enerPLUS

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2012

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2012	2011
Financial (000's)		
Funds Flow[1]	$ 162,706	$ 161,224
Cash Flow from Operating Activities	68,981	132,403
Dividends to Shareholders	105,995	96,686
Net Income/(Loss)	(33,821)	29,549
Debt Outstanding – net of cash	902,937	849,685
Capital Spending	317,066	174,444
Property and Land Acquisitions	33,020	48,218
Divestments	52,611	59,693
Dividends paid per share	0.54	0.54
Debt to Trailing 12 Month Funds Flow	1.6x	1.2x
Financial per Weighted Average Shares Outstanding		
Funds Flow[1]	$ 0.86	$ 0.90
Net Income/(Loss)	(0.18)	0.17
Weighted Average Number of Shares Outstanding	189,844	178,832
Selected Financial Results per BOE[2]		
Oil & Gas Sales[3]	$ 47.04	$ 46.92
Royalties	(9.26)	(8.62)
Commodity Derivative Instruments	(1.48)	0.44
Operating Costs	(9.81)	(8.86)
G&A and Equity Based Compensation	(3.09)	(3.28)
Interest and Other Expenses	(0.72)	(2.75)
Taxes	(0.10)	(0.12)
Funds Flow[1]	$ 22.58	$ 23.73

SELECTED OPERATING RESULTS	Three months ended March 31, 2012	2011
Average Daily Production		
Crude oil (bbls/day)	34,074	30,338
NGLs (bbls/day)	4,002	3,232
Natural gas (Mcf/day)	246,686	251,480
Total (BOE/day)	79,190	75,483
% Crude Oil & Natural Gas Liquids	48%	44%
Average Selling Price[3]		
Crude oil (per bbl)	$ 85.91	$ 77.69
NGLs (per bbl)	56.77	60.29
Natural gas (per Mcf)	2.27	3.91
USD/CDN exchange rate	1.00	1.02
Net Wells drilled	34	26

(1) See "Non-GAAP Measures" in the accompanying MD&A.
(2) Non-cash amounts have been excluded.
(3) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SHARE TRADING SUMMARY For the three months ended March 31, 2012	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 26.94	$ 26.54
Low	$ 22.19	$ 22.20
Close	$ 22.34	$ 22.42

* TSX and other Canadian trading data combined.
** NYSE and other U.S. trading data combined.

2012 CASH DIVIDENDS PER SHARE Payment Month	CDN$	US$
January	$ 0.18	$ 0.18
February	$ 0.18	$ 0.18
March	$ 0.18	$ 0.18
First Quarter Total	$ 0.54	$ 0.54

US$ dividends represent CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

PRESIDENT'S MESSAGE

I am pleased to report that our operating and financial results for the first quarter of 2012 were generally on track with our expectations. In addition, we advanced a number of strategic initiatives in order to preserve our financial flexibility during this period of weak natural gas prices.

Our production volumes increased during the first quarter by approximately 3% over the fourth quarter of 2011, averaging 79,190 BOE/day. We continued to see positive growth in our oil and natural gas liquids production which was up approximately 9% from the previous quarter primarily due to our successful drilling and completion activities in North Dakota. Total liquids production represented 48% of our total production mix compared to 45% in the previous quarter. We continue to expect our production volumes to grow throughout 2012 as we execute our capital spending plans. Overall, we anticipate production growth of 10% in 2012, averaging 83,000 BOE/day and to exit 2012 producing approximately 88,000 BOE/day.

We invested approximately $317 million in capital during the first quarter, higher than originally planned due to better than expected winter weather conditions that allowed us to accelerate our capital investment activities, particularly our delineation program in new plays in Alberta, British Columbia and on our operated leases in the Marcellus. In addition, we realized higher activity levels on our operated leases and more non-operated spending than anticipated in North Dakota. Approximately half of our spending was on our tight oil assets. We expect spending will moderate through the remainder of the year as the majority of our delineation activity is now complete and we have also reduced our rig count in North Dakota from four to three rigs. We also believe that inflation is stabilizing in the Fort Berthold region and costs appear to be in line with expectations across our other plays. We continue to expect total capital spending of $800 million for the year.

We generated approximately $163 million in funds flow ($0.86/share) in the first quarter, which was virtually unchanged from the previous quarter. Higher crude oil production helped mitigate widening oil price differentials and weakening natural gas prices (which were approximately 33% lower than the previous quarter). Operating costs and general and administrative costs (including equity based compensation) in the first quarter were in line with expectations at approximately $10.00/BOE and $3.51/BOE respectively.

We also took a number of steps to ensure our balance sheet remains strong. In February, we closed an equity offering that raised net proceeds of approximately $330 million. At quarter end, we had approximately $900 million in debt outstanding, net of cash, including approximately $450 million drawn on our $1 billion credit facility. Our debt to trailing 12 months funds flow ratio was 1.6x. We also expect to close a private placement of long-term, senior unsecured notes for $405 million on May 15, 2012, using the proceeds to reduce the amount drawn on our bank credit facility. The notes will have terms ranging from seven to twelve years with interest rates from 4.34% to 4.4%.

On May 11, 2012, we received approval from our shareholders at our Annual & Special Meeting to implement a Stock Dividend Program ("SDP") available to all shareholders, replacing our current Dividend Reinvestment Plan ("DRIP") which is available only to Canadian shareholders. In comparison with the DRIP, the SDP offers certain tax advantages to all investors holding their Enerplus stock in taxable accounts and we expect this program will provide additional retention of funds to support our capital spending plans in the future.

With weak natural gas prices, our oil production is providing the majority of our revenues. We have hedges in place on approximately 62% of our expected 2012 net oil production at a WTI reference price of US$96/bbl and we continue to actively hedge our 2013 crude oil production with approximately 42% of our expected net crude oil production hedged at WTI price of US$103/bbl. Although we have no financial hedges in place on our gas production, we do have physical fixed price natural gas contracts on approximately 65 MMcf/day or 27% of our expected net natural gas production after royalties for the period April through October 2012 at an average price of CDN$2.17/Mcf. At this time, we have no plans to shut-in or curtail any of our operated natural gas production and we will continue to monitor both prices and activities in our non-operated natural gas properties.

OPERATIONAL HIGHLIGHTS

Production and Capital Spending – for the three months ended March 31, 2012

Play Type	Average Daily Production	Capital Spending ($ millions)
Tight Oil (BOE/day)	15,620	$ 162,094
Crude Oil Waterflood (BOE/day)	16,101	42,785
Conventional Oil (BOE/day)	4,794	11,939
Total Crude Oil (BOE/day)	36,515	$ 216,818
Marcellus Shale Gas (Mcfe/day)	28,119	61,257
Other Natural Gas (Mcfe/day)	227,931	38,991
Total Gas (Mcfe/day)	256,050	$ 100,248
Company Total (BOE/day)	79,190	$ 317,066

Net Drilling Activity – for the three months ended March 31, 2012

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Tight Oil	12.0	1.1	13.1	10.4	5.3	–
Crude Oil Waterfloods	11.8	–	11.8	8.0	7.6	0.1
Conventional Oil	3.2	–	3.2	2.2	2.5	–
Total Oil	**27.0**	**1.1**	**28.1**	**20.6**	**15.4**	**0.1**
Marcellus Shale Gas	3.7	–	3.7	3.7	2.3	–
Other Natural Gas	2.0	–	2.0	2.0	0.2	–
Total Gas	**5.7**	**–**	**5.7**	**5.7**	**2.5**	**–**
Company Total	**32.7**	**1.1**	**33.8**	**26.3**	**17.9**	**0.1**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment.
** Total wells brought on-stream during the quarter regardless of when they were drilled.

Tight Oil – Fort Berthold, ND

Our Fort Berthold light oil assets in North Dakota continued to attract a significant portion of our capital investment during the first quarter of 2012. We invested approximately $138 million drilling nine net operated wells (six long horizontal wells and three short horizontal wells), completed five net wells and brought three net wells (two long and one short horizontal well) on-stream. Although early, we believe these new wells are performing in line with our type curve expectations. We also drilled our second salt water disposal well during the quarter and expect these two wells will be sufficient to handle all of the disposal water associated with our Fort Berthold leases. Production in this area increased by 28% from the fourth quarter of 2011 to average approximately 8,700 BOE/day during the first quarter. Capital spending was higher than anticipated on both our operated leases and by our non-operated partners in the area. We expect this to moderate through the remainder of the year as we are dropping our rig count to three rigs from four as was originally planned. We continue to work to reduce our well costs through changes in completion and frac design and we are also seeing evidence of costs beginning to stabilize in the region.

