$112.2 million in 2008. Our payout ratio and adjusted payout ratio for the quarter was 43% and 61% respectively, reflecting our reduced distribution levels and decreased capital spending.

During the quarter we successfully closed an offering of senior unsecured notes by way of private placement and raised gross proceeds of approximately \$338.7 million that were used to pay down bank indebtedness. We continue to have significant financial flexibility to pursue acquisition opportunities with over \$1.3 billion of available credit capacity on our syndicated bank facility and a debt to trailing twelve month cash flow ratio of 0.7x.

RESULTS OF OPERATIONS

Production

Production in the second quarter of 2009 averaged 94,501 BOE/day, in-line with our expectations but slightly below 2009 first quarter production of 94,962 BOE/day and 6% lower than production of 100,188 BOE/day in the second quarter of 2008. The 6% decrease from 2008 is primarily due to natural production declines.

Average production volumes for the three and six months ended June 30, 2009 and 2008 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Daily Production Volumes	**2009**	**2008**	**% Change**	**2009**	**2008**	**% Change**
Natural gas (Mcf/day)	**338,193**	359,349	(6)%	**338,538**	333,559	1%
Crude oil (bbls/day)	**33,715**	35,486	(5)%	**34,075**	34,376	(1)%
Natural gas liquids (bbls/day)	**4,420**	4,810	(8)%	**4,241**	4,712	(10)%
Total daily sales (BOE/day)	**94,501**	100,188	(6)%	**94,739**	94,681	–%

We are expecting lower production levels during the second half of 2009 due to planned facility turnarounds, a reduction in capital spending and declines from flush production associated with our winter drilling program. We currently have a modest amount of natural gas production shut in due to pricing and are not expecting a significant amount of additional curtailment as the majority of our wells are covering their variable costs at current prices. We continue to expect 2009 annual production volumes to average 91,000 BOE/day and our 2009 exit rate to be approximately 88,000 BOE/day.

Pricing

The prices received for our natural gas and crude oil production have a direct impact on our earnings, cash flow and financial condition. The following table compares our average selling prices and benchmark price indices for the three and six months ended June 30, 2009 and 2008.

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price(1)	**2009**	**2008**	**% Change**	**2009**	**2008**	**% Change**
Natural gas (per Mcf)	**$ 3.49**	$ 9.87	(65)%	**$ 4.31**	$ 8.79	(51)%
Crude oil (per bbl)	**$ 59.80**	$ 114.04	(48)%	**$ 51.06**	$ 100.47	(49)%
Natural gas liquids (per bbl)	**$ 35.47**	$ 80.55	(56)%	**$ 37.91**	$ 75.29	(50)%
Per BOE	**$ 35.60**	$ 80.56	(56)%	**$ 35.42**	$ 71.85	(51)%

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

	Three months ended June 30,			Six months ended June 30,		
Average Benchmark Pricing	**2009**	**2008**	**% Change**	**2009**	**2008**	**% Change**
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.66**	$ 9.35	(61)%	**$ 4.65**	$ 8.24	(44)%
AECO natural gas – daily index (CDN$/Mcf)	**$ 3.45**	$ 10.22	(66)%	**$ 4.18**	$ 9.06	(54)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**$ 3.60**	$ 10.80	(67)%	**$ 4.19**	$ 9.43	(56)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**$ 4.19**	$ 10.91	(62)%	**$ 5.05**	$ 9.53	(47)%
WTI crude oil (US$/bbl)	**$ 59.62**	$ 123.98	(52)%	**$ 51.35**	$ 110.95	(54)%
WTI crude oil CDN$ equivalent (CDN$/bbl)	**$ 69.33**	$ 125.23	(45)%	**$ 61.87**	$ 112.07	(45)%
CDN$/US$ exchange rate	**0.86**	0.99	(13)%	**0.83**	0.99	(16)%

During the quarter the average of the AECO monthly and daily gas price declined 33% from $5.28/Mcf in the first quarter to $3.56/Mcf in the second quarter. The decrease was a continuation of the price erosion seen earlier in the year as weak demand and strong North American supply continued to push gas prices down. Seasonally high gas storage inventories combined with a lack of warm weather, which usually drives up the demand for cooling related, gas fired electricity generation, have put downward pressure on gas prices.

We realized an average price on our natural gas of $3.49/Mcf (net of transportation costs) during the second quarter of 2009, a decrease of 65% from $9.87/Mcf for the same period in 2008. For the six months ended June 30, 2009 we realized an average price of $4.31/Mcf, a 51% decrease from the same period in 2008. The majority of our natural gas sales are priced with reference to the average of the monthly and daily AECO indices. The index decreases for the three and six months ended June 30, 2009 are comparable to the changes experienced in our realized prices at AECO.

The price of crude oil increased quarter over quarter with the average West Texas Intermediate ("WTI") price increasing 38% from US$43.08/bbl in the first quarter of 2009 to US$59.62/bbl in the second quarter of 2009. However, in comparison to last year, crude oil prices remained depressed during the quarter mainly as a result of high inventories and declining demand with WTI averaging US$59.62/bbl, a 52% decrease compared to US$123.98/bbl for the same period in 2008. In Canadian dollars WTI decreased 45% to $69.33/bbl from $125.23/bbl for the same period in 2008. Enerplus' average realized crude oil sales price was $59.80/bbl (net of transportation costs) for the second quarter, a 48% decrease from $114.04/bbl during the same period in 2008. For the six months ended June 30, 2009 our realized crude oil sales prices was $51.06/bbl (net of transportation costs), a 49% decrease from $100.47/bbl during the same period in 2008. The decrease in our realized prices for the three and six months ended June 30, 2009 are comparable to the changes experienced with the benchmark price for crude oil.

The Canadian dollar weakened against the U.S. dollar during the three and six months ended June 30, 2009 compared to the same periods in 2008. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate increased the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We continue to adjust 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 upfront and potential costs of our risk management program as we seek to limit our exposure to price downturns. Hedge positions for any given term are transacted across a range of prices and periods.

Given the above framework and objectives, we have entered into additional commodity contracts during and subsequent to the second quarter of 2009. Considering all financial contracts transacted as of July 29, 2009, we have protected a portion of our natural gas sales through October 2010 and a portion of our crude oil sales through December 2010. We have also hedged a portion of our electricity consumption through December 2011 to protect against rising electricity costs in the Alberta power market. 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 July 29, 2009 expressed as a percentage of our anticipated production volumes net of royalties:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)	
	July 1, 2009 – October 31, 2009	**November 1, 2009 – March 31, 2010**	**April 1, 2010 – October 31, 2010**	**July 1, 2009 – December 31, 2009**	**January 1, 2010 – December 31, 2010**
Purchased Puts (floor prices)	$ 8.30	$ 8.99	$ –	$ 98.08	$ –
%	18%	9%	–%	25%	–%
Sold Puts (limiting downside protection)	$ 7.85	$ –	$ –	$ 66.17	$ 47.50
%	4%	–%	–%	11%	10%
Swaps (fixed price)	$ 7.41	$ 7.33	$ 7.33	$ 100.05	$ 74.78
%	11%	10%	10%	2%	23%
Sold Calls (capped price)	$ –	$ 12.13	$ –	$ 92.98	$ –
%	–%	2%	–%	11%	–%
Bought Calls (increasing upside participation)	$ –	$ –	$ –	$ –	$ 93.06
%	–%	–%	–%	–%	17%

Based on weighted average price (before premiums), estimated average annual production of 91,000 BOE/day, net of royalties and assuming an 18% royalty rate.

Accounting for Price Risk Management

During the second quarter of 2009 our price risk management program generated cash gains of $20.6 million on our natural gas contracts and $22.0 million on our crude oil contracts. In comparison, during the second quarter of 2008 we experienced cash losses of $16.0 million and $48.0 million respectively. For the six months ended June 30, 2009 we experienced cash gains of $34.9 million on our natural gas contracts and $53.6 million on our crude oil contracts, compared to cash losses of $11.8 million and $63.2 million respectively, for the same period in 2008. The cash gains in 2009 are a result of commodity floor protection which helped to offset the drop in commodity prices.

At June 30, 2009 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented gains of $47.6 million and $36.1 million respectively. These gains are recorded as current deferred financial assets on our balance sheet. In comparison, at March 31, 2009 the fair value of our natural gas and crude oil derivative instruments represented gains of $57.3 million and $76.3 million respectively. 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 a non-cash gain to earnings. The change in the fair value of our commodity derivative instruments between the first and second quarter of 2009 resulted in unrealized losses of $9.7 million for natural gas and $40.2 million for crude oil. For the six months ended June 30, 2009 the change in fair value of our commodity derivative instruments resulted in an unrealized gain of $23.3 million for natural gas and an unrealized loss of $60.5 million for crude oil. See Note 8 for details.

