THE ENERGY OF
enerPLUS

Third Quarter Report

NINE MONTHS ENDED SEPTEMBER 30, 2009

SELECTED FINANCIAL RESULTS

(in Canadian dollars)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Financial (000's)				
Cash Flow from Operating Activities	**$ 207,211**	$ 383,573	**$ 587,207**	$ 1,004,246
Cash Distributions to Unitholders[1]	**93,504**	224,417	**272,651**	619,121
Excess of Cash Flow Over Cash Distributions	**113,707**	159,156	**314,556**	385,125
Net Income	**38,182**	465,773	**86,399**	699,397
Debt Outstanding – net of cash	**561,218**	522,254	**561,218**	522,254
Development Capital Spending	**45,417**	163,215	**180,222**	377,485
Acquisitions	**192,484**	4,574	**222,877**	1,771,383
Divestments	**519**	502,489	**2,255**	504,697
Actual Cash Distributions paid to Unitholders	**$ 0.54**	$ 1.31	**$ 1.69**	$ 3.83
Financial per Weighted Average Trust Units[2]				
Cash Flow from Operating Activities	**$ 1.23**	$ 2.33	**$ 3.52**	$ 6.32
Cash Distributions per Unit[1]	**0.55**	1.36	**1.63**	3.89
Excess of Cash Flow Over Cash Distributions	**0.68**	0.97	**1.89**	2.42
Net Income	**0.23**	2.82	**0.52**	4.40
Payout Ratio[3]	**45%**	59%	**46%**	62%
Adjusted Payout Ratio[3]	**68%**	102%	**78%**	100%
Selected Financial Results per BOE[4]				
Oil & Gas Sales[5]	**$ 35.23**	$ 73.62	**$ 35.36**	$ 72.44
Royalties	**(5.56)**	(13.71)	**(6.10)**	(13.54)
Commodity Derivative Instruments	**4.89**	(6.82)	**5.08**	(5.19)
Operating Costs	**(10.00)**	(10.10)	**(9.84)**	(9.51)
General and Administrative	**(2.21)**	(1.50)	**(2.18)**	(1.66)
Interest and Other Income and Foreign Exchange	**(0.79)**	(1.46)	**(0.22)**	(1.23)
Taxes	**(0.35)**	(0.59)	**(0.22)**	(1.19)
Asset Retirement Obligations Settled	**(0.31)**	(0.54)	**(0.34)**	(0.52)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 20.90**	$ 38.90	**$ 21.54**	$ 39.60
Weighted Average Number of Trust Units Outstanding[2]	**168,521**	164,908	**166,724**	158,980
Debt to Trailing Twelve Month Cash Flow Ratio[6]	**0.7x**	0.4x	**0.7x**	0.4x

SELECTED OPERATING RESULTS

	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Average Daily Production				
Natural gas (Mcf/day)	**323,884**	341,803	**333,606**	336,328
Crude oil (bbls/day)	**32,218**	34,119	**33,454**	34,295
Natural gas liquids (bbls/day)	**3,912**	4,557	**4,129**	4,660
Total daily sales (BOE/day)	**90,111**	95,644	**93,184**	95,010
% Natural gas	**60%**	60%	**60%**	59%
Average Selling Price(5)				
Natural gas (per Mcf)	**$ 2.95**	$ 8.25	**$ 3.86**	$ 8.60
Crude oil (per bbl)	**64.94**	110.63	**55.57**	103.85
NGLs (per bbl)	**32.59**	81.20	**36.21**	77.21
CDN$/US$ exchange rate	**0.91**	0.96	**0.85**	0.98
Net Wells drilled	**27.6**	272	**156.6**	469
Success Rate(7)	**100%**	99%	**99%**	99%

(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 September 30, 2009	TSX – ERF.un (CDN$)	U.S.* – ERF (US$)
High	$ 24.82	$ 23.18
Low	$ 21.28	$ 18.23
Close	$ 24.50	$ 22.89

* U.S. Composite Exchange Data including NYSE.

2009 CASH DISTRIBUTIONS PER TRUST UNIT

Payment Month	**CDN$**	**US$**
First Quarter Total	**$ 0.61**	**$ 0.49**
Second Quarter Total	**$ 0.54**	**$ 0.47**
July	$ 0.18	$ 0.16
August	0.18	0.16
September	0.18	0.17
Third Quarter Total	**$ 0.54**	**$ 0.49**
Total Year-to-Date	**$ 1.69**	**$ 1.45**

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

president's message

In early 2009, we outlined a number of strategic initiatives to improve our performance and transition our business to a more focused early stage resource play company that provides both income and growth for our investors in the future. I am pleased to report that we continued to make progress on many of these initiatives during the third quarter. In September we acquired a 21.5% working interest in over 540,000 gross acres in the Marcellus shale gas play located primarily in Pennsylvania. This play is considered one of the best developing shale gas plays in North America characterized by superior economics and tremendous growth potential. We have continued to maintain our financial strength, balancing our capital spending and distributions to unitholders in order to minimize any increases to our debt levels outside of acquisition activity. Our adjusted payout ratio which includes cash distributions and capital spending is 78% year-to-date and we continue to have one of the lowest debt to cash flow ratios in the energy sector. This will allow us to pursue additional acquisitions of tight oil and or tight gas assets that offer attractive growth. We've also improved the performance of our existing assets through the optimization of our development capital spending and a reduction in operating costs. We are on track with our production volumes, general and administrative costs, and development capital spending guidance and are reducing our operating cost guidance as a result of cost reduction initiatives.

Marcellus Shale Gas and Additional Bakken Asset Acquisitions

A key component of our corporate strategy is to acquire early stage resource play assets in North America focusing on tight gas and tight oil that offer superior economics and significant growth potential. Adding these types of assets will be crucial as we strive to strike a balance of both income and growth in our asset base. We also expect to divest of non-core assets over time to improve the focus of our operations.

A major step in this strategy was our acquisition of an average 21.5% working interest in over 540,000 gross acres of land in the Marcellus shale region in the northeast United States from Chief Oil & Gas LLC and certain affiliated entities ("Chief"). Total consideration for this interest was approximately US$411 million, consisting of an upfront payment of US$164 million that was paid upon closing and US$247 million to be paid as a carry of 50% of Chief's future drilling and completion costs in the Marcellus shale play, which we expect will be invested over the next four years. Our net production at the time of the transaction was approximately 1.8 MMcfe/day, with a line of sight to approximately 100 MMcfe/day within the next five years. Our internal assessment has identified over 1.4 trillion cubic feet of best estimate contingent resources on these lands, net to Enerplus, which would almost double our proved plus probable natural gas reserves currently booked.

Subsequent to quarter end, we purchased a 50% non-operated working interest in over 22,000 gross acres of prospective Bakken land in North Dakota for US$27 million, consisting of US$15 million in cash and US$12 million of carry capital to be invested over the next 12 months. We have assessed an internal best estimate of the contingent resources on this acreage of approximately 7.4 million barrels, net to Enerplus, based upon a 13% recovery factor.

In addition, we sold approximately 4.5 net sections of low working interest, non-core property interests in southeast Saskatchewan for approximately $100 million subsequent to the quarter. These lands were producing approximately 200 BOE/day of oil with 1.5 million BOE of booked proved plus probable reserves. We continue to prepare to sell additional non-core oil and gas assets that will allow us to focus our efforts and capital on existing core properties and expand our interests in targeted resource plays. We expect to be in a position for further non-core asset sales in 2010.

Operations

Our daily production volumes during the third quarter averaged 90,111 BOE/day and 93,184 BOE/day for the first nine months of 2009, on track with our full year guidance of 91,000 BOE/day. Cash flow from operations during the quarter was $207 million which was comparable to that of the second quarter of 2009. Monthly cash distributions to our unitholders were maintained at $0.18/unit, representing approximately 45% of our cash flow during the quarter versus 43% last quarter. We spent approximately $45 million developing our assets and when we combine this with our distributions to unitholders, we realized an adjusted payout ratio of 68% for the quarter. We continue to expect our adjusted payout ratio to average approximately 100% for the full year excluding acquisitions as we expect to spend a significant portion of our full year development capital in the last quarter.

We have actively been working to control costs throughout 2009 and our efforts have resulted in operating costs of $10.07/BOE for the third quarter and an average of $9.94/BOE for the year. Based on these results, we are lowering our full year guidance from $10.65/BOE to $10.20/BOE, an improvement of over 4% from our original target. Our general and administrative costs have remained on track to meet our full year guidance of $2.45/BOE.

Our development capital spending continues to reflect the prudent approach we undertook at the start of 2009 in light of commodity price uncertainty and a focus on achieving compelling returns on our investment. Our activities in the first half of 2009 were focused on natural gas drilling in our shallow gas and tight gas resource plays. As the price of natural gas continued to deteriorate throughout the year and oil prices strengthened, we began shifting our development program. This shift resulted in a low level of spending in the third quarter and set up a high activity level for the fourth quarter. We expect to focus on oil projects on our Bakken lands and waterflood assets and are limiting our natural gas activities primarily to the Marcellus and utilizing the Alberta Drilling Royalty Credit ("DRC") incentive. As we participate in more early stage growth plays, we anticipate increasing our land and seismic expenditures in key areas. We continue to maintain our capital guidance of $330 million for 2009 including our carry obligations associated with the Marcellus shale gas play and which is net of the credits associated with the DRC incentive, with fourth quarter spending up significantly over the previous quarters of 2009.

Production and Capital Spending Summary

	Three months ended September 30, 2009			
	Production Volumes	Capital Spending	Wells Drilled	
Play Type	**(BOE/day)**	**($ millions)**	**Total Gross**	**Total Net**
Shallow Gas	22,478	9.1	22	21
Crude Oil Waterfloods	15,703	8.5	1	1
Tight Gas	15,310	9.7	1	0.1
Bakken/Tight Oil	9,756	9.3	10	2
Conventional Oil & Gas	26,766	4.3	11	3
Shale Gas*	98	3.1	3	0.5
Total Conventional	**90,111**	**44.0**	**48**	**27.6**
Oil Sands	–	1.4	–	–
Total	**90,111**	**45.4**	**48**	**27.6**

* The Marcellus shale gas acquisition closed September 1, 2009.