Crude Oil Waterfloods

Throughout the first quarter, we invested approximately $43 million in our oil waterflood properties drilling 11.8 net wells with 7.6 net wells brought on-stream. Our activities were focused largely in our Ratcliffe assets in southern Saskatchewan and in our Pembina Cardium and Medicine Hat Glauconitic “C” oil waterfloods in Alberta. We expanded our Enhanced Oil Recovery (“EOR”) project at Giltedge during the quarter adding polymer to another three injection wells in January. We continue to expect production to increase by two to three times in the project area over the next two years due to the polymer injection and remain on track to make a decision on full-field expansion in late 2012 or early 2013. We continued to prepare for our second polymer flood project at Medicine Hat and anticipate polymer injection to begin late in the second quarter with response expected 12 months after initial injection.

Deep Gas

Our Deep Gas drilling activities during the first quarter were primarily focused in the Stacked Mannville play at Ansell where we drilled, completed and tested a horizontal Wilrich well and invested in infrastructure to tie-in the field to existing pipelines. The well tested with a peak rate of over 30 MMcf/day with minimal associated liquids at a pressure of 19 Mpa after 90 hours with 6,900 barrels of water recovered. The well was choked back due to constraints at the facility, however we expect tie-in to occur during the second quarter which will allow us to further evaluate the resource potential in this area. This is the largest gas well ever drilled by Enerplus and is the second well drilled at Ansell following our Wilrich test in late 2011 that had peak rate production of 13 MMcf/day at 14 Mpa after 165 hours with over 15,000 barrels of water recovered. This well was also choked back during the test due to capacity constraints at the facility, however produced 10 MMcf/day during its first 30 days on production. We remain very encouraged by these early tests and by the potential in this region.

Marcellus

We continued to invest in the Marcellus during the first quarter, primarily to retain leases on our non-operated acreage and to advance our work on our operated leases. With the prolonged weakness in natural gas prices, the pace of activity in the region is slowing. Much of this slowdown was reflected in our 2012 budget, however we may see a further reduction in activity and costs in the latter half of the year. In total we invested $61 million during the quarter with $37 million spent on non-operated projects where we participated in drilling 2.7 net wells and brought 2.3 net wells on-stream. On our operated leases, we invested approximately $24 million drilling one net well, completing another and advancing our facilities/seismic projects that we expect will position us to respond quickly to a gas price recovery. The majority of our operated program will be completed by mid-year. Total Marcellus production averaged 28 MMcf/day, up from 24 MMcf/day during the fourth quarter of 2011.

Outlook

Our production continues to grow and we remain on track to meet our operating guidance for the year. We have a portfolio of mature oil and gas properties combined with early stage growth assets that we believe will support our strategy of providing both growth and income to investors.

We have taken a number of steps to maintain our financial flexibility in this weak natural gas price environment. In addition, we have plans to monetize between $250 million and $500 million in assets over the next 18 months which may include selling a portion of our portfolio of equity investments along with the sale or joint venture of a portion of our undeveloped acreage. We have retained an advisor with respect to our undeveloped acreage to examine alternatives for our operated Marcellus, Montney and Duvernay plays. We expect these monetization events would have minimal impact on our current production, reserves or cash flow.

Should current commodity prices continue and/or we do not make significant progress on the aforementioned monetization plans, we are prepared to reduce our capital spending, moderate our growth expectations and/or reduce our dividend to ensure we maintain a strong financial position. I am optimistic about the prospects for our company in the year ahead and look forward to advancing our plans for the rest of the year in spite of the challenges of weak natural gas prices.

I am also pleased to announce that Mr. Edward McLaughlin has been promoted to the position of President of Enerplus USA. Mr. McLaughlin will oversee the day-to-day activities of our Bakken oil play in North Dakota and Montana as well as our Marcellus natural gas assets in the northeastern U.S. and will continue to be based in our Denver office. Mr. McLaughlin has more than 30 years of oil and gas experience in the U.S. and has held numerous senior positions within the industry including President of the U.S. subsidiary of a major oil and gas company. He will report to Mr. Ray Daniels, Senior Vice-President of Operations for Enerplus.

It is with sadness that I advise that Mr. Donald West, a member of our Board of Directors since 2003, passed away recently. Don was a valued member of our Board and recognized for his knowledge and experience within the oil and gas industry. He will be greatly missed. I would also like to thank Messrs. Harry Wheeler, Clayton Woitas and Robert Zorich, who have retired from our Board, for their many contributions to Enerplus over the years and wish them well in their future endeavours.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

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

The following discussion and analysis of financial results is dated May 10, 2012 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the years ended December 31, 2011 and 2010; and
- the unaudited interim consolidated financial statements of Enerplus as at and for the three months ended March 31, 2012 and 2011.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and may not be comparable to information produced by other entities.

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 further information.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Funds flow" is a term used to evaluate operating performance and assess leverage. Enerplus considers funds flow an important measure of its ability to generate funds necessary to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow is calculated based on cash flow from operating activities before changes in non-cash operating working capital and decommissioning expenditures. Funds flow as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow from operating activities to funds flow:

	Three months ended March 31,	
($ thousands)	**2012**	**2011**
Cash flow from operating activities	$ 68,981	$ 132,403
Decommissioning expenditures	7,298	4,210
Changes in non-cash operating working capital	86,427	24,611
Funds Flow	$ 162,706	$ 161,224

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders plus capital spending (including office capital) divided by funds flow.

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

OVERVIEW

Our first quarter production was in line with expectations averaging 79,190 BOE/day, with a crude oil and liquids weighting of approximately 48%. Capital spending totaled $317.1 million which was higher than expected as mild weather allowed us to accelerate our capital investment activities which included approximately $60 million of delineation spending. We also had higher activity levels on our operated leases and more non-operated spending than anticipated in North Dakota. We expect that our pace of spending will slow over the remainder of the year and we are continuing to manage toward an annual capital budget of $800 million. Operating costs for the quarter were on target at $10.00/BOE.

Low natural gas prices continue to be a challenge. Funds flow for the quarter totaled $162.7 million, up marginally from the previous quarter as lower natural gas prices offset higher crude oil production levels. Net income was impacted by non-cash impairments of $86.9 million on our Canadian natural gas assets due to the decrease in forecast natural gas prices from year end.

With our current capital spending plans and the low natural gas price environment we expect our capital program and dividends to exceed our funds flow for the year. We have plans to manage our balance sheet through this period and have made notable progress during the quarter. In February we successfully closed an equity offering for 14,708,500 common shares, raising net proceeds of approximately $330.6 million. In addition, on May 15, 2012 we expect to close a $405 million private placement of senior unsecured notes with interest rates ranging from 4.34% to 4.4%. We continue to maintain a conservative balance sheet with a trailing twelve month debt to funds flow ratio of 1.6x at March 31, 2012.

We are maintaining all of our previous guidance targets for 2012.

RESULTS OF OPERATIONS

Production

Production in the first quarter of 2012 was in line with our expectations averaging 79,190 BOE/day. In comparison, we had average production of 77,221 BOE/day in the fourth quarter of 2011 and we exited 2011 at 82,000 BOE/day. We anticipated a modest decrease in the first quarter from our 2011 exit production given the high rate of decline for wells that were brought on stream late in December in the Fort Berthold area. Compared to the first quarter of 2011, production increased 5%, or 3,707 BOE/day.

Average daily production volumes for the three months ended March 31, 2012 and 2011 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2012**	**2011**	**% Change**
Crude oil (bbls/day)	34,074	30,338	12%
Natural gas liquids (bbls/day)	4,002	3,232	24%
Natural gas (Mcf/day)	246,686	251,480	(2)%
Total daily sales (BOE/day)	79,190	75,483	5%

During the first quarter of 2012 our weighting of crude oil and liquids production increased to 48% from 44% in 2011. As we bring on additional production from our Fort Berthold crude oil property and other waterflood projects we expect our crude oil and liquids weighting to increase throughout the year and exit 2012 at approximately 50%. With respect to our natural gas production, increased production from our U.S. Marcellus assets is essentially offsetting production declines on our shallow and conventional natural gas assets in Canada.

We continue to expect 2012 production to average 83,000 BOE/day and production volumes to increase throughout the year exiting 2012 at approximately 88,000 BOE/day. This guidance does not contemplate any acquisitions or dispositions.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for the three months ended March 31, 2012 and 2011. It also compares the benchmark price indices for the same periods.

	Three months ended March 31,		
Average Selling Price[1]	**2012**	**2011**	**% Change**
Crude oil (per bbl)	$ 85.91	$ 77.69	11%
Natural gas liquids (per bbl)	56.77	60.29	(6)%
Natural gas (per Mcf)	2.27	3.91	(42)%
Per BOE	47.04	46.92	–%

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

	Three months ended March 31,		
Average Benchmark Pricing	**2012**	**2011**	**% Change**
WTI crude oil (US$/bbl)	$ 102.93	$ 94.10	9%
WTI crude oil CDN$ equivalent (CDN$/bbl)	102.93	92.22	12%
AECO natural gas – monthly index (CDN$/Mcf)	2.52	3.77	(33)%
AECO natural gas – daily index (CDN$/Mcf)	2.15	3.76	(43)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	2.77	4.14	(33)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	2.77	4.06	(32)%
USD/CDN exchange rate	1.00	0.98	2%

CRUDE OIL

Crude oil prices strengthened during the first quarter of 2012 averaging over US$100/bbl. Globally, geopolitical threats to supply continue to put upward pressure on price, especially in light of the low inventories outside of the U.S. However, the West Texas Intermediate ("WTI") price continues to be discounted relative to Brent pricing due to the lack of take-away infrastructure out of the U.S. Midwest. Crude oil inventories at Cushing rose significantly during the quarter and are now near record levels. As a result, light sweet differentials for both U.S. Bakken and Canadian light sweet crudes widened considerably at the end of the first quarter. Going forward we expect that increased rail capacity to move production out of the region will have a positive impact on pricing.