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

Risk Management Costs ($ millions, except per unit amounts)	**Three months ended June 30, 2009**				Three months ended June 30, 2008			
Cash gains/(losses):								
Natural gas	**$**	**20.6**	**$**	**0.67/Mcf**	$	(16.0)	$	(0.49)/Mcf
Crude oil		**22.0**	**$**	**7.16/bbl**		(48.0)	$	(14.86)/bbl
Total Cash gains/(losses)	**$**	**42.6**	**$**	**4.95/BOE**	$	(64.0)	$	(7.03)/BOE
Non-cash losses on financial contracts:								
Change in fair value – natural gas	**$**	**(9.7)**	**$**	**(0.31)/Mcf**	$	(39.7)	$	(1.21)/Mcf
Change in fair value – crude oil		**(40.2)**	**$**	**(13.11)/bbl**		(121.3)	$	(37.56)/bbl
Total non-cash losses	**$**	**(49.9)**	**$**	**(5.80)/BOE**	$	(161.0)	$	(17.65)/BOE
Total losses	**$**	**(7.3)**	**$**	**(0.85)/BOE**	$	(225.0)	$	(24.68)/BOE

Risk Management Costs ($ millions, except per unit amounts)	**Six months ended June 30, 2009**				Six months ended June 30, 2008			
Cash gains/(losses):								
Natural gas	**$**	**34.9**	**$**	**0.57/Mcf**	$	(11.8)	$	(0.19)/Mcf
Crude oil		**53.6**	**$**	**8.69/bbl**		(63.2)	$	(10.10)/bbl
Total Cash gains/(losses)	**$**	**88.5**	**$**	**5.16/BOE**	$	(75.0)	$	(4.35)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – natural gas	**$**	**23.3**	**$**	**0.38/Mcf**	$	(98.0)	$	(1.61)/Mcf
Change in fair value – crude oil		**(60.5)**	**$**	**(9.82)/bbl**		(142.4)	$	(22.77)/bbl
Total non-cash losses	**$**	**(37.2)**	**$**	**(2.17)/BOE**	$	(240.4)	$	(13.95)/BOE
Total gains/(losses)	**$**	**51.3**	**$**	**2.99/BOE**	$	(315.4)	$	(18.30)/BOE

Revenues

Crude oil and natural gas revenues were marginally higher during the second quarter of 2009 compared to the first quarter of 2009 as the impact of increased oil prices was generally offset by lower natural gas prices and a slight decrease in production.

Crude oil and natural gas revenues for the three months ended June 30, 2009 were $306.2 million ($312.5 million, net of $6.3 million transportation costs) compared to $734.4 million ($741.5 million, net of $7.1 million transportation costs) for the same period in 2008. For the six months ended June 30, 2009 revenues were $607.4 million ($620.1 million, net of $12.7 million transportation costs) compared to $1,238.1 million ($1,251.5 million, net of $13.4 million transportation costs) during the same period in 2008. The majority of the decrease in revenues in 2009 was due to the significant decline in commodity prices.

The following table summarizes the changes in sales revenue:

Analysis of Sales Revenue(1) ($ millions)	Crude Oil	NGLs	Natural Gas	Total
Quarter ended June 30, 2008	$ 368.3	$ 35.4	$ 330.7	$ 734.4
Price variance(1)	(166.4)	(18.2)	(203.3)	(387.9)
Volume variance	(18.4)	(2.9)	(19.0)	(40.3)
Quarter ended June 30, 2009	**$ 183.5**	**$ 14.3**	**$ 108.4**	**$ 306.2**

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Year-to-date June 30, 2008	$ 628.6	$ 64.6	$ 544.9	$ 1,238.1
Price variance(1)	(304.9)	(28.7)	(286.5)	(620.1)
Volume variance	(8.8)	(6.8)	5.0	(10.6)
Year-to-date June 30, 2009	**$ 314.9**	**$ 29.1**	**$ 263.4**	**$ 607.4**

(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. On January 1, 2009 a new royalty regime came into effect in the province of Alberta where approximately 60% of our production is located. This new regime has provisions for escalating royalty rates depending on production and price levels. For the three and six months ended June 30, 2009 royalties were $54.0 million and $109.0 million respectively, both approximately 18% of oil and gas sales net of transportation costs. In the comparable periods of 2008, royalties were $138.0 million and $231.9 million respectively, both approximately 19% of oil and gas sales net of transportation costs. The decrease in royalties is attributable to lower commodity prices.

On March 3, 2009, the Alberta government announced a Drilling Royalty Credit program designed to stimulate drilling activity in the province by offering a credit of $200 per metre drilled. To date we have not recorded any benefits under the program but are currently reviewing the program details for incorporation into our capital spending plans, particularly on our shallow gas projects which we would otherwise defer under current economic conditions.

Operating Expenses

Operating expenses during the second quarter of 2009 increased to $9.93/BOE from $9.84/BOE in the first quarter of 2009, primarily due to non-cash losses on our power hedging of $3.0 million or $0.35/BOE.

For the second quarter of 2009 operating expenses were $85.4 million or $9.93/BOE compared to $86.0 million or $9.43/BOE for the second quarter of 2008. For the six months ended June 30, 2009 operating expenses were $169.5 million or $9.89/BOE compared to $158.0 million or $9.17/BOE for the same period in 2008. Operating expenses for 2009 were in-line with our expectations and higher than 2008 mainly due to power hedging losses and increased spending on regulatory requirements and well maintenance.

We are monitoring our operations to prudently reduce costs where possible, however we expect costs to increase on a $/BOE basis during the remainder of the year due to planned turnarounds and the anticipated decline in production. We are maintaining our annual guidance for operating costs of approximately $10.65/BOE.

General and Administrative Expenses ("G&A")

During the second quarter of 2009 G&A expenses increased 13% per BOE to $2.49/BOE compared to $2.21/BOE for the first quarter of 2009, largely due to transaction costs of $2.3 million related to the new senior notes offering. Excluding these transaction costs G&A would have otherwise been $2.23/BOE for the second quarter.

G&A expenses for the three months ended June 30, 2009 were $21.4 million or $2.49/BOE compared to $17.3 million or $1.90/BOE for the second quarter of 2008. G&A expenses totaled $40.3 million or $2.35/BOE for the six months ended June 30, 2009 compared to $33.8 million or $1.96/BOE for the same period in 2008. The increase was due to transaction costs related to the new senior notes offering and the impact of lower overhead recoveries resulting from a reduced capital program.

Non-cash G&A charges have remained relatively flat year-over-year. For the three and six months ended June 30, 2009 our G&A expenses included non-cash charges of $1.9 million or $0.22/BOE and $3.3 million or $0.19/BOE respectively, compared to $2.1 million or $0.23/BOE and $3.6 million or $0.21/BOE for the same periods in 2008. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. See Note 7 for further details.

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

	Three months ended June 30,		Six months ended June 30,	
General and Administrative Costs ($ millions)	**2009**	**2008**	**2009**	**2008**
Cash	**$ 19.5**	$ 15.2	**$ 37.0**	$ 30.2
Trust unit rights incentive plan (non-cash)	**1.9**	2.1	**3.3**	3.6
Total G&A	**$ 21.4**	$ 17.3	**$ 40.3**	$ 33.8
(Per BOE)	**2009**	**2008**	**2009**	**2008**
Cash	**$ 2.27**	$ 1.67	**$ 2.16**	$ 1.75
Trust unit rights incentive plan (non-cash)	**0.22**	0.23	**0.19**	0.21
Total G&A	**$ 2.49**	$ 1.90	**$ 2.35**	$ 1.96

We continue to pursue G&A cost cutting measures however the transaction costs on the senior notes and lower capital overhead recoveries have offset our savings. We are maintaining our guidance for G&A expenses at $2.45/BOE, which includes non-cash G&A costs of approximately $0.20/BOE.

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes issued in June 2002, 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 excluding non-cash charges totaled $5.2 million and $10.8 million for the three and six months ended June 30, 2009, compared to $12.9 million and $26.3 million respectively, for the same periods in 2008. The decrease in 2009 was due to lower average outstanding indebtedness and lower interest rates.

Non-cash interest charges totaled $16.4 million and $22.8 million for the three and six months ended June 30, 2009, compared to $6.4 million and nil respectively, for the same periods in 2008. The changes in the fair value of our interest rate swaps and the interest component on our CCIRS that result from movements in forward market interest rates cause non-cash interest to fluctuate between periods.

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

	Three months ended June 30,		Six months ended June 30,	
Interest Expense ($ millions)	**2009**	**2008**	**2009**	**2008**
Interest on long-term debt	**$ 5.2**	$ 12.9	**$ 10.8**	$ 26.2
Non-cash interest loss	**16.4**	6.4	**22.8**	0.1
Total Interest Expense	**$ 21.6**	$ 19.3	**$ 33.6**	$ 26.3

As a result of the additional senior unsecured notes issued on June 18, 2009, approximately 74% of our debt is based on fixed interest rates and 26% based on floating interest rates at June 30, 2009. Our average cash interest rate for the first six months of 2009 was approximately 2%. For the remainder of the year we expect our average cash interest cost to be approximately 6%, which reflects the new senior notes and less outstanding bank indebtedness.

Capital Expenditures

During the three and six months ended June 30, 2009 development capital spending was $35.6 million and $134.8 million respectively, compared to $88.0 million and $214.3 million during the same periods in 2008. The reduced spending levels in 2009 reflect a more conservative development capital budget versus 2008 due to a decrease in commodity prices. Our development capital spending in 2009 has also decreased from $99.2 million in the first quarter to $35.6 million in the second quarter which emphasizes our cautious spending approach in the current commodity price environment. Our capital spending in the first quarter of 2009 was focused on completing projects that were initiated in the fourth quarter of 2008, whereas spending in the second quarter of 2009 was generally focused on new projects. To date in 2009 we have achieved a 99% success rate with our drilling program on 128 net wells.

Property acquisitions for the three and six months ended June 30, 2009 totaled $28.4 million and $30.4 million respectively, compared to $1.8 million and $9.3 million for the same periods in 2008. The majority of our 2009 second quarter spending was related to a property acquisition in southeast Saskatchewan that included approximately 200 BOE/day of non-operated Bakken production and 11 net sections of land. Corporate acquisitions for the first quarter of 2008 totaling approximately $1.7 billion were related to the Focus acquisition.