	Nine months ended September 30, 2009			
	Production Volumes	Capital Spending	Wells Drilled	
Play Type	**(BOE/day)**	**($ millions)**	**Total Gross**	**Total Net**
Shallow Gas	23,504	38.7	143	126
Crude Oil Waterfloods	16,007	22.0	3	2
Tight Gas	15,689	45.0	21	11.1
Bakken/Tight Oil	10,350	26.8	12	3
Conventional Oil & Gas	27,601	30.0	47	14
Shale Gas*	33	3.1	3	0.5
Total Conventional	**93,184**	**165.6**	**229**	**156.6**
Oil Sands	–	14.6	–	–
Total	**93,184**	**180.2**	**229**	**156.6**

* The Marcellus shale gas acquisition closed September 1, 2009.

Shallow Gas and DRC Incentives

We remain active in our shallow gas resource play but due to weak natural gas prices we drilled only a modest number of wells (12) in the third quarter to complete our activities at Shackleton for the year, and have elected not to tie these wells in until gas prices recover. However, we started drilling the first nine of approximately 250 shallow gas wells in Alberta to take advantage of the DRC incentive. This incentive offers a drilling credit of $200 for every metre drilled, allowing us to substantially recover the cost of drilling a shallow gas well. We plan to utilize the benefits of this program primarily at Verger, Bantry, Hanna Garden and Princess. Most of the drilling activity is expected to occur in the fourth quarter of 2009 however we expect to complete and tie in wells as economic conditions warrant. As a result, the benefit of new production volumes associated with this drilling are not anticipated until 2010. We also plan on drilling approximately 15 oil wells under the DRC program at various locations throughout Alberta late this year or early 2010. Based on drilling plans for the fourth quarter, we are estimating a recovery of approximately $22 million from the DRC program in the current year.

Marcellus Shale Gas

Capital spending in our Marcellus shale gas play is expected to be approximately $40 million in 2009, up from our original estimate of $30 million. This spending will consist of approximately $20 million in drilling capital, $5 million in land and seismic, and $15 million of carry obligations mentioned previously. A total of 39 wells have now been drilled to date on our Marcellus lands, comprised of 28 horizontal wells and 11 vertical wells. Eight of these wells have been drilled since we acquired our interest in September. Currently 20 horizontal wells are waiting on completion and 7 horizontal wells are being drilled or remain to be drilled in 2009. Given encouraging results to date, we are adding a fourth rig and expect 2010 capital expenditures to exceed our initial estimates. Activities have been focused on testing new areas and drilling and completion methods to identify the optimal approach. We expect to move to pad drilling this winter in several areas which have been derisked by offset wells. Chief Gathering LLC, the midstream subsidiary of Chief Oil & Gas, continues to progress with the construction of its pipeline infrastructure. Chief Gathering has secured seven interstate pipeline interconnects: two each in Lycoming and Fayette counties and one each in Bradford, Susquehanna and Clearfield counties. We expect to provide a more detailed update on drilling results and capital plans, as part of our 2010 guidance announcement planned for mid-December. Current production is approximately 10 MMcfe/day gross (2.1 MMcfe/day net to Enerplus) from 11 producing wells of which 6 are horizontal and 5 vertical.

Bakken/Tight Oil

The improvement in crude oil prices has also resulted in increased activity in our Bakken/Tight Oil assets. At Sleeping Giant, we are resuming our drilling activity and have increased our refrac program to 18 refracs for the year. We plan to utilize tri-fracs (three wells frac'd simultaneously) to complete the program. Twelve refracs had been completed at the end of the third quarter. This activity continues to yield positive results with production gains of approximately 50 BOE/day gross (35 BOE/day net) per refrac and expected reserve additions of approximately 50 MBOE gross (35 MBOE net). We have contracted two rigs and plan to drill four wells at Sleeping Giant by year end. We estimate at year end we will have eight third well and 40 lease line drilling opportunities remaining on our lands as well as approximately 100 refracs in our inventory. We also plan to continue drilling at Taylorton in southern Saskatchewan where we participated in the drilling of 5 gross wells (1.25 net wells) in the third quarter and have another three gross wells (0.75 net wells) planned with our partner for the fourth quarter. On our newly acquired North Dakota acreage, initial plans include four gross wells (two net wells) drilled in late 2009 or early 2010. Although this is a non-operated position for Enerplus, due to our considerable drilling expertise in the Bakken, Enerplus will operate the drilling activities. Additionally, we are drilling on our operated Bakken lands in other areas as part of our overall Bakken portfolio.

Waterfloods and Other Oil

Drilling activity is also expected to increase on our crude oil waterflood properties in the fourth quarter. We currently have development plans at Virden, Manitoba and the Glauconitic "C" unit at Medicine Hat in Alberta, and at our Freda Lake waterflood in Saskatchewan. A total of 11 gross wells are planned in these areas, all of which will be horizontal wells. The current moratorium on licensing any wells with H_2S in Alberta may slow our plans. We are also increasing our conventional oil activities on select fields primarily in southeast Saskatchewan and plan to drill approximately three wells in the fourth quarter.

Financial Strength

A sound balance sheet and its corresponding financial strength continue to be an essential element in the successful execution of our corporate strategy. In early September we issued approximately 10 million units for gross proceeds of $225 million. The proceeds of this equity issuance were used to fund the upfront costs of the Marcellus acquisition, with the balance used to reduce outstanding bank debt to zero at the end of the quarter. Our entire $1.4 billion bank credit facility is currently available for use.

Outlook

Looking ahead, our business strategy is clear. We believe a balance of growth and income will provide a compelling investment opportunity and the addition of more early stage resource play assets to our portfolio of core cash flow generating assets will help us to achieve this. We expect these early stage assets to be focused on tight gas and tight oil that we believe will deliver top quartile economics. We plan to utilize our balance sheet strength prudently to acquire additional assets and to help fund the capital needs of these growth plays. We also remain focused on the successful execution of our operational plans, maintaining the discipline we apply to our spending and improving the efficiencies of our day-to-day business.

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 November 12, 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 nine months ended September 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

On September 1, 2009 we executed our first significant transaction in an early stage growth resource play with the acquisition of an average 21.5% non-operated working interest in approximately 540,000 gross acres in the Marcellus shale natural gas play in the U.S. Total consideration was US$411 million comprised of US$164.4 million of cash paid on closing and US$246.6 million to be paid over time as a carry representing 50% of our partners' future drilling and completion costs. In conjunction with the acquisition we closed an equity offering on September 9, 2009, raising gross proceeds of $225.3 million through the issuance of 10.4 million trust units. At the end of the quarter we had $1.4 billion of undrawn credit capacity which provides us with significant financial flexibility to pursue additional acquisition opportunities.

Our third quarter operating results continue to be on target with guidance as production averaged 90,111 BOE/day, operating costs were $10.07/BOE and general and administrative costs were $2.41/BOE. Our overall guidance is on track however given our operating cost reduction efforts, we are reducing our operating cost guidance to $10.20/BOE from $10.65/BOE.

Low commodity price levels, particularly natural gas, continue to impact our cash flow and earnings. Our cash flow totaled $207.2 million for the quarter, a 46% decrease from $383.6 million in the third quarter of 2008. Third quarter net income was $38.2 million compared to $465.8 million in the same quarter of 2008. Our payout ratio and adjusted payout ratio for the quarter were 45% and 68% respectively, reflecting both our reduced distributions and capital spending.

RESULTS OF OPERATIONS

Production

Production in the third quarter of 2009 averaged 90,111 BOE/day, 5% lower than the second quarter of 2009. For the three and nine months ended September 30, 2009 production decreased 6% and 2% respectively, compared to the same periods in 2008. These decreases were in-line with our expectations and resulted from facility turnarounds, reduced capital spending and natural reservoir declines in 2009. We continue to have a modest amount of natural gas production shut in due to pricing but are not expecting a significant amount of additional curtailment.

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

	Three months ended September 30,			Nine months ended September 30,		
Daily Production Volumes	**2009**	**2008**	**% Change**	**2009**	**2008**	**% Change**
Natural gas (Mcf/day)	**323,884**	341,803	(5)%	**333,606**	336,328	(1)%
Crude oil (bbls/day)	**32,218**	34,119	(6)%	**33,454**	34,295	(2)%
Natural gas liquids (bbls/day)	**3,912**	4,557	(14)%	**4,129**	4,660	(11)%
Total daily sales (BOE/day)	**90,111**	95,644	(6)%	**93,184**	95,010	(2)%

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, net of transportation costs, for the three and nine months ended September 30, 2009 and 2008. It also compares the benchmark price indices for the same periods:

	Three months ended September 30,			Nine months ended September 30,		
Average Selling Price(1)	**2009**	**2008**	**% Change**	**2009**	**2008**	**% Change**
Natural gas (per Mcf)	**$ 2.95**	$ 8.25	(64)%	**$ 3.86**	$ 8.60	(55)%
Crude oil (per bbl)	**$ 64.94**	$ 110.63	(41)%	**$ 55.57**	$ 103.85	(46)%
Natural gas liquids (per bbl)	**$ 32.59**	$ 81.20	(60)%	**$ 36.21**	$ 77.21	(53)%
Per BOE	**$ 35.23**	$ 73.62	(52)%	**$ 35.36**	$ 72.44	(51)%
Average Benchmark Pricing						
AECO natural gas — monthly index (CDN$/Mcf)	**$ 3.02**	$ 9.25	(67)%	**$ 4.10**	$ 8.58	(52)%
AECO natural gas — daily index (CDN$/Mcf)	**$ 2.94**	$ 7.75	(62)%	**$ 3.77**	$ 8.62	(56)%
NYMEX natural gas — monthly NX3 index (US$/Mcf)	**$ 3.41**	$ 10.09	(66)%	**$ 3.96**	$ 9.65	(59)%
NYMEX natural gas — monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**$ 3.75**	$ 10.51	(64)%	**$ 4.66**	$ 9.85	(53)%
WTI crude oil (US$/bbl)	**$ 68.30**	$ 117.98	(42)%	**$ 57.00**	$ 113.29	(50)%
WTI crude oil CDN$ equivalent (CDN$/bbl)	**$ 75.05**	$ 122.90	(39)%	**$ 67.06**	$ 115.60	(42)%
CDN$/US$ exchange rate	**0.91**	0.96	(5)%	**0.85**	0.98	(13)%

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

During the quarter the average of the AECO monthly and daily gas prices dropped 16% from $3.56/Mcf in the second quarter to $2.98/Mcf in the third quarter, hitting a low of $2.03/Mcf in early September. The downward pressure on prices was a result of the continuing sluggish economy resulting in record gas storage inventory levels, along with mild summer weather and minimal disruptions associated with hurricane activity.