The average price received for our crude oil (net of transportation) in the first quarter of 2012 increased by 11% to $85.91/bbl from $77.69/bbl in the first quarter of 2011. In comparison the WTI benchmark expressed in CDN$/bbl increased by 12% over the same period. Light sweet differentials weakened and Canadian heavy differentials improved in the first quarter of 2012 compared to the first quarter of 2011.

NATURAL GAS

Natural gas prices continued to decline in the first quarter of 2012 with the lack of cold winter weather. The average AECO day price reached a low of $1.81/Mcf for the month of March. With high storage levels and continued strong U.S. production, summer natural gas prices are expected to remain low. Higher industrial demand and summer air conditioning power demand are the key factors that could have a positive impact on natural gas prices.

For the three months ended March 31, 2012 we sold our natural gas for an average price of $2.27/Mcf (net of transportation costs) which represented a 42% decline from the prices received during the same period of 2011. This decrease was similar to the decrease in the AECO daily index which affects a significant portion of our Canadian gas sales. As well due to an increase in supply in the region, our natural gas production in the Marcellus did not attract a premium to Nymex which it experienced through most of 2011.

Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. Consideration is also given to the cost of our risk management program as we seek to limit our exposure to price downturns. See Note 14 for further information regarding our current price risk management positions.

We have continued to add crude oil hedge positions for 2013. As of May 2, 2012 we have swapped 12,500 bbls/day at US$103.05/bbl, which represents approximately 42% of our forecasted net oil production after royalties for 2013.

We currently do not have any financial contracts with respect to our natural gas production. However, we have entered into physical fixed price natural gas transactions for 65,161 Mcf/day, or approximately 27% of our forecasted net natural gas production after royalties, at an average price of $2.17/Mcf for the period of April through October 2012.

The following is a summary of the financial contracts in place at May 2, 2012 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)	
	April 1, 2012 – December 31, 2012	**January 1, 2013 – December 31, 2013**
WTI Purchased Puts (floor prices)	$ 103.00	$ –
%	3%	–
WTI Sold Puts (limiting downside protection)	$ 65.00	$ 63.00
%	7%	3%
WTI Swaps (fixed price)	$ 95.83	$ 103.05
%	59%	42%
WTI Sold Calls (capped price)	$ 133.00	$ –
%	3%	–
WTI Purchased Calls (repurchasing upside)	$ 103.00	$ 102.95
%	3%	3%
Brent – WTI Spread	$ 13.75	$ –
%	11%	–
WTI 1st to 2nd Month Spread	$ –	$ 0.35
%	–	7%

Based on weighted average price (before premiums), estimated average annual production of 83,000 BOE/day (net of royalties of 21%) for 2012 and 2013.

ACCOUNTING FOR PRICE RISK MANAGEMENT

During the first quarter of 2012 we recorded $10.6 million of cash losses on crude oil contracts. In comparison, during the first quarter of 2011 we realized cash losses of $10.3 million on crude oil contracts and cash gains of $13.3 million on natural gas contracts. The crude oil cash losses in 2012 and 2011 are a result of crude oil prices rising above our fixed price swap positions. The cash gains in 2011 were due to natural gas contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At March 31, 2012 the fair value of our crude oil contracts, net of premiums, represented a loss of $36.6 million which is recorded as a current deferred financial credit on our balance sheet. At December 31, 2011 the fair value of our crude oil contracts represented a loss of $19.6 million. The change in the fair value of our contracts during the quarter resulted in unrealized losses of $17.0 million. See Note 14 for details.

The following table summarizes the effects of our risk management gains and losses:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended March 31, 2012**				**Three months ended March 31, 2011**			
Cash gains/(losses):								
Crude Oil	$	(10.6)	$	(3.42)/bbl	$	(10.3)	$	(3.77)/bbl
Natural Gas		–	$	–/Mcf		13.3	$	0.59/Mcf
Total cash gains/(losses)	$	(10.6)	$	(1.48)/BOE	$	3.0	$	0.44/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	(17.0)	$	(5.48)/bbl	$	(66.5)	$	(24.36)/bbl
Change in fair value – natural gas		–	$	–/Mcf		(12.6)	$	(0.56)/Mcf
Total non-cash gains/(losses)	$	(17.0)	$	(2.36)/BOE	$	(79.1)	$	(11.60)/BOE
Total gains/(losses)	$	(27.6)	$	(3.84)/BOE	$	(76.1)	$	(11.16)/BOE

Revenues

Crude oil and natural gas revenues were $339.0 million ($345.2 million, net of $6.2 million of transportation costs) in the first quarter of 2012, representing an increase of 6% or $20.3 million compared to $318.7 million ($324.0 million, net of $5.3 million of transportation costs) during the same period in 2011. Higher crude oil prices and production volumes in 2012 more than offset the impact of lower natural gas prices. Crude oil and liquids revenues accounted for approximately 85% of our corporate revenues during the quarter.

Analysis of Sales Revenue(1) ($ millions)		**Crude Oil**		**NGLs**		**Natural Gas**		**Total**
Quarter ended March 31, 2011	$	212.1	$	17.5	$	89.1	$	318.7
Price variance		25.5		(1.2)		(36.5)		(12.2)
Volume variance		28.8		4.4		(0.7)		32.5
Quarter ended March 31, 2012	$	266.4	$	20.7	$	51.9	$	339.0

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three months ended March 31, 2012 royalties increased to $66.7 million from $58.6 million in the same quarter of 2011 primarily due to an increased proportion of U.S. production where royalty rates are generally higher than on our Canadian production. As a percentage of oil and gas sales, net of transportation costs, royalties in the first quarter were 20% in 2012 compared to 18% in 2011. We continue to expect an average royalty rate of 21% in 2012.

Operating Expenses

Our operating costs for the three months ended March 31, 2012 were in line with expectations at $72.1 million or $10.00/BOE compared to $57.1 million or $8.40/BOE for the same quarter of 2011. We had increased well servicing and repairs and maintenance activity in Canada as well as in the Fort Berthold area during the first quarter of 2012 compared to the first quarter of 2011. Fluid handling costs in the U.S. also increased compared to the same period of 2011. In addition, we recorded a non-cash power hedging loss of $1.4 million during 2012 compared to a gain of $3.1 million in the first quarter of 2011.

We are maintaining our annual guidance of $10.40/BOE for operating costs during 2012.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three months ended March 31, 2012 and 2011. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day.

	Three months ended March 31, 2012		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	36,515 BOE/day	256,050 Mcfe/day	79,190 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 79.31	$ 3.24	$ 47.04
Royalties	(16.99)	(0.44)	(9.26)
Cash operating costs	(11.38)	(1.41)	(9.81)
Netback before hedging	$ 50.94	$ 1.39	$ 27.97
Cash gains/(losses)	(3.20)	–	(1.48)
Netback after hedging	$ 47.74	$ 1.39	$ 26.49
Netback before hedging ($ millions)	$ 169.3	$ 32.3	$ 201.6
Netback after hedging ($ millions)	$ 158.7	$ 32.3	$ 191.0

	Three months ended March 31, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	33,655 BOE/day	250,962 Mcfe/day	75,483 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 71.81	$ 4.48	$ 46.92
Royalties	(15.79)	(0.48)	(8.62)
Cash operating costs	(9.63)	(1.37)	(8.86)
Netback before hedging	$ 46.39	$ 2.63	$ 29.44
Cash gains/(losses)	(3.39)	0.59	0.44
Netback after hedging	$ 43.00	$ 3.22	$ 29.88
Netback before hedging ($ millions)	$ 140.4	$ 59.5	$ 199.9
Netback after hedging ($ millions)	$ 130.1	$ 72.8	$ 202.9

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Our crude oil properties accounted for 84% of our corporate netback before hedging during the first quarter of 2012 compared to 70% for the same period in 2011. Crude oil netbacks have increased in 2012 due to higher prices and increased production. Natural gas netbacks have decreased due to lower prices and lower hedging gains as our natural gas hedges expired on March 31, 2011.

General and Administrative ("G&A") and Equity Based Compensation Expenses

G&A expenses during the first quarter of 2012 were $20.7 million or $2.87/BOE compared to $17.0 million or $2.52/BOE in the first quarter of 2011. The increase in G&A is primarily related to additional technical staff that were added throughout 2011 to support our growing operations.