Total net capital expenditures for 2009 and 2008 are outlined below:

	Three months ended June 30,		Six months ended June 30,	
Capital Expenditures ($ millions)	**2009**	2008	**2009**	2008
Development expenditures	**$ 18.0**	$ 56.0	**$ 97.9**	$ 165.3
Plant and facilities	**17.6**	32.0	**36.9**	49.0
Development Capital	**35.6**	88.0	**134.8**	214.3
Office	**2.5**	2.0	**3.1**	3.6
Sub-total	**38.1**	90.0	**137.9**	217.9
Property acquisitions[1]	**28.4**	1.8	**30.4**	9.3
Corporate acquisitions	**–**	–	**–**	1,757.5
Property dispositions[1]	**(1.7)**	(0.1)	**(1.7)**	(2.2)
Total Net Capital Expenditures	**$ 64.8**	$ 91.7	**$ 166.6**	$ 1,982.5
Capital Expenditures financed with cash flow	**$ 64.8**	$ 91.7	**$ 166.6**	$ 226.0
Capital Expenditures financed with debt and equity	**–**	–	**–**	1,756.5
Total Net Capital Expenditures	**$ 64.8**	$ 91.7	**$ 166.6**	$ 1,982.5

(1) Net of post-closing adjustments.

With respect to our development capital spending we continue to favour oil projects given the continued softness in natural gas prices with the exception of those natural gas projects that may be supported by the Alberta government's drilling incentive program. We are maintaining our 2009 guidance of $300 million for annual development capital spending. However, if commodity prices weaken further we may adjust our spending levels down.

Oil Sands

Our current oil sands portfolio includes the 100% owned and operated Kirby steam assisted gravity drainage ("SAGD") project and a 11% minority equity ownership interest in Laricina Energy Ltd., a private oil sands company focused on SAGD development in the Athabasca oil sands. On April 17, 2009 we announced that we are deferring further development of the Kirby project, however several key activities are being completed in order to finalize efforts underway at this time.

During the second quarter we focused on capturing the value of our efforts to date and reducing costs should we decide to reinstate the project at a later date. These activities included obtaining an updated independent Kirby resource estimate and advancing the regulatory application, which we expect should be completed early in 2010. During the quarter an updated independent resource estimate was received and the best estimate of contingent resources has increased 22% to 507 million barrels from 414 million barrels. For additional information on contingent resource estimates, see "Information Regarding Contingent Resource Estimates" at the end of the MD&A. We have also redeployed the majority of our oil sands staff within the organization.

Our oil sands projects inception to date capitalized costs are $271.6 million. As these projects have not commenced commercial production all associated costs, inclusive of acquisition expenditures, are capitalized and excluded from our depletion calculation.

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 June 30, 2009, DDA&A increased to $19.05/BOE compared to $18.93/BOE during the corresponding period in 2008. For the six months ended June 30, 2009, DDA&A increased to $19.03/BOE compared to $18.12/BOE during the same period in 2008. The increase is primarily due to additional PP&E as a result of the Focus acquisition.

No impairment of the Fund's assets existed at June 30, 2009 using year-end reserves updated for acquisitions, divestitures, and management's estimates of future prices.

Goodwill

The goodwill balance of $624.7 million arose as 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.

Accounting standards require the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate the balance might be impaired. If such impairment exists, it would be charged to income in the period in which the impairment occurs. No goodwill impairment exists as at June 30, 2009.

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 are estimated by management based on Enerplus' 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. Enerplus has estimated the net present value of its total asset retirement obligations to be approximately $211.4 million at June 30, 2009 compared to $207.4 million at December 31, 2008.

The following chart compares the amortization of the asset retirement cost, accretion of the asset retirement obligation, and asset retirement obligations settled during the period.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2009**	**2008**	**2009**	**2008**
Total Amortization and Accretion of Asset Retirement Obligations	**$ 8.4**	$ 8.2	**$ 17.0**	$ 15.4
Asset Retirement Obligations Settled	**$ 2.5**	$ 4.8	**$ 6.2**	$ 8.8

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2038 and 2047. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

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 that is recorded on the balance sheet will be recovered through earnings before 2011. The balance will be realized when future income tax assets and liabilities are realized or settled.

Our future income tax recovery was $32.9 million and $59.0 million for the three and six months ended June 30, 2009 respectively, compared to a recovery of $50.4 million and $85.6 for the same periods in 2008. The decreased recovery is mainly due to lower taxable income transferred to the Fund in 2009.

Current Income Taxes

In our current structure, payments are made by our operating entities to the Fund which ultimately transfers both the income and future tax liability to our unitholders. As a result, we expect minimal cash income taxes to be paid by our Canadian operating entities in 2009. A current tax recovery of $5.3 million and $7.9 million was recorded for the three and six months ended June 30, 2008 respectively, related to the recovery of income taxes paid by Focus as a result of the acquisition.

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 three and six months ended June 30, 2009, we recorded current income taxes of $1.8 million and $2.6 million respectively, compared to $21.5 million and $33.7 million during the same periods in 2008. The decrease in current taxes is due to a decrease in net income.

We continue to expect our U.S. current income taxes to average approximately 10% of our cash flow from U.S. operations for 2009.

Net Income/(Loss)

Our net loss for the second quarter of 2009 was $3.6 million or $0.02 per trust unit compared to net income of $112.2 million or $0.68 per trust unit for the same period in 2008. Net income for the six months ended June 30, 2009 was $48.2 million or $0.29 per trust unit compared to $233.6 million or $1.50 per trust unit for the same period in 2008. The $185.4 million decrease in net income for the six months ended June 30, 2009 was primarily due to a decrease in oil and gas sales of $631.5 million which was partially offset by an increase in commodity derivative instrument gains of $366.7 million and a decrease in royalties of $122.8 million.

Cash Flow from Operating Activities ("Cash flow")

Cash flow for the three and six months ended June 30, 2009 was $210.6 million ($1.27 per trust unit) and $380.0 million ($2.29 per trust unit) respectively, compared to $364.5 million ($2.22 per trust unit) and $620.7 million ($3.98 per trust unit) for the three and six months ended June 30, 2008. The decrease in cash flow per unit is largely due to a lower weighted average sales price partially offset by cash gains on our commodity derivative instruments, lower royalties and decreases in our non-cash operating working capital.

Selected Financial Results

Per BOE of production (6:1)	Three months ended June 30, 2009 Operating Cash Flow[1]	Non-Cash & Other Items	Total	Three months ended June 30, 2008 Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			**94,501**			100,188
Weighted average sales price[2]	**$ 35.60**	**$ –**	**$ 35.60**	$ 80.56	$ –	$ 80.56
Royalties	**(6.28)**	**–**	**(6.28)**	(15.14)	–	(15.14)
Commodity derivative instruments	**4.95**	**(5.80)**	**(0.85)**	(7.03)	(17.65)	(24.68)
Operating costs	**(9.58)**	**(0.35)**	**(9.93)**	(9.43)	–	(9.43)
General and administrative	**(2.27)**	**(0.22)**	**(2.49)**	(1.67)	(0.23)	(1.90)
Interest expense, net of other income	**(0.61)**	**(1.90)**	**(2.51)**	(1.37)	(0.70)	(2.07)
Foreign exchange gain/(loss)	**1.63**	**(0.16)**	**1.47**	0.05	0.10	0.15
Current income tax	**(0.21)**	**–**	**(0.21)**	(1.78)	–	(1.78)
Restoration and abandonment cash costs	**(0.29)**	**0.29**	**–**	(0.52)	0.52	–
Depletion, depreciation, amortization and accretion	**–**	**(19.05)**	**(19.05)**	–	(18.93)	(18.93)
Future income tax recovery/(expense)	**–**	**3.83**	**3.83**	–	5.53	5.53
Total per BOE	**$ 22.94**	**$ (23.36)**	**$ (0.42)**	$ 43.67	$ (31.36)	$ 12.31

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

Per BOE of production (6:1)	Six months ended June 30, 2009 Operating Cash Flow[1]	Non-Cash & Other Items	Total	Six months ended June 30, 2008 Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			**94,739**			94,681
Weighted average sales price[2]	**$ 35.42**	**$ –**	**$ 35.42**	$ 71.85	$ –	$ 71.85
Royalties	**(6.36)**	**–**	**(6.36)**	(13.46)	–	(13.46)
Commodity derivative instruments	**5.16**	**(2.17)**	**2.99**	(4.35)	(13.95)	(18.30)
Operating costs	**(9.77)**	**(0.12)**	**(9.89)**	(9.21)	0.04	(9.17)
General and administrative	**(2.16)**	**(0.19)**	**(2.35)**	(1.75)	(0.21)	(1.96)
Interest expense, net of other income	**(0.62)**	**(1.33)**	**(1.95)**	(1.10)	(0.01)	(1.11)
Foreign exchange gain/(loss)	**0.69**	**–**	**0.69**	–	(0.13)	(0.13)
Current income tax	**(0.15)**	**–**	**(0.15)**	(1.49)	–	(1.49)
Restoration and abandonment cash costs	**(0.36)**	**0.36**	**–**	(0.51)	0.51	–
Depletion, depreciation, amortization and accretion	**–**	**(19.03)**	**(19.03)**	–	(18.12)	(18.12)
Future income tax recovery/(expense)	**–**	**3.44**	**3.44**	–	4.97	4.97
Gain on sale of marketable securities[3]	**–**	**–**	**–**	–	0.48	0.48
Total per BOE	**$ 21.85**	**$ (19.04)**	**$ 2.81**	$ 39.98	$ (26.42)	$ 13.56

(1) Cash flow from operating activities before changes in non-cash operating working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(3) Gain on sale of marketable securities was a cash item, however it is included in cash flow from investing activities not cash flow from operating activities.