We realized an average price on our natural gas of $2.95/Mcf (net of transportation costs) during the third quarter of 2009, a decrease of 64% from $8.25/Mcf for the same period in 2008. For the nine months ended September 30, 2009 we realized an average price of $3.86/Mcf, a 55% decrease from the same period in 2008. The majority of our natural gas sales are priced with reference to either the monthly or daily AECO indices. The decreases in the index prices for the three and nine months ended September 30, 2009 are comparable to the changes experienced in our realized prices at AECO.

The West Texas Intermediate ("WTI") price for the third quarter of 2009 increased 15% to average US$68.30/bbl, up from an average of US$59.62/bbl during the second quarter of 2009. However, this price was still 42% lower quarter over quarter compared to the same period in 2008 when crude oil WTI averaged US$117.98/bbl. In Canadian dollars WTI decreased 39% to $75.05/bbl from $122.90/bbl for the same period in 2008. Enerplus' average realized crude oil sales price was $64.94/bbl (net of transportation costs) for the third quarter which is a 41% decrease from the $110.63/bbl during the same period in 2008. For the nine months ended September 30, 2009 our realized crude oil sales price was $55.57/bbl (net of transportation costs) which was a 46% decrease from $103.85/bbl during the same period in 2008. These decreases in our realized prices for the three and nine months ended September 30, 2009 are comparable to the changes experienced by the benchmark price for crude oil.

The Canadian dollar has recently been strengthening against the U.S. dollar however overall has been weaker during the three and nine months ended September 30, 2009 compared to the same period in 2008. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, a weaker Canadian dollar increases the 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 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 time.

Given the above framework and objectives, we have entered into additional commodity contracts during and subsequent to the third quarter of 2009. Including all financial contracts transacted as of November 4, 2009, we have protected a portion of our natural gas and crude oil sales through December 2010. We have also hedged approximately 50% of our Alberta power consumption on operated properties. For 2010 approximately 60% of this consumption has been hedged and 40% in 2011. See Note 9 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at November 4, 2009, expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)				Crude Oil (US$/bbl)	
	October 1, 2009 – October 31, 2009	**November 1, 2009 – March 31, 2010**	**April 1, 2010 – October 31, 2010**	**November 1, 2010 – December 31, 2010**	**October 1, 2009 – December 31, 2009**	**January 1, 2010 – December 31, 2010**
Purchase Puts (floor prices)	$ 8.30	$ 8.24	$ 5.48	$ 5.48	$ 98.08	–
%	18%	11%	8%	8%	25%	–
Sold Puts (limiting downside protection)	$ 7.85	$ 3.96	$ 3.96	$ 3.96	$ 66.17	$ 47.50
%	4%	2%	8%	8%	11%	16%
Swaps (fixed price)	$ 7.41	$ 7.33	$ 7.33	–	$ 100.05	$ 75.87
%	11%	10%	10%	–	2%	32%
Sold Calls (capped price)	–	$ 12.13	–	–	$ 92.98	–
%	–	2%	–	–	7%	–
Purchased Calls (repurchasing upside)	–	–	–	–	–	$ 92.29
%	–	–	–	–	–	24%

Based on weighted average price (before premiums), estimated 2009 average annual production of 91,000 BOE/day, net of royalties and assuming an 18% royalty rate.

Accounting for Price Risk Management

During the third quarter of 2009 our price risk management program generated cash gains of $24.5 million on our natural gas contracts and $16.1 million on our crude oil contracts. In comparison, during the third quarter of 2008 we experienced cash losses of $18.8 million and $41.2 million respectively. For the nine months ended September 30, 2009 we experienced cash gains of $59.4 million on our natural gas contracts and $69.7 million on our crude oil contracts, compared to cash losses of $30.6 million and $104.4 million respectively, for the same periods in 2008. The cash gains in 2009 are a result of our floor protection which helped to offset the drop in commodity prices.

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. At September 30, 2009 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented gains of $26.5 million and $14.6 million respectively. These gains are recorded as current deferred financial assets on our balance sheet. In comparison, at June 30, 2009 the fair value of our natural gas and crude oil derivative instruments represented gains of $47.6 million and $36.1 million respectively. The change in the fair value of our commodity derivative instruments between the second and third quarter of 2009 resulted in unrealized losses of $21.1 million for natural gas and $21.5 million for crude oil. For the nine months ended September 30, 2009 the change in fair value of our commodity derivative instruments resulted in an unrealized gain of $2.2 million for natural gas and an unrealized loss of $82.0 million for crude oil. See Note 9 for details.

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

Risk Management Results ($ millions, except per unit amounts)	**Three months ended September 30, 2009**				Three months ended September 30, 2008			
Cash gains/(losses):								
Natural gas	**$**	**24.5**	**$**	**0.82/Mcf**	$	(18.8)	$	(0.60)/Mcf
Crude oil		**16.1**		**5.43/bbl**		(41.2)		(13.13)/bbl
Total cash gains/(losses)	**$**	**40.6**	**$**	**4.89/BOE**	$	(60.0)	$	(6.82)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – natural gas	**$**	**(21.1)**	**$**	**(0.71)/Mcf**	$	103.9	$	3.30/Mcf
Change in fair value – crude oil		**(21.5)**		**(7.25)/bbl**		176.8		56.30/bbl
Total non-cash gains/(losses)	**$**	**(42.6)**	**$**	**(5.13)/BOE**	$	280.7	$	31.90/BOE
Total gains/(losses)	**$**	**(2.0)**	**$**	**(0.24)/BOE**	$	220.7	$	25.08/BOE

Risk Management Results ($ millions, except per unit amounts)	**Nine months ended September 30, 2009**				Nine months ended September 30, 2008			
Cash gains/(losses):								
Natural gas	**$**	**59.4**	**$**	**0.65/Mcf**	$	(30.6)	$	(0.33)/Mcf
Crude oil		**69.7**		**7.63/bbl**		(104.4)		(11.11)/bbl
Total cash gains/(losses)	**$**	**129.1**	**$**	**5.08/BOE**	$	(135.0)	$	(5.19)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – natural gas	**$**	**2.2**	**$**	**0.02/Mcf**	$	5.9	$	0.06/Mcf
Change in fair value – crude oil		**(82.0)**		**(8.98)/bbl**		34.4		3.66/bbl
Total non-cash gains/(losses)	**$**	**(79.8)**	**$**	**(3.14)/BOE**	$	40.3	$	1.55/BOE
Total gains/(losses)	**$**	**49.3**	**$**	**1.94/BOE**	$	(94.7)	$	(3.64)/BOE

Revenues

Crude oil and natural gas revenues were 5% lower during the third quarter of 2009 compared to the second quarter of 2009 as the impact of higher oil prices was offset by lower natural gas prices and a 5% decrease in production.

Crude oil and natural gas revenues for the three months ended September 30, 2009 were $292.1 million ($299.0 million, net of $6.9 million transportation) compared to $647.8 million ($654.6 million, net of $6.8 million transportation) for the same period in 2008. For the nine months ended September 30, 2009 revenues were $899.5 million ($919.0 million, net of $19.5 million transportation) compared to $1,885.9 million ($1,906.1 million, net of $20.2 million transportation) 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 September 30, 2008	$	347.3	$	34.0	$	266.5	$	647.8
Price variance[1]		(135.4)		(17.5)		(165.0)		(317.9)
Volume variance		(19.4)		(4.8)		(13.6)		(37.8)
Quarter ended September 30, 2009	**$**	**192.5**	**$**	**11.7**	**$**	**87.9**	**$**	**292.1**

($ millions)		**Crude Oil**		**NGLs**		**Natural Gas**		**Total**
Year-to-date ended September 30, 2008	$	975.9	$	98.6	$	811.4	$	1,885.9
Price variance[1]		(441.0)		(46.2)		(450.9)		(938.1)
Volume variance		(27.4)		(11.6)		(9.3)		(48.3)
Year-to-date ended September 30, 2009	**$**	**507.5**	**$**	**40.8**	**$**	**351.2**	**$**	**899.5**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and nine months ended September 30, 2009 royalties were $46.1 million and $155.1 million respectively, compared to $120.6 million and $352.5 million for the same periods in 2008. As a percentage of oil and gas sales, net of transportation, royalties were 16% for the quarter and 17% for the nine months ended September 30, 2009 compared to 19% during the same periods in 2008. The decrease in royalties during 2009 is the result of lower commodity prices.

On March 3, 2009, the Alberta government announced the Drilling Royalty Credit ("DRC") program designed to stimulate drilling activity in the province by offering a credit of $200 per metre drilled. We have incorporated additional drilling into our capital spending plans and expect to realize approximately $22 million of the DRC incentive this year. Drilling credits are being reflected as a reduction to development capital and will have no impact on royalties. To date approximately $1.5 million of drilling credits have been realized.