Equity based compensation expenses include our cash-based long-term incentive plans and non-cash expenses for our stock option plan (see Note 13 for further details). Our cash equity based compensation expenses were $1.6 million or $0.22/BOE compared to $5.2 million or $0.76/BOE in the first quarter of 2011. The significant decrease was due to our lower share price at March 31, 2012. Non-cash equity based compensation expenses were comparable to the same period in the prior year.

The following table summarizes our G&A and equity based compensation expenses:

G&A and Equity Based Compensation Expenses ($ millions)	Three months ended March 31, 2012	2011
G&A	$ 20.7	$ 17.0
Equity based compensation:		
Cash (long-term incentive plans)	1.6	5.2
Non-cash (stock option plan)	3.0	3.5
	4.6	8.7
Total G&A and Equity Based Compensation Expenses	$ 25.3	$ 25.7

(Per BOE)	Three months ended March 31, 2012	2011
G&A	$ 2.87	$ 2.52
Equity based compensation:		
Cash (long-term incentive plans)	0.22	0.76
Non-cash (stock option plan)	0.42	0.51
	0.64	1.27
Total G&A and Equity Based Compensation Expenses	$ 3.51	$ 3.79

We are maintaining our annual guidance for G&A and equity based compensation expenses for 2012 at $3.55/BOE.

Finance Expense

Interest on our senior notes and bank credit facility for the first quarter of 2012 totaled $10.8 million compared to $11.9 million in 2011. Although we had higher average debt levels in 2012 the impact of lower interest rates on our bank credit facility resulted in lower interest costs overall.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). See Note 10 for further details.

The following table summarizes the cash and non-cash finance expense:

Finance Expense ($ millions)	Three months ended March 31, 2012	2011
Interest on senior notes and bank credit facility	$ 10.8	$ 11.9
Non-cash finance expense	5.0	2.1
Total Finance Expense	$ 15.8	$ 14.0

At March 31, 2012, after including our underlying derivatives, approximately 41% of our debt was based on fixed interest rates while 59% had floating interest rates. In comparison, at March 31, 2011 approximately 51% of our debt was based on fixed interest rates and 49% was floating. We expect our percentage of fixed rate debt to increase upon the closing of our private placement of senior unsecured notes on May 15, 2012.

Foreign Exchange

We recorded a foreign exchange gain of $5.3 million during the quarter compared to a loss of $1.7 million for the first quarter of 2011. In both the first quarter of 2012 and 2011 the Canadian dollar strengthened relative to the U.S. dollar. Realized gains of $5.3 million in the first quarter of 2012 were primarily attributable to settlements of U.S. dollar denominated bank facility borrowings during the quarter. The realized foreign exchange loss of $7.3 million in the first quarter of 2011 mainly related to our U.S. dollar denominated receivables from our U.S. subsidiary.

During the first quarter of 2012 unrealized gains on the translation of our U.S. dollar debt offset unrealized losses on our CCIRS and foreign exchange swaps resulting in no overall reported unrealized amounts. In 2011 we had unrealized gains on our U.S. dollar debt of $11.9 million and unrealized losses on our CCIRS and foreign exchange swaps of $6.3 million for a total net unrealized gain of $5.6 million.

	Three months ended March 31,	
Foreign Exchange ($ millions)	**2012**	**2011**
Realized loss/(gain)	$ (5.3)	$ 7.3
Unrealized loss/(gain)	–	(5.6)
Total Foreign Exchange loss/(gain)	$ (5.3)	$ 1.7

Capital Investment

Capital spending for the first quarter of 2012 totaled $317.1 million compared to $174.4 million during the same period in 2011, representing an increase of $142.7 million. We had high activity levels in the first quarter focused predominantly on our key growth areas with $138.5 million directed toward development of our tight oil assets at Fort Berthold and $42.8 million on our crude oil waterflood properties. Capital spending on our Marcellus assets was $61.3 million focused primarily on drilling to delineate and retain leases. In aggregate we spent approximately $60 million on delineation activities across our plays during the first quarter which included drilling on our Stacked Mannville, Montney and Cardium acreage in Canada along with drilling on our operated Marcellus acreage in the U.S.

Going forward we expect activity and spending to moderate and we are continuing to manage toward our annual capital spending guidance of $800 million. In Fort Berthold we have high-graded the rig fleet (going from four to three rigs) and are testing different completion techniques in an effort to control costs. We believe that inflation has begun to stabilize in Fort Berthold and costs appear to be in line with expectations across all our other plays.

Property and land acquisitions for the first quarter of 2012 totaled $33.0 million compared to $48.2 million for the same period in 2011. The majority of our first quarter acquisitions related to undeveloped land acquisitions of $15.5 million along with US$16.1 million related to our Marcellus carry obligation. Our remaining carry obligation at March 31, 2012 was US$19.9 million. For 2012 we plan on spending $40 million on the acquisition of undeveloped land which we expect to fund through our disposition activity. Property and land acquisitions in the first quarter of 2011 related to undeveloped land acquisitions of $18.2 million and spending of US$29.2 million on our Marcellus carry obligation.

Dispositions during the first quarter of 2012 included transactions both in Canada and the U.S. In Canada we disposed of undeveloped land interests to Laricina Energy Ltd. in exchange for additional common shares in the company with a value of approximately $30.0 million. In the U.S. we disposed of non-core assets for proceeds of approximately $22.0 million. In aggregate we recognized gains of $24.1 million during the quarter on these dispositions. In the first quarter of 2011 we disposed of non-core assets for total proceeds of $59.7 million which resulted in a gain of $26.2 million.

Our total capital investment activity for the first quarter of 2012 and 2011 are outlined below:

	Three months ended March 31,	
Capital Investment ($ millions)	**2012**	**2011**
Exploration and Evaluation ("E&E") assets	$ 69.8	$ 95.3
Developed and Producing ("D&P") assets	247.3	79.1
Capital Spending	317.1	174.4
Office Capital	2.5	1.6
Sub-total	319.6	176.0
E&E asset acquisitions	31.9	47.5
D&P asset acquisitions	1.1	0.7
Property and Land Acquisitions	33.0	48.2
Property Dispositions	(52.6)	(59.7)
Total Net Capital Investment	$ 300.0	$ 164.5

Depletion, Depreciation and Amortization ("DD&A")

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended March 31, 2012 DD&A increased to $118.5 million or $16.45/BOE from $99.9 million or $14.70/BOE during the same period in 2011 primarily due to higher cost wells with respect to our U.S. operations resulting in higher depletion on a dollar per BOE basis.

Impairments

When indicators of impairment are present, tests are carried out on our Cash Generating Units ("CGU"s) to determine if D&P asset carrying values, including goodwill, are impaired. Our impairment test compares the CGU recoverable amount, which is estimated using proved plus probable reserves discounted at 10%, to the CGU carrying value. Calculated impairments are initially allocated to any goodwill carried by the CGU with the remainder recorded against its carrying value.

During the first quarter of 2012 forecast natural gas prices decreased from year end 2011 which resulted in our Canadian natural gas focused CGUs recording D&P asset impairments totaling $86.9 million. For the same quarter of 2011 D&P asset impairments of $32.4 million were also recognized in our Canadian natural gas CGUs due to lower price forecasts. Further fluctuations in forecast prices could cause additional impairments or impairment reversals going forward.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. The change in fair value of these investments for the quarter ended March 31, 2012 resulted in an unrealized loss of $4.8 million compared to an unrealized gain of $3.4 million for the same period last year. During the first quarter of 2012 we disposed of undeveloped land in exchange for $30.0 million in the form of additional common shares of Laricina Energy Ltd, a private oil sands company. At March 31, 2012 we held approximately five million common shares in Laricina.

Decommissioning Liabilities

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our decommissioning liability to be $533.5 million at March 31, 2012 compared to $563.8 million at December 31, 2011. The majority of this decrease relates to the increase in the risk-free rate used to calculate the present value of the future cash outflows, which increased to 2.66% at March 31, 2012 from 2.49% at December 31, 2011. See Note 9 for further information.

Taxes

Current Income Taxes

We recorded current taxes of $0.7 million for the quarter ended March 31, 2012 as compared to $0.8 million for the same period in 2011. Our current tax is comprised mainly of Alternative Minimum Tax ("AMT") payable by our U.S. subsidiary. We expect to recover this AMT in future years as an offset to regular U.S. income taxes otherwise payable.

We continue to expect to pay U.S. AMT up to a maximum of 5% of our U.S. cash flow in 2012 and 2013. We do not expect to pay material cash taxes in Canada until after 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. These estimates may vary depending on numerous factors, including but not limited to fluctuating commodity prices, production levels, capital spending and acquisition or disposition activity.

Deferred Income Taxes

Our deferred income tax recovery was $11.1 million for the quarter ended March 31, 2012 compared to a recovery of $50.4 million for the same period in 2011. Our 2011 recovery included a $34.1 million tax rate reduction related to our corporate conversion along with $8.8 million of previously unrecognized tax losses.