Selected Canadian and U.S. Results

The following tables provide a geographical analysis of key operating and financial results for the three and six months ended June 30, 2009 and 2008.

	Three months ended June 30, 2009			Three months ended June 30, 2008		
(CDN$ millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Daily Production Volumes						
Natural gas (Mcf/day)	**323,941**	**14,252**	**338,193**	346,554	12,795	359,349
Crude oil (bbls/day)	**25,221**	**8,494**	**33,715**	25,652	9,834	35,486
Natural gas liquids (bbls/day)	**4,420**	**–**	**4,420**	4,810	–	4,810
Total Daily Sales (BOE/day)	**83,632**	**10,869**	**94,501**	88,221	11,967	100,188
Pricing[1]						
Natural gas (per Mcf)	**$ 3.45**	**$ 4.34**	**$ 3.49**	$ 9.80	$ 11.80	$ 9.87
Crude oil (per bbl)	**59.56**	**60.53**	**59.80**	112.41	118.27	114.04
Natural gas liquids (per bbl)	**35.47**	**–**	**35.47**	80.55	–	80.55
Capital Expenditures						
Development capital and office	**$ 31.8**	**$ 6.3**	**$ 38.1**	$ 76.5	$ 13.5	$ 90.0
Acquisitions of oil and gas properties	**28.1**	**0.3**	**28.4**	2.0	(0.2)	1.8
Dispositions of oil and gas properties	**(1.7)**	**–**	**(1.7)**	(0.1)	–	(0.1)
Revenues						
Oil and gas sales[1]	**$ 253.7**	**$ 52.5**	**$ 306.2**	$ 614.8	$ 119.6	$ 734.4
Royalties[2]	**(42.0)**	**(12.0)**	**(54.0)**	(112.4)	(25.6)	(138.0)
Commodity derivative instruments gain/(loss)	**(7.3)**	**–**	**(7.3)**	(225.0)	–	(225.0)
Expenses						
Operating	**$ 81.9**	**$ 3.5**	**$ 85.4**	$ 80.8	$ 5.2	$ 86.0
General and administrative	**19.8**	**1.6**	**21.4**	16.0	1.3	17.3
Depletion, depreciation, amortization and accretion	**141.5**	**22.3**	**163.8**	149.6	22.9	172.5
Current income taxes (recovery)/expense	**–**	**1.8**	**1.8**	(5.3)	21.5	16.2

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2009 Canada	U.S.	Total	Six months ended June 30, 2008 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	**324,865**	**13,673**	**338,538**	321,177	12,382	333,559
Crude oil (bbls/day)	**25,300**	**8,775**	**34,075**	24,687	9,689	34,376
Natural gas liquids (bbls/day)	**4,241**	**–**	**4,241**	4,712	–	4,712
Total Daily Sales (BOE/day)	**83,685**	**11,054**	**94,739**	82,929	11,752	94,681
Pricing[1]						
Natural gas (per Mcf)	**$ 4.28**	**$ 4.83**	**$ 4.31**	$ 8.72	$ 10.42	$ 8.79
Crude oil (per bbl)	**51.43**	**50.01**	**51.06**	98.89	104.50	100.47
Natural gas liquids (per bbl)	**37.91**	**–**	**37.91**	75.29	–	75.29
Capital Expenditures						
Development capital and office	**$ 120.8**	**$ 17.1**	**$ 137.9**	$ 184.8	$ 33.1	$ 217.9
Acquisitions of oil and gas properties	**29.9**	**0.5**	**30.4**	9.4	(0.1)	9.3
Dispositions of oil and gas properties	**(1.7)**	**–**	**(1.7)**	(2.2)	–	(2.2)
Revenues						
Oil and gas sales[1]	**$ 516.0**	**$ 91.4**	**$ 607.4**	$ 1,030.3	$ 207.8	$ 1,238.1
Royalties[2]	**(88.5)**	**(20.5)**	**(109.0)**	(187.4)	(44.5)	(231.9)
Commodity derivative instruments gain/(loss)	**51.3**	**–**	**51.3**	(315.4)	–	(315.4)
Expenses						
Operating	**$ 162.2**	**$ 7.3**	**$ 169.5**	$ 149.4	$ 8.6	$ 158.0
General and administrative	**36.8**	**3.5**	**40.3**	31.1	2.7	33.8
Depletion, depreciation, amortization and accretion	**280.4**	**46.0**	**326.4**	268.0	44.3	312.3
Current income taxes (recovery)/expense	**–**	**2.6**	**2.6**	(7.9)	33.7	25.8

(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

In general, crude oil and natural gas sales increased from 2007 to mid-2008 due to increased commodity prices and increased production from the Focus acquisition. Oil and gas sales decreased in the latter part of 2008 with the sharp decline in commodity prices. During the second quarter of 2009 crude oil prices have started to recover; however, this has largely been offset by natural gas prices which have continued to decline since the start of the year.

Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating costs and changes in future tax provisions due to the SIFT tax and corporate tax rate reductions. Furthermore, changes in the fair value of our commodity derivative instruments and other financial instruments cause net income to continually fluctuate between quarters.

Quarterly Financial Information ($ millions, except per trust unit amounts)	**Oil and Gas Sales**[1]	**Net Income/(Loss)**	**Net Income/(Loss) per trust unit** Basic	Diluted
2009				
Second quarter	**$ 306.2**	**$ (3.6)**	**$ (0.02)**	**$ (0.02)**
First quarter	**301.2**	**51.8**	**0.31**	**0.31**
Total	**$ 607.4**	**$ 48.2**	**$ 0.29**	**$ 0.29**
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
2007				
Fourth quarter	$ 389.8	$ 98.7	$ 0.76	$ 0.76
Third quarter	364.8	93.0	0.72	0.72
Second quarter	382.5	40.1	0.31	0.31
First quarter	380.0	107.9	0.88	0.87
Total	$ 1,517.1	$ 339.7	$ 2.66	$ 2.66

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

Liquidity and Capital Resources

Capital Markets and Enerplus' Credit Exposure

We are gradually seeing some improvements in the financial markets as the global economic crisis is showing signs of easing. During the second quarter we saw a significant increase in activity in the equity and debt capital markets. On June 18, 2009 we successfully closed a private offering of senior unsecured notes that raised gross proceeds of approximately $338.7 million. The proceeds of the offering were used to pay down bank indebtedness giving us additional financial flexibility to pursue acquisitions. See the Long-Term Debt section of this MD&A for more information on the terms of the new notes.

Low crude oil and natural gas prices are placing a greater emphasis on evaluating credit capacity, understanding counterparty credit risk and overall liquidity concerns. We discuss these risks below as they relate to our credit facility, oil and gas sales counterparties, financial derivative counterparties and joint venture partners.

Credit Facility

Enerplus' $1.4 billion bank credit facility is an unsecured, covenant-based, three-year term agreement ending 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. Of the thirteen syndicate members in Enerplus' facility, seven are major Canadian banks which collectively represent approximately $985 million or 70% of the commitments under the $1.4 billion facility. We have the ability to request an extension of the facility each year or repay the entire balance at the end of the term. 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 generally increased in the marketplace due to the global economic credit crisis. At June 30, 2009 we have drawn only $96.9 million or approximately 7% of the $1.4 billion facility as the proceeds of the June 18, 2009 note offering were used to pay down credit facility debt. At June 30, 2009, we are in compliance with all covenants under the credit facility.

Our exposure to our lenders relates to their potential inability to provide funding. Should a lender be unable or choose not to fund, other lenders have the right, but not the obligation, to increase their commitment levels to cover the shortfall. Failure to fund would be considered a breach of contract and could result in potential damages in our favour, however the likelihood of substantiating and receiving damages is unknown. We have not experienced any funding issues under the facility to date.

Oil and Gas Sales Counterparties

The Fund's oil and gas receivables are with customers in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our credit risk. This process is utilized for both our oil and gas sales counterparties as well as our financial derivative counterparties.

Financial Derivative Counterparties

The Fund is exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. The Fund mitigates this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection in that they generally allow parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. Absent an ISDA we rely on long form confirmations which provide Enerplus with similar credit protection. At June 30, 2009, we had $88.0 million in mark-to-market assets offset by $53.6 million of mark-to-market liabilities consisting of net asset positions of $27.0 million with major Canadian institutions and $7.4 million with U.S. institutions.

We will continue to monitor developments in the financial markets that could impact the creditworthiness of our financial counterparties. To date we have not experienced any losses due to non-performance by our derivative counterparties.

Joint Venture Partners

We attempt to mitigate the credit risk associated with our joint interest receivables by reviewing and actively following up on older accounts. In addition, we are specifically monitoring our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or highly drawn bank facilities. We do not anticipate any significant issues in the collection of our joint interest receivables at this time. However, if the current low commodity prices and tight capital markets prevail, there is a risk of increased bad debts related to our industry partners.

Distribution Policy

The amount of cash distributions 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 are 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.

The sharp decrease in commodity prices has resulted in a decrease in our overall cash flows relative to 2008 levels. This commodity price downturn, combined with the ongoing uncertainty in the capital markets, has reinforced our belief in the importance of maintaining strong financial flexibility. We have maintained our monthly distribution rate of $0.18 per unit distribution since February 2009 and we intend to manage our distribution levels and capital spending in order to minimize increases in our debt levels and preserve our balance sheet strength for future acquisitions.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level, determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

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.