Operating Expenses

Operating expenses during the third quarter of 2009 increased slightly to $10.07/BOE from $9.93/BOE in the second quarter of 2009 due to reduced production as a result of scheduled turnarounds and reservoir declines associated with oil and gas operations. For the third quarter of 2009 operating expenses were $83.5 million or $10.07/BOE compared to $89.8 million or $10.21/BOE for the third quarter of 2008. For the nine months ended September 30, 2009 operating expenses were $253.0 million or $9.94/BOE compared to $247.8 million or $9.52/BOE for the same period in 2008. Compared to 2008 our operating expenses are at similar levels based on total dollars; however with lower production levels operating costs have increased on a $/BOE basis.

Throughout the year we have been monitoring our operations to prudently reduce costs where possible and have realized savings related to electricity, well servicing, chemicals and labour from what we initially expected. As a result, we are reducing our annual guidance for operating costs from $10.65/BOE to $10.20/BOE.

General and Administrative Expenses ("G&A")

G&A expenses for the three months ended September 30, 2009 were $20.0 million ($2.41/BOE) compared to $21.4 million ($2.49/BOE) for the second quarter of 2009 and $14.9 million ($1.70/BOE) for the third quarter of 2008. G&A expenses totaled $60.3 million ($2.37/BOE) for the nine months ended September 30, 2009 compared to $48.7 million ($1.87/BOE) for the same period in 2008. Our 2009 G&A expenses include $2.3 million of transaction costs related to our senior notes issued in the second quarter. Lower overhead recoveries resulting from our reduced capital program also increased our year-over-year net G&A expense.

For the three and nine months ended September 30, 2009 our G&A expenses included non-cash charges of $1.7 million ($0.20/BOE) and $4.9 million ($0.19/BOE) respectively, compared to $1.8 million ($0.20/BOE) and $5.4 million ($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 8 for further details.

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

General and Administrative Costs ($ millions)	Three months ended September 30, **2009**	**2008**	Nine months ended September 30, **2009**	**2008**
Cash	**$ 18.3**	$ 13.1	**$ 55.4**	$ 43.3
Trust unit rights incentive plan (non-cash)	**1.7**	1.8	**4.9**	5.4
Total G&A	**$ 20.0**	$ 14.9	**$ 60.3**	$ 48.7

(Per BOE)	**2009**	**2008**	**2009**	**2008**
Cash	**$ 2.21**	$ 1.50	**$ 2.18**	$ 1.66
Trust unit rights incentive plan (non-cash)	**0.20**	0.20	**0.19**	0.21
Total G&A	**$ 2.41**	$ 1.70	**$ 2.37**	$ 1.87

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 issue, 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 6 for further details.

Interest on long-term debt excluding non-cash charges totaled $10.3 million and $21.1 million for the three and nine months ended September 30, 2009, compared to $8.8 million and $35.1 million respectively, for the same periods in 2008. Lower interest rates and lower debt levels on average in 2009 resulted in lower interest charges over the first half of the year. However, our interest charges increased in the third quarter due to the new senior notes issued in June 2009.

For the third quarter of 2009 we generated non-cash interest gains of $5.3 million compared to non-cash gains of $1.6 million in the third quarter of 2008. For the nine months ended September 30, 2009 we generated non-cash interest losses of $17.5 million compared to non-cash gains of $1.6 million during the same period in 2008. The changes in the fair value of our interest rate swaps and the interest component on our CCIRS cause non-cash interest to fluctuate between periods.

The following table summarizes our cash and non-cash interest expense:

Interest Expense ($ millions)	Three months ended September 30, **2009**	**2008**	Nine months ended September 30, **2009**	**2008**
Interest on long-term debt	**$ 10.3**	$ 8.8	**$ 21.1**	$ 35.1
Non-cash interest (gain)/loss	**(5.3)**	(1.6)	**17.5**	(1.6)
Total Interest Expense	**$ 5.0**	$ 7.2	**$ 38.6**	$ 33.5

Approximately 77% of our effective debt is based on fixed interest rates and 23% based on floating interest rates at September 30, 2009. For the remainder of the year we expect our average cash interest rate to be approximately 6%.

Capital Expenditures

During the three and nine months ended September 30, 2009 development capital spending was $45.4 million and $180.2 million respectively, compared to $163.2 million and $377.5 million during the same periods in 2008. The reduced spending levels in 2009 reflect a more conservative development capital program due to decreased commodity prices. We have adjusted the direction of our capital spending throughout 2009 given the volatility in commodity prices, with certain oil projects being deferred early in the year as oil prices bottomed and natural gas projects being deferred in the second and third quarters as natural gas prices continued to deteriorate. We are expecting higher spending levels in the fourth quarter as commodity prices have started to improve and government incentives such as the DRC program will improve the economics of certain projects. To date in 2009 we have achieved a 99% success rate with our drilling program on 156.6 net wells.

Property acquisitions for the three and nine months ended September 30, 2009 totaled $192.5 million and $222.9 million respectively, compared to $4.6 million and $13.9 million for the same periods in 2008. On September 1, 2009 we successfully closed a property acquisition in the Marcellus shale gas play in the north eastern United States, acquiring an average 21.5% non-operated working interest in approximately 540,000 gross acres. Total consideration for the acquisition was US$411 million, comprised of US$164.4 million in cash that was paid upon closing and US$246.6 million to be paid over time as a carry representing 50% of the operator's future drilling and completion costs. We expect this carry will be expended over the next four years and will be reported as property acquisitions as it is incurred. The remainder of our reported property acquisitions at September 30, 2009 primarily relate to non-operated Bakken interests in southeast Saskatchewan that occurred during the second quarter. Corporate acquisitions during 2008 totaling approximately $1.7 billion relate to the Focus acquisition.

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

	Three months ended September 30,		Nine months ended September 30,	
Capital Expenditures ($ millions)	**2009**	**2008**	**2009**	**2008**
Development expenditures	**$ 35.4**	$ 131.7	**$ 133.3**	$ 299.9
Plant and facilities	**10.0**	31.5	**46.9**	77.6
Development Capital	**45.4**	163.2	**180.2**	377.5
Office	**1.0**	2.4	**4.1**	6.0
Sub-total	**46.4**	165.6	**184.3**	383.5
Property acquisitions(1)	**192.5**	4.6	**222.9**	13.9
Corporate acquisitions	**–**	–	**–**	1,757.5
Property dispositions(1)	**(0.6)**	(502.5)	**(2.3)**	(504.7)
Total Net Capital Expenditures	**$ 238.3**	$ (332.3)	**$ 404.9**	$ 1,650.2
Capital Expenditures financed with cash flow	**$ 113.7**	$ 159.2	**$ 314.6**	$ 385.1
Capital Expenditures financed with debt and equity	**125.2**	11.0	**92.6**	1,769.8
Proceeds received on property dispositions(1)	**(0.6)**	(502.5)	**(2.3)**	(504.7)
Total Net Capital Expenditures	**$ 238.3**	$ (332.3)	**$ 404.9**	$ 1,650.2

(1) Net of post-closing adjustments.

We expect capital development activity levels will be high during the fourth quarter as over 40% of our annual capital spending will occur during the remainder of 2009. Spending during the fourth quarter will be focused on our new Marcellus shale gas interests, various crude oil projects across our Canadian and US asset base, growth oriented land acquisitions, and increased drilling of shallow natural gas as a result of the DRC program. We have increased capital spending activity related to our shallow gas program during the fourth quarter of 2009 and expect to receive approximately $22 million of credits under the DRC program for the year.

As we transition to more early stage growth plays, it will become more difficult to forecast capital spending patterns given the uncertainty of factors such as land acquisitions and non-operated partnering arrangements. We continue to expect annual 2009 development capital spending to be approximately $315 million, including offsetting DRC credits of $22 million. At September 30, 2009 we have satisfied US$2.8 million of our Marcellus carry commitment and have a remaining balance US$243.8 million. We expect our total Marcellus carry spending in 2009 will be approximately $15 million.

Subsequent to September 30, 2009 we divested of a non-core oil property within Western Canada with production of approximately 200 BOE/day for proceeds of $101 million. We also acquired a non-operated working interest in over 22,000 acres of prospective Bakken lands located in North Dakota for approximately US$27 million.

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 the deferral of further development of the Kirby project, however a few key activities were continued to finalize efforts that were underway.

During the third quarter we continued to advance on the regulatory application which we expect will be completed in early 2010. During the second quarter an updated independent resource estimate was received and the best estimate of contingent resources increased to approximately 500 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 capitalized $273 million in costs to date associated mainly with our Kirby project. 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 September 30, 2009, DDA&A increased to $19.04/BOE compared to $18.32/BOE during the corresponding period in 2008. For the nine months ended September 30, 2009 DDA&A increased to $19.03/BOE compared to $18.19/BOE during the corresponding period in 2008. The sale of our Joslyn oil sands property in July 2008 lowered our 2008 depletion charges. Conversely, negative reserve revisions at December 31, 2008 have effectively increased our depletion rate in 2009.

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

Goodwill

The goodwill balance of $611.3 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. No goodwill impairment exists at September 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 included on our balance sheet are estimated by management based on our net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. Enerplus has estimated the net present value of its total asset retirement obligations to be approximately $212 million at September 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 September 30,		Nine months ended September 30,	
($ millions)	**2009**	2008	**2009**	2008
Total Amortization and Accretion of Asset Retirement Obligations	**$ 8.4**	$ 8.0	**$ 25.4**	$ 23.4
Asset Retirement Obligations Settled	**$ 2.5**	$ 4.7	**$ 8.7**	$ 13.5

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 $27.6 million and $86.6 million for the three and nine months ended September 30, 2009 respectively, compared to an expense of $1.4 million and a recovery of $84.3 for the same periods in 2008. The increased recovery is mainly due to lower income in the operating entities 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.

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 nine months ended September 30, 2009, we recorded current income taxes of $2.9 million and $5.5 million respectively, compared to $5.2 million and $31.0 million during the same periods in 2008. The decrease in current taxes is mainly due to a decrease in net income.