Net Income/(Loss)

We reported higher overall revenues in 2012 with increased production, oil prices and reduced losses on our commodity derivatives. However, in 2012 we also had higher non-cash impairment charges resulting from lower natural gas prices along with lower deferred income tax recoveries. These items more than offset the increase in revenues resulting in a net loss for the quarter.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three months ended March 31, 2012 and 2011.

	Three months ended March 31, 2012			Three months ended March 31, 2011		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,602	13,472	34,074	19,195	11,143	30,338
Natural gas liquids (bbls/day)	3,797	205	4,002	3,098	134	3,232
Natural gas (Mcf/day)	208,114	38,572	246,686	217,373	34,107	251,480
Total average daily production (BOE/day)	59,084	20,106	79,190	58,522	16,961	75,483
Pricing(1)						
Crude oil (per bbl)	$ 85.06	$ 87.20	$ 85.91	$ 75.24	$ 81.89	$ 77.69
Natural gas liquids (per bbl)	57.14	49.96	56.77	61.28	37.24	60.29
Natural gas (per Mcf)	2.11	3.14	2.27	3.69	5.28	3.91
Capital Expenditures						
Capital spending	$ 111.2	$ 205.9	$ 317.1	$ 92.2	$ 83.8	$ 176.0
Acquisitions	11.4	21.6	33.0	12.2	36.0	48.2
Dispositions	(30.7)	(21.9)	(52.6)	(59.7)	–	(59.7)
Revenues						
Oil and gas sales(1)	$ 220.0	$ 119.0	$ 339.0	$ 219.9	$ 98.8	$ 318.7
Royalties(2)	(35.7)	(31.0)	(66.7)	(33.7)	(24.8)	(58.5)
Commodity derivative instruments gain/(loss)	(27.7)	–	(27.7)	(76.1)	–	(76.1)
Expenses						
Operating	$ 60.1	$ 12.0	$ 72.1	$ 50.6	$ 6.5	$ 57.1
G&A and equity based compensation	21.7	3.6	25.3	22.3	3.4	25.7
Depletion, depreciation and amortization	80.7	37.8	118.5	78.8	21.1	99.9
Impairment	86.9	–	86.9	32.4	–	32.4
Current income taxes expense/(recovery)	(0.6)	1.3	0.7	–	0.8	0.8

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

Quarterly Financial Information

In the first quarter of 2012 higher crude oil prices and production volumes more than offset the impact of lower natural gas prices. During 2011 and 2010 higher crude oil prices were also offset by the decline in natural gas prices as well as a reduction in production levels due to our disposition activity. As a result, oil and gas sales year-over-year have remained relatively flat.

Net income was also affected by risk management costs along with the fluctuating Canadian dollar.

Quarterly Financial Information ($ millions, except per share amounts)	**Oil and Gas Sales**[(1)]	**Net Income/(Loss)**	**Net Income/(Loss) Per Share**	
			Basic	**Diluted**
2012				
First quarter	$ 339.0	$ (33.8)	$ (0.18)	$ (0.18)
2011				
Fourth Quarter	$ 357.3	$ (299.4)	$ (1.66)	$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
Total	$ 1,343.1	$ 109.4	$ 0.61	$ 0.61
2010				
Fourth Quarter	$ 313.2	$ 64.5	$ 0.37	$ 0.36
Third Quarter	305.5	(136.3)	(0.77)	(0.77)
Second Quarter	318.2	76.5	0.44	0.38
First Quarter	363.3	(184.0)	(1.05)	(1.08)
Total	$ 1,300.2	$ (179.3)	$ (1.02)	$ (1.02)

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

LIQUIDITY AND CAPITAL RESOURCES

We are continuing to manage our liquidity in the context of the current natural gas price environment and our 2012 capital spending plans. We have made progress managing our balance sheet through equity and debt issues during and subsequent to the first quarter. On February 8, 2012 we closed an equity offering of 14,708,500 common shares for net proceeds of $331 million. In addition, on May 15, 2012 we expect to close a private placement of senior unsecured notes for proceeds of approximately $405 million. The notes are to be issued in three separate tranches with terms ranging from seven to twelve years and interest rates from 4.34% to 4.40%. We intend to use the proceeds from the notes to repay advances on our bank credit facility.

We are also pursuing a number of other alternatives to manage our balance sheet. Subject to shareholder approval, we will be replacing our Dividend Reinvestment Program ("DRIP"), which is currently only available to Canadian shareholders, with a Stock Dividend Program ("SDP") that will be available to all shareholders. Additionally we plan to monetize $250 to $500 million of non-core assets in the next 18 months, which is expected to include selling our portfolio of equity investments along with a potential sale or joint venture with respect to some of our undeveloped acreage. We expect these alternatives would have a minimal impact on our 2012 production, reserves and cash flow. Should current commodity prices prevail and/or we do not make progress on these initiatives we may reduce our capital spending plans and growth expectations and/or reduce our dividend levels.

Total debt at March 31, 2012, including the current portion, was $904.4 million compared to $907.1 million at December 31, 2011. Total debt at March 31, 2012 was comprised of $451.0 million of bank indebtedness and $453.4 million of senior notes. Proceeds from our February equity offering and funds flow generated in the quarter offset our capital spending and dividends keeping our debt levels in line with December 31, 2011.

Our working capital deficiency at March 31, 2012, excluding cash and current deferred financial assets and credits, decreased by $73.0 million compared to December 31, 2011. The change in our working capital resulted from decreased accounts payable balances due to lower capital spending compared to the fourth quarter of 2011. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as dividends divided by funds flow, was 65% for the first quarter of 2012 compared to 60% for the first quarter of 2011. Our adjusted payout ratio, which is calculated as dividends plus capital spending and office capital divided by funds flow, was 262% for the first quarter of 2012 compared to 169% for the first quarter of 2011. Despite the higher adjusted payout ratio we continue to maintain a conservative balance sheet with a trailing twelve-month debt to funds ratio of 1.6x at March 31, 2012. Refer to "Non-GAAP Measures" section of this MD&A.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	March 31, 2012	December 31, 2011
Long-term debt to funds flow (12 month trailing)(1)(2)	1.6 x	1.6 x
Funds flow to interest expense (12 month trailing)(2)(3)	12.5 x	12.2 x
Long-term debt to long-term debt plus equity(1)	21%	22%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) See "Non-GAAP Measures" in this MD&A.
(3) Interest expense is finance expense excluding non-cash items.

Our unsecured, covenant-based, $1.0 billion bank credit facility will mature on October 13, 2014. Drawn fees under the facility range between 160 and 325 basis points over bankers' acceptance rates. We are currently paying 160 basis points over bankers' acceptance rates, which are trading around 1.2%, for a combined rate of 2.8%.

At March 31, 2012 we were in compliance with our debt covenants. Our bank credit facility and senior note purchase agreements have been filed as material documents on the Company's SEDAR profile at www.sedar.com.

Dividend Policy

During the first quarter of 2012 we paid $106.0 million ($0.54/share) in dividends to our shareholders. We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions. In the event that realized commodity prices remain at current levels and we do not make progress on our asset monetization efforts discussed above, then a dividend reduction may be considered.

During the quarter we announced a proposal to replace our current DRIP that was available only to Canadian shareholders with a SDP that will be available to all shareholders. The proposed SDP will allow shareholders to receive dividends in the form of shares of Enerplus at a 5% discount to the current weighted average price instead of a cash dividend. For Canadian and non-Canadian investors holding their shares in taxable accounts, the SDP is expected to have attractive tax attributes in comparison to a DRIP. Participation in the SDP will be completely optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. As with the DRIP, the SDP will serve as a source of capital for us by allowing us to retain cash that would otherwise be paid out as dividends. The implementation of the SDP requires approval of two-thirds of the shareholders voting at our Annual and Special Meeting taking place on May 11, 2012.

Shareholders' Capital

On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs). During the first quarter of 2012, a total of 595,000 shares (2011 – 629,000) were issued pursuant to the DRIP and the stock option plan, resulting in $13.3 million (2011 – $16.0 million) of additional equity for the company. For further details see Note 13.

We had 196,463,000 shares outstanding at March 31, 2012 compared to 179,278,000 shares outstanding at March 31, 2011. We had 181,159,000 shares outstanding at December 31, 2011. The weighted average basic number of shares outstanding for the three months ended March 31, 2012 was 189,844,000 (2011 – 178,832,000). At May 2, 2012 we had 196,660,000 shares outstanding.

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 14 and are based on forward markets as at April 30, 2012. The impact of a change in one factor may be compounded or offset by changes in other factors and this table does not consider the impact of any interrelationship among the factors. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2012 Funds Flow per Share(1)
Change of $0.50 per Mcf in the price of natural gas	$ 0.15
Change of US$5.00 per barrel in the price of crude oil	$ 0.10
Change of 1,000 BOE/day in production(2)	$ 0.04
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.04
Change of 1% in interest rate	$ 0.02

(1) Assumes 199,698,000 weighted average shares outstanding.
(2) Sensitivity is calculated in proportion to forecasted production mix.