Enerplus currently has approximately $9.5 billion of safe harbour growth capacity within the context of the Canadian Government's "normal growth" guidelines for SIFT's.

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 second quarter of 2009, cash distributions of $89.6 million were funded entirely through cash flow of $210.6 million. For the six months ended June 30, 2009, our cash distributions were $179.1 million and were funded entirely through cash flow of $380.0 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 43% and 47% for the three and six months ended June 30, 2009 respectively, compared to 56% and 64% for the same periods in 2008. The decrease in our payout ratio is due to the reduction in our monthly cash distributions along with fluctuations in our working capital balances that impact cash flow. Our adjusted payout ratio, which is calculated as cash distributions plus development capital and office expenditures divided by cash flow, was 61% for the second quarter and 83% for the six months ended June 30, 2009. See "Non-GAPP Measures" above. Our reduced capital spending levels combined with decreases in our non-cash operating working capital in the second quarter has reduced the second quarter adjusted payout ratio to 61% from 112% in the first quarter of 2009. We expect to support our distributions and capital expenditures with our cash flow over the remaining quarters in 2009, however, we may fund acquisitions and growth through additional debt and equity if required. We continue to have conservative debt levels with a debt to trailing twelve month cash flow ratio of 0.7x at June 30, 2009 and a debt to annualized year-to-date 2009 cash flow ratio of 1.1x.

For the three months ended June 30, 2009, our cash distributions exceeded our net income/(loss) by $93.2 million (2008 – $90.1 million), however net income includes $203.4 million of non-cash items (2008 – $290.6 million). For the six months ended June 30, 2009 our cash distributions exceeded our net income by $130.9 million (2008 – $161.1 million) which included $332.6 million of non-cash items (2008 – $472.3 million). Non-cash items such as changes in the fair value of our derivative instruments and future income taxes 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 costs of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

It is not possible 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 June 30, 2009		Six months ended June 30, 2009		Year ended December 31, 2008		Year ended December 31, 2007
Cash flow from operating activities	**$**	**210.6**	**$**	**380.0**	$	1,262.8	$	868.5
Cash distributions		**89.6**		**179.1**		786.1		646.8
Excess of cash flow over cash distributions	**$**	**121.0**	**$**	**200.9**	$	476.7	$	221.7
Net income/(loss)	**$**	**(3.6)**	**$**	**48.2**	$	888.9	$	339.7
(Shortfall)/excess of net income/(loss) over cash distributions		**(93.2)**		**(130.9)**		102.8		(307.1)
Cash distributions per weighted average trust unit	**$**	**0.54**	**$**	**1.08**	$	4.90	$	5.07
Payout ratio(1)		**43%**		**47%**		62%		74%

(1) Based on cash distributions divided by cash flow from operating activities.

Long-Term Debt

On June 18, 2009, we closed a private offering of senior unsecured notes to U.S. and Canadian institutional investors that raised gross proceeds of approximately $338.7 million. The notes were priced at par and have semi-annual interest payments on June 18 and December 18 of each year. The proceeds from the offering repaid a portion of our outstanding bank debt, which increased the available credit under our bank facility. The three new note series along with the terms and rates are summarized in the table below.

Amount	Term	Coupon Rate
US$225 million	12 year amortizing term repayable 2017 – 2021	7.97%
US$40 million	6 year term repayable in 2015	6.82%
CDN$40 million	6 year term repayable in 2015	6.37%

Long-term debt at June 30, 2009 was $713.7 million, an increase of $49.4 million from $664.3 million at December 31, 2008. Long-term debt at June 30, 2009 was comprised of $96.9 million of bank indebtedness and $616.8 million of senior unsecured notes.

Our bank indebtedness of $96.9 million at June 30, 2009 decreased $284.0 million from $380.9 million at December 31, 2008. This decrease is primarily due to the proceeds of the June 18, 2009 private offering of senior unsecured notes partially offset by funding working capital requirements.

Our working capital at June 30, 2009, excluding cash, current deferred financial assets and credits and future income taxes, increased by $91.5 million compared to December 31, 2008. This change is due to decreased accounts payable that resulted from lower capital spending activity along with decreased distributions payable as a result of the reduction in our monthly distributions.

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

Financial Leverage and Coverage	June 30, 2009	December 31, 2008
Long-term debt to cash flow (12 month trailing)	**0.7 x**	0.5 x
Cash flow to interest expense (12 month trailing)	**32.5 x**	46.5 x
Long-term debt to long-term debt plus equity	**15%**	13%

Long-term debt is measured net of cash.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes 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 June 30, 2009, we are 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, 2008 for a detailed description of these covenants.

We anticipate that we will continue to have adequate liquidity under our bank credit facility and from cash flow to fund planned development capital spending and working capital requirements in 2009.

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 166,022,000 trust units outstanding at June 30, 2009 compared to 164,709,000 trust units at June 30, 2008 and 165,590,000 trust units outstanding at December 31, 2008. This includes 6,654,000 exchangeable limited partnership units which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (2,828,000 trust units). During the second quarter of 2009, 187,000 partnership units were converted into 79,000 trust units.

During the three months ended June 30, 2009, 194,000 trust units (2008 – 683,000) 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 $4.5 million (2008 – $28.8 million) of additional equity to the Fund. For the six months ended June 30, 2009, $9.9 million of additional equity (2008 – $40.7 million) and 432,000 trust units (2008 – 1,000,000) were issued pursuant to the DRIP and the trust unit rights incentive plan. For further details see Note 7.

The weighted average basic number of trust units outstanding for the six months ended June 30, 2009 was 165,807,000 (2008 – 155,984,000). At July 29, 2009, we had 166,095,000 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 the 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 2009, 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 were subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable and non-taxable portion of the distribution as computed under Canadian tax law. 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 in 2010. We are unable to determine whether or to what extent the preferred rate of tax on "Qualified Dividends" may be extended.

For 2009, 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 production, commodity prices, and cash flow experienced throughout the year.

In July 2009, we estimated our non-resident ownership to be 66%.

CHANGE IN INDEPENDENT RESERVES ENGINEER

Effective August 6, 2009, McDaniel & Associates Consultants Ltd. ("McDaniel"), has been appointed as our independent reserves evaluator for Enerplus' Canadian conventional properties replacing Sproule Associates Limited ("Sproule") in that capacity. Reserve estimates are, by necessity, projections and are based upon the professional judgement and experience of the independent evaluator. McDaniel's reserve estimates may differ from the previous estimates made by Sproule with respect to these properties and the differences may be material. GLJ Petroleum Consultants Ltd. has continued to evaluate our contingent resources associated with our oil sands and we expect Netherland Sewell Associates Inc. will continue to evaluate our U.S. properties.

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on April 1, 2009 and ended on June 30, 2009 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 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP being converged with IFRS by 2011 for public reporting entities. On February 13, 2008 the AcSB confirmed that IFRS will be required for public companies beginning January 1, 2011.

In order to meet our reporting requirements and transition to IFRS we have established a project team comprised of individuals from Finance, Information Systems and Business Solutions, Tax, Investor Relations and Management. Our transition plan consists of four main phases:

- An IFRS diagnostic phase which involves an assessment of the differences between Canadian GAAP and IFRS,
- An assessment and selection phase whereby we will determine accounting policies for transition and our continuing IFRS accounting policies,
- An evaluation of our information systems, business processes, procedures and controls to support the new reporting standards, and
- Training and development throughout the organization.

To date we have completed our IFRS diagnostic assessment and have started to analyze and identify accounting policy choices, which include assessing the impact on information systems and business processes. We have also provided training to certain business groups which are impacted. We intend to generate financial information in accordance with IFRS during 2010 to provide comparative information for the 2011 financial statements.

In July 2009, the International Accounting Standards Board finalized an amendment to IFRS 1, *First-Time Adoption of International Financial Reporting Standards*, that allows a first-time adopter using full cost accounting to elect to measure oil and gas assets at the date of transition to IFRS using the amount determined based on the entity's previous GAAP. The effective date is years beginning on or after January 1, 2010 with early adoption permitted. Enerplus intends to use this election on adoption of IFRS.

The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. As we have not yet finalized our accounting policies, we are unable to quantify the impact of adopting IFRS on our financial statements. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to our adoption of IFRS, our plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

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 management's discussion and analysis ("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" 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: the amount, timing and tax treatment of cash distributions to unitholders; payout ratios and adjusted payout ratios; tax treatment of income trusts such as the Fund; the structure of the Fund and its subsidiaries including conversion to a corporate structure; the Fund's income taxes, tax liabilities and tax pools; the volume and product mix of the Fund's oil and gas production; production and operational matters including shut-in wells and delayed projects; oil and natural gas prices and the Fund's risk management programs; the amount of asset retirement obligations; future liquidity and financial capacity and resources; future capital expenditures; cost and expense estimates; results from operations and financial ratios; the impact of the conversion to IFRS on the financial results of the Fund; the Fund's ongoing strategy; the Fund's credit exposure; cash flow sensitivities; royalty rates and their impact on the Fund's operations and results; future growth including development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities. This MD&A also contains estimates of contingent resources, which are by their nature estimates that the quantities described exist in the amounts estimated.