We now expect our U.S. current income taxes to average approximately 5% of our cash flow from U.S. operations, down from our prior guidance of 10%. This decrease is primarily due to lower net income in our U.S. operations as a result of lower oil prices during 2009.

Net Income

Net income for the third quarter of 2009 was $38.2 million or $0.23 per trust unit compared to $465.8 million or $2.82 per trust unit during the same period of 2008. The $427.6 million decrease was primarily due to a decrease in oil and gas sales of $355.7 million and a decline in commodity derivative instrument gains of $222.6 million, partially offset by decreased royalties of $74.6 million.

Net income for the nine months ended September 30, 2009 was $86.4 million or $0.52 per trust unit compared to $699.4 million or $4.40 per trust unit for the same period in 2008. The $613.0 million decrease in net income was primarily due to a decrease in oil and gas sales of $986.4 million which was partially offset by an increase in commodity derivative instrument gains of $144.1 million and a decrease in royalties of $197.4 million.

Cash Flow from Operating Activities

Cash flow for the three and nine months ended September 30, 2009 was $207.2 million ($1.23 per trust unit) and $587.2 million ($3.52 per trust unit) respectively, compared to $383.6 million ($2.33 per trust unit) and $1,004.2 million ($6.32 per trust unit) respectively for the same periods in 2008. The decrease in cash flow per unit is due to lower commodity prices and lower production, partially offset by cash gains on our commodity derivative instruments and lower royalties.

Selected Financial Results

Per BOE of production (6:1)	Three months ended September 30, 2009 Operating Cash Flow(1)	Non-Cash & Other Items	Total	Three months ended September 30, 2008 Operating Cash Flow(1)	Non-Cash & Other Items	Total
Production per day			**90,111**			95,644
Weighted average sales price(2)	**$ 35.23**	**$ –**	**$ 35.23**	$ 73.62	$ –	$ 73.62
Royalties	**(5.56)**	**–**	**(5.56)**	(13.71)	–	(13.71)
Commodity derivative instruments	**4.89**	**(5.13)**	**(0.24)**	(6.82)	31.90	25.08
Operating costs	**(10.00)**	**(0.07)**	**(10.07)**	(10.10)	(0.11)	(10.21)
General and administrative	**(2.21)**	**(0.20)**	**(2.41)**	(1.50)	(0.20)	(1.70)
Interest expense, net of other income	**(1.22)**	**0.64**	**(0.58)**	(0.97)	0.18	(0.79)
Foreign exchange gain/(loss)	**0.43**	**3.87**	**4.30**	(0.49)	0.19	(0.30)
Current income tax	**(0.35)**	**–**	**(0.35)**	(0.59)	–	(0.59)
Restoration and abandonment cash costs	**(0.31)**	**0.31**	**–**	(0.54)	0.54	–
Depletion, depreciation, amortization and accretion	**–**	**(19.04)**	**(19.04)**	–	(18.32)	(18.32)
Future income tax recovery/(expense)	**–**	**3.33**	**3.33**	–	(0.15)	(0.15)
Total per BOE	**$ 20.90**	**$ (16.29)**	**$ 4.61**	$ 38.90	$ 14.03	$ 52.93

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

Per BOE of production (6:1)	Nine months ended September 30, 2009 Operating Cash Flow(1)	Non-Cash & Other Items	Total	Nine months ended September 30, 2008 Operating Cash Flow(1)	Non-Cash & Other Items	Total
Production per day			**93,184**			95,010
Weighted average sales price(2)	**$ 35.36**	**$ –**	**$ 35.36**	$ 72.44	$ –	$ 72.44
Royalties	**(6.10)**	**–**	**(6.10)**	(13.54)	–	(13.54)
Commodity derivative instruments	**5.08**	**(3.14)**	**1.94**	(5.19)	1.55	(3.64)
Operating costs	**(9.84)**	**(0.10)**	**(9.94)**	(9.51)	(0.01)	(9.52)
General and administrative	**(2.18)**	**(0.19)**	**(2.37)**	(1.66)	(0.21)	(1.87)
Interest expense, net of other income	**(0.81)**	**(0.69)**	**(1.50)**	(1.06)	0.06	(1.00)
Foreign exchange (loss)/gain	**0.59**	**1.27**	**1.86**	(0.17)	(0.02)	(0.19)
Current income tax	**(0.22)**	**–**	**(0.22)**	(1.19)	–	(1.19)
Restoration and abandonment cash costs	**(0.34)**	**0.34**	**–**	(0.52)	0.52	–
Depletion, depreciation, amortization and accretion	**–**	**(19.03)**	**(19.03)**	–	(18.19)	(18.19)
Future income tax recovery/(expense)	**–**	**3.40**	**3.40**	–	3.24	3.24
Gain on sale of marketable securities(3)	**–**	**–**	**–**	–	0.32	0.32
Total per BOE	**$ 21.54**	**$ (18.14)**	**$ 3.40**	$ 39.60	$ (12.74)	$ 26.86

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(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 nine months ended September 30, 2009 and 2008.

(CDN$ millions, except per unit amounts)	Three months ended September 30, 2009			Three months ended September 30, 2008		
	Canada	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Daily Production Volumes						
Natural gas (Mcf/day)	**310,212**	**13,672**	**323,884**	329,047	12,756	341,803
Crude oil (bbls/day)	**24,346**	**7,872**	**32,218**	25,484	8,635	34,119
Natural gas liquids (bbls/day)	**3,912**	**–**	**3,912**	4,557	–	4,557
Total Daily Sales (BOE/day)	**79,960**	**10,151**	**90,111**	84,833	10,761	95,644
Pricing[1]						
Natural gas (per Mcf)	**$ 2.88**	**$ 4.55**	**$ 2.95**	$ 8.17	$ 10.39	$ 8.25
Crude oil (per bbl)	**64.77**	**65.47**	**64.94**	110.10	112.02	110.63
Natural gas liquids (per bbl)	**32.59**	**–**	**32.59**	81.20	–	81.20
Capital Expenditures						
Development capital and office	**$ 38.5**	**$ 7.9**	**$ 46.4**	$ 146.7	$ 18.9	$ 165.6
Acquisitions of oil and gas properties	**2.3**	**190.2**	**192.5**	4.5	0.1	4.6
Dispositions of oil and gas properties	**(0.6)**	**–**	**(0.6)**	(502.6)	0.1	(502.5)
Revenues						
Oil and gas sales[1]	**$ 238.9**	**$ 53.2**	**$ 292.1**	$ 546.5	$ 101.3	$ 647.8
Royalties[2]	**(33.9)**	**(12.2)**	**(46.1)**	(98.8)	(21.8)	(120.6)
Commodity derivative instruments gain/(loss)	**(2.0)**	**–**	**(2.0)**	220.7	–	220.7
Expenses						
Operating	**$ 80.4**	**$ 3.1**	**$ 83.5**	$ 85.1	$ 4.7	$ 89.8
General and administrative	**18.8**	**1.2**	**20.0**	13.6	1.3	14.9
Depletion, depreciation, amortization and accretion	**138.0**	**19.8**	**157.8**	139.2	22.0	161.2
Current income taxes (recovery)/expense	**–**	**2.9**	**2.9**	(9.0)	14.2	5.2

(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)	Nine months ended September 30, 2009			Nine months ended September 30, 2008		
	Canada	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Daily Production Volumes						
Natural gas (Mcf/day)	**319,927**	**13,679**	**333,606**	323,819	12,509	336,328
Crude oil (bbls/day)	**24,979**	**8,475**	**33,454**	24,955	9,340	34,295
Natural gas liquids (bbls/day)	**4,129**	**–**	**4,129**	4,660	–	4,660
Total Daily Sales (BOE/day)	**82,429**	**10,755**	**93,184**	83,585	11,425	95,010
Pricing[1]						
Natural gas (per Mcf)	**$ 3.83**	**$ 4.74**	**$ 3.86**	$ 8.53	$ 10.41	$ 8.60
Crude oil (per bbl)	**55.81**	**54.85**	**55.57**	103.73	106.83	103.85
Natural gas liquids (per bbl)	**36.21**	**–**	**36.21**	77.21	–	77.21
Capital Expenditures						
Development capital and office	**$ 159.3**	**$ 25.0**	**$ 184.3**	$ 331.5	$ 52.0	$ 383.5
Acquisitions of oil and gas properties	**32.2**	**190.7**	**222.9**	13.9	–	13.9
Dispositions of oil and gas properties	**(2.3)**	**–**	**(2.3)**	(504.8)	0.1	(504.7)
Revenues						
Oil and gas sales[1]	**$ 754.9**	**$ 144.6**	**$ 899.5**	$ 1,576.8	$ 309.1	$ 1,885.9
Royalties[2]	**(122.4)**	**(32.7)**	**(155.1)**	(286.2)	(66.3)	(352.5)
Commodity derivative instruments gain/(loss)	**49.3**	**–**	**49.3**	(94.7)	–	(94.7)
Expenses						
Operating	**$ 242.6**	**$ 10.4**	**$ 253.0**	$ 234.5	$ 13.3	$ 247.8
General and administrative	**55.6**	**4.7**	**60.3**	44.7	4.0	48.7
Depletion, depreciation, amortization and accretion	**418.4**	**65.8**	**484.2**	407.2	66.3	473.5
Current income taxes (recovery)/expense	**–**	**5.5**	**5.5**	(16.9)	47.9	31.0

(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 and into 2009 with the sharp decline in commodity prices. During the third quarter of 2009 crude oil prices have continued to recover from levels earlier in the year; however, this has largely been offset by natural gas prices which have continued to decline since the start of the year. Our reduced production levels in 2009 have also put downward pressure on oil and gas sales.