2012 GUIDANCE

A summary of our 2012 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2012 Expectations	Target
Average annual production	83,000 BOE/day
Exit rate production	88,000 BOE/day
Capital spending	$800 million
Marcellus carry commitment spending	$37 million ($19.9 million remaining at the end of Q1 2012)
Exit production mix (volumes)	50% natural gas, 50% crude oil and liquids
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.40/BOE
G&A and equity based compensation expenses	$3.55/BOE
Average interest and financing costs	6%

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on January 1, 2012 and ending on March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2012 average and exit production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2012 and its impact on our production levels; the amount of our future abandonment and reclamation costs and decommissioning liabilities; our 2012 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund* *capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of future asset dispositions.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital and operating requirements and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves 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 including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in our MD&A for the year ended December 31, 2011 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 dated March 9, 2012, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 9, 2012 available on EDGAR at www.sec.gov.

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2012	December 31, 2011
Assets			
Current assets			
Cash		$ 1,453	$ 5,629
Accounts receivable		119,045	124,806
Deferred financial assets	14	899	2,312
Other current		24,201	14,655
		145,598	147,402
Exploration and evaluation assets	4	845,345	874,799
Property, plant and equipment	5	4,416,565	4,332,011
Goodwill		152,017	154,691
Deferred financial assets	14	6,533	6,585
Other assets	7	233,032	207,824
Total Assets		$ 5,799,090	$ 5,723,312
Liabilities			
Current liabilities			
Accounts payable		$ 351,582	$ 422,666
Dividends payable		35,363	32,609
Current portion of long-term debt	8	45,947	46,808
Deferred financial credits	14	54,295	35,711
		487,187	537,794
Long-term debt	8	858,443	860,286
Deferred financial credits	14	33,595	31,820
Deferred tax liability		435,452	452,670
Decommissioning liability	9	533,520	563,763
		1,861,010	1,908,539
Total Liabilities		2,348,197	2,446,333
Equity			
Shareholders' capital	13	3,786,906	3,442,364
Contributed surplus	13	29,258	26,910
Accumulated deficit		(419,283)	(279,467)
Accumulated other comprehensive income/(loss)		54,012	87,172
		3,450,893	3,276,979
Total Liabilities & Equity		$ 5,799,090	$ 5,723,312

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

Three months ended March 31 (CDN$ thousands) unaudited	Note	2012	2011
Revenues			
Oil and gas sales		$ 345,151	$ 324,002
Royalties		(66,726)	(58,553)
Commodity derivative instruments gain/(loss)	14	(27,654)	(76,127)
		250,771	189,322
Expenses			
Operating		72,063	57,075
General and administrative		20,720	17,067
Equity based compensation		4,575	8,664
Transportation		6,152	5,274
Depletion, depreciation and amortization	5	118,518	99,901
Impairments	6	86,906	32,394
Foreign exchange	11	(5,320)	1,662
Finance expense	10	15,798	14,007
Asset disposition (gain)/loss		(24,100)	(26,235)
Other expense/(income)		(342)	(407)
		294,970	209,402
Income/(loss) before taxes		(44,199)	(20,080)
Current tax expense/(recovery)	12	703	782
Deferred tax expense/(recovery)	12	(11,081)	(50,411)
Net Income/(loss)		$ (33,821)	$ 29,549
Other Comprehensive Income			
Change in fair value of available for sale financial instruments, net of tax	7	(4,176)	2,948
Change in cumulative translation adjustment		(28,984)	(31,165)
Other Comprehensive Income, net of tax		(33,160)	(28,217)
Total Comprehensive Income/(loss)		(66,981)	1,332
Net income/(loss) per share			
Basic		$ (0.18)	$ 0.17
Diluted		$ (0.18)	$ 0.16
Weighted average number of shares outstanding (thousands)	13		
Basic		189,844	178,832
Diluted		190,060	179,452

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Three months ended March 31 (CDN$ thousands) unaudited	2012	2011
Shareholders' Capital		
Balance, beginning of year	$ 3,442,364	$ 5,639,380
Reclassification of EELP units	–	44,387
Reclassification of accumulated deficit	–	(2,314,775)
Public offering	330,618	–
Stock option plan – cash	747	4,922
Stock option plan – non cash	644	4,753
Dividend Reinvestment Plan	12,533	11,078
Balance, end of period	$ 3,786,906	$ 3,389,745
Contributed Surplus		
Balance, beginning of year	$ 26,910	$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock option plan – exercised	(644)	(4,753)
Stock option plan – expensed	2,992	3,483
Balance, end of period	$ 29,258	$ 22,681
Accumulated Deficit		
Balance, beginning of year	$ (279,467)	$ (2,314,775)
Reclassification to Shareholders' Capital	–	2,314,775
Net income/(loss)	(33,821)	29,549
Dividends on common shares	(105,995)	(96,686)
Balance, end of period	$ (419,283)	$ (67,137)
Accumulated other comprehensive income		
Balance, beginning of year	$ 87,172	$ (22)
Change in fair value of available for sale financial instruments, net of tax	(4,176)	2,948
Change in cumulative translation adjustment	(28,984)	(31,165)
Balance, end of period	$ 54,012	$ (28,239)
Total Equity	$ 3,450,893	$ 3,317,050

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	2012	2011
Operating Activities		
Net income/(loss)	$ (33,821)	$ 29,549
Non-cash items add/(deduct):		
Depletion, depreciation and amortization	118,518	99,901
Impairments	86,906	32,394
Change in fair value of derivative instruments	21,824	80,777
Deferred tax expense/(recovery)	(11,081)	(50,411)
Foreign exchange (gain)/loss on U.S. dollar debt	(2,365)	(11,934)
Accretion expense	3,453	3,415
Equity based compensation – non cash	2,992	3,483
Amortization of debt transaction costs	380	285
Asset disposition (gain)/loss	(24,100)	(26,235)
	162,706	161,224
Decommissioning expenditures	(7,298)	(4,210)
Changes in non-cash operating working capital	(86,427)	(24,611)
Cash flow from operating activities	68,981	132,403
Financing Activities		
Issuance of shares	343,898	16,000
Dividends to shareholders	(105,995)	(96,686)
Change in bank debt	(229)	132,971
Changes in non-cash financing working capital	2,755	123
Cash flow from financing activities	240,429	52,408
Investing Activities		
Capital expenditures	(319,570)	(176,055)
Property and land acquisitions	(33,020)	(48,218)
Property dispositions	22,611	59,693
Changes in non-cash investing working capital	14,712	(25,265)
Cash flow from investing activities	(315,267)	(189,845)
Effect of exchange rate changes on cash	1,681	276
Change in cash	(4,176)	(4,758)
Cash, beginning of year	5,629	8,374
Cash, end of year	$ 1,453	$ 3,616
Supplementary Cash Flow Information		
Cash income taxes (received)/paid	$ 14,438	$ 123
Cash interest paid	$ 3,163	$ 4,467

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. REPORTING ENTITY

These interim condensed consolidated financial statements and notes ("interim Consolidated Financial Statements") present the results of Enerplus Corporation including its Canadian and U.S. subsidiaries.

Enerplus is a North American crude oil and natural gas exploration and development company, and is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada.

The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on May 10, 2012.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") for the three months ended March 31, 2012, and the 2011 comparative periods. They have been prepared in accordance with IAS 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board ("IASB"). These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2011. There have been no changes to the use of estimates or judgments since December 31, 2011.

3. SIGNIFICANT ACCOUNTING POLICIES

Enerplus' accounting policies are unchanged compared to December 31, 2011. There have been no new accounting pronouncements during the period. These interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2011.

4. EXPLORATION AND EVALUATION ("E&E") ASSETS

Carrying value ($ thousands)	**E&E assets**
At January 1, 2011	$ 1,545,378
Capital spending and acquisitions	620,172
Dispositions	(300,629)
Transfers to Property, Plant and Equipment	(969,036)
Impairment expense	(25,401)
Foreign currency translation adjustment	4,315
At December 31, 2011	$ 874,799
Capital spending and acquisitions	101,665
Dispositions	(23,478)
Transfers to Property, Plant and Equipment	(96,831)
Foreign currency translation adjustment	(10,810)
As at March 31, 2012	$ 845,345

As at March 31, 2012 the E&E asset balance of $845,345,000 (December 31, 2011 – $874,799,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability. The transfer of approximately $96,831,000 of E&E assets to PP&E for the three months ended March 31, 2012 primarily relates to U.S. Marcellus assets.