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 continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions and tax and regulatory regimes; availability of cash flow, debt and/or equity sources to fund the Fund's capital and operating requirements as needed; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable at this time 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; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves and resources volumes; limited, unfavourable or no access to debt or equity capital markets; increased costs and expenses; 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 identified in the MD&A, our MD&A for the year ended December 31, 2008 and in the Fund's Annual Information Form for the year ended December 31, 2008, copies of which are available on the Fund's SEDAR profile at www.sedar.com and which also form part of the Fund's Form 40-F for the year ended December 31, 2008 filed with the SEC, a copy of which is available at www.sec.gov.

The forward-looking information and statements contained in this MD&A speak only as of the date of this release 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. For a description of Enerplus' Kirby oil sands project, including the primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Kirby oil sands project as reserves and the inherent risks and contingencies associated with the resource estimates and development of the project, see "Presentation of Enerplus' Oil and Gas Reserves, Resources and Production Information", "Operational Information – Enerplus' Play Types – Oil Sands" and "Risk Factors" in the Fund's Annual Information Form and Form 40-F as described above.

Consolidated Balance Sheets

(CDN$ thousands) (Unaudited)	June 30, 2009	December 31, 2008
Assets		
Current assets		
Cash	**$ 175**	$ 6,922
Accounts receivable	**111,987**	163,152
Deferred financial assets *(Note 8)*	**83,697**	121,281
Other current	**8,398**	3,783
	204,257	295,138
Property, plant and equipment *(Note 2)*	**5,063,164**	5,246,998
Goodwill	**624,748**	634,023
Deferred financial assets *(Note 8)*	**4,281**	6,857
Other assets *(Note 8)*	**47,116**	47,116
	5,739,309	5,934,994
	$ 5,943,566	$ 6,230,132
Liabilities		
Current liabilities		
Accounts payable	**$ 146,257**	$ 272,818
Distributions payable to unitholders	**29,883**	41,397
Future income taxes	**17,937**	30,198
Deferred financial credits *(Note 8)*	**9,985**	–
	204,062	344,413
Long-term debt *(Note 4)*	**713,711**	664,343
Deferred financial credits *(Note 8)*	**43,636**	26,392
Future income taxes	**592,161**	648,821
Asset retirement obligations *(Note 3)*	**211,422**	207,420
	1,560,930	1,546,976
Equity		
Unitholders' capital *(Note 7)*	**5,484,505**	5,471,336
Accumulated deficit	**(1,312,129)**	(1,181,199)
Accumulated other comprehensive income	**6,198**	48,606
	(1,305,931)	(1,132,593)
	4,178,574	4,338,743
	$ 5,943,566	$ 6,230,132

Consolidated Statements of Accumulated Deficit

(CDN$ thousands) (Unaudited)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Accumulated income, beginning of period	**$ 3,227,605**	$ 2,408,321	**$ 3,175,819**	$ 2,286,927
Net income/(loss)	**(3,569)**	112,230	**48,217**	233,624
Accumulated income, end of period	**$ 3,224,036**	$ 2,520,551	**$ 3,224,036**	$ 2,520,551
Accumulated cash distributions, beginning of period	**$ (4,446,555)**	$ (3,763,238)	**$ (4,357,018)**	$ (3,570,880)
Cash distributions	**(89,610)**	(202,346)	**(179,147)**	(394,704)
Accumulated cash distributions, end of period	**$ (4,536,165)**	$ (3,965,584)	**$ (4,536,165)**	$ (3,965,584)
Accumulated deficit, end of period	**$ (1,312,129)**	$ (1,445,033)	**$ (1,312,129)**	$ (1,445,033)

Consolidated Statements of Accumulated Other Comprehensive Income

(CDN$ thousands) (Unaudited)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Balance, beginning of period	**$ 73,122**	$ (87,505)	**$ 48,606**	$ (108,727)
Other comprehensive income/(loss)	**(66,924)**	(5,623)	**(42,408)**	15,599
Balance, end of period	**$ 6,198**	$ (93,128)	**$ 6,198**	$ (93,128)

Consolidated Statements of Income

(CDN$ thousands except per trust unit amounts) (Unaudited)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Revenues				
Oil and gas sales	**$ 312,537**	$ 741,470	**$ 620,052**	$ 1,251,539
Royalties	**(54,009)**	(138,040)	**(109,047)**	(231,876)
Commodity derivative instruments *(Note 8)*	**(7,336)**	(225,015)	**51,309**	(315,394)
Other income	**31**	411	**175**	15,527
	251,223	378,826	**562,489**	719,796
Expenses				
Operating	**85,389**	85,974	**169,519**	157,990
General and administrative	**21,447**	17,327	**40,317**	33,764
Transportation	**6,356**	7,127	**12,657**	13,444
Interest *(Note 5)*	**21,575**	19,313	**33,572**	26,301
Foreign exchange *(Note 6)*	**(12,611)**	(1,408)	**(11,758)**	2,276
Depletion, depreciation, amortization and accretion	**163,798**	172,496	**326,358**	312,290
	285,954	300,829	**570,665**	546,065
Income/(loss) before taxes	**(34,731)**	77,997	**(8,176)**	173,731
Current taxes	**1,777**	16,211	**2,616**	25,752
Future income tax recovery	**(32,939)**	(50,444)	**(59,009)**	(85,645)
Net Income/(loss)	**$ (3,569)**	$ 112,230	**$ 48,217**	$ 233,624
Net income/(loss) per trust unit				
Basic	**$ (0.02)**	$ 0.68	**$ 0.29**	$ 1.50
Diluted	**$ (0.02)**	$ 0.68	**$ 0.29**	$ 1.50
Weighted average number of trust units outstanding (thousands)[1]				
Basic	**165,899**	164,483	**165,807**	155,984
Diluted	**166,264**	164,633	**165,807**	156,102

(1) Includes the exchangeable limited partnership units.

Consolidated Statements of Comprehensive Income

(CDN$ thousands) (Unaudited)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Net income/(loss)	**$ (3,569)**	$ 112,230	**$ 48,217**	$ 223,624
Other comprehensive income/(loss), net of tax:				
Unrealized gain on marketable securities	**–**	–	**–**	2,578
Realized gain on marketable securities included in net income	**–**	–	**–**	(6,158)
Gains and losses on derivatives designated as hedges in prior periods included in net income	**–**	–	**–**	74
Change in cumulative translation adjustment	**(66,924)**	(5,623)	**(42,408)**	19,105
Other comprehensive income/(loss)	**(66,924)**	(5,623)	**(42,408)**	15,599
Comprehensive income/(loss)	**$ (70,493)**	$ 106,607	**$ 5,809**	$ 239,223

Consolidated Statements of Cash Flows

(CDN$ thousands) (Unaudited)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Operating Activities				
Net income/(loss)	**$ (3,569)**	$ 112,230	**$ 48,217**	$ 233,624
Non-cash items add / (deduct):				
Depletion, depreciation, amortization and accretion	**163,798**	172,496	**326,358**	312,290
Change in fair value of derivative instruments *(Note 8)*	**84,110**	168,787	**67,389**	235,259
Unit based compensation *(Note 7)*	**1,877**	2,094	**3,256**	3,580
Foreign exchange on translation of senior notes *(Note 6)*	**(13,270)**	(2,158)	**(5,033)**	7,075
Future income tax	**(32,939)**	(50,444)	**(59,009)**	(85,645)
Amortization of senior notes premium	**(192)**	(157)	**(394)**	(310)
Reclassification adjustments from AOCI to net income	**–**	–	**–**	92
Gain on sale of marketable securities	**–**	–	**–**	(8,263)
Asset retirement obligations settled *(Note 3)*	**(2,530)**	(4,747)	**(6,182)**	(8,767)
	197,285	398,101	**374,602**	688,935
Decrease/(Increase) in non-cash operating working capital	**13,323**	(33,644)	**5,394**	(68,262)
Cash flow from operating activities	**210,608**	364,457	**379,996**	620,673
Financing Activities				
Issue of trust units, net of issue costs *(Note 7)*	**4,513**	28,811	**9,913**	40,696
Cash distributions to unitholders	**(89,610)**	(202,346)	**(179,147)**	(394,704)
Decrease in bank credit facilities	**(350,857)**	(68,656)	**(283,940)**	(36,054)
Issuance of senior unsecured notes	**338,735**	–	**338,735**	–
Decrease/(Increase) in non-cash financing working capital	**35**	241	**(11,514)**	14,658
Cash flow from financing activities	**(97,184)**	(241,950)	**(125,953)**	(375,404)
Investing Activities				
Capital expenditures	**(38,013)**	(89,961)	**(137,887)**	(217,884)
Property acquisitions	**(28,416)**	(1,740)	**(30,393)**	(9,289)
Property dispositions	**1,723**	86	**1,736**	2,208
Proceeds on sale of marketable securities	**–**	–	**–**	18,320
Increase in non-cash investing working capital	**(46,633)**	(30,218)	**(93,034)**	(40,636)
Cash flow from investing activities	**(111,339)**	(121,833)	**(259,578)**	(247,281)
Effect of exchange rate changes on cash	**(2,035)**	(1,404)	**(1,212)**	1,033
Change in cash	**50**	(730)	**(6,747)**	(979)
Cash, beginning of period	**125**	1,453	**6,922**	1,702
Cash, end of period	**$ 175**	$ 723	**$ 175**	$ 723
Supplementary Cash Flow Information				
Cash income taxes (received)/paid	**$ (22,790)**	$ 24,756	**$ (22,790)**	$ 33,758
Cash interest paid	**$ 7,198**	$ 17,980	**$ 9,899**	$ 26,298

Notes to Consolidated Financial Statements (Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2008. 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, 2008. All amounts are stated in Canadian dollars unless otherwise specified.