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	Net Income/(Loss) per trust unit: Diluted
2009				
Third quarter	**$ 292.1**	**$ 38.2**	**$ 0.23**	**$ 0.23**
Second quarter	**306.2**	**(3.6)**	**(0.02)**	**(0.02)**
First quarter	**301.2**	**51.8**	**0.31**	**0.31**
Total	**$ 899.5**	**$ 86.4**	**$ 0.52**	**$ 0.52**
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

The capital markets have continued to improve since March of 2009. On June 18, 2009 we successfully closed a private placement of senior unsecured notes that raised gross proceeds of approximately $338.7 million. The proceeds were used to pay down bank indebtedness giving us additional financial flexibility to pursue acquisitions. On September 9, 2009 we closed an equity offering raising gross proceeds of approximately $225.3 million. The majority of the proceeds were used to fund the cash portion of our Marcellus acquisition and the remainder to decrease bank indebtedness.

The recent volatility of commodity 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. We expect to renew our credit facility in 2010 prior to its expiry. At September 30, 2009 the entire facility is undrawn and we are in compliance with all covenants under the 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 September 30, 2009, we had $43.5 million in mark-to-market assets offset by $59.8 million of mark-to-market liabilities resulting in a net liability position of $16.3 million.

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.

We have maintained our monthly distribution rate of $0.18 per unit 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.

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 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 third quarter of 2009, cash distributions of $93.5 million were funded entirely through cash flow of $207.2 million. For the nine months ended September 30, 2009, our cash distributions were $272.7 million and were funded entirely through cash flow of $587.2 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 45% and 46% for the three and nine months ended September 30, 2009 respectively, compared to 59% and 62% for the same periods in 2008. Our adjusted payout ratio, which is calculated as cash distributions plus development capital and office expenditures divided by cash flow, was 68% for the third quarter and 78% for the nine months ended September 30, 2009 compared to 102% and 100% respectively for the same periods in 2008. The decrease in our payout ratio and adjusted payout ratio is due to the reduction in our monthly cash distributions and capital spending along with changes in our working capital balances that impact cash flow. See "Non-GAAP Measures" above. We expect to support our distributions and capital expenditures with our cash flow in the final quarter of 2009 however, we may fund acquisitions with 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 September 30, 2009.

For the three months ended September 30, 2009, our cash distributions exceeded our net income by $55.3 where as in 2008 our net income exceeded our cash distributions by $241.4 million. For the nine months ended September 30, 2009 our cash distributions exceeded our net income by $186.2 million where as in 2008 our net income exceeded our cash distributions by $80.3 million. Non-cash items such as changes in the fair value of our derivative instruments and future income taxes cause net income to fluctuate between periods but do not reduce or increase our cash flow. Future income taxes can fluctuate from period to period as a result of changes in tax rates as well as changes in interest, royalties and dividends from our operating subsidiaries paid to the Fund. In addition, we believe that other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical 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 September 30, 2009	Nine months ended September 30, 2009	Year ended December 31, 2008	Year ended December 31, 2007
Cash flow from operating activities	**$ 207.2**	**$ 587.2**	$ 1,262.8	$ 868.5
Cash distributions	**93.5**	**272.6**	786.1	646.8
Excess of cash flow over cash distributions	**$ 113.7**	**$ 314.6**	$ 476.7	$ 221.7
Net income	**$ 38.2**	**$ 86.4**	$ 888.9	$ 339.7
(Shortfall)/excess of net income over cash distributions	**(55.3)**	**(186.2)**	102.8	(307.1)
Cash distributions per weighted average trust unit	**$ 0.55**	**$ 1.63**	$ 4.90	$ 5.07
Payout ratio(1)	**45%**	**46%**	62%	74%

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

Long-Term Debt

In the second quarter of 2009, we closed a private offering of senior unsecured notes that raised gross proceeds of approximately $338.7 million. The notes 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 series of new notes along with the terms and rates are summarized in the table below.

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

Long-term debt at September 30, 2009 was $571.8 million, a decrease of $92.5 million from $664.3 million at December 31, 2008. Long-term debt at September 30, 2009 was comprised of $571.8 million of senior unsecured notes. Our credit facility was undrawn at September 30, 2009 compared to a drawn balance of $380.9 million at December 31, 2008. This decrease in our bank indebtedness is primarily due to the proceeds from our June 2009 offering of senior unsecured notes and a portion of the proceeds from our September 2009 equity offering being applied against bank indebtedness. As well, we have supported our distributions and capital expenditures with our cash flows throughout the year in order to preserve our balance sheet strength.

Our working capital at September 30, 2009, excluding cash, current deferred financial assets and credits and future income taxes, increased by $31.8 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	September 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)	**28.9 x**	46.5 x
Long-term debt to long-term debt plus equity	**12%**	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 September 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 continue to have adequate liquidity under our bank credit facility and from cash flow to fund planned development capital spending and working capital requirements for the remainder of 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

On September 9, 2009, in conjunction with the Marcellus property acquisition, Enerplus completed an equity offering of 10,406,000 trust units at a price of $21.65 per unit for gross proceeds of approximately $225.3 million ($213.5 net of issuance costs).

We had 176,741,000 trust units outstanding at September 30, 2009 compared to 165,197,000 trust units at September 30, 2008 and 165,590,000 trust units outstanding at December 31, 2008. The balance at September 30, 2009 includes 6,557,000 exchangeable limited partnership units which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (2,787,000 trust units). During the third quarter of 2009, a total of 97,000 partnership units were converted into 41,000 trust units.

During the three months ended September 30, 2009, a total of 313,000 trust units (2008 – 488,000) 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 $6.9 million (2008 – $19.3 million) of additional equity to the Fund. For the nine months ended September 30, 2009, $16.8 million of additional equity (2008 – $60.0 million) and 745,000 trust units (2008 – 1,488,000) were issued pursuant to the DRIP and the trust unit rights incentive plan. For further details see Note 8.

The weighted average basic number of trust units outstanding for the nine months ended September 30, 2009 was 166,724,000 (2008 – 158,980,000). At November 4, 2009, we had 176,834,000 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 October 2009, we estimated our non-Canadian ownership to be 67%.

CHANGE IN AND APPOINTMENT OF 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 in Montana, North Dakota, Wyoming and Utah.

On October 15, 2009, we appointed Haas Petroleum Engineering Services, Inc. to evaluate our reserves and contingent resources associated with our Marcellus shale gas property.

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on July 1, 2009 and ending on September 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 we continue to analyze and identify our accounting policy choices and our assessment of the impact on information systems and business processes. We continue to provide training to business groups impacted and have communicated general IFRS information on a company-wide basis.

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 on or after January 1, 2010. Enerplus intends to use this election on adoption of IFRS.

The transition from 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 the Fund and its subsidiaries; 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 drilling plans, shut-in production 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, including the potential future renewal of our credit facility; 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; interest rates and expense; royalty rates and credits and their impact on the Fund's operations and results; future growth including development, exploration, and acquisition and development activities and related expenditures; and potential dispositions of oil and gas assets,. 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. The resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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. The primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Marcellus and Bakken properties as "reserves" consist of: additional delineation drilling to establish economic productivity in the development areas, limitations to development based on adverse topography or other surface restrictions (primarily Marcellus), the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the lands, and access to confidential information of other operators in the area. Significant negative factors related to the estimate include: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, ongoing litigation related to minimum royalties payable to freehold landowners, and other issues related to oil and gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the acquired interests in the Marcellus and Bakken properties, including commodity price fluctuations, project costs, Enerplus' ability to make the necessary capital expenditures to develop the properties, reliance on Enerplus' industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described under "Risk Factors" in our annual information form for the year ended December 31, 2008, a copy of which is available on our SEDAR profile at www.sedar.com and on our website at www.enerplus.com, and which forms part of our annual report on Form 40-F filed with the U.S. Securities and Exchange Commission at www.sec.gov.

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

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

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

Consolidated Balance Sheets

(CDN$ thousands) (Unaudited)	September 30, 2009	December 31, 2008
Assets		
Current assets		
Cash	**$ 10,564**	$ 6,922
Accounts receivable	**103,466**	163,152
Deferred financial assets (Note 9)	**41,148**	121,281
Other current	**7,838**	3,783
	163,016	295,138
Property, plant and equipment (Note 2)	**5,092,925**	5,246,998
Goodwill	**611,261**	634,023
Deferred financial assets (Note 9)	**2,357**	6,857
Other assets (Note 9)	**47,116**	47,116
	5,753,659	5,934,994
	$ 5,916,675	$ 6,230,132
Liabilities		
Current liabilities		
Accounts payable	**$ 195,004**	$ 272,818
Distributions payable to unitholders	**31,813**	41,397
Future income taxes	**6,046**	30,198
Deferred financial credits (Note 9)	**14,363**	–
	247,226	344,413
Long-term debt (Note 5)	**571,782**	664,343
Deferred financial credits (Note 9)	**45,419**	26,392
Future income taxes	**562,148**	648,821
Asset retirement obligations (Note 4)	**211,965**	207,420
	1,391,314	1,546,976
Equity		
Unitholders' capital (Note 8)	**5,706,608**	5,471,336
Accumulated deficit	**(1,367,451)**	(1,181,199)
Accumulated other comprehensive income	**(61,022)**	48,606
	(1,428,473)	(1,132,593)
	4,278,135	4,338,743
	$ 5,916,675	$ 6,230,132

Consolidated Statements of Accumulated Deficit

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Accumulated income, beginning of period	**$ 3,224,036**	$ 2,520,551	**$ 3,175,819**	$ 2,286,927
Net income	**38,182**	465,773	**86,399**	699,397
Accumulated income, end of period	**$ 3,262,218**	$ 2,986,324	**$ 3,262,218**	$ 2,986,324
Accumulated cash distributions, beginning of period	**$ (4,536,165)**	$ (3,965,584)	**$ (4,357,018)**	$ (3,570,880)
Cash distributions	**(93,504)**	(224,417)	**(272,651)**	(619,121)
Accumulated cash distributions, end of period	**$ (4,629,669)**	$ (4,190,001)	**$ (4,629,669)**	$ (4,190,001)
Accumulated deficit, end of period	**$ (1,367,451)**	$ (1,203,677)	**$ (1,367,451)**	$ (1,203,677)