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

Carrying value before accumulated depletion and depreciation ($ thousands)	D&P assets	Office and other	Total
As at January 1, 2011	$ 4,253,439	$ 59,542	$ 4,312,981
Capital spending and acquisitions	500,748	11,264	512,012
Transfers from Exploration and Evaluation	969,036	–	969,036
Change in decommissioning costs (Note 9)	178,943	–	178,943
Dispositions	(38,613)	–	(38,613)
Foreign currency translation adjustment	41,306	210	41,516
As at December 31, 2011	$ 5,904,859	$ 71,016	$ 5,975,875
Capital spending and acquisitions	248,420	2,505	250,925
Transfers from Exploration and Evaluation	96,831	–	96,831
Change in decommissioning costs (Note 9)	(26,427)	–	(26,427)
Dispositions	(5,035)	–	(5,035)
Foreign currency translation adjustment	(29,107)	(118)	(29,225)
As at March 31, 2012	$ 6,189,541	$ 73,403	$ 6,262,944

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at January 1, 2011	$ 827,331	$ 45,082	$ 872,413
Depletion, Depreciation and Amortization	425,806	7,560	433,366
Impairment expense (Note 6)	334,302	–	334,302
Foreign currency translation adjustment	3,760	23	3,783
As at December 31, 2011	$ 1,591,199	$ 52,665	$ 1,643,864
Depletion, Depreciation and Amortization	116,930	1,588	118,518
Impairment expense (Note 6)	86,906	–	86,906
Foreign currency translation adjustment	(2,870)	(39)	(2,909)
As at March 31, 2012	$ 1,792,165	$ 54,214	$ 1,846,379

Net carrying value	D&P assets	Office and other	Total
As at January 1, 2011	$ 3,426,108	$ 14,460	$ 3,440,568
As at December 31, 2011	$ 4,313,660	$ 18,351	$ 4,332,011
As at March 31, 2012	$ 4,397,376	$ 19,189	$ 4,416,565

As at March 31, 2012 the Marcellus carry commitment balance remaining was US$19,868,000.

6. IMPAIRMENT

	Three months ended March 31	
($ thousands)	2012	2011
D&P assets	$ 86,906	$ 32,394
Impairment expense	$ 86,906	$ 32,394

The estimated recoverable amounts used for impairment testing were based on the respective assets value in use, calculated using proved plus probable reserves discounted at 10%. D&P asset impairments recorded for the three months ended March 31, 2012 and 2011 relate to natural gas focused cash generating units ("CGU"s) and reflect lower forecast natural gas prices.

The following table outlines forecasted commodity prices and exchange rates used in Enerplus' CGU impairment tests at March 31, 2012. The forecast commodity prices are consistent with those used by Enerplus' external reserve evaluators determined as of April 1, 2012.

Year	WTI Crude Oil[1] US$/bbl	Exchange Rate USD$/CDN$	Edm Light Crude[1] CDN$/bbl	U.S. Henry Hub Gas price[1] US$/Mcf	Natural Gas 30 day spot @ AECO[1] CDN$/Mcf
2012[2]	$ 100.00	$ 1.025	$ 97.60	$ 2.95	$ 2.65
2013	100.00	1.025	101.60	3.90	3.60
2014	100.00	1.025	101.50	4.55	4.20
2015	100.80	1.025	102.30	5.15	4.75
2016	101.70	1.025	103.20	5.60	5.15
Thereafter[3]	+2% yr	1.025	+2% yr	+2% yr	+2% yr

(1) Prices used in the impairments test were adjusted for commodity price differentials specific to Enerplus.
(2) Represents nine months remaining for 2012.
(3) Escalation varies after 2016.

7. OTHER ASSETS

Other assets of $233,032,000 (December 31, 2011 – $207,824,000) represent Enerplus' marketable securities portfolio. For the three months ended March 31, 2012 the change in fair value of these investments represented an unrealized loss of $4,792,000 ($4,176,000 net of tax). For the three months ended March 31, 2011 the change in fair value of these investments represented an unrealized gain of $3,432,000 ($2,948,000 net of tax).

8. DEBT

($ thousands)	March 31, 2012	December 31, 2011
Current:		
Current portion of long-term debt	$ 45,947	$ 46,808
	45,947	46,808
Long-term:		
Bank credit facility	$ 450,996	$ 446,182
Senior notes		
CDN$40 million (Matures June 18, 2015)	40,000	40,000
US$40 million (Matures June 18, 2015)	39,964	40,680
US$225 million (Matures June 18, 2021)	224,798	228,825
US$54 million (Matures October 1, 2015)[1][2]	32,371	32,951
US$175 million (Matures June 19, 2014)[1][3]	70,314	71,648
	858,443	860,286
Total debt	$ 904,390	$ 907,094

(1) A portion of which is classified as current.
(2) The outstanding U.S. principal as at March 31, 2012 was US$43,200,000.
(3) The outstanding U.S. principal as at March 31, 2012 was US$105,000,000.

On April 16, 2012 Enerplus announced a proposed offering of senior unsecured notes to be issued on a private placement basis in the United States and Canada with an aggregate principal amount of approximately $405,000,000. The notes will rank equally with the bank credit facility and other outstanding senior notes. Subject to the completion of customary closing conditions, the private placement is expected to close on May 15, 2012. The proceeds from the offering will be used to repay bank indebtedness.

9. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $533,520,000 as at March 31, 2012 compared to $563,763,000 at December 31, 2011, based on a total undiscounted liability of $640,090,000 and $644,922,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.66% at March 31, 2012 (December 31, 2011 – 2.49%). The majority of the change in estimates relates to changes in the risk free rate used to calculate the present value of the liability.

($ thousands)	March 31, 2012	December 31, 2011
Decommissioning liability, beginning of year	$ 563,763	$ 392,709
Change in estimates	(28,280)	174,807
Property acquisition and development activity	2,134	4,828
Dispositions	(281)	(692)
Capitalized decommissioning costs	(26,427)	178,943
Decommissioning expenditures	(7,298)	(21,656)
Accretion	3,453	13,803
Foreign currency translation adjustment	29	(36)
Decommissioning liability	$ 533,520	$ 563,763

10. FINANCE EXPENSE

	Three months ended March 31	
($ thousands)	2012	2011
Realized:		
Interest on bank debt and senior notes	$ 10,848	$ 11,900
Unrealized:		
Cross currency interest rate swap (gain)/loss	1,449	(832)
Interest rate swap (gain)/loss	(332)	(761)
Premium and transaction cost amortization	380	285
Accretion of decommissioning liability	3,453	3,415
Finance expense	$ 15,798	$ 14,007

11. FOREIGN EXCHANGE

	Three months ended March 31	
($ thousands)	2012	2011
Realized:		
Foreign exchange (gain)/loss	$ (5,280)	$ 7,259
Unrealized:		
Translation of U.S. dollar debt (gain)/loss	(2,365)	(11,934)
Cross currency interest rate swap (gain)/loss	2,061	3,927
Foreign exchange swaps (gain)/loss	264	2,410
Foreign exchange (gain)/loss	$ (5,320)	$ 1,662

12. INCOME TAXES

	Three months ended March 31	
($ thousands)	2012	2011
Current tax expense/(recovery)		
Canada	$ (633)	$ –
U.S.	1,336	782
Total current tax expense/(recovery)	$ 703	$ 782
Deferred tax expense/(recovery)	(11,081)	(50,411)
Total income tax expense/(recovery)	$ (10,378)	$ (49,629)

13. SHAREHOLDERS' CAPITAL

(a) Share Capital

Authorized unlimited number of common shares	Three months ended March 31 2012		Year ended December 31 2011	
Issued: (thousands)	Shares	Amount	Shares	Amount
Balance, beginning of year	181,159	$ 3,442,364	176,946	$ 5,639,380
Corporate Conversion:				
Reclassification of EELP units (non-cash)	–	–	1,703	44,387
Reclassification of Accumulated Deficit (non-cash)	–	–	–	(2,314,775)
Issued for cash:				
Pursuant to public offerings	14,709	330,618	–	–
Dividend reinvestment plan	552	12,533	1,928	52,375
Pursuant to stock option plan	43	747	582	11,626
Non-cash:				
Pursuant to stock option plan	–	644	–	9,371
Balance, end of period	196,463	$ 3,786,906	181,159	$ 3,442,364

On February 8, 2012 Enerplus issued 14,708,500 common shares for gross proceeds of $344,914,000 ($330,618,000 net of issuance costs).

(b) Dividends

For the three months ended March 31, 2012 Enerplus paid dividends of $0.18 per share per month for a total of $105,995,000.

(c) Equity Based Compensation

Equity based compensation includes Enerplus' stock option plan and its Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") long term incentive plans. The following table summarizes Enerplus' equity based compensation expense:

	Three months ended March 31	
($ thousands)	2012	2011
Stock option plan (non-cash)	$ 2,992	$ 3,483
Long term incentive plans (cash)	1,583	5,181
Equity based compensation expense	$ 4,575	$ 8,664

(i) Stock Option Plan

The following assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	March 31, 2012	December 31, 2011
Dividend yield(1)	7.7%	7.14%
Volatility(1)	30.2%	35.0%
Risk-free interest rate	1.47%	2.34%
Forfeiture rate	10%	9.4%
Expected life	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the life of the option which may differ from the volatility and dividend yield as at March 31, 2012.