2. PROPERTY, PLANT AND EQUIPMENT (PP&E)

($ thousands)	June 30, 2009	December 31, 2008
Property, plant and equipment	**$ 8,612,868**	$ 8,497,206
Accumulated depletion, depreciation and accretion	**(3,549,704)**	(3,250,208)
Net property, plant and equipment	**$ 5,063,164**	$ 5,246,998

Capitalized development general and administrative ("G&A") expense of $12,813,000 (2008 – $10,812,000) is included in PP&E for the six months ended June 30, 2009. Excluded from PP&E for the depletion and depreciation calculation is $271,555,000 (December 31, 2008 – $257,608,000) related to oil sands projects which have not yet commenced commercial production.

3. ASSET RETIREMENT OBLIGATIONS

Following is a reconciliation of the asset retirement obligations:

($ thousands)	Six months ended June 30, 2009	Year ended December 31, 2008
Asset retirement obligations, beginning of period	**$ 207,420**	$ 165,719
Corporate acquisition	**–**	36,784
Changes in estimates	**3,290**	4,087
Property acquisition and development activity	**828**	7,394
Dispositions	**(318)**	(110)
Asset retirement obligations settled	**(6,182)**	(18,308)
Accretion expense	**6,384**	11,854
Asset retirement obligations, end of period	**$ 211,422**	$ 207,420

4. LONG-TERM DEBT

($ thousands)	June 30, 2009	December 31, 2008
Bank credit facilities (a)	**$ 96,948**	$ 380,888
Senior notes (b)		
CDN$40 million (Issued June 18, 2009)	**40,000**	–
US$225 million (Issued June 18, 2009)	**261,563**	–
US$40 million (Issued June 18, 2009	**46,500**	–
US$54 million (Issued October 1, 2003)	**62,775**	66,128
US$175 million (Issued June 19, 2002)*	**205,925**	217,327
Total long-term debt	**$ 713,711**	$ 664,343

* The June 19, 2010 principal repayment of US$35 million has not been included in current liabilities as we expect to refinance this amount with our long-term bank credit facility.

(a) Unsecured Bank Credit Facility

Enerplus 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 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 are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The weighted average interest rate on the facility for the six months ended June 30, 2009 was 1.2% (June 30, 2008 – 4.0%).

(b) Senior Unsecured Notes

On June 18, 2009 Enerplus closed a private offering of senior unsecured notes raising gross proceeds of approximately $338,735,000. The terms and rates of Enerplus' outstanding senior unsecured notes are detailed below:

($ thousands)

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

In September 2007 Enerplus 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 for purposes of interest and principal repayments 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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2009**	2008	**2009**	2008
Realized				
Interest on long-term debt	**$ 5,212**	$ 12,918	**$ 10,767**	$ 26,263
Unrealized				
(Gain)/loss on cross currency interest rate swap	**17,904**	7,219	**25,868**	(1,125)
(Gain)/loss on interest rate swaps	**(1,349)**	(667)	**(2,669)**	1,473
Amortization of the premium on senior unsecured notes	**(192)**	(157)	**(394)**	(310)
Interest expense	**$ 21,575**	$ 19,313	**$ 33,572**	$ 26,301

6. FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Realized				
Foreign exchange (gain)/loss	**$ (13,991)**	$ (550)	**$ (11,626)**	$ 18
Unrealized				
Foreign exchange (gain)/loss on translation of U.S. dollar denominated senior notes	**(13,270)**	(2,158)	**(5,033)**	7,075
Foreign exchange (gain)/loss on cross currency interest rate swap	**10,643**	(320)	**2,325**	(4,491)
Foreign exchange (gain)/loss on foreign exchange swaps	**4,007**	1,620	**2,576**	(326)
Foreign exchange (gain)/loss	**$ (12,611)**	$ (1,408)	**$ (11,758)**	$ 2,276

7. UNITHOLDERS' CAPITAL

Unitholders' capital as presented on the Consolidated Balance Sheets consists of trust unit capital, exchangeable limited partnership unit capital and contributed surplus.

Unitholders' capital ($ thousands)	Six months ended June 30, 2009	Year ended December 31, 2008
Trust units	**$ 5,348,470**	$ 5,328,629
Exchangeable limited partnership units	**113,179**	123,107
Contributed surplus	**22,856**	19,600
Balance, end of period	**$ 5,484,505**	$ 5,471,336

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	Six months ended June 30, 2009		Year ended December 31, 2008	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**162,514**	**$ 5,328,629**	129,813	$ 4,020,228
Issued for cash:				
Pursuant to rights incentive plan	**–**	**–**	210	6,755
Cancelled trust units			(116)	(3,794)
Exchangeable limited partnership units exchanged	**248**	**9,928**	786	31,444
Trust unit rights incentive plan (non-cash) – exercised	**–**	**–**	–	3,642
DRIP*, net of redemptions	**432**	**9,913**	1,671	63,761
Issued for acquisition of corporate and property interests (non-cash)	**–**	**–**	30,150	1,206,593
	163,194	**$ 5,348,470**	162,514	$ 5,328,629
Equivalent exchangeable partnership units	**2,828**	**113,179**	3,076	123,107
Balance, end of period	**166,022**	**$ 5,461,649**	165,590	$ 5,451,736

* Distribution Reinvestment and Unit Purchase Plan

(b) Exchangeable Limited Partnership Units

The limited partnership units of Enerplus Exchangeable Limited Partnership are exchangeable into Enerplus trust units at a ratio of 0.425 of an Enerplus trust unit for each limited partnership unit. During the period January 1, 2009 to June 30, 2009, 584,000 exchangeable limited partnership units were converted into 248,000 trust units. As at June 30, 2009, the 6,654,000 outstanding exchangeable limited partnership units represent the equivalent of 2,828,000 trust units.

(thousands)	Six months ended June 30, 2009		Year ended December 31, 2008	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Assumed on February 13, 2008	**7,238**	**$ 123,107**	9,087	$ 154,551
Exchanged for trust units	**(584)**	**(9,928)**	(1,849)	(31,444)
Balance, end of period	**6,654**	**$ 113,179**	7,238	$ 123,107

(c) Contributed Surplus

Contributed surplus ($ thousands)	Six months ended June 30, 2009	Year ended December 31, 2008
Balance, beginning of period	**$ 19,600**	$ 12,452
Trust unit rights incentive plan (non-cash) – exercised	**–**	(3,642)
Trust unit rights incentive plan (non-cash) – expensed	**3,256**	6,996
Cancelled trust units	**–**	3,794
Balance, end of period	**$ 22,856**	$ 19,600

(d) Trust Unit Rights Incentive Plan

As at June 30, 2009 a total of 5,839,000 rights were issued and outstanding pursuant to the Trust Unit Rights Incentive Plan (“Rights Incentive Plan”) with an average exercise price of $35.14 per right. This represents 3.5% of the total trust units outstanding of which 2,646,000 rights, with an average exercise price of $45.11, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first two quarters of 2009 did not reduce the exercise price of the outstanding rights.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value for rights granted during the second quarter:

Dividend yield	**8.32%**
Volatility	**45.62%**
Risk-free interest rate	**2.44%**
Forfeiture rate	**12.40%**
Right’s exercise price reduction	**$ 1.76**

Non-cash compensation costs related to rights issued charged to general and administrative for the three and six months ended June 30, 2009 were $1,877,000 ($0.11 per unit) and $3,256,000 ($0.19 per unit) respectively. Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	Six months ended June 30, 2009		Year ended December 31, 2008	
	Number of Rights (000's)	Weighted Average Exercise Price[1]	Number of Rights (000's)	Weighted Average Exercise Price[1]
Trust unit rights outstanding				
Beginning of period	**4,001**	**$ 45.05**	3,404	$ 47.59
Granted	**1,987**	**17.24**	1,403	42.00
Exercised	**–**	**–**	(210)	32.22
Cancelled	**(149)**	**40.74**	(596)	44.94
End of period	**5,839**	**$ 35.14**	4,001	$ 45.05
Rights exercisable at end of period	**2,646**	**$ 45.11**	2,024	$ 46.44

(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 Plan.

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

	Six months ended June 30,	
(thousands)	2009	2008
Weighted average units	**165,807**	155,984
Dilutive impact of rights	**–**	118
Diluted trust units	**165,807**	156,102

(f) Performance Trust Unit Plan

In 2007 the Fund adopted a Performance Trust Unit ("PTU") plan for executives and employees. For the three and six months ended June 30, 2009 the Fund recorded cash compensation costs of $1,863,000 (2008 – $1,217,000) and $3,689,000 (2008 – $2,300,000), respectively, under the plan which are included in general and administrative expenses.

At June 30, 2009 there were 399,000 performance trust units outstanding.

(g) Restricted Trust Unit Plan

In 2009 the Fund adopted a new Restricted Trust Unit ("RTU") plan for executives and employees, which will replace the PTU plan. Under the RTU plan employees and officers receive cash compensation in relation to the value of a specified number of underlying notional trust units. The number of notional trust units awarded is variable to individuals and they vest one-third at the end of each year for three years. Upon vesting, plan participants receive a cash payment based on the value of the underlying trust units plus notional accrued distributions.

For the three and six months ended June 30, 2009 the Fund recorded cash compensation costs of $1,707,000 and $3,000,000, respectively, under the plan which are included in general and administrative expenses.