Consolidated Statements of Accumulated Other Comprehensive Income

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Balance, beginning of period	**$ 6,198**	$ (93,128)	**$ 48,606**	$ (108,727)
Other comprehensive income/(loss)	**(67,220)**	28,075	**(109,628)**	43,674
Balance, end of period	**$ (61,022)**	$ (65,053)	**$ (61,022)**	$ (65,053)

Consolidated Statements of Income

(CDN$ thousands except per trust unit amounts) (Unaudited)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Revenues				
Oil and gas sales	**$ 298,982**	$ 654,592	**$ 919,034**	$ 1,906,131
Royalties	**(46,084)**	(120,635)	**(155,131)**	(352,511)
Commodity derivative instruments *(Note 9)*	**(1,959)**	220,652	**49,350**	(94,742)
Other income	**129**	295	**304**	15,822
	251,068	754,904	**813,557**	1,474,700
Expenses				
Operating	**83,446**	89,801	**252,965**	247,791
General and administrative	**20,019**	14,935	**60,336**	48,699
Transportation	**6,886**	6,757	**19,543**	20,201
Interest *(Note 6)*	**4,984**	7,238	**38,556**	33,539
Foreign exchange *(Note 7)*	**(35,638)**	2,655	**(47,396)**	4,931
Depletion, depreciation, amortization and accretion	**157,872**	161,178	**484,230**	473,468
	237,569	282,564	**808,234**	828,629
Income before taxes	**13,499**	472,340	**5,323**	646,071
Current taxes	**2,882**	5,211	**5,498**	30,963
Future income tax (recovery)/expense	**(27,565)**	1,356	**(86,574)**	(84,289)
Net Income	**$ 38,182**	$ 465,773	**$ 86,399**	$ 699,397
Net income per trust unit				
Basic	**$ 0.23**	$ 2.82	**$ 0.52**	$ 4.40
Diluted	**$ 0.23**	$ 2.82	**$ 0.52**	$ 4.40
Weighted average number of trust units outstanding (thousands)[1]				
Basic	**168,521**	164,908	**166,724**	158,980
Diluted	**168,817**	165,001	**166,919**	159,089

(1) Includes the exchangeable limited partnership units.

Consolidated Statements of Comprehensive Income

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Net income	**$ 38,182**	$ 465,773	**$ 86,399**	$ 699,397
Other comprehensive income/(loss), net of tax:				
Unrealized gain on marketable securities	**–**	–	**–**	2,578
Realized gains 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	**(67,220)**	28,075	**(109,628)**	47,180
Other comprehensive income/(loss)	**(67,220)**	28,075	**(109,628)**	43,674
Comprehensive income/(loss)	**$ (29,038)**	$ 493,848	**$ (23,229)**	$ 743,071

Consolidated Statements of Cash Flows

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Operating Activities				
Net income	**$ 38,182**	$ 465,773	**$ 86,399**	$ 699,397
Non-cash items add / (deduct):				
Depletion, depreciation, amortization and accretion	**157,872**	161,178	**484,230**	473,468
Change in fair value of derivative instruments *(Note 9)*	**50,634**	(292,419)	**118,023**	(57,160)
Unit based compensation *(Note 8)*	**1,682**	1,783	**4,938**	5,363
Foreign exchange on translation of senior notes *(Note 7)*	**(44,796)**	9,570	**(49,829)**	16,645
Future income tax	**(27,565)**	1,356	**(86,574)**	(84,289)
Amortization of senior notes premium	**(185)**	(164)	**(579)**	(474)
Reclassification adjustments from AOCI to net income	**–**	–	**–**	92
Gain on sale of marketable securities	**–**	–	**–**	(8,263)
Asset retirement obligations settled *(Note 4)*	**(2,550)**	(4,734)	**(8,732)**	(13,501)
	173,274	342,343	**547,876**	1,031,278
Decrease/(Increase) in non-cash operating working capital	**33,937**	41,230	**39,331**	(27,032)
Cash flow from operating activities	**207,211**	383,573	**587,207**	1,004,246
Financing Activities				
Issue of trust units, net of issue costs *(Note 8)*	**220,421**	19,255	**230,334**	59,951
Cash distributions to unitholders	**(93,504)**	(224,417)	**(272,651)**	(619,121)
Decrease in bank credit facilities	**(96,948)**	(514,893)	**(380,888)**	(550,947)
Issuance of senior unsecured notes	**–**	–	**338,735**	–
Decrease/(Increase) in non-cash financing working capital	**1,930**	8,463	**(9,584)**	23,121
Cash flow from financing activities	**31,899**	(711,592)	**(94,054)**	(1,086,996)
Investing Activities				
Capital expenditures	**(46,404)**	(165,647)	**(184,291)**	(383,531)
Property acquisitions	**(192,484)**	(4,574)	**(222,877)**	(13,863)
Property dispositions	**519**	502,489	**2,255**	504,697
Proceeds on sale of marketable securities	**–**	–	**–**	18,320
Purchase of equity investments	**–**	(7,150)	**–**	(7,150)
Decrease/(Increase) in non-cash financing working capital	**11,120**	3,378	**(81,914)**	(37,258)
Cash flow from investing activities	**(227,249)**	328,496	**(486,827)**	81,215
Effect of exchange rate changes on cash	**(1,472)**	(640)	**(2,684)**	393
Change in cash	**10,389**	(163)	**3,642**	(1,142)
Cash, beginning of period	**175**	723	**6,922**	1,702
Cash, end of period	**$ 10,564**	$ 560	**$ 10,564**	$ 560
Supplementary Cash Flow Information				
Cash income taxes (received)/paid	**$ (5,054)**	$ 28,320	**$ (27,844)**	$ 62,078
Cash interest paid	**$ 1,846**	$ 5,017	**$ 11,745**	$ 31,315

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 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)	September 30, 2009	December 31, 2008
Property, plant and equipment	**$ 8,766,028**	$ 8,497,206
Accumulated depletion, depreciation and accretion	**(3,673,103)**	(3,250,208)
Net property, plant and equipment	**$ 5,092,925**	$ 5,246,998

Capitalized development general and administrative ("G&A") expense of $17,391,000 (2008 – $16,870,000) is included in PP&E for the nine months ended September 30, 2009. Excluded from PP&E for the depletion and depreciation calculation is $272,959,000 (December 31, 2008 – $257,608,000) related to oil sands projects which have not yet commenced commercial production and $189,500,000 related to our U.S. undeveloped land.

3. PROPERTY ACQUISITION

On September 1, 2009 Enerplus acquired a non-operated interest in the Marcellus Shale natural gas formation. Consideration of $181,342,000 (US$164,400,000) in cash was paid upon closing. In addition, up to $272,033,000 (US$246,600,000) may be paid as a carry of 50% of our partners' future drilling and completion costs. The carry spending will be recorded as a property acquisition as it is spent over time.

4. ASSET RETIREMENT OBLIGATIONS

Following is a reconciliation of the asset retirement obligations:

($ thousands)	Nine months ended September 30, 2009	Year ended December 31, 2008
Asset retirement obligations, beginning of period	**$ 207,420**	$ 165,719
Corporate acquisition	**–**	36,784
Changes in estimates	**3,074**	4,087
Property acquisition and development activity	**1,009**	7,394
Dispositions	**(414)**	(110)
Asset retirement obligations settled	**(8,732)**	(18,308)
Accretion expense	**9,608**	11,854
Asset retirement obligations, end of period	**$ 211,965**	$ 207,420

5. LONG-TERM DEBT

($ thousands)	September 30, 2009	December 31, 2008
Bank credit facilities (a)	**$ –**	$ 380,888
Senior notes (b)		
CDN$40 million (Issued June 18, 2009)	**40,000**	–
US$40 million (Issued June 18, 2009)	**42,888**	–
US$225 million (Issued June 18, 2009)	**241,245**	–
US$54 million (Issued October 1, 2003)	**57,899**	66,128
US$175 million (Issued June 19, 2002)*	**189,750**	217,327
Total long-term debt	**$ 571,782**	$ 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 nine months ended September 30, 2009 was 1.10% (September 30, 2008 – 3.8%).

(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	CDN$40,000	6.37%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$40,000	6.82%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$225,000	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in 5 equal installments beginning June 18, 2017
October 1, 2003	US$54,000	5.46%	April 1 and October 1	October 1, 2015	Principal payments required in 5 equal 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%.

6. INTEREST EXPENSE

($ thousands)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Realized				
Interest on long-term debt	**$ 10,288**	$ 8,813	**$ 21,055**	$ 35,076
Unrealized				
(Gain)/loss on cross currency interest rate swap	**(7,001)**	(2,426)	**18,867**	(3,551)
(Gain)/loss on interest rate swaps	**1,882**	1,015	**(787)**	2,488
Amortization of the premium on senior unsecured notes	**(185)**	(164)	**(579)**	(474)
Interest expense	**$ 4,984**	$ 7,238	**$ 38,556**	$ 33,539

7. FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Realized				
Foreign exchange (gain)/loss	**$ (3,499)**	$ 4,349	**$ (15,125)**	$ 4,367
Unrealized				
Foreign exchange (gain)/loss on translation of U.S. dollar denominated senior notes	**(44,796)**	9,570	**(49,829)**	16,645
Foreign exchange (gain)/loss on cross currency interest rate swap	**10,733**	(9,125)	**13,058**	(13,616)
Foreign exchange (gain)/loss on foreign exchange swaps	**1,924**	(2,139)	**4,500**	(2,465)
Foreign exchange (gain)/loss	**$ (35,638)**	$ 2,655	**$ (47,396)**	$ 4,931

8. UNITHOLDERS' CAPITAL

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

Unitholders' capital ($ thousands)	Nine months ended September 30, 2009	Year ended December 31, 2008
Trust units	**$ 5,570,541**	$ 5,328,629
Exchangeable limited partnership units	**111,529**	123,107
Contributed surplus	**24,538**	19,600
Balance, end of period	**$ 5,706,608**	$ 5,471,336

(a) Trust Units

On September 9, 2009, in conjunction with the Marcellus property acquisition, Enerplus completed an equity offering of 10,406,250 trust units at a price of $21.65 per unit for gross proceeds of approximately $225,300,000 ($213,531,000 net of issuance costs).