The weighted average grant date fair value of options granted during the three months ended 2012 was $2.54 (March 31, 2011 – $4.38). At March 31, 2012, 3,337,000 options were exercisable at a weighted average reduced exercise price of $30.05 with a weighted average remaining contractual term of 3.9 years, giving an aggregate intrinsic value of $4,017,000 (March 31, 2011 – $11,503,000).

For the three months ended March 31, 2012, a total of 43,000 options were exercised at a weighted average reduced exercise price of $17.50. The weighted average share price during the period was $23.79.

For the three months ended March 31, 2012, Enerplus expensed a total of $2,992,000 related to its stock option plan. The total unamortized fair value of outstanding options of $12,740,000 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Three months ended March 31, 2012		Year ended December 31, 2011	
	Number of Options (000's)	Weighted Average Exercise Price[1]	Number of Options (000's)	Weighted Average Exercise Price[1]
Options outstanding				
Beginning of year	5,098	$ 29.41	5,457	$ 32.11
Granted	4,292	23.00	2,154	30.27
Exercised	(43)	17.50	(582)	19.97
Forfeited	(109)	27.29	(845)	33.22
Expired	–	–	(1,086)	47.05
End of period	9,238	$ 26.51	5,098	$ 29.41
Options exercisable at the end of period	3,337	$ 30.05	1,932	$ 33.86

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

The following table summarizes the Contributed Surplus activity:

($ thousands)	Three months ended March 31, 2012	Year ended December 31, 2011
Balance, beginning of year	$ 26,910	$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock option plan – exercised	(644)	(9,371)
Stock option plan – expensed	2,992	12,330
Balance, end of period	$ 29,258	$ 26,910

The following table summarizes the Contributed Surplus balance as at:

($ thousands)	March 31, 2012	December 31, 2011
Cancelled shares	$ 3,795	$ 3,795
Stock option plan	25,463	23,115
Balance, end of period	$ 29,258	$ 26,910

(ii) Long-term Incentive Plan

The following table summarizes the PSU, RSU and DSU activity for the three months ended March 31, 2012:

(thousands of units)	PSUs	RSUs	DSUs
Number of units, beginning of year	170	895	13.9
Granted	275	379	29.4
Settled	–	(480)	–
Forfeited	(4)	(28)	–
Number of units, end of period	441	766	43.3

(d) Basic and Diluted Earnings per Share

Net income per share has been determined based on the following:

	Three months ended March 31	
(thousands of shares)	2012	2011
Weighted average shares	189,844	178,832
Dilutive impact of options	216	620
Diluted shares	190,060	179,452

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Enerplus' non-derivative financial instruments include accounts receivable, accounts payable, marketable securities, dividends payable, bank indebtedness and long-term debt.

(i) Accounts Receivable, Accounts Payable, Dividends Payable, Bank Credit Facilities and Senior Notes

The carrying value of accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at March 31, 2012 and December 31, 2011 due to their short term nature. At March 31, 2012 the combined fair values of Enerplus' senior notes was $528,481,000 and the carrying amount was $453,394,000 (December 31, 2011 – fair value of $540,426,000 and carrying value of $460,912,000). The fair value of the senior notes was estimated by discounting future interest and principal payments using available market information at the balance sheet date.

(b) Fair Value of Derivative Financial Instruments

Derivative instruments are recorded at their estimated fair value using observable market inputs, other than quoted prices, at the balance sheet date. The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At March 31, 2012 a current deferred financial asset of $899,000, a current deferred financial credit of $54,295,000, a non-current deferred financial asset of $6,533,000 and a non-current deferred financial credit of $33,595,000 are recorded on the Consolidated Balance Sheet.

The following table summarizes the fair value as at March 31, 2012 and change in fair value for the three months ended March 31, 2012.

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Oil Commodity Derivative Instruments	Total
Deferred financial assets/(liabilities), beginning of year	$ (1,603)	$ (46,317)	$ 6,642	$ 2,255	$ (19,611)	$ (58,634)
Change in fair value gain/(loss)	332(1)	(3,510)(2)	(264)(3)	(1,356)(4)	(17,026)(5)	(21,824)
Deferred financial assets/(liabilities), end of period	**$ (1,271)**	**$ (49,827)**	**$ 6,378**	**$ 899**	**$ (36,637)**	**$ (80,458)**
Balance Sheet classification:						
Current assets/(liabilities)	$ (1,077)	$ (16,426)	$ (155)	$ 899	$ (36,637)	$ (53,396)
Non-current assets/(liabilities)	$ (194)	$ (33,401)	$ 6,533	$ –	$ –	$ (27,062)
Total	**$ (1,271)**	**$ (49,827)**	**$ 6,378**	**$ 899**	**$ (36,637)**	**$ (80,458)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (loss of $2,061) and finance expense (loss of $1,449).
(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 Enerplus' commodity derivative instruments:

	Three months ended March 31	
($ thousands)	2012	2011
Change in fair value of commodity derivative instruments gain/(loss)	$ (17,026)	$ (79,158)
Net realized cash gain/(loss)	(10,628)	3,031
Commodity derivative instruments gain/(loss)	$ (27,654)	$ (76,127)

(c) Risk Management

Commodity Price Risk

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties.

Crude Oil Instruments:

At March 31, 2012 the fair value of Enerplus' crude oil derivative contracts represented a liability of $36,637,000 and the change in fair value of these contracts during the first three months of 2012 represented an unrealized loss of $17,026,000.

The following table summarizes Enerplus' crude oil risk management positions at May 2, 2012:

Instrument Type	bbls/day	US$/bbl(1)
Apr 1, 2012 – Jun 30, 2012		
WTI Swap	17,500	95.83
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent – WTI Spread	3,500	13.82
Jul 1, 2012 – Dec 31, 2012		
WTI Swap	17,500	95.83
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent – WTI Spread	3,000	13.71
Jan 1, 2013 – Dec 31, 2013		
WTI Swap	12,500	103.05
WTI Purchased Call	1,000	102.95
WTI Sold Put	1,000	63.00
WTI 1st to 2nd Month Swap	2,000	0.35

(1) Swap transactions with a common term have been aggregated and presented as the weighted average price/bbl.

Enerplus has also sold a call swaption for 1,000 bbls/day for 2013 which gives the counterparty the option to buy a West Texas Intermediate ("WTI") swap from Enerplus at US$115/bbl.

Enerplus does not have any financial contracts with respect to natural gas production. Enerplus has entered into physical fixed price delivery sales contracts for 65,161 Mcf/day, or approximately 27% of our forecasted net gas production after royalties, at an average price of $2.17/Mcf from April 1, 2012 through to October 31, 2012.

Electricity:

Enerplus 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. At March 31, 2012 the fair value of Enerplus' electricity contracts represented an asset of $899,000 and the change in fair value of these contracts during the first three months of 2012 represented an unrealized loss of $1,356,000. The Company's outstanding electricity derivative contracts at May 2, 2012 are summarized below:

Instrument Type	MWh	CDN$/Mwh
Apr 1, 2012 – Dec 31, 2012		
AESO Power Swap	13.0	54.04
Jan 1, 2013 – Dec 31, 2013		
AESO Power Swap	6.0	70.63

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

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Corporate Director
Calgary, Alberta

David O'Brien(3)
Corporate Director
Calgary, Alberta

Elliott Pew(5)(8)
Corporate Director
Boerne, Texas

Glen D. Roane(4)(5)
Corporate Director
Canmore, Alberta

W. C. (Mike) Seth(3)(7)
President
Seth Consultants Ltd.
Calgary, Alberta

(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 Safety & Social Responsibility Committee
(12) Chairman of the Safety & Social Responsibility Committee

OFFICERS

ENERPLUS CORPORATION

Gordon J. Kerr
President & Chief Executive Officer

Ian C. Dundas
Executive Vice President & Chief Operating Officer

Ray J. Daniels
Senior Vice President, Operations

Eric G. Le Dain
Senior Vice President, Strategic Planning, Reserves, & Marketing

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

Rodney D. Gray
Vice President, Finance

Robert A. Kehrig
Vice President, Resource Development

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

Brien A. Perry
Vice President, Human Resources

Patrick "Scott" Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

ENERPLUS RESOURCES (USA) CORPORATION

Edwin L. McLaughlin
President

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Partnership
Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

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

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

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

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

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

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ABBREVIATIONS

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AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices

AOCI accumulated other comprehensive income

API American Petroleum Institute

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

Bcf billion cubic feet

Bcfe billion cubic feet equivalent

BOE barrels of oil equivalent

Brent Crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

CTA cumulative translation adjustment

D&P developed and producing

E&E exploration and evaluation

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

HH "Henry Hub" a reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent purposes

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

Mcf/day thousand cubic feet per day

Mcfe/day thousand cubic feet equivalent per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMBtu/day million British Thermal Units per day

MMcf million cubic feet

MMcf/day million cubic feet per day

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserve reporting in Canada)

OCI other comprehensive income

PDP Reserves proved developed producing reserves

P+P Reserves proved plus probable reserves

RLI reserve life index

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WI percentage working interest ownership

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

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