At June 30, 2009 there were 894,000 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.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables and are reported at amortized cost. At June 30, 2009 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 2009 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 June 30, 2009 the Fund reported investments in marketable securities of private companies at cost of $47,116,000 (December 31, 2008 – $47,116,000) 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 and distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At June 30, 2009 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 cost. At June 30, 2009 the carrying value of the bank credit facilities approximated their fair value.

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**
US$225,000	US$225,000	$ 261,563	**$ 255,122**
US$40,000	US$40,000	46,500	**45,352**
CDN$40,000	CDN$40,000	40,000	**39,365**
US$175,000	US$177,305	205,925	**203,804**
US$54,000	US$54,000	62,775	**60,959**
		$ 616,763	**$ 604,602**

(b) Fair Value of Derivative Financial Instruments

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 Sheets result from recording derivative financial instruments at fair value. At June 30, 2009 a current deferred financial asset of $83,697,000, a current deferred financial credit of $9,985,000, a non-current deferred financial asset of $4,281,000 and a long-term deferred financial credit of $43,636,000 are recorded on the Consolidated Balance Sheet.

The deferred financial asset relating to crude oil instruments is $36,080,000 at June 30, 2009 including deferred premiums of $12,154,000. The deferred financial asset relating to natural gas instruments is $47,617,000 at June 30, 2009 including deferred premiums of $10,891,000.

The following table summarizes the fair value as at June 30, 2009 and change in fair value for the six months ended June 30, 2009 of the Fund's derivative financial instruments. The fair values indicated below are determined using observable market data including price quotations in active markets.

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swaps	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments		Total
					Oil	Gas	
Deferred financial (credits)/assets, beginning of period	$ (10,051)	$ (16,341)	$ 6,857	$ 348	$ 96,641	$ 24,292	$ 101,746
Change in fair value asset/(credits)	2,669[(1)]	(28,193)[(2)]	(2,576)[3)]	(2,053)[(4)]	(60,561)[(5)]	23,325[(5)]	(67,389)
Deferred financial (credits)/assets, end of period	**$ (7,382)**	**$ (44,534)**	**$ 4,281**	**$ (1,705)**	**$ 36,080**	**$ 47,617**	**$ 34,357**
Balance sheet classification:							
Current asset/(liability)	**$ (4,286)**	**$ (3,994)**	**$ –**	**$ (1,705)**	**$ 36,080**	**$ 47,617**	**$ 73,712**
Non-current asset/(liability)	**$ (3,096)**	**$ (40,540)**	**$ 4,281**	**$ –**	**$ –**	**$ –**	**$ (39,355)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (loss of $2,325) and interest expense (loss of $25,868).
(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 June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Loss due to change in fair value	**$ (49,900)**	$ (160,955)	**$ (37,235)**	$ (240,400)
Net realized cash gains/(losses)	**42,564**	(64,060)	**88,544**	(74,994)
Commodity derivative instruments (loss)/gain	**$ (7,336)**	$ (225,015)	**$ 51,309**	$ (315,394)

(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 July 29, 2009 are summarized below.

Crude Oil:

	Daily Volumes bbls/day	WTI US$/bbl Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term						
July 1, 2009 – December 31, 2009						
Put	1,400	–	–	$ 122.00	–	–
Put	1,000	–	–	$ 120.00	–	–
Put	500	–	–	$ 116.00	–	–
Put	1,000	–	–	$ 92.00	–	–
Put Spread	1,000	–	–	–	$ 79.00	–
Collar	850	–	$ 100.00	$ 85.00	–	–
3-Way option	1,000	–	$ 85.00	$ 70.00	$ 57.50	–
3-Way option	1,000	–	$ 95.00	$ 79.00	$ 62.00	–
Swap	500	–	–	–	–	$ 100.05
Jan 1, 2010 – December 31, 2010						
Purchased Call(1)	1,500	$ 95.00	–	–	–	–
Purchased Call(1)	1,000	$ 95.00	–	–	–	–
Purchased Call(2)	1,000	$ 90.00	–	–	–	–
Purchased Call(2)	500	$ 90.00	–	–	–	–
Purchased Call(2)	500	$ 92.50	–	–	–	–
Swap(1)	1,500	–	–	–	–	$ 78.45
Swap(1)	1,000	–	–	–	–	$ 78.80
Swap(2)	1,000	–	–	–	–	$ 68.05
Swap(2)	500	–	–	–	–	$ 69.33
Swap(2)	500	–	–	–	–	$ 72.15
Swap(2)	500	–	–	–	–	$ 74.30
Swap(2)	500	–	–	–	–	$ 76.20
Swap(2)	500	–	–	–	–	$ 76.38
Put(1)	2,500	–	–	–	$ 47.50	–

(1) Financial contracts entered into during the second quarter of 2009.
(2) Financial contracts entered into subsequent to June 30, 2009.

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term						
Julyl 1, 2009 – October 31, 2009						
Put	9.5	–	–	$ 8.44	–	–
Put	14.2	–	–	$ 7.70	–	–
Put	2.8	–	–	$ 7.78	–	–
Put	4.7	–	–	$ 7.87	–	–
Put	4.7	–	–	$ 7.72	–	–
Put Spread	2.8	–	–	$ 9.23	$ 7.65	–
Put Spread	2.8	–	–	$ 9.50	$ 7.91	–
Put Spread	5.7	–	–	$ 9.60	$ 7.91	–
Swap	3.8	–	–	–	–	$ 7.86
July 1, 2009 – October 31, 2010						
Swap	23.7	–	–	–	–	$ 7.33

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
November 1, 2009 – March 31, 2010						
Put	4.7	–	–	$ 8.92	–	–
Put	9.5	–	–	$ 8.97	–	–
Put	2.8	–	–	$ 9.07	–	–
Put	4.7	–	–	$ 9.06	–	–
Call	4.7	–	$ 12.13	–	–	–
2009 – 2010						
Physical	2.0	–	–	–	–	$ 2.67

There were no new contracts entered into during or subsequent to the quarter.

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 June 30, 2009 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

($ thousands)	Increase/(decrease) to after-tax net income 25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	**$ 20,208**	**$ (17,857)**
Natural gas derivative contracts	**$ 15,379**	**$ (14,894)**

Electricity:

The Fund is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. The Fund's outstanding electricity derivative contracts as at July 29, 2009 are summarized below:

Term	**Volumes MWh**	**Price CDN$/MWh**
July 1, 2009 – December 31, 2009	4.0	$ 74.50
July 1, 2009 – December 31, 2009	2.0	$ 64.00
July 1, 2009 – December 31, 2010	4.0	$ 77.50
July 1, 2009 – December 31, 2010	2.0	$ 68.75
January 1, 2010 – December 31, 2011(1)	3.0	$ 66.00

(1) Electricity contracts entered into during the second quarter of 2009

(d) Foreign Exchange:

The following sensitivities show the impact to after-tax net income of the respective changes in the period end exchange rate as at June 30, 2009, with all other variables held constant:

($ thousands)	Increase/(decrease) to after-tax net income 25% decrease in $CDN relative to $US	25% increase in $CDN relative to $US
Translation of US$225 million senior notes	**$ (46,212)**	**$ 46,212**
Translation of US$40 million senior notes	**(8,215)**	**8,215**
Translation of US$54 million senior notes	**(11,091)**	**11,091**
Translation of US$175 million senior notes	**(36,416)**	**36,416**
Total	**$ (101,934)**	**$ 101,934**

(e) Interest:

The Fund's cash flows are impacted by fluctuations in interest rates as its outstanding bank debt carries floating interest rates and payments made under the CCIRS are based on floating interest rates. To manage a portion of interest rate risk relating to the bank debt, the Fund has entered into interest rate swaps on $120,000,000 of notional debt at rates varying from 3.70% to 4.61% that mature between June 2011 and July 2013.

If interest rates change by 1%, either lower or higher, on our variable rate debt outstanding at June 30, 2009 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $217,000.

Board of Directors

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Calgary, Alberta

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Corporate Director
Calgary, Alberta

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

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Corporate Director
Calgary, Alberta

Glen D. Roane(5)(10)
Corporate Director
Canmore, Alberta

W. C. (Mike) Seth(3)(8)
President
Seth Consultants Ltd.
Okotoks, Alberta

Donald T. West(7)(11)
Corporate Director
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Corporate Director
Calgary, Alberta

Clayton H. Woitas(7)(11)
President
Range Royalty Management Ltd.
Calgary, Alberta

Robert L. Zorich(4)(9)
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 & Environment Committee
(12) Chairman of the Health, Safety & Environment Committee

Officers

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Garry A. Tanner
Executive Vice President & Chief Operating Officer

Ian C. Dundas
Senior Vice President, Business Development

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

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Eric G. Le Dain
Vice President, Regulatory, Environment & 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 Operating 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, CO

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

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates Inc.
Dallas, Texas

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

U.S. Office
Wells Fargo Center
1300, 1700 Lincoln Street
Denver, Colorado 80203

Telephone: 720.279.5500
Fax: 720.279.5550

Abbreviations

AECO Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

BOE(s)/day barrel of oil equivalent per day (6 Mcf of gas:1 BOE)

CBM coalbed methane, otherwise known as natural gas from coal – NGC

GAAP Generally accepted accounting principles

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf/day thousand cubic feet per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMcf/day million cubic feet per day

MWh Megawatt hour(s) of electricity

NGLs natural gas liquids

NYSE New York Stock Exchange

SAGD steam assisted gravity drainage

SEDAR System for Electronic Document Analysis and Retrieval

TSX Toronto Stock Exchange

WI percentage working interest ownership

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

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