Authorized: Unlimited number of trust units

(thousands)	Nine months ended September 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 public offerings	**10,406**	**213,531**	–	–
Pursuant to rights incentive plan	**–**	**–**	210	6,755
Cancelled trust units	**–**	**–**	(116)	(3,794)
Exchangeable limited partnership units exchanged	**289**	**11,578**	786	31,444
Trust unit rights incentive plan (non-cash) – exercised	**–**	**–**	–	3,642
DRIP*, net of redemptions	**745**	**16,803**	1,671	63,761
Issued for acquisition of corporate and property interests (non-cash)	**–**	**–**	30,150	1,206,593
	173,954	**$ 5,570,541**	162,514	$ 5,328,629
Equivalent exchangeable partnership units	**2,787**	**111,529**	3,076	123,107
Balance, end of period	**176,741**	**$ 5,682,070**	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 September 30, 2009, 681,000 exchangeable limited partnership units were converted into 289,000 trust units. As at September 30, 2009, the 6,557,000 outstanding exchangeable limited partnership units represent the equivalent of 2,787,000 trust units.

(thousands)	Nine months ended September 30, 2009		Year ended December 31, 2008	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**7,238**	**$ 123,107**	9,087	$ 154,551
Exchanged for trust units	**(681)**	**(11,578)**	(1,849)	(31,444)
Balance, end of period	**6,557**	**$ 111,529**	7,238	$ 123,107

(c) Contributed Surplus

Contributed surplus ($ thousands)	Nine months ended September 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	**4,938**	6,996
Cancelled trust units	**–**	3,794
Balance, end of period	**$ 24,538**	$ 19,600

(d) Trust Unit Rights Incentive Plan

As at September 30, 2009 a total of 5,719,000 rights were issued and outstanding pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $35.13 per right. This represents 3.2% of the total trust units outstanding of which 2,645,000 rights, with an average exercise price of $45.02, 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, second and third quarters of 2009 did not reduce the exercise price of the outstanding rights.

Non-cash compensation costs related to rights issued charged to general and administrative expenses for the three and nine months ended September 30, 2009 were $1,682,000 ($0.01 per unit) and $4,938,000 ($0.03 per unit) respectively. Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	Nine months ended September 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	**1,996**		**17.26**	1,403		42.00
Exercised	**–**		**–**	(210)		32.22
Forfeited and expired	**(278)**		**37.89**	(596)		44.94
End of period	**5,719**	**$**	**35.13**	4,001	$	45.05
Rights exercisable at end of period	**2,645**	**$**	**45.02**	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 Incentive Plan.

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

	Nine months ended September 30,	
(thousands)	2009	2008
Weighted average units	**166,724**	158,980
Dilutive impact of rights	**195**	109
Diluted trust units	**166,919**	159,089

(f) Performance Trust Unit Plan

In 2007 the Fund adopted a Performance Trust Unit ("PTU") plan for executives and employees. For the three and nine months ended September 30, 2009 the Fund recorded cash compensation costs of $1,792,000 (2008 – $1,240,000) and $5,481,000 (2008 – $3,540,000) respectively, under the plan which are included in general and administrative expenses.

At September 30, 2009 there were 389,248 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 nine months ended September 30, 2009 the Fund recorded cash compensation costs of $1,310,000 and $4,310,000 respectively, under the plan which are included in general and administrative expenses.

At September 30, 2009 there were 878,572 Restricted Trust Units outstanding.

9. 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 September 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 September 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 September 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 September 30, 2009 there were no amounts outstanding under the bank credit facility.

Senior Unsecured Notes

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

Principal Private Placement amount ($thousands)	**Amortized Cost**	**Reported CDN$ Amortized Cost**	**CDN$ Fair Value**
CDN$40,000	CDN$40,000	$ 40,000	**$ 39,825**
US$40,000	US$40,000	42,888	**43,041**
US$225,000	US$225,000	241,245	**243,658**
US$54,000	US$54,000	57,899	**55,943**
US$175,000	US$177,140	189,750	**191,950**
		$ 571,782	**$ 574,417**

(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 September 30, 2009 a current deferred financial asset of $41,148,000, a current deferred financial credit of

$14,363,000, a non-current deferred financial asset of $2,357,000 and a non-current deferred financial credit of $45,419,000 are recorded on the Consolidated Balance Sheet.

The deferred financial asset relating to crude oil instruments is $14,594,000 at September 30, 2009 including deferred premiums of $13,606,000. The deferred financial asset relating to natural gas instruments is $26,554,000 at September 30, 2009 including deferred premiums of $10,014,000.

The following table summarizes the fair value as at September 30, 2009 and change in fair value for the nine months ended September 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)	787[(1)]	(31,925)[(2)]	(4,500)[(3)]	(2,600)[(4)]	(82,047)[(5)]	2,262[(5)]	(118,023)
Deferred financial (credits)/assets, end of period	**$ (9,264)**	**$ (48,266)**	**$ 2,357**	**$ (2,252)**	**$ 14,594**	**$ 26,554**	**$ (16,277)**
Balance sheet classification:							
Current asset/(liability)	**$ (4,316)**	**$ (7,795)**	**$ –**	**$ (2,252)**	**$ 14,594**	**$ 26,554**	**$ 26,785**
Non-current asset/(liability)	**$ (4,948)**	**$ (40,471)**	**$ 2,357**	**$ –**	**$ –**	**$ –**	**$ (43,062)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (loss of $13,058) and interest expense (loss of $18,867).
(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 September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Gain/(loss) due to change in fair value	**$ (42,551)**	$ 280,687	**$ (79,785)**	$ 40,288
Net realized cash gains/(losses)	**40,592**	(60,035)	**129,135**	(135,030)
Commodity derivative instruments gain/(loss)	**$ (1,959)**	$ 220,652	**$ 49,350**	$ (94,742)

(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 November 4, 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						
October 1, 2009 – December 31, 2009						
Put	1,400	–	–	$ 122.00	–	–
Put	1,000	–	–	$ 120.00	–	–
Put	500	–	–	$ 116.00	–	–
Put Spread	1,000	–	–	$ 92.00	$ 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	2,500	$ 95.00	–	–	–	–
Purchased Call(1)	3,000	$ 90.00	–	–	–	–
Purchased Call(1)	500	$ 92.50	–	–	–	–
Swap	1,500	–	–	–	–	$ 78.45
Swap	1,000	–	–	–	–	$ 78.80
Swap(1)	1,000	–	–	–	–	$ 68.05
Swap(1)	500	–	–	–	–	$ 69.33
Swap(1)	500	–	–	–	–	$ 72.15
Swap(1)	500	–	–	–	–	$ 74.30
Swap(1)	500	–	–	–	–	$ 76.20
Swap(1)	500	–	–	–	–	$ 76.38
Swap(1)	500	–	–	–	–	$ 78.15
Swap(2)	1,000	–	–	–	–	$ 79.20
Swap(2)	500	–	–	–	–	$ 80.00
Put	2,500	–	–	–	$ 47.50	–
Put(1)	1,500	–	–	–	$ 47.50	–

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

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term						
October 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

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
October 1, 2009 – October 31, 2010						
Swap	23.7	–	–	–	–	$ 7.33
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	–	–	–
January 1, 2010 – December 31, 2010						
Put Spread(1)	4.7	–	–	$ 5.28	$ 3.96	–
Put Spread(1)	4.7	–	–	$ 5.44	$ 3.96	–
April 1, 2010 – December 31, 2010						
Put Spread(2)	9.5	–	–	$ 5.59	$ 3.96	–
2009 – 2010						
Physical	2.0	–	–	–	–	$ 2.67

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

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 September 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	**$ 30,396**	**$ (24,726)**
Natural gas derivative contracts	**$ 12,997**	**$ (12,212)**

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 November 4, 2009 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
October 1, 2009 – December 31, 2009	4.0	$ 74.50
October 1, 2009 – December 31, 2009	2.0	$ 64.00
October 1, 2009 – December 31, 2010	4.0	$ 77.50
October 1, 2009 – December 31, 2010	2.0	$ 68.75
January 1, 2010 – December 31, 2010(1)	3.0	$ 49.50
January 1, 2010 – December 31, 2010(1)	3.0	$ 52.25
January 1, 2010 – December 31, 2011	3.0	$ 66.00
January 1, 2011 – December 31, 2011(1)	3.0	$ 55.00
January 1, 2011 – December 31, 2011(1)	3.0	$ 57.25

(1) Electricity contracts entered into during the third 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 September 30, 2009, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in $CDN relative to $US	25% increase in $CDN relative to $US
Translation of US$40 million senior notes	$ (7,577)	$ 7,577
Translation of US$225 million senior notes	(42,622)	42,622
Translation of US$54 million senior notes	(10,229)	10,229
Translation of US$175 million senior notes	(33,556)	33,556
Total	$ (93,984)	$ 93,984

(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 effective variable rate debt outstanding at September 30, 2009 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $262,000.

10. COMMITMENTS AND CONTINGENCIES

As part of the Marcellus acquisition on September 1, 2009 the Fund has committed to pay 50% of the operator's future drilling and completion costs up to an aggregate amount of US$246,600,000. Our outstanding commitment balance at September 30, 2009 is approximately US$243,807,000. We expect the remainder of the commitment will be incurred over the next four years.

11. SUBSEQUENT EVENT

On October 16, 2009 the Fund completed the disposition of a non-operated property located in Western Canada for proceeds of approximately $101,000,000. On October 27, 2009 the Fund acquired additional land interests in North Dakota for approximately US$27,000,000.

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Calgary, Alberta

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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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President & Chief Executive Officer

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

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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

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
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New York Stock Exchange: ERF

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